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P.O. Box 1188
Houston, TX 77251-1188

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BUREAU OF AIR REGULATION

January 26, 2001

Mr. Al Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Deerfield Beach Energy Center, LLC
Permit Application for Deerfield Beach Energy Center

Dear Mr. Linero:

On behalf of Deerfield Beach Energy Center, LLC, enclosed are four (4) copies of an air permit application for the Deerfield Beach Energy Center in Broward County, Florida. This application is for a PSD permit for a simple cycle combustion turbine power plant consisting of 3 General Electric 7FA dual-fuel units. Also enclosed is a CD-ROM containing the modeling archive required for your review. Separate copies of this application are being sent to the Southeast District of the Florida DEP as well as the Broward County Air Quality Division. An application processing fee has not been enclosed. Due to previously-submitted and withdrawn applications, Enron North America believes that it has an existing positive fee balance with the Florida Department of Environmental Management.

If you have any questions, please don't hesitate to call me at (713) 853-3161.

Sincerely,
Enron North America

David A. Kellermeyer

David A. Kellermeyer
Director

Enclosures

cc: Mr. Lennon Anderson, Southeast District
Mr. Jarrett Mack, Air Quality Division, Broward County

Deerfield Beach Energy Center, LLC

Houston, TX

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PSD Permit Application for the Deerfield Beach Energy Center

ENSR International
January 2001
Document Number 6792-140-200R

CONTENTS

1.0 INTRODUCTION 1-1

1.1 Application Summary 1-1

1.2 General Applicant Information 1-2

1.2.1 Applicant's Address 1-2

1.2.2 Applicant's Contacts 1-3

1.3 Project Location 1-3

1.4 Document Organization 1-4

2.0 PROJECT DESCRIPTION 2-1

2.1 Power Generation Facility 2-1

2.2 Major Facility Components 2-2

2.2.1 Gas Turbines 2-2

2.2.2 Simple-Cycle 2-4

2.2.3 Fuel Gas System 2-4

2.2.4 Distillate Oil Storage 2-5

2.2.5 Cooling Towers 2-5

2.2.6 Ancillary Facilities 2-5

3.0 PROJECT EMISSIONS 3-1

3.1 Combustion Turbines 3-1

3.1.1 Criteria Pollutants 3-1

3.1.2 Non-Criteria Pollutants 3-2

3.2 Natural Gas Fuel Heater 3-4

3.3 Cooling Towers 3-5

3.4 Fugitive Emissions 3-5

3.5 Total Project Criteria Pollutant Emission Summary 3-5

4.0 APPLICABLE REGULATIONS AND STANDARDS 4-1

4.1 Prevention of Significant Deterioration 4-1

4.2 NSPS 4-3

4.3 NESHAPS 4-4

4.4 Acid Rain 4-4

CONTENTS (Cont'd)

4.5 CAA Operating Permit Program 4-4

4.6 State SIP Rules 4-5

5.0 CONTROL TECHNOLOGY EVALUATION 5-1

5.1 Introduction 5-1

5.1.1 Top-Down BACT Approach 5-1

5.1.2 Cost Determination Methodology 5-2

5.1.3 Capital Costs 5-2

5.2 Previous BACT/LAER Determinations for Simple-Cycle Combustion Turbines 5-6

5.2.1 Base Load Power (Combined-Cycle) 5-6

5.2.2 Peaking Power (Simple-Cycle) 5-7

5.2.3 BACT Determinations for Simple-Cycle Combustion Turbines 5-8

5.2.4 Combustion Turbine Fuel Use 5-8

5.3 BACT for Nitrogen Oxides (NO_x) 5-9

5.3.1 Formation 5-9

5.3.2 Front – End Control 5-9

5.3.3 Back – End Control 5-10

5.3.4 Gas Turbines - Ranking of Available Control Techniques 5-13

5.3.5 Natural Gas Fuel Heater 5-18

5.4 BACT for Carbon Monoxide 5-18

5.4.1 Formation 5-18

5.4.2 Gas Turbines-Ranking of Available Control Techniques 5-19

5.4.3 Natural Gas Fuel Heater 5-24

5.5 BACT for Particulate Matter and Trace Metals 5-24

5.5.1 Formation 5-24

5.5.2 Gas Turbines 5-25

5.5.3 Natural Gas Fuel Heater 5-25

5.6 BACT for Sulfur Dioxide and Sulfuric Acid Mist 5-25

5.6.1 Formation 5-25

5.6.2 Gas Turbines and Fuel Gas Heater 5-26

5.7 Summary and Conclusions 5-26

6.0 AMBIENT AIR QUALITY IMPACT ANALYSIS 6-1

6.1 Overview of Analysis Methodology 6-1

CONTENTS (Cont'd)

6.2 Model Selection 6-1

6.2.1 Physical Source Geometry 6-1

6.2.2 Dispersion Environment 6-4

6.2.3 Terrain Considerations 6-4

6.3 Model Application 6-5

6.3.1 Meteorological Data 6-5

6.3.2 Model Receptor Grid 6-5

6.3.3 Physical Source and Emissions Data 6-8

6.4 Ambient Impact Criteria 6-8

6.5 Results of Ambient Air Quality Impact Analysis 6-13

6.6 Broward County Air Modeling Requirement 6-16

7.0 ADDITIONAL IMPACTS 7-1

7.1 Vegetation and Soils 7-1

7.2 Associated Growth 7-2

7.3 Class I Area Impact Analysis 7-2

APPENDICES

A FLORIDA DEP APPLICATION FORMS

B EMISSION CALCULATIONS

C BACT SUPPORTING INFORMATION

D BPIP MODEL OUTPUT FILE

E DETAILED ISCST3 MODELING RESULTS

F KEY TO ISCST3 MODELING FILES ON CD-ROM

G BROWARD COUNTY POLLUTION PREVENTION PLAN

LIST OF TABLES

Table 3-1 Hourly Emission Rate Summary for the DBEC Combustion Turbines 3-3

Table 3-2 Annual Emission Summary for the DBEC Combustion Turbines 3-4

Table 3-3 Facility HAP Emission Summary 3-4

Table 3-4 Criteria Pollutant Emissions Summary for the Fuel Heater 3-4

Table 3-5 Project Hourly Emissions (lb/hr) Summary, Criteria Pollutants, DBEC 3-6

Table 3-6 Project Annual Emissions (tons/yr) Summary, Criteria Pollutants, DBEC 3-6

Table 4-1 Project PTE (TPY) Criteria Pollutant Emissions Summary, Deerfield Beach Energy Center 4-2

Table 4-2 Project PTE Non-Criteria Pollutant Emissions Summary 4-4

Table 5-1 Capital Cost Estimation Factors 5-3

Table 5-2 Annualized Cost Factors 5-5

Table 5-3 Ranking of NO_x Control Technologies for a Dual Fuel Simple-Cycle Peaking Turbine 5-13

Table 5-4 US EPA National Simple Cycle PSD Turbine Projects 5-14

Table 5-5 High Temperature Oxidation Catalyst (Carbon Monoxide) General Electric, Simple-Cycle, Model 7 FA 5-22

Table 5-6 Summary of Selected BACTs 5-27

Table 6-1 Summary of GEP Analysis (Units in Feet) 6-4

Table 6-2 Combustion Turbine Performance Data for Natural Gas and Distillate Fuel Oil Operation 6-9

Table 6-3 Worst-Case Turbine Stack Data for Dispersion Modeling 6-11

Table 6-4 Ambient Impact Criteria[1] 6-12

Table 6-5 ISCST3 Modeling Results for Natural Gas 6-14

Table 6-6 ISCST3 Modeling Results for Distillate Oil 6-15

Table 6-7 Comparison of Maximum ISCST3 Concentrations to Class II Significant Impact Levels 6-16

Table 6-8 Compliance Demonstration for Broward County Code Section 27.176(c)(2)(b) 6-17

Table 6-9 Ozone Compliance Demonstration for Broward County Code Section 27.176(c)(2)(b) 6-18

LIST OF TABLES (Cont'd)

Table 7-1 Comparison to U.S. EPA Criteria for Gaseous Pollutant Impacts on Natural Vegetation and Crops 7-2

LIST OF FIGURES

Figure 1-1 Site Plan 1-5

Figure 1-2 Plot Plan 1-6

Figure 2-1 Process Flow Diagram - Simple Cycle Combustion Turbines – Deerfield Beach Energy Center 2-3

Figure 6-1 Location of Turbine Stacks Relative to Structures Included in the GEP Analysis 6-3

Figure 6-2 Near-Field Receptor Locations 6-6

Figure 6-3 Far-Field Receptors 6-7

1.0 INTRODUCTION

1.1 Application Summary

Deerfield Beach Energy Center, LLC is proposing to construct and operate a 510 MW (nominal) simple-cycle combustion turbine peaking electric generating facility in Broward County. The facility, to be known as the Deerfield Beach Energy Center (DBEC), will be located on approximately 30 acres of property in Deerfield Beach, Florida. From an air emissions perspective, the key elements of the proposed action include:

- Three (3) combustion turbines;
- Natural gas fuel heater;
- Two distillate oil storage tanks; and
- Nine (9) chiller units, each with a two (2) cell wet mechanical draft cooling tower

Deerfield Beach Energy Center, LLC desires to commence construction as early as April 2001 and begin commercial operation as soon as May 1, 2002 (pending receipt of all necessary local and environmental approvals).

As part of its application, the Deerfield Beach Energy Center is requesting flexibility regarding the ability to burn 1,000 hours per year of oil. While the intention is to burn natural gas at every opportunity, near term constraints on the Florida Gas Transmission ("FGT") pipeline may impede the ability to burn natural gas during periods of peak demand often associated with the summer season. In general, the FGT natural gas transmission line flows near its maximum pipeline capacity of 1.5 Bcf/day during the summer season. In order to accommodate the demand for incremental generation within the state of Florida, FGT plans to expand its pipeline capacity by approximately 600,000 MMbtu/day before the summer of 2002. Additionally, FGT is in active discussions with potential shippers to perform another expansion of its pipeline in 2003. The addition of this capacity should reduce periods of pipeline constraint and will result in an increased availability of natural gas to the proposed site. The request for oil burning flexibility is necessitated by near term FGT capacity constraints and is not due to deficient gas supplies received by FGT. Moreover, operational guidelines dictate that natural gas be the primary fuel source and that oil will be used as a backup fuel to the extent that transmission capacity constraints on FGT pipeline preclude the delivery of natural gas to the site.

Since the proposed action will be a major stationary source under the Part C of the Clean Air Act, DBEC is applying to the Florida Department of Environmental Protection (FDEP) for a Prevention of Significant Deterioration (PSD) permit and for a State Air Construction Permit. This application provides technical analyses and supporting data for a permit to construct the facility under the federal PSD program, as well as the state construction permit program. The federal PSD program in Florida is administered by the FDEP under a State Implementation Plan program approved by U.S. EPA under 40 CFR 51.166.

This application addresses the air construction permitting requirements specified under the provision of Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The application is divided into seven additional sections. Section 2.0 presents an overview of the proposed action and processes covered by this permit application. Section 3.0 describes the methods used to calculate facility emissions and provides a summary of expected emissions. Section 4.0 reviews the regulatory requirements with which the facility must comply. Section 5.0 presents a control technology evaluation for those pollutants subject to PSD review. Section 6.0 presents the air dispersion modeling analysis required by PSD and FDEP regulations. Finally, Section 7.0 provides the additional impacts analysis required by PSD regulations.

FDEP application forms are located in Appendix A. Supporting emission calculations are presented in Appendix B. Information supporting the control technology review is presented in Appendix C. BPIP output data for establishing modeling downwash parameters is presented in Appendix D. Appendix E provides a description of the dispersion modeling input data and output files, which have been submitted to FDEP on CD-ROM.

General information about the applicant and the location of the project site, are presented below. A more detailed discussion on the organization of this document is also presented. To facilitate FDEP's review of this document, individuals familiar with both the facility and the preparation of this application have been identified in the following section. FDEP should contact these individuals if additional information or clarification is required during the review process.

1.2 General Applicant Information

Listed below are the applicant's primary points of contact, and the address and phone number where they can be contacted. Since this permit application has been prepared by a third party under the direction of Deerfield Beach Energy Center, LLC, a contact has been included for the permitting consultant.

1.2.1 Applicant's Address

<u>Corporate Office</u> Deerfield Beach Energy Center, LLC
1400 Smith Street
Houston, TX 77002-7631

Project Site	Deerfield Beach Energy Center West of the intersection of N. Powerline Rd. and NW 48th St. and east of the Florida Turnpike Deerfield Beach, FL 33069

1.2.2 Applicant's Contacts

Corporate Officer	Ben Jacoby Director 1400 Smith Street Houston, TX 77002-7631
Environmental Contact	Dave Kellermeyer Director 1400 Smith Street, EB-3146C Houston, TX 77002-7631 Telephone: (713) 853-3161 Fax: (713) 646-3037
Permitting Consultant	Robert Iwanchuk Project Manager ENSR International 2 Technology Park Drive Westford, MA 01886 Telephone (978) 589-3265 Fax (978) 589-3374

1.3 Project Location

The Deerfield Beach Energy Center will be located on an approximately 30-acre parcel of land located in Deerfield Beach, Broward County, Florida. The site is located West of intersection of N. Powerline Road and NW 48th Street and east of the Florida Turnpike. The facility will be connected to electrical transmission lines and a natural gas pipeline located in close proximity to the site. The approximate project property boundary and local road network is shown on Figure 1-1. A detailed representation of the property boundary is shown on the plot plan drawing contained in Figure 1-2. The site is clear and contains low topographic relief.

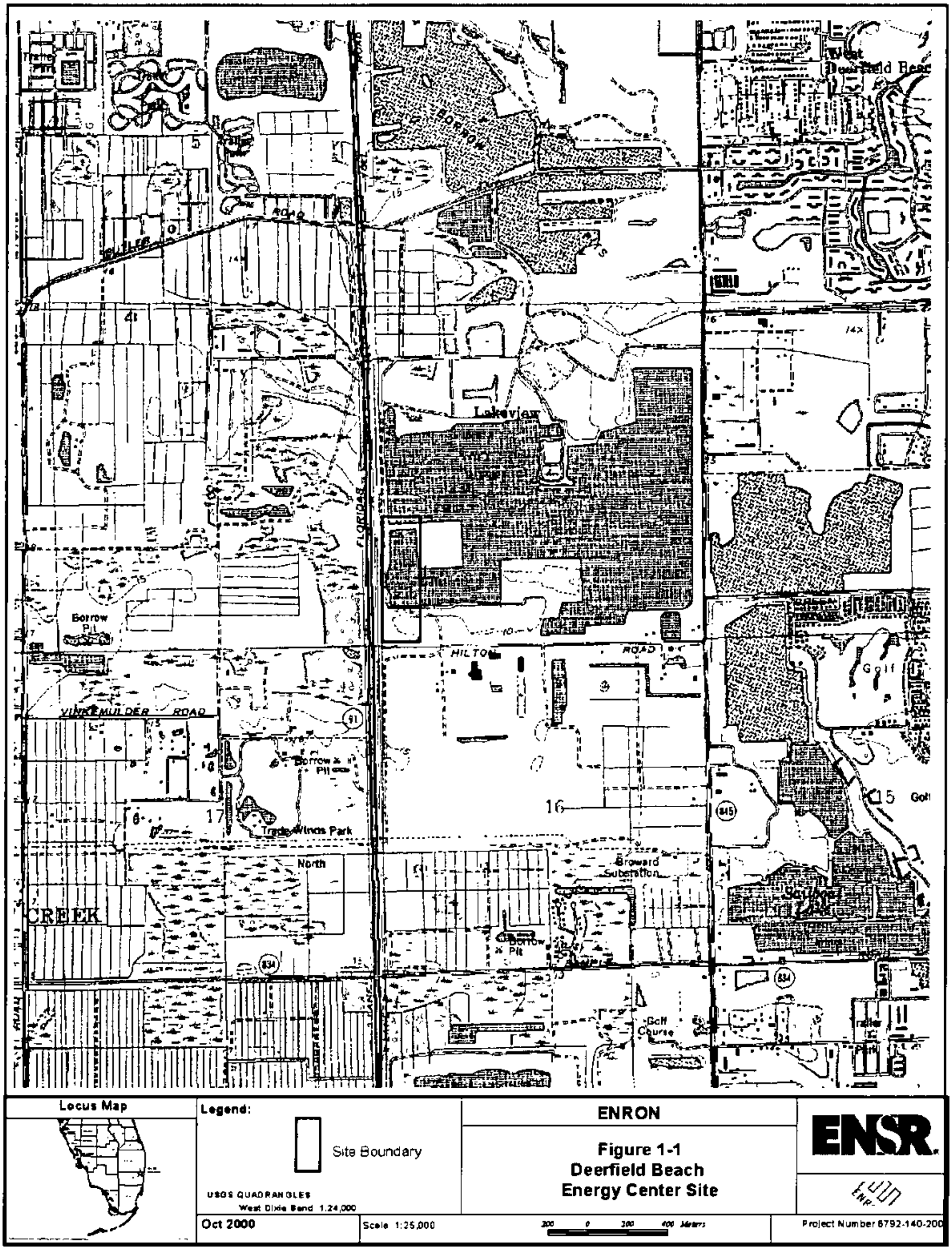
Benchmark Universal Transverse Mercator (UTM) coordinates for the plant, corresponding to the middle combustion turbine stack location shown in Figure 1-2 and the power island grade elevation are as follows:

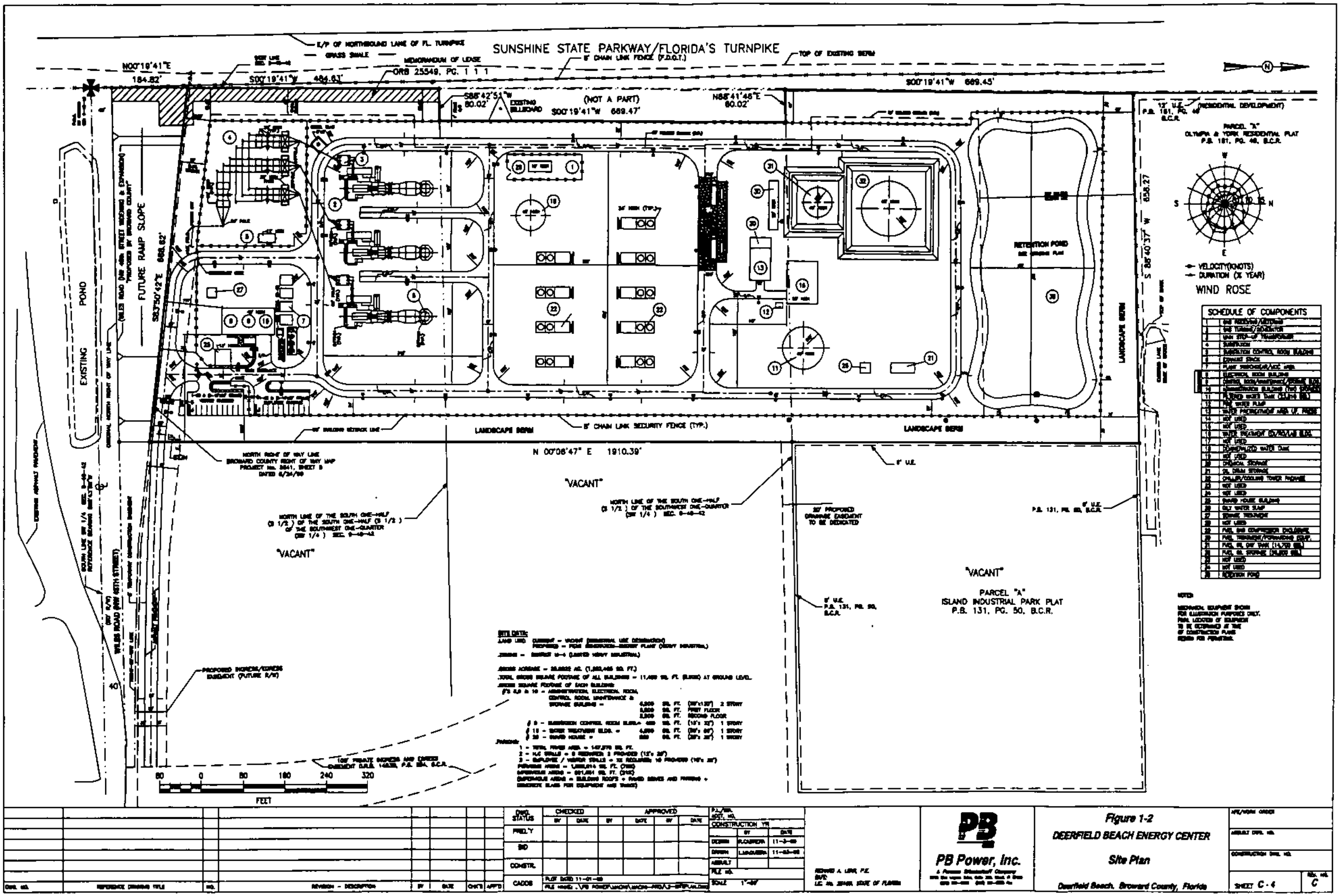
Zone Number	17
Northing (m)	2907940.00
Easting (m)	583074.00
Site Elevation (ft msl)	10

1.4 Document Organization

The balance of this document is divided into sections which address the major issues of a preconstruction air quality permit review. The outline below provides an overview of the contents of each of the remaining sections.

Figure 1-1 Site Plan





SUNSHINE STATE PARKWAY/FLORIDA'S TURNPIKE
N00°19'41"E
184.82'
S00°19'41"W 464.63'
ORB 25549, PG. 1 1 1
S00°19'41"W 669.45'
S88°42'51"W
80.02'
(NOT A PART)
S00°19'41"W 669.47'
N88°41'48"E
80.02'
EXISTING POND
FUTURE RAMP SLOPE
S83°50'42"E 668.82'
RETENTION POND
LANDSCAPE BERM
8' CHAIN LINK SECURITY FENCE (TYP.)
N 00°06'47" E 1910.39'
"VACANT"
"VACANT"
"VACANT"
PARCEL "A"
ISLAND INDUSTRIAL PARK PLAT
P.B. 131, PG. 50, B.C.R.
VELOCITY(KNOTS)
DURATION (% YEAR)
WIND ROSE
SCHEDULE OF COMPONENTS
FEET
Figure 1-2
DEERFIELD BEACH ENERGY CENTER
Site Plan
Deerfield Beach, Broward County, Florida
PB Power, Inc.
SHEET C-4

- **Section 2.0 - Project Description** provides an overview of the facility including major facility components. A general description of the Simple-Cycle process by which power will be produced at this site is presented.

- **Section 3.0 - Emissions Summary** presents a detailed review of the emissions which will be generated at the project site subsequent to the completion of project development, under normal operating conditions. The basis and methods used to calculate emissions from the project are presented.

- **Section 4.0 - Applicable Regulations and Standards** presents a detailed review of both Federal and State regulations. The focus of this section will be on establishing which regulations are directly applicable to the proposed project and for which compliance must be demonstrated.

- **Section 5.0 - Control Technology Evaluation** is a substantial requirement for the PSD application. Since the proposed project will result in a significant increase in the emission of certain criteria pollutants, as defined under PSD regulations, a detailed review of control technologies is provided. Annual "Potential-to-Emit" (PTE) emissions, as defined by FDEP, are expected to be significant for Carbon Monoxide (CO), Particulate Matter ($PM\backslash PM_{10}$), Sulfur Dioxide (SO_2) Nitrogen Oxides (NO_x) and Sulfuric Acid Mist (H_2SO_4). Therefore, control technology analyses for these pollutants have been prepared. The review conforms to the EPA's Top-Down protocol.

- **Section 6.0 - Air Dispersion Modeling Analysis** provides the results of the air quality impact assessment required under the PSD regulations to demonstrate compliance with National Ambient Air Quality Standards (NAAQS), PSD Class II Increments, and the significant impact levels defined for them. The air quality impact analysis predicted no significant impacts; therefore no further modeling for compliance with the NAAQS and PSD increments was required. The air dispersion modeling was done in conformance with EPA modeling guidelines. This section also includes cumulative modeling analysis required by the Broward County Department of Planning and Environmental Protection.

- **Section 7.0 - Additional Impacts** contains supplemental information regarding the potential impacts of the project. Specifically this section discusses the potential for impacts on local soils, vegetation, visibility, and growth related air quality impacts. PSD Class I area assessments of regional haze, increment and deposition impacts using the CALPUFF dispersion model will be submitted as a supplement to this permit application.

- **Section 8.0 - References** include a list of the documents relied upon during the preparation of this document.

- **Appendix** - Permit application forms, emission calculations, and supplemental materials supporting the information presented herein are contained in the appendices to this document. Modeling results, both input and output files, are provided on the enclosed CD-ROM.

The pollution prevention plan required by the Broward County Department of Planning and Environmental Protection, under the provisions of Broward County Code, Sec.27-178, is also presented in the appendix.

2.0 PROJECT DESCRIPTION

The following section provides an overview of the facility addressed by this permit application. The facility will be owned and operated by Deerfield Beach Energy Center, LLC. The proposed project is a dual fuel Simple-Cycle merchant power plant to be located in Deerfield Beach, Florida. A merchant power plant is a non-utility generation facility designed to produce power within the emerging deregulated electricity market. The Deerfield Beach Energy Center is designed to have a nominal generating capacity in the range of 510 MW. Commercial operation is scheduled to commence by May 1, 2002. As a merchant plant in a deregulated electricity market, the DBEC is being designed to convert fuel to useful power quickly, cleanly, and reliably.

As part of its application, the Deerfield Beach Energy Center is requesting flexibility regarding the ability to burn 1,000 hours per year of oil. While the intention is to burn natural gas at every opportunity, near term constraints on the Florida Gas Transmission ("FGT") pipeline may impede the ability to burn natural gas during periods of peak demand often associated with the summer season. In general, the FGT natural gas transmission line flows near its maximum pipeline capacity of 1.5 Bcf/day during the summer season. In order to accommodate the demand for incremental generation within the state of Florida, FGT plans to expand its pipeline capacity by approximately 600,000 MMbtu/day before the summer of 2002. Additionally, FGT is in active discussions with potential shippers to perform another expansion of its pipeline in 2003. The addition of this capacity should reduce periods of pipeline constraint and will result in an increased availability of natural gas to the proposed site. The request for oil burning flexibility is necessitated by near term FGT capacity constraints and is not due to deficient gas supplies received by FGT. Moreover, operational guidelines dictate that natural gas be the primary fuel source and that oil will be used as a backup fuel to the extent that transmission capacity constraints on FGT pipeline preclude the delivery of natural gas to the site

2.1 Power Generation Facility

The DBEC will include three (3) General Electric 7FA combustion turbine generators (CTGs) operating in Simple-Cycle mode. The CTGs will be designed to operate on both natural gas and low-sulfur diesel oil. Dry, low NO_X combustors will be used to minimize NO_X formation during combustion, and water injection will be employed during diesel oil-firing to reduce NO_X emissions. Each turbine will be equipped with its own exhaust stack.

The proposed generation facility will utilize the Best Available Control Technology (BACT), as defined by U.S. EPA, for NO_X, CO, SO_2, Sulfuric Acid Mist, and PM/PM_{10} to minimize air emissions. The project will not be a major source of hazardous air pollutants.

2.2 Major Facility Components

The primary source of criteria pollutants associated with the DBEC are the three combustion turbine generators which exhaust through three separate stacks. A process flow diagram for a simple-cycle combustion turbine is shown in Figure 2-1. There will be a minor amount of emissions associated with the plant's ancillary facilities, including the two diesel fuel storage tanks, a fuel gas heater, and a chiller system with nine small mechanical draft cooling towers for cooling the inlet air to the turbines during high ambient temperature conditions. A brief description of the major components of the facility is provided in the following sections.

Operating parameters for the combustion turbine at three loads (100%, 75%, 50%), and four ambient temperatures (30°F, 42°F, 50°F, 91°F), are presented in Appendix B. This covers the expected operating range of the facility.

2.2.1 Gas Turbines

DBEC proposes to install three (3) General Electric combustion turbine generators in Simple-Cycle mode with independent exhaust stacks. Each turbine will include an advanced firing combustion turbine air compressor, gas combustion system (dry, low NO_X combustors), power turbine, and a 60-hertz (Hz), 13.8 kilovolt (kV) generator. The turbines will run predominantly on pipeline-quality natural gas, but will have the capability to operate on diesel oil. Each turbine is designed to produce a nominal 170 MW of electrical power.

The power output from a combustion turbine generator (CTG) is proportional to the mass flow rate of air and fuel through the expansion (power) turbine. Thus at high ambient temperatures the power available from a CTG is significantly reduced due to the lower density of the inlet air. As the CTG's proposed are intended to provide peak power generation, in an area where ambient temperatures frequently rise above 80°F, the CTG's have been equipped with inlet air chilling equipment. At high ambient temperatures, inlet air chillers will be operated to cool the inlet air to the turbines in order to compensate for the loss of power output due to lower compressor inlet density. At an ambient temperature of 91°F, chilling will reduce the compressor inlet temperature to 50°F resulting in an approximately 24 MW increase in gross power output per CTG unit.

The gas turbine is the heart of a Simple-Cycle power system. First, air is filtered and compressed in a multiple-stage axial flow compressor. Compressed air and natural gas are mixed and combusted in the turbine combustion chamber. Dry, low NO_X combustors and water injection are used to minimize NO_X formation during combustion, depending on which fuel is fired. Exhaust gas from the combustion chamber is expanded through a multi-stage power turbine which drives both the air compressor and electric generator. The exhaust exits the power turbine at atmospheric pressure and approximately 1,100°F.

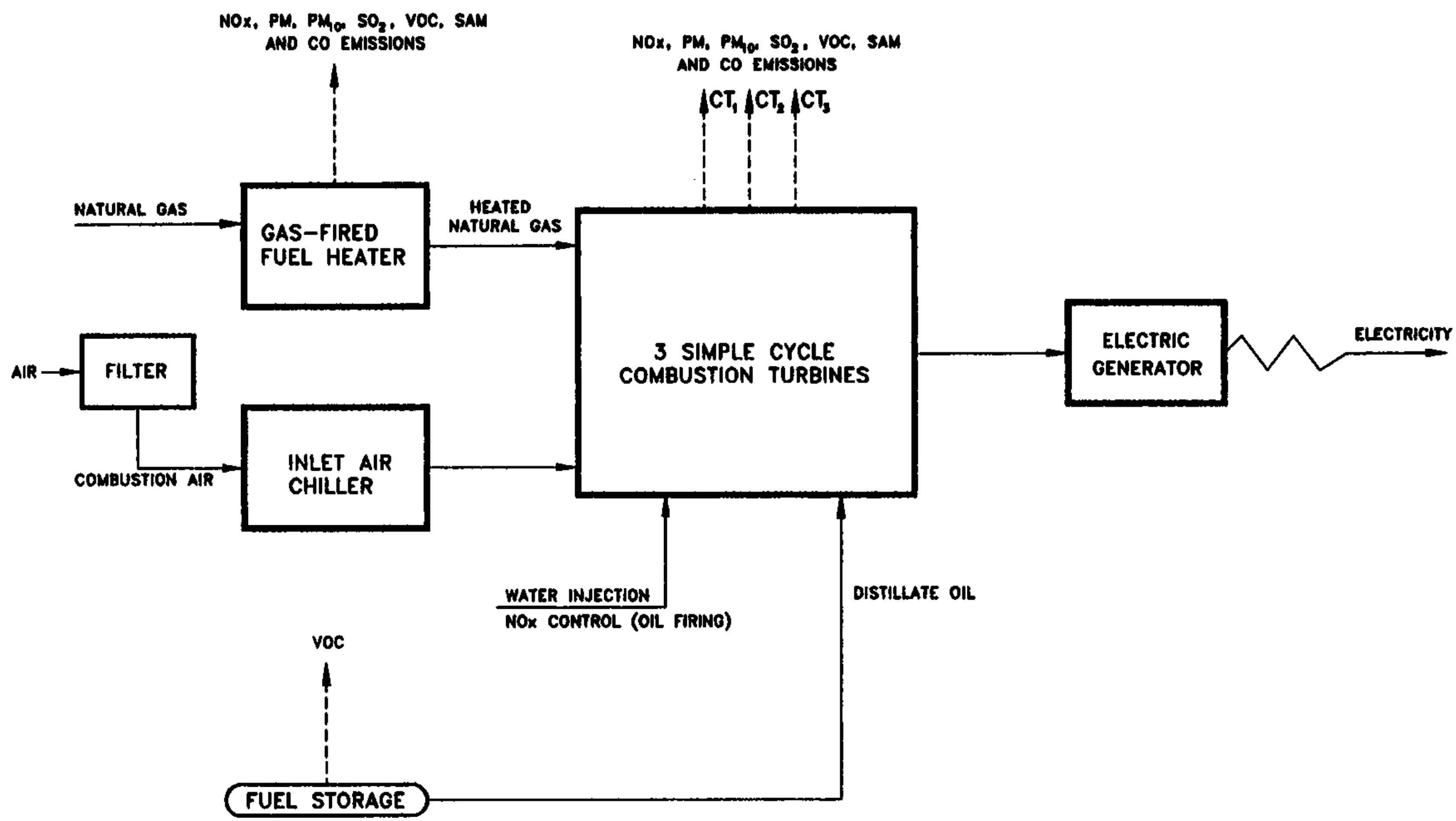


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FIGURE 2–1
PROCESS FLOW DIAGRAM
SIMPLE CYCLE COMBUSTION TURBINE
DEERFIELD BEACH ENERGY CENTER

DRAWN:	JK	DATE:	10/00	PROJECT NUMBER:		REV.	
APPV'D:	DD	REVISED:	X	6792–140		0	

67920BA.DWG

2.2.2 Simple-Cycle

The DBEC will use Simple-Cycle power generation technology to deliver electrical peaking power during periods when short-term demand exceeds base load requirements. Peaking power units are able to be brought on and off-line quickly, in response to nearly instantaneous fluctuations in electricity demand.

2.2.2.1 The Brayton "Simple" Cycle

The production of electricity using a combustion turbine engine coupled to a shaft driven generator is referred to as the Brayton Cycle. This power generation cycle has a thermodynamic efficiency which generally approaches 40%. This is also referred to as "Simple-Cycle" and has been traditionally utilized for electricity peaking generation since the turbine(s) and subsequent electrical output can be brought on line very quickly. The largest energy loss from this cycle is from the turbine exhaust in which heat is discarded to the atmosphere at about 1,100°F.

2.2.3 Fuel Gas System

Pipeline-quality natural gas is delivered to the plant boundary at a sufficient pressure so that no additional fuel compression will normally be required. If gas compression is required, it will be accomplished using an electrically-driven compression system. The gas is first sent through a knockout drum for removal of any large slugs of liquid which may have been carried through from the pipeline. Only one knockout drum is provided.

The natural gas then passes through a filter/separator to remove particulate matter and entrained liquids. The gas flows through the filter/separator's first chamber, the filtration section, where entrained liquid is coalesced on the filter cartridges, drops to the bottom of the chamber and either vaporizes and returns to the main gas stream or drains to the sump below. The gas then flows through the coalescing filters which remove any particulate matter. Next, the gas passes to the second chamber, the separation section, where any entrained liquid remaining in the stream is further separated by impingement on a net or labyrinth and drains to the bottom sump.

The gas is then heated by a natural gas-fired heater, prior to being split for distribution to the three GE turbines. The fuel gas heater is designed for use as a means to prevent condensation of moisture and hydrates in the natural gas used in the CTGs. Each stream is sent through one last knockout drum to protect against the presence of liquid in the fuel. Finally, the gas is delivered to the turbines and combusted as part of the power generation cycle.

2.2.4 Distillate Oil Storage

Diesel fuel will be provided by tanker trucks and stored in two, above-ground storage tanks made of steel. These tanks will also supply fuel to the combustion turbines during diesel oil-firing. On site oil storage requirements have been estimated to be a maximum of 2.5 million gallons, with a maximum day storage tank requirement of 0.6 million gallons.

2.2.5 Cooling Towers

To dissipate the heat extracted from the CTG inlet air a closed loop chilling system will be used. This closed loop chilling system will lower the inlet air temperature from ambient conditions to approximately 50°F. The heat extracted by the closed loop chilling system will discard this waste heat to the atmosphere through the use of nine (9) chiller units, each with a 2-cell wet mechanical draft cooling tower.

2.2.6 Ancillary Facilities

Other systems supporting plant operations and safety include:

- Auxiliary Cooling Water System
- Fire Protection System
- Service Water System
- Process Waste Water System
- Potable Water and Sanitary Waste Water System
- Storm Water System
- Plant and Instrument Air System
- Continuous Emissions Monitoring System (CEMS)
- Maintenance Lifting System
- Unit Control System

3.0 PROJECT EMISSIONS

This section discusses the basis and methods used to calculate emissions for the DBEC. The section is organized according to the primary emission source groups. Within each section the methods used to calculate emissions and any adjustments that are required appear first, followed by a summary of the emissions resulting from the specific operation or activity.

The calculation procedures used during the development of this application rely on process information developed by DBEC for the operations to be conducted at the DBEC, manufacturers' data, and methods presented by the U.S. EPA in the "Compilation of Air Pollution Emission Factor, AP-42". The summary presented below has been prepared for each major emission-generating component of the proposed project, which includes:

- Combustion Turbines (3 Units);
- Natural gas fuel heater;
- Fugitive Emissions from distillate oil storage ; and
- Nine (9) chiller units, each with a two (2) cell wet mechanical draft cooling tower.

Detailed emission calculations for each emission source or source category are presented in Appendix B.

3.1 Combustion Turbines

3.1.1 Criteria Pollutants

Criteria pollutant emissions are those that contribute to the formation of ambient air concentrations of pollutants for which the EPA has established National Ambient Air Quality Standards (NAAQS) based on health effects criteria. The PSD-regulated criteria pollutant emissions associated with natural gas combustion are CO, NO_X, VOC, SO_2, and Particulates (PM/PM_{10}). The only PSD-regulated non-criteria pollutant expected to be emitted in significant quantities is sulfuric acid mist (SAM).

The primary emission sources at the DBEC will be the three (3) combustion turbines. Hourly emissions from these units were calculated from manufacturers' operating parameters and guaranteed in-stack concentrations for CO, NO_X, and VOC. SO_2 emissions were calculated using the manufacturers' supplied fuel consumption data and fuel gas sulfur content. Particulate emissions include front-half and back-half particulate matter as measured by EPA Methods 5 and 202.

Maximum hourly emission rates for each compound are based on the type of fuel fired, the four ambient temperatures, and the three turbine load conditions (100%, 75%, and 50%) that represent the range of expected operating conditions. Annual emissions are based on the hourly emission rates for the worst-case loads during both natural gas and distillate oil-firing at an ambient temperature of 50°F (the inlet temperature for the majority of expected operating hours during the summer with inlet chilling). Annual emission estimates for NO_X, CO, VOC, SO_2, and PM/PM_{10} are calculated using a worst-case operating schedule of:

- 3,500 hours total operation per turbine, considering both natural gas and distillate oil;
- up to 3,500 hours of operation per year per turbine on natural gas; and
- 1,000 hours of operation per year per turbine on distillate oil.

The PSD permit will limit each turbine to 3,500 hours of operation per year.

The data used in this analysis is presented in Appendix B. Table 3-1 presents a summary of worst-case hourly emissions for the three combustion turbines. Table 3-2 presents a summary of estimates of annual potential emissions.

3.1.2 Non-Criteria Pollutants

Non-criteria pollutant emissions include PSD-regulated non-criteria pollutants and pollutants regulated by U.S. EPA under the National Emissions Standards for Hazardous Air Pollutants (NESHAPS). Estimates of Sulfuric Acid Mist and Lead emissions are included in Tables 3-1 and 3-2, and have been prepared using the same calculation methodology as presented for PSD-regulated criteria pollutants.

An estimate of total Hazardous Air Pollutants emissions has also been performed. The calculation procedures used during the development of this application rely on process information developed for the proposed project, manufacturers' data and emission factors presented by U.S. EPA in the "Compilation of Air Pollution Emission Factor, AP-42". The summary presented below has been prepared for each source category identified previously. Detailed emission calculations for each emission source or source category are presented in Appendix B.

The primary emission sources at the DBEC will be the three (3) combustion turbines. Hourly emissions from these units were calculated using the manufacturers' fuel feed rate (as MMBtu/hr). Emission factors were derived from one of two sources: 1) Section 3.1 of AP-42 or 2) information from the California Air Resources Board (CARB) CATEF database. The source of emission factors for each pollutant is identified in the Appendix B.

Maximum hourly emission rates for each compound were established using the highest hourly fuel feed rate (as MMBtu/hr, Higher Heating Value (HHV)) for the three load and the four ambient temperature conditions identified above. Annual emissions were based on the hourly fuel feed rate for 50°F, 100% load and 3,500 hours of operation with up to 1,000 hours of distillate oil operation. Table 3-3 presents a summary of emissions for the combustion turbines and the fuel heater.

Table 3-1 Hourly Emission Rate Summary for the DBEC Combustion Turbines

Compound	Load (%)	Temperature (°F)			
		91	50	42	30
Emissions for One GE 7FA Turbine – Natural Gas Operation					
NO_x	100	53.5	59.6	60.4	61.6
	75	43.5	47.5	48.1	49.0
	50	34.4	37.7	38.1	38.7
CO	100	26.5	29.6	30.1	30.9
	75	21.8	23.5	23.8	24.3
	50	18.4	19.5	19.7	20.0
VOC	100	2.6	2.9	2.9	3.0
	75	2.2	2.3	2.3	2.3
	50	1.8	1.9	1.9	1.9
SO_2	100	9.5	10.6	10.7	10.9
	75	7.8	8.5	8.6	8.8
	50	6.2	6.8	6.9	7.0
H_2SO_4	100	1.5	1.6	1.6	1.7
	75	1.2	1.3	1.3	1.3
	50	0.9	1.0	1.1	1.1
PM	100	18.0	18.0	18.0	18.0
	75	18.0	18.0	18.0	18.0
	50	18.0	18.0	18.0	18.0
Emissions for One GE 7FA Turbine – Distillate Oil Operation					
NO_x	100	289.6	321.0	325.5	332.1
	75	232.7	254.0	257.9	263.2
	50	181.9	199.2	201.5	204.6
CO	100	59.5	66.6	67.8	69.6
	75	50.7	56.8	57.5	58.5
	50	78.3	66.5	64.6	67.6
VOC	100	2.7	3.0	3.0	3.1
	75	2.2	2.3	2.3	2.4
	50	1.8	1.9	1.9	1.9
SO_2	100	90.3	100.2	101.6	103.6
	75	73.3	80.0	81.3	82.9
	50	57.9	63.4	64.2	65.1
H_2SO_4	100	13.8	15.3	15.6	15.9
	75	11.2	12.2	12.4	12.7
	50	8.9	9.7	9.8	10.0
PM	100	34.0	34.0	34.0	34.0
	75	34.0	34.0	34.0	34.0
	50	34.0	34.0	34.0	34.0
Pb	100	0.025	0.027	0.028	0.028
	75	0.020	0.022	0.022	0.023
	50	0.016	0.017	0.018	0.018

Table 3-2 Annual Emission Summary for the DBEC Combustion Turbines

Turbine	NO_x	CO	VOC	SO_2	H_2SO_4	PM	PM_{10}	Pb
	Emissions for One Combustion Turbine (tons/year) [1]							
GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	39.5	0.013
	Emissions for All Combustion Turbines (tons/year) [1]							
3 x GE7FA	705.0	210.9	15.3	190.2	29.1	118.5	118.5	0.042

Notes:
[1] Based on worst case hourly emission rate over the load range (50% - 100% base load), at the effective Annual Average Temperature of 50°F, and the following operation schedule:
NG Annual Operation 2,500 hrs/year/turbine
Oil Annual Operation 1,000 hrs/year/turbine
Total Annual Operation 3,500 hrs/year/turbine

Table 3-3 Facility HAP Emission Summary

		3500 hrs Natural Gas	2500 hrs NG	1000 hrs Oil	2500 hrs NG & 1000 hrs Oil	CTGs All Cases	Fuel Heater	Facility Total
Total HAPs	tpy	5.0	3.6	3.9	7.5	7.5	0.04	7.6
Max Single HAP	tpy	2.6	1.8	2.4	2.4	2.6	4.01E-02	2.6
Max HAP Compound		Formaldehyde	Formaldehyde	Manganese	Formaldehyde	Formaldehyde	Hexane	
							Major Total HAPs	No
							Major Single HAP	No

3.2 Natural Gas Fuel Heater

Emission calculations for this unit are presented in Appendix B and summarized in Table 3-4 for criteria pollutants.

Table 3-4 Criteria Pollutant Emissions Summary for the Fuel Heater

Criteria Pollutants	Emission Rate - per Unit Hourly (Lbs/Hr)	Emission Rate - per Unit Annual (Tons/Year)
Nitrogen Oxides	1.3	2.3
Carbon Monoxide	1.2	2.1
Volatile Organic Carbon	0.78	1.37
Sulfur Oxides	0.07	0.13
Particulate	0.13	0.23

3.3 Cooling Towers

There will be nine (9) two (2)-cell cooling towers at the DBEC, which will provide inlet air cooling capability for the combustion turbines. Since the tower is a non-contact tower it will only be an emission source of particulate matter. The level of emissions from the tower is dependent on the chemistry (solids contents) of the circulating water and the amount of drift which leaves the unit. The method used to estimate particulate matter emissions is based on the approach presented by the U.S. EPA (AP-42, Section 13.4).

Using the cooling tower's design characteristics (See Appendix B), the total particulate emissions from the tower have been estimated to be a maximum of 0.38 Lbs/Hr, and 0.66 Tons/Yr. The annual potential emissions are an extremely conservative estimate that assumes that the cooling tower would be operated at maximum capacity for all 3,500 hours per year. Based on its potential emissions, the cooling tower satisfies the applicable criteria of Rule 62-210.300(b)1 for exemption from permitting as an insignificant emission unit. As such, the cooling tower has not been addressed in Section III (Emission Unit Information) of the FDEP application forms.

3.4 Fugitive Emissions

Breathing and working losses from the two, above-ground distillate oil storage tanks will constitute the main fugitive emissions from the DBEC. The emission calculations were performed using Tanks 4.0, a U.S. EPA computer model, which considers tank characteristics, meteorological data, and annual material throughput to estimate emissions. A summary of the tanks' fugitive emissions is presented in Appendix B.

3.5 Total Project Criteria Pollutant Emission Summary

Tables 3-5 and 3-6 combine the analyses summarized on the preceding pages to establish the maximum emissions for the DBEC. The annual emissions summaries reflect the maximum number of hours the turbines and fuel heater will operate. This will become a federally enforceable limitation specified in the PSD permit upon issuance.

Table 3-5 Project Hourly Emissions (lb/hr) Summary, Criteria Pollutants, DBEC

Source Name	Source	NO_x	CO	VOC	SO_2	H_2SO_4	PM_{10}	Pb
	Hourly Emission Rates (lb/hr)							
Combustion Turbine No. 1	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Combustion Turbine No. 2	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Combustion Turbine No. 3	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Fuel Heater No. 1		1.3	1.2	0.78	0.07		0.13	
Cooling Towers							0.38	
Fuel Tanks				3.19				
Total		**997.6**	**236.1**	**13.3**	**310.9**	**47.7**	**102.5**	**0.1**

Note: This table presents the maximum emission rate over the potential operating range (50% to 100% load and 30 to 91°F) for all operating conditions (Natural Gas or Oil).

Table 3-6 Project Annual Emissions (tons/yr) Summary, Criteria Pollutants, DBEC

Source Name	Source	NO_x	CO	VOC	SO_2	H_2SO_4	PM_{10}	Pb
Combustion Turbine No. 1	GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Combustion Turbine No. 2	GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Combustion Turbine No. 3	GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Fuel Heater No. 1		2.3	2.1	1.37	0.07		0.23	
Cooling Tower							0.66	
Fuel Tanks				1.3				
Total		**707.3**	**213.0**	**18.0**	**190.3**	**29.1**	**119.4**	**<0.1**

Note: This table presents the annual potential emissions based on maximum hourly emissions over 50% to 100% load range at the effective annual average temperature of 50 °F for all operating conditions (Natural Gas or Oil)

4.0 APPLICABLE REGULATIONS AND STANDARDS

The following air regulations have been reviewed as they may apply to the proposed facility:

- Prevention of Significant Deterioration (PSD) pre-construction review under 40 CFR Part 52;
- New Source Performance Standards (NSPS) under 40 CFR Part 60;
- National Emissions Standards for Hazardous Air Pollutants (NESHAPs) under 40 CFR Part 63;
- Acid Rain Deposition Control Program under 40 CFR Parts 72, 73, and 75;
- CAA Operating Permit Program under 40 CFR Part 70; and
- State of Florida Air Resource Management Rules under Chapter 62 of the Florida Administrative Code.

These regulations are implemented by the FDEP through the federally-approved CAA State Implementation Plan (SIP) or by U.S. EPA-delegated authority. A review of the applicability criteria for these rules and the conclusions drawn relative to the proposed facility is presented below.

Additionally, Broward County has implemented Air Quality requirements in Article IV of its code, of which Sections 27-171 through 27-178 contain county-specific rules. These, however, are not part of the SIP and thus are not federally-enforceable.

4.1 Prevention of Significant Deterioration

The proposed facility is required to submit an application for a permit to construct under the Prevention of Significant Deterioration (PSD) rules codified at 40 CFR Part 52 and incorporated as a SIP-approved program into Rule 62-212.400, F.A.C. The facility would be subject to PSD review for PSD-regulated pollutants, if it is a "major" source. New sources of air emissions are considered major sources if they have the "Potential-to-Emit" (PTE) more than the 100 tons/year for "listed" source categories or 250 tons/year for all other source categories. One of the 28 source categories listed in the PSD regulations is "fossil-fuel fired steam electric plants of more than 250 million Btu per hour heat input." Gas turbines used without heat recovery, such as simple cycle peaking units, have been determined to fall outside of the 28-source category list, and thus are subject to PSD review if potential emissions of any regulated pollutant exceed 250 tons/year.

As shown in Table 3-6, air emissions from the DBEC will exceed the 250 ton per year threshold for one or more criteria pollutants. As such, PSD review is required for each pollutant emitted in excess of the Significant Emission Rates listed in Table 62-212.400-2 F.A.C. and shown in Table 4-1.

Table 4-1 Project PTE (TPY) Criteria Pollutant Emissions Summary, Deerfield Beach Energy Center

Source Name	NO_X	CO	VOC	SO_2	H_2SO_4	$PM/_{PM10}$	Pb
Combustion Turbine No. 1	235.0	70.3	5.1	63.4	9.7	39.5	0.01
Combustion Turbine No. 2	235.0	70.3	5.1	63.4	9.7	39.5	0.01
Combustion Turbine No. 3	235.0	70.3	5.1	63.4	9.7	39.5	0.01
Natural Gas Heater	2.3	2.1	1.4	0.13		0.23	
Distillate Oil Storage			1.3				
Cooling Towers for Inlet Chiller						0.66	
Total (Tons/year)	**707.3**	**213.0**	**18.0**	**190.3**	**29.1**	**119.4**	**<0.1**
PSD Major Source Threshold	**250**	**250**	**250**	**250**	**250**	**250**	**250**
PSD Significant Threshold	**40**	**100**	**40**	**40**	**7**	**25/15**	**0.6**

The following requirements are encompassed by PSD review.

- Compliance with any applicable emission limitation under the State Implementation Plan (SIP);
- Compliance with any applicable NSPS or NESHAPS;
- Application of Best Available Control Technology (BACT), as defined by the PSD rules, to emissions of NOx, CO, SO2, and PM/PM10 from all significant sources at the facility;
- A demonstration that the facility's potential emissions, and any emissions of regulated pollutants resulting from directly related growth of a residential, commercial or industrial nature, will neither cause nor contribute to a violation of the NAAQS or allowable PSD increments;
- An analysis of the impacts on local soils, vegetation and visibility resulting from emissions from the facility and emissions from directly related growth of a residential, commercial, or industrial nature;
- An evaluation of impacts on Visibility and Air Quality Related Values (AQRVs) in PSD Class I areas (if applicable); and
- At the discretion of FDEP, pre-construction and/or post-construction air quality monitoring for NO_x, CO, SO_2, and PM/PM_{10}.

Potentially applicable SIP limitations, NSPS and NESHAPs requirements are discussed below. A detailed BACT analysis is presented in Section 5. Contributions to the NAAQS and PSD increments are discussed in Section 6. Impacts on local soils, vegetation, and visibility are addressed in Section 7.

4.2 NSPS

The NSPS regulation that applies to combustion turbines is Subpart GG. This standard is applicable to stationary gas turbine units that have a heat input of greater than 10 MMBtu/hr. Under Subpart GG, units with a heat input at peak load greater than 100 MMBtu/hr and which supply more than one third of their electric generating capacity to a utility distribution system shall not emit NO_x in excess of:

$$STD = 0.0075(14.4/Y) + F$$

Where:

STD is the allowable NO_x emission, percent volume (corrected to 15 percent oxygen dry basis)

Y is rated heat rate at peak load, kilojoules/watt hour

F is NO_x emission allowance for fuel bound nitrogen, percent volume (for nitrogen content greater than 0.25 percent weight, F is 0.005 percent volume)

Applying the heat rate to the proposed General Electric 7FA turbine results in an applicable NSPS for NO_x emissions of approximately 110 ppmv on a dry basis, corrected to 15 percent oxygen, when firing natural gas. For distillate oil firing, the applicable NSPS limit is 102 ppm @ 15% oxygen. Both of these emission limits are well above the levels proposed as BACT (see Section 5).

Subpart GG also regulates the discharge of SO_2 by requiring compliance with one of the following two options:

- Limit SO_2 emissions to 0.015 percent or less by volume at 15 percent O_2 on a dry basis, or
- Limit the sulfur content of the fuel to 0.8 percent by weight or less.

The proposed project will readily meet the NSPS for SO_2 as both the proposed natural gas (2 grains/100 SCF) and distillate oil (<0.05 wt%) fuels will contain less than 0.8 percent sulfur content by weight.

Subpart Kb applies to each storage vessel, with some specified exceptions, with a capacity greater than or equal to 40 m^3 that is used to store volatile organic liquids for which construction commenced after July 23, 1984. Subpart Kb establishes storage vessel control equipment specifications, testing and associated procedures, and reporting and record keeping requirements. For this project, the distillate oil storage vessels will be subject to Subpart Kb based upon their maximum storage capacity. Due to the low vapor pressure of No. 2 distillate oil, these tanks will only be required to maintain records of the dimensions and maximum capacity of the tanks. No control requirements will apply.

4.3 NESHAPS

There is currently no NESHAPs for stationary gas turbines, although this is a source category scheduled for a determination of Maximum Achievable Control Technology (MACT) under 40 CFR Part 63. However, 40 CFR Part 63, Subpart B governs the construction or reconstruction of major sources of Hazardous Air Pollutants (HAPs) for which a NESHAP has not been promulgated. The rule requires new major sources of HAPs to install MACT for HAPs. MACT must be determined as a condition of pre-construction approval. A major source of HAPs is any stationary source that has the potential to emit 10 tons/year or more of a single HAP or 25 tons/year of combined HAPs.

Table 4-2 summarizes the project PTE for non-criteria pollutants. The project is not a major HAP source, and, therefore, 40 CFR Part 63 Subpart B does not apply.

Table 4-2 Project PTE Non-Criteria Pollutant Emissions Summary

Emission Source	HAP Emission Rate		Maximum HAP Emission Rate	
	Lbs/Hr	tons/year	Lbs/Hr	tons/year
Combustion Turbines[a]	8.1	7.5	5.0	2.6
Fuel Heater[b]	2.5×10^{-2}	0.04	2.3×10^{-2}	0.04
Total	8.1	7.6	5.0	2.6

(a) Formaldehyde is the single HAP that has the greatest contribution to the Total HAP Potential to Emit from the combustion turbines.
(b) Hexane is the single HAP that has the greatest contribution to the Total HAP Potential to Emit from the fuel heater.

4.4 Acid Rain

The proposed facility meets the definition of "utility unit" and will be an affected Phase II unit under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act. Title IV requirements for the proposed facility will be included in the Title V permit. Title IV requires that the facility hold calendar-year allowances for each ton of SO_2 that is emitted and conduct emissions monitoring for SO_2 and NO_x pursuant to the requirements in 40 CFR Parts 72, 73, and 75.

4.5 CAA Operating Permit Program

FDEP administers the CAA Operating Permit Program under Rule 62-213 which has been approved by EPA under 40 CFR Part 70. A new major source must submit a Title V operating permit application to FDEP within 180 days after commencing operation. The Title V application will incorporate applicable emission limitations, monitoring, record keeping and reporting requirements from the PSD construction permit.

4.6 State SIP Rules

In addition to the above regulations, the proposed facility is also subject to the Florida Air Pollution Control Regulations codified in Chapters 62-204 through 62-297 of the Florida Administrative Code (F.A.C.). The F.A.C. rules that are potentially applicable to the proposed project are as follows:

- General Pollutant Emission Limiting Standards

  Rule 62-296.320 limits visible emissions from any activity not specifically addressed by another Florida Regulation in Chapter 62-296. The general visible emission standard for stacks limits opacity to 20%. Compliance with the visible emission standard must be done in accordance with U.S. EPA Method 9. A companion rule limits visible emissions from fugitive sources by requiring sources to take reasonable precautions to prevent such emissions. Fugitive emissions may occur during construction of the facility. Wet suppression or similar techniques will be used to control emissions as necessary during construction activities

- General Construction Permitting Requirements

  Rule 62-210.310 requires that an air construction permit be obtained prior to commencing construction. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, and 62-210.300(1). This document includes the general information required by the FDEP for a construction permit application.

- Stack Height Policy

  Rule 62-210.550 specifies the stack height requirements and permissible dispersion techniques for permitting air emission sources. The facility will comply with the provisions of this regulation as presented in the air quality impact assessment (Section 6).

- Excess Emissions

  Rule 62-210.700 provides allowances for excess emissions for emission units that may occur during periods of startup, shutdown, malfunction, and load changes (non steady-state operations). Excess emissions from the combustion turbines are expected to occur during startup and shutdowns. The facility will apply best operational practices to minimize the duration of excess emissions.

- Annual Emissions Reporting

  Rule 62-210.370 requires Title V sources to submit an annual operating report that provides emissions information for the previous calendar year. Deerfield Beach Energy Center, LLC will submit to the FDEP annual emissions reports by March 1 of the following year.

5.0 CONTROL TECHNOLOGY EVALUATION

5.1 Introduction

In accordance with PSD requirements, FDEP requires the application of Best Available Control Technology (BACT) for the control of each regulated pollutant emitted in significant quantities from a new major stationary source located in an attainment area for that pollutant. The proposed Deerfield Beach Energy Center's combustion turbines must demonstrate the application of BACT for oxides of nitrogen (NO_X), carbon monoxide (CO), fine particulate (PM_{10}), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4).

5.1.1 Top-Down BACT Approach

The BACT requirements are intended to ensure that a proposed facility or major modification will incorporate air pollution control systems that reflect the latest demonstrated practical techniques for each particular emission unit, and will not result in the exceedance of a National Ambient Air Quality Standard (NAAQS), PSD Increment, or other standards imposed at the state level. The BACT evaluation requires the documentation of performance levels achievable for each air pollution control technology applicable to the Deerfield Beach Energy Center.

EPA and FDEP recommend a "top-down" approach when evaluating available air pollution control technologies. This approach to BACT involves determining the most stringent control technique available, known as the Lowest Achievable Emission Rate (LAER) for a similar or identical emission source. If it can be shown that the LAER is technically, environmentally, or economically impractical on a case-by-case basis for the proposed emission source, then the next most stringent level of control is similarly evaluated. This process continues until a control technology and associated emission level is determined that cannot be eliminated by any technical, environmental, or economic objections. The top-down BACT evaluation process is described in U.S. EPA's draft document "New Source Review Workshop Manual (U.S. EPA, October 1990). The five steps involved in a top-down BACT evaluation are:

- Identify options with practical potential for control of the regulated pollutant under evaluation;
- Eliminate technically infeasible or unavailable technology options;
- Rank the remaining control technologies by control effectiveness;
- Evaluate the most effective controls and document the results; if the top option is not selected as BACT, evaluate the next most effective control option; and

- Select BACT, which will be the most effective practical option not rejected based on prohibitive energy, environmental, or economic impacts.

ENSR employed the "top-down" approach in evaluating available pollution controls for the Deerfield Beach Energy Center.

5.1.2 Cost Determination Methodology

Economic analyses of certain BACT alternatives were performed to compare capital and annual control costs in terms of cost-effectiveness (i.e., dollars per ton of pollutant removed). Capital costs include the initial cost of components intrinsic to the complete control system. High-temperature SCR, for example, would include catalyst modules, transition piece, support frame, ammonia storage tanks, ammonia dilution air and injection system, piping, flue gas attemperation system, provisions for catalyst cleaning and removal, instrumentation, and installation costs. Annual operating costs consist of the financial efficiency losses, parasitic loads, and revenue loss from operation of the control system and include overhead, maintenance, labor, raw materials, and utilities.

5.1.3 Capital Costs

The capital cost estimating technique used in this analysis is based on a factored method of determining direct and indirect installation costs. This technique is a modified version of the "Lang Method," whereby installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA guidance manual (OAQPS Control Cost Manual) on estimating control technology costs (U.S. EPA, January 1996). The estimation factors used to calculate total capital costs are shown in Table 5-1.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for continuous operation of the device. These may include such items as reagent storage tanks, supply piping, turbine outlet transition piece, catalyst removal crane, spare parts and catalyst, and air dilution system. Auxiliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage based on the average requirements of typical systems and their auxiliary equipment (U.S. EPA, January 1996). In this BACT evaluation, basic equipment costs were obtained from data provided by qualified vendors (see Appendix C). Instrumentation, which is usually not included in the basic equipment cost, is estimated at 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor including site preparation, foundations, structural steel, insulation erection, piping, electrical, painting, and enclosure.

Table 5-1 Capital Cost Estimation Factors

Item	Basis
Direct Costs	
Purchased Equipment Cost	
Equipment cost + auxiliaries[1]	A
Instrumentation	0.10 x A
Sales taxes	0.06 x A
Freight	0.05 x A
Total Purchased equipment cost, (PEC)	B = 1.21 x A
Direct installation costs	
Foundations and supports	0.08 x B
Handling and erection	0.14 x B
Electrical	0.04 x B
Piping	0.02 x B
Insulation for ductwork	0.01 x B
Painting	0.01 x B
Total direct installation cost	0.30 x B
Site Preparation, SP	As Required
Buildings, Bldg	As Required,
Total Direct Cost, DC	1.30B + SP + Bldg.
Indirect Costs (installation)	
Engineering	0.10 x B
Construction and field expenses	0.05 x B
Contractor fees	0.10 x B
Start-up	0.02 x B
Performance test	0.01 x B
Contingencies	Variable
Other[2]	As Required
Interest during construction[3]	DC x i x n
Total Indirect Cost, IC	0.28B + Interest + Contingencies
[1]Auxilliaries include ammonia tank, transition piece, crane, spare catalyst, dilution air system, etc.	
[2]Emergency Response Plan (ER), Spill Prevention Countermeasure and Control (SPCC), Risk Management Plan (RMP), etc.	
[3]Simple Interest During Construction, i = interest rate; n = interest period	
Total Capital Investment (TCI) = DC + IC	**1.58B+ SP + Bldg. + Interest + Contingencies**

Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, contingencies, and additional permits and licensing costs.

Direct installation costs are expressed as a function of the purchased equipment cost, based on average installation requirements of typical systems. Indirect installation costs are designated as a percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment startup and performance testing, contingencies, and working capital.

5.1.3.1 Annualized Costs

Annualized costs are comprised of direct and indirect operating costs. Direct costs include electricity losses, labor, maintenance, replacement parts, raw materials, and utilities. Indirect operating costs include overhead, taxes, insurance, general administration, contingencies, and capital charges. Annualized cost factors used to estimate total annualized cost are listed in Table 5-2, and are consistent with the EPA guidance on estimating control technology costs (U.S. EPA, January 1996).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs are calculated as 3 percent of total direct cost (TDC). Replacement part costs, such as the cost to replace aged or failed catalyst, have been included where appropriate. Reagent and utility costs are based upon estimated annual consumption and the unit costs are summarized in Table 5-2. The presence of a catalyst bed would increase turbine back pressure resulting in heat rate (efficiency) losses to the system. This is reflected in the economic analysis as the value of lost power output and is based on turbine vendor estimates. Based on the experience of other facilities contacted, the catalyst for a catalytic oxidation or reduction technology is assumed in this analysis to require replacement every 3 years due to failure or aging. The cost of replacement catalyst was provided by catalyst vendors which was then annualized over 3 years.

With the exception of overhead and contingency, indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where "i" is the annual interest rate and "n" is the equipment economic life (years). An emission control system's economic life is typically 10 to 20 years (U.S. EPA, January 1996). In this analysis, a 10-year equipment economic life (typical length of financing) was used. The average interest rate is assumed to be 7 percent (U.S. EPA, January 1996). CRF is therefore calculated to be 0.142.

Table 5-2 Annualized Cost Factors

Item	Cost Factor	Unit Cost
DIRECT ANNUAL COSTS, DC		
Electricity		
Heat rate loss due to pressure drop	0.1% output loss for every inch of delta P	$0.10/kW-hr
Dilution air fan electricity	Dilution air to prevent catalyst deterioration	$0.10/kW-hr
Operating labor		
SCR Labor Req.	0.5 hr/shift	$30.00/hr
Supervisor	15% Operating Labor	NA
Ammonia Delivery Requirement	24 hr/yr (3 deliveries per year)	
Ammonia Recordkeeping and Reporting	40 hr/yr (1 week of reporting)	
Catalyst Cleaning	80 hr/yr (2 workers x 40 hr/yr)	
Maintenance		
Catalyst Replacement Labor	8 workers, 40 hr, every 3 years	$30.00/hr
Catalyst System Maintenance Labor Req.	0.5 hr/shift	$30.00/hr
Ammonia System Maintenance Labor Req.	1 hr/day, 365 day/yr	$30.00/hr
Material	100% Maintenance Labor	NA
Ammonia	ammonia	$315 per ton
Process Air	350 scf/lb NH_3	$0.20 per thousand scf
Catalyst	100% replaced/3 years plus disposal	
INDIRECT ANNUAL COSTS, IC		
Overhead	60% labor + materials	
Administrative Charges	2% TCI	
Property Taxes	1% TCI	
Insurance	1% TCI	
Capital Recovery	CRF x TCI	
Contingency for new technology	NA	0-20% DC
Total Annual Cost (TAC) ($)		Sum of Annual Costs
Total Pollutant Controlled (ton/yr)		As Calculated
COST EFFECTIVENESS ($/ton)		**TAC/tpy controlled**

5.1.3.2 Cost Effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the technology and its annual pollutant emission reduction. Cost-effectiveness is calculated by dividing the annualized cost of the available control technology by the theoretical tons of pollutant that would be removed by that control technology each year. The basis for determining the percent reduction of a given technology was based on comparing the uncontrolled emission rate with the achievable emission rate based on information contained in issued permits, EPA literature and vendors of the control equipment.

5.2 Previous BACT/LAER Determinations for Simple-Cycle Combustion Turbines

The proposed Deerfield Beach Energy Center is a "Simple-Cycle" electrical peaking facility. A Simple-Cycle peaking project is fundamentally different than the more common "Combined-Cycle" base load systems that represent the majority of listings in EPA's RACT/BACT/LAER Clearinghouse. The differences in these two types of power generation technology are reviewed in Sections 5.2.1 and 5.2.2.

In a deregulated market for electricity, new generation capacity will be built only when there is a sufficient customer demand for that capacity. The electric output of any new capacity must be sold (and must therefore be priced competitively with existing capacity) in order to earn a Return On Investment (ROI) commensurate with the financial risk of building the powerplant. A market need exists in Florida for peak load power and, therefore, the Deerfield Beach Energy Center is being developed to serve that specific peak power market.

5.2.1 Base Load Power (Combined-Cycle)

Regional power demand is variable from night to day, from hot summer days (which reflect air-conditioning loads) to cold winter days, from workdays to weekends, etc. However,, there is a certain constant level of electrical demand that is always present, referred to as "base load". The nature of generation capacity built to provide base load power is that it is designed to maximize annual operation at a constant or "base" load at the lowest operating cost possible. Since fuel cost is the single biggest component of the cost to produce power, competitive base load generators must be designed to operate at the highest possible fuel efficiency and to produce their rated output continuously at maximum availability. The Combined-Cycle plant meets these criteria.

A rotating combustion turbine, driving a generator via a connecting shaft represents a thermodynamic cycle known as the Brayton Cycle; this arrangement is also referred to as "Simple-Cycle". In a Simple-Cycle turbine, air and products of combustion exiting the turbine are exhausted to the atmosphere at temperatures of about 1,100°F, which represents a substantial energy loss.

A boiler that produces steam which is then used to generate electricity in a steam turbine/generator is referred to as the Rankine Cycle. In this thermodynamic cycle, energy lost as waste heat from a surface condenser is typically rejected to cooling towers or a large body of cooling water. Traditional central utility powerplants are of this design. Condensation of steam with cooling water also represents a substantial energy loss.

Each of these cycles is significantly limited in achievable "heat rate" (the amount of electricity that can be generated per Btu of fuel input) because in each case substantial amounts of heat energy are wasted. When a Brayton Cycle turbine is connected in series with a Rankine Cycle waste heat boiler, a much lower heat rate (higher thermal efficiency) can be achieved. This is referred to as "Combined-Cycle". While a Combined-Cycle powerplant exhibits much higher initial capital cost, these costs can be quickly recovered in greater fuel efficiency in a base load plant which operates around the clock at near full capacity. The Combined-Cycle powerplant therefore, by definition incorporates a waste heat boiler or Heat Recovery Steam Generator (HRSG) and steam turbine generator. The HRSG recovers waste heat exiting the turbine at about 1,100°F and exhausts at about 220°F. With an HRSG as a component of the above-mentioned combined cycle, a temperature "window" exists which has allowed catalytic pollution control technology to be widely applied to new Combined-Cycle powerplants. This post combustion control technology is responsible for the very low (i.e. 2.5 – 3.5 ppm) NO_x emission rates reported for recent Combined-Cycle units in EPA's RACT/BACT/LAER Clearinghouse.

5.2.2 Peaking Power (Simple-Cycle)

Once base load demand is satisfied, a need still exists to supply additional power at certain times when base load requirements are exceeded by the short term peak power demand. Average peak power prices tend to be higher than for base load power. However, peaking units operate substantially fewer hours per year than base load units. The economics of providing peak power favor lower initial capital cost (there are fewer operating hours per year in which to earn back the capital investment) and are less sensitive to optimization of heat rate. Most importantly, peak power must be able to come on-and off-line very quickly and, in some cases is designed to "follow" electrical demand.

Simple-Cycle is the only combustion turbine configuration that meets this requirement. For example, a common application of combustion turbine engines that do not employ an HRSG is for aircraft applications. Helicopters and turbo-prop commuter aircraft utilize combustion turbine engines that drive a mechanical propeller shaft. These engines are routinely shut down during boarding, started up for taxiing and accelerated to full output during takeoff, all within a matter of minutes. Combined-Cycle units, on the other hand require a cold start-up schedule, measured in hours, to be brought from ambient temperature to full load. This is because the heat transfer surfaces and catalyst beds within the HRSG are sensitive to "thermal shock". Ceramics and steel that are heated too quickly are subjected to uneven thermal expansion and will warp, crack and/or fail if not allowed sufficient time to be brought to temperature more gradually. Start up schedules that are designed to protect back end equipment typically involve several steps of "ramping" and "soaking." This soaking time is required to protect the back-end equipment from failure due to thermal stress limits the feasibility of HRSG's and catalysts for use in quick response peaking applications. On any given day, the demand for peak power may only last three to four hours. By the time a Combined-Cycle unit has been warmed up to full operating load, the market demand to produce the peak power may be over.

5.2.3 BACT Determinations for Simple-Cycle Combustion Turbines

When reviewing emission levels that have been permitted as BACT or LAER in EPA's database, it is important to distinguish between Simple-Cycle and Combined-Cycle source categories, although the Clearinghouse listings are not always clearly categorized. It should also be noted that natural gas pipeline compressor engines are mechanical compressor drive applications; while they do not employ HRSG's, these sources are much smaller units (2-5 MW equivalent) and do not cycle on and off to meet demand as quickly or as frequently as power generation peaking turbines do. Compressor station turbines are not representative of a large scale peaking powerplant application.

A list of previous BACT/LAER determinations for all types of combustion turbines is presented in Appendix C. These tables are compiled from EPA's RACT/BACT/LAER Clearinghouse and from ENSR's database of combustion turbine projects. The RACT/BACT/LAER Clearinghouse keeps a listing of RACT/BACT/LAER determinations by governmental agencies for many types of air emission sources, and is available in hard copy or through a computerized database. While the RACT/BACT/LAER Clearinghouse covers information from the past 10 to 12 years, only the more recent decisions (1993-present) have been included here.

It should be noted that all listings in California represent LAER, even though they are often listed as BACT (BACT and LAER in California are identical). LAER is a much more stringent requirement than BACT, and involves application of control technology regardless of cost. This is not the case for the proposed Deerfield Beach Energy Center peaking project. ENSR also reviewed the California Air Pollution Control Officers Association (CAPCOA) on-line BACT Clearinghouse and found the only LAER decisions listed after 1993 to be for the same facilities. ENSR also called regulators in Indiana, California and several other states to determine levels of control which are being proposed or required of the most recent projects. Finally, ENSR contacted the turbine and catalyst manufacturers. Our search identified several Simple Cycle projects not listed in EPA's BACT/RACT/LAER Clearinghouse which have been permitted recently in California with lower emission limits and which employ add-on control technology.

5.2.4 Combustion Turbine Fuel Use

As part of its application, the Deerfield Beach Energy Center is requesting flexibility regarding the ability to burn 1,000 hours per year of oil. While the intention is to burn natural gas at every opportunity, near term constraints on the Florida Gas Transmission ("FGT") pipeline may impede the ability to burn natural gas during periods of peak demand often associated with the summer season. In general, the

FGT natural gas transmission line flows near its maximum pipeline capacity of 1.5 Bcf/day during the summer season. In order to accommodate the demand for incremental generation within the state of Florida, FGT plans to expand its pipeline capacity by approximately 600,000 MMbtu/day before the summer of 2002. Additionally, FGT is in active discussions with potential shippers to perform another expansion of its pipeline in 2003. The addition of this capacity should reduce periods of pipeline constraint and will result in an increased availability of natural gas to the proposed site. The request for oil burning flexibility is necessitated by near term FGT capacity constraints and is not due to deficient gas supplies received by FGT. Moreover, operational guidelines dictate that natural gas be the primary fuel source and that oil will be used as a backup fuel to the extent that transmission capacity constraints on FGT pipeline preclude the delivery of natural gas to the site.

As the proposed facility is intended to provide peak power which will typically occur during periods when natural gas demand will be high, the ability to operate using distillate oil as an alternative fuel is necessary to provide system reliability. The control technology analysis has been performed assuming the maximum amount of oil consumption, when determining potential emissions.

5.3 BACT for Nitrogen Oxides (NO_x)

5.3.1 Formation

NO_x is primarily formed in combustion processes in two ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen (EPA 1996); therefore, NO_x emissions from combustion turbines when burning natural gas originate as thermal NO_x. The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. Liquid fuels such as No. 2 distillate contain significant levels of fuel bound nitrogen. The combustion of liquid fuels results in inherently higher emissions of NO_x due to the combination of both thermal NO_x and fuel NO_x which forms when fuel nitrogen is exposed to high flame temperatures in the presence of free oxygen.

5.3.2 Front – End Control

"Front-end" NO_x control techniques are aimed at controlling one or more of these variables. The primary front-end combustion controls for gas turbines include water or steam injection and dry low NO_x combustors. The addition of an inert diluent such as water or steam into the high temperature region of the flame controls NO_x formation by quenching peak flame temperature, which reduces emissions of both thermal and fuel NO_x. This technique can be operationally very hard on the turbine and combustors due to vibration and flame instability. Recent advances in the state-of-the-art have resulted in dry low NO_x combustors for gas firing that limit peak flame temperature and excess oxygen with lean, pre-mix flames, that can achieve equal or better NO_x control without the addition of water or steam. Catalytic combustion is an emerging front-end technology for gas-only fired turbines using an oxidation catalyst within the combustor to produce a lower temperature flame and hence, low NO_x. Catalytic combustion is potentially capable of reducing natural gas-fired turbine NO_x emissions to 2-5 ppmv, but is not applicable to oil-fired or dual fuel applications. Catalytica, Inc. was the first company to commercially develop catalytic combustion controls for certain (mostly smaller) turbine engines and markets them under the name XONON™. Catalytic combustion technology is not yet commercially available for 170 MW F-Class turbines, and is not a technically feasible technology for dual fuel operation. Therefore, XONON™ does not represent an available control option for the Deerfield Beach Energy Center.

5.3.3 Back – End Control

Other control methods, known as "back-end" controls, remove NO_x from the exhaust gas stream once NO_x has been formed. Selective Catalytic Reduction (SCR) using ammonia as a reagent represents the state-of-the-art for back end gas turbine NO_x removal from base load, combined cycle turbines. Conventional SCR is not applicable to simple cycle turbines due to materials temperature limitations which preclude its application in high temperature simple cycle turbine exhaust. A high temperature SCR technology has recently been introduced for potential application to simple-cycle turbines but with limited success to date. In particular, high temperature SCR has been applied at a few small peaking turbines in California.

Selective catalytic reduction (SCR) is a process which involves post-combustion removal of NO_x from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho, 1994):

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O \qquad (2)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (3)$$

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \qquad (4)$$

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O \qquad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling", design of the NH_3 injection system, and high NH_3 slip. There are only four U.S. installations of this technology on simple cycle peaking turbines (Booth, 1999), and none of these has a long-term history of success. Three of these applications are on relatively small natural gas-only peaking turbines that have limited hours of operation to date. While these units have reported some initial problems, U.S.

EPA has indicated that they consider high temperature SCR to be "demonstrated in practice" for natural gas fired peaking turbines.

One of the high temperature SCR installations is the Puerto Rico Electric Power Authority (PREPA) Cambalache Electric Generating Facility, located in Puerto Rico. This project consists of three (3) ABB GT 11N1 combustion turbines operated in simple cycle mode, using distillate oil. The original permit issued for these turbines required the use of SCR to achieve NO_x emissions of 10 ppm, with a limit of 10 ppm on ammonia emissions. This plant has been operating since 1997 with very poor results for the operation of the SCR system. This project has not been able to operate for any extended period of time while staying within the NO_x and NH_3 limits and has been issued a Notice of Violation by EPA for exceedances of both NO_x and NH_3. Several attempts have been made to regenerate, or clean the catalyst, with no significant improvement in the performance of the system. EPA has been working with PREPA to solve the difficulties that have resulted from installation of hot SCR at the Cambalache facility. In January of 2000, US EPA Region 2 issued a press release stating: "...on oil-fired turbines, SCR cannot consistently achieve the expected reductions in nitrogen oxide emissions. As a result, EPA is removing the SCR requirement..." (US EPA Region 2 Press Release, the complete press release is included in Appendix C).

As a result of this experience, Englehard is no longer offering this technology for oil-fired turbine applications. The Deerfield Beach Energy Center is a dual fuel peaking project that must have the flexibility to burn liquid fuel as backup to natural gas. High temperature SCR is not technically feasible for oil fired combustion turbines, and has not been demonstrated in practice on dual fuel peaking turbines. However, at the request of FDEP, a cost effectiveness calculation for high temperature SCR has been performed for the proposed turbines, disregarding costs associated with a control technology that would represent a first of a kind application. Also not included in this cost evaluation is the impact of the catalyst on the operating strategies that would require an extended startup sequence to protect the catalyst bed. The results of this analysis clearly indicate that high temperature SCR would not be cost effective. As shown in Appendix C, high temperature SCR controlling NO_x emissions to the LAER levels of 3.5 ppmvd @ 15% O_2 while firing natural gas and 16 ppmvd @ 15% O_2 while firing distillate oil would cost over $15,000/ton of NO_x removed. If the lost revenue to the fundamental changes in operation were incorporated into this analysis, primarily resulting from extended startup duration, the overall cost effectiveness would exceed $20,000/ton.

On August 4, 2000 US EPA issued draft combustion turbine BACT guidance for public review (Appendix C). While this draft document is only being circulated for comment and does not represent official EPA policy, it does contain useful information relative to the application of SCR to GE's 9 ppm DLN generation turbines. Note that the discussion by EPA identifies several negative collateral environmental impacts associated with application of SCR to 9 ppm base load, combined cycle turbines. These negative impacts are exacerbated for simple cycle peaking applications, as discussed below:

Peaking turbines start and stop quickly, and may only operate a few hours at a time. Until the SCR catalyst reaches temperature, ammonia (NH_3) may not be introduced (resulting in less relative NO_x control), or if it is introduced will result in elevated NH_3 slip. Since a significant portion of a peaking turbines operation is spent warming up, following load (transient operation) and shutting down, high temperature SCR would control less NO_x and emit more slip when dispatched than a base load turbine would.

To reduce NO_x from 9 ppm to 3.5 ppm on units that will operate less than 3,500 hours per year will result in much lower NO_x reduction benefits than for EPA's analysis of combined cycle units. It should be noted that 3,500 hours represents an upper limit on operation for permitting, but in actual operation peaking units may in fact be normally dispatched less than 1,000 hours per year.

Peaking turbines may be thought of as similar to emergency generators. When they are called upon to operate, it is to fill a temporary shortfall in generation capability. SCR systems rob electrical output (due to backpressure) precisely when that output is most needed (peak demand).

High temperature SCR is therefore, not technically feasible, would exhibit overriding negative collateral environmental impacts, and in any event would not be cost effective for application to the dual fuel Deerfield Beach Energy Center.

An emerging technology called $SCONO_X^{TM}$, which also uses a back-end catalyst but operates without ammonia, has shown promise during initial trials on a 23 MW turbine installation in California, and a 5 MW turbine in Massachusetts. $SCONO_X^{TM}$ is an emerging technology that offers the promise of reducing NO_x concentrations to approximately 2-3.5 ppmv for smaller turbine applications. Despite this promise, $SCONO_X^{TM}$ is still very new and only operates effectively over a narrow 300°F to 500°F temperature range. According to the ABB Alstom internet website, ($SCONO_X^{TM}$ is marketed for applications greater than 100MW by Alstom). $SCONO_X^{TM}$ is not available for application to simple cycle combustion turbines. The planned Deerfield Beach Energy Center turbines will have exhaust temperatures of 1100 to 1200°F therefore, $SCONO_X^{TM}$ is not a technically feasible control option for the proposed Deerfield Beach Energy Center.

Two other back-end catalytic reduction technologies, Selective Non-Catalytic Reduction (SNCR) and Nonselective Catalytic Reduction (NSCR), have been used to control emissions from certain other combustion process applications. However, both of these technologies have limitations that make them inappropriate for application to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1300 to 2100°F, with an optimum operating temperature zone between 1600 and 1900°F (Fuel Tech, 1991). Simple-cycle combustion turbines have exhaust temperatures of approximately 1100°F. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible and inappropriate for the Deerfield Beach Energy Center turbines. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible and inappropriate for the Deerfield Beach Energy Center turbines.

The technologies that may represent effective controls for the proposed dual fuel peaking turbines are ranked and evaluated in the following sections. It should be stressed that levels of control being evaluated as BACT must be applicable to a dual fuel peaking power plant that will employ simple-cycle turbines for limited annual hours of operation.

5.3.4 Gas Turbines - Ranking of Available Control Techniques

Emission levels and control technologies for all types of combustion turbines have been identified and ranked for application to simple cycle dual fuel peaking turbines (see Table 5-3). Dry low NO_x controls (as described in EPA's draft turbine policy) represent the most stringent control technology for the planned turbine installation. Environmental, technical, and economic analyses of various DLN emissions levels are reviewed in the remaining BACT evaluation sections.

Table 5-3 Ranking of NO_x Control Technologies for a Dual Fuel Simple-Cycle Peaking Turbine

Control Technology	Typical Control Efficiency Range (% Removal)	Typical Emission Level[(a)] (ppmv)	Technically Feasible on Dual Fuel Simple-Cycle Gas Turbine
$SCONO_x$™	90-95	2-3.5	No
XONON™ flameless combustion	80-90	2-5	No
NSCR	30-70	9-25	No
SNCR	30-70	9-25	No
Conventional (low temperature) SCR plus water injection or SCR plus low-NO_x combustor	50-95	2-6	No
High Temperature SCR plus water/steam injection or advanced low-NO_x combustor	50-95	5-12	No
Dry low-NO_x Combustor	30-70	9-25 (gas)	Yes
Water/steam injection Combustor	30-70	25-42 (oil)	Yes
(a) **Values represent long-term emission rates.**			

A search of the U.S. EPA RACT/BACT/LAER Clearinghouse was completed to assist in the identification of potential control alternatives. The RACT/BACT/LAER Clearinghouse has become out of date due to the rapid pace of power projects being permitted due to deregulation of the power generation industry.

In order to determine the specific NO_x emission levels being permitted for recent peaking turbine projects, ENSR also reviewed an informal list of recent projects obtained from US EPA. The simple cycle turbines subject to BACT in EPA's list are provided in Table 5-4. It can be seen from this list that many simple cycle turbines are being permitted with dry low NO_x combustors in the range of 9–15 ppm. These emission levels are discussed in the following sections as candidates for BACT from the Deerfield Beach Energy Center.

Table 5-4 US EPA National Simple Cycle PSD Turbine Projects

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 4	AL	Applic. Under review	South Eastern Energy Corp.	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SC R if CC		For NOx and CO: SC w/GE or SC w/SW501F or CC (either)
REGION 4	AL	applic. under review	Tenaska Alabama II Generating Station	3	3	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 720 FO	15/42 ppm (SC); 4/42 ppm (CC)	DLN/WI , SCR/WI		
REGION 4	FL	10-99	Polk Power (TECO)	2		GE 7 FA (165 MW)	NG; FO	SC	5,130; 750 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	11-99	Oleander Power	5		GE 7FA (190 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	10-99	Hardee Power Partners (TECO)	1		GE 7EA (75 MW)	NG, FO	SC	8,760; 876 FO	9 ppm NG, 42 ppm FO	DLN; WI		
REGION 4	FL	12-99	Reliant Energy Osceola	3		GE 7FA (170 MW)	NG, FO	SC	3,000; 2,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	12-99	Florida Power Corp., Intercession City	3		GE 7EA (87 MW)	NG, FO	SC	3,390; 1,000 FO	9 ppm NG, 42 ppm FO	DLN; WI		
REGION 4	FL	10-99	Jacksonville Electric Authority – Brandy Branch	3		GE 7FA (170 MW)	NG; FO	SC	4,000; 800 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	1-00	IPS Avon Park - Shady Hills	3		GE 7FA (170 MW)	NG; FO	SC	3,390, 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	draft permit	Palmetto Power	3		SW 501F (180 MW)	NG	SC	3,750	15 ppm	DLN		
REGION 4	FL	applic. under review	Granite Power Partners	3		(180 MW)	NG; FO	SC	3,000; 500 FO	10.5/15/15/ 25 ppm NG, 42 ppm FO	DLN		4 vendor options: GE 7FA/SW 501F/SW 501D5A/ABB GT-24
REGION 4	FL	draft permit	IPS Avon Park Corp. – DeSoto Power Project	3		GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG, 42 ppm FO	DLN; WI		
REGION 4	FL	applic. under review	Florida Power & Light - Martin Power Plant	2		GE 7FA (170 MW)	NG, FO	SC	3,390, 500 FO	10.5 ppm NG (15 ppm HPM); 42 ppm FO	DLN; WI		HPM = High Power Mode (power augmentation)
REGION 4	GA	12-98	Tenaska Georgia Partners, L.P.	6		GE 7FA (160 MW)	NG, FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	GA	6-99	West Georgia Generating; Thomaston	4		GE 7FA (170 MW)	NG, FO	SC	4,760; 1,687 FO	12 ppm NG (15 ppm 30-day avg. for peak firing); 42 ppm FO	DLN; WI		
REGION 4	GA	10-99	Heard County Power	3		SW 501FD (170 MW)	NG	SC	4,000	15 ppm	DLN		

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 4	GA	8-99	Georgia Power, Jackson County	16		GE 7EA (76 MW)	NG; FO	SC	4,000; 1,000 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI		
REGION 4	KY	applic. under review	Duke Energy – Marshall Co.	8		GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI	1-hr	
REGION 4	FL	7-10-98	City of Lakeland, McIntosh Power Plant	1		SW 501G (230 MW)	NG; FO	SC (later CC)	7,008; 250 FO	25 ppm until 5/2002, 9 ppm after, 7.5 ppm if CC. NG; 42 ppm or 15 ppm FO	DLN or SCR; WI or SCR		Power Augmentation
REGION 4	MS	applic. under review	Duke Energy Southaven	8		GE 7EA (80 MW)	NG; FO	SC	2,500, 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN; WI		
REGION 4	MS	applic. under review	Warren Power LLC	4		GE 7EA (80 MW)	NG	SC	2,000	9 ppm	DLN		
REGION 4	NC	11-99	Carolina Power & Light, Richmond Co.	7		GE 7FA (170 MW)	NG; FO	SC	2,000; 1,000 FO	9 ppm NG at startup, 10.5 ppm long-term; 42 ppm FO	DLN; WI		
REGION 4	NC	11-99	Carolina Power & Light, Rowan Co.	5		GE 7FA (170 MW)	NG; FO	SC	2,000; 1,000 FO	9 ppm NG at startup, 10.5 ppm long-term; 42 ppm FO	DLN; WI		
REGION 4	NC	6-99	Rockingham Power (Dynegy)	5		SW 501F (156 MW)	NG; FO	SC	3,000; 1,000 FO	25 ppm NG until 4/01, 20 ppm until 4/02, 15 ppm after; 42 ppm FO	DLN; WI		
REGION 4	NC	applic. under review	Butler-Warner Generation Plant	2		GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	SC	draft permit	Santee Cooper, Rainey Generating Station	4		GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	SC	12-99	Broad River Energy (SkyGen)	3		GE 7FA (171 MW)	NG, FO	SC	3,000, 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	TN	7-99	TVA, Johnsonville Fossil Plant	4		GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI ?		10% NG base mode, 10% NG peaking, 10% FO base
REGION 4	TN	7-99	TVA, Gallatin Fossil Plant	4		GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI ?		10% NG base mode, 10% NG peaking, 10% FO base
REGION 4	TN	applic. under review	TVA, Lagoon Creek Plant	16		GE 7EA (110 MW)	NG; FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI ?	30;15 day	10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
REGION 5	IL	Dec-98	Peoples Gas, McDonell Energy	4		170 MW	NG, ethane	SC	1,500	15 ppm	DLN	1-hr	BACT; operational
REGION 5	IL	Sep-99	Enron, Des Plaines Green Land	8	0	83 MW	NG	SC	3,250	9/12/15 ppm	DLN	an/mo/hr	BACT; Ox Cat rejected at $6800/ton
REGION 5	IL	Jan-00	Enron, Kendall New Century	8	0	83 MW	NG	SC	3,300	9/12/15 ppm	DLN	an/mo/hr	BACT; Ox Cat rejected at $6700/ton

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 5	IL	Jan-00	LS Power, Nelson Project	4		220 MW	NG; FO	SC	2,549 total, 2,000 each	25/15	DLN	1-hr	Synth Minor; minor until test under 15 ppm
REGION 5	IL	draft permit	Duke Energy	8	0	83 MW	NG; FO	SC	2,000; 500 FO	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.); 1 hr	
REGION 5	IN	Jul-99	Vermillion Generating Station	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500	12/15 ppm NG; 42 ppm FO	DLN and WI	an	BACT; Usage limit of 20,336 MMCF NG-12 consec months. Also 2 Emergency Generators; 1 Emergency Diesel Fire Pump; 4 Diesel Storage Tanks; SCR @ $19,309/ton (avg.); Ox Cat @ 90% Control, rejected at $8,977/ton
REGION 5	IN	applic under review	DeSoto Generating Station	8		GE 7EA (80 MW)	NG	SC	2,500	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.); 1 hr	BACT
REGION 5	MN	draft permit	Lakefield Junction	6		GE model PG7121EA (92 MW)	NG; FO	SC	7,300	9 base, 25 peak, 42 FO	DLN, WI	3-hr	PSD; SCR rejected @ $11,500/ton; Ox Cat rejected at $3000/ton
REGION 5	OH	Jul-99	Duke Energy Madison LLC	8		GE 7EA (80 MW)	NG; FO	SC	2,500 NG; 500 FO	15 ppm (12 ppm) NG; 42 ppm FO	DLN	1 hr (ann.)	BACT; SCR rejected at $19,000/ton; Ox Cat rejected at $9000/ton
REGION 5	WI	Jan-99	RockGen Energy	3		GE 7FA (175 MW)	NG; FO	SC	3,800 Total, 800 FO	12/15 ppm NG; 42 ppm FO	DLN	24 hr/inst; 1 hr	BACT; SCR not chosen; cost $23,018/ton; Ox Cat rejected at $15 K/ton
REGION 5	WI	Feb-99	Manitowoc Public Utility	1		GE Frame 5 (24.5 MW)	NG; FO	SC	2,328 Total	77 ppm NG; 77 ppm FO	WI	1-hr	BACT
REGION 5	WI	Feb-99	Southern Energy	2		GE 7FA (180 MW)	NG; FO	SC	8,760 Total, 699 FO	12/15 ppm NG; 42 ppm FO	DLN	24 hr/inst, 1 hr	BACT; Ox Cat rejected at $14 K/ton
REGION 5	WI	Jul-99	Wisconsin Public Service	1		GE 7EA (102 MW)	NG; FO	SC	4,000 Total, 2,000 FO	9 ppm NG; 42 ppm FO	DLN	hr, nat gas, FO	BACT; SCR rejected at $13,866/ton, Ox Cat rejected at $6053/ton incremental cost
REGION 5	WI	draft permit	Wisconsin Electric	1		GE 7EA (85 MW)	NG; FO	SC	178,000 MWhrs, 2,000 hrs, 100 hr power aug	9 ppm NG (20 ppm w/power aug.); 42 ppm FO	DLN	24-hr, 1-hr FO	BACT, SCR rejected at $10,257/ton; Ox Cat rejected at $5984/ton incremental cost
REGION 7	KS	draft permit	Western Resources	3		2 - 100 MW, 1 - 180 MW	NG, FO	SC		15 ppm NG; 42 ppm FO	DLN; WI		NOx limits are for > 70% load NSPS limits will apply at < 70 % Load
REGION 7	MO	1-96	Kansas City Power & Light – Jackson	1		(200 MW)	NG	SC					
REGION 7	MO	draft permit	AECI – Nodaway	2		(100 MW)	NG	SC		25 ppm	DLN		
REGION 7	MO	applic. under review	Kansas City Power & Light – Jackson	2		(75 MW)	NG	SC		9 ppm	DLN		
REGION 7	MO	applic. under review	Duke Energy – Audrain	8		GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 1-hr avg.); 42 ppm FO	DLN; WI		
REGION 7	MO	applic. under review	Duke Energy – Bollinger	8		GE 7EA (80 MW)	NG	SC	2,500	12 ppm (15 ppm 1-hr avg.)	DLN		
REGION 7	NE	7-99	Omaha Public Power	4		(25 MW)	NG, FO	SC		25 ppm NG; 42 ppm FO	WI		
REGION 7	NE	6-99	Lincoln Electric System	1		(90 MW)	NG; FO	SC		25 ppm NG; 42 ppm FO	DLN; WI		

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 8	CO	final 4/99	Colorado Springs Utilities/Nixon (66 MW)	2		GE PG6541(B)	NG	SC	8,660 (both CTs)	15 ppm	DLN	1-hr	did not trigger BACT for CO
REGION 8	CO	final 8/99	Fulton Cogeneration /Manchief (284 MW)	2		SW V84.3A1	NG	SC	8,760	15 ppm	DLN	1-hr	
REGION 8	CO	applic. 11/99	KN Energy/Front Range Energy Associates - Ft. Lupton (160 MW)	4		GE LM6000	NG	SC	**	25 ppm (proposed)	WI		project originally PSD application; State drafted syn minor permit w/ operating hours restrictions in 7/99; EPA commented to State concerning single source issue w/ adjacent PSCo facility; PSCo appealed to US 10th circuit court - currently
REGION 8	CO	applic. 3/00	Platte River Power Authority/Rawhide (82 MW)	1		GE Frame 7EA	NG	SC	8,760	9 ppm	DLN		plan startup 5/2002; CO PTE below significance level so didn't do BACT; characterized as peaking plant, but not restricted in operating hours
REGION 8	CO	draft permit 5/00	Public Service Co. of Colo./Ft. St. Vrain Unit 4 (242 MW)	1	1	GE PG7241 (FA)	NG	SC/CC	8,760	4 ppm (CC); 9 ppm (SC)	DLN+SCR (CC); DLN (SC)	24-hr	plan startup 6/2001;
REGION 8	CO	applic. 11/99	Front Range Power Project/Ray Nixon Sta., Fountain, CO (480 MW)	2	2	GE Frame 7	NG	SC/CC	8,760	9 ppm/16 ppm w/ DB	DLN		plan to begin construction 1/01, operation 7/02; PSD mod to existing Colo Springs Utils/Nixon coal-fired power plant, revising application to net out of PSD for NOx using reductions at coal-fired unit, applicant calculated PTE using 95% ca
REGION 8	SD	applic. 11/99	Black Hills Power & Light/Lange CT Facility (80 MW)	2		GE LM6000PD	NG	SC	8,760	25ppm (proposed)	DLN	24-hr	Characterized as peaking plant, but not restricted in operating hours
REGION 8	WY	final 3/00	Black Hills Power & Light/Niel Simpson II (80 MW)	2		GE LM6000PD	NG	SC	8,760	25 ppm	DLN	24-hr	Region provided written comment disagreeing w/ NOx BACT determination; characterized as peaking plant, bur not restricted in operating hours
REGION 8	WY	final 2/98	Two Elk Generation Partners (33 MW turbine)	1		GE LM5000	NG	SC	8,760	25 ppm	DLN	1-hr	Facility is 250 MW coal-fired steam electric plus 33 MW NG CT; characterized as peaking plant, but not restricted in operating hours

The GE 7FA turbines proposed for the Deerfield Beach Energy Center will employ General Electric's state-of-the-art 9 ppm NO_x Dry low-NO_x (DLN) Combustion technology. EPA acknowledges that 9 ppm is the lowest Dry low- NO_x emission level that has been demonstrated for any combined cycle, base load turbine. Since add-on controls have previously been shown to be not technically feasible for application to the proposed dual fuel fired simple cycle peakers (and would not be cost effective in any case), the lowest emission rate continuously achievable using Dry low- NO_x combustors represents the next candidate for BACT. The Deerfield Beach Energy Center will utilize the lowest emitting DLN turbine technology on the market today to achieve a NO_x emission limit of 9 ppmvd @ 15% O_2 while firing natural gas, which therefore represents Best Available Control Technology (BACT).

While most of the discussion has been dealing with achievable NO_x emissions limits for natural gas fired operation, Deerfield Beach Energy Center, LLC proposes a NO_x emission limit of 42 pmvd @ 15% O_2 achieved using water injection. Similar to other permits issued in Florida Deerfield Beach Energy Center, LLC proposes that within 18 months after the initial compliance test, an engineering report will be prepared regarding the lowest NO_x emission rate that can be consistently achieved while firing distillate oil. This lowest NO_x emission rate would account for long-term performance expectations and reasonable operating margins. Based on the results of this report, the NO_x emission limit for distillate oil fired operation could be lowered.

5.3.4.1 Summary of Gas Turbine NO_x BACT

Deerfield Beach Energy Center, LLC proposes to implement NO_x BACT through the application of state-of-the-art GE 7FA turbines with 9 ppmvd @ 15% O_2 while firing natural gas, and 42 ppmvd @ 15% O_2 while firing distillate oil.

5.3.5 Natural Gas Fuel Heater

Based on a review of the RACT/BACT/LAER Clearinghouse the top NO_x control technology for heaters which fire less than 20 MMBtu/hr is the use of Low-NO_x burners. For a heater of this size, with limited hours of operation add-on control technology would not be cost effective. Deerfield Beach Energy Center will install a natural gas fired fuel heater equipped with Low-NO_x burner technology which will achieve a NO_x emission rate of less than 0.10 lb/MMBtu which will result in annual NO_x emissions of less than 2.3 tons/year. It should also be noted that the natural gas fuel heater is incorporated into this project to ensure that the natural gas fuel being used in the three combustion turbines is at the appropriate temperature for effective operation of GE's advanced DLN system.

5.4 BACT for Carbon Monoxide

5.4.1 Formation

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (by water injection or aggressive dry lean pre-mix) tends to result in higher levels of CO emissions. Thus, a compromise must be established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emission rates at acceptable levels.

5.4.2 Gas Turbines-Ranking of Available Control Techniques

CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Alternative Simple-Cycle turbine CO control methods include exhaust gas cleanup methods such as high temperature catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the combustors.

A review of EPA's RACT/BACT/LAER Clearinghouse (Appendix C) indicates several levels of CO control which may be achieved for Simple-Cycle natural gas fired gas turbines. High temperature oxidation catalyst (analogous to high temperature SCR) is a relatively new add-on control technology that could be applied to Simple-Cycle peaking turbines. The Carson Energy project in California, a 64 MW peaker, uses this technology. As shown in Appendix C, the majority of projects in the Clearinghouse reference combustion controls (burner design) as BACT for CO. Emission levels and control technologies have been identified and ranked as follows:

- 2 to 6 ppm: High-temperature CO oxidation catalyst
- 10 to 50 ppm: Good combustion practices

These levels of CO control are evaluated in terms of Best Available Control Technology in the following sections.

5.4.2.1 LAER: 2 to 6 ppm CO with High-Temperature Catalytic Oxidation

The most stringent CO control level available for Simple-Cycle gas turbines would be achieved with the use of a high temperature (zeolite based) oxidation catalyst system, which can remove up to 90 percent of CO in the flue gas (Booth, 1998). According to the list of Simple-Cycle turbines in the RACT/BACT/LAER Clearinghouse with limits for CO, none are listed with high-temperature oxidation catalyst systems. Our search identified one Simple-Cycle peaking project in California, and Englehard offers the technology commercially. A high temperature CO oxidation catalyst is, therefore, concluded to represent a technically feasible add-on control technology to control CO from natural gas fired, Simple-Cycle turbines. This zeolite catalyst technology, however, exhibits many of the same start-up responsiveness limitations and negative environmental impacts expressed previously for high temperature SCR. The use of an oxidation catalyst would extend the startup period for the combustion turbines, and increase back pressure on the turbine, which in both cases would contribute to increased emissions of pollutants. Also the installation of an oxidation catalyst would contribute to increased formation of SO_3, which is a precursor for PM_{10} and H_2SO_4 formation.

Technical Analysis

As with SCR catalyst technology for NO_x control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to occur. Rather, the oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include turbine back pressure losses, unknown catalyst life due to masking or poisoning, greater emissions and reduced market responsiveness due to extended start-ups, and potential collateral increases in emissions of SO_3, sulfuric acid mist and condensible PM_{10}.

As with SCR, traditional CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700°F to 900°F. According to Englehard, high-temperature oxidation catalyst is rated up to 1,200°F, so a dilution air system would not be required for the proposed General Electric 7 FA turbines.

Typical pressure losses across an oxidation catalyst reactor are in the range of 1.5 to 3.0 inches of water (Englehard, 1997). Pressure drops in this range correspond roughly to a 0.15 to 0.30 percent loss in power output and fuel efficiency (General Electric, 1997), or approximately 0.1 percent loss in power output for each 1.0 inch of water pressure loss.

All catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement has been considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life, but no operating units were identified with more than about 3,500 hours. Periodic testing of catalyst material is necessary to predict actual catalyst life for a given installation. The following economic analysis assumes that catalyst will be replaced every 3 years per vendor guarantee. This system would also be expected to control as much as 40 percent of hydrocarbon (VOC) emissions.

Like high-temperature SCR, this technology has yet to be demonstrated-in-practice on Simple-Cycle turbines in this size range. It is, however, a passive control technology (does not require NH_3 injection) and can withstand higher turbine exhaust temperatures. It would however, limit the project's ability to come on line quickly enough to meet peak power market demand.

Environmental Analysis

A CO catalyst will also oxidize other species within the turbine exhaust. For example, sulfur in natural gas (fuel sulfur and mercaptans added as an odorant) is oxidized to gaseous SO_2 within the combustor, but will be further oxidized to SO_3 across a high temperature catalyst (70% conversion is assumed). SO_3 will be emitted and/or combined to form H_2SO_4 (sulfuric acid mist) in the exhaust stack or downstream in the ambient air. These sulfates condense as additional PM_{10} (and $PM_{2.5}$). Thus, an oxidation catalyst would reduce emissions of CO and VOC, but would increase emissions of PM_{10} and $PM_{2.5}$.

The negative environmental impacts associated with this technology are less than for high-temperature SCR since no ammonia slip or ammonium salts are emitted. Collateral emissions due to efficiency losses or forced outages would still result in negative regional environmental impacts.

Economic Analysis

A high-temperature CO oxidation catalyst cost effectiveness evaluation was performed for the proposed Simple-Cycle General Electric 7FA turbines. Capital and annual costs associated with installation of a high temperature CO oxidation catalyst system were obtained from Engelhard, the vendor of high-temperature oxidation catalyst systems. Based on the quote from Engelhard (see Appendix C), the purchased equipment cost for each turbine is estimated at $1,484,700. Capital costs include the catalytic reactor, support structure, turbine transition piece, dilution air fan and flow straightener, spare parts and catalyst charge, freight, engineering and design, and installation. As shown in Table 5-5, when adding direct installation costs and indirect costs, the total capital cost (per turbine) is estimated at $2,390,300. Catalyst replacement is treated separately in this analysis as an operating cost. Annual operating costs, also summarized in Table 5-5, include operating labor (0.5 hour/shift), routine inspection and maintenance, spent catalyst replacement, and lost cycle efficiency due to increased back pressure. Annualized catalyst replacement cost was calculated based on a 3-year life.

Table 3-2 presents a worst-case CO emission estimate for the proposed project of 240 tons per year (70.3 tons per year per turbine). This estimate is based on 2,500 hours per year per turbine on natural gas at 50°F and 100 percent load and 1,000 hours per year per turbine on distillate oil at 50 °F and 100 percent load, which serves as a conservative estimate of the maximum annual emissions for the proposed turbines. The amount of CO removed annually by the oxidation catalyst would be 71.6 tons per turbine, based on estimated removal efficiency of 90 percent. The total annualized cost of oxidation catalyst for this case is estimated at $832,600, resulting in an overall cost-effectiveness of about $13,200 per ton of CO removed which is a prohibitive figure for non-LAER control of CO.

Another cost that has been removed from this analysis at the request of FL DEP is the lost revenue from this facility due to extended startup periods caused by the addition of an oxidation catalyst to the system. As the proposed turbines are intended to provide peak demand power, the ability to respond quickly to system demands is paramount to effective operation. Any operational constraints that restrict the ability of the proposed turbines to respond to these demands would result in lost revenues for the plant operators. The addition of an oxidation catalyst that is sensitive to sudden changes in temperature would require the plant operators to lengthen the startup sequence of the proposed turbines. A change of this type could potentially result in lost revenues in excess of $1,300,000 per

Table 5-5 High Temperature Oxidation Catalyst (Carbon Monoxide) General Electric, Simple-Cycle, Model 7 FA

Facility Input Data

Item	Value
Operating Schedule	Assumed 8 hours per shift
Total Hours per year	3,500
Natural Gas Firing (Normal Operation)	2,500
Distillate Oil Firing (Normal Operation)	1,000
Source(s) Controlled[1]	One Power Block, 175 MW
CO From Normal Natural Gas Operation (lb/hr)	29.6
CO From Distillate Oil Operation (lb/hr)	66.6
CO From Source(s) (tpy)	70.3
Site Specific Enclosure (Building) Cost	NA
Site Specific Electricity Value ($/kWh)	0.10
Site Specific Natural Gas Cost ($/MMBtu)	NA
Site Specific Operating Labor Cost ($/hr)	30
Site Specific Maint. Labor Cost ($/hr)	30

[1]CO emissions are based on data at 100% load and intake air chilled to maximum of 50°F.

Capital Costs[1]

Item	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$1,227,000	Scaled Engelhard quote + auxiliaries, A
b.) Instrumentation	$122,700	0.10 x A
c.) Sales taxes	$61,400	0.05 x A
d.) Freight	$73,600	0.06 x A
Total Purchased equipment cost, (PEC)	$1,484,700	B = 1.21 x A
2.) Direct installation costs		
a.) Foundations and supports	$118,800	0.08 x B
b.) Handling and erection	$207,900	0.14 x B
c.) Electrical	$59,400	0.04 x B
d.) Piping	$29,700	0.02 x B
e.) Insulation for ductwork	$14,800	0.01 x B
f.) Painting	$14,800	0.01 x B
Total direct installation cost	$445,400	0.30 x B
3.) Site preparation, SP	NA	NA
4.) Buildings, Bldg	NA	NA
Total Direct Cost, DC	$1,930,100	1.30B + SP + Bldg
Indirect Costs (installation)		
5.) Engineering	$148,500	0.10 x B
6.) Construction and field expenses	$74,200	0.05 x B
7.) Contractor fees	$148,500	0.10 x B
8.) Start-up	$29,700	0.02 x B
9.) Performance test	$14,800	0.01 x B
10.) Contingencies	$44,500	0.03 x B
Total Indirect Cost, IC	$460,200	0.28B
Total Capital Investment (TCI) = DC + IC	**$2,390,300**	**1.58B + SP + Bldg**

1 See Appendix C, Tables C-1 and C-1A

Table 5-5 High Temperature Oxidation Catalyst (Carbon Monoxide) General Electric, Simple-Cycle, Model 7 FA (Continued)

Annual Costs

Item	Value	Basis	Source
1) Electricity			
Press. Drop (in. W.C.)	2.2	Pressure drop - catalyst bed	Vendor
Power Output of Turbine (kW)	175,000		
Power Loss Due to Pressure Drop (%)	0.23%	0 105% for every 1" pressure drop	Vendor
Power Loss Due to Pressure Drop (kW)	404		
Unit Cost ($/kWh)	$0.10	Estimated Market Value	Estimate
Cost of Heat Rate Loss ($/yr)	$141,490		
Fan for Ambient Air Cooling (kW)	75	Estimated from Cooling Air Requirements	
Energy Required for Fan (kWh)	262,500		
Unit Cost ($/kW-hr)	$0.10	Estimated Market Value	Estimate
Cost of Cooling Fan Power ($)	$26,250		
Total Electricity Cost ($)	$167,740		
2) Operating Labor			
Requirement (hr/yr)	218.75	1/2 hr/shift, 3,500 hours per year	OAQPS
Unit Cost ($/hr)	$30 00	Facility Data	Estimate
Cost ($/yr)	$6,560		
3) Supervisory Labor			
Cost ($/yr)	$980	15% Operating Labor	OAQPS
4) Maintenance			
Labor Req. (hr/shift)	218.75	1/2 hour per shift	OAQPS
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Labor Cost ($/yr)	$6,563		
Material Cost ($/yr)	$6,560	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$13,120		
7) Catalyst Replacement			
Catalyst Cost ($)	$680,000	Catalyst modules	Vendor
Catalyst Disposal Cost ($)	$50,000	Disposal of catalyst modules	Estimate
Sales Tax ($)	$34,000	5% sales tax in Indiana	Estimate
Catalyst Life (yrs)	3	n	OAQPS
Interest Rate (%)	7	i	
CRF	0.38	Amortization of Catalyst	OAQPS
Annual Cost ($/yr)	$291,120	(Volume)(Unit Cost)(CRF)	
9) Indirect Annual Costs			
Overhead	$12,400	60% of O&M Costs	OAQPS
Administration	$47,800	2% of Total Capital Investment	OAQPS
Property Tax	$23,900	1% of Total Capital Investment	OAQPS
Insurance	$23,900	1% of Total Capital Investment	OAQPS
Capital Recovery	$245,100	10 yr life; 7% interest (-cat. cost)	OAQPS
Total Indirect ($/yr)	$353,100		

Total Annualized Cost ($/yr)	**$832,600**
Total CO Controlled (tpy)	**63.3**
Cost Effectiveness ($/ton)	**$13,200**

Additional Cost of Extended Startup sequence.

Power Loss Due to Extended Startups (kW-hr)	13,125,000	Extended startup time due to catalyst bed	Estimate
Cost of Extra Startups ($/yr)	$1,312,500	$0 10/kWh	

Total Annualized Cost ($/yr)	**$2,145,100**
Total CO Controlled (tpy)	**63.3**
Cost Effectiveness ($/ton)	**$33,900**

year. If this cost is incorporated into the cost-effectiveness calculation the cost of installing an oxidation catalyst would exceed $30,000/ton.

5.4.2.2 Next Best Level of Control – 10 to 50 ppm with Combustion Control

The next best level of control is the General Electric 7FA combustors optimized CO emission rate of 9 ppmvd while firing natural gas and 20 ppmvd while firing distillate oil. This level of control is available, will not cause negative operational or environmental impacts, is cost effective, and represents BACT.

Summary

The use of a high temperature oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10} (and $PM_{2.5}$) NO_x, SO_2, and CO_2 emissions, is not cost effective, and does not represent BACT for the Deerfield Beach Energy Center. Further, it would also lengthen peaking start-up times and limit the responsiveness of the project in its ability to address the peak power market. The next best level of control, 9 ppmvd while firing natural gas and 20 ppmvd while firing distillate oil using combustion control, is concluded to represent BACT for this facility.

5.4.3 Natural Gas Fuel Heater

The natural gas fuel heater will employ good combustion control for CO which has been determined to represent BACT for this source type. No add on control would be considered cost effective for control of CO emissions from this source.

5.5 BACT for Particulate Matter and Trace Metals

5.5.1 Formation

Particulate (PM) emissions from natural gas and distillate oil combustion sources consist of inert contaminants in the fuel, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, particulates of carbon and hydrocarbons resulting from incomplete combustion, and condensibles, including sulfates and nitrates. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions. Trace metals that may be emitted from natural gas combustion are discussed in this section because they form a portion of particulate emissions. Lead and mercury, which are regulated in Florida's SIP regulations, may be a metal constituent of distillate fuel oils. However, neither lead nor mercury are estimated to emit more than the significant emission rates established in 40 CFR 52.21.

5.5.2 Gas Turbines

When the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA recognized that "particulate emissions from stationary gas turbines are minimal," and noted that particulate control devices are not typically installed on gas turbines and that the cost of installing a particulate control device is prohibitive (U.S. EPA, September 1977). Performance standards for particulate control of stationary gas turbines were, therefore, not proposed or promulgated.

The most stringent particulate control method demonstrated for gas turbines or diesel engines is the use of low ash fuel (such as natural gas or low sulfur transportation diesel) and the avoidance of catalytic technologies such as SCR when not required for LAER. No particulate matter or mercury-specific add-on control technologies are listed in the RACT/BACT/LAER Clearinghouse listings for Simple Cycle combustion turbines as shown in Appendix C. Proper combustion control and the firing of fuels with negligible or zero ash content (natural gas and 0.05% sulfur transportation diesel) is the predominant control method listed.

Add on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas fired turbines. The use of ESPs or baghouse filters is technically infeasible, and does not represent an available control technology.

The use of negligible or zero ash fuels such as natural gas and low sulfur diesel, and good combustion control is concluded to represent BACT for PM control for the proposed Simple-Cycle peaking turbines and diesel engine. BACT for PM_{10} precludes the selection of high-temperature SCR for NO_x control as NH3 slip at 10 ppm could result in additional PM_{10} (and PM_{10} precursor) emissions.

5.5.3 Natural Gas Fuel Heater

The most stringent particulate control method demonstrated for, natural gas fired heaters is the use of low ash fuel (such as natural gas). Proper combustion control and the firing of fuels with negligible or zero ash content is the predominant control method listed in the RACT/BACT/LAER Clearinghouse for similar sources. Add-on controls, such as ESPs or baghouses, have never been applied to small natural gas fired heaters. The use of ESPs and baghouse filters is considered technically infeasible, and does not represent an available control technology.

5.6 BACT for Sulfur Dioxide and Sulfuric Acid Mist

5.6.1 Formation

Sulfur dioxide (SO_2) is exclusively formed through the oxidation of sulfur present in the fuel. The emission rate is a function of the sulfur content of the fuel, since virtually all fuel sulfur is converted to

SO_2. Another by-product of sulfur oxidation is when sulfur trioxide (SO_3) combines with water to form sulfuric acid (H_2SO_4). As a condensable gas, the sulfuric acid will appear in mist form in the stack if the temperatures are sufficiently low for condensation to occur. Since the stack exhaust will be in the 1050°F – 1250°F range, and the boiling point of sulfuric acid is less than 650°F, sulfuric acid mist will not form in the stack.

5.6.2 Gas Turbines and Fuel Gas Heater

The proposed simple cycle gas turbines will fire pipeline-quality natural gas and low sulfur transportation grade distillate fuel, the natural gas fuel heater will fire pipeline-quality natural gas only. Pipeline grade natural gas typically averages between 1-10 grains of sulfur per hundred standard cubic feet gas. A review of EPA RACT/BACT/LAER Clearinghouse information shows low sulfur fuel as the only available SO_2 control method selected as BACT in previous determinations for gas turbines. This indicates that the firing of pipeline quality natural gas and low sulfur transportation grade distillate fuel is the most stringent SO_2 control methodology that has been demonstrated in practice for any combustion turbine. Therefore, this evaluation concludes that that firing of pipeline quality natural gas and low sulfur transportation grade distillate fuel in the proposed Simple-Cycle peaking turbines and pipeline quality natural gas in the proposed fuel gas heater is BACT for SO_2.

If BACT were to be applied to H_2SO_4, which would preclude the use of an oxidation catalyst or SCR as the catalysts would further oxidize SO_2 to SO_3 which is a precursor of H_2SO_4. We should also state that H_2SO_4 would not be directly emitted from the turbine stack as the stack temperatures are too high. We should state that even though H_2SO_4 would not be emitted directly the test method used for sampling SO_2 if used could cause the formation of H_2SO_4 when the sample is cooled.

5.7 Summary and Conclusions

A summary of technologies determined to represent BACT for the DBEC project is are presented in Table 5-6. Expected total emissions are summarized in Section 3 which are estimated based on 100% load for 3,500 hours per year including up to 1,000 hours per year of distillate oil operation and application of BACT as determined in this analysis.

Table 5-6 Summary of Selected BACTs

Pollutant	Gas Turbines
NO_x	Dry Low NO_x Combustors with Natural Gas (9 ppmvd, 15% O_2, 24 hour average), Water injection with Distillate Oil (42 ppmvd, 15% O_2)
CO	Good combustion control (9 ppmvd with Natural Gas, 20 ppmvd with Distillate Oil)
PM	Good combustion control; low ash, low sulfur fuel
SO_2	Low sulfur fuel; natural gas (2 grains S / 100 scf gas) distillate oil (0.05 wt% S)

6.0 AMBIENT AIR QUALITY IMPACT ANALYSIS

6.1 Overview of Analysis Methodology

The PSD rules require an analysis of the impact of the proposed facility on ambient concentrations of pollutants emitted in significant quantities, for which there is a National Ambient Air Quality Standard or PSD Increment. For the proposed facility, this includes NO_x, CO, SO_2, and PM_{10}. Although the project is not subject to PSD review for lead, the air quality standards analysis included a compliance assessment of this pollutant.

The ambient concentrations of PSD pollutants resulting from allowable emissions from the proposed facility are predicted using an approved U.S. EPA atmospheric dispersion model in accordance with U.S. EPA's "Guideline on Air Quality Models" (U.S. EPA, 1999). The atmospheric dispersion of emissions is simulated for a record of representative sequential hourly meteorological conditions over a historical five-year period. Ground-level concentrations at various averaging periods depending on the pollutant are predicted for a grid of ground-level model "receptors" surrounding the proposed facility. The following sections detail the specific aspects of the ambient air quality impact analysis.

6.2 Model Selection

The selection of an appropriate dispersion model must take into consideration the physical geometry of the sources, the local dispersion environment, and terrain characteristics. These factors, which formulate the basis for choosing one or more of the models recommended in the U.S. EPA modeling guidelines for both screening and refined modeling, are discussed below.

6.2.1 Physical Source Geometry

The sources of PSD pollutants from the proposed facility consist of high velocity, high temperature exhausts from stacks connected to the combustion turbines. This requires the use of a model capable of simulating the dispersion of buoyant releases from elevated point sources. The U.S. EPA modeling guidelines require the evaluation of the potential for physical structures to affect the dispersion of emissions from elevated point sources. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" (GEP) stack height analysis. Stacks with heights below physical GEP are considered to be subject to building downwash. In the absence of structural effects, U.S. EPA has established a "default" GEP height of 213 feet. Any portion of a stack above the maximum of the physical or default GEP height cannot be used in the dispersion modeling analysis for purposes of comparison to U.S EPA's ambient impact criteria.

Each of the three combustion turbines at the proposed facility will have its own stack. A GEP stack height analysis was performed for the proposed project configuration in accordance with U.S. EPA's guidelines (U.S. EPA, 1985). Per the guidelines, the physical GEP height, H_{GEP}, is determined from the dimensions of all buildings which are within the region of influence using the following equation:

$$H_g = H + 1.5L$$

where:

H = height of the structure within 5L of the stack which maximizes H_g, and

L = lesser dimension (height or projected width) of the structure.

For a squat structure, i.e., height less than projected width, the formula reduces to:

$$H_g = 2.5H$$

In the absence of influencing structures, a "default" GEP stack height is credited up to 65 meters (213 feet). The locations and dimensions of the various structures at the proposed facility relative to the exhaust stacks are depicted in Figure 6-1. An analysis of the potential for building downwash is presented below.

The significant structures of the proposed facility will include the turbine enclosures, turbine air intake structures, control room/electrical room/administration building, water storage tanks, and fuel storage tanks. U.S. EPA's Building Profile Input Processor (BPIP), as implemented in Lakes-Environmental *BPIP View* software, was used to determine the GEP stack height and to develop building input data for the modeling analysis. The output of the BPIP analysis is provided in Appendix D. A summary of the GEP analysis and the controlling building is provided in Table 6-1. The table lists the physical GEP stack height calculated for each influencing structure. Based on the BPIP analysis, the GEP stack height for the turbine stacks is 135 feet. Since the proposed height of the combustion turbine stacks is 80 feet, building downwash affects must be simulated in the dispersion modeling analysis. Also, since the stacks are less than the default GEP height of 213 feet, their full height can be considered in the modeling.

Figure 6-1 Location of Turbine Stacks Relative to Structures Included in the GEP Analysis

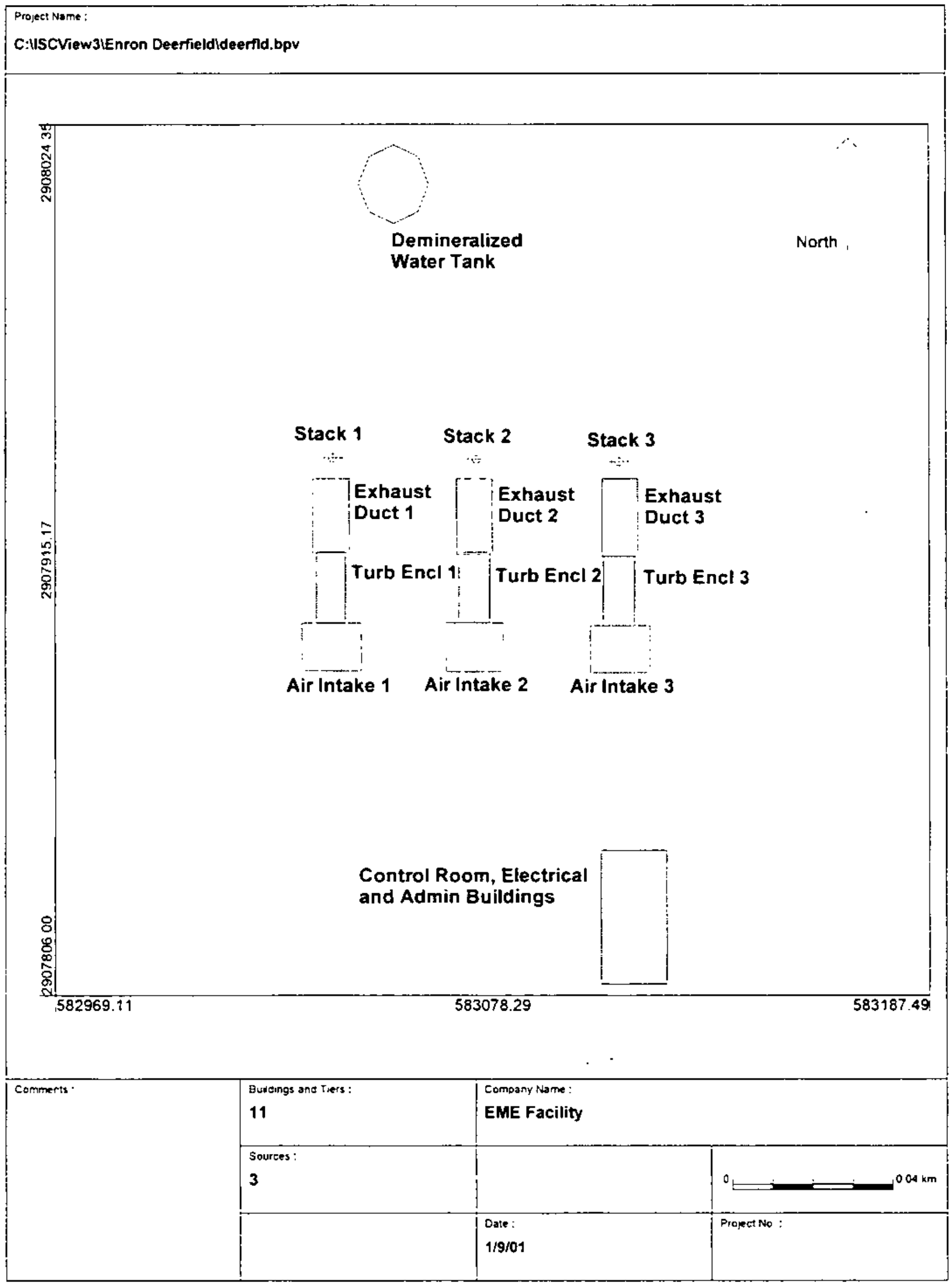


Table 6-1 Summary of GEP Analysis (Units in Feet)

Structure	Height	Length	Width	MPW(2)	GEP Formula Height	5L(3)	Distance to Turbine Stack (4)	Turbine Stack(s) Potentially Effected By Downwash Yes/No
Turbine Air Intake(1)	54	45	36	57	135	270	112	Yes
Turbine Enclosure (1)	45	49	23	54	113	225	62	Yes
Exhaust Duct (1)	27	62	26	67	67.5	135	0	Yes
Control/Admin Building	45	110	45	119	112.5	225	315	No
Demineralized Water Tank	48	59	59	59	120	240	180	Yes

(1) One associated with each turbine (see Figure 6-1).
(2) Maximum projected width.
(3) 5 times the lessor of the MPW or height is the maximum influence region.
(4) Closest distance relative to all turbine stacks.

6.2.2 Dispersion Environment

The selection and application of the model requires characterization of the local (within 3 km) dispersion environment as either urban or rural, based on a U.S. EPA-recommended procedure that characterizes an area by prevalent land use. This land use approach classifies an area according to 12 land use types. In this scheme, areas of industrial, commercial, and compact residential land use are designated urban. According to U.S. EPA modeling guidelines, if more than 50 percent of an area within a three-kilometer radius of the proposed facility is classified as rural, then rural dispersion coefficients are to be used in the dispersion modeling analysis.

For this analysis, the 1:24,000 scale United States Geological Survey (USGS) topographic maps for West Dixie Bend was obtained. Visual observation of the land use depicted on these maps clearly indicates that the region within 3 km is predominately rural.

6.2.3 Terrain Considerations

The U.S. EPA modeling guidelines require that the differences in terrain elevations, between the stack base and each location (receptor) at which air quality impacts are predicted, be considered in the modeling analyses. There are three types of terrain:

- simple terrain – locations where the terrain elevation is at or below the exhaust height of the stacks to be modeled;
- intermediate terrain – locations where the terrain is between the height of the stack and the modeled exhaust "plume" centerline (this varies as a function of plume rise, which in turn, varies as a function of meteorological condition);
- complex terrain – locations where the terrain is above the plume centerline.

Based on a review of USGS topographical maps, the area throughout the modeling domain is generally flat. The dispersion model must therefore be capable of simulating impacts on simple terrain only.

Based on a review of the factors discussed above, the ISCST3-Version 00101 dispersion model was selected for use in the modeling analysis.

6.3 Model Application

The ISCST3 model was used to calculate concentrations at simple receptor locations. The model was applied using the ISCST3 regulatory default option, in accordance with the U.S. EPA Guidelines.

6.3.1 Meteorological Data

The ISCST3 model requires a sequential hourly record of dispersion meteorology representative of the region within which the proposed source is located. In the absence of site-specific measurements, the EPA Guidelines recommend the use of data from nearby National Weather Service (NWS) stations, provided they are representative. For this analysis a five-year sequential meteorological data set was used consisting of surface observations and concurrent mixing height data from the NWS station at West Palm Beach International airport from 1987 through 1991. The West Palm Beach data are the closest representative data available and were recommended by the DEP for use in this application. The DEP provided the data in the processed format required for input to ISCST3.

6.3.2 Model Receptor Grid

A cartesian receptor grid was generated for use in the ISCST3 modeling. The grid consisted of densely spaced receptors at 100 meters apart starting at and extending to 3000 meters from the fenceline. Beyond 3000 meters, a spacing of 500 meters was used out to five kilometers from the facility. From six to ten kilometers, a spacing of 1000 meters was used. Between ten and twenty kilometers, a spacing of 2000 meters was used. Additional receptors were placed approximately every 50 meters along the property fence-line for increased resolution of impacts. As recommended by DEP, terrain elevations were not used for the receptors given that the terrain in the study area is generally flat. The extent of this grid was sufficient to capture maximum impacts.

Figure 6-2 shows the near-field receptors (out to three kilometers) including the near-field portion of the cartesian grid and fence-line receptors. The full cartesian receptor grid out to twenty kilometers is shown in Figure 6-3.

Figure 6-2 Near-Field Receptor Locations

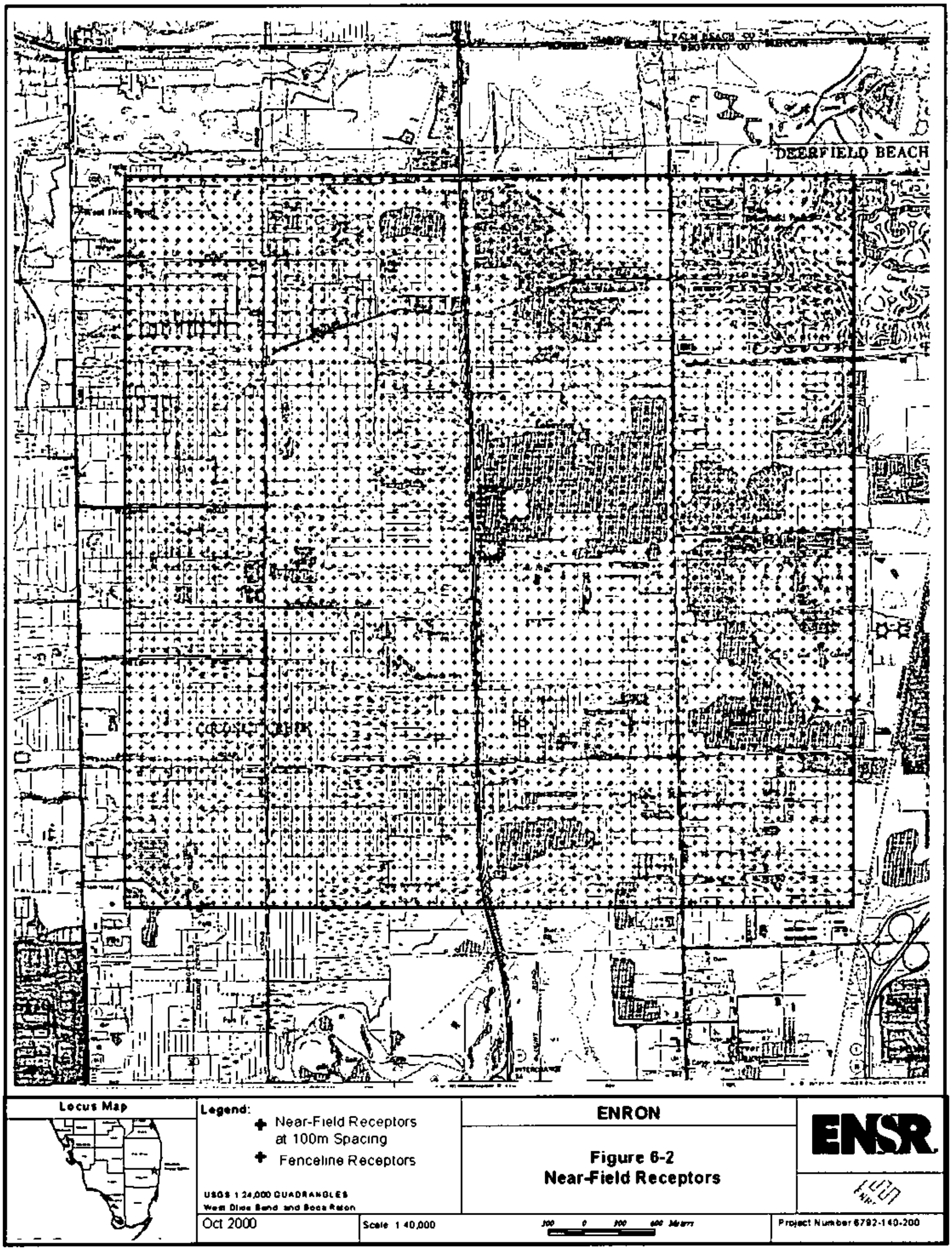
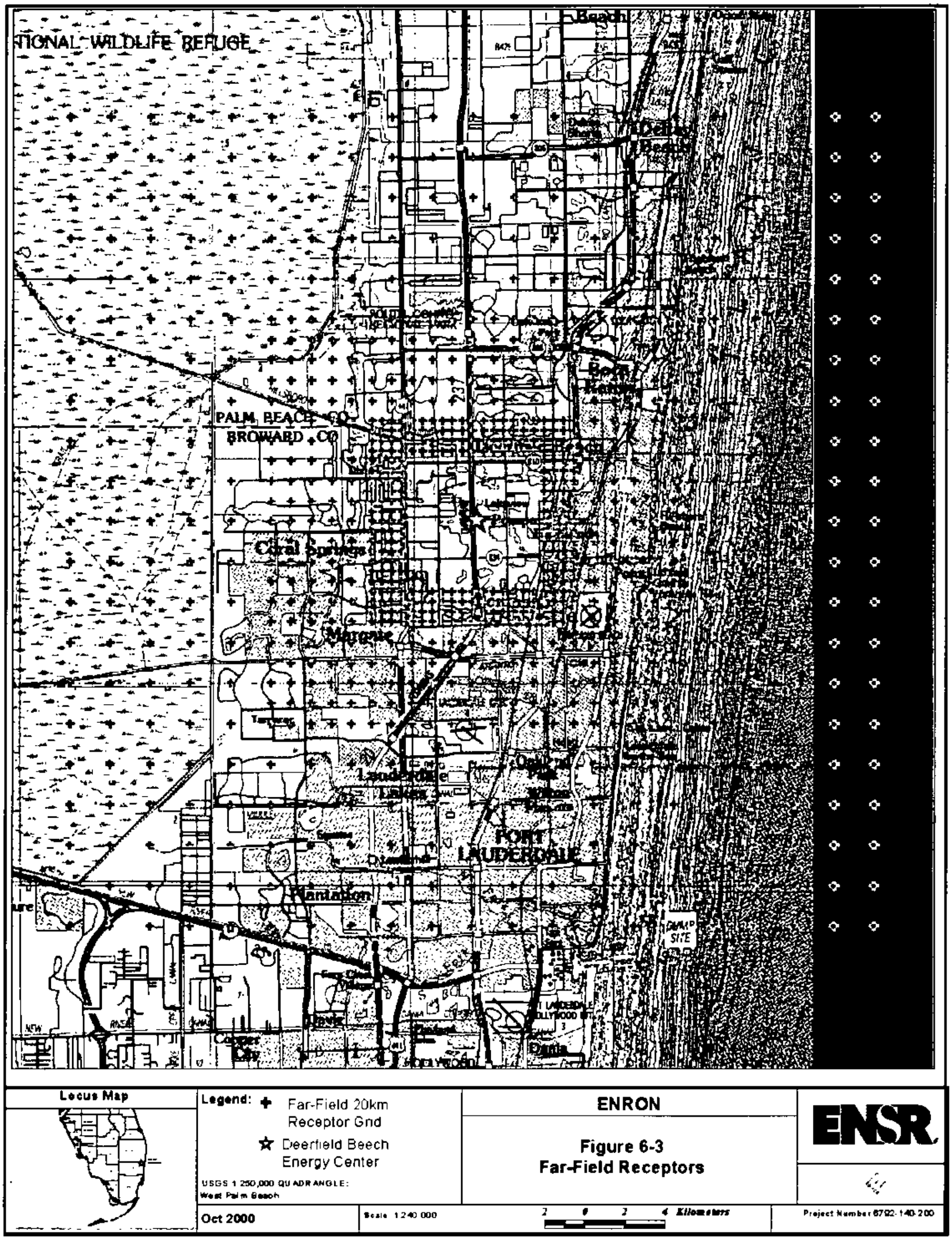


Figure 6-3 Far-Field Receptors



6.3.3 Physical Source and Emissions Data

The air dispersion modeling analysis was conducted with emission rates and flue gas exhaust characteristics (flow rate and temperature) that are expected to represent the worst-case parameters among the range of possible values for the GE turbine model under consideration. Because turbine emission rates and flue gas characteristics for a given turbine load vary as a function of ambient temperature and fuel use, data were derived for four ambient temperatures for each proposed fuel at each of the three operating load scenarios (100%, 75% and 50%). The temperatures selected were:

- 30°F, an extreme lower boundary
- 42°F,
- 50°F, the effective inlet air temperature when the chillers are operating
- 91°F, a representative upper boundary

A summary of the exhaust data and emission rates for the PSD regulated pollutants for each fuel at each temperature and the three operating loads is provided in Table 6-2 for the GE 7FA turbines. Detailed calculations of the emissions parameters are presented in Appendix B.

In order to conservatively calculate ground-level concentrations, a composite "worst-case" set of emissions parameters was developed for each proposed fuel for input to the modeling. For each operating load, the highest pollutant-specific emission rate, the lowest exhaust temperature and the lowest exhaust flow rate were selected. Table 6-3 summarizes the worst-case emissions parameters for the two fuels at three operating loads.

Wind-direction-specific dimensions of the structures potentially causing building downwash of the turbine stacks were derived using the U.S. EPA BPIP processor. The BPIP inputs to the ISCST3 model are provided in Appendix D.

6.4 Ambient Impact Criteria

The U.S. EPA has established specific ambient impact criteria against which to evaluate the impact of a proposed new source. These are listed in Table 6-4 for the pollutants considered in this analysis. A description of each of the criteria and the relevance to the PSD application is described below.

Table 6-2 Combustion Turbine Performance Data for Natural Gas and Distillate Fuel Oil Operation

100 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1149	1109	1100	1087
Exit Velocity (Ft./sec)		150.4	160.6	162.0	164.0
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	53.5	59.6	60.4	61.6
	CO	26.5	29.6	30.1	30.9
	SO_2	9.5	10.6	10.7	10.9
	PM_{10}	18.0	18.0	18.0	18.0

75 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1180	1147	1142	1134
Exit Velocity (Ft./sec)		125.8	130.8	131.5	132.7
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	43.5	47.5	48.1	49.0
	CO	21.8	23.5	23.8	24.3
	SO_2	7.8	8.5	8.6	8.8
	PM_{10}	18.0	18.0	18.0	18.0

50 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1200	1194	1189	1182
Exit Velocity (Ft./sec)		106.9	111.3	111.8	112.4
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	34.4	37.7	38.1	38.7
	CO	18.4	19.5	19.7	20.0
	SO_2	6.2	6.8	6.9	7.0
	PM_{10}	18.0	18.0	18.0	18.0

Table 6-2 Combustion Turbine Performance Data for Natural Gas and Distillate Fuel Oil Operation (continued)

100 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1138	1088	1079	1065
Exit Velocity (Ft./sec)		154.4	165.0	166.5	168.6
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	289.6	321.0	325.5	332.1
	CO	59.5	66.6	67.8	69.6
	SO_2	90.3	100.2	101.6	103.6
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.03	0.03	0.03	0.03

75 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1186	1153	1148	1142
Exit Velocity (Ft./sec)		128.3	133.0	134.0	135.5
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	232.7	254.0	257.9	263.2
	CO	50.7	56.8	57.5	58.5
	SO_2	73.3	80.0	81.3	82.9
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.02	0.02	0.02	0.02

50 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1200	1200	1200	1193
Exit Velocity (Ft./sec)		109.0	112.5	112.9	113.4
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	181.9	199.2	201.5	204.6
	CO	78.3	66.5	64.6	67.6
	SO_2	57.9	63.4	64.2	65.1
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.02	0.02	0.02	0.02

Table 6-3 Worst-Case Turbine Stack Data for Dispersion Modeling

Natural Gas Operation

Parameter		Value		
Load (%)		100	75	50
Stack Height (Ft.)		80	80	80
Stack Diameter (Ft.)		18	18	18
Exit Temperature (^{o}F)		1087	1134	1182
Exit Velocity (Ft./sec)		150.4	125.8	106.9
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	61.6	49.0	38.7
	CO	30.9	24.3	20.0
	SO_2	10.9	8.8	7.0
	PM_{10}	18.0	18.0	18.0

No. 2 Fuel Operation

Parameter		Value		
Load (%)		100	75	50
Stack Height (Ft.)		80	80	80
Stack Diameter (Ft.)		18	18	18
Exit Temperature (^{o}F)		1065	1142	1193
Exit Velocity (Ft./sec)		154.4	128.3	109.0
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	332.1	263.2	204.6
	CO	69.6	58.5	78.3
	SO2	103.6	82.9	65.1
	PM_{10}	34.0	34.0	34.0
	Lead	0.028	0.023	0.018

Table 6-4 Ambient Impact Criteria[1]

Pollutant	Averaging Period	NAAQS Primary	NAAQS Secondary	Maximum Allowable PSD Class II Increments	PSD Significant Monitoring Concentration	PSD Class II Significant Impact Levels	PSD Class I Significant Impact Levels
NO_2	Annual	100	100	25	14	1	0.1
CO	1-hour	40,000	NA	NA	NA	2,000	NA
	8-hour	10,000	NA	NA	575	500	NA
PM_{10}	24-hour	150	150	30	10	5	0.3
	Annual	50	50	17	NA	1	0.2
SO_2	3-hour	NA	1300	512	NA	25	1.0
	24-hour	365	NA	91	13	5	0.2
	Annual	80	NA	20	NA	1	0.1
Lead	Quarter	1.5	1.5	NA	NA	NA	NA

[1] All values in $\mu g/m^3$. Annual averages are the maximum over all receptors. Short-term averages are the highest of the second-highest concentration over all receptors.
NA = Not Applicable

National Ambient Air Quality Standards (NAAQS)

National Ambient Air Quality Standards (NAAQS) are set by U.S. EPA, based on specific health and welfare effects criteria. Hence the term "criteria" pollutants. Ambient air refers to the air to which the general public is exposed, not the air inside buildings or in workplaces. The combined impacts of all existing sources cannot exceed the NAAQS. The primary NAAQS are established to protect the health of sensitive individuals. The secondary NAAQS are established to protect the general welfare of the public-at-large from adverse impacts on air quality related values such as visibility.

Allowable PSD Increments

The PSD increments are maximum allowable incremental increases in the ambient concentrations of the criteria pollutants in NAAQS attainment areas. The net combined impacts of all emissions increases and decreases from all sources occurring after a specified baseline date cannot exceed the PSD Increments. The PSD Class II increments apply to most areas of the country, including most of Florida with the exception of the designated PSD Class I areas. PSD Class I areas are National Parks and Wilderness Areas designated by U.S. EPA for special protection, including tighter PSD increments. The nearest PSD Class I area to the proposed facility is the Everglades National Park located about 60 kilometers to the southwest. New sources are presumed to have an insignificant impact on a PSD Class I area if maximum modeled impacts are less than the levels shown in Table 6-4. Since long range transport modeling involving the use of the CALPUFF dispersion model is required for the Class I impact assessment, a separate analysis is being completed for this assessment in coordination with the National Park Service Air Quality Division. The results of the PSD Class I area assessment will be submitted as a supplement to this permit application.

PSD Significant Monitoring Concentrations

PSD applicants can be granted a discretionary waiver from PSD pre-construction air quality monitoring requirements if the modeled impacts of the new source are below these concentrations.

PSD Significant Impact Levels

As can be seen from the concentrations representing these levels, the Significant Impact Levels (SILs) are small fractions of the NAAQS and PSD increments. The U.S. EPA guidelines require these levels to be used to determine the extent of the area surrounding a proposed source within which the source could significantly add to ambient air quality concentrations. For proposed sources whose impacts are above these levels, an analysis of the combined impacts of the proposed source with other existing sources is required. If a proposed source's impacts are below these levels it is considered to be unable to either cause or contribute to violations of the NAAQS, PSD Class II, or Class I increments. Therefore, a cumulative impact assessment is not required.

6.5 Results of Ambient Air Quality Impact Analysis

The emissions from the turbine stacks (3) were modeled with ISCST3 to estimate the maximum concentrations for the criteria pollutants including NO_x, PM/PM_{10}, SO_2, CO, and lead for each year of meteorological data. Note that the modeling of annual impacts reflects limited operation of the combustion turbines (3500 hours/year/turbine including up to 1000 hours/year/turbine of distillate fuel oil usage).

Class II Area Receptors

Tables 6-5 and 6-6 provide summaries of the ISCST3 modeling results for NO_x, PM/PM_{10}, SO_2, CO, and lead for the Class II cartesian grid and fence-line receptors for natural gas and oil firing, respectively. The maximum air concentrations over the five years modeled and corresponding receptor locations are listed for each turbine load case (100%, 75% and 50%). The modeling results for all years of modeling are provided in Appendix E. Note that in Table 6-5 (results for natural gas), the maximum annual concentrations are based on a maximum of 3500 hours/year of natural gas firing (i.e., the results have been scaled by a factor of 3500/8760). Similarly, in Table 6-6 (results for oil), the maximum annual concentrations are based on a maximum of 1000 hours/year of oil firing (i.e., the results have been scaled by a factor of 1000/8760).

Table 6-5 ISCST3 Modeling Results for Natural Gas

100% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m^3)*	Receptor Location UTM East (m)	UTM North (m)
NO_X	Annual	0.015	574074	2912940
PM-10	24-hour	0.149	567074	2917940
	Annual	0.005	574074	2912940
SO_2	3-hour	0.369	589074	2891940
	24-hour	0.090	567074	2917940
	Annual	0.003	574074	2912940
CO	1-hour	2.716	583574	2908540
	8-hour	0.620	565074	2903940

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

75% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m^3)*	Receptor Location UTM East (m)	UTM North (m)
NO_X	Annual	0.015	574074	2912940
PM-10	24-hour	0.171	567074	2917940
	Annual	0.005	574074	2912940
SO_2	3-hour	0.353	583474	2908440
	24-hour	0.083	567074	2917940
	Annual	0.003	574074	2912940
CO	1-hour	2.921	583474	2908440
	8-hour	0.563	565074	2903940

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

50% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m^3)*	Receptor Location UTM East (m)	UTM North (m)
NO_X	Annual	0.014	574074	2912940
PM-10	24-hour	0.194	573074	2913940
	Annual	0.006	574074	2912940
SO_2	3-hour	0.372	583474	2908440
	24-hour	0.076	573074	2913940
	Annual	0.002	574074	2912940
CO	1-hour	3.191	583474	2908440
	8-hour	0.526	565074	2903940

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

Table 6-6 ISCST3 Modeling Results for Distillate Oil

100% Load

Pollutant	Averaging Period	Maximum Concentration (µg/m³)*	Receptor Location UTM East (m)	UTM North (m)
NO_X	Annual	0.023	574074	2912940
PM-10	24-hour	0.277	567074	2917940
	Annual	0.002	574074	2912940
SO_2	3-hour	3.439	589074	2891940
	24-hour	0.844	567074	2917940
	Annual	0.007	574074	2912940
CO	1-hour	5.939	583574	2908540
	8-hour	1.373	565074	2903940
Lead	24-hour	2.28E-04	567074	2917940

* Annual concentrations based on a maximum of 1000 hours/year of oil use.

75% Load

Pollutant	Averaging Period	Maximum Concentration (µg/m³)*	Receptor Location UTM East (m)	UTM North (m)
NO_X	Annual	0.022	574074	2912940
PM-10	24-hour	0.317	567074	2917940
	Annual	0.003	574074	2912940
SO_2	3-hour	3.213	589074	2891940
	24-hour	0.772	567074	2917940
	Annual	0.007	574074	2912940
CO	1-hour	6.765	583574	2908540
	8-hour	1.331	565074	2903940
Lead	24-hour	2.61E-04	567074	2917940

* Annual concentrations based on a maximum of 1000 hours/year of oil use.

50% Load

Pollutant	Averaging Period	Maximum Concentration (µg/m³)*	Receptor Location UTM East (m)	UTM North (m)
NO_X	Annual	0.020	574074	2912940
PM-10	24-hour	0.359	573074	2913940
	Annual	0.003	574074	2912940
SO_2	3-hour	3.337	583474	2908440
	24-hour	0.688	573074	2913940
	Annual	0.006	574074	2912940
CO	1-hour	12.041	583474	2908440
	8-hour	2.020	565074	2903940
Lead	24-hour	2.96E-04	573074	2913940

* Annual concentrations based on a maximum of 1000 hours/year of oil use.

A comparison of the overall maximum pollutant impacts with the Class II Significant Impact Levels is presented in Table 6-7. For each pollutant and averaging period, the table lists the maximum predicted concentration for all fuels, years of meteorology, and worst-case turbine operating load. All of the modeled concentrations are below the SILs. Based on these results it can be concluded that the proposed facility will neither cause nor contribute to a violation of the NAAQS or PSD Class II increments. It is also pointed out that these impacts are below the relevant PSD significant monitoring concentrations as well. Thus, the facility is eligible for a waiver from pre-construction monitoring.

Table 6-7 Comparison of Maximum ISCST3 Concentrations to Class II Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)*	SIL ($\mu g/m^3$)
NO_X	Annual	0.034	1
PM-10	24-hour	0.359	5
	Annual	0.008	1
SO_2	3-hour	3.439	25
	24-hour	0.844	5
	Annual	0.009	1
CO	1-hour	12.041	2,000
	8-hour	2.020	500
Lead**	Quarterly	2.96E-04	1.5

*** Annual concentrations based on a worst-case composite of maximum natural gas concentration scaled by 2500 hours/year plus maximum oil concentration scaled by 1000 hours/year.**

**** Lead concentration is conservatively represented by the maximum 24-hour value. There is no SIL for Lead. The lead concentration is compared to the NAAQS.**

6.6 Broward County Air Modeling Requirement

The Broward County Code Sec. 27-175 and 27-176(c)(2)b prohibits major sources from allowing emissions of criteria pollutants in quantities that would reduce by more than one half the margin between the existing ambient concentrations and the applicable NAAQS. This section provides the modeling analysis to demonstrate compliance with this local requirement.

The Broward County Department of Planning and Environmental Protection (DPEP) was contacted to obtain air monitoring data to establish a baseline of existing ambient concentrations in Broward County. The DPEP provided 1999 ambient monitoring data from sites operated by the Broward County Air Quality Division. These data consisted of eight monitoring sites for PM_{10}, one for SO_2, one for NO_2, three for ozone and five for CO. To be conservative, ENSR selected the highest measured concentrations for each averaging period from among all the sites for use in this analysis.

Table 6-8 shows that the DBEC will consume substantially less than one-half of the margin between the maximum baseline concentration and the NAAQS. In fact, the project impact is less than one percent of this margin for all criteria pollutants modeled.

Table 6-8 Compliance Demonstration for Broward County Code Section 27.176(c)(2)(b)

Pollutant	Averaging Period	Baseline Conc.[1] (μg/m³)	Site No.	NAAQS (μg/m³)	½ [NAAQS-Baseline] (μg/m³)	Maximum Predicted Impact of Facility (μg/m³)
PM_{10}	24 hr	38	3	150	56	0.4
	Annual	18	28,29	50	16	0.01
SO_2	3-hr	272	28	1300	514	3.4
	24-hr	47	28	365	159	0.8
	Annual	9	28	80	35.5	0.01
NO_2	Annual	20	31	100	40	0.05
CO	1-hr	10,877	18	40,000	14,563	12.0
	8-hr	6,298	28	10,000	1,851	2.0
[1]**Highest measured concentration in 1999 from Broward Co. Air Quality Division Monitoring Stations**						

Although ambient ozone data is available and was provided by the county, the above table did not provide a comparison for ozone for several reasons. Ozone is a regional phenomenon and it's not feasible to model the impact of a single source on resultant ambient ozone levels. Typically, such analyses are resource intensive, and are conducted as multi-source regional studies. Further, utilizing the EPA Urban Airshed Model (UAM) for ozone requires various databases that are not yet available for southeast Florida.

However, for the purpose of addressing the Broward County requirement, the potential for the DBEC to impact regional ozone levels can be addressed in a reasonable, yet simplistic way. Ozone is a secondary pollutant formed primarily from photochemical reactions involving the precursors NOx, VOCs and CO, that are emitted from a variety of sources distributed throughout the airshed. Therefore, ozone concentrations will be materially affected only if there is a substantial change in the emissions burden throughout the airshed. Thus, if one were to compare the project's estimated emissions of these precursors to the countywide total, a rough estimate could be made of the resultant increase in ozone levels. Although the change in ozone can be highly non-linear in response to changes in ozone emissions, there is simply no easy way to quantitatively address this issue, short of an actual multi-source regional study.

Table 6-9 illustrates that the maximum percent increase of ozone precursors associated with the DBEC is 1.09 percent. The highest second high ozone concentration measured in 1999 in Broward was 0.084 ppm. The halfway point between this measurement and the standard of 0.12 ppm is 0.102 ppm, an increase of 21.4 percent above current levels. Although the change in ozone can be highly nonlinear in response to changes in precursor emissions, it is extremely unlikely that such a small increase (approximately one percent) in precursor emissions could result in such a magnitude of increase (>20 percent) in ozone levels.

Table 6-9 Ozone Compliance Demonstration for Broward County Code Section 27.176(c)(2)(b)

Broward County 1997 Ozone Precursor Emission Inventory			
	NO_x (tons/year)	VOC (tons/year)	CO (tons/year)
Total 1997 Emissions in Broward	**63,916**	**124,733**	**343,772**
Proposed DBEC Emissions Compared to Total Emissions Inventoried in Broward County In 1997			
Source Type	**NO_x (tons/year)**	**VOC (tons/year)**	**CO (tons/year)**
Deerfield Beach Energy Center (DBEC) 3 natural gas fired turbines - 0 hrs oil	326	18	165.1
Percent of Total DBEC Emissions in Broward County - 0 hrs oil	***0.51***	***0.03***	***0.05***
Deerfield Beach Energy Center (DBEC) Worst Case 2500 hours gas - 1000 hours oil	705	15.3	210.9
Percent of Total DBEC Emissions in Broward County - 1000 hrs oil	***1.09***	***0.01***	***0.06***

7.0 ADDITIONAL IMPACTS

The preceding sections of this permit application have focused on demonstrating the proposed action will incorporate Best Available Control Technology and will not have a significant impact on air quality. Beyond consideration of these basic air quality concerns, PSD regulations require a review of some of the more subtle effects a project may induce. The following section discusses the potential impacts which may result from the proposed project with respect to the following:

- Vegetation and Soils
- Associated Growth
- PSD Class I Area Impacts – Air Quality Increments, Regional Haze, and Deposition

7.1 Vegetation and Soils

The project lies in an area of primarily agricultural use. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. The following discussion reviews the project's potential to impact its surroundings, based on the facility's PTE and the model-predictions of maximum ground level concentrations of SO_2, NO_x and CO, the PSD-applicable pollutants of concern for potential impact to soils and vegetation.

The criteria for evaluating impacts on soils and vegetation is taken from U.S. EPA's A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (U.S. EPA 1980). Table 7-1 lists the U.S. EPA suggested criteria for the gaseous pollutants emitted directly from the proposed facility and the predicted facility impacts. These criteria are established for sensitive vegetation and crops exposed to the effects of the gaseous pollutants through direct exposure. Adverse impacts on soil systems result more readily from the secondary effects of these pollutants' impacts on the stability of the soil system. These impacts could include increased soil temperature and moisture stress and/or increased runoff and erosion resulting from damage to vegetative cover. Thus, the Table 7-1 criteria have been applied to the proposed facility to evaluate impacts on both soils and vegetation. As shown in Table 7-1, the results clearly indicate that no adverse impacts will occur to sensitive vegetation, crops, or soil systems as a result of operation of the proposed facility.

Table 7-1 Comparison to U.S. EPA Criteria for Gaseous Pollutant Impacts on Natural Vegetation and Crops

Pollutant	Averaging Time*	Minimum Impact Level for Affects On Sensitive Plants ($\mu g/m^3$)	Maximum Impact of Proposed Facility ($\mu g/m^3$)
SO_2	1 hour	917	10.01
	3 hours	786	3.44
	Annual	18	0.009
NO_x	4 hours	3760	11.02
	8 hours	3760	6.55
	1 month	564	2.71
	Annual	94	0.034
CO	1 week	1,800,000	0.83

*** 24-hour average used to conservatively represent 1-week and 1-month average impacts and 3-hour average used to conservatively represent 4-hour average impact.**

7.2 Associated Growth

The proposed project will employ approximately 200 personnel during the construction phase. The project will employ approximately 10 personnel on a permanent basis. It is a goal of the project to hire from the local community when possible. There should be no substantial increase in community growth, or need for additional infrastructure. It is not anticipated that the proposed action will result in an increase in secondary emissions associated with non-project related activities. Therefore, in accordance with PSD guidelines, the analysis of ambient air quality impacts need consider only emissions from the facility itself.

7.3 Class I Area Impact Analysis

The nearest PSD Class I area to the proposed facility is the Everglades National Park located about 60 kilometers to the southwest. Given that the Class I area is greater than 50 kilometers from the proposed facility, long range transport modeling involving the use of the CALPUFF dispersion model is required for the Class I impact assessment. The analysis will evaluate the potential impact of the proposed facility emissions in terms of air quality, regional haze, and deposition (sulfur and nitrogen). A separate analysis is being completed for this assessment in coordination with the National Park Service Air Quality Division. The results of the PSD Class I area assessment will be submitted as a supplement to this permit application.

APPENDIX A

FLORIDA DEP APPLICATION FORMS

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Deerfield Beach Energy Center, LLC**	
2. Site Name: **Deerfield Beach Energy Center**	
3. Facility Identification Number: [✔] Unknown	
4. Facility Location: Street Address or Other Locator: **West of intersection of "N. Powerline Rd" and "NW 48th St" and east of the Florida Turnpike** City: **Deerfield Beach** County: **Broward** Zip Code: **33069**	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [ ] Yes [✔] No

Application Contact

1. Name and Title of Application Contact: **Dave Kellermeyer, Director**
2. Application Contact Mailing Address: Organization/Firm: **Deerfield Beach Energy Center, LLC** Street Address: **1400 Smith Street** City: **Houston** State: **TX** Zip Code: **77002-7631**
3. Application Contact Telephone Numbers: Telephone: **(713) 853-3161** Fax: **(713) 646-3037**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3-5-01
2. Permit Number:	0112534-001-AC
3. PSD Number (if applicable):	PSD-FL-314
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:________________________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:________________________________

Operation permit number to be revised:______________________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:_________________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:______________________________

Reason for revision:____

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[✔] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: **Ben Jacoby – Director**	
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Deerfield Beach Energy Center, L.L.C.** Street Address: **1400 Smith Street** City: **Houston** State: **TX** Zip Code: **77002-7631**	
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(713) 853-6173** Fax: **(713) 646-3037**	
4. Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✔], if so) of the Title V source addressed in this application, whichever is applicable. 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. 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 any permitted emissions unit.* Ben F. [signature] 1-5-01 Signature Date	

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: **Blair Burgess** Registration Number: **45460**	
2. Professional Engineer Mailing Address: Organization/Firm: **ENSR** Street Address: **2809 West Mall Drive** City: **Florence** State: **AL** Zip Code: **35630**	
3. Professional Engineer Telephone Numbers: Telephone: **(256) 767-1210** Fax: **(256) 767-1211**	

4. 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.

If the purpose of this application is to obtain a Title V source 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 schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit 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.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision 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.

1/22/01

Signature ______________________ Date 1/22/01

EMBOSSED METALLIC

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
CT001 – CT003	PG7241S(FA) Simple Cycle Combustion Turbines (Three identical combustion turbines)	AC1A	$7,500 Similar emissions unit fee per Rule 62-4.050(4)(a)(4)
T001 – T002	Distillate Fuel Oil Storage Tanks (Main Tank and Day Tank)	AC1F	
NGH	Natural Gas Fuel Heater	ACIF	
CTWR	Cooling Tower	ACIF	

Application Processing Fee

Check one: [] Attached - Amount: [✔] Not Applicable

Note: Due to previously-submitted and withdrawn permit applications, the parent company of Deerfield Beach Energy Center has an existing positive application fee balance with the Florida Department of Environmental Protection.

Construction/Modification Information

1. Description of Proposed Project or Alterations

Deerfield Beach Energy Center, LLC proposes to construct and operate a peaking electrical power generating facility at a greenfield site in Broward County, Florida. The facility will consist of three (3) GE PG7241S(FA) (GE 7FA) combustion turbines operating in simple cycle mode; each turbine has a nominal generating capacity of 170 MW at ISO base rating. The combustion turbines will be fired up to 1,000 hours on low sulfur distillate oil, the remaining operation on natural gas, for a total of up to 3,500 hours. Ancillary equipment includes one 2.5 million gallon distillate oil main storage tank, one 617,400 gallon distillate oil day storage tank, one 13 MMBtu/hr natural gas fuel heater and nine small cooling towers for inlet chilling.

2. Projected or Actual Date of Commencement of Construction:

   April 1, 2001

3. Projected Date of Completion of Construction:

   May 1, 2002

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **583.1**	North (km): **2,907.9**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):		Longitude (DD/MM/SS):	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Dave Kellermeyer, Director**
2. Facility Contact Mailing Address: Organization/Firm: **Deerfield Beach Energy Center, LLC** Street Address: **1400 Smith Street** City: **Houston** State: **TX** Zip Code: **77002-7631**
3. Facility Contact Telephone Numbers: Telephone: **(713) 853-3161** Fax: **(713) 646-3037**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [✔] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [✔] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [✔] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations (Facility-wide)

Chapter 62-4	Permits
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements for Sources Subject to the Federal Acid Rain Program
Rule 62-296.	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications
40 CFR 60	Applicable sections of Subpart A, General Requirements, NSPS Subparts GG and Kb
40 CFR 72	Acid Rain Permits
40 CFR 75	Monitoring
40 CFR 77	Acid Rain Program – Excess Emissions

Broward County Code of Ordinances, Article IV, Air Quality	Applicable parts are Sections 27-171 to 27-178. This rule is not part of the Florida SIP and is therefore not federally enforceable under Title V.

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	**A**				
CO	**A**				
SO2	**A**				
VOC	**B**				**Units T001 and T002 subject to record keeping requirements of 40 CFR 60, Subpart Kb**
PM	**A**				
PM10	**A**				
PB	**B**				
H114	**B**				
SAM	**B**				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [✔] Attached, Document ID: **Fig. 1-1** [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [✔] Attached, Document ID: **Fig. 1-2** [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [✔] Attached, Document ID: **Fig. 2-1** [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [✔] Attached, Document ID: **ENSR Document No. 6792-140-200R** [ ] Not Applicable
7. Supplemental Requirements Comment: **See PSD BACT analysis in Section 5, air quality modeling results in Section 6, and additional impacts analysis in Section 7. Class I area analysis will be submitted as a supplement to the application at a later date.**

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [✔] Attached, Document ID: **Section 2** [ ] Not Applicable **Qualifying insignificant emission units based on PTE are the fuel gas heater and the cooling tower used for inlet chilling. See Appendix B for supporting emission calculations.**	
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [✔] Not Applicable	
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [✔] Not Applicable	
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [✔] Not Applicable	
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [✔] Not Applicable	
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:__________________________) [✔] Not Applicable	
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [✔] Not Applicable	
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [✔] Not Applicable	

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[✔] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[✔] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
CT001 through CT003 are identical GE PG7241S(FA) (GE 7FA) simple cycle combustion turbines (CT) each having a nominal rating 170 megawatts (MW) at base load ISO conditions. Each CT will be fired with natural gas or low sulfur distillate oil.

4. Emissions Unit Identification Number: [✔] No ID [ ] ID Unknown
ID: **CT001; CT002; CT003**

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**May 2002**	**49**	[✔]

9. Emissions Unit Comment: (Limit to 500 Characters)
Each combustion turbine (CT001, CT002, CT003) should be considered separate emissions units. The grouping of all turbines into one Emissions Unit Information Section has been done for administrative convenience since the information required in Subsections A through J is identical for each combustion turbine.

Emissions Unit Control Equipment

1.	Control Equipment/Method Description (Limit to 200 characters per device or method): **NOx is limited through use of dry low NOx combustors for natural gas firing and water injection for distillate oil firing. See BACT analysis in Section 5.**
2.	Control Device or Method Code(s): **024**

Emissions Unit Details

1.	Package Unit: Manufacturer: **General Electric**	Model Number: **PG7241S(FA)**
2.	Generator Nameplate Rating:	**170** MW **(nominal @ base load ISO)**
3.	Incinerator Information: **N/A** Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Heat Input Rate: **2027 MMBtu** hr **HHV (base load on fuel oil @ 30°F)**			
2.	Maximum Incineration Rate:	**N/A** lb/hr		**N/A** tons/day
3.	Maximum Process or Throughput Rate: **N/A**			
4.	Maximum Production Rate: **N/A**			
5.	Requested Maximum Operating Schedule:			
		24 hours/day		**7** days/week
		52 weeks/year		**3500**[1] hours/year
6.	Operating Capacity/Schedule Comment (limit to 200 characters): **1 – Annual operations are based on a total of 3,500 hours per year per unit of which 1,000 hours per year per unit may be distillate fuel oil.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A (General Provisions for New Source Performance Standards)	
40 CFR 60.332(a)(1) – NO_x standards for Stationary Gas Turbines	
40 CFR 60.333 – SO_2 standards for Stationary Gas Turbines	
40 CFR 60.334 – Monitoring Provisions for Stationary Gas Turbines	
40 CFR Part 72 – Acid Rain Program Requirements Regulations	
40 CFR Part 73 – Acid Rain Program SO_2 Allowances System	
40 CFR Part 75 – Acid Rain Program Continuous Emissions Monitoring	
Rule 62-296.320(4)(b)1 – Visible emissions	
40 CFR 52.21 – Prevention of Significant Deterioration	
Rule 62-212.400 – Prevention of Significant Deterioration	
Applicable part of Article IV, "Air Quality", sections 27-171 to 27-178, Broward County Code of Ordinances. This rule is not part of the Florida SIP and is therefore not federally enforceable under Title V.	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CT001, CT002, CT003**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhaust stacks for combustion turbines; one stack per turbine unit.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **80** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1109°F (NG)** **1088°F (Oil)**	9. Actual Volumetric Flow Rate: **2,451,600 acfm (NG)** **2,519,400 acfm (Oil)**	10. Water Vapor: **8.54 % (NG)** **11.05 % (Oil)**
11. Maximum Dry Standard Flow Rate: **754,000 dscfm (NG)** **764,000 dscfm (Oil)**	12. Nonstack Emission Point Height: **N/A** feet	
13. Emission Point UTM Coordinates: **Zone: 17 CT001: East (km): 583.038 North (km): 2,907.941**; **CT002: East (km): 583.074 North (km): 2,907.941**; **CT003: East (km): 583.110 North (km): 2,907.940**		
14. Emission Point Comment (limit to 200 characters): **Exhaust temperatures and flow rates (items 8, 9, 10, 11) are at 100% load and 50° F operating conditions. It is expected that the proposed turbines will operate using inlet air chilling during summer peaking operations and as such the inlet air temperature will effectively be at 50° F during the majority of operating hours. Stack temperatures and flow rates will vary with load and ambient temperature.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural gas**		
1. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
6. Maximum Hourly Rate: **1.912 (per turbine)**	7. Maximum Annual Rate: **6,691 (per turbine)**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **2 grains/100 SCF**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **978 (HHV)**
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate is based on the hourly fuel consumption rate at base load, 50°F for 3500 hours per year.**		

Segment Description and Rate: Segment __2__ of __2__

2. Segment Description (Process/Fuel Type) (limit to 500 characters): **No. 2 Distillate Fuel Oil**		
3. Source Classification Code (SCC): **2-01-001-0**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **14.6 (per turbine)**	5. Maximum Annual Rate: **14,600 (per turbine)**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **Trace**	9. Million Btu per SCC Unit: **139 (HHV)**
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate is based on the hourly fuel consumption rate at base load and 50° F for 1,000 hours per year.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**024 (GE DLN on gas)/028 (oil firing)**		**EL**
CO	**0**		**EL**
PM	**0**		**EL**
PM10	**0**		**EL**
SO2	**0**		**EL**
VOC	**0**		**EL**
PB	**0**		**EL**
SAM	**0**		**EL**
H114	**0**		**EL**
EL-Annual emissions potential to emit is based on operating 3,500 hours per year at full load, with 1,000 hours on oil.			

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **332.1** lb/hour **(per turbine)** **235** tons/year **(per turbine)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **9 ppmvd @15% O_2 on gas** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual NOx emissions based on 2,500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of __2____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **9 ppmvd@15%O2 on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **61.6** lb/hour **235** tons/year
5. Method of Compliance (limit to 60 characters): **Compliance with 9 ppm limit during initial and annual performance stack tests using EPA Method 20. Compliance with 9 ppm limit shall be with CEM on a 24-hour block average.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2____ of ___2___

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **42 ppmvd@15% O_2 on oil for 1,000 of 3,500 hours (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **332.1** lb/hour **235** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests with EPA Method 20. Continuous compliance based on CEM 3-hour average.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **78.3** lb/hour **(per turbine)** **70.3** tons/year **(per turbine)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **9 ppmvd @15% O_2 on gas** **30 ppmvd @15% O_2 on oil** Reference: **See Appendix B for emission calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperatures. Annual CO emissions based on 2,500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **9 ppmvd @ 15% O_2 on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **30.9** lb/hour **70.3** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests using EPA Method 10.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2___ of __2____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **30 ppmdv @15% O_2 on oil (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **78.3** lb/hour **70.3** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests using EPA Method 10.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **34.0** lb/hour(**per turbine**) **39.5** tons/year (**per turbine**)	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.03 lb/MMBtu on oil** **0.017 lb/MMBtu on gas** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual PM/PM10 emissions based on 2,500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **18 lb/hr on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **18** lb/hour **39.5** tons/year
5. Method of Compliance (limit to 60 characters): **Visible emissions testing as a surrogate for PM compliance testing.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **34 lb/hr on oil (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **34** lb/hour **39.5** tons/year
5. Method of Compliance (limit to 60 characters): **Visible emissions testing as a surrogate for PM compliance testing.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.6** lb/hour **(per turbine)** **63.4** tons/year **(per turbines)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
7. Emission Factor: **0.02 gr S / SCF nat. gas. 0.05% S in oil.** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual SO_2 emissions based on 2,500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **10.9 lb/hr on gas (CT001, CT002, CT003) Sulfur content 2 gr/100 dscf**	4. Equivalent Allowable Emissions: **10.9** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Use of pipeline natural gas and custom fuel monitoring schedule.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **103.6 lb/hr on oil; 0.05% S content fuel**	4. Equivalent Allowable Emissions: **103.6** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Use of low sulfur distillate fuel oil.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.1** lb/hour **(per turbine)** **5.1** tons/year **(per turbine)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.4 ppmvw** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual VOC emissions based on 2,500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__ N/A

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **3.0 lb/hr on natural gas**	4. Equivalent Allowable Emissions: **3.0** lb/hour **5.1** tons/year
5. Method of Compliance (limit to 60 characters): **Initial Stack Test using Method 18, 25 or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions ___2__ of ___2__

2. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
4. Requested Allowable Emissions and Units: **3.1 lb/hr on fuel oil**	4. Equivalent Allowable Emissions: **3.1** lb/hour **5.1** tons/year
5. Method of Compliance (limit to 60 characters): **Initial stack test using Method 18, 25 or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.028** lb/hour **(per turbine)** **0.014** tons/year **(per turbine)**	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.000014 lb/MMBtu** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Emission factor is for worst case, firing on distillate oil. No Pb is expected from natural gas combustion.**	

Allowable Emissions Allowable Emissions ______ of _____N/A_

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **15.9** lb/hour **(per turbine)** **9.7** tons/year **(per turbine)**	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.009 lb/MMBtu on oil** Reference: **See Appendix B for emissions calculations.**	8. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **SAM is not expected to be generated prior to leaving the stack, due to the high temperatures. However, precursor to SAM (SO3) is generated.**	

Allowable Emissions Allowable Emissions ______ of ______N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **H114**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.51 E-3** lb/hour **1.21 E-4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 1.2 E-6 lb/MMBtu Reference: **See Appendix B for emissions calculations.**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission factor for mercury (Hg) is for worst case, firing on distillate oil. No Hg is expected from natural gas combustion.**	

Allowable Emissions Allowable Emissions ______ of ______**N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation __1__ of __1__

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [✔] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9.**	
5. Visible Emissions Comment (limit to 200 characters): **The general visible emission standard requirements of Rule 62-296.320(4)(b)1, F.A.C. apply to each turbine stack.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor __1__ of __1__

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✔] Rule (NOX) [ ] Other
4. Monitor Information: **TBD** Manufacturer: **TBD** Model Number: **TBD**	Serial Number: **TBD**
5. Installation Date: **Prior to start up**	6. Performance Specification Test Date: **90 days after unit commences commercial operation in accordance with 40 CFR 75.4(b)(2).**
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1.	Process Flow Diagram [✔] Attached, Document ID:**Fig. 2-2** [ ] Not Applicable [ ] Waiver Requested
2.	Fuel Analysis or Specification [✔] Attached, Document ID:**App. B** [ ] Not Applicable [ ] Waiver Requested
3.	Detailed Description of Control Equipment [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
4.	Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [✔] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7.	Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8.	Supplemental Information for Construction Permit Application [✔] Attached, Document ID: **ENSR Doc. No. 6792-140-200R**
9.	Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [✔] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [✔] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [✔] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [✔] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [✔] Acid Rain Part – Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: **To be supplied at a later date** [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

III. TANK EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[✔] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[✔] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Distillate fuel oil storage tanks

4. Emissions Unit Identification Number: [✔] No ID
ID: **T001, T002** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**May 2002**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

T001 – main storage tank
T002 – day storage tank.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **None**
2. Control Device or Method Code(s):

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate: **N/A** mmBtu/hr				
2. Maximum Incineration Rate:	**N/A** lb/hr		**N/A** tons/day	
3. Maximum Process or Throughput Rate: **43,750,000 gal/year**				
4. Maximum Production Rate: **N/A**				
5. Requested Maximum Operating Schedule:	**24** hours/day		**7** days/week	
	52 weeks/year		**8760** hours/year	
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Peak demand anticipated June – August; December – February** **T001 – 2.5 MM gallon capacity** **T002 – 617,400 gallon capacity**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A (General Provisions for New Source Performance Standards)	
40 CFR 60.116b(a) and (b) – Record Keeping requirements under Subpart Kb	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **T001, T002**	2. Emission Point Type Code: **4**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **N/A** feet	7. Exit Diameter: **N/A** feet
8. Exit Temperature: **N/A**	9. Actual Volumetric Flow Rate: **N/A**	10. Water Vapor: **N/A**

11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates: **Main tank: Zone 17; 583.049 East (km) 2908.242 North (km)** **Day tank: Zone 17; 583.046 East (km) 2908.195 North (km)**	
14. Emission Point Comment (limit to 200 characters):	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate fuel oil storage tanks**		
2. Source Classification Code (SCC): **40301021**	3. SCC Units: **Thousand Gallons Throughput**	
4. Maximum Hourly Rate: **N/A**	5. Maximum Annual Rate: **43,750**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment ___ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
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 (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
VOC			**NS**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Potential VOC emissions from distillate fuel oil storage tanks are less than 5 tons per year (less than the threshold amount for reporting in this subsection). See Appendix B for emission calculations.**	

Allowable Emissions Allowable Emissions 1 of 1 **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: N/A

<table>
<tr><td>1. Visible Emissions Subtype:</td><td>2. Basis for Allowable Opacity:
[ ] Rule [ ] Other</td></tr>
<tr><td colspan="2">3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour</td></tr>
<tr><td colspan="2">4. Method of Compliance:</td></tr>
<tr><td colspan="2">5. Visible Emissions Comment (limit to 200 characters):</td></tr>
</table>

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule (**NOX**) [ ] Other (**CO**)
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1.	Process Flow Diagram [ ] Attached, Document ID: [✔] Not Applicable [ ] Waiver Requested
2.	Fuel Analysis or Specification [ ] Attached, Document ID: [✔] Not Applicable [ ] Waiver Requested
3.	Detailed Description of Control Equipment [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
4.	Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [✔] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7.	Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8.	Supplemental Information for Construction Permit Application [✔] Attached, Document ID: **See calculations in Appendix B for tank information.**
9.	Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [✔] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [✔] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [✔] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [✔] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part – Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [✔] Not Applicable

APPENDIX B

EMISSION CALCULATIONS

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Natural Gas Only					Proposed Design Specification
Fuel Heating Value		(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content		(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	151000	174800	178000	182200		
Heat Input Rate		(MMBtu/Hr, LHV)	1,464.7	1,629.1	1,652.7	1,684.4		Manufacturer Supplied Data
Fuel Feed Rate		(SCF/Hr)	1,662,354	1,848,939	1,875,724	1,911,701		Calculated
Exhaust Temperature		(F)	1,149	1,109	1,100	1,087		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	150.4	160.6	162.0	164.0		Calculated
Exhaust Analysis	Argon		0.87	0.90	0.90	0.90		39.948 lb/lb mol Ar
	Nitrogen		72.83	74.32	74.55	74.94		28.0134 lb/lb mol N_2
	Oxygen		12.22	12.50	12.57	12.68		31.998 lb/lb mol O_2
	Carbon Dioxide		3.69	3.75	3.74	3.74		44.009 lb/lb mol CO_2
	Water		10.40	8.54	8.25	7.75		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.16	28.37	28.40	28.45		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	3,301,000	3,642,000	3,700,000	3,783,000		Manufacturer Supplied Data
		(ACFHW)	137,744,689	147,096,451	148,423,690	150,200,713		Calculated
		(ACFMW)	2,295,745	2,451,608	2,473,728	2,503,345		Calculated
		(ACFHD)	123,419,241	134,534,414	136,178,735	138,560,158		Calculated
		(ACFMD)	2,056,987	2,242,240	2,269,646	2,309,336		Calculated
		(SCFHW)	45,182,505	49,480,378	50,214,935	51,243,258		Calculated
		(SCFMW)	753,042	824,673	836,916	854,054		Calculated
		(SCFHD)	40,483,524	45,254,754	46,072,203	47,271,906		Calculated
		(SCFMD)	674,725	754,246	767,870	787,865		Calculated
Exhaust Moisture		(%)	10.40	8.54	8.25	7.75		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	13.64	13.67	13.70	13.75		Calculated
Concentration of NOx in Exhaust		(ppmvd@15% O2)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd)	11.1	11.0	11.0	10.9		Calculated
Concentration of CO in Exhaust		(ppmvd)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	7.3	7.3	7.4	7.4		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.5	1.5	1.5		Calculated
		(ppmvd @ 15% O2)	1.3	1.2	1.3	1.3		Calculated

Note:

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd)} \cdot \text{(Exhaust Flow Rate, SCFMD)} \cdot \text{(Mol Wt. NOx, Lbs/Lb-Mol)} \cdot \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} \cdot \text{(1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	53.5	59.6	60.4	61.6	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd)} \cdot \text{(Exhaust Flow Rate, SCFMD)} \cdot \text{(Mol Wt. CO, Lbs/Lb-Mol)} \cdot \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} \cdot \text{(1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	26 5	29.6	30.1	30.9	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw)} \cdot \text{(Exhaust Flow Rate, SCFMW)} \cdot \text{(Mol Wt. VOC, Lbs/Lb-Mol)} \cdot \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} \cdot \text{(1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.6	2.9	2.9	3.0	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M Lafond — Date: 9/24/00
Checked by: M. Griffin — Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Gas Sulfur Content, Grains/SCF) * (Fuel Feed Rate, SCF/Hr) * (64 Lbs SO_2/32 Lbs S) / (7,000 Grains/Lbs)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	9.5	10.6	10.7	10.9	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.5	1.6	1.6	1.7	

Note:
Assume 10% conversion of SO_2 to SO_3. Assume all SO_3 is converted to H_2SO_4

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18	18	18	18	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters	Units	Design Data				Proposed Permit Limit	Comments
Turbine Load	(%)	100					Manufacturer Supplied Data
Stack Diameter	(Feet)	18					Proposed Design Specification
Fuel Type		Natural Gas Only					Proposed Design Specification
Fuel Heating Value	(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content	(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature	(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity	(%)						Manufacturer Supplied Data
CTG - Gross Power Output	(kW)	113300	131100	133500	136700		
Heat Input Rate	(MMBtu/Hr, LHV)	1,202.1	1,312.3	1,328.3	1,353.3		Manufacturer Supplied Data
Fuel Feed Rate	(SCF/Hr)	1,364,317	1,489,388	1,507,547	1,535,921		Calculated
Exhaust Temperature	(F)	1,180	1,147	1,142	1,134		Manufacturer Supplied Data
Exhaust Velocity	(F/S)	125.8	130.8	131.5	132.7		Calculated
Exhaust Analysis Argon		0.87	0.89	0.89	0.89		39.948 lb/lb mol Ar
Nitrogen		72.86	74.31	74.53	74.90		28.0134 lb/lb mol N_2
Oxygen		12.30	12.48	12.51	12.58		31.998 lb/lb mol O_2
Carbon Dioxide		3.65	3.76	3.77	3.79		44.009 lb/lb mol CO_2
Water		10.32	8.56	8.30	7.84		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight	(Lbs/Lb-Mol)	28.16	28.36	28.39	28.44		Calculated
Exhaust Flow Rate	(Lbs/Hr, Wet)	2,710,000	2,897,000	2,923,000	2,970,000		Manufacturer Supplied Data
	(ACFHW)	115,254,389	119,863,053	120,440,174	121,542,995		Calculated
	(ACFMW)	1,920,906	1,997,718	2,007,336	2,025,717		Calculated
	(ACFHD)	103,360,136	109,602,775	110,443,639	112,014,025		Calculated
	(ACFMD)	1,722,669	1,826,713	1,840,727	1,866,900		Calculated
	(SCFHW)	37,090,563	39,365,979	39,679,002	40,243,333		Calculated
	(SCFMW)	618,176	656,100	661,317	670,722		Calculated
	(SCFHD)	33,262,817	35,996,251	36,385,644	37,088,256		Calculated
	(SCFMD)	554,380	599,938	606,427	618,138		Calculated
Exhaust Moisture	(%)	10.32	8.56	8.30	7.84		Manufacturer Supplied Data
Exhaust O2 Dry	(%)	13.72	13.65	13.64	13.65		Calculated
Concentration of NOx in Exhaust	(ppmvd@15% O2)	9	9	9	9		Manufacturer Supplied Data
	(ppmvd)	11.0	11.1	11.1	11.1		Calculated
Concentration of CO in Exhaust	(ppmvd)	9	9	9	9		Manufacturer Supplied Data
	(ppmvd @ 15% O2)	7.4	7.3	7.3	7.3		Calculated
Concentration of VOC in Exhaust	(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
	(ppmvd)	1.6	1.5	1.5	1.5		Calculated
	(ppmvd @ 15% O2)	1.3	1.2	1.2	1.2		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 — Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions — Date: 9/26/00

OXIDES OF NITROGEN

Lbs/Hr = (NOx Concentration, ppmvd) *(Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr / (385 SCF/Lb-Mol) * (1,000,000)

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	43.5	47.5	48.1	49.0	

CARBON MONOXIDE

Lbs/Hr = (CO Concentration, ppmvd) *(Exhaust Flow Rate, SCFMD) * (Mol Wt CO, Lbs/Lb-Mol) * 60 Min/Hr / (385 SCF/Lb-Mol) * (1,000,000)

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	21.8	23.5	23.8	24.3	

VOLATILE ORGANIC COMPOUNDS

Lbs/Hr = (VOC Concentration as Methane, ppmvw) *(Exhaust Flow Rate, SCFMW) * (Mol Wt VOC, Lbs/Lb-Mol) * 60 Min/Hr / (385 SCF/Lb-Mol) * (1,000,000)

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.2	2.3	2.3	2.3	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions Date: 9/26/00

SULFUR DIOXIDE

$$\text{Lbs/Hr} = \frac{(\text{Expected Fuel Gas Sulfur Content, Grains/SCF}) * (\text{Fuel Feed Rate, SCF/Hr}) * (64 \text{ Lbs } SO_2/32 \text{ Lbs S})}{(7{,}000 \text{ Grains/Lbs})}$$

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	7.8	8.5	8.6	8.8	

SULFURIC ACID MIST

$$\text{Lbs/Hr} = (SO_2 \text{ Emission Rate, lb/hr}) * (SO_2 \text{ to } SO_3 \text{ Conversion Rate, lb/Hr}) * (98.07 \text{ Lbs } SO_2/64.062 \text{ Lbs S})$$

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.2	1.3	1.3	1 3	

Note:
Assume 10% conversion of SO_2 to SO_3. Assume all SO_3 is converted to H_2SO_4.

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18	18	18	18	

Notes:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters	Units	Design Data				Proposed Permit Limit	Comments
Turbine Load	(%)	100					Manufacturer Supplied Data
Stack Diameter	(Feet)	18					Proposed Design Specification
Fuel Type		Natural Gas Only					Proposed Design Specification
Fuel Heating Value	(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content	(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature	(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity	(%)						Manufacturer Supplied Data
CTG - Gross Power Output	(kW)	75500	87400	89000	91100		
Heat Input Rate	(MMBtu/Hr, LHV)	961.1	1,052.3	1,063.6	1,079.5		Manufacturer Supplied Data
Fuel Feed Rate	(SCF/Hr)	1,090,796	1,194,303	1,207,127	1,225,173		Calculated
Exhaust Temperature	(F)	1,200	1,194	1,189	1,182		Manufacturer Supplied Data
Exhaust Velocity	(F/S)	106.9	111.3	111.8	112.4		Calculated
Exhaust Analysis Argon		0.88	0.88	0.89	0.90		39.948 lb/lb mol Ar
Nitrogen		73.02	74.43	74.64	75.02		28.0134 lb/lb mol N_2
Oxygen		12.76	12.81	12.84	12.90		31.998 lb/lb mol O_2
Carbon Dioxide		3.44	3.61	3.62	3.64		44.009 lb/lb mol CO_2
Water		9.91	8.27	8.01	7.55		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight	(Lbs/Lb-Mol)	28.19	28.38	28.41	28.46		Calculated
Exhaust Flow Rate	(Lbs/Hr, Wet)	2,278,000	2,396,000	2,416,000	2,444,000		Manufacturer Supplied Data
	(ACFHW)	97,960,041	101,973,241	102,405,341	102,950,915		Calculated
	(ACFMW)	1,632,667	1,699,554	1,706,756	1,715,849		Calculated
	(ACFHD)	88,252,201	93,540,054	94,202,673	95,178,121		Calculated
	(ACFMD)	1,470,870	1,559,001	1,570,045	1,586,302		Calculated
	(SCFHW)	31,145,092	32,538,669	32,775,647	33,090,761		Calculated
	(SCFMW)	519,085	542,311	546,261	551,513		Calculated
	(SCFHD)	28,058,613	29,847,721	30,150,318	30,592,408		Calculated
	(SCFMD)	467,644	497,462	502,505	509,873		Calculated
Exhaust Moisture	(%)	9.91	8.27	8.01	7.55		Manufacturer Supplied Data
Exhaust O2 Dry	(%)	14.16	13.96	13.96	13.95		Calculated
Concentration of NOx in Exhaust	(ppmvd@15% O2)	9	9	9	9		Manufacturer Supplied Data
	(ppmvd)	10.3	10.6	10.6	10.6		Calculated
Concentration of CO in Exhaust	(ppmvd)	9	9	9	9		Manufacturer Supplied Data
	(ppmvd @ 15% O2)	7.9	7.7	7.6	7.6		Calculated
Concentration of VOC in Exhaust	(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
	(ppmvd)	1.6	1.5	1.5	1.5		Calculated
	(ppmvd @ 15% O2)	1.4	1.3	1.3	1.3		Calculated

Note:

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Date: 9/25/00
Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd)} * \text{(Exhaust Flow Rate, SCFMD)} * \text{(Mol Wt NOx, Lbs/Lb-Mol)} * 60 \text{ Min/Hr}}{\text{(385 SCF/Lb-Mol)} * (1{,}000{,}000)}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34.4	37.7	38.1	38.7	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd)} * \text{(Exhaust Flow Rate, SCFMD)} * \text{(Mol Wt. CO, Lbs/Lb-Mol)} * 60 \text{ Min/Hr}}{\text{(385 SCF/Lb-Mol)} * (1{,}000{,}000)}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18.4	19.5	19.7	20.0	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw)} * \text{(Exhaust Flow Rate, SCFMW)} * \text{(Mol Wt VOC, Lbs/Lb-Mol)} * 60 \text{ Min/Hr}}{\text{(385 SCF/Lb-Mol)} * (1{,}000{,}000)}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.8	1.9	1.9	1.9	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Gas Sulfur Content, Grains/SCF) * (Fuel Feed Rate, SCF/Hr) * (64 Lbs SO2/32 Lbs S) / (7,000 Grains/Lbs)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	6.2	6.8	6.9	7.0	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.9	1.0	1.1	1.1	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

PARTICULATE MATTER

Base Equations

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18	18	18	18	

Notes:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Distillate Oil					Proposed Design Specification
Fuel Heating Value		(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content		(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	160,800.00	182500	185,400.00	189300		
Heat Input Rate		(MMBtu/Hr, LHV)	1,645.0	1,825.0	1,851.2	1,887.3		Manufacturer Supplied Data
Fuel Feed Rate		(lb/Hr)	90,385	100,275	101,714	103,698		Calculated
Exhaust Temperature		(F)	1,138	1,088	1,079	1,065		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	154.4	165.0	166.5	168.6		Calculated
Exhaust Analysis	Argon		0.85	0.85	0.85	0.87		39.948 lb/lb mol Ar
	Nitrogen		70.33	71.37	71.56	71.86		28.0134 lb/lb mol N_2
	Oxygen		11.02	11.26	11.32	11.41		31.998 lb/lb mol O_2
	Carbon Dioxide		5.44	5.47	5.46	5.45		44.009 lb/lb mol CO_2
	Water		12.37	11.05	10.81	10.42		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.19	28.33	28.36	28.40		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	3,417,000	3,789,000	3,850,000	3,939,000		Manufacturer Supplied Data
		(ACFHW)	141,445,658	151,166,218	152,573,185	154,428,463		Calculated
		(ACFMW)	2,357,428	2,519,437	2,542,886	2,573,808		Calculated
		(ACFHD)	123,948,830	134,462,350	136,080,024	138,337,017		Calculated
		(ACFMD)	2,065,814	2,241,039	2,268,000	2,305,617		Calculated
		(SCFHW)	46,715,924	51,539,332	52,323,300	53,445,839		Calculated
		(SCFMW)	778,599	858,989	872,055	890,764		Calculated
		(SCFHD)	40,937,164	45,844,236	46,667,152	47,876,782		Calculated
		(SCFMD)	682,286	764,071	777,786	797,946		Calculated
Exhaust Moisture		(%)	12.37	11.05	10.81	10.42		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	12.58	12.66	12.69	12.74		Calculated
Concentration of NOx in Exhaust		(ppmvd@15% O2)	42	42	42	42		Manufacturer Supplied Data
		(ppmvd)	59.3	58.7	58.4	58.1		Calculated
Concentration of CO in Exhaust		(ppmvd)	20	20	20	20		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	14.2	14.3	14.4	14.5		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.6	1.6	1.6		Calculated
		(ppmvd @ 15% O2)	1.1	1.1	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd)} * \text{(Exhaust Flow Rate, SCFMD)} * \text{(Mol Wt NOx, Lbs/Lb-Mol)} * \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} * \text{(1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	289 6	321 0	325 5	332 1	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd)} * \text{(Exhaust Flow Rate, SCFMD)} * \text{(Mol Wt CO, Lbs/Lb-Mol)} * \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} * \text{(1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	59 5	66.6	67.8	69.6	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw)} * \text{(Exhaust Flow Rate, SCFMW)} * \text{(Mol Wt. VOC, Lbs/Lb-Mol)} * \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} * \text{(1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.7	3.0	3.0	3.1	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	90.3	100.2	101.6	103.6	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0 02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	13.8	15.3	15.6	15.9	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34	34	34	34	

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0 025	0.027	0.028	0.028	

Note:
Use AP-42 Section 3.1 Emission Factor. 0.000014 lb/MMBtu

CALCULATIONS AND COMPUTATIONS

Project. Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date 9/25/00
Checked by: M. Griffin Date 9/26/00

Design Parameters	Units	Design Data				Proposed Permit Limit	Comments
Turbine Load	(%)	100					Manufacturer Supplied Data
Stack Diameter	(Feet)	18					Proposed Design Specification
Fuel Type		Distillate Oil					Proposed Design Specification
Fuel Heating Value	(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content	(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature	(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity	(%)						Manufacturer Supplied Data
CTG - Gross Power Output	(kW)	120,600	136,900	139,000	142,000		
Heat Input Rate	(MMBtu/Hr, LHV)	1,336.2	1,458.0	1,480.4	1,510.9		Manufacturer Supplied Data
Fuel Feed Rate	(lb/Hr)	73,418	80,110	81,341	83,016		Calculated
Exhaust Temperature	(F)	1,186	1,153	1,148	1,142		Manufacturer Supplied Data
Exhaust Velocity	(F/S)	128.3	133.0	134.0	135.5		Calculated
Exhaust Analysis Argon		0.85	0.85	0.86	0.86		39.948 lb/lb mol Ar
Nitrogen		70.71	71.57	71.69	71.90		28.0134 lb/lb mol N_2
Oxygen		11.15	11.13	11.13	11.14		31.998 lb/lb mol O_2
Carbon Dioxide		5.42	5.60	5.62	5.65		44.009 lb/lb mol CO_2
Water		11.88	10.86	10.71	10.45		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight	(Lbs/Lb-Mol)	28.24	28.37	28.39	28.42		Calculated
Exhaust Flow Rate	(Lbs/Hr, Wet)	2,761,000	2,934,000	2,968,000	3,015,000		Manufacturer Supplied Data
	(ACFHW)	117,511,976	121,810,383	122,756,013	124,110,414		Calculated
	(ACFMW)	1,958,533	2,030,173	2,045,934	2,068,507		Calculated
	(ACFHD)	103,551,553	108,581,776	109,608,844	111,140,876		Calculated
	(ACFMD)	1,725,859	1,809,696	1,826,814	1,852,348		Calculated
	(SCFHW)	37,679,209	39,856,688	40,291,021	40,888,162		Calculated
	(SCFMW)	627,987	664,278	671,517	681,469		Calculated
	(SCFHD)	33,202,919	35,528,252	35,975,853	36,615,349		Calculated
	(SCFMD)	553,382	592,138	599,598	610,256		Calculated
Exhaust Moisture	(%)	11.88	10.86	10.71	10.45		Manufacturer Supplied Data
Exhaust O2 Dry	(%)	12.65	12.49	12.47	12.44		Calculated
Concentration of NOx in Exhaust	(ppmvd@15% O2)	42	42	42	42		Manufacturer Supplied Data
	(ppmvd)	58.7	59.9	60.0	60.2		Calculated
Concentration of CO in Exhaust	(ppmvd)	21	22	22	22		Manufacturer Supplied Data
	(ppmvd @ 15% O2)	15.0	15.4	15.4	15.3		Calculated
Concentration of VOC in Exhaust	(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
	(ppmvd)	1.6	1.6	1.6	1.6		Calculated
	(ppmvd @ 15% O2)	1.1	1.1	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine				
Project	Number: 6792-140	Computed by:	M. Lafond	Date:	9/25/00
Subject:	Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions	Checked by:	M. Griffin	Date:	9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{(\text{NOx Concentration, ppmvd}) * (\text{Exhaust Flow Rate, SCFMD}) * (\text{Mol Wt NOx, Lbs/Lb-Mol}) * 60 \text{ Min/Hr}}{(385 \text{ SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	232.7	254.0	257.9	263.2	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{(\text{CO Concentration, ppmvd}) * (\text{Exhaust Flow Rate, SCFMD}) * (\text{Mol Wt CO, Lbs/Lb-Mol}) * 60 \text{ Min/Hr}}{(385 \text{ SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	50.7	56.8	57.5	58.5	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{(\text{VOC Concentration as Methane, ppmvw}) * (\text{Exhaust Flow Rate, SCFMW}) * (\text{Mol Wt. VOC, Lbs/Lb-Mol}) * 60 \text{ Min/Hr}}{(385 \text{ SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.2	2.3	2.3	2.4	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	73.3	80.0	81.3	82.9	

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	11.2	12.2	12.4	12.7	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34	34	34	34	

Notes:

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.020	0.022	0.022	0.023	

Note:
Use AP-42 Section 3 1 Emission Factor. 0.000014 lb/MMBtu

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters	Units	Design Data				Proposed Permit Limit	Comments
Turbine Load	(%)	100					Manufacturer Supplied Data
Stack Diameter	(Feet)	18					Proposed Design Specification
Fuel Type		Distillate Oil					Proposed Design Specification
Fuel Heating Value	(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content	(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature	(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity	(%)						Manufacturer Supplied Data
CTG - Gross Power Output	(kW)	80,400.00	91300	92,700.00	94600		
Heat Input Rate	(MMBtu/Hr, LHV)	1,054.8	1,155.9	1,168.9	1,186.3		Manufacturer Supplied Data
Fuel Feed Rate	(lb/Hr)	57,956	63,511	64,225	65,181		Calculated
Exhaust Temperature	(F)	1,200	1,200	1,200	1,193		Manufacturer Supplied Data
Exhaust Velocity	(F/S)	109.0	112.5	112.9	113.4		Calculated
Exhaust Analysis Argon		0.86	0.86	0.85	0.86		39.948 lb/lb mol Ar
Nitrogen		71.45	72.18	72.29	72.53		28.0134 lb/lb mol N_2
Oxygen		11.91	11.67	11.63	11.64		31.998 lb/lb mol O_2
Carbon Dioxide		5.03	5.34	5.39	5.42		44.009 lb/lb mol CO_2
Water		10.75	9.95	9.84	9.55		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight	(Lbs/Lb-Mol)	28.32	28.44	28.46	28.49		Calculated
Exhaust Flow Rate	(Lbs/Hr, Wet)	2,333,000	2,419,000	2,427,000	2,451,000		Manufacturer Supplied Data
	(ACFHW)	99,860,109	103,104,272	103,386,331	103,839,200		Calculated
	(ACFMW)	1,664,335	1,718,405	1,723,106	1,730,653		Calculated
	(ACFHD)	89,125,148	92,845,397	93,213,116	93,922,557		Calculated
	(ACFMD)	1,485,419	1,547,423	1,553,552	1,565,376		Calculated
	(SCFHW)	31,749,193	32,780,632	32,870,309	33,154,127		Calculated
	(SCFMW)	529,153	546,344	547,838	552,569		Calculated
	(SCFHD)	28,336,155	29,518,959	29,635,870	29,987,908		Calculated
	(SCFMD)	472,269	491,983	493,931	499,798		Calculated
Exhaust Moisture	(%)	10.75	9.95	9.84	9.55		Manufacturer Supplied Data
Exhaust O2 Dry	(%)	13.34	12.96	12.90	12.87		Calculated
Concentration of NOx in Exhaust	(ppmvd@15% O2)	42	42	42	42		Manufacturer Supplied Data
	(ppmvd)	53.8	56.5	57.0	57.2		Calculated
Concentration of CO in Exhaust	(ppmvd)	38	31	30	31		Manufacturer Supplied Data
	(ppmvd @ 15% O2)	29.7	23.0	22.1	22.8		Calculated
Concentration of VOC in Exhaust	(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
	(ppmvd)	1.6	1.6	1.6	1.5		Calculated
	(ppmvd @ 15% O2)	1.2	1.2	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	181.9	199.2	201.5	204.6	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	78 3	66.5	64.6	67.6	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) * (Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.8	1.9	1.9	1.9	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 | Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions | Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO_2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	57.9	63.4	64.2	65.1	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0 02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO_2 Emission Rate, lb/hr) * (SO_2 to SO_3 Conversion Rate, lb/Hr) * (98 07 Lbs SO_2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	8.9	9 7	9.8	10.0	

Note:
Assume 10% conversion of SO_2 to SO_3. Assume all SO_3 is converted to H_2SO_4.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine

Project Number: 6792-140		Computed by: M. Lafond	Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions		Checked by: M. Griffin	Date: 9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34	34	34	34	

Notes.

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0 016	0.017	0.018	0.018	

Note:
Use AP-42 Section 3.1 Emission Factor. 0 000014 lb/MMBtu

Deerfield Beach Energy Center
Estimated NSPS NO_X Emission Standard

Turbine General Electric Model 7FA **Natural Gas Firing**		
Nominal Maximum Electrical Capacity	174.8	MW
Maximum Energy Input	1629.1	MMBtu/hr (LHV)
	1,719,677,960	kJ/hr
Heat Rate	9,320	Btu/kWh
	9.8	kJ/Wh
NSPS Subpart GG NOx Limit	0.0110%	Volume % NOx @ 15% O2
	110	ppmvd @ 15% O2

Turbine General Electric Model 7FA **Distillate Fuel Oil Firing**		
Nominal Maximum Electrical Capacity	182.5	MW
Maximum Energy Input	1825	MMBtu/hr (LHV)
	1,926,470,000	kJ/hr
Heat Rate	10,000	Btu/kWh
	10.6	kJ/Wh
NSPS Subpart GG NOx Limit	0.0102%	Volume % NOx @ 15% O2
	102	ppmvd @ 15% O2

Note:

These calculations have been performed using nominal turbine data at 50 degrees F conditions and are intended to provide an estimate of 40 CFR 60 Subpart GG NOx Emission Limits.

CALCULATIONS AND COMPUTATIONS

Project	Florida GE 7FA Turbine				
Project Number:	6792-140	Computed by:	M. Lafond	Date:	9/25/00
Subject	Natural Gas Heater - Emission Calculations	Checked by:	M. Griffin	Date:	10/6/00

Emission Source:	Natural Gas Heater
Source Type:	Natural Gas Fueled Heater
Heat Input (MMBtu/hr):	13
Number of Units:	1
Sulfur Content of Fuel (grains/scf):	0.02
Fuel Heating Value, HHV (Btu/scf):	1020
LHV (Btu/scf):	908
Operating Hours per Year:	3500
Fuel Feed Rate (scf/HR):	12745

Compound	Emission Factor (a) (Lbs/MMBtu)	Emission Rate - per Unit Hourly (b) (Lbs/Hr)	Annual (c) (Tons/Year)
Criteria Pollutants			
Nitrogen Oxides	0.102	1.3	2.3
Carbon Monoxide	0.09	1.2	2.1
Volatile Organic Carb	0.06	0.78	1.37
Sulfur Oxides (d)	0.01	0.07	0.13
Particulate	0.01	0.13	0.23

Notes:

(a) Emission Factors based on the information supplied by ENRON on 8/11/99.

(b) Hourly Emission Rate (Lbs/Hr) = (Heat Input * Emission Factor)

(c) Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

(d) Sulfur Oxides Emission Rate (Lbs/Hr) based on the sulfur content of the fuel.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine

Project Number: 6792-140 Computed by: M. Griffin Date: 10/2/00

Subject: Cooling Tower Emissions Checked by: Date:

Water Circulation Rate (a), per cell	(GPM)	4,000
Number of Cells		9
Total Water Circulation Rate (a), all cells	(GPM)	36,000
Annual Operation	(hrs/year)	3,500
Total Liquid Drift (b)	(%)	0.001
Expected TDS/TSS of Circulated Water (c)	(ppmw)	2085
Emission Rate - Total Cooling Tower		
Total Suspended Particulate (d)	(Lbs/Hr)	0.376
	(Tons/Yr)	0.658

Notes:
(a) Design Water Circulation Rate, Gallons/Minute (GPM)
(b) Design Total Liquid Drift, Percent (%)
(c) Process Design Data
(d) Based on USEPA AP-42 Section 13.4 Wet Cooling Towers, Table 13.4-1. Modified to Cooling Tower Design
Lbs/Hr = (Water Circulation Rate,GPM)*60*(Drift,%) / 100 * (8.3453 Lbs/Gal) * (TDS, Lbs PM/1,000,000 Lbs Water)
Tons/Yr = (Lbs/Hr) * (8,760 Hrs/Yr) / (2,000 Lbs/Ton)

TANKS 4.07 Output and VOC Emissions Calculations for Deerfield Beach Energy Center, Florida
T001 No. 2 Oil Main Tank

TANKS Ouput:

Maximum Hourly Emission Rate:

Total Hours=	1,000	
July =	744	hours
July Max Fuel Use =	32,551,686	gallons/month
Greatest monthly total standing plus working loss (July) =	1338.29	lb/month
Maximum VOC emission rate =	1.80	lb/hr
Hours each for June, August =	128.00	hours
Fuel use for June, August each =	5,600,290	gallons/month

Annual Total Emission Rate:

Annual total standing plus working losses =	1876.74	lb/year
PTE =	0.9	tons/yr

Tank Specifications Used:

Vertical fixed roof
Vented to atmosphere, default breather vent +/- 0.03 psig
Non-heated
Flat roof
Shell in good condition
43,752,266 gallons/year throughput
2,502,754 gallons capacity

17.4817 turnovers/year Throughput/capacity)
Average liquid height in tank 1/2 tank height

TANKS 4.07 Output and VOC Emissions Calculations for Deerfield Beach Energy Center, Florida

T002 No. 2 Oil Day Tank

TANKS Ouput:

Maximum Hourly Emission Rate:

Total Hours=	1,000	
July =	744	hours
July Max Fuel =	32,551,686	gallons/month
Greatest monthly total standing plus working loss (July) =	1033.8	lb/month
Maximum VOC emission rate =	1.39	lb/hr
Hours each for June, August =	128.00	hours
Fuel use for June, August each =	5,600,290	gallons/month

Annual Total Emission Rate:

Annual total standing plus working losses =	763.9	lb/year
PTE =	0.38	tons/yr

Tank Specifications Used:

Vertical fixed roof
Vented to atmosphere, default breather vent +/- 0.03 psig
Non-heated
Flat roof
Shell in good condition
43,752,266 gallons/year throughput 6250
617,751 gallons capacity

70.8251 turnovers/year Throughput/capacity)
Average liquid height in tank 1/2 tank height

Florida GE 7FA Turbine
Summary of Facility HAP Emissions

		3500 hrs Natural Gas	2500 hrs NG	1000 hrs Oil	2500 hrs NG & 1000 hrs Oil	CTGs All Cases	Fuel Heater	Facility Total
Total HAPs	tpy	5.0	3.6	3.9	7.5	7.5	0.04	7.6
Max HAP	tpy	2.6	1.8	2.4	2.4	2.6	4.01E-02	2.6
Max HAP Compound		Formaldehyde	Formaldehyde	Manganese	Formaldehyde	Formaldehyde	Hexane	
Major Total HAPs								**No**
Major Single HAP								**No**
Total HAPs	lb/hr	3.0	3.0	8.1	8.1	8.1	2.45E-02	8.1
Max HAP	lb/hr	1.5	1.5	5.0	5.0	5.0	2.29E-02	5.0

Calculations and Computations

HAP Emissions from Simple Cycle CTG Facility

Project:	Florida GE 7FA Turbine				
Project Number:	6792-140	Computed by:	M. Behnke	Date:	9/21/00
Subject:	Natural Gas Turbine Non-Criteria Regulated Pollutant Emissions	Checked by:	M. Griffin	Date:	12/6/00

					CTG Natural Gas Combustion		Natural Gas Fired CTG Emissions		Facility		Facility
Pollutant	Type[a]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas (lb/10^6 scf)	(lb/MMBtu)[d]	Rating	Maximum Heat Input, per turbine (MMBtu/Hr)[b]	Average Heat Input, per turbine (MMBtu/Hr)[c]	Emission Rate, Per Turbine Hourly[e] (lb/hr)	Annual[f] (tpy)	Emission Rate All CTGs Hourly[e] (lb/hr)	Annual[f] (tpy)	Major Source (Y/N)
1,3-Butadiene	HAP		4.30E-07	D	1,892.6	1,830.4	8.14E-04	1.38E-03	2.44E-03	4.13E-03	No
Acetaldehyde	HAP		4.00E-05	C	1,892.6	1,830.4	7.57E-02	1.28E-01	2.27E-01	3.84E-01	No
Acrolein	HAP		6.40E-06	C	1,892.6	1,830.4	1.21E-02	2.05E-02	3.63E-02	6.15E-02	No
Benzene [g]	HAP	1.36E-02	1.33E-05	B	1,892.6	1,830.4	2.52E-02	4.27E-02	7.57E-02	1.28E-01	No
Ethylbenzene	HAP		3.20E-05	C	1,892.6	1,830.4	6.06E-02	1.03E-01	1.82E-01	3.08E-01	No
Formaldehyde [h]	HAP	2.72E-01	2.66E-04		1,892.6	1,830.4	5.04E-01	8.53E-01	1.51E+00	2.56E+00	No
Naphthalene	HAP		1.30E-06	C	1,892.6	1,830.4	2.46E-03	4.16E-03	7.38E-03	1.25E-02	No
PAHs	HAP		2.20E-06	C	1,892.6	1,830.4	4.16E-03	7.05E-03	1.25E-02	2.11E-02	No
Propylene Oxide	HAP		2.90E-05	D	1,892.6	1,830.4	5.49E-02	9.29E-02	1.65E-01	2.79E-01	No
Toluene [g]	HAP	7.10E-02	6.96E-05	B	1,892.6	1,830.4	1.32E-01	2.23E-01	3.95E-01	6.69E-01	No
Xylene	HAP		6.40E-05	C	1,892.6	1,830.4	1.21E-01	2.05E-01	3.63E-01	6.15E-01	No

	Hours of Operation
Natural Gas CTG	3,500
Number of Turbines	3

	Hourly	Annual	Major Source
Total HAPs	3.0	5.0	No
Maximum Individual HAP	1.5	2.6	No

Natural Gas Heating Value [i] 1020 Btu/SCF (HHV)
908 Btu/SCF (LHV)

Notes:
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions
(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions
(d) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (1040 Btu/scf)
(e) Hourly Emission Rate (lb/hr) = [Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (2,500 hr/yr) / (2,000 lb/ton)
(g) Emission Factors from CARB CATEF emission factor database for natural gas fired combustion turbines
(h) Modified from AP-42 Section 3.1 emissions database for large turbines
(i) Natural gas heating value is taken from a gas analysis report provided by Duke Energy.

Calculations and Computations

HAP Emissions from Simple Cycle CTG Facility

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Natural Gas Turbine Non-Criteria Regulated Pollutant Emissions

Computed by: M. Behnke — Date: 9/21/00
Checked by: M. Griffin — Date: 12/6/00

Pollutant	Type[a]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas (lb/10⁶scf)	Emission Factor (lb/MMBtu)[d]	Rating	CTG Natural Gas Combustion: Maximum Heat Input, per turbine (MMBtu/Hr)[b]	CTG Natural Gas Combustion: Average Heat Input, per turbine (MMBtu/Hr)[c]	Natural Gas Fired CTG Emissions: Emission Rate, Per Turbine, Hourly[e] (lb/hr)	Natural Gas Fired CTG Emissions: Emission Rate, Per Turbine, Annual[f] (tpy)	Facility: Emission Rate All CTGs, Hourly[e] (lb/hr)	Facility: Emission Rate All CTGs, Annual[f] (tpy)	Facility Major Source (Y/N)
1,3-Butadiene	HAP		4.30E-07	D	1,892.6	1,830.4	8.14E-04	9.84E-04	2.44E-03	2.95E-03	No
Acetaldehyde	HAP		4.00E-05	C	1,892.6	1,830.4	7.57E-02	9.15E-02	2.27E-01	2.75E-01	No
Acrolein	HAP		6.40E-06	C	1,892.6	1,830.4	1.21E-02	1.46E-02	3.63E-02	4.39E-02	No
Benzene [g]	HAP	1.36E-02	1.33E-05	B	1,892.6	1,830.4	2.52E-02	3.05E-02	7.57E-02	9.15E-02	No
Ethylbenzene	HAP		3.20E-05	C	1,892.6	1,830.4	6.06E-02	7.32E-02	1.82E-01	2.20E-01	No
Formaldehyde [h]	HAP	2.72E-01	2.66E-04		1,892.6	1,830.4	5.04E-01	6.09E-01	1.51E+00	1.83E+00	No
Naphthalene	HAP		1.30E-06	C	1,892.6	1,830.4	2.46E-03	2.97E-03	7.38E-03	8.92E-03	No
PAHs	HAP		2.20E-06	C	1,892.6	1,830.4	4.16E-03	5.03E-03	1.25E-02	1.51E-02	No
Propylene Oxide	HAP		2.90E-05	D	1,892.6	1,830.4	5.49E-02	6.64E-02	1.65E-01	1.99E-01	No
Toluene [g]	HAP	7.10E-02	6.96E-05	B	1,892.6	1,830.4	1.32E-01	1.59E-01	3.95E-01	4.78E-01	No
Xylene	HAP		6.40E-05	C	1,892.6	1,830.4	1.21E-01	1.46E-01	3.63E-01	4.39E-01	No

	Hours of Operation
Natural Gas CTG	2,500
Number of Turbines	3

	Hourly	Annual	Major Source
Total HAPs	3.0	3.6	No
Maximum Individual HAP	1.5	1.8	No

Natural Gas Heating Value [i] 1020 Btu/SCF (HHV)
908 Btu/SCF (LHV)

Notes:
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant
(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions.
(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions.
(d) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10⁶ scf) / (1040 Btu/scf)
(e) Hourly Emission Rate (lb/hr) = [Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (2,000 hr/yr) / (2,000 lb/ton)
(g) Emission Factors from CARB CATEF emission factor database for natural gas fired combustion turbines.
(h) Modified from AP-42 Section 3.1 emissions database for large turbines
(i) Natural gas heating value is taken from a gas analysis report provided Duke Energy.

Calculations and Computations

HAP Emissions from Simple Cycle CTG Facility

Project:	Florida GE 7FA Turbine			
Project Number:	6792-140	Computed by: M. Behnke	Date:	9/21/00
Subject:	Distillate Oil-Fired Turbine Non-Criteria Regulated Pollutant Emissions	Checked by: M. Griffin	Date:	12/6/00

Pollutant	Type[a]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine - Distillate Oil (lb/10³gal)	Emission Factor (lb/MMBtu)[d]	Rating	CTG Distillate Oil Combustion: Maximum Heat Input, per turbine (MMBtu/Hr)[b]	CTG Distillate Oil Combustion: Average Heat Input, per turbine (MMBtu/Hr)[c]	Distillate Oil-Fired CTG Emissions: Emission Rate, Per Turbine Hourly[e] (lb/hr)	Distillate Oil-Fired CTG Emissions: Emission Rate, Per Turbine Annual[f] (tpy)	Facility: Emission Rate All CTGs Hourly[e] (lb/hr)	Facility: Emission Rate All CTGs Annual[f] (tpy)	Facility: Major Source (Y/N)
1,3-Butadiene	HAP		1.60E-05	D	2,094.1	2,025 0	3 35E-02	1 62E-02	1.01E-01	4 86E-02	No
Benzene	HAP		5 50E-05	C	2,094 1	2,025 0	1.15E-01	5 57E-02	3.46E-01	1 67E-01	No
Formaldehyde	HAP		2 80E-04	B	2,094.1	2,025 0	5 86E-01	2 83E-01	1.76E+00	8 50E-01	No
Naphthalene	HAP		3 50E-05	C	2,094.1	2,025 0	7.33E-02	3 54E-02	2.20E-01	1 06E-01	No
PAHs	HAP		4 00E-05	C	2,094 1	2,025 0	8 38E-02	4 05E-02	2.51E-01	1 21E-01	No
Arsenic	HAP		1.10E-05	D	2,094 1	2,025 0	2 30E-02	1 11E-02	6 91E-02	3 34E-02	No
Beryllium	HAP		3 10E-07	D	2,094 1	2,025 0	6 49E-04	3 14E-04	1.95E-03	9 42E-04	No
Cadmium	HAP		4 80E-06	D	2,094.1	2,025 0	1.01E-02	4 86E-03	3 02E-02	1.46E-02	No
Chromium	HAP		1.10E-05	D	2,094.1	2,025 0	2.30E-02	1.11E-02	6 91E-02	3 34E-02	No
Lead	HAP		1 40E-05	D	2,094.1	2,025 0	2 93E-02	1.42E-02	8.80E-02	4.25E-02	No
Manganese	HAP		7.90E-04	D	2,094.1	2,025 0	1.65E+00	8 00E-01	4 96E+00	2 40E+00	No
Mercury	HAP		1.20E-06	D	2,094.1	2,025 0	2 51E-03	1.21E-03	7 54E-03	3 64E-03	No
Nickel	HAP		4 60E-06	D	2,094.1	2,025 0	9 63E-03	4 66E-03	2 89E-02	1 40E-02	No
Selenium	HAP		2.50E-05	D	2,094.1	2,025 0	5 24E-02	2 53E-02	1 57E-01	7 59E-02	No

	Hours of Operation
Distillate Oil CTG	1,000
Number of Turbines	3

	Hourly (lb/hr)	Annual (tpy)	Major Source
Total HAPs	8.1	3.9	No
Maximum Individual HAP	5.0	2.4	No

Distillate Oil Heating Value: 139 MMBtu/10³ gal (HHV)
125 MMBtu/10³ gal (LHV)

Notes:

(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant

(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions.

(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions

(d) Emission factors from AP-42, Section 3 1, Tables 3.1-4 and 3.1-5

(e) Hourly Emission Rate (lb/hr) = (Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu))

(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (500 hr/yr) / (2,000 lb/ton)

Calculations and Computations

HAP Emissions

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Natural Gas Fuel Heater Non-Criteria Regulated Pollutant Emissions

Computed by: M. Griffin
Checked by:

					Auxiliary Boiler Natural Gas Combustion		Auxiliary Boiler Emissions		Facility		Facility
Pollutant	Type[a]	Emission Factor AP-42 Section 1.4 03/98 - Natural Gas Combustion (lb/10⁶scf)	(lb/MMBtu)[b]	Rating	Maximum Heat Input, per boiler (MMBtu/Hr)	Averge Heat Input, per boiler (MMBtu/Hr)	Emission Rate, Per Boiler Hourly[c] (lb/hr)	Annual[d] (tpy)	Emission Rate All CTG/DB/HRSGs Hourly[c] (lb/hr)	Annual[d] (tpy)	Major Source (Y/N)
1,3-Butadiene	HAP				13	13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	No
2-Methylnaphthalene	HAP	2.40E-05	2.35E-08	D	13	13	3.06E-07	5.35E-07	3.06E-07	5.35E-07	No
3-Methylchloranthrene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
7,12-Dimethylbenz(a)anthracene	HAP	1.60E-05	1.57E-08	E	13	13	2.04E-07	3.57E-07	2.04E-07	3.57E-07	No
Acenaphthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Acenaphthylene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Anthracene	HAP	2.40E-06	2.35E-09	E	13	13	3.06E-08	5.35E-08	3.06E-08	5.35E-08	No
Benz(a)anthracene	HAP	1.80E-06	1.76E-09		13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Benzene	HAP	2.10E-03	2.06E-06	B	13	13	2.68E-05	4.68E-05	2.68E-05	4.68E-05	No
Benzo(a)pyrene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Benzo(b)flouoranthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Benzo(g,h,l)perylene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Benzo(k)fluoranthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Chrysene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Dibenzo(a,h)anthracene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Dichlorobenzene	HAP	1.20E-03	1.18E-06	E	13	13	1.53E-05	2.68E-05	1.53E-05	2.68E-05	No
Fluoranthene	HAP	3.00E-06	2.94E-09	E	13	13	3.82E-08	6.69E-08	3.82E-08	6.69E-08	No
Fluorene	HAP	2.80E-06	2.75E-09	E	13	13	3.57E-08	6.25E-08	3.57E-08	6.25E-08	No
Formaldehyde	HAP	7.50E-02	7.35E-05	B	13	13	9.56E-04	1.67E-03	9.56E-04	1.67E-03	No
Hexane	HAP	1.80E+00	1.76E-03		13	13	2.29E-02	4.01E-02	2.29E-02	4.01E-02	No
Indeno(1,2,3-cd)pyrene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Naphthalene	HAP	6.10E-04	5.98E-07	E	13	13	7.77E-06	1.36E-05	7.77E-06	1.36E-05	No
Phenanathrene	HAP	1.70E-05	1.67E-08	D	13	13	2.17E-07	3.79E-07	2.17E-07	3.79E-07	No
Pyrene	HAP	5.00E-06	4.90E-09	E	13	13	6.37E-08	1.12E-07	6.37E-08	1.12E-07	No
Toluene	HAP	3.40E-03	3.33E-06	C	13	13	4.33E-05	7.58E-05	4.33E-05	7.58E-05	No
Arsenic	HAP	2.00E-04	1.96E-07	E	13	13	2.55E-06	4.46E-06	2.55E-06	4.46E-06	No
Barium	HAP	4.40E-03	4.31E-06	D	13	13	5.61E-05	9.81E-05	5.61E-05	9.81E-05	No
Beryllium	HAP	1.20E-05	1.18E-08	E	13	13	1.53E-07	2.68E-07	1.53E-07	2.68E-07	No
Cadmium	HAP	1.10E-03	1.08E-06	D	13	13	1.40E-05	2.45E-05	1.40E-05	2.45E-05	No
Chromium	HAP	1.40E-03	1.37E-06	D	13	13	1.78E-05	3.12E-05	1.78E-05	3.12E-05	No
Cobalt	HAP	8.40E-05	8.24E-08	D	13	13	1.07E-06	1.87E-06	1.07E-06	1.87E-06	No
Copper	HAP	8.50E-04	8.33E-07	C	13	13	1.08E-05	1.90E-05	1.08E-05	1.90E-05	No
Lead	HAP	5.00E-04	4.90E-07	D	13	13	6.37E-06	1.12E-05	6.37E-06	1.12E-05	No
Manganese	HAP	3.80E-04	3.73E-07	D	13	13	4.84E-06	8.48E-06	4.84E-06	8.48E-06	No
Mercury	HAP	2.60E-04	2.55E-07	D	13	13	3.31E-06	5.80E-06	3.31E-06	5.80E-06	No
Molybdenum	HAP	1.10E-03	1.08E-06	D	13	13	1.40E-05	2.45E-05	1.40E-05	2.45E-05	No
Nickel	HAP	2.10E-03	2.06E-06	C	13	13	2.68E-05	4.68E-05	2.68E-05	4.68E-05	No
Selenium	HAP	2.40E-05	2.35E-08	E	13	13	3.06E-07	5.35E-07	3.06E-07	5.35E-07	No
Vanadium	HAP	2.30E-03	2.25E-06	D	13	13	2.93E-05	5.13E-05	2.93E-05	5.13E-05	No
Zinc	HAP	2.90E-02	2.84E-05	E	13	13	3.70E-04	6.47E-04	3.70E-04	6.47E-04	No

Hours of Operation
Auxiliary Boiler 3,500
Number of Auxiliary Boilers per Facility 1

Natural Gas Heating Value 1020 Btu/SCF (HHV)

	Hourly	Annual	Major Source
Facility Total HAPs	**0.02**	**0.04**	**No**
Maximum Individual HAP	**0.02**	**0.04**	**No**

Notes
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10⁶ scf) / (1,020 Btu/scf)
(c) Hourly Emission Rate (lb/hr) = [Heat Input (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(d) Annual Emission Rate (tpy) = (Hourly Emission Rate, lb/hr) * (8,760 hr/yr) / (2,000 lb/ton)

Calculations and Computations

Project:	**Florida GE 7FA Turbine**	**Computed by:** L. Sherburne	**Date:** 7/19/00
Project Number:	**6792-140**	**Checked by:** M. Griffin	**Date:** 9/21/00
Subject:	**Formaldehyde Emission Factor**		

Facility	Manufacturer	Model	Rating (MW)	AP-42 1998 Draft (lb/Mmcuft)	Large Turbines (>70 MW) (lb/Mmcuft)
Gilroy Energy Co./Gilroy, CA	General Electric	Frame 7	87	0.722160	0.722160
Sithe Energies, 32nd St. Naval S/San Diego, CA	General Electric	MS6000	44	0.110160	
SD Gas & Electric Co./San Diego, CA	General Electric	5221	17	0.483480	
Modesto Irrigation District/Mclure/Modesto, CA	General Electric	Frame 7B	50	0.135660	
Willamette Industries, Inc./Oxnard, CA	General Electric	LM2500-PE	67.4	0.044982	
Sycamore Cogen. Co./Bakersfield, CA	General Electric	Frame 7	75	0.085884	0.085884
Calpine / Agnews Cogen./San Jose, CA	General Electric	LM5000	23.33	0.063036	
Dexzel Inc./Bakersfield, CA	General Electric	LM2500	29 1	0.026520	
Procter & Gamble Manufacturing/Sacramento, CA	General Electric	LM2500	20.5	0.088434	
Chevron Inc./Gaviota, CA	Allison	K501	2.5	3.570000	
Ell / Stewart & Stevenson/Berkeley, CA	General Electric	LM2500	25	0.480420	
Calpine Corp./Sumas, WA	General Electric	MS7001EA	87.83	0.006834	0.006834
Sargent Canyon Cogen/Bakersfield, CA	General Electric	Frame 6	42.5	0.059568	
Watsonville Cogen. Partnership/Watsonville, CA	General Electric	LM 2500	24	0.091596	
Southern Cal. Edison Co./Long Beach, CA	Brown-Boveri-Sulzer	11-D	61.75	1.326000	
NR/NR	General Electric	Frame 3	7.7	0.265200	
NR/NR	General Electric	Frame 3	7 7	0.427380	
NR/NR	Solar	T12000	9.4	0.015810	
NR/NR	Solar	T12000	9.4	9.618600	
NR/NR	General Electric	LM1500	10.6	4.273800	
NR/NR	General Electric	LM1500	10 6	25.908000	
Southern Cal. Edison Co /Coolwater, CA	Westinghouse	PACE520	63	38.964000	
Southern Cal. Edison Co./Coolwater, CA	Westinghouse	PACE520	63	0.350880	
Imperial Irrigation D / Choachella/Imperial, CA	General Electric	NS5000P	46 3	0.306000	
Bonneville Pacific Corp./Somis, CA	Solar	Mars	9	0.743580	
WSPA/SWEPI GT/Bakersfield, CA	Allison	501 KB5	4	0.013872	
			Mean (lb/Mmcuft)	3.39	0.27

Note: The AP-42 1998 Draft document calculates the proposed Formaldehyde Emission factor as an average of all of the test data present in the data base. For the purposes of calculating an appropriate emission factor for the Big Cajun One Expansion Project only the data presented for large turbines has been used.

APPENDIX C

BACT SUPPORTING INFORMATION

EPA INTENDS TO MAKE CHANGES TO DRAFT PREPA RE-POWERING PERMIT

FOR RELEASE: Thursday, January 20, 2000

(#00015) San Juan, Puerto Rico – In response to public concerns and new information about the best way to control nitrogen oxide emissions from oil-fired power plants, the **U.S. Environmental Protection Agency (EPA) intends to make changes to a proposed permit for the Puerto Rico Electric Power Authority's (PREPA) re-powering project** in San Juan. The draft permit, **released in March 1999**, would allow PREPA to increase the electric generating capacity at its San Juan Power Plant and lower total emissions by replacing two, decades-old, 44 megawatt boilers with two 232-megawatt combined cycle turbines. **The intended changes to the draft permit will require PREPA to replace one of the two nitrogen control technologies proposed for installation on the new turbines with special burners to be installed on four old boilers that will remain in service.** While this change will increase nitrogen oxide emissions over the levels under the original draft permit, the emissions will still be at lower levels than those from the old plant.

"An additional benefit of making this change in the control technology requirement is that there will be a decrease, from the original proposed permit, in two pollutants of particular concern in the San Juan area – sulfuric acid mist and fine particles," said Jeanne M. Fox, EPA Region 2 Administrator.

In its draft permit, proposed in March 1999, EPA included Selective Catalytic Reduction (SCR), which uses an ammonia injection system to reduce nitrogen oxide emissions, and steam injection. However, new data indicate that, on oil-fired turbines, SCR cannot consistently achieve the expected reductions in nitrogen oxide emissions. As a result, EPA is removing the SCR requirement and will instead require PREPA to install special burners, called "low NOx burners," on the four old boilers at its facility. PREPA would still use steam injection on its turbines.

"After carefully considering the feasibility of using SCR on an oil-fired plant and reviewing public comments, the choice was clear," said Jeanne M. Fox, EPA Regional Administrator. "We want to ensure that PREPA uses the most reliable pollution controls. Steam injection systems and low NOx burners are both tried and true nitrogen oxide controls."

For more information contact:

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Return to top of this News Release
Return to News Release Index.
Return to EPA R2 Frontpage
http://www.epa.gov/region02/

Region 2 Main Page | Search Region 2 | Comments | EPA Main Page

Table C-1
PRICE QUOTE ADJUSTMENTS
Deerfield Beach Energy Center, LLC
General Electric 7 FA Turbine

NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 FA - Proposed option with DLN to 9 ppm

	Hours of Operation
3,500	
$3,010,000	Budgetary cost for SCR (without auxiliaries)[1]
$1,440,000	Catalyst Support Structure
$1,570,000	Catalyst Bed
$3,010,000	Budgetary cost for SCR (without auxiliaries)
$50,000	Transition = Transition piece , stainless steel, spool piece, = $50k
$20,000	Crane = Crane to handle modules = $20k
$100,000	Auxiliaries not included in Engelhard quote = ($10k per tank + $20K insulation and heating + $20k pumps, piping flow meters, safety equipment) x 2 tanks = $100k
$30,000	Fan = Dilution air fan, variable speed drive, ductwork, starter = $30k
$523,000	Spare Catalyst = 1 spare catalyst on site at all times for 3 turbines
$3,733,000	

Carbon Monoxide High Temperature Oxidation Catalyst - Top Control Option
Simple Cycle, General Electric 7 FA, Baseline and Proposed Control Option

$900,000	Budgetary cost for CO catalyst (without auxililiaries)[1]
$210,000	Catalyst Support Structure
$680,000	Catalyst Bed
$900,000	Oxidation System (catalyst and structure)
$50,000	Transition = Transition piece , stainless steel, spool piece, = $50k
$20,000	Crane = Crane to handle modules = $20k
$30,000	Fan = Dilution air fan, variable speed drive, ductwork, starter = $30k
$227,000	Spare Catalyst = 1 spare catalyst on site at all times for 3 turbines
$1,227,000	

[1]The 12/13/99 Engelhard quote was provided for a combined CO oxidation and SCR system.
The original quotation has been adjusted for separate oxidation and SCR systems.
The original quotation has also been escalated to reflect current control system costs using the Vatavuk Air Pollution Control Cost Indexes per OAQPS control cost manual.
The original quotation has also been used to estimate catalyst costs for differing operating scenarios.

Table C-1A
Deerfield Beach Energy Center, LLC
General Electric 7 FA Turbine
Control Equipment Cost Adjustment

Budgetary Cost	Costs from Engelhard Quote
Turbine Operation (hrs/year)	3,500
Base Exhaust Air Flow (lb/hr)	3,900,000
Actual Exhaust Air Flow (lb/hr)	3,642,000
Original Quotation Costs [1]	
Total System (SCR & Oxidation Catalyst)	3,678,000
Replacement CO	643,000
Replacement ZNX	1,479,000
Support Equipment Cost	1,556,000
Total Catalyst Cost	2,122,000
Catalyst Cost/Total Cost	57.7%
SCR System Only [2]	
SCR Costs from 12/13/99 Quote	
Cost Index [3]	105.7
SCR Support Equipment	1,356,000
SCR Catalyst Cost	1,479,000
SCR Total Cost	2,835,000
Escalated Cost for June 2000	
Cost Index [3]	112.3
SCR Support Equipment	1,440,000
SCR Catalyst Cost	1,570,000
SCR Total Cost	3,010,000
Oxidation Catalyst System only [2]	
Costs from 11/13/98 Quote	
Cost Index [3]	105.7
OxCat Support Equipment	200,000
OxCat Catalyst Cost	643,000
OxCat Total Cost	843,000
Escalated Cost for June 2000	
Cost Index [3]	112.3
OxCat Support Equipment	210,000
OxCat Catalyst Cost	680,000
OxCat Total Cost	900,000

Notes:
1 - From original Engelhard quotation, December 13, 1999 provided by Jeff Koerner of FL DEP.
2 - Original quotation was provided for a combined SCR/Oxidation Catalyst System. For BACT analysis costs have been separated.
3 - Vatavuk Air Pollution Control Cost Index for Catalytic Incinerators. Base index fourth quarter 1999, Escalated index 2nd quarter 2000.

TABLE C-2
Deerfield Beach Energy Center, LLC
NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 FA

Control Efficiency (%)	61%

Facility Input Data

Item	Value
Operating Schedule	Assumed 8 hours per shift
Total Hours per year	3,500
Natural Gas Firing (Normal Operation)	2,500
Distillate Oil Firing (Normal Operation)	1,000
Source(s) Controlled	One Power Block, 175 MW
NOx From Normal Natural Gas Operation (lb/hr)[1]	59.6
NOx From Distillate Oil Operation (lb/hr)	321.0
NOx From Source(s) (tpy)	235.0
Site Specific Enclosure (Building) Cost	NA
Site Specific Electricity Value ($/kWh)	0.10
Site Specific Natural Gas Cost ($/MMBtu)	NA
Site Specific Operating Labor Cost ($/hr)	30
Site Specific Maint. Labor Cost ($/hr)	30

[1]NOx emissions are based on data at 100% load and intake air chilled to maximum of 50°F.

Capital Costs[1]

	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$3,733,000	Engelhard Quote plus auxiliaries, A
b.) Instrumentation	$373,300	0.10 x A
c.) Sales taxes	$224,000	0.06 x A
d.) Freight	$186,700	0.05 x A
Total Purchased equipment cost, (PEC)	$4,517,000	B = 1.21 x A
2.) Direct installation costs		
a.) Foundations and supports	$361,400	0.08 x B
b.) Handling and erection	$632,400	0.14 x B
c.) Electrical	$180,700	0.04 x B
d.) Piping	$90,300	0.02 x B
e.) Insulation for ductwork	$45,200	0.01 x B
f.) Painting	$45,200	0.01 x B
Total direct installation cost	$1,355,200	0.30 x B
3.) Site preparation, SP	NA	NA
4.) Buildings, Bldg	NA	NA
Total Direct Cost, DC	$5,872,200	1.30B + SP + Bldg
Indirect Costs (installation)		
5.) Engineering	$451,700	0.10 x B
6.) Construction and field expenses	$225,900	0.05 x B
7.) Contractor fees	$451,700	0.10 x B
8.) Start-up	$90,300	0.02 x B
9.) Performance test	$45,200	0.01 x B
10.) Contingencies	$135,500	0.03 x B
Total Indirect Cost, IC	$1,400,300	0.28B
Total Capital Investment (TCI) = DC + IC	$7,272,500	1.58B + SP + Bldg

1 See Appendix C, Tables C-1 and C-1A

TABLE C-2
Deerfield Beach Energy Center, LLC
NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 FA

Control Efficiency (%)	61%

Annual Costs

Item	Value	Basis	Source
1) Electricity			
Catalyst Press. Drop (in. W.C.)	4.2	Pressure drop - catalyst bed	Vendor, estimate
Power Output of Turbine (kW)	175,000	Output at Average Conditions	
Power Loss Due to Pressure Drop (%)	0.44%	0.105% for every 1" pressure drop	Vendor
Power Loss Due to Pressure Drop (kW)	772		
Unit Cost ($/kW-hr)	$0.10	Estimated Market Value	Estimate
Cost of Heat Rate Loss ($)	$270,110		
Fan for Ambient Air Cooling (kW)	75	Estimated from Cooling Air Requirements	
Energy Required for Fan (kWh)	262,500		
Unit Cost ($/kW-hr)	$0.10	Estimated Market Value	Estimate
Cost of Cooling Fan Power ($)	$26,250		
Total Electricity Cost ($)	$296,360		
2) Operating Labor			
SCR Requirement (hr/yr)	218.75	1/2 hr/shift, 3,500 hours per year	Estimate
Ammonia Delivery Requirement (hr/yr)	24	3 deliveries per year, 8 hr/delivery	Estimate
Ammonia Recordkeeping/Reporting (hr/yr)	40.0	One week of reporting	Estimate
Catalyst Cleaning (hr/yr)	80.0	2 workers x 40 hours per year	
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Cost ($/yr)	$10,883		
3) Supervisory Labor			
Cost ($/yr)	$1,630	15% Operating Labor	OAQPS
4) Maintenance			
SCR Labor Req. (hr/yr)	218.75	1/2 hour per shift	OAQPS
Catalyst Replacement Labor Req. (hr/yr)	106.7	8 workers, 40 hours every 3 yrs	Estimate
Ammonia System Maintenance Labor Req. (hr/yr)	365.0	1 hr/day, 365 day/yr	Estimate
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Labor Cost ($/yr)	$20,713		
Material Cost ($/yr)	$20,710	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$41,420		
5) Ammonia Requirement			
Requirement (ton/yr)	78	Ammonia requirement, 0.5436 lb NH3/lb NOx Removed	Vendor
Unit Cost ($/ton)	$315	For pure ammonia	Chemical Market Reporter
Total Cost ($/yr)	$24,590		
6) Process Air			
Requirement (scf/lb NH3)	350		Vendor
Requirement (Mscf/yr)	54,647		Vendor
Unit Cost ($/Mscf)	$0.20	Peters and Timmerhaus	Standard
Total Cost ($/yr)	$10,930		
7) Catalyst Replacement			
Catalyst Cost ($)	$1,570,000	Catalyst modules	Vendor
Catalyst Disposal Cost ($)	$50,000	Disposal of catalyst modules	Estimate
Sales Tax ($)	$78,500	5% sales tax in Indiana	Estimate
Catalyst Life (yrs)	3	n	OAQPS
Interest Rate (%)	7	i	
CRF	0.381	Amortization of Catalyst	OAQPS
Annual Cost ($/yr)	$647,220	(Volume)(Unit Cost)(CRF)	
8) Indirect Annual Costs			
Overhead	$32,400	60% of O&M Costs	OAQPS
Administration	$145,500	2% of Total Capital Investment	OAQPS
Property Tax	$72,730	1% of Total Capital Investment	OAQPS
Insurance	$72,730	1% of Total Capital Investment	OAQPS
Capital Recovery	$805,700	10 yr life; 7% interest (-cat. cost)	OAQPS
Total Indirect ($/yr)	$1,129,060		

Total Annualized Cost ($/yr)	**$2,162,100**
Total NOx Controlled (tpy)	**143.6**
Cost Effectiveness ($/ton)	**$15,100**

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

7FA – Simple Cycle

ASSUMED AMBIENT		59	59
GIVEN TURBINE EXHAUST TEMPERATURE, F		1,100	1,100
GIVEN TURBINE EXHAUST FLOW, lb/hr		3,900,000	4,080,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL.	N2	75.23	71.63
	O2	12.61	11.04
	CO2	3.63	5.20
	H2O	7.60	11.20
	Ar	0.93	0.93
AMBIENT AIR FLOW, lb/hr		332,949	348,316
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr		4,232,949	4,428,316
AMBIENT + EXHAUST GAS ANALYSIS, % VOL.	N2	75.70	72.37
	O2	13.09	11.64
	CO2	3.35	4.80
	H2O	7.01	10.33
	Ar	0.86	0.86
CALCULATED AIR + GAS MOL. WT.		28.48	28.32
GIVEN: TURBINE CO, ppmvd		9.0	20.0
CALC.: TURBINE CO, lb/hr		31.9	71.7
GIVEN: TURBINE NOx, ppmvd @ 15% O_2		9.0	42.0
CALC.: TURBINE NOx, lb/hr		64.5	355.2
CALC.: CO, ppmvd @ 15% O2 - AT CATALYST FACE		7.1	13.6
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE		8.8	41.0
FLUE GAS TEMP. @ SCR CATALYST, F		1,025	1,025
DESIGN REQUIREMENTS			
CO CATALYST CO CONVERSION, %		90%	90%
SCR CATALYST NOx OUT, ppmvd @ 15% O2		3.5	ADVISE
NH3 SLIP, ppmvd @ 15% O2		9	12
SCR PRESSURE DROP, 4.0"WG – Nom.			
GUARANTEED PERFORMANCE DATA			
CO CONVERSION - % Min.		90.0%	90.0%
CO OUT, ppmvd @ 15% O2		0.7	1.4
CO OUT, lb/hr		3.2	7.2
CO PRESSURE DROP		2.2	2.4
SCR CATALYST NOx CONVERSION, % - Min.		61.1%	61.1%
NOx OUT, lb/hr – Max.		25.1	138.1
NOx OUT, ppmvd@15%O2 – Max.		3.4	16.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr		139	424
NH3 SLIP, ppmvd@15%O2 – Max.		9	12
SCR PRESSURE DROP, "WG - Max.		4.2	4.4
REQUIRED CROSS SECTION - INSIDE LINER - A x B, sq ft		1650.0	
CO SYSTEM		$643,000	
REPLACEMENT CO CATALYST MODULES		$643,000	
SCR SYSTEM		$2,835,000	
REPLACEMENT SCR CATALYST MODULES		$1,479,000	

Post-it® Fax Note 7671
Date 11-27-00 # of pages 1
To Mike Griffin From Jeff Koerner
Co./Dept ENSR Co. DEP/NSR Section
Phone # 978/635-9500 Phone # 850/414-7268
Fax # 978/635-9180 Fax # 850/922-6979

Mike,
Check out the "Peace River" Technical Evaluation on our web site.
Jeff

ENSR INTERNATIONAL

APPENDIX D

BPIP MODEL OUTPUT FILE

```
                          BPIP (Dated: 95086)
DATE :  1/ 5/ 1
TIME : 14:37:41
C:\ISCView3\Enron Deerfield\deerfld.bpv

============================
BPIP PROCESSING INFORMATION:
============================

  The ST flag has been set for processing for an ISCST2 run.

  Inputs entered in Meters     will be converted to meters using
   a conversion factor of    1.0000.  Output will be in meters.

  The UTMP variable is set to UTMY.  The input is assumed to be in
    UTM coordinates.  BPIP will move the UTM origin to the first pair of
    UTM coordinates read.  The UTM coordinates of the new origin will
    be subtracted from all the other UTM coordinates entered to form
    this new local coordinate system.

  The new local coordinates will be displayed in parentheses just below
    the UTM coordinates they represent.

  Plant north is set to   0.00 degrees with respect to True North.



==============
INPUT SUMMARY:
==============


Number of buildings to be processed :  11


AIRINT1  has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

AIRINT1     1        1     16.46     4
                                              583030.72  2907899.56 meters
                                          (        0.00        0.00) meters
                                              583045.44  2907899.56 meters
                                          (       14.72        0.00) meters
                                              583045.44  2907887.47 meters
                                          (       14.72      -12.09) meters
                                              583030.72  2907887.47 meters
                                          (        0.00      -12.09) meters


EXHDUCT1 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

EXHDUCT1    1        5      8.23     4
                                              583034.38  2907936.03 meters
                                          (        3.66       36.47) meters
                                              583042.34  2907936.03 meters
                                          (       11.63       36.47) meters
                                              583042.34  2907917.09 meters
                                          (       11.63       17.53) meters
                                              583034.38  2907917.09 meters
```

```
                                     (       3.66       17.53) meters

TURBENC1 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

TURBENC1    1        9     13.72     4
                                            583034.94  2907917.19 meters
                                     (          4.22        17.63) meters
                                            583042.16  2907917.19 meters
                                     (         11.44        17.63) meters
                                            583042.16  2907899.66 meters
                                     (         11.44         0.09) meters
                                            583034.94  2907899.66 meters
                                     (          4.22         0.09) meters

WATERTNK has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

WATERTNK    1       13     14.63     8
                                            583062.22  2908009.44 meters
                                     (         31.50       109.88) meters
                                            583059.59  2908002.59 meters
                                     (         28.88       103.03) meters
                                            583053.50  2907999.69 meters
                                     (         22.78       100.13) meters
                                            583047.41  2908002.59 meters
                                     (         16.69       103.03) meters
                                            583044.78  2908009.44 meters
                                     (         14.06       109.88) meters
                                            583047.41  2908016.38 meters
                                     (         16.69       116.81) meters
                                            583053.50  2908019.28 meters
                                     (         22.78       119.72) meters
                                            583059.59  2908016.38 meters
                                     (         28.88       116.81) meters

AIRINT2  has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

AIRINT2     1       17     16.46     4
                                            583066.63  2907899.66 meters
                                     (         35.91         0.09) meters
                                            583081.06  2907899.66 meters
                                     (         50.34         0.09) meters
                                            583081.06  2907887.19 meters
                                     (         50.34       -12.38) meters
                                            583066.63  2907887.19 meters
                                     (         35.91       -12.38) meters

AIRINT3  has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

AIRINT3     1       21     16.46     4
                                            583103.00  2907899.09 meters
                                     (         72.28        -0.47) meters
```

D2

```
                                        583116.97  2907899.09 meters
                                    (       86.25       -0.47) meters
                                        583116.97  2907887.09 meters
                                    (       86.25      -12.47) meters
                                        583103.00  2907887.09 meters
                                    (       72.28      -12.47) meters


TURBENC2 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF     CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS      X           Y

TURBENC2    1       25     13.72     4
                                        583069.81  2907916.81 meters
                                    (       39.09       17.25) meters
                                        583078.25  2907916.81 meters
                                    (       47.53       17.25) meters
                                        583078.25  2907899.75 meters
                                    (       47.53        0.19) meters
                                        583069.81  2907899.75 meters
                                    (       39.09        0.19) meters


EXHDUCT2 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF     CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS      X           Y

EXHDUCT2    1       29      8.23     4
                                        583070.28  2907935.84 meters
                                    (       39.56       36.28) meters
                                        583078.06  2907935.84 meters
                                    (       47.34       36.28) meters
                                        583078.06  2907916.63 meters
                                    (       47.34       17.06) meters
                                        583070.28  2907916.63 meters
                                    (       39.56       17.06) meters


TURBENC3 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF     CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS      X           Y

TURBENC3    1       33     13.72     4
                                        583106.19  2907916.44 meters
                                    (       75.47       16.88) meters
                                        583113.97  2907916.44 meters
                                    (       83.25       16.88) meters
                                        583113.97  2907898.91 meters
                                    (       83.25       -0.66) meters
                                        583106.19  2907898.91 meters
                                    (       75.47       -0.66) meters


EXHDUCT3 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF     CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS      X           Y

EXHDUCT3    1       37      8.23     4
                                        583106.00  2907935.84 meters
                                    (       75.28       36.28) meters
                                        583114.44  2907935.84 meters
                                    (       83.72       36.28) meters
                                        583114.44  2907916.25 meters
```

D7

```
                                         (        83.72       16.69) meters
                                              583106.00  2907916.25 meters
                                         (        75.28       16.69) meters


BLDG14   has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

BLDG14      1       41     13.72     4
                                              583105.51  2907842.15 meters
                                         (        74.79      -57.41) meters
                                              583121.92  2907842.15 meters
                                         (        91.20      -57.41) meters
                                              583121.92  2907808.90 meters
                                         (        91.20      -90.67) meters
                                              583105.51  2907808.90 meters
                                         (        74.79      -90.67) meters

Number of stacks to be processed :    3

                   STACK            STACK   COORDINATES
 STACK NAME     BASE  HEIGHT          X          Y

 STCK1          0.00   24.38 Meters
                                    583038.40  2907941.04 meters
                              (          7.68       41.48) meters
 STCK2          0.00   24.38 Meters
                                    583074.31  2907940.71 meters
                              (         43.59       41.15) meters
 STCK3          0.00   24.38 Meters
                                    583110.22  2907940.06 meters
                              (         79.50       40.50) meters

   No stacks have been detected as being atop any structures.


                      Overall GEP Summary Table
                          (Units: meters)


StkNo:  1  Stk Name:STCK1    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:   16.47             *Eqn1 Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  350.75
  Bldg-Tier nos. contributing to GEP:   1

StkNo:  2  Stk Name:STCK2    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:   16.47             *Eqn1 Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:   10.50
  Bldg-Tier nos. contributing to GEP:  17

StkNo:  3  Stk Name:STCK3    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:   17.77             *Eqn1 Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:   60.50
  Bldg-Tier nos. contributing to GEP:   1
```

DH

BPIP (Dated: 95086)

DATE : 1/ 5/ 1
TIME : 14:37:41
C:\ISCView3\Enron Deerfield\deerfld.bpv

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

The UTMP variable is set to UTMY. The input is assumed to be in UTM coordinates. BPIP will move the UTM origin to the first pair of UTM coordinates read. The UTM coordinates of the new origin will be subtracted from all the other UTM coordinates entered to form this new local coordinate system.

Plant north is set to 0.00 degrees with respect to True North.

C:\ISCView3\Enron Deerfield\deerfld.bpv

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
STCK1	24.38	0.00	41.15	65.00
STCK2	24.38	0.00	41.15	65.00
STCK3	24.38	0.00	41.15	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 1/ 5/ 1
TIME : 14:37:41

C:\ISCView3\Enron Deerfield\deerfld.bpv

BPIP output is in meters

75

```
SO BUILDHGT STCK1       16.46   16.46    8.23    8.23    8.23    8.23
SO BUILDHGT STCK1        8.23    0.00    0.00    0.00    8.23    8.23
SO BUILDHGT STCK1        8.23    8.23    8.23   13.72   13.72   14.63
SO BUILDHGT STCK1       14.63   14.63    8.23    8.23    8.23    8.23
SO BUILDHGT STCK1        8.23    0.00    0.00    8.23    8.23   16.46
SO BUILDHGT STCK1       16.46   16.46   16.46   16.46   16.46   16.46
SO BUILDWID STCK1       16.60   17.97   16.37   18.28   19.63   20.38
SO BUILDWID STCK1       20.52    0.00    0.00    0.00   20.52   20.38
SO BUILDWID STCK1       19.63   18.28   16.37   20.91   16.60   17.44
SO BUILDWID STCK1       17.17   16.39   16.37   18.28   19.63   20.38
SO BUILDWID STCK1       20.52    0.00    0.00   20.28   20.52   17.38
SO BUILDWID STCK1       18.17   19.07   18.74   17.83   16.60   14.72

SO BUILDHGT STCK2       16.46   16.46   16.46   16.46   16.46   13.72
SO BUILDHGT STCK2        8.23    8.23    0.00    0.00    8.23    8.23
SO BUILDHGT STCK2        8.23    8.23    8.23   14.63   14.63   13.72
SO BUILDHGT STCK2       13.72   13.72    8.23    8.23    8.23    8.23
SO BUILDHGT STCK2        8.23    8.23    0.00    8.23    8.23   13.72
SO BUILDHGT STCK2       16.46   16.46   16.46   16.46   16.46   16.46
SO BUILDWID STCK2       16.38   17.83   18.79   19.05   18.73   18.79
SO BUILDWID STCK2       20.52   20.03    0.00    0.00   20.72   20.54
SO BUILDWID STCK2       19.72   18.32   16.35   16.39   17.17   14.44
SO BUILDWID STCK2       16.38   13.76   16.35   18.32   19.72   20.54
SO BUILDWID STCK2       20.72   20.28    0.00   20.76   20.72   19.07
SO BUILDWID STCK2       18.17   18.41   18.10   17.83   16.38   14.44

SO BUILDHGT STCK3       16.46   16.46   16.46   16.46   16.46   16.46
SO BUILDHGT STCK3        8.23    8.23    0.00    8.23    8.23    8.23
SO BUILDHGT STCK3        8.23    8.23    8.23   13.72   13.72   13.72
SO BUILDHGT STCK3       13.72   13.72    8.23    8.23    8.23    8.23
SO BUILDHGT STCK3        8.23    8.23    0.00    8.23    8.23    8.23
SO BUILDHGT STCK3        8.23    8.23    8.23   16.46   16.46   16.46
SO BUILDWID STCK3       15.84   17.23   18.74   19.07   18.73   17.83
SO BUILDWID STCK3       20.72   20.28    0.00   20.76   21.30   21.19
SO BUILDWID STCK3       20.43   19.06   17.10   20.34   15.90   13.97
SO BUILDWID STCK3       15.84   20.17   17.10   19.06   20.43   21.19
SO BUILDWID STCK3       21.30   20.76    0.00   20.76   21.30   21.19
SO BUILDWID STCK3       20.43   19.06   17.10   17.23   15.84   13.97
```

06.

APPENDIX E

DETAILED ISCST3 MODELING RESULTS

ISCST3 Model Resultsfor the Proposed Combustion Turbines

Table E-1 Distillate Oil

DistillateOil - Class II Receptors								
	Normalized Concentration (µg/m³ per g/sec)*						Location	
100% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	0.522	0.620	0.571	0.632	0.677	0.677	583574	2908540
3-Hr	0.257	0.260	0.240	0.248	0.263	0.263	589074	2891940
8-Hr	0.138	0.157	0.149	0.141	0.125	0.157	565074	2903940
24-hr	0.056	0.056	0.053	0.065	0.051	0.065	567074	2917940
Annual	0.0044	0.0044	0.0047	0.0047	0.0049	0.0049	574074	2912940
75% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	0.734	0.636	0.586	0.717	0.918	0.918	583574	2908540
3-Hr	0.294	0.299	0.280	0.284	0.308	0.308	589074	2891940
8-Hr	0.166	0.181	0.174	0.157	0.145	0.181	565074	2903940
24-hr	0.070	0.069	0.061	0.074	0.060	0.074	567074	2917940
Annual	0.0052	0.0053	0.0057	0.0056	0.0059	0.0059	574074	2912940
50% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	0.977	0.652	0.839	0.845	1.221	1.221	583474	2908440
3-Hr	0.332	0.339	0.322	0.321	0.407	0.407	583474	2908440
8-Hr	0.197	0.205	0.199	0.177	0.176	0.205	565074	2903940
24-hr	0.078	0.080	0.070	0.084	0.075	0.084	573074	2913940
Annual	0.0060	0.0062	0.0066	0.0066	0.0069	0.0069	574074	2912940
* Based on 1 g/sec for each turbine stack (3)								

ISCST3 Model Resultsfor the Proposed Combustion Turbines

Table E-2 Natural Gas

Natural Gas - Class II Receptors								
Normalized Concentration (μg/m³ per g/sec)*							Location	
100% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	0.524	0.622	0.572	0.634	0.698	0.698	583574	2908540
3-Hr	0.261	0.264	0.245	0.252	0.268	0.268	589074	2891940
8-Hr	0.141	0.159	0.152	0.142	0.126	0.159	565074	2903940
24-hr	0.057	0.060	0.054	0.066	0.052	0.066	567074	2917940
Annual	0.0044	0.0045	0.0049	0.0048	0.0050	0.0050	574074	2912940
75% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	0.736	0.638	0.588	0.720	0.954	0.954	583474	2908440
3-Hr	0.299	0.305	0.286	0.289	0.318	0.318	583474	2908440
8-Hr	0.170	0.184	0.178	0.160	0.148	0.184	565074	2903940
24-hr	0.071	0.071	0.063	0.075	0.062	0.075	567074	2917940
Annual	0.0053	0.0054	0.0058	0.0057	0.0060	0.0060	574074	2912940
50% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	1.004	0.654	0.842	0.848	1.266	1.266	583474	2908440
3-Hr	0.338	0.346	0.328	0.327	0.422	0.422	583474	2908440
8-Hr	0.203	0.209	0.203	0.181	0.181	0.209	565074	2903940
24-hr	0.079	0.081	0.072	0.086	0.078	0.086	573074	2913940
Annual	0.0062	0.0063	0.0067	0.0068	0.0070	0.0070	574074	2912940
* Based on 1 g/sec for each turbine stack (3)								

APPENDIX F

KEY TO ISCST3 MODELING FILES ON CD-ROM

11/02/00

Key to files on CDROM - Deerfield Beach Energy, L.L.C. Florida

- *Directory :\Deerfld\GEP-BPIP - contains BPIP input and output files*

File Naming Convention:

Deergep.bpi - BPIP input file
Deergep.sum - BPIP input summary
Deergep.bpo - BPIP output file

- *Directory :\Deerfld\ISCST3\Natural Gas - contains ISCST3 input and output files for Natural Gas* modeled with an emission rate of 1 g/sec.

File Naming Convention:

NG10087 - Natural Gas with turbines at 100% load with 1987 metdata, repeat for '88, '89, '90 and '91
NG07587 - Natural Gas with turbines at 75% load with 1987 metdata, repeat for '88, '89, '90 and '91
NG05087 - Natural Gas with turbines at 50% load with 1987 metdata, repeat for '88, '89, '90 and '91

- *Directory :\Deerfld\ISCST3\Distillate Oil - contains ISCST3 input and output files for Distillate Oil modeled with an emission rate of 1 g/sec.*

File Naming Convention:

OI10087 - Distillate Oil with turbines at 100% load with 1987 metdata, repeat for '88, '89, '90 and '91
OI07587 - Distillate Oil with turbines at 75% load with 1987 metdata, repeat for '88, '89, '90 and '91
OI05087 - Distillate Oil with turbines at 50% load with 1987 metdata, repeat for '88, '89, '90 and '91

- *Directory :\Deerfld\metdata - contains five years ISCST3 meteorological data, 1987-1991, West Palm Beach International Airport*

File Naming Convention:

12844-87 - 1987 meteorological data, repeat for '88,'89,'90 and '91

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APPENDIX G

BROWARD COUNTY POLLUTION PREVENTION PLAN

Pollution Prevention Planning

for the

Deerfield Beach Energy Center (DBEC) LLC

in fulfillment of

Broward County Ordinance 27-178

BACKGROUND

Pollution Prevention Requirements

Pollution Prevention Planning is addressed under Broward County Code Section 27-178. Applicability is directed toward any owner or operator of a source constructed or modified after the effective date (April 2000), that results in a potential to emit any pollutant in excess of a major source criteria; or of a major source reconstructed or modified after the effective date which results in an increase in the potential to emit in excess of established criteria. These types of projects are to submit to the Broward County Department of Planning and Environmental Protection (DPEP) a Pollution Prevention (P2) Plan as part of their permit application.

The P2 Plan is to address a reduction in the generation of regulated air pollutants, including hazardous air pollutants (HAPs), and is to consider the cross-media transfer of pollutants and energy efficiency. The plan is to be submitted to the DPEP at the time of submittal of a construction or modification permit application and shall be considered part of the application.

The P2 Plan may consist of a certification by a Florida-registered professional engineer with appropriate documentation that there are no reasonably available technically and economically feasible alternatives to the proposed level of emissions of regulated air pollutants.

The P2 Plan is to include a summary of all data and information in the plan, including the following:

- The names, addresses and telephone numbers of the contact person responsible for the P2 Plan, the owner or operator, and the Responsible Official at the source;
- A statement of the scope and objectives of the P2 Plan and target emission reductions;
- The identification and explanation of technology, procedures and options considered available and technically feasible for reducing the use of each hazardous air pollutant (HAP) and/or regulated air pollutant at the source, and a time schedule for implementing chosen options; and
- An analysis of P2 activities that are already in place and that are consistent with the requirements of this section. The analysis shall include a description of existing P2 activities and the associated estimated emission reductions from each P2 activity listed.

Finally, the permittee may modify or update the P2 Plan. If the permittee modifies or updates the P2 Plan during the course of the life of the permit, a copy of the modified or updated P2 Plan is to be kept on site and made available for inspection. A copy of the modified or updated P2 Plan is to be submitted to the DPEP along with the permit renewal application.

Project Description

The facility addressed by this P2 Plan will be owned and operated by Deerfield Beach Energy Center, LLC (DBEC). The proposed project is a dual-fuel simple-cycle merchant power plant to be located in Deerfield Beach, Florida. A merchant power plant is a non-utility generation facility designed to produce power within the emerging deregulated electricity market. The DBEC is designed to have a nominal generating capacity in the range of 510 MW. Commercial operation is scheduled to commence as soon as May 1, 2002. As a merchant peaking plant, the DBEC is being designed to convert fuel to useful power quickly, cleanly, and reliably.

The DBEC will include three (3) General Electric 7FA combustion turbine generators (CTGs) operating in a simple-cycle mode. A simple-cycle peaking project is fundamentally different than the more common "combined-cycle" base load systems. The design, purpose and energy efficiency of a simple-cycle system will be described in more detail in the "Energy Efficiency" section of this Plan. The CTGs will be designed to operate on both natural gas and low-sulfur distillate fuel oil. Dry, low NO_X (DLN) combustors will be used to minimize NO_X formation during combustion, and water injection will be employed during diesel oil-firing to reduce NO_X emissions. The use of DLN combustors during natural gas firing further serves to minimize the use of water for the project.

The proposed generation facility will utilize the Best Available Control Technology (BACT), as defined by U.S. EPA, for NO_X, CO, SO_2, Sulfuric Acid Mist (SAM), and particulates (PM/PM_{10}) to minimize air emissions. The project will not be a major source of hazardous air pollutants (HAPs).

As part of its application, the DBEC is requesting the ability to burn 1,000 hours per year of oil. While the intention is to burn natural gas at every opportunity, near term constraints on the Florida Gas Transmission (FGT) pipeline may impede the ability to burn natural gas during periods of peak demand often associated with the summer season. In general, the FGT natural gas transmission line flows near its maximum pipeline capacity of 1.5 billion cubic feet per day (Bcf/day) during the summer season. In order to accommodate the demand for incremental generation within the state of Florida, FGT plans to expand its pipeline capacity by approximately 600,000 MMBtu/day before the summer of 2002. Additionally, FGT is in active discussions with potential shippers to perform another expansion of its pipeline in 2003. The addition of this capacity should reduce periods of pipeline constraint and will result in an increased availability of natural gas to the proposed site. The request for oil burning flexibility is necessitated by near-term FGT capacity constraints and is not due to deficient gas supplies received by FGT. Moreover, operational guidelines dictate that natural gas be the primary fuel source and that oil will be used as a backup fuel to the extent that transmission capacity constraints on FGT preclude the delivery of natural gas to the site.

As the proposed facility is intended to provide peak power which will typically occur during periods when natural gas demand will be high, the ability to operate using distillate oil as an alternative fuel is necessary to provide system reliability. As the facility is being proposed as a dual-fuel facility, the control technology analysis has been performed assuming the maximum amount of oil consumption, when determining potential emissions.

P2 PLAN CONTACTS

Listed below are the applicant's primary points of contact, and the address and phone number where they can be contacted.

Applicant's Address

Corporate Office	Deerfield Beach Energy Center, LLC 1400 Smith Street Houston, TX 77002-7631
Project Site	Deerfield Beach Energy Center West of the intersection of N. Powerline Rd. and N.W. 48th St. and east of the Florida Turnpike Deerfield Beach, FL 33069

Applicant's Contacts

Corporate Officer	Ben Jacoby Director 1400 Smith Street Houston, TX 77002-7631
Environmental Contact	Dave Kellermeyer Director 1400 Smith Street, EB-3146C Houston, TX 77002-7631 Telephone: (713) 853-3161 Fax: (713) 646-3037

SCOPE AND OBJECTIVES

Broward County provides the following definition for pollution prevention: The act of using materials, processes, or practices that:

(a) reduce or eliminate the creation of pollutants or wastes at the source; and

(b) protect the environment and reduce the hazards to public health associated with the release of pollutants or wastes. This includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, material substitution, on site recycling/reuse, conservation of energy, water, and other natural resources, and improvements in housekeeping, maintenance, training, or inventory control. This does not include off site recycling, waste treatment, concentrating hazardous or toxic constituents to reduce volume, diluting constituents to reduce hazard or toxicity, or transferring hazardous or toxic constituents from one environmental medium to another.

The primary objectives of this Pollution Prevention (P2) plan are to: 1) document the process of determining technically and economically feasible control alternatives for emissions from this project, and 2) to document that pollution prevention considerations were inherent in the design features of this project. Some of these design features are addressed in the section heading of "Other P2 Activities". The scope of this plan also includes energy efficiency issues, cross-media transfer of pollutants, and other considerations written into the Broward County Ordinance

The Pollution Planning provision, as written in the Broward County code, tends to broadly apply to the types of projects it addresses, as long as the above-cited applicability criteria are triggered. As such, some new or modified construction projects that may be subject to this provision, may not be required to meet additional federal or state requirements that could be duplicative or more stringent. In the case of the Deerfield Beach Energy Center, the proposed facility is required to submit an application for a permit to construct under the Prevention of Significant Deterioration (PSD) rules codified at 40 CFR Part 52 and incorporated as a SIP-approved program into Rule 62-212.400, F.A.C.

The following requirements are encompassed by PSD review:

- Compliance with any applicable emission limitation under the State Implementation Plan (SIP);
- Compliance with any applicable New Source Performance Standard (NSPS);
- Compliance with any applicable National Emission Standard for HAPs (NESHAPS);
- Application of Best Available Control Technology (BACT), as defined by the PSD rules, to emissions of NO_x, CO, SO_2, PM/PM_{10} and HAPs from all significant sources at the facility;
- A demonstration that the facility's potential emissions, and any emissions of regulated pollutants resulting from directly related growth of a residential, commercial or industrial nature, will neither cause nor contribute to a violation of the NAAQS or allowable PSD increments;

- An analysis of the impacts on local soils, vegetation and visibility resulting from emissions from the facility and emissions from directly related growth of a residential, commercial, or industrial nature;
- An evaluation of impacts on Visibility and Air Quality Related Values (AQRVs) in PSD Class I areas (if applicable); and
- At the discretion of FDEP, pre-construction and/or post-construction air quality monitoring for NO_x, CO, SO_2, and PM/PM_{10}.

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

In accordance with federal and state Prevention of Significant Deterioration (PSD) requirements, FDEP requires the application of Best Available Control Technology (BACT) for the control of each regulated pollutant emitted in significant quantities from a new major stationary source located in an attainment area for that pollutant. The proposed Deerfield Beach Energy Center's combustion turbines are to be located in an area that is currently attainment for all pollutants, and must demonstrate the application of BACT for oxides of nitrogen (NO_X), carbon monoxide (CO), fine particulate (PM_{10}), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4).

The BACT requirements are intended to ensure that a proposed facility or major modification will incorporate air pollution control systems that reflect the latest demonstrated practical techniques for each particular emission unit, and will not result in the exceedance of a National Ambient Air Quality Standard (NAAQS), PSD Increment, or other air quality standard protective of the public health imposed at the state level. The BACT evaluation requires the documentation of performance levels achievable for each air pollution control technology applicable to the DBEC.

The five steps involved in a top-down BACT evaluation are:

- Identify options with practical potential for control of the regulated pollutant under evaluation;
- Eliminate technically infeasible or unavailable technology options;
- Rank the remaining control technologies by control effectiveness;
- Evaluate the most effective controls and document the results; if the top option is not selected as BACT, evaluate the next most effective control option; and
- Select BACT, which will be the most effective practical option not rejected based on prohibitive energy, environmental, or economic impacts.

The "top-down" approach was employed in evaluating available pollution controls for the DBEC.

BACT for Nitrogen Oxides (NO_x)

NO_x is primarily formed in combustion processes in two ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Natural gas does not contain fuel bound nitrogen; therefore, NO_x emissions from combustion turbines when burning natural gas originate as thermal NO_x. The rate of formation of thermal NO_x is a function of residence time and free oxygen, and increases exponentially with flame temperature. Liquid fuels such as No. 2 distillate contain fuel bound nitrogen. The combustion of liquid fuels results in inherently higher emissions of NO_x due to the combination of both thermal NO_x and fuel NO_x ; however, due to the oil refining process, low sulfur fuels have been found to have minimal amounts of fuel bound nitrogen. The specification of low sulfur fuel for this project also serves to minimize the amount of fuel bound nitrogen available for NOx formation.

DBEC proposes to implement NO_x BACT through the application of state-of-the-art GE 7FA turbines with DLN combustors. These turbines will be able to achieve NOx levels of "9 ppm" while firing natural gas and 42 ppm (water injected) while firing distillate oil. The use of "dry" low NOx combustors during natural gas firing also serves to minimize the use of water at the site. This is equivalent to or more stringent than other recent BACT decisions for dual-fuel simple cycle peaking projects.

BACT for Carbon Monoxide

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (by water injection or aggressive dry combustion design) tends to result in higher levels of CO emissions. Thus, a compromise must be established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while minimizing CO emission rates.

Therefore, it's concluded that CO emission levels of 9 ppmvd while firing natural gas and 20 ppmvd while firing distillate oil using combustion control, represent BACT for this facility.

BACT for Particulate Matter and Trace Element Emissions

Particulate (PM) emissions from natural gas and distillate oil combustion sources consist of inert contaminants in the fuel, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, particulates of carbon and hydrocarbons resulting from incomplete combustion, and condensibles, including sulfates and nitrates. Units firing fuels with low ash content and high combustion efficiency, such as the units proposed, exhibit correspondingly low particulate emissions. Minimal trace elements may be a constituent of distillate fuel oils and, if so, may be emitted from the combustion turbine in the form of particulate emissions. These trace element particulates are present in quantities significantly lower than the thresholds that require further air quality analysis.

The use of add-on controls, such as electrostatic precipitators (ESPs) or baghouses, is technically infeasible, and does not represent an available control technology. The use of negligible or zero ash fuels such as natural gas and low sulfur distillate fuel oil, and good combustion control is concluded to represent BACT for PM control for the proposed simple-cycle peaking turbines.

BACT for Sulfur Dioxide and Sulfuric Acid Mist

Sulfur dioxide (SO_2) is exclusively formed through the oxidation of sulfur present in the fuel. The emission rate is a function of the sulfur content of the fuel, since virtually all fuel sulfur is converted to SO_2. Another by-product of sulfur oxidation is when sulfur trioxide (SO_3) combines with water to form sulfuric acid (H_2SO_4). As a condensable gas, the sulfuric acid will appear in mist form in the stack if the temperatures are sufficiently low for condensation to occur. Since the stack exhaust will be in the 1050°F – 1250°F range, and the boiling point of sulfuric acid is less than 650°F, sulfuric acid mist will not form in the stack.

The proposed simple-cycle gas turbines will fire pipeline-quality natural gas and low sulfur transportation grade distillate fuel. Pipeline grade natural gas typically averages between 1-10 grains of sulfur per hundred standard cubic feet gas. The firing of pipeline quality natural gas and low sulfur transportation grade distillate fuel is the most stringent SO_2 control methodology that has been demonstrated in practice for any combustion turbine. Therefore, this evaluation concludes that that firing of pipeline quality natural gas and low sulfur transportation grade distillate fuel in the proposed simple-cycle peaking turbines and pipeline quality natural gas in the proposed fuel gas heater is BACT for SO_2.

BACT Summary

A summary of technologies determined to represent BACT for the DBEC project is presented in Table 1. Expected total emissions are summarized in Table 2, which are estimated based on 100% load for 3,500 hours per year including up to 1,000 hours per year of distillate oil operation and application of BACT as determined in this analysis.

Table 1. Summary of Selected BACTs

Pollutant	Gas Turbines
NO_x	Dry Low NO_x Combustors with Natural Gas (9 ppmvd at 15% O_2), Water injection with Distillate Oil (42 ppmvd at 15% O_2)
CO	Good combustion control (9 ppmvd with Natural Gas, 20 ppmvd with Distillate Oil)
PM	Good combustion control; low ash, low sulfur fuel
SO_2	Low sulfur fuel; natural gas (2 grains S / 100 scf gas) distillate oil (0.05 wt% S)

Table 2. Annual Emission Summary for the DBEC Combustion Turbines

Turbine	NO_x	CO	VOC	SO_2	H_2SO_4	PM	PM_{10}	Pb
	Emissions for One Combustion Turbine (tons/year) [1]							
GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	39.5	0.01
	Emissions for All Combustion Turbines (tons/year) [1]							
3 x GE7FA	705.0	210.9	15.3	190.2	29.1	118.5	118.5	0.04

Notes:
[1] Based on worst case hourly emission rate over the load range (50% - 100% base load), at the effective Annual Average Temperature of 50°F, and the following operation schedule:
NG Annual Operation 2,500 hrs/year/turbine
Oil Annual Operation 1,000 hrs/year/turbine
Total Annual Operation 3,500 hrs/year/turbine

OTHER P2 ACTIVITIES

The Deerfield Beach Energy Center (DBEC) has further been designed to minimize potential and real environmental impacts.

Water Supply & Water Quality Impacts.

Water is needed for use in the inlet air chiller and for injection for NOx control during fuel oil firing. An evaluation of water supply alternatives and water disposal alternatives was performed to determine the best option to protect the water resources and the environment. It was found that this site has a unique opportunity to satisfy its water requirements without consuming freshwater from groundwater or surface water resources. Reuse wastewater provided by the Broward County North Region Wastewater Treatment Plant was selected as the primary source of process water for the plant. The Broward County North Region Wastewater Treatment Plant (WWTP) has the capacity to produce 10,000,000 gallons per day of reclaimed quality water for reuse. Currently, only 40 to 60 percent of the available reclaimed water capacity is being utilized and the remainder is disposed of by either discharging to the ocean outfall or to a deep well. The DBEC will consume a large percentage of the available reuse water, thereby minimizing the costly and environmental sensitivities associated with its discharge to the ocean and/or deep well.

To insure the operation of the Deerfield Beach Energy Center under any conditions, groundwater from water supply wells located on site will be utilized to provide a secondary source of water for back-up of the primary reclaimed water supply. The Surficial and Biscayne aquifers will provide the back-up source, by water supply wells approximately 160-feet deep, with no significant effect on the groundwater resource. Due to the reliable supply of reclaimed water, it is not expected that significant quantities of groundwater would ever be required.

Peak water demands for the power plant will be approximately 1.6 MMgal/day during operation of all turbines. Raw water will be treated in a reverse osmosis (RO) system and in demineralizer units to remove impurities. The demineralizers will be portable units that are regenerated offsite, thus avoiding the need to discharge regeneration wastewater from the power plant site. The side stream off the RO system will be used as makeup water in the small cooling tower that is used as part of the inlet air chilling system. A small quantity of cooling tower blowdown will be generated. Constituents of this wastewater stream will be the naturally occurring substances in the raw water, cycled up to higher concentrations by evaporation in the cooling tower. This small quantity of blowdown will be returned to the Broward County North Region WWTP.

Waste Minimization.

No hazardous or non-hazardous waste will be generated as a by-product during operation of the facility. Extremely small quantities of listed hazardous wastes, such as spent solvents and paint thinners may be generated during the course of normal operation and maintenance activities. These substances will be stored, manifested, and disposed of in accordance with the hazardous waste regulations contained in applicable Florida regulations. Non-hazardous waste generated from plant operations include garbage and paper wastes, waste oils, and equipment maintenance washes. These wastes will be generated during routine maintenance of the plant equipment. Waste oils and spent solvents will be recycled. The procedure for equipment maintenance washes will generate a minimal amount of waste, which will be sent offsite for treatment. No wastes will remain onsite.

Accidental Release Prevention.

No hazardous materials, as defined by 40 CFR 302, will be used at this facility. Pipeline natural gas will meet all U.S. Department of Transportation safety standards that will greatly reduce the risk of an accidental release of natural gas. Turbine oil will be used and stored within the gas turbine lube oil reservoirs. Each turbine will have a lube oil reservoir with a capacity of 150 gallons. No. 2 Fuel Oil for the combustion turbines and the emergency fire-water pump will be stored on site in above-ground fuel oil storage tanks. Tanks will be constructed with impervious containment materials and in accordance with all applicable safety standards. Fuel oil spill containment for the project is governed by ¶ 5239.13 of the South Florida Fire Code (because the fuel is a combustible liquid) and NFPA 30 "Flammable and Combustible Liquids Code, 2000 Edition" (because NFPA 30 is adopted by specific reference into Section 5239 by ¶ 5239.1). Further, Paragraph 5239.13(h) of the South Florida Fire Code provides that above-ground storage tanks be surrounded by embankments or impervious dikes. Spill Prevention and Countermeasures plans (SPCC plans) for turbine oil and fuel oil handling will be written and implemented as required. The SPCC plan will identify potential leak pathways, will put in place plans for responding to releases and will describe measures taken to minimize the risk of an accidental release occurring

Energy Efficiency

Adequate electric generation is essential for the maintenance and growth of industry and commerce, as well as for the comfort and well being of Florida's residents based on recent shortfalls in the supply of electricity in the Southeast. Electricity can be generated from other non-fossil fuel resources, such as, wind energy, solar energy, hydro-energy and nuclear energy. However, Florida is in a flat terrain of the sub-tropical area; therefore, wind energy, hydro-energy, and solar energy are not capable of economically satisfying peak energy demands. Nuclear power plants will generate less criteria pollutants than natural gas fired plants, but present problems associated with the use of nuclear fuel and waste storage and handling. Generating electricity using natural gas fired combustion turbines is the most reliable, efficient, economic and cleanest option available for meeting the region's on-demand peak electric supply needs. There are no demonstrated alternative technologies that would offer greater environmental protection.

There are two types of combustion turbine electric generating facilities typically utilized to meet customer demand: 1) simple-cycle units and 2) combined cycle units. A simple-cycle unit consists mainly of a combustion turbine and is designed to start up quickly to meet peak energy demands. A combined-cycle unit uses the heating value of the exhaust gas to generate steam and drive a steam turbine, thus generating additional electricity. This type of design requires a longer startup time, is more efficient and is well suited to be used as a "base load" unit.

While a combined-cycle power plant exhibits much higher initial capital cost, these costs can be quickly recovered in greater fuel efficiency in a base load plant which operates around the clock at near full capacity. The combined-cycle power plant therefore, by definition incorporates a waste heat boiler or Heat Recovery Steam Generator (HRSG) and steam turbine generator. The HRSG recovers waste heat exiting the turbine at about 1,100°F and exhausts at about 220°F.

Regional power demand is variable from night to day, from hot summer days (which reflect air-conditioning loads) to cold winter days, from workdays to weekends, etc. However, there is a certain constant level of electrical demand that is always present, referred to as "base load". The nature of generation capacity built to provide base load power is that it is designed to maximize annual operation at a constant or "base" load at the lowest operating cost possible. Since fuel cost is the single biggest component of the cost to produce power, competitive base load generators must be designed to operate at the highest possible fuel efficiency and to produce their rated output continuously at maximum availability. The combined-cycle plant meets these criteria.

Once base load demand is satisfied, a need still exists to supply additional power at certain times when base load requirements are exceeded by the short-term peak power demand. Average peak power prices tend to be higher than for base load power. However, peaking units operate substantially fewer hours per year than base load units. The economics of providing peak power favor lower initial capital cost (there are fewer operating hours per year in which to earn back the capital investment) and are less sensitive to optimization of heat rate. Most importantly, peak power must be able to come on-and off-line very quickly and, in some cases is designed to "follow" electrical demand. Simple-cycle is the only combustion turbine configuration that meets this requirement. Combined-cycle units, on the other hand require a cold start-up schedule, measured in hours, to be brought from ambient temperature to full load. This is because the heat transfer surfaces and catalyst beds within the HRSG are sensitive to "thermal shock". On any given day, the demand for peak power may only last three to four hours. By the time a combined-cycle unit has been warmed up to full operating load, the market demand to produce the peak power may be over.

For the reasons presented above, simple-cycle peaking units operate intermittently and must be designed to follow electrical demand. As such, it is not economically feasible to rely on the heating value of the exhaust gas for commercial application to any type of process steam demand. DBEC commits to continually evaluate the economics and needs for the project, with a focus on optimizing the energy efficiency.

CONCLUSIONS

It is our belief that measures to provide for pollution prevention and prevent significant environmental impacts are inherent design features of the project. Some of these design features include:

- The use of highly efficient state-of-the-art combustion turbines to minimize air emissions, as well as the amount of fuel needed to produce electricity.
- Emissions of nitrogen oxides will be measured in real time using a continuous emission monitoring system (CEMS). This instrument will provide ongoing assurance that good combustion is being achieved and that the facility's air quality impacts are insignificant.
- Clean burning, low sulfur natural gas and fuel oil will be used, with natural gas being the primary fuel.

- The combustion turbines will be equipped with Dry Low NOx burners, simultaneously achieving the lowest emissions currently demonstrated and eliminating the need for water injection for NOx control through its "dry" design.

- The project will prepare and implement a Spill Prevention Control and Countermeasure (SPCC) plan to ensure that areas in which oil (distillate, lubricating, turbine) is stored and used is protected by appropriate measures such as containment dikes, and that procedures exist to prevent the occurrence of spills.

- Discharges of process wastewater will be minimal and consist of blowdown from an evaporative cooler. No significant quantities of treatment chemicals are anticipated to be required.

- Process water needs will be met by the reuse of wastewater from the Broward County North Region WWT Plant.

We believe that the proposed project represents the most environmentally responsible manner for the production of on-demand peaking power. As a result, there is no need to identify additional mitigation measures to reduce environmental impacts.

Finally, DBEC conducts environmental awareness training programs. These programs cover all media and emphasize waste minimization. Employees are always encouraged to look at their job responsibilities and identify further reduction opportunities. In addition, DBEC has an ongoing training program for operators, mechanics, and electricians to help them identify ways to improve and maintain efficient operation of equipment.

DBEC anticipates that additional opportunities for pollution prevention may come from this increased awareness by our employees and will, therefore commit to revisit this plan and consider revisions where appropriate. If the P2 plan is modified or updated during the course of the life of the permit, a copy of the modified or updated P2 plan will be kept on site and made available for inspection. A copy of the modified or updated P2 plan will also be submitted to the DPEP along with the permit renewal application.