LAKELAND ELECTRIC & WATER

PRODUCTION ENGINEERING

*Excellence Is Our Goal, Service Is Our Job*

December 13, 1990

Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Mr. C. H. Fancy, Chief, Bureau of Air Regulation

Gentlemen:

Enclosed is an original and two copies of the City of Lakeland Combustion Turbine Project application for construction permit.

Each bound application prepared by our consultant - Black and Veatch, contains a copy of FDER Form 17-1.202 (1), the Ambient Air Quality Impact Assessment and the BACT Analysis. In addition, computer printouts and a diskette of all the air modeling computer runs supporting the application are enclosed.

Attached you will find a letter of authorization for the undersigned and the required $5,000 application fee.

If you have any questions please call our Manager of Environmental Affairs, Mr. G. A. "Bill" Rodriguez at (813)/499-6589) or Mr. Steve Day at Black & Veatch (813/339-2820).

Very truly yours,

Alfred M. Dodd

Alfred M. Dodd, P.E.
E & W Engineering Manager
City of Lakeland
Department of Electric and Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050
(813) 499-6461

Enclosure

cc: G. A. Rodriguez
Steve Day
File LPE-01-88
P. Lewis
B. Andrews
L. Holladay
[illegible] EPA
[illegible] APS
[illegible]

FEDERAL EXPRESS

QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL
PACKAGE TRACKING NUMBER 8384312823

8384312823

Date 12/14/90

RECIPIENT'S COPY

1 From (Your Name) Please Print

Your Phone Number (Very Important)

Company: CITY OF LAKELAND ELEC & WATER

Department/Floor No.

Street Address: 01 EAST LEMON ST

City: LAKELAND State: FL ZIP Required: 3 3 8 0 1

2 To (Recipient's Name) Please Print

Recipient's Phone Number (Very Important)

Company: IT

Department/Floor No.

Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip + Codes.)

City State ZIP Required

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.)

H IF HOLD FOR PICK-UP, Print FEDEX Address Here

Street Address

City State ZIP Required

3 PAYMENT 1 [X] Bill Sender 2 [ ] Bill Recipient's FedEx Acct No. 3 [ ] Bill 3rd Party FedEx Acct No. 4 [ ] Bill Credit Card 5 [ ] Cash/Check

4 SERVICES (Check only one box)

Priority Overnight Service (Delivery by next business morning†)
11 [X] YOUR PACKAGING
18 [ ] FEDEX LETTER *
12 [ ] FEDEX PAK *
13 [ ] FEDEX BOX
14 [ ] FEDEX TUBE

Standard Overnight Service (Delivery by next business afternoon†)
51 [ ]
56 [ ] FEDEX LETTER *
52 [ ] FEDEX PAK *
53 [ ] FEDEX BOX
54 [ ] FEDEX TUBE

Economy Two-Day Service (formerly Standard Air) (Delivery by second business day†)
30 [ ] ECONOMY TWO-DAY SVC.

Heavyweight Service (for Extra Large or any package over 150 lbs)
70 [ ] HEAVYWEIGHT **
80 [ ] DEFERRED HEAVYWEIGHT **

† Delivery commitment may be later in some areas.
*Declared Value Limit $100
**Call for delivery schedule

DELIVERY AND SPECIAL HANDLING (Check services required)

1 [ ] HOLD FOR PICK-UP (Fill in Box H)
2 [ ] DELIVER WEEKDAY
3 [X] DELIVER SATURDAY (Extra charge) (Not available to all locations)
4 [ ] DANGEROUS GOODS (Extra charge)
5 [ ]
6 [ ] DRY ICE ____ Lbs
7 [ ] OTHER SPECIAL SERVICE
8 [ ]
9 [ ] SATURDAY PICK-UP (Extra charge)
10 [ ]
11 [ ] DESCRIPTION
12 [ ] HOLIDAY DELIVERY (If offered) (Extra charge)

| PACKAGES | WEIGHT In Pounds Only | YOUR DECLARED VALUE |
|---|---|---|
| 1 | 11 | |
| Total 1 | Total 11 | Total |

DIM SHIPMENT (Chargeable Weight) [ ] ____ lbs

Received At
1 [ ] Regular Stop 3 [ ] Drop Box
2 [X] On Call Stop 4 [ ] BSC 5 [ ] Station

FedEx Emp. No. 17465 Date/Time 12/14/90 1619

Emp. No. Date
[ ] Cash Received
[ ] Return Shipment
[ ] Third Party [ ] Chg. To Del. [ ] Chg. To Hold
Street Address
City State Zip
Received By X
Date/Time Received FedEx Employee Number

5 Release Signature:

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 8/90
PART #119501 FXEM 8/90
FORMAT #041

041

City of Lakeland
WORLD CITRUS CENTER

| DATE | CHECK NO. |
|---|---|
| 12-13-90 | 00024009 |
| LK CH | 15719 |

STATE OF FLORIDA SALES TAX EXEMPTION CERTIFICATE NO. 63-21-061508-54C

| DATE | INVOICE OR CREDIT MEMO NUMBER | TYPE | DESCRIPTION | REFERENCE NO. | GROSS | AMOUNTS DISCOUNTS | NET |
|---|---|---|---|---|---|---|---|
| 120790 | T013004 | | T013004 | 664830 | 500000 | | 500000 |
| THE ATTACHED CHECK IS IN PAYMENT FOR ITEMS DESCRIBED ABOVE. | | | | TOTAL | 500000 | | 500000 |

THIS DOCUMENT CONTAINS AN ARTIFICIAL WATERMARK - HOLD AT AN ANGLE TO VIEW

City of Lakeland
WORLD CITRUS CENTER

SUN FIRST NATIONAL BANK OF POLK COUNTY, WINTERHAVEN, FL 63-526/631

CENTRAL PAYING ACCOUNT
VOID AFTER 180 DAYS

CHECK NO. 00024009

024009

FIVE THOUSAND DOLLARS NO CENTS

PAY TO THE ORDER OF
DEPT OF ENVIRONMENTAL REG.

DATE 12-13-90

CHECK AMOUNT *****5,000.00

CITY MANAGER
CITY TREASURER
FINANCE DIRECTOR

⑈024009⑈ ⑆063105269⑆052400800327 4⑈

CITY OF LAKELAND, FLORIDA
COMBUSTION TURBINE PROJECT

# AMBIENT AIR QUALITY IMPACT ANALYSIS

FILE 16587.32.0402

DECEMBER 1990

Black & Veatch
Engineers-Architects

$5,000.00
12-17-90
Receipt #151223

STATE OF FLORIDA

# DEPARTMENT OF ENVIRONMENTAL REGULATION

RTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207

AC 53-190437
PSD-FL-166

BOB GRAHAM
GOVERNOR
VICTORIA J. TSCHINKEL
SECRETARY
G. DOUG DUTTON
DISTRICT MANAGER

## APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Combustion Turbine (CT) [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: City of Lakeland, Florida COUNTY: Polk

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) CT, Gas/Distillate Fired

SOURCE LOCATION: ~~Street~~ Charles Larsen Power Plant City Lakeland

UTM: East 409.185 km North 3102.754 km

Latitude 28 ° 2 ' 56 "N Longitude 81 ° 55 ' 25 "W

APPLICANT NAME AND TITLE: City of Lakeland Department of Electric and Water Utilities

APPLICANT ADDRESS: 501 E. Lemon Street, Lakeland, FL 33801-5050

### SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of the City of Lakeland

I certify that the statements made in this application for a construction permit are true, correct and complete to the best of my knowledge and belief. Furthe I agree to maintain and operate the pollution control source and pollution contr facilities in such a manner as to comply with the provision of Chapter 403, Flori Statutes, and all the rules and regulations of the department and revisions thereof. also understand that a permit, if granted by the department, will be non-transferab and I will promptly notify the department upon sale or legal transfer of the permitt establishment.

*Attach letter of authorization

Signed: Alfred M. Dodd

Alfred M. Dodd, Engr. Mgr.
Name and Title (Please Type)

Date: 12/13/90 Telephone No. 813/499-6461

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project ha been designed/examined by me and found to be in conformity with modern engineeri principles applicable to the treatment and disposal of pollutants characterized in t permit application. There is reasonable assurance, in my professional judgment, th

[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed D D Schultz

Donald D. Schultz, Project Manager
Name (Please Type)

Black & Veatch
Company Name (Please Type)

P. O. Box 8405, Kansas City, MO 64114
Mailing Address (Please Type)

Florida Registration No. 30304 Date: November 20, 1980 Telephone No. (913) 339-2028

## SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

See Sections 2.0 and 6.0 of the AAQIA. The project will result in full compliance with all applicable regulations.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction June 1991 Completion of Construction December 1992

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

See Section 6.0 of the AAQIA. Note that water injection for reduction of $NO_x$ emissions is an integral part of the gas turbine.

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

NA

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52

if power plant, hrs/yr 8760 ; if seasonal, describe: NA

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? No

   a. If yes, has "offset" been applied? _____

   b. If yes, has "Lowest Achievable Emission Rate" been applied? _____

   c. If yes, list non-attainment pollutants. _____

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. Yes

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. Yes

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? Yes

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? No

   a. If yes, for what pollutants? _____

   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

## SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

| Description | Contaminants | | Utilization Rate - lbs/hr | Relate to Flow Diagram |
|---|---|---|---|---|
| | Type | % Wt | | |
| NA | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

B. Process Rate, if applicable: (See Section V, Item 1) NA

1. Total Process Input Rate (lbs/hr): _____

2. Product Weight (lbs/hr): _____

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

| Name of Contaminant | Emission[1] | | Allowed[2] Emission Rate per Rule 17-2 | Allowable[3] Emission lbs/hr | Potential[4] Emission | | Relate to Flow Diagram |
|---|---|---|---|---|---|---|---|
| | Maximum lbs/hr | Actual T/yr | | | lbs/yr | T/yr | |
| See Section 3.3 of the AAQIA. | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |

[1]See Section V, Item 2.

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated without control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4)

| Name and Type (Model & Serial No.) | Contaminant | Efficiency | Range of Particles Size Collected (in microns) (If applicable) | Basis for Efficiency (Section V Item 5) |
|---|---|---|---|---|
| See Sections 3.3 and 6.0 of the AAQIA. | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

E. Fuels

| Type (Be Specific) | Consumption* | | Maximum Heat Input (MMBTU/hr) |
|---|---|---|---|
| | avg/hr | max./hr | |
| Natural Gas | | 1.14 MMCF/hr | 1054.6 MMBtu/hr |
| or | | (@ 25 F Ambient Conditions) | |
| No. 2 Fuel Oil | | $8.17 \times 10^3$ gal/hr | 1038.1 MMBtu/hr |
| | | (@ 25 F Ambient Conditions) | |

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis:

Percent Sulfur: Gas: 2,000 gr/MMCF; Oil: 0.20% by wgt.

Percent Ash: Nil (both fuels)

Density: Gas: 1 lb/23.8 CF; Oil: 7.05 lb/gal lbs/gal

Typical Percent Nitrogen: 0.73%

Heat Capacity: Gas: 22,090; Oil: 18,010 BTU/lb

Gas: 928 Btu/CF; Oil: 127,000 Btu/gal (LHV) BTU/gal

Other Fuel Contaminants (which may cause air pollution): Negl.

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average None Maximum None

G. Indicate liquid or solid wastes generated and method of disposal.

NA

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: See Table 3-1 in the AAQIA ft. Stack Diameter: _____ ft

Gas Flow Rate: _____ ACFM _____ DSCFM Gas Exit Temperature: _____ °F

Water Vapor Content: _____ % Velocity: _____ FP

## SECTION IV: INCINERATOR INFORMATION

NA

| Type of Waste | Type 0 (Plastics) | Type I (Rubbish) | Type II (Refuse) | Type III (Garbage) | Type IV (Pathological) | Type V (Liq.& Gas By-prod.) | Type VI (Solid By-prod.) |
|---|---|---|---|---|---|---|---|
| Actual lb/hr Incinerated | | | | | | | |
| Uncontrolled (lbs/hr) | | | | | | | |

Description of Waste _____

Total Weight Incinerated (lbs/hr) _____ Design Capacity (lbs/hr) _____

Approximate Number of Hours of Operation per day _____ day/wk _____ wks/yr. _____

Manufacturer _____

Date Constructed _____ Model No. _____

| | Volume $(ft)^3$ | Heat Release (BTU/hr) | Fuel | | Temperature (°F) |
|---|---|---|---|---|---|
| | | | Type | BTU/hr | |
| Primary Chamber | | | | | |
| Secondary Chamber | | | | | |

Stack Height: _____ ft. Stack Diamter: _____ Stack Temp. _____

Gas Flow Rate: _____ ACFM _____ DSCFM* Velocity: _____ FP

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) _____

Brief description of operating characteristics of control devices: _____

_____

_____

_____

_____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water ash, etc.):

_____

_____

_____

_____

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

## SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]

2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proper methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. See Appendix B of the AAQIA

3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test). See Appendix B of the AAQIA

4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.) See Section 6.0 of the AAQIA

5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). See Section 6.0 of the AAQIA

6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained. See Figure 2-3 in the AAQIA

7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map). See Figure 2-1 in the AAQIA

8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing process and outlets for airborne emissions. Relate all flows to the flow diagram. See Figure 2-2 in the AAQIA

9. The appropriate application fee in accordance with Rule 17-4.05. The check should made payable to the Department of Environmental Regulation.

10. With an application for operation permit, attach a Certificate of Completion of C struction indicating that the source was constructed as shown in the construct permit.

## SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part applicable to the source?

[X] Yes [ ] No Subpart GG

| Contaminant | Rate or Concentration |
|---|---|
| $SO_2$ | 150 ppmvd at 15% $O_2$ |
| $NO_x$ | * |
| | |
| | |

*75 ppmvd at 15% $O_2$ corrected for nitrogen content and heat rate, or 84 ppmvd at 15% $O_2$

B. Has EPA declared the best available control technology for this class of sources yes, attach copy)

[ ] Yes [X] No Case by case determination

| Contaminant | Rate or Concentration |
|---|---|
| | |
| | |
| | |
| | |

C. What emission levels do you propose as best available control technology?

| Contaminant | Rate or Concentration |
|---|---|
| See Section 6.0 of the AAQIA | |
| $NO_x$ | 25 ppmvd at 15% $O_2$ (Natural Gas) |
| | 42 ppmvd at 15% $O_2$ (Distillate) for FBN <0.015% |
| $SO_2$ | 0.2 percent Fuel Oil (Distillate) |

D. Describe the existing control and treatment technology (if any). NA

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

| Contaminant | Rate or Concentration |
|---|---|
| | |
| | |
| | |
| | |

10. Stack Parameters

a. Height: ft.

b. Diameter: ft

c. Flow Rate: ACFM

d. Temperature: °F

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicabl use additional pages if necessary).

1. See Section 6.0 of the AAOIA

a. Control Device:

b. Operatin: Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operat within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and opera within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and opera within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Costs:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operat within proposed levels:

F. Describe the control technology selected: See Section 6.0 of the AAQIA

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

| Contaminant | Rate or Concentration |
|---|---|
| | |
| | |
| | |

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

| Contaminant | Rate or Concentration |
|---|---|
| | |
| | |
| | |

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not available, applicant must state the reason(s) why.

## SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data See Section 5.2 of the AAQIA

1. _____ no. sites _____ TSP _____ ( ) $SO_2$ _____ Wind spd/dir

Period of Monitoring _____/_____/_____ to _____/_____/_____
month day year month day year

Other data recorded _____

Attach all data or statistical summaries to this application.

specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling See Section 4.3 of the AAQIA

1. _____ Year(s) of data from _____ to _____
month day year month day year

2. Surface data obtained from (location) _____

3. Upper air (mixing height) data obtained from (location) _____

4. Stability wind rose (STAR) data obtained from (location) _____

C. Computer Models Used See Section 4.1 of the AAQIA

1. _____ Modified? If yes, attach description.

2. _____ Modified? If yes, attach description.

3. _____ Modified? If yes, attach description.

4. _____ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

Applicants Maximum Allowable Emission Data See Section 3.3 of the AAQIA

| Pollutant | Emission Rate | |
|---|---|---|
| TSP | _____ | grams/sec |
| $SO^2$ | _____ | grams/sec |

E. Emission Data Used in Modeling *

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions and normal operating time.

F. Attach all other information supportive to the PSD review. *

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources.*

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. *

* E-H: See AAQIA for details

CONTENTS

CONTENTS (cont.)



LIST OF TABLES

CONTENTS (cont.)

LIST OF FIGURES

# 1.0 INTRODUCTION

The City of Lakeland Department of Electric and Water Utilities proposes to construct and operate a combustion turbine generator at the existing Charles Larsen Power Plant located in Lakeland, Florida. The combustion turbine (CT) will be capable of generating approximately 80 MW while operating in simple cycle, and 120 MW when in combined cycle operation. While in combined cycle, a single heat recovery steam generator (HRSG) will be used to repower an existing steam turbine generator (Larsen Unit 5). No expansion in steam capacity at the site is planned, and thus the facility is not required to be licensed under the Electrical Power Plant Siting Act which requires an increase in steam capacity before coverage is applied.

This report describes the Ambient Air Quality Impact Analysis (AAQIA) performed in support of a Florida Department of Environmental Regulation (FDER) permit to construct an air pollution source at the Larsen facility. The purpose of the AAQIA is to demonstrate that the combustion turbine installation will not cause or contribute to an exceedance of any national or state Ambient Air Quality Standards (AAQSs) and will not consume more than the applicable amount of Prevention of Significant Deterioration (PSD) air quality Class II increment. A Workplan which described the proposed methodology to be followed in this AAQIA was submitted to and conditionally approved by the appropriate FDER staff.

## 2.0 PROJECT DESCRIPTION

The Lakeland Combustion Turbine Project is located at the existing City of Lakeland Charles Larsen Plant site in Lakeland, Florida. The site is located on the south side of Lake Parker as shown in Figure 2-1. The plant site arrangement and a flowchart showing the combustion turbine process are shown in Figures 2-2 and 2-3, respectively.

The Project will consist of a new CT generator with the addition of a heat recovery steam generator (HRSG). When operating in the combined cycle mode, the CT will exhaust combustion gases to a dedicated HRSG and eventually to a 155-foot high stack. Steam produced in the HRSG will be directed to the existing Larsen Unit 5 steam turbine. During periods when the HRSG is not operating, the combustion turbine will operate in a simple cycle mode and exhaust through a 100-foot bypass stack. The new CT will be natural gas or No. 2 fuel oil (distillate) fired.

The proposed CT will have an independent air cooling system. The steam cycle and associated equipment will be cooled using the existing once-through cooling system. Makeup water for the HRSG boiler and $NO_x$ control water injection for the CT will be supplied from the Larsen Plant demineralized water supply. Wastewater will be routed to the existing wastewater system.

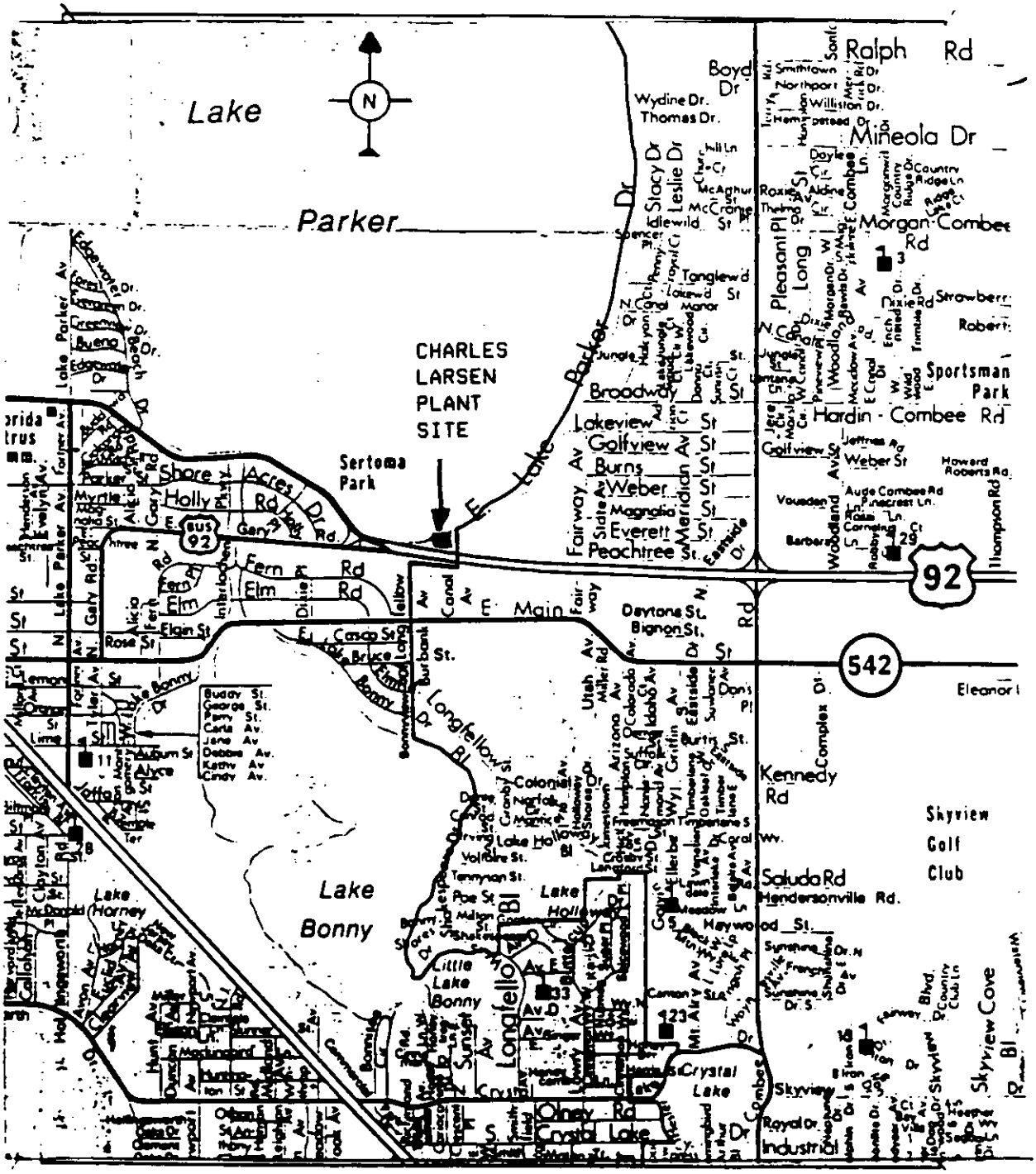



FIGURE 2-1. LOCATION OF CHARLES LARSEN PLANT SITE

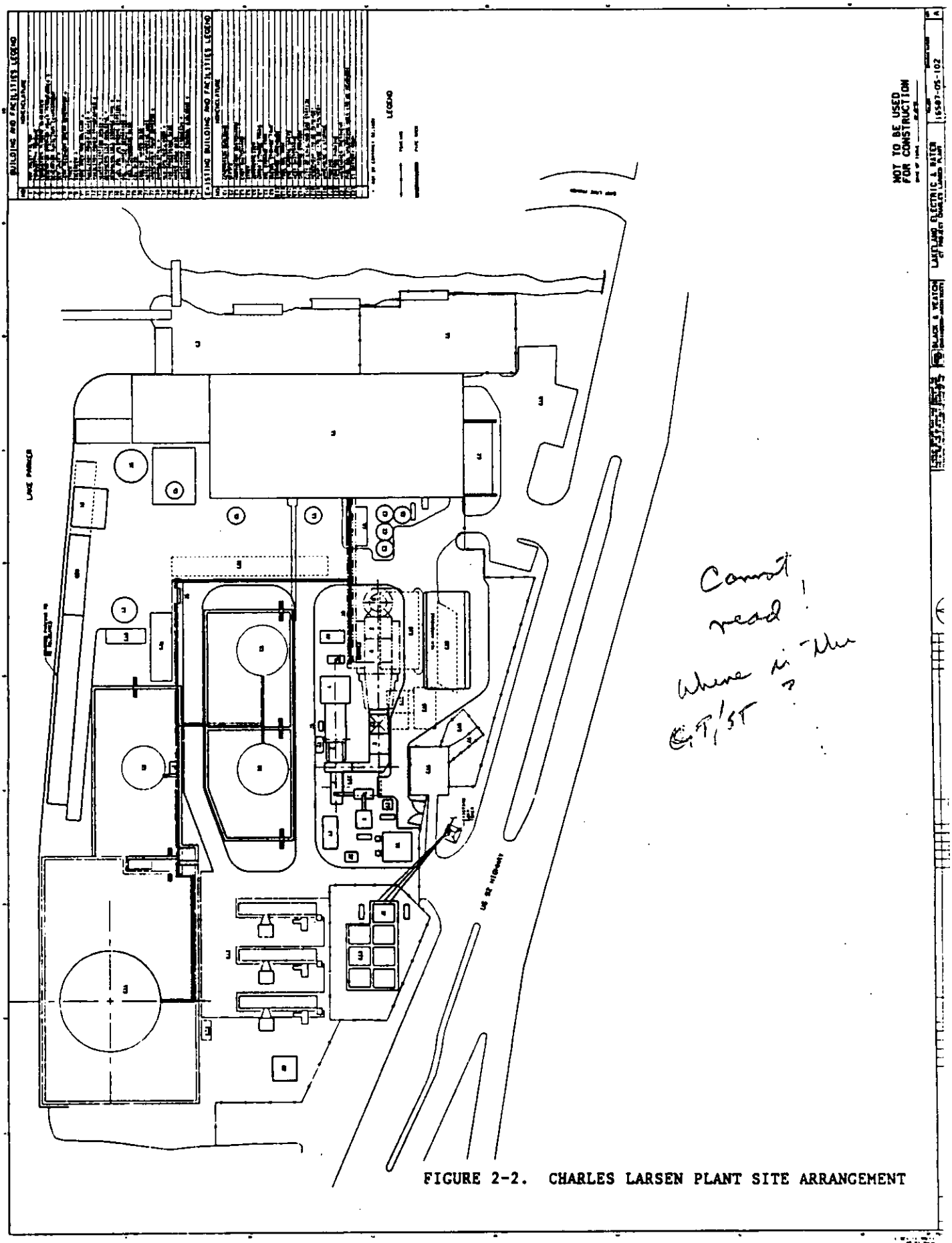



FIGURE 2-2. CHARLES LARSEN PLANT SITE ARRANGEMENT

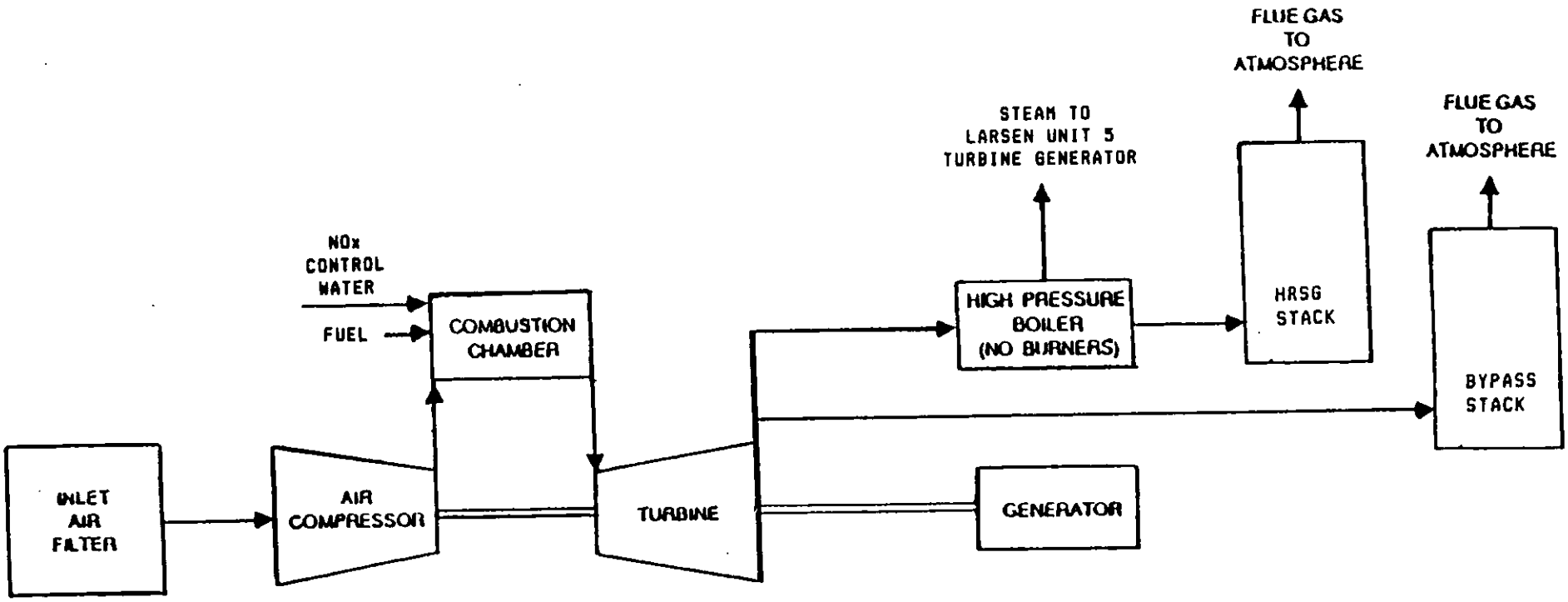



FIGURE 2-3. COMBUSTION TURBINE FLOW DIAGRAM

# 3.0 SOURCE CHARACTERIZATION

This section discusses the applicability of federal, state and local air quality regulations, good engineering practice (GEP) stack height determination, stack parameters and source emission rates, and the current air quality status at the Lakeland site. Best engineering estimates and plant conceptual design information were used to establish the modeling parameters.

## 3.1 APPLICABILITY OF REGULATIONS

The proposed Lakeland Project is subject to PSD regulations because the installation of the combustion turbine constitutes a major modification to an existing major stationary source and the plant will be located in an area designated as "attainment" for applicable pollutants. In addition, the requirements of the Florida Air Pollution and Permit Rules and Regulations and New Source Performance Standards (NSPS) Subpart GG will be applicable.

## 3.2 GEP STACK HEIGHT DETERMINATION

A GEP stack height analysis was conducted for the existing and proposed buildings and structures at the Larsen Power Plant. Pollutant dispersion from stacks built to the maximum GEP height are not influenced by surrounding building turbulence. If stacks are built lower than GEP, special air quality modeling techniques such as downwash and cavity analyses are required to demonstrate compliance with air quality standards.

EPA's Guideline For Determination of Good Engineering Practice Stack Height (1985) was used as a basis for this GEP analysis. The dominant structure influencing the proposed combustion turbine stacks is the existing turbine generator building. The maximum height of the generation building is 121.5 feet above grade. The maximum projected width of the generation building is 73.6 feet. The GEP height is calculated as the height of the dominant nearby building plus 1.5 times the lesser of the building height or maximum projected width. Therefore, the maximum GEP height is calculated to be 232 feet. Since the CT stack heights (155 and 100 feet) are less than the GEP height, building downwash considerations were

included in the modeling analysis. In fact, since the proposed stacks will be subject to Schulman-Scire downwash, direction-specific building heights and widths were used in the modeling analysis. Appendix A shows the output of Trinity Consultant's "BRZWAKE" program, which was used to determine direction-specific building dimensions.

## 3.3 STACK PARAMETERS AND SOURCE EMISSIONS

Stack parameters for both natural gas and fuel oil firing are given in Table 3-1 for both combined and simple cycle operation. All calculations were based on preliminary engineering design information and manufacturer performance data. Combustion turbine outputs (megawatts, fuel burn rates, and emissions) increase for operation at lower ambient temperatures. Therefore, the maximum emission rates for a combustion turbine do not occur at 59 F ISO standard day conditions, but occur during lower ambient temperatures. The lowest anticipated temperature for the Lakeland project is 25 F. To keep the analysis conservative, the maximum short-term emission rates and stack parameters used in the modeling analysis are based on an ambient temperature of 25 F. Annual impacts are based on ISO condition (59 F and 60 percent relative humidity) emission rates. The stack parameters given in Table 3-1 are based on the 25 F ambient condition.

Estimated maximum hourly emissions for the combustion turbine when firing either natural gas or fuel oil is provided in Table 3-2. These emissions are applicable for both simple and combined cycle operation. Duct burning is not proposed for the project. Estimates are based on a design fuel burn rate assuming the lower heating value (LHV) of the fuels and both the 25 and 59 F ambient temperature conditions. As stated previously, the 25 F emission rates are used to calculate short-term impacts and the ISO emission rates are used for annual calculations. These assumptions are representative of the facility's maximum generation capability.

The nitrogen oxides ($NO_x$) emission rate for natural gas firing is based on operations with Low-$NO_x$-burner technology and multi-nozzle water injection (see BACT determination in Section 6.0). These controls result in an outlet concentration of 25 ppmvd referenced to 15 percent oxygen when

TABLE 3-1. COMBUSTION TURBINE SOURCE PARAMETERS AT 25 F

| Parameter | Combined Cycle | | Simple Cycle | |
|---|---|---|---|---|
| | Natural Gas | No. 2 Fuel Oil | Natural Gas | No. 2 Fuel Oil |
| Fuel LHV (Btu/ft$^3$) | 928 | -- | 928 | -- |
| (Btu/gal) | -- | 127,000 | -- | 127,000 |
| Heat Rate (MMBtu/h) | 1,055 | 1,038 | 1,055 | 1,038 |
| Exhaust Temperature (F) | 481 | 481 | 949 | 950 |
| Exhaust Flow (lb/h) | 2,588,000 | 2,589,000 | 2,588,000 | 2,589,000 |
| Exhaust Gas Molecular Weight (lb/lb-mole) | 28.16 | 28.66 | 28.16 | 28.66 |
| Exhaust Flow Water Vapor Content (% vol) | 10.13 | 7.25 | 10.13 | 7.25 |
| Exhaust Flow Oxygen Content (% vol) | 12.93 | 13.44 | 12.93 | 13.44 |
| Exhaust Volumetric Flow (acfm) | 1,058,000 | 1,040,000 | 1,570,000 | 1,575,000 |
| Exhaust Flow Velocity (fpm) | 3,732 | 3,668 | 5,537 | 5,555 |
| Stack Height (ft) | 155 | 155 | 100 | 100 |
| Stack Diameter (ft) | 19 | 19 | 19 | 19 |
| Dominant Building Height (ft) | 121.5 | 121.5 | 121.5 | 121.5 |
| Maximum Projected Width (ft) | 73.6 | 73.6 | 73.6 | 73.6 |

TABLE 3-2. COMBUSTION TURBINE SOURCE EMISSIONS[1]

| Parameter | @ 25 F[2] | | @ 59 F[3] | |
|---|---|---|---|---|
| | Natural Gas | No. 2 Fuel Oil | Natural Gas | No. 2 Fuel Oil |
| $SO_2$ (lb/h)[4] | 0.7 | 231 | 0.6 | 210 |
| $NO_x$ (ppmvd @ 15% $O_2$)[5] | 25 | 42 | 25 | 42 |
| $NO_x$ (lb/h)[5] | 106 | 183 | 97 | 167 |
| CO (ppmvd)[5] | 25 | 25 | 25 | 25 |
| CO (lb/h)[5] | 58 | 58 | 53 | 54 |
| VOC (ppmvw)[5] | 1.4 | 3.5 | 1.4 | 3.5 |
| VOC (lb/h)[5] | 2 | 5 | 2 | 4.5 |
| Particulate (lb/h)[5] | 5 | 15 | 5 | 15 |

[1]HRSG and Bypass stack emissions are equivalent.

[2]25 F emissions are used to calculate short-term impacts.

[3]59 F emissions are used to calculate annual emissions and impacts.

[4]Natural gas emissions are based on 2,000 gr/MMCF sulfur content. No. 2 fuel oil emissions are based on 0.2 percent sulfur by weight. See Appendix B for a derivation of $SO_2$ emission rates.

[5]Based on manufacturer performance data.

firing natural gas. The $NO_x$ emission rate for fuel oil firing is also based on operations with low $NO_x$ burner technology and multi-nozzle water injection. These controls result in an outlet concentration of 42 ppmvd referenced to 15 percent oxygen.

The sulfur dioxide ($SO_2$) emission rate with natural gas firing is based on a sulfur content of 2,000 grains of sulfur per million cubic feet (MCF) of natural gas and a heat content of 928 Btu/$ft^3$ (LHV). The $SO_2$ emission rate for fuel oil combustion is based on a 0.2 percent by weight fuel sulfur content and a heat content of 127,000 Btu/gal. $SO_2$ emission rates are derived in Appendix B.

The emission rates of carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM) were obtained from typical manufacturer performance data for the GE PG7111(EA) Frame 7 improved low $NO_x$ combustion turbine.

Emission rates for other regulated and hazardous air pollutant emissions were based on manufacturer information and on information contained in the EPA publication Toxic Air Pollutant Emissions Factors - A Compilation For Selected Air Toxic Compounds and Sources (EPA-450/2-88-006a). Emissions of beryllium (Be), lead (Pb), mercury (Hg), and sulfuric acid ($H_2SO_4$) mist were estimated for fuel oil combustion. These pollutants are not found in natural gas firing. Asbestos (As), fluoride (F), and vinyl chloride ($C_2H_3Cl$) are not found in No. 2 fuel oil or natural gas.

Be, Pb, and Hg are found in No. 2 fuel oil in trace amounts. A typical Be concentration in fuel oil is $2.5 \times 10^{-6}$ pounds per million Btu. Pb concentrations are estimated at $2.8 \times 10^{-5}$ pounds per million Btu. Hg concentrations are estimated to be $3.0 \times 10^{-6}$ pounds per million Btu.

$H_2SO_4$ mist results from oxidation of the $SO_2$ in the flue gas to sulfur trioxide ($SO_3$). The $SO_3$ then combines with water vapor to form $H_2SO_4$ mist. Approximately 3 percent of the $SO_2$ is converted to $H_2SO_4$ mist. Based on these estimates, the $H_2SO_4$ mist concentration is $6.7 \times 10^{-3}$ pounds per million Btu for fuel oil firing, and $1.9 \times 10^{-5}$ pounds per million Btu for natural gas.

Table 3-3 presents the maximum potential annual emissions from the combustion turbine addition assuming 8,760 hours of annual operation. Appendix B shows the calculations supporting the annual emission rates.

TABLE 3-3. POTENTIAL ANNUAL EMISSIONS FROM THE COMBUSTION TURBINE

| Pollutant | Potential Annual Emission @ 59 F Natural Gas (tpy) | Potential Annual Emission @ 59 F Fuel Oil (tpy) | PSD Significance Levels (tpy) | PSD Significance (yes/no) |
|---|---|---|---|---|
| CO | 232 | 237 | 100 | yes |
| $NO_x$ | 425 | 732 | 40 | yes |
| $SO_2$ | 2.6 | 920 | 40 | yes |
| TSP | 22 | 66 | 25 | yes |
| $PM_{10}$* | 22 | 66 | 15 | yes |
| VOC | 9 | 20 | 40 | no |
| Lead | 0.0 | 0.12 | 0.6 | no |
| Asbestos | 0.0 | 0.0 | 0.007 | no |
| Beryllium | 0.0 | 0.01 | 0.0004 | yes |
| Mercury | 0.0 | 0.01 | 0.1 | no |
| Vinyl Chloride | 0.0 | 0.0 | 1.0 | no |
| Fluorides | 0.0 | 0.0 | 3.0 | no |
| $H_2SO_4$ mist | 0.08 | 27.6 | 7.0 | yes |
| Total Reduced S | <<10 | <<10 | 10 | no |
| Reduced S | <<10 | <<10 | 10 | no |
| $H_2S$ | <<10 | <<10 | 10 | no |

*The assumption is made that all particulate matter is less than 10 microns in diameter ($PM_{10}$).

NOTE: Emissions are based on the combustion turbine operating at ISO conditions (59 F and 60 percent relative humidity) with natural gas or fuel oil for 8,760 hours per year (See Appendix B for calculations). PSD significance for a pollutant is triggered if emissions from either fuel exceed the significance levels.

The results indicate that the new unit will require additional PSD review for CO, $NO_x$, $SO_2$, PM, Be, and $H_2SO_4$ mist. VOC, Pb, As, Hg, $C_2H_3Cl$, F, and reduced sulfur compounds require no further analyses. PSD review requires a BACT analysis, an ambient air quality impact analysis, and additional impact analysis.

## 3.4 CURRENT AIR QUALITY STATUS

The Charles Larsen Power Plant is located in an area which is designated as attainment for all applicable criteria pollutants.

# 4.0 MODELING METHODOLOGY

This section discusses the modeling methodology used for determining ambient air quality impacts for $SO_2$, $NO_x$, CO, and PM resulting from the proposed combustion turbine addition. The proposed methodology was reviewed and approved by FDER in the AAQIA Workplan. Section 5.0 gives the results of the dispersion modeling analysis.

## 4.1 MODEL SELECTION AND DESCRIPTION

The combustion turbine will burn either natural gas or low sulfur No. 2 fuel oil. Tables 3-2 and 3-3 show that the $SO_2$, $NO_x$, and PM emissions from fuel oil combustion are significantly higher than natural gas combustion, while the gas flow characteristics are fairly similar. Therefore, it can be concluded without screening-level analysis that fuel oil combustion will result in the higher ground-level pollutant impacts.

The terrain surrounding the Larsen facility is relatively flat. Following the recommended EPA guidance for refined models, the Industrial Source Complex Short Term (ISCST) dispersion model was used with five years of hourly meteorological data to predict maximum and highest, second-highest ambient pollutant impacts at receptor locations surrounding the plant site. The ISCST model is designed to predict ambient pollutant impacts for several averaging periods and from a variety of industrial sources. In addition, the model has the ability to evaluate external parameters such as rural or urban environments and building downwash.

All recommended EPA default options were utilized. The following is a listing of the options selected for the modeling:

- Rural-urban option : rural
- Wind profile exponents : default
- Vertical potential temperature gradient values : default
- Final plume rise only : yes
- Adjust stack heights for downwash : yes
- Buoyancy induced dispersion : yes

- o Calm processing option : yes
- o Above ground receptors used : no
- o Schulman - Scire downwash : yes

For unstable through stable atmospheric conditions, the wind profile exponents are 0.07, 0.07, 0.10, 0.15, 0.35, and 0.55, respectively.

## 4.2 RECEPTOR LOCATIONS

Receptor locations were selected with adequate density to ensure that the maximum and highest, second-highest predicted concentrations were determined. Dispersion modeling for the HRSG and bypass stacks was performed with receptors placed along the 36 standard radial directions surrounding a point half-way between the two stacks at the following downwind distances: 100-meter intervals from 100 to 1,000 meters, 250-meter intervals from 1,250 to 3,000 meters, and 1,000-meter intervals from 4,000 to 15,000 meters. Furthermore, discrete receptors were placed at the boundaries that restrict public access along the 36 radial directions.

## 4.3 METEOROLOGICAL DATA

The ISCST dispersion model was used with five years (1982-1986) of sequential hourly surface meteorological data and twice-daily mixing heights. The surface and mixing height data were selected from a location most representative of the general area being modeled. A representative location corresponds to the station closest to the location being modeled which is in the same climatic regime.

Hourly surface and mixing height data from the Tampa, Florida NWS reporting station were obtained from FDER. The data were selected by FDER as the most representative of meteorological conditions at the City of Lakeland Charles Larsen Power Plant. The data had been preprocessed into the "CRSTER" format and all five years were used in the modeling.

# 5.0 AIR QUALITY IMPACT ANALYSIS

An air quality impact analysis was performed using the modeling methodology approved by the FDER in the AAQIA Workplan and reviewed in Section 4.0. The analysis was performed to determine which pollutants emitted from the combustion turbine project have the potential to impact ambient air quality above PSD ambient air quality "significance levels". In addition, if significant impacts are determined, a "significant impact area" must be defined, preconstruction monitoring requirements need to be examined, and a ambient air quality standard (AAQS) and PSD increment consumption analysis outline must be developed.

## 5.1 MODELING RESULTS

The results of the refined-level dispersion modeling are presented in Tables 5-1 and 5-2. Table 5-1 shows the modeled concentrations for each averaging period assuming a nominal (1 g/s) $SO_2$ emission rate. Table 5-2 shows the impacts for each pollutant after ratioing the annual nominal impacts to the 59 F actual emission rates and the short-term nominal impacts to the 25 F actual emission rates. A description of the modeling runs is given in Appendix C. Printed and floppy diskette copies of the runs will be provided to the FDER.

Table 5-1 shows that the highest impacts for all averaging periods except the 24-hour period are predicted to occur when the combustion turbine is operating in the simple cycle mode (Bypass). The highest 24-hour impact occurs in the combined cycle mode (HRSG). The maximum impact location for the annual averaging period is 100 meters from the plant. The highest, second-highest 1-, 3-, 8-, and 24-hour average impact locations are also 100 meters from the plant. The highest, second-highest 24-hour impact occurred 200 meters from the plant.

Table 5-2 shows the maximum annual and highest, second-highest 3-, and 24-hour average impacts of $SO_2$ are 0.2, 4.7, and 19.2 $ug/m^3$, respectively. These values are below the PSD significance levels of 1.0, 5.0, and 25.0 $ug/m^3$, respectively. Therefore, no further air quality impact analysis is required for $SO_2$.

TABLE 5-1. REFINED MODELING RESULTS - FUEL OIL COMBUSTION SO2

| Operating Condition | 1-Hour Impact* | 3-Hour Impact* | 8-Hour Impact* | 24-Hour Impact* | Annual Impact** |
|---|---|---|---|---|---|
| Simple Cycle - Bypass*** | | | | | |
| Concentration (ug/m$^3$) | 1.28234 | 0.66011 | 0.37247 | 0.14412 | 0.00698 |
| Receptor Dist. (m) | 100 | 100 | 100 | 100 | 100 |
| Receptor Dir. (deg) | 100 | 350 | 20 | 100 | 260 |
| Modeled Year | 1984 | 1985 | 1985 | 1983 | 1982 |
| Combined Cycle - HRSG*** | | | | | |
| Concentration (ug/m$^3$) | 0.78584 | 0.47293 | 0.25268 | 0.15978 | 0.00484 |
| Receptor Dist. (m) | 200 | 200 | 200 | 200 | 4,000 |
| Receptor Dir. (deg) | 290 | 120 | 120 | 120 | 90 |
| Modeled Year | 1983 | 1984 | 1984 | 1984 | 1986 |

*Concentrations are highest, second-highest values.

**Concentrations are maximum values when averaged over 8,760 hours.

***All impacts are based on a nominal 1 g/s emission rate.

TABLE 5-2. MODELED POLLUTANT IMPACT DETERMINATION

| Pollutant | Averaging Period | Significant Impact Criteria ug/m3 | Monitoring Criteria ug/m3 | Maximum Impact* ug/m3 | Location Dist. m | Location Dir. deg | Year | Operating Mode** |
|---|---|---|---|---|---|---|---|---|
| $SO_2$ | Annual | 1 | -- | 0.2 | 100 | 260 | 1982 | SC |
| | 24-Hour | 5 | 13 | 4.7 | 200 | 120 | 1984 | CC |
| | 3-Hour | 25 | -- | 19.2 | 100 | 350 | 1985 | SC |
| $NO_x$ | Annual | 1 | 14 | 0.2 | 100 | 260 | 1982 | SC |
| CO | 8-Hour | 500 | 575 | 2.7 | 100 | 20 | 1985 | SC |
| | 1-Hour | 2,000 | -- | 9.4 | 100 | 100 | 1984 | SC |
| PM | Annual | 1 | -- | 0.01 | 100 | 260 | 1982 | SC |
| | 24-Hour | 5 | 10 | 0.3 | 200 | 120 | 1984 | CC |

*Annual pollutant impacts are based on maximum modeled concentrations assuming 8,760 hours per year operation. The 3-hour and 24-hour impacts are based on highest, second-highest modeled concentrations.

**CC - Combined Cycle Operation.
SC - Simple Cycle Operation.

The maximum annual average impact for $NO_x$ is 0.2 ug/m$^3$. This value is below the significant ambient air quality impact level of 1.0 ug/m$^3$. No further air quality impact analysis is necessary for $NO_x$.

The highest, second-highest 1- and 8-hour CO impacts are 9.4 and 2.7 ug/m3, respectively. These values are well below the significant ambient air quality levels of 2,000 and 500 ug/m3, respectively. Consequently, no further air quality impact analysis is required for CO.

The maximum annual and highest, second-highest 24-hour average impact for PM ($TSP/PM_{10}$) are 0.01 and 0.3 ug/m$^3$, respectively. These values are well below the significant ambient air quality impact levels of 1.0 and 5.0 ug/m$^3$, respectively. No further air quality impact analysis is necessary for particulates.

## 5.2 PRECONSTRUCTION MONITORING REQUIREMENTS

Based on the results of the ISCST modeling presented in Table 5-2, pollutant emissions from the project will not result in ambient impacts above PSD de minimis monitoring levels. Therefore, ambient monitoring will not be required.

## 5.3 SIGNIFICANT IMPACT AREA DETERMINATION

For each PSD applicable pollutant, the extent of the significant impact area must be defined. The radii of significant impacts are determined by extending the receptor array outward until the predicted maximum concentration at the farthest receptor is less than the appropriate ambient significance level.

Modeling results from Section 5.1 show that none of the applicable pollutants have impacts above ambient significance levels. Therefore, there is not a significant impact area for this project.

## 5.4 AAQS AND PSD INCREMENT COMPLIANCE DETERMINATION

Criteria pollutants with ambient air quality impacts above significance levels must demonstrate compliance with AAQS and PSD increment consumption. Based on the ISCST modeling results, no compliance determination is required for the project since all impacts are below significance levels.

# 6.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

## 6.1 INTRODUCTION

The Lakeland Combustion Turbine Project will consist of one combustion turbine operating in combined cycle. The primary fuel for the project will be natural gas. However, No. 2 fuel oil will be used as a backup combustion turbine fuel. Pollutant emissions are generally higher when burning No. 2 fuel oil. Section 3.0 concluded that when fuel oil is used for the maximum project operation or 8,760 hours per year (100 percent capacity factor), the following regulated pollutants are subject to the provisions of the PSD Program.

- Nitrogen Oxides ($NO_x$)
- Sulfur Dioxide ($SO_2$)
- Sulfuric acid mist ($H_2SO_4$)
- Particulate (Total and PM10)
- Beryllium (Be)
- Carbon Monoxide (CO)

Consequently, this BACT analysis will address the control of emissions of these PSD applicable pollutants when burning either natural gas, or No. 2 fuel oil. Also included are evaluations of the effects of the BACT systems selected on the emissions of unregulated hazardous pollutants.

Under the federal Clean Air Act, BACT represents the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emission limits established by the applicable New Source Performance Standards (NSPS) Subpart GG.

This BACT analysis follows the general requirements of EPA's draft "top down" BACT guidance document. This approach requires that the BACT analysis start by assuming the use of the LAER control alternative. Other, less efficient emission control technologies are subsequently evaluated if LAER is determined to be unreasonable considering the above factors.

Based on a review of EPA's BACT/LAER Clearinghouse - A Compilation of Control Technology Determinations including the 1990 edition, a combustion turbine with HRSG that utilizes water or steam injection and selective catalytic reduction (SCR) for $NO_x$ emission control represents LAER. A recent FDER BACT decision for the TECO, Hardee County Project allowed for

the use of water or steam injection for $NO_x$ control to 42 ppmvd (@ 15 percent $O_2$) and no supplemental control devices. The TECO Project is very similar to the proposed Lakeland Project with the exception of some operating limitations. The TECO project is restricted to a lifetime average capacity factor of 60 percent and limitations on the fuel burn rate. The permit also stipulated that only natural gas or No. 2 fuel oil can be burned in the combustion turbine. $SO_2$ emissions for the TECO project will be controlled by limiting the average annual sulfur content of the fuel oil to 0.3 percent by weight with the maximum not to exceed 0.5 percent.

The BACT analysis for the Lakeland Combustion Turbine Project is contained in the following sections.

## 6.2 NITROGEN OXIDES EMISSIONS CONTROL

During combustion, two types of $NO_x$ are formed; fuel $NO_x$ and thermal $NO_x$. Fuel $NO_x$ emissions are formed through the oxidation of a portion of the nitrogen contained in the fuel. Thermal $NO_x$ emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. Nitrogen oxides formation can be limited by lowering combustion temperatures, and staging combustion (a reducing atmosphere followed by an oxidizing atmosphere).

### 6.2.1 Alternative NOx Emission Reduction Systems

The EPA has established an NSPS limitation for $NO_x$ emissions from electric utility combustion turbines at 75 parts per million dry volume (ppmvd) at 15 percent oxygen ($O_2$), with a correction for fuel nitrogen content and turbine heat rate [40 CFR 60.332(b)]. A review of EPA's BACT/LAER Clearinghouse - A Compilation of Control Technology Determinations through the 1990 edition, indicated that the lowest $NO_x$ emission limit to be 4.5 ppmvd at 15 percent $O_2$. This limit is for a combustion turbine with an HRSG located in California. That permit value was based on the use of water injection in the combustion turbine and a SCR system contained within the HRSG (combined cycle operation).

Either water or steam could be used to limit $NO_x$ formation during combustion. Therefore, the LAER $NO_x$ emission control alternative for use with combustion turbines is established as water or steam injection followed by an SCR system.

Other $NO_x$ emission control systems have been identified for evaluation as BACT. Injection of water into a turbine with a low $NO_x$ combustion chamber(s) can limit $NO_x$ emissions to 25 ppmvd (at 15 percent $O_2$) when burning natural gas and 42 ppmvd when burning fuel oil.

In addition to the two alternatives, $NO_x$ emissions from other types of combustion sources have also been controlled through installation of selective non-catalytic reduction (SNCR) systems such as Thermal $DeNO_x$. A SNCR system requires gas temperatures of at least 1,500 F for $NO_x$ reduction. The temperature at the outlet of a combustion turbine is too low (950 F to 1,100 F) for such systems. Since raising the flue gas exit temperature to 1,500 F would require supplemental heating of the flue gas, thereby increasing total emissions due to increased fuel usage, this alternative is judged technically unacceptable for application on a combustion turbine.

6.2.1.1 Selective Catalytic Reduction. SCR is a post-combustion method for control of $NO_x$ emissions. The SCR process combines vaporized ammonia with $NO_x$ in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90 percent reduction of $NO_x$ with a new catalyst. An aged catalyst will provide a maximum of approximately 80 to 85 percent $NO_x$ reduction.

The optimum flue gas temperature range for SCR operation is approximately 650 to 750 F. Flue gas from the combustion turbines will typically be 950 F to 1100 F. Therefore, an SCR would be installed in an intermediate point of the HRSG where a temperature of approximately 700 F occurs.

Operation of the unit in the simple cycle mode would require that the SCR be bypassed in order to prevent permanent damage to the catalyst from the high exhaust gas temperatures due to the HRSG not being in operation.

6.2.1.2 Improved Low NOx Combustion Chamber. Combustion turbine manufacturers have begun to market an improved low $NO_x$ burner design.

These burners provide improved air/fuel mixing and reduced flame temperatures. The result is lower concentrations of $NO_x$ in comparison to standard combustion chamber design (25 versus 42 ppmvd when firing natural gas). However, these machines also have significantly higher CO emissions.

The capital and annual cost of a low $NO_x$ combustor which meets a 25/42 (natural gas/oil) ppmvd $NO_x$ emission limit is considered base for this project.

6.2.1.3 Water/Steam Injection. Use of water or steam injection in the combustion zones of a combustion turbine can limit the amount of $NO_x$ formed. Thermal $NO_x$ formation is avoided due to lower combustion temperatures resulting from the water or steam injection. The degree of reduction in $NO_x$ formation is somewhat proportional to the amount of water or steam injected into the turbine.

Since the combustion turbine NSPS was last revised in 1982, combustion turbines have improved their tolerance to the water steam necessary to control $NO_x$ emissions below the current NSPS level. However, there is still a point at which the amount of water or steam injected into the turbine seriously degrades the turbine's reliability and operational life. With the manufacturers' existing turbine designs and standard combustors, this generally occurs below a $NO_x$ emission level of about 42 ppmvd (at 15 percent $O_2$) when firing natural gas and 65 ppmvd when firing fuel oil.

These $NO_x$ emission levels can be achieved with little additional cost and without significant impact on reliability or power output over those costs required to comply with the NSPS.

### 6.2.2 Capital and Operating Costs of Alternatives

Tables 6-1 and 6-2 present the capital and levelized annual costs of the two feasible $NO_x$ control systems for the combustion turbine facility: a low $NO_x$ combustor with and without an SCR. The incremental annual $NO_x$ emissions are based on firing natural gas for a maximum of 8,760 hours per year (100 percent capacity factor) in the turbines.

The differential capital costs for the SCR system include the costs of the ammonia storage/injection system, the catalytic reactors, HRSG modifications and balance of plant equipment.

TABLE 6-1. COMPARATIVE CAPITAL COSTS OF ALTERNATIVE NOx CONTROL TECHNOLOGY*

| | Low $NO_x$ Combustor Design Plus SCR | Low $NO_x$ Combustor Design |
|---|---|---|
| Differential combustion turbine costs | Base | Base |
| SCR reactors | $1,990,000 | NA |
| Ammonia storage and injection equipment | $200,000 | NA |
| HRSG Modification | NA | Base |
| Water Treatment, Storage and injection equipment | NA | Base |
| Balance of plant | $60,000 | Base |
| Direct capital cost (1990) | $2,250,000 | Base |
| Contingency | $230,000 | Base |
| Escalation | $280,000 | Base |
| Direct capital cost | $2,760,000 | Base |
| Indirects | $410,000 | Base |
| Interest during construction | $160,000 | Base |
| Total Capital Costs (1992) | $3,330,000 | Base |

*Based on one turbine.

TABLE 6-2. COMPARATIVE LEVELIZED ANNUAL COSTS OF ALTERNATIVE NOx CONTROL TECHNOLOGY*

| | Low $NO_x$ Combustor Design Plus SCR | Low $NO_x$ Combustor Design |
|---|---|---|
| Operation and maintenance costs | $1,090,000 | Base |
| Ammonia | $90,000 | NA |
| Energy | $210,000 | Base |
| Generating Cost Adjustment | $270,000 | Base |
| Fixed charges | $530,000 | Base |
| Total Annual Costs | $2,190,000 | Base |
| Annual $NO_x$ Emissions (tpy) | 150 | 425 |
| Incremental Annual $NO_x$ Emissions Reduction (tpy) | 275 | Base |
| Incremental Levelized Cost per Ton of $NO_x$ Removed | $7,960 | Base |

*Based on one turbine and 8,760 hours/year of natural gas fired operation at ISO conditions (59 F and 60 percent relative humidity).

In addition to the 1990 equipment costs of the two alternatives, the total capital costs include a contingency charge, escalation, indirect costs, and interest during construction.

The levelized annual costs assume a total station fuel consumption of about 8.5 x $10^6$ MMBtu/yr (8,760 h/yr per turbine at base load). This same annual fuel consumption was used in Section 3.0 of this application as the basis for determining pollutant applicability to the PSD Program. Levelized annual costs include operating and maintenance costs (including catalyst replacement), ammonia additive, energy, lost generating capacity and fixed charges on capital investment. The differential energy cost and lost generating capacity for the SCR alternative is the result of the reduced net output of the turbine due to the additional back pressure added by the SCR and the energy requirements of the associated equipment.

The incremental levelized annual cost for adding an SCR to a low $NO_x$ combustor is about $2.2 million/year. This cost results in an incremental removal cost of approximately $7,960 per ton of $NO_x$ reduction (275 tons per year while burning natural gas).

### 6.2.3 Other Considerations

The following lists other considerations that effect the operation of the facility.

- Compared to the low $NO_x$ combustor with water or steam injection, the energy requirements of the SCR system would reduce the output of the combustion turbines by approximately one percent.

- The use of an SCR system could result in a negative environmental impact due to the release of quantities of unreacted ammonia to the atmosphere. Ammonia and a number of amine compounds are recognized hazardous air pollutants. Although ammonia emissions are not regulated nationally, at least one air pollution control district in California recently set a limit of 10 ppm. Unreacted ammonia emissions from an SCR system could average 7 to 10 ppm. This emission level could create an objectionable odor and health hazards.

3 Ammonia is also a hazardous material. Accordingly, this material must be handled and stored with extreme care. Working on and around ammonia equipment will cause operational personnel to be less productive and functional than under normal working conditions.

4
- Over time with exposure to trace elements in the flue gas, catalysts become contaminated and could be classified as a hazardous waste. Therefore, the spent catalyst must be handled and disposed of following hazardous waste procedures. Some catalytic elements are toxic and must be replaced periodically. This replacement must follow hazardous waste disposal procedures.

- The ambient air modeling did not show any significant impacts for $NO_x$ emissions of 25/42 ppmvd (at 15 percent $O_2$) when burning natural gas or fuel oil, respectively.

### 6.2.4 Conclusions

Installation of an SCR system designed to meet a $NO_x$ emission limit of 9 ppm (approximately 64 percent reduction) would add over $3.3 million to the capital cost of the project. The addition of an SCR system increases the total levelized annual costs for the project by about $2.2 million. This increase results in an incremental removal cost of approximately $7,960 per ton of $NO_x$ removed while burning natural gas (100 percent capacity factor).

64% x 722 = T/Y
462 T/Y FOR OIL
$ 4740 TON FOR OIL

Natural gas will be the primary fuel for the project and fuel oil will be used only in the event of an interruption of natural gas supply. The use of an SCR system could result in adverse environmental effects due to unreacted ammonia being released to the atmosphere causing a potential human health hazard.

Therefore, based on economic, energy, and environmental considerations $NO_x$ BACT proposed for this combustion turbine facility is the use of a low $NO_x$ combustor with water or steam injection. The low $NO_x$ combustor will achieve $NO_x$ emissions of 25/42 ppmvd (at 15 percent $O_2$) while burning natural gas or No. 2 fuel oil, respectively. The economics are based on

operating the unit for 8,760 hours per year (100 percent capacity factor). This proposed level of BACT represents a level of $NO_x$ control that is lower than recent determinations in the state of Florida.

## 6.3 SULFUR DIOXIDE AND SULFURIC ACID MIST EMISSIONS

The NSPS established by EPA for emissions from combustion turbines sets a maximum $SO_2$ level in the flue gas of 150 ppmvd (at 15 percent $O_2$) and a maximum fuel sulfur content of 0.8 percent by weight (40 CFR 60.333). The EPA has not established a combustion turbine NSPS for sulfuric acid mist ($H_2SO_4$). The turbine manufacturers' emission data indicate that on average, approximately 3 percent of the $SO_2$ in the flue gas is oxidized to $SO_3$ which combines with water to form $H_2SO_4$.

Typically, natural gas has only a trace of sulfur (2,000 grains per million standard cubic feet or less). Recent permits for No. 2 fuel oil fired combustion turbines have included limits on maximum allowable fuel sulfur contents. Current BACT/LAER Clearinghouse documents do not list any natural gas, or No. 2 fuel oil fired combustion turbines that are required to use flue gas desulfurization (FGD) systems to meet $SO_2$ emission requirements. Addition of an FGD system would be a superfluous method of $SO_2$ emission control. The significant capital and operating cost associated with FGD systems would result in termination of the project.

The primary fuel for the Lakeland Combustion Turbine Project will be natural gas. Fuel oil will only be fired when the supply of natural gas is limited to this project.

The use of low sulfur fuel oil (maximum of 0.20 percent sulfur) would impose no differential capital costs on the project. Additionally modeling showed that no significant impacts for $SO_2$ emissions resulted when burning 0.20 percent sulfur fuel oil.

Based on economic, energy, and environmental considerations limitation of the fuel sulfur content to 0.20 percent by weight is proposed as BACT for the $SO_2$ emissions during oil firing from the Lakeland Combustion Turbine Project. Natural gas typically contains only trace amounts of sulfur and no further controls will be necessary.

## 6.4 PARTICULATE MATTER EMISSIONS

The natural gas and No. 2 fuel oil fuels to be used in the proposed combustion turbines will only contain trace quantities of noncombustible material. Therefore, emission of particulate matter from the combustion turbine facility will be controlled by ensuring as complete combustion of the fuel as possible. The NSPS for combustion turbines do not establish an emission limit for particulate matter. A review of the EPA's BACT/LAER Clearinghouse documents did not reveal any post-combustion particulate matter control technologies being used on gas/oil fueled combustion turbines. The manufacturers' standard combustion turbine operating procedures will ensure as complete combustion of the fuel as possible. Accordingly, combustion control is proposed as BACT for total particulate matter and PM-10.

## 6.5 BERYLLIUM EMISSIONS

The emissions of beryllium (Be) from the combustion turbine facility will be determined by the Be content of the fuels. Natural gas has no measurable Be content and the Be emissions when firing natural gas are predicted to be insignificant on an annual basis. No. 2 fuel oil typically contains a trace amount of Be, on the order of $2.5 \times 10^{-6}$ pounds per million Btu (lb/MMBtu). The annual Be emissions when firing fuel oil for 8,760 hours/year (100 percent capacity factor) are predicted to be 0.01 tons per year. While this is above EPA's significant emission rate of $4.0 \times 10^{-4}$ tons per year, a review of the EPA's BACT/LAER Clearinghouse documents did not reveal any combustion turbine project which has been required to install supplemental pollution control equipment to reduce Be emissions. Accordingly, complete combustion of the No. 2 fuel oil is proposed as BACT for Be emissions.

## 6.6 CARBON MONOXIDE (CO)

Based on a review of EPA's <u>BACT/LAER Clearinghouse - A Compilation of Control Technology Determinations</u> (1990 edition), a combustion turbine with proper combustion control and an oxidizing catalyst that limits carbon monoxide (CO) emissions to 2 ppmvd represents LAER.

Due to the combustion characteristics of a combustion turbine, it is necessary to consider the BACT determination for the emissions of $NO_x$ in establishing the emissions of CO. Typically, measures taken to minimize the formation of $NO_x$ during combustion inhibit complete combustion which increases the emissions of CO.

CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Co is limited by ensuring complete, efficient combustion of the fuel in the turbines. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion minimize CO. Therefore, staging combustion and lowering combustion temperatures by water injection, which are used for $NO_x$ emission control, can be counterproductive with regard to CO emissions.

Combustion turbines designed to meet the proposed BACT $NO_x$ emissions of 25/42 ppmvd (gas/oil) will be capable of maintaining CO emission rates of 25 ppmvd (15 percent $O_2$). At this emission rate, the annual emission will exceed the PSD significance level for carbon monoxide. The use of an CO catalyst would not result in appreciably lower CO emissions.

### 6.6.1 Catalytic Reduction.

Catalytic reduction is a post-combustion method for removal of CO emissions. The process oxidizes CO to $CO_2$ with the use of a catalyst. Carbon monoxide control catalyst utilizes a precious metal based catalyst to promote to oxidation process. None of the catalyst components are considered toxic.

The optimum flue gas temperature range for CO catalyst operation is between 850 F and 1100 F. Flue gas from the combustion turbine will typically be between 950 F to 1100 F. Therefore, a CO catalyst can be installed between the discharge of the combustion turbine and the inlet to the HRSG.

### 6.6.2 Capital and Operating Costs.

Table 6-3 presents the capital and levelized annual costs of a CO emissions control system. The CO emissions are based on firing natural gas for a maximum of 8,760 hr/yr (100 percent capacity factor) in the turbine. The capital costs of the SCR system includes the cost of the catalytic

TABLE 6-3 COMPARATIVE CAPITAL COSTS OF ALTERNATIVE CO CONTROL TECHNOLOGY*

| | Carbon Monoxide Catalyst |
|---|---|
| SCR reactors | $890,000 |
| Balance of plant | $100,000 |
| Direct capital cost (1990) | $990,000 |
| Contingency | $100,000 |
| Escalation | $120,000 |
| Direct capital cost | $1,210,000 |
| Indirects | $180,000 |
| Interest during construction | $70,000 |
| Total Capital Costs (1992) | $1,460,000 |
| Operation and maintenance costs | $560,000 |
| Generating Cost Adjustment | $250,000 |
| Fixed charges | $230,000 |
| Total Annual Costs | $1,040,000 |
| Annual CO Emissions (tpy) | 240 |
| Incremental Annual CO Emissions Reduction (tpy) | 140 |
| Incremental Levelized Cost per Ton of CO Removed | $7,430 |

*Based on one turbine and 8,760 hours/year of natural gas fired operation at ISO conditions (59 F and 60 percent relative humidity).

reactor and balance-of-plant equipment. In addition to the 1990 equipment costs, the total capital costs include a a contingency charge, escalation, indirect costs, and interest during construction. Levelized annual costs include operating and maintenance costs (including catalyst replacement), lost generating capacity, and fixed charges on capital investment.

An incremental levelized cost for the SCR of $1.0 million/year results in an incremental removal cost of approximately $7,340 per ton of CO removed (140 tons per year while burning natural gas).

### 6.6.3 Other Considerations.

The following are other considerations that are associated with a CO catalyst.

- A CO catalyst reactor located downstream of the combustion turbine exhaust will produce an additional backpressure on the combustion turbine. The added backpressure will reduce the output capability of the turbine. Additional backpressure of 3 to 4 inches of water gage would reduce turbine output by approximately 0.5 percent. Lost generating capacity translates directly into lost revenue to the project.

- A CO catalyst is an oxidizing catalyst, consequently it will also oxidize $SO_2$ to $SO_3$ which upon condensation will form sulfuric acid mist. The formation of sulfuric acid will result in increased corrosion in the cold end of the heat recovery steam generator.

- There is no long term operating experience with a CO catalyst on the size of combustion turbine proposed for this project.

### 6.6.4 Conclusions.

Installation of a CO catalyst control system designed to meet a CO emission limit of 10 ppmvd would add approximately $1.5 million to the capital cost of the project. The total levelized annual costs for the

project increases by $1.0 million resulting in an incremental removal cost of approximately $7,430 per ton of CO removed while burning natural gas (100 percent capacity factor).

Therefore, based on economic, energy, and environmental considerations CO BACT proposed for this combustion turbine facility is the use of good combustion controls to achieve CO emissions of 25 ppmvd when burning natural gas or fuel oil and operating the unit for 8,760 hours per year (100 percent capacity factor).

## 6.7 OTHER EMISSIONS

The following sections discuss pollutants which are either below the significant emission levels established for the PSD program or have been identified by EPA as hazardous pollutants. Federal and state regulations do not require that BACT be applied for these pollutants, but the effects of the proposed BACT determinations on these pollutants must be considered.

### 6.7.1 Other Regulated and Hazardous Pollutants

Table 6-4 presents uncontrolled emission estimates for other regulated pollutants (fluorides, mercury, and lead) and hazardous pollutants when firing No. 2 fuel oil. These emission rates have been developed based on manufacturers' information and on information contained in the EPA publication Toxic Air Pollutant Emission Factors - A Compilation For Selected Air Toxic Compounds and Sources (EPA-450/2-88-006a).

The only identified methods of controlling the emission of these pollutants are complete combustion of the fuel and the inherent quality of the fuel. Injection of water into the turbines to control $NO_x$ emissions is not expected to have a significant effect on the emissions of these pollutants. Complete combustion will be required to achieve the identified emission rates of formaldehyde. The quality of the fuel will comply with standard commercial No. 2 fuel oil.

When fuel oil is used, no adverse environmental impacts would occur at the tabulated, uncontrolled emission rates.

TABLE 6-4. OTHER REGULATED AND HAZARDOUS POLLUTANT EMISSIONS

| Pollutant | Emission Rate lb/MMBtu | Annual Emission* tpy |
|---|---|---|
| Arsenic | 4.2 E-6 | 0.02 |
| Beryllium | 2.5 E-6 | 0.01 |
| Cadmium | 1.1 E-5 | 0.05 |
| Chromium | 4.8 E-5 | 0.20 |
| Copper | 2.8 E-4 | 1.16 |
| Formaldehyde** | 4.1 E-4 | 1.70 |
| Lead | 2.8 E-5 | 0.12 |
| Manganese | 2.6 E-5 | 0.11 |
| Mercury | 3.0 E-6 | 0.012 |
| Nickel | 1.7 E-4 | 0.70 |

*Annual emissions are total for one combustion turbine and are based on annual operation of 8,760 hours firing No. 2 fuel oil at ISO conditions (59 F and 60 percent relative humidity) and a fuel burn rate of 945.5 MMBtu/h.

**Formaldehyde is also found in natural gas combustion. The emission rates are 8.8 E-5 lb/MMBtu or 0.37 tpy.

# APPENDIX A

# DIRECTION-SPECIFIC BUILDING ANALYSIS

RBRZWAKE
IBM-PC VERSION (2.0 )
(C) COPYRIGHT 1989, TRINITY CONSULTANTS, INC.
SERIAL NUMBER 6440 SOLD TO BLACK & VEATCH CONSULTING ENG
RUN NAME: TEMP
RUN BEGAN ON 09-28-90 AT 08:07:58

NUMBER OF SOURCES = 2

THE FOLLOWING OPTIONS HAVE BEEN CHOSEN:

CALCULATIONS ARE MADE FOR THE ISCST MODEL.

ALL STACKS MUST BE WITHIN 5L TO BE CONSIDERED FOR DIRECTION SPECIFIC DOWNWASH.

DOWNWASH IS CALCULATED IN 36 RADIAL DIRECTIONS.

BUILDINGS ARE COMBINED REPEATEDLY.

ALGORITHMS:

---

0 = NO DOWNWASH
1 = HUBER-SNYDER DOWNWASH
2 = SCHULMAN-SCIRE DOWNWASH

---

INPUT BUILDINGS

| DESCRIPTION | BLDG # | BLDG HT(M) | # OF CORNERS | X(M) | Y(M) |
|---|---|---|---|---|---|
| NW CORNER GEN BLDG. | 1 | 37.03 | 4 | | |
| | | | | 50.60 | 57.00 |
| | | | | 68.58 | 57.00 |
| | | | | 68.58 | 70.41 |
| | | | | 50.60 | 70.41 |
| GEN BLDG. | 2 | 20.27 | 6 | | |
| | | | | 52.43 | -27.13 |
| | | | | 91.44 | -27.13 |
| | | | | 91.44 | 77.11 |
| | | | | 69.80 | 77.11 |
| | | | | 69.80 | 52.43 |
| | | | | 52.43 | 52.43 |
| STORAGE TANK 1 | 3 | 15.24 | 10 | | |
| | | | | -28.87 | 42.99 |
| | | | | -25.99 | 39.03 |
| | | | | -25.99 | 34.13 |
| | | | | -28.87 | 30.17 |
| | | | | -33.53 | 28.66 |
| | | | | -38.19 | 30.17 |
| | | | | -41.07 | 34.13 |
| | | | | -41.07 | 39.03 |
| | | | | -38.19 | 42.99 |
| | | | | -33.53 | 44.51 |
| STORAGE TANK 2 | 4 | 15.24 | 10 | | |
| | | | | 9.23 | 42.99 |
| | | | | 12.11 | 39.03 |
| | | | | 12.11 | 34.13 |
| | | | | 9.23 | 30.17 |
| | | | | 4.57 | 28.66 |
| | | | | -.09 | 30.17 |
| | | | | -2.97 | 34.13 |
| | | | | -2.97 | 39.03 |
| | | | | -.09 | 42.99 |
| | | | | 4.57 | 44.51 |
| AIR INLET | 5 | 13.72 | 4 | | |
| | | | | -12.80 | 5.79 |
| | | | | -4.27 | 5.79 |
| | | | | -4.27 | 18.29 |
| | | | | -12.80 | 18.29 |

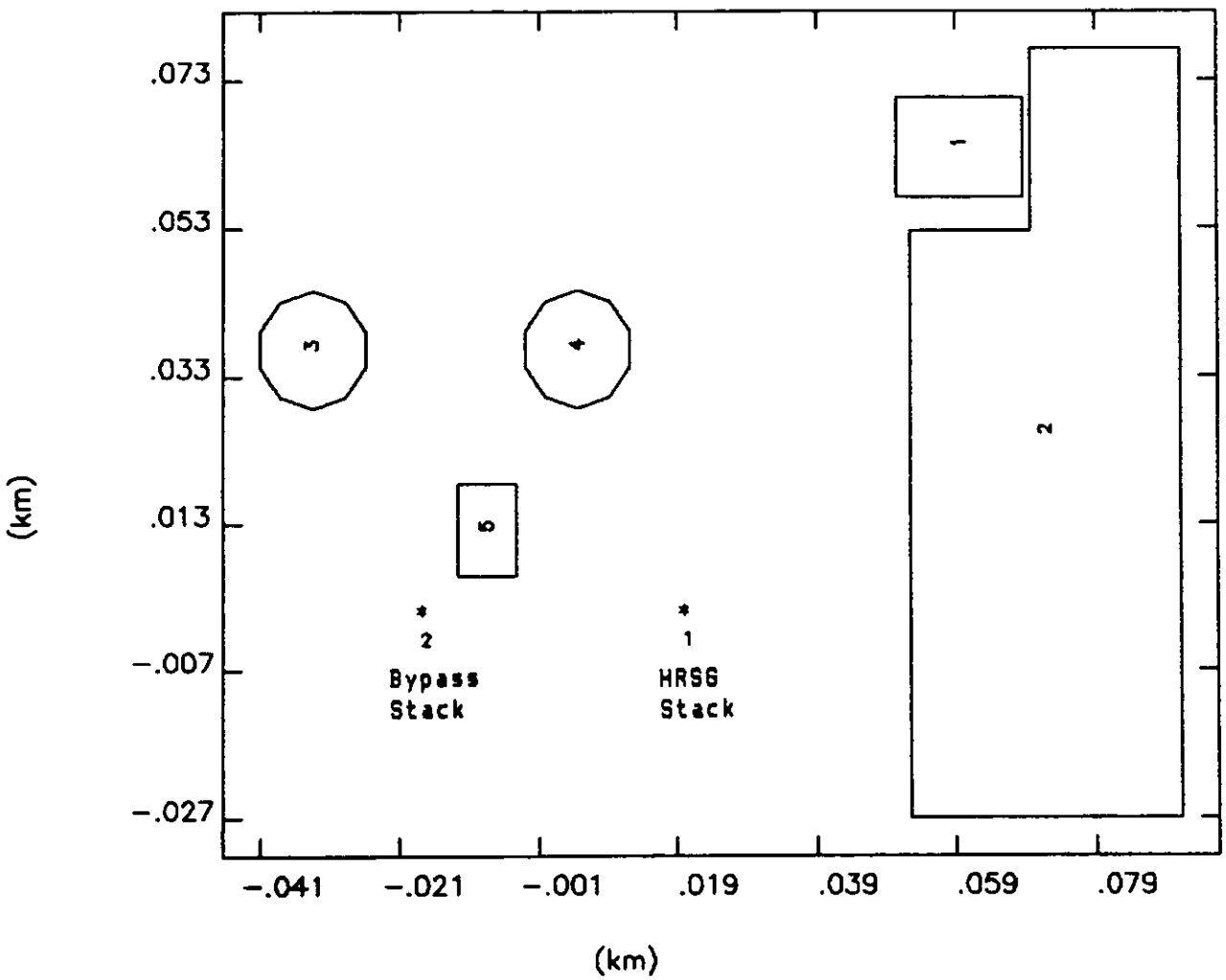
COMBINED BUILDINGS

```
STRUCTURE  1 HAS A HEIGHT 37.03 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 1:  NW CORNER GEN BLDG.
STRUCTURE  2 HAS A HEIGHT 20.27 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 1:  NW CORNER GEN BLDG.
             BUILDING # 2:  GEN BLDG.
STRUCTURE  3 HAS A HEIGHT 15.24 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 3:  STORAGE TANK 1
STRUCTURE  4 HAS A HEIGHT 15.24 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 4:  STORAGE TANK 2
STRUCTURE  5 HAS A HEIGHT 13.72 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 4:  STORAGE TANK 2
             BUILDING # 5:  AIR INLET
```

INPUT STACKS

| STACK ID # | STACK # | STACK HT(M) | X(M) | Y(M) |
|---|---|---|---|---|
| 1 | 1 | 47.24 | 18.90 | .00 |
| 2 | 2 | 30.48 | -18.90 | .00 |

# CITY OF LAKELAND SITE



STACK ID # 1, STACK # 1

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 37.03 W= 22.43 GEP= 70.68

DIRECTION SPECIFIC BUILDING DOWNWASH

| DEGREE | STRUCTURE # | HEIGHT | WIDTH | GEP | ALGORITHM |
|---|---|---|---|---|---|
| 10 | 0 | .00 | .00 | .00 | 0 |
| 20 | 2 | 20.27 | 71.74 | 50.68 | 1 |
| 30 | 2 | 20.27 | 84.14 | 50.68 | 1 |
| 40 | 2 | 20.27 | 93.98 | 50.68 | 1 |
| 50 | 2 | 20.27 | 100.97 | 50.68 | 1 |
| 60 | 2 | 20.27 | 104.89 | 50.68 | 1 |
| 70 | 2 | 20.27 | 105.63 | 50.68 | 1 |
| 80 | 2 | 20.27 | 106.41 | 50.68 | 1 |
| 90 | 2 | 20.27 | 104.24 | 50.68 | 1 |
| 100 | 2 | 20.27 | 109.43 | 50.68 | 1 |
| 110 | 2 | 20.27 | 111.30 | 50.68 | 1 |
| 120 | 2 | 20.27 | 109.78 | 50.68 | 1 |
| 130 | 2 | 20.27 | 104.93 | 50.68 | 1 |
| 140 | 2 | 20.27 | 96.89 | 50.68 | 1 |
| 150 | 0 | .00 | .00 | .00 | 0 |
| 160 | 0 | .00 | .00 | .00 | 0 |
| 170 | 0 | .00 | .00 | .00 | 0 |
| 180 | 0 | .00 | .00 | .00 | 0 |
| 190 | 0 | .00 | .00 | .00 | 0 |
| 200 | 1 | 37.03 | 21.48 | 69.25 | 2 |
| 210 | 1 | 37.03 | 22.28 | 70.44 | 2 |
| 220 | 1 | 37.03 | 22.39 | 70.62 | 2 |
| 230 | 2 | 20.27 | 100.97 | 50.68 | 1 |
| 240 | 2 | 20.27 | 104.89 | 50.68 | 1 |
| 250 | 2 | 20.27 | 105.63 | 50.68 | 1 |
| 260 | 2 | 20.27 | 106.41 | 50.68 | 1 |
| 270 | 2 | 20.27 | 104.24 | 50.68 | 1 |
| 280 | 2 | 20.27 | 109.43 | 50.68 | 1 |
| 290 | 2 | 20.27 | 111.30 | 50.68 | 1 |
| 300 | 2 | 20.27 | 109.78 | 50.68 | 1 |
| 310 | 2 | 20.27 | 104.93 | 50.68 | 1 |
| 320 | 2 | 20.27 | 96.89 | 50.68 | 1 |
| 330 | 0 | .00 | .00 | .00 | 0 |
| 340 | 0 | .00 | .00 | .00 | 0 |
| 350 | 0 | .00 | .00 | .00 | 0 |
| 360 | 0 | .00 | .00 | .00 | 0 |

STACK ID # 2, STACK # 2

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 37.03 W= 22.43 GEP= 70.68

DIRECTION SPECIFIC BUILDING DOWNWASH

| DEGREE | STRUCTURE # | HEIGHT | WIDTH | GEP | ALGORITHM |
|---|---|---|---|---|---|
| 10 | 5 | 13.72 | 21.78 | 34.30 | 1 |
| 20 | 5 | 13.72 | 17.99 | 34.30 | 1 |
| 30 | 5 | 13.72 | 15.50 | 34.30 | 1 |
| 40 | 2 | 20.27 | 93.98 | 50.68 | 1 |
| 50 | 2 | 20.27 | 100.97 | 50.68 | 1 |
| 60 | 5 | 13.72 | 30.13 | 34.30 | 1 |
| 70 | 5 | 13.72 | 33.53 | 34.30 | 1 |
| 80 | 5 | 13.72 | 36.59 | 34.30 | 1 |
| 90 | 5 | 13.72 | 38.71 | 34.30 | 1 |
| 100 | 5 | 13.72 | 41.14 | 34.30 | 1 |
| 110 | 0 | .00 | .00 | .00 | 0 |
| 120 | 0 | .00 | .00 | .00 | 0 |
| 130 | 0 | .00 | .00 | .00 | 0 |
| 140 | 3 | 15.24 | 15.38 | 38.10 | 1 |
| 150 | 3 | 15.24 | 15.50 | 38.10 | 1 |
| 160 | 3 | 15.24 | 15.84 | 38.10 | 1 |
| 170 | 3 | 15.24 | 15.70 | 38.10 | 1 |
| 180 | 3 | 15.24 | 15.07 | 37.85 | 1 |
| 190 | 5 | 13.72 | 21.78 | 34.30 | 1 |
| 200 | 4 | 15.24 | 15.84 | 38.10 | 1 |
| 210 | 4 | 15.24 | 15.50 | 38.10 | 1 |
| 220 | 1 | 37.03 | 22.39 | 70.62 | 2 |
| 230 | 1 | 37.03 | 21.83 | 69.77 | 2 |
| 240 | 1 | 37.03 | 20.60 | 67.94 | 2 |
| 250 | 2 | 20.27 | 105.63 | 50.68 | 1 |
| 260 | 2 | 20.27 | 106.41 | 50.68 | 1 |
| 270 | 2 | 20.27 | 104.24 | 50.68 | 1 |
| 280 | 2 | 20.27 | 109.43 | 50.68 | 1 |
| 290 | 2 | 20.27 | 111.30 | 50.68 | 1 |
| 300 | 0 | .00 | .00 | .00 | 0 |
| 310 | 0 | .00 | .00 | .00 | 0 |
| 320 | 3 | 15.24 | 15.38 | 38.10 | 1 |
| 330 | 0 | .00 | .00 | .00 | 0 |
| 340 | 0 | .00 | .00 | .00 | 0 |
| 350 | 0 | .00 | .00 | .00 | 0 |
| 360 | 3 | 15.24 | 15.07 | 37.85 | 1 |

```
                    STACK #   1
STACK ID:  1,    BUILDING HEIGHT:  37.03,    BUILDING WIDTH:  22.43
   .00 20.27 20.27 20.27 20.27 20.27 20.27 20.27 20.27 20.27 20.27 20.27
 20.27 20.27   .00   .00   .00   .00   .00 37.03 37.03 37.03 20.27 20.27
 20.27 20.27 20.27 20.27 20.27 20.27 20.27 20.27   .00   .00   .00   .00
   .00 71.74 84.14 93.98100.97104.89105.63106.41104.24109.43111.30109.78
104.93 96.89   .00   .00   .00   .00   .00 21.48 22.28 22.39100.97104.89
105.63106.41104.24109.43111.30109.78104.93 96.89   .00   .00   .00   .00
                    STACK #   2
STACK ID:  2,    BUILDING HEIGHT:  37.03,    BUILDING WIDTH:  22.43
 13.72 13.72 13.72 20.27 20.27 13.72 13.72 13.72 13.72 13.72   .00   .00
   .00 15.24 15.24 15.24 15.24 15.24 13.72 15.24 15.24 37.03 37.03 37.03
 20.27 20.27 20.27 20.27 20.27   .00   .00 15.24   .00   .00   .00 15.24
 21.78 17.99 15.50 93.98100.97 30.13 33.53 36.59 38.71 41.14   .00   .00
   .00 15.38 15.50 15.84 15.70 15.07 21.78 15.84 15.50 22.39 21.83 20.60
105.63106.41104.24109.43111.30   .00   .00 15.38   .00   .00   .00 15.07
```

# APPENDIX B

# EMISSION CALCULATIONS AND SUPPORT

# 7.0 ADDITIONAL AMBIENT AIR QUALITY IMPACT ANALYSIS

## 7.1 VISIBILITY

The nearest PSD Class I area is the Chassahowitzka National Wildlife Refuge, located approximately 90 kilometers northwest of the site. A screening level visibility analysis was performed per EPA's Workbook for Plume Visual Impact Screening Level Analysis (1988). The analysis showed that the proposed facility will have no significant effect on visibility at the Class I area. Appendix D contains the output from EPA's "VISCREEN" model.

## 7.2 SOILS AND VEGETATION

Ambient air quality standards have been established to protect public health and welfare from any adverse effects of air pollutants. It is not expected that the estimated effects of the proposed project will significantly add to the background pollutant concentrations. Therefore, no adverse effects on soils and terrestrial vegetation is expected.

## 7.3 GROWTH

The addition of the combustion turbine unit at the City of Lakeland Charles Larsen Power Plant is not expected to induce any secondary growth in the surrounding area.

CALCULATIONS IN SUPPORT OF CITY OF LAKELAND COMBUSTION TURBINE PROJECT
AMBIENT AIR QUALITY IMPACT ANALYSIS

The following parameters are based on performance estimates of a GE PG7111(EA) combustion turbine (FRAME 7) with water injection to reduce $NO_x$ emissions to 25/42 ppmvd (natural gas/distillate), referenced to 15 percent oxygen.

| Fuel Fired | Natural Gas | Distillate |
|---|---|---|
| Heat Rate (LHV) @ 25 F, MMBtu/h | 1,054.6 | 1,038.1 |
| @ ISO, MMBtu/h | 964.7 | 945.5 |
| Fuel Flow Rate @ 25 F | 18,949 scfm | 136.4 gal/min |
| @ ISO | 17,333 scfm | 124.2 gal/min |
| Emission Rates | | |
| $NO_x$, ppmvd @ 15% $O_2$ | 25 | 42 |
| lb/h @ 25 F | 106 | 183 |
| lb/h @ ISO | 97 | 167 |
| CO, ppmvd | 25 | 25 |
| lb/h @ 25 F | 58 | 58 |
| lb/h @ ISO | 53 | 54 |
| VOC, ppmvw | 1.4 | 3.5 |
| lb/h @ 25 F | 2 | 5 |
| lb/h @ ISO | 2 | 4.5 |
| Particulate, lb/h @ 25 F | 5 | 15 |
| lb/h @ ISO | 5 | 15 |

**CALCULATIONS:**

Fuel Heat Content - Natural Gas

$(1{,}054.6 \times 10^6 \text{ Btu/h}) \times (1 \text{ min}/18{,}949 \text{ ft}^3) \times (1 \text{ h}/60 \text{ min})$
$= 928 \text{ Btu/ft}^3$

Fuel Heat Content - Distillate

$(1{,}038.1 \times 10^6 \text{ Btu/h}) \times (1 \text{ min}/136.4 \text{ gal}) \times (1 \text{ h}/60 \text{ min})$
$= 127{,}000 \text{ Btu/gal}$

SO2 Emission Rate - Natural Gas

Assume natural gas contains 2,000 gr S/MCF (AP-42 factor) and that there are 7,000 grains in one pound of sulfur (AP-42 factor).

@ 25F: $(18{,}949 \text{ ft}^3/\text{min}) \times (60 \text{ min/h}) \times (2{,}000 \text{ gr S}/10^6 \text{ ft}^3) \times (1 \text{ lb S}/7{,}000 \text{ gr S}) \times (2 \text{ lb } SO_2/1 \text{ lb S})$
$= 0.65 \text{ lb/h}$

@ISO: $(17{,}333 \text{ ft}^3/\text{min}) \times (60 \text{ min/h}) \times (2{,}000 \text{ gr S}/10^6 \text{ ft}^3) \times (1 \text{ lb S}/7{,}000 \text{ gr S}) \times (2 \text{ lb } SO_2/1 \text{ lb S})$
$= 0.59 \text{ lb/h}$

SO2 Emission Rate - Distillate

Assume distillate contains 0.2 percent sulfur and that there are 7.05 pounds in one gallon of distillate (AP-42 factor).

@ 25F: $(136.4 \text{ gal oil/min}) \times (60 \text{ min/h}) \times (0.2 \text{ lb S}/100 \text{ lb oil}) \times (7.05 \text{ lb oil/gal}) \times (2 \text{ lb } SO_2/1 \text{ lb S})$
$= 231 \text{ lb/h}$

@ISO: $(124.2 \text{ gal oil/min}) \times (60 \text{ min/h}) \times (0.2 \text{ lb S}/100 \text{ lb oil}) \times (7.05 \text{ lb oil/gal}) \times (2 \text{ lb } SO_2/1 \text{ lb S})$
$= 210 \text{ lb/h}$

SO2 Potential Annual Emissions

Assume turbine operates for 8,760 hours per year. ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions.

Natural Gas: $(0.6 \text{ lb/h}) \times (8{,}760 \text{ hr/y}) \times (\text{ton}/2{,}000 \text{ lb})$
$= 2.6 \text{ tpy}$

Distillate: $(210 \text{ lb/h}) \times (8{,}760 \text{ hr/y}) \times (\text{ton}/2{,}000 \text{ lb})$
$= 920 \text{ tpy}$

## NOx Potential Annual Emissions

Assume turbine operates for 8,760 hours per year (100 percent capacity factor). ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions.

Natural Gas: (97 lb/h) x (8,760 hr/y) x (ton/2,000 lb)
= 425 tpy

Distillate: (167 lb/h) x (8,760 hr/y) x (ton/2,000 lb)
= 732 tpy

## CO Potential Annual Emissions

Assume turbine operates for 8,760 hours per year (100 percent capacity factor). ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions.

Natural Gas: (53 lb/h) x (8,760 hr/y) x (ton/2,000 lb)
= 232 tpy

Distillate: (54 lb/h) x (8,760 hr/y) x (ton/2,000 lb)
= 237 tpy

## VOC Potential Annual Emissions

Assume turbine operates for 8,760 hours per year (100 percent capacity factor). ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions.

Natural Gas: (2.0 lb/h) x (8,760 hr/y) x (ton/2,000 lb)
= 8.8 tpy

Distillate: (4.5 lb/h) x (8,760 hr/y) x (ton/2,000 lb)
= 20 tpy

## Particulate Potential Annual Emissions

Assume turbine operates for 8,760 hours per year (100 percent capacity factor). ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions. It is assumed all particulate matter is less than 10 microns in diameter ($PM_{10}$).

Natural Gas: (5 lb/h) x (8,760 hr/y) x (ton/2,000 lb)
= 22 tpy

Distillate: (15 lb/h) x (8,760 hr/y) x (ton/2,000 lb)
= 66 tpy

Lead Potential Annual Emissions

Assume turbine operates for 8,760 hours per year (100 percent capacity factor). ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions. Lead emission taken from EPA's Toxic Air Pollutant Emissions Factors - A Compilation For Selected Air Toxic Compounds and Sources (EPA-450/2-88-006a).

Natural Gas: (No measurable emissions)

Distillate: $(2.8 \times 10^{-5}$ lb/MMBtu) x (945.5 MMBtu/h) x (8,760 hr/y) x (ton/2,000 lb)
= 0.12 tpy

Beryllium Potential Annual Emissions

Assume turbine operates for 8,760 hours per year (100 percent capacity factor). ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions. Emission factor taken from EPA's Toxic Air Pollutant Emissions Factors - A Compilation For Selected Air Toxic Compounds and Sources (EPA-450/2-88-006a).

Natural Gas: (No measurable emissions)

Distillate: $(2.5 \times 10^{-6}$ lb/MMBtu) x (945.5 MMBtu/h) x (8,760 hr/y) x (ton/2,000 lb)
= 0.01 tpy

Mercury Potential Annual Emissions

Assume turbine operates for 8,760 hours per year (100 percent capacity factor). ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions. Emission factor taken from EPA's Toxic Air Pollutant Emissions Factors - A Compilation For Selected Air Toxic Compounds and Sources (EPA-450/2-88-006a).

Natural Gas: (No measurable emissions)

Distillate: $(3.0 \times 10^{-6}$ lb/MMBtu) x (945.5 MMBtu/h) x (8,760 hr/y) x (ton/2,000 lb)
= 0.01 tpy

Sulfuric Acid Mist Potential Annual Emissions

Assume turbine operates for 8,760 hours per year (100 percent capacity factor). ISO condition (59 F and 60 percent relative humidity) pound per hour emission rates are used for annual emissions. It is assumed that approximately 3 percent of the $SO_2$ is converted to $H_2SO_4$.

Natural Gas: (0.03) x (2.6 tpy) = 0.08 tpy

Distillate: (0.03) x (920 tpy) = 27.6 tpy

Other Regulated Pollutant Potential Annual Emissions

Asbestos, Vinyl Chloride, Flourides, Total Reduced S, Reduced S, and $H_2S$ have no measurable emissions for either natural gas or distillate combustion.

# APPENDIX C

## LISTING OF MODELING RUNS

120790
LAAQIA

LISTING OF MODELING RUNS SUPPORTING THE CITY OF LAKELAND, FLORIDA AMBIENT AIR QUALITY IMPACT ANALYSIS

| Model Output File (.LST) | Model Input File (.DAT) | Model Stack File (.PNT) | Description |
|---|---|---|---|
| ISCST RUNS - COMBINED CYCLE (1982-1986) | | | |
| QC82 | QC82 | QC155 | 155-ft HRSG Stack, F.O. Combustion*, Std. Receptors**, 1982 |
| QC83 | QC83 | QC155 | 155-ft HRSG Stack, F.O. Combustion*, Std. Receptors**, 1983 |
| QC84 | QC84 | QC155 | 155-ft HRSG Stack, F.O. Combustion*, Std. Receptors**, 1984 |
| QC85 | QC85 | QC155 | 155-ft HRSG Stack, F.O. Combustion*, Std. Receptors**, 1985 |
| QC86 | QC86 | QC155 | 155-ft HRSG Stack, F.O. Combustion*, Std. Receptors**, 1986 |
| ISCST RUNS - SIMPLE CYCLE (1982-1986) | | | |
| QS82 | QS82 | QS100 | 100-ft Bypass Stack, F.O. Combustion*, Std. Receptors**, 1982 |
| QS83 | QS83 | QS100 | 100-ft Bypass Stack, F.O. Combustion*, Std. Receptors**, 1983 |
| QS84 | QS84 | QS100 | 100-ft Bypass Stack, F.O. Combustion*, Std. Receptors**, 1984 |
| QS85 | QS85 | QS100 | 100-ft Bypass Stack, F.O. Combustion*, Std. Receptors**, 1985 |
| QS86 | QS86 | QS100 | 100-ft Bypass Stack, F.O. Combustion*, Std. Receptors**, 1986 |

*F.O. - Fuel Oil

**Standard Receptors: 0.1, 0.2, 0.3, 0.4, 0.5, 0.6, 0.7, 0.8, 0.9, 1.0, 1.25, 1.5, 1.75, 2.0, 2.25, 2.5, 2.75, 3.0, 4.0, 5.0, 6.0, 7.0, 8.0, 9.0, 10.0, 11.0, 12.0, 13.0, 14.0, 15.0 km. In addition, discrete receptors were placed along the property boundary at each of the 36 radial directions.

# APPENDIX D

## "VISCREEN" VISIBILITY MODEL RESULTS

Visual Effects Screening Analysis for
Source: CITY OF LAKELAND CT
Class I Area: CHASSAHOWITZKA W.R.

*** Level-1 Screening ***

Input Emissions for

| | | |
|---|---|---|
| Particulates | 15.00 | LB /HR |
| NOx (as NO2) | 183.00 | LB /HR |
| Primary NO2 | .00 | LB /HR |
| Soot | .00 | LB /HR |
| Primary SO4 | .00 | LB /HR |

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

| | |
|---|---|
| Background Ozone: | .04 ppm |
| Background Visual Range: | 25.00 km |
| Source-Observer Distance: | 86.00 km |
| Min. Source-Class I Distance: | 86.00 km |
| Max. Source-Class I Distance: | 107.00 km |
| Plume-Source-Observer Angle: | 11.25 degrees |

Stability: 6
Wind Speed: 1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

| | | | | | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| Backgrnd | Theta | Azi | Distance | Alpha | Crit | Plume | Crit | Plume |
| SKY | 10. | 84. | 86.0 | 84. | 2.00 | .070 | .05 | -.000 |
| SKY | 140. | 84. | 86.0 | 84. | 2.00 | .021 | .05 | -.001 |
| TERRAIN | 10. | 84. | 86.0 | 84. | 2.00 | .004 | .05 | .000 |
| TERRAIN | 140. | 84. | 86.0 | 84. | 2.00 | .001 | .05 | .000 |

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

| | | | | | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| Backgrnd | Theta | Azi | Distance | Alpha | Crit | Plume | Crit | Plume |
| SKY | 10. | 75. | 83.2 | 94. | 2.00 | .073 | .05 | -.000 |
| SKY | 140. | 75. | 83.2 | 94. | 2.00 | .022 | .05 | -.001 |
| TERRAIN | 10. | 60. | 78.7 | 109. | 2.00 | .006 | .05 | .000 |
| TERRAIN | 140. | 60. | 78.7 | 109. | 2.00 | .002 | .05 | .000 |

LAKELAND ELECTRIC & WATER

PRODUCTION ENGINEERING

*Excellence Is Our Goal, Service Is Our Job*

December 11, 1990

Mr. Dale Twachtmann, Secretary
Florida Department of Environmental Regulation
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Dear Sir:

This is to authorize Alfred M. Dodd to act as the authorized representative for the City of Lakeland in dealing with the Florida Department of Environmental Regulation in all matters pertaining to the New Generation Addition Project at Larsen Power Plant.

It is further acknowledged that this letter of authorization shall remain in effect and be applied to all matters requiring authorization until your office is notified of a change of representative.

Sincerely,

G. S. Strickland
City Manager

RGS/JAL/AMD/nl

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