RECEIVED
DEC 11 2006
BUREAU OF AIR REGULATION

PREVENTION OF SIGNIFICANT DETERIORATION CONSTRUCTION PERMIT APPLICATION FOR THE ADDITION OF LOW NO_x BURNERS, OVERFIRE AIR, AND SELECTIVE CATALYTIC REDUCTION IN UNIT NO. 3

C.D. MCINTOSH, JR. POWER PLANT
LAKELAND, FLORIDA

Prepared For:
City of Lakeland, Department of Electric Utilities
C.D. McIntosh, Jr. Power Plant
3030 East Lake Parker Drive
Lakeland, Florida 33805

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

December 2006

063-7630

DISTRIBUTION:
4 Copies - FDEP
2 Copies – City of Lakeland
1 Copies - Golder Associates Inc.

APPLICATION FOR AIR PERMIT – LONG FORM

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL)

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **City of Lakeland, Department of Electric Utilities**	
2. Site Name: **C.D. McIntosh, Jr. Power Plant**	
3. Facility Identification Number: **1050004**	
4. Facility Location...: Street Address or Other Locator: **3030 East Lake Parker Drive** City: **Lakeland** County: **Polk** Zip Code: **33805**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Ms. Farzie Shelton,** **Associate General Manager - Technical Support**
2. Application Contact Mailing Address... Organization/Firm: **Lakeland Electric** Street Address: **501 East Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5079**
3. Application Contact Telephone Numbers... Telephone: **(863) 834-6603** ext. Fax: **(863) 834-8187**
4. Application Contact Email Address: **farzie.shelton@lakelandelectric.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 12/11/06	3. PSD Number (if applicable):
2. Project Number(s): 1050004-014-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.
☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.
☐ Title V air operation permit revision.
☐ Title V air operation permit renewal.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.
☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Lakeland Electric is seeking authorization to install Low-NOx burners and selective catalytic reduction (SCR) in McIntosh Unit 3 to meet the requirements of EPA's Clean Air Interstate Rule (CAIR) as implemented by FDEP in Rule 62-296.470 Florida Administrative Code (F.A.C.)

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
006	McIntosh Unit 3	ACIA	NA

Application Processing Fee

Check one: ☐ Attached - Amount: $_____ ☒ Not Applicable

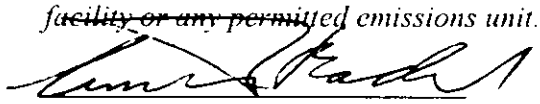
APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name :
   City of Lakeland / Lakeland Electric - Mr. Timothy Bachand
2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: **Lakeland Electric**
   Street Address: **501 East Lemon Street, MS-MO1**
   City: **Lakeland** State: **FL** Zip Code: **33801**
3. Owner/Authorized Representative Telephone Numbers...
   Telephone: **(863) 834-6633** ext.**Direct line** Fax: **(863) 834-5760**
4. Owner/Authorized Representative Email Address: **timothy.bachand@lakelandelectric.com**
5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.



Signature

12/8/06

Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Kennard F. Kosky**
   Registration Number: **14996**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext. **516** Fax: **(352) 336-6603**
4. Professional Engineer Email Address: **kkosky@golder.com**
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Kennard F. Kosky — 12/9/06
Signature — Date

(seal) 7/55

* Attach any exception to certification statement.
** Board of Professional Engineers Certificate of Authorization #00001670

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **409.0** North (km) **3106.2**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **26/4/50** Longitude (DD/MM/SS) **81/55/32**	
3. Governmental Facility Code: **4**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment : **The McIntosh Power Plant consists of 3 fossil fuel fired-steam generators (FFFSG), 2 diesel powered generators, 1 gas turbine peaking unit, and 1 combustion turbine operating in combined cycle (Unit 5). FFFSG Units 1 and 2 are fired with No. 6 fuel oil and natural gas (distillate oil is used as an ignitor). FFFSG Unit 3 is primarily fired with coal, refuse derived fule and petroleum coke. Unit 5 is a Westinghoue 501G combustion turbine and is primarily fired with natural gas with distillate oil as backup.**			

Facility Contact

1. Facility Contact Name: **Andrew Nguyen, Environmental Permitting**
2. Facility Contact Mailing Address... Organization/Firm: **Lakeland Electric** Street Address: **501 East Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5079**
3. Facility Contact Telephone Numbers: Telephone: **(863) 834-8180** ext. Fax: **(863) 603-8187**
4. Facility Contact Email Address: **andrew.nguyen@lakelandelectric.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Unit 1, Unit 2, Unit 3, and Unit 5 are regulated under Acid Rain, Phase II** **Unit 2 is subject to NSPS Subpart D,** **Unit 3 is subject to Subpart Da,** **Unit 5 is subject to Subpart KKKK.** **State:** **Unit 1 is subject to 62-296.405** **Unit 2, 3, and 5 are subject to 62-204.800** **Unit 3 is subject to 62-212.400(6)**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	A	N
PM10	A	N
VOC	A	N
SO2	A	N
H106	A	N
NOX	A	N
HAPS	A	N
HCl	A	N
SAM	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Part II** ☐ Previously Submitted, Date:____
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Part II** ☐ Previously Submitted, Date:____
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:____ ☒ Previously Submitted, Date: **June 14, 1996**

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:____ ☒ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **See Part II**
3. Rule Applicability Analysis: ☒ Attached, Document ID: **See Part II**
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **See Part II** ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):
   ☐ Attached, Document ID:____ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only):
   ☐ Attached, Document ID:____ ☐ Not Applicable (revision application)

2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought):
   ☐ Attached, Document ID:____
   ☐ Not Applicable (revision application with no change in applicable requirements)

3. Compliance Report and Plan (Required for all initial/revision/renewal applications):
   ☐ Attached, Document ID:____
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.

4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only):
   ☐ Attached, Document ID:____
   ☐ Equipment/Activities On site but Not Required to be Individually Listed
   ☐ Not Applicable

5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) :
   ☐ Attached, Document ID:____ ☐ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
   ☐ Attached, Document ID:____ ☐ Not Applicable

Additional Requirements Comment

See Part II.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

EMISSIONS UNIT INFORMATION
Section [1]
UNIT No. 3

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section: **McIntosh Unit 3 – Fossil-Fuel-Fired Steam Generator (FFFSG)**

3. Emissions Unit Identification Number: **006**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A		**1982**	**49**	☒ Yes ☐ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **364** MW

11. Emissions Unit Comment: **This emission unit is a coal-fired steam-generating unit which also co-fires refuse-derived fuel and petroleum coke.**

EMISSIONS UNIT INFORMATION
Section [1]
UNIT No. 3

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   PM – Electrostatic Precipitator (ESP), followed by
   SO2 – Flue Gas Desulfurization (FGD) system.
   NOX – Low NOX burners (LNB), Selective Catalytic Reduction (SCR) with ammonia injection.

2. Control Device or Method Code(s): **10, 67, 24, 139, and 032**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **3,640** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year

6. Operating Capacity/Schedule Comment:

Emission unit co-fires coal and coal/petroleum coke and/or RDF. Unit is also authorized to burn residual oil and gas. Heat input based on fuel flow sampling. The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5) F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.

EMISSIONS UNIT INFORMATION
Section [1]
UNIT No. 3

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Site Plan**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **250**feet	7. Exit Diameter: **18**feet
8. Exit Temperature: **125**°F	9. Actual Volumetric Flow Rate: **1,260,536** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **409.3** North (km): **3106.3**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type): **Coal**		
2. Source Classification Code (SCC): **1-01-001-01**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **159.6**	5. Maximum Annual Rate: **1,398,096**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.3**	8. Maximum % Ash: **16**	9. Million Btu per SCC Unit: **23**
10. Segment Comment: **Up to 20 percent petroleum coke is authorized to be co-fired with coal.**		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type): **Oil**		
2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **24,268**	5. Maximum Annual Rate: **212,584**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.73**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type): **Coal/Petroleum Coke (80/20 weight basis)**		
2. Source Classification Code (SCC): **1-01-001-01**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **152.6**	5. Maximum Annual Rate: **1,336,776**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.3**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **24**
10. Segment Comment:		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **3.56**	5. Maximum Annual Rate: **31,139**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.3**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,024**
10. Segment Comment: **Natural gas or propane only or in combination with any other fuels or fuel combinations.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	010		EL
SAM	032	010	NS
CO			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **99.1**
3. Potential Emissions: **273** lb/hour **483.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.075 lb/MMBtu** Reference: **Title V Permit No. 1050004-016-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if Required): Tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Potential Actual Emissions (if Required): Tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **0.075 lb/mmBtu x 3,640 mmBtu/hr = 273 lb/hr**	
11. Pollutant Potential/Estimated Fugitive Emissions Comment: **Annual emissions based on actual emissions for 2003-2002. See Part II**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.070 lb/mmBtu**	4. Equivalent Allowable Emissions: **254**lb/hour **483.1**tons/year
5. Method of Compliance: **Annual stack test; EPA Method 5 and 5B, if greater than 400 hours.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emission limit based on Title V Permit No. 1050004-016-AV for oil firing. No increase in representative actual annual emissions plus the PSD significant emission rate will occur as a result of the project.**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.075 lb/MMBtu**	4. Equivalent Allowable Emissions: **273** lb/hour **483.1**tons/year
5. Method of Compliance: **Annual stack test; EPA Method 5 or 5B, if greater than 400 hours.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emission limit based on Title V Permit No. 1050004-016-AV for oil/RDF firing. No increase in representative actual annual emissions plus the PSD significant emission rate will occur as a result of the project.**	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **182** lb/hour **483.1** tons/year
5. Method of Compliance: **Annual stack test; EPA Method 5 and 5B.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emission limit based on Title V Permit No. 1050004-016-AV for coal/petroleum coke/RDF firing and coal/RDF firing. No increase in representative actual annual emissions plus the PSD significant emission rate will occur as a result of the project.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **4** of **4**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.044 lb/mmBtu**	4. Equivalent Allowable Emissions: **160**lb/hour **483.1**tons/year
5. Method of Compliance: **Annual stack test; EPA Method 5 and 5B.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emission limit based on Title V Permit No. 1050004-016-AV for coal firing and coal/petroleum coke firing. No increase in representative actual annual emissions plus the PSD significant emission rate will occur as a result of the project.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control: **30+%**
3. Potential Emissions: lb/hour **135.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if Required): Tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Potential Actual Emissions (if Required): Tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Annual emissions based on actual emissions for 2002-2001. See Part II**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **135.6 tons/yr**	4. Equivalent Allowable Emissions: lb/hour **135.6** tons/year
5. Method of Compliance: **Annual Operating Reports; See Part II**	
6. Allowable Emissions Comment (Description of Operating Method): **No increase in representative actual annual emissions plus th PSD significant emission rate will occur as a result of the addition of the project.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **728** lb/hour **3,188.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.20 lb/MMBtu** Reference: **BACT See Part II**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if Required): Tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Potential Actual Emissions (if Required): Tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.20 lb/mmBtu x 3,640 mmBtu/hr = 728.0 lb/hr** **728.0 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 3,188.6 ton/yr**	
11. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **728** lb/hour **3,188.6** tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **2**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **Annual VE testing; EPA Method 9**	
5. Visible Emissions Comment: **Title V Permit 1050004-016-AV**	

Visible Emissions Limitation: Visible Emissions Limitation **2** of **2**

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **Excess VE emissions allowed under FDEP Rule 62-210.700(1) and 40 CFR 60.8(c), and 60.11(c) for 2 hours (120 minutes) per 24-hour period for startup, shutdown, and malfunction.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Advanced Pollution Inst.** Model Number: **152**	Serial Number: **139/176 and 172/156**
5. Installation Date: **09 Nov 1994**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR Part 75, Title V Permit No. 1050004-016-AV.**	

Continuous Monitoring System: Continuous Monitor **2** of **8**

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Advanced Pollution Inst.** Model Number: **252**	Serial Number: **165 and 136**
5. Installation Date: **09 Nov 1994**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR Part 75, Title V Permit No. 1050004-016-AV.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **3** of **8**

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **United Science Inc.** Model Number: **500C**	Serial Number: **0993688**
5. Installation Date: **09 Nov 1994**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR Part 75 and Title V Permit No. 1050004-016-AV.**	

Continuous Monitoring System: Continuous Monitor **4** of **8**

1. Parameter Code: **CO2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **California Instruments** Model Number: **3300**	Serial Number: **N3L2487T and N3L2490T**
5. Installation Date: **09 Nov 1994**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR Part 75.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **5** of **8**

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **United Science Ultraflow** Model Number: **100** Serial Number: **1001060**	
5. Installation Date: **10 Nov 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Flow monitor required pursuant to 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor **6** of **8**

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Lear Siegler** Model Number: **SM 810** Serial Number: **29259M**	
5. Installation Date: **17 Sep 1982**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 60.45.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **7** of **8**

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Lear Seigler** Model Number: **CM50**	Serial Number: **291230**
5. Installation Date: **17 Sep 1982**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **COM required pursuant to 40 CFR 60.45.**	

Continuous Monitoring System: Continuous Monitor **8** of **8**

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Lear Siegler** Model Number: **RM41**	Serial Number:
5. Installation Date: **17 Sep 1982**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **O2 required pursuant to 40 CFR 60.45.**	

EMISSIONS UNIT INFORMATION
Section [1]
UNIT No. 3

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Part II** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Part II** ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____
   ☒ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1]
UNIT No. 3

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☒ Attached, Document ID: **Part II** ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☒ Attached, Document ID: **Part II** ☐ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☐ Attached, Document ID: _____ ☐ Not Applicable
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☐ Not Applicable
3. Alternative Methods of Operation
   ☐ Attached, Document ID: _____ ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☐ Not Applicable
5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID: _____
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1]
UNIT No. 3

Additional Requirements Comment

PART II

TABLE OF CONTENTS

1.0 INTRODUCTION

Lakeland Electric is seeking authorization from the Florida Department of Environmental Protection (FDEP) to install low-nitrogen oxides (NO_x) burners (LNB), overfire air (OFA), and selective catalytic reduction (SCR) in Unit 3 at the C.C. McIntosh, Jr. Power Plant (McIntosh Power Plant) to meet the requirements of the Environmental Protection Agency (EPA) Clean Air Interstate Rule (CAIR) as implemented by FDEP in Rule 62-296.470 Florida Administrative Code (FAC). In addition, the addition of SCR will have the co-benefits of reducing emissions of mercury to meet EPA's Clean Air Mercury Rule (CAMR) implemented by FDEP in Rule 62-296.480 FAC The primary purpose of the project will be to decrease (NO_x) emissions from Unit 3 to meet the annual and ozone season NO_x CAIR allocations. While the addition of SCR will substantially decrease emissions of NO_x, there is the potential for collateral increases in emissions of carbon monoxide, sulfuric acid mist (SAM) and particulate matter (PM). The potential increase in carbon monoxide (CO) is a result of the installation of LNBs that would decrease NO_x from current levels. The potential increase of SAM emissions is a result of the oxidation of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) that is emitted as SAM after the flue gas desulfurization (FGD) system. Potential increases in SAM emissions will be minimized through the injection of ammonia (NH_3) to react with SO_3 prior to the electrostatic precipitator (ESP). The reactants, primarily ammonium sulfate, will be collected in the ESP. The potential increase in PM from the reaction of NH_3 and SO_3 will be collected in the ESP and FGD system. With the exception of CO, there will be no emissions over the prevention of significant deterioration (PSD) emission rates from the installation of LNBs and SCR.

The C. D. McIntosh Power Plant is located at 3030 East Lake Parker Drive, Lakeland, Polk County, Florida. The facility is authorized to operate under Title V Permit [Final Title V Permit No. 1050004-016-AV].

Golder Associates Inc. (Golder) was contracted to prepare the necessary air permit application seeking authorization to install LNBs, OFA, and SCR on Unit No. 3. The air permit application consists of the appropriate applications form [Part I; DEP Form 62-210.900(1)], a technical description of the project (Part II Section 2.0), rule applicability for the project (Part II, Section 3.0) and a PSD evaluation for CO (Part II Section 4.0).

2.0 PROJECT DESCRIPTION

LNBs and SCR have been selected as the control systems to meet the NO_x CAIR for Unit 3. The LNB will be supplied by Siemens Power Group, Inc. (SPG). The system will include new LNBs and OFA equipment. Advanced Burner Technologies, Inc. (ABT) is a wholly owned subsidiary of SPG, and will be providing the design, fabrication, delivery, and field testing services for the new LNB system. The following major components are part of the LNB system and will be installed at Unit 3 in April 2007:

- 32 complete new Opti-Flow™ low NO_x burner assemblies, with features to accommodate the existing igniter and flame scanner assemblies. These will be installed in the existing burner locations on both the front and rear furnace walls.
- Complete new OFA system including new OFA windboxes mounted on the boiler front and rear walls. Interconnecting ductwork to the existing secondary air ducts will be required.
- 8 complete new OFA register assemblies, 4 each to be located within the new front and rear OFA windboxes.
- Computational Fluid Dynamic (CFD) modeling of the existing secondary air and newly supplied OFA system.
- Testing and Field Advisory Services.

Average NO_x emissions levels are expected to be in the 0.30 lb/MMBtu range following the installation of the LNB and OFA system. Average CO emission levels are not expected to exceed 200 parts per million (ppm). VOC emission levels and particulate levels are not expected to change from current emission levels following the installation of the new LNB and OFA system.

The SCR system is designed to work in conjunction with the new LNB and OFA system that will be added to the boiler to maintain stack NOx emissions levels at or below 0.10 pounds per million British thermal units (lb/MMBtu) on an annual average.

2.1 SCR Process

The SCR system uses an NH_3 reagent over a vanadium/titanium based catalyst to convert NO_x (NO and NO_2) to elemental nitrogen (N_2) and water (H_2O). The chemical reactions that take place are as follows:

Primary Reaction: $4NO + 4NH_3 + O_2 \rightarrow 4N2 + 6H_2O$

Secondary Reactions: $2NO_2 + 4NH_3 + O_2 \rightarrow 3N2 + 6H_2O$

$6NO + 4NH_3 \rightarrow 5N2 + 6H2O$

$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$

$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 2H_2O$

NO_x from coal combustion is about 95 percent NO and 5 percent NO_2, so the primary reaction is the most significant for the SCR process. This reaction indicates that one mole of NH_3 is required to remove one mole of NO. The function of the catalyst is to lower the required activation energy for the reaction and to increase the reaction rate. As flue gas passes over the catalyst surface, activated sites rapidly adsorb NH_3 and NO to form an activated complex. The reaction proceeds to produce nitrogen (N_2) and water (H_2O), which are then desorbed back to the flue gas. The site at which the reaction occurs is then reactivated via oxidation.

SCR is a process that uses catalyst to promote the conversion of nitrogen oxides (NO_x) to N_2 and H_2O in the flue gas. This conversion occurs between the boiler economizer and the air heaters in a specially designed ductwork section, called the SCR reactor that contains the catalyst. NH_3 vapor, mixed with dilution air, is injected into the flue gas upstream of the catalyst and is thoroughly mixed with the flue gas prior to its admittance to the catalyst. As the flue gas passes over the catalyst, the NO and NO_2 combine with the NH_3 to form N_2 and H_2O.

Unit 3 will have two SCR reactors. Each SCR reactor will consist of a steel reactor box designed to support the SCR catalyst modules and to properly distribute flue gas through the catalyst layers. Flue gas flow will be vertically downward through the catalyst to minimize ash pluggage. Flue gas ductwork will be provided from the economizer outlet to the air heater inlet (including an SCR bypass duct and associated dampers). The SCR inlet duct will include a static flue gas mixer, and NH_3 injection grid.

Figure 2-1 presents a schematic flow diagram of the SCR system showing the inlet duct from the economizer, the NH_3 injection grid and SCR catalyst. A photograph of the existing Unit 3 boiler showing the air heaters and ESP is shown in Figure 2-2. The general arrangement of the SCR system is illustrated in Figure 2-3.

2.2 NH_3 System

NH_3 is introduced in the SCR as a mixture of anhydrous NH_3 and air. The air/NH_3 vapor mixture (typically 5 percent NH_3 by volume) is produced in NH_3 vaporization equipment and supplied to the NH_3 injection grid header. The air/NH_3 vapor mixture is distributed across the entire duct cross section using the NH_3 injection grid (AIG). The AIG consists of a series of pipes, each with nozzles that inject the mixture into a particular section of the SCR reactor inlet duct. The pipes will extend the entire width of the ductwork and contain a sufficient number of nozzles with orifices sized for the particular NH_3 distribution requirement. If necessary, as determined by the physical flow model test of the SCR reactor and associated ductwork, a static mixer may be required upstream of the NH_3 injection grid to help reduce the stratification of temperature and chemical composition of the flue gas flow out of the economizers.

Anhydrous NH_3 will be delivered to the site by tank truck and unloaded into one of two bulk storage tanks (each with the storage capacity of ~75 tons). Liquid anhydrous NH_3 will be transferred from the storage tanks to NH_3 vaporizers. After vaporization, the NH_3 gas will be mixed with ambient air and distributed into the flue gas through ammonia injection grids located upstream of the reactor.

2.3 SCR Catalyst Details

The catalyst used for NO_x reduction primarily consists of a vanadium and titanium (Ti) mixture. However, the final catalyst composition can consist of many active metals and support materials. Titanium dioxide (TiO_2) is used as the base material that disperses and supports vanadium pentoxide (V_2O_5), which is the active catalyst material. V_2O_5 is widely used in the SCR industry due to its resistance to sulfur poisoning. The vanadium content controls the reactivity of the catalyst, but also catalyzes the oxidation of SO_2 to SO_3. For moderate to high sulfur coal applications, it is necessary to minimize the vanadium content to reduce SO_2 oxidation. Additionally, the vanadium already present in the petcoke fuel will deposit on the catalyst, potentially increasing the oxidation of SO_2 to SO_3. Tungsten oxide also provides thermal and mechanical stability to the catalyst. The concentrations of vanadium pentoxide, titanium dioxide, and tungsten oxide will be customized by the catalyst vendor to meet the specific requirements for Unit 3 SCR system installation. The catalyst will be made up of several identical catalyst modules that will be loaded into the SCR reactor.

2.4 SCR Cleaning and Replacement Schedule

Each SCR reactor will include sonic horns to keep the catalyst free of fly ash buildup. Provisions for catalyst loading into the reactors will be included. The SCR reactors will be designed for three initial

layers of catalyst and a spare level for a future additional layer of catalyst. The catalyst replacement schedule will be determined as data are collected and reviewed once the SCR system is in operation.

2.5 Schedule

The SCR project is currently scheduled for operation in December 2008. Initial foundation construction is scheduled for the third quarter of 2007. Some small existing equipment at grade is planned for relocation during the Spring 2007 outage to allow future construction space for constructing the SCR foundation.

The conceptual SCR system design characteristics are listed below:

- Baseline NO_x Loading: 0.36 lb/MMBtu (after installation of LNB, 0.36lb/MMbtu is the SCR Design basis and is calculated at 20% over 0.30lb/MMbtu←LNB guarantee)
- Target NO_x Emissions: 0.10 lb/MMBtu (annual average)
- NH_3 Slip: 2 ppm volume dry (vd) at 4 percent O_2
- SO_2 to SO_3 Conversion: 0.8 percent
- Catalyst Type: High Dust
- Catalyst Configuration: Vertical
- Number of Reactors : 2
- Number of Initial Catalyst Layers (Per Reactor): 3
- Number of Spare Layers (Per Reactor): 1
- Modules Per Layer (Per Reactor): 9 x 5
- Reactor Dimensions (Inside x Inside)" 34'- 3" x 30'- 3"
- Full Load Gas Flow: 1,730,060 actual cubic feet per meter (acfm) at SCR inlet
- Normal Operating Temperature 640° F
- Superficial Velocity Through Catalyst: 15 to 16 feet per second (ft/sec)
- Pressure Drop Through Box and Ductwork: 10.0 inches (w.c.)
- NH_3 Consumption at Design Conditions: 415 pounds per hour (lb/hr)
- Reagent (NH_3) Storage Required: 2 x 30,000 gallons = ~ 2 x 75 tons at 60°F

TABLE 2-1
MCINTOSH UNIT 3 ANNUAL HEAT INPUT, 2002 - 2005

Year	Heat Input (MMBtu/yr)				
	Coal	Oil/Gas	Pet Coke	MSW	Total
2005	24,739,432	88,531	2,202,682	0	27,030,645
2004	18,727,073	149,795	398,533	0	19,275,401
2003	23,556,583	170,380	541,898	62,413	24,331,274
2002	19,914,927	284,194	3,012,015	135,529	23,346,665
2001	22,521,423	480	3,868,418	261,180	26,651,502

Note: Heat Input calculated from Annual Operating Reports based on fuel use and heat content.

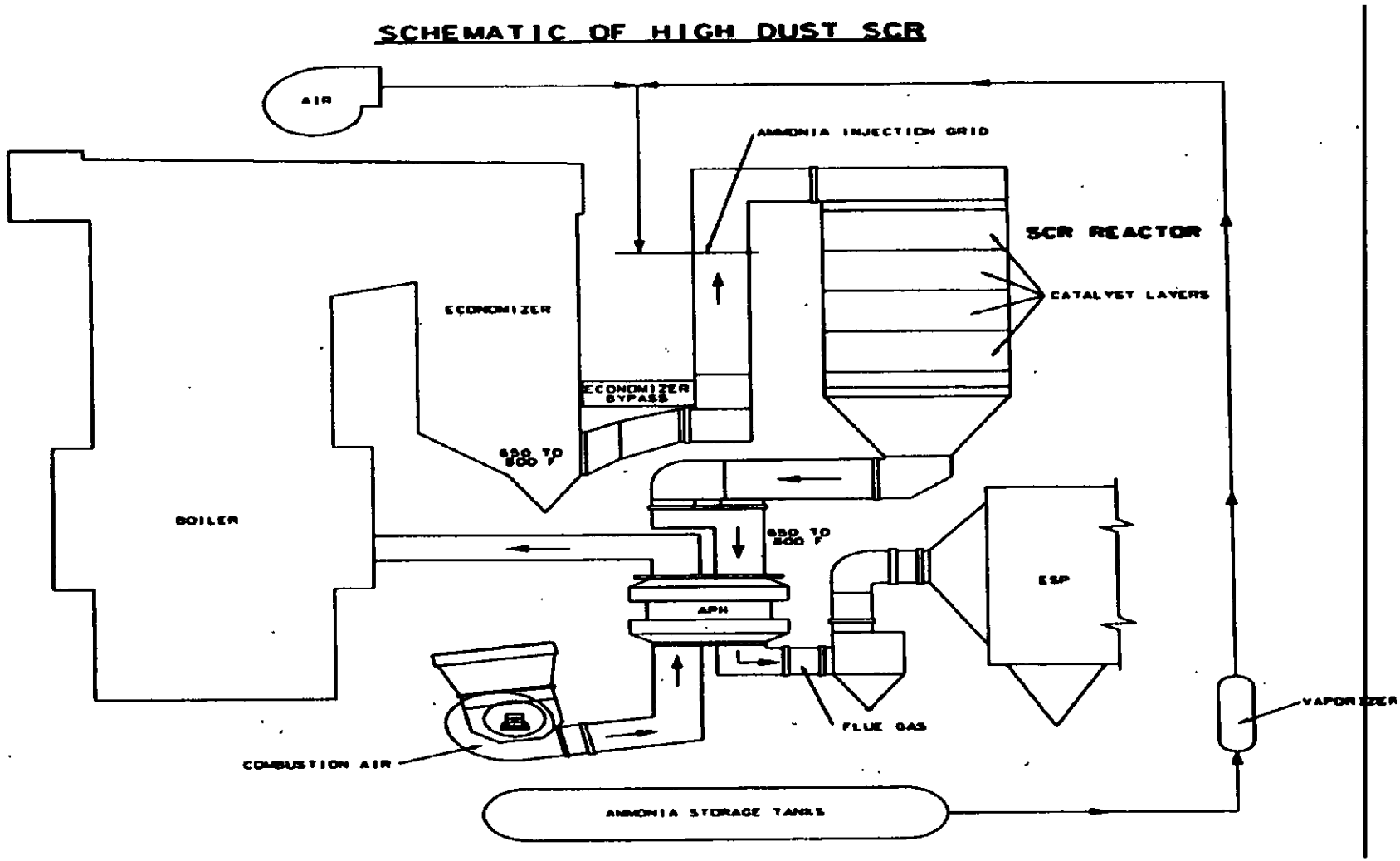
TABLE 2-2
MCINTOSH UNIT 3 ANNUAL EMISSIONS REPORTED IN ANNUAL OPERATING REPORTS, 1999 - 2003

Year	Pollutant	Unit 3 (tons)
2005	CO	136.1
	PM	264.6
	SAM	147.3
2004	CO	93.1
	PM	302.1
	SAM	103.9
2003	CO	129.5
	PM	486.0
	SAM	131.1
2002	CO	157.4
	PM	390.1
	SAM	125.6
2001	CO	195.7
	PM	266.5
	SAM	145.6

Note: Data from Annual Operating Reports.

FIGURE 2-1

PROCESS FLOW DIAGRAM



Boiler

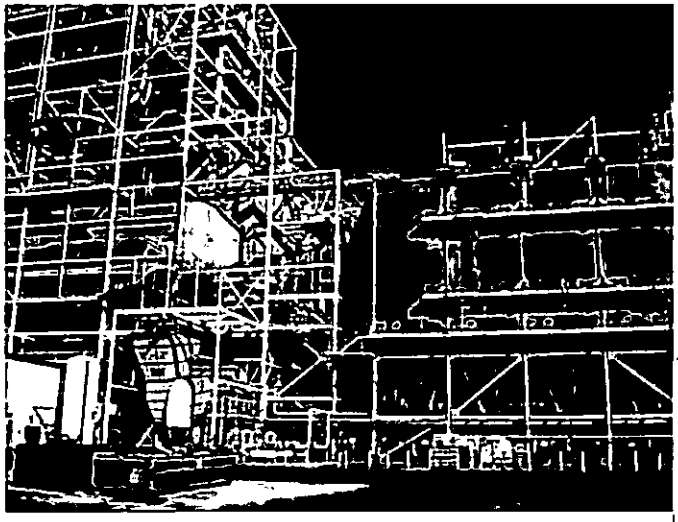


FIGURE 2-2

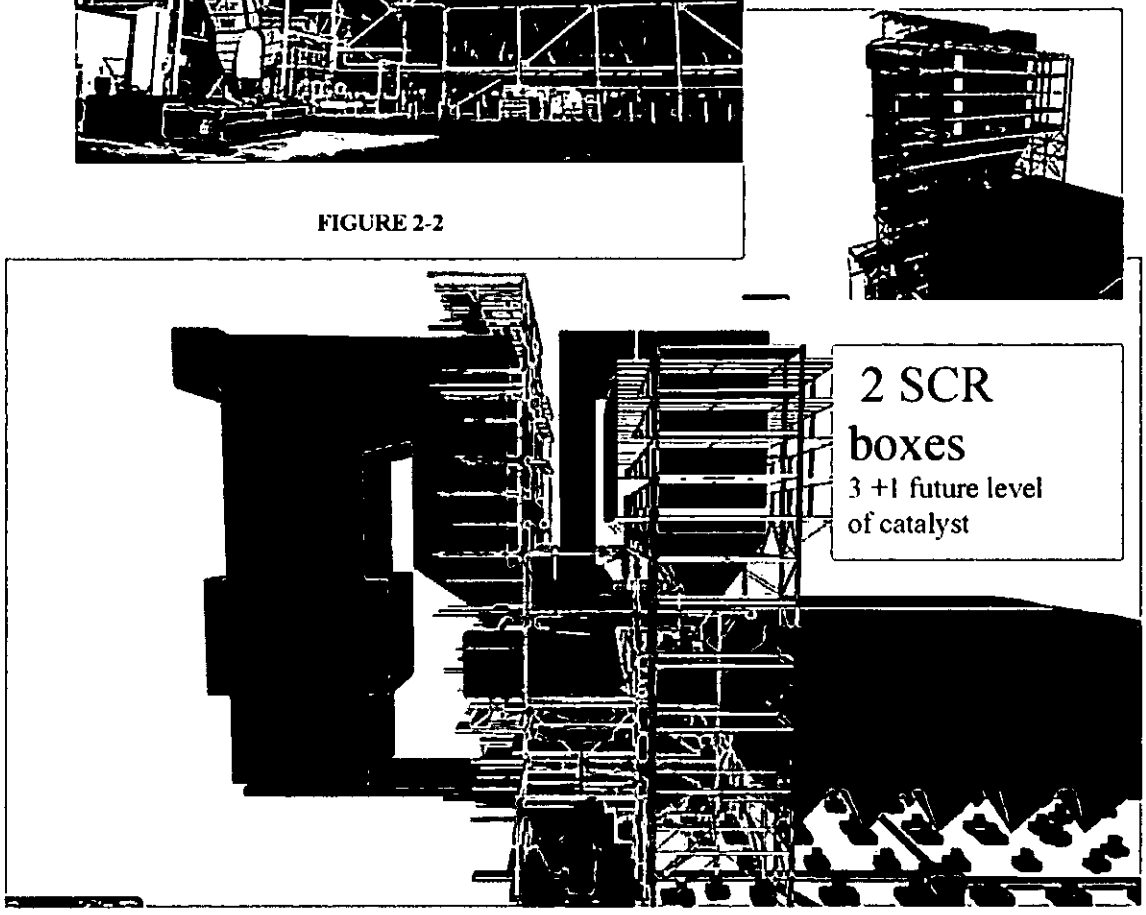
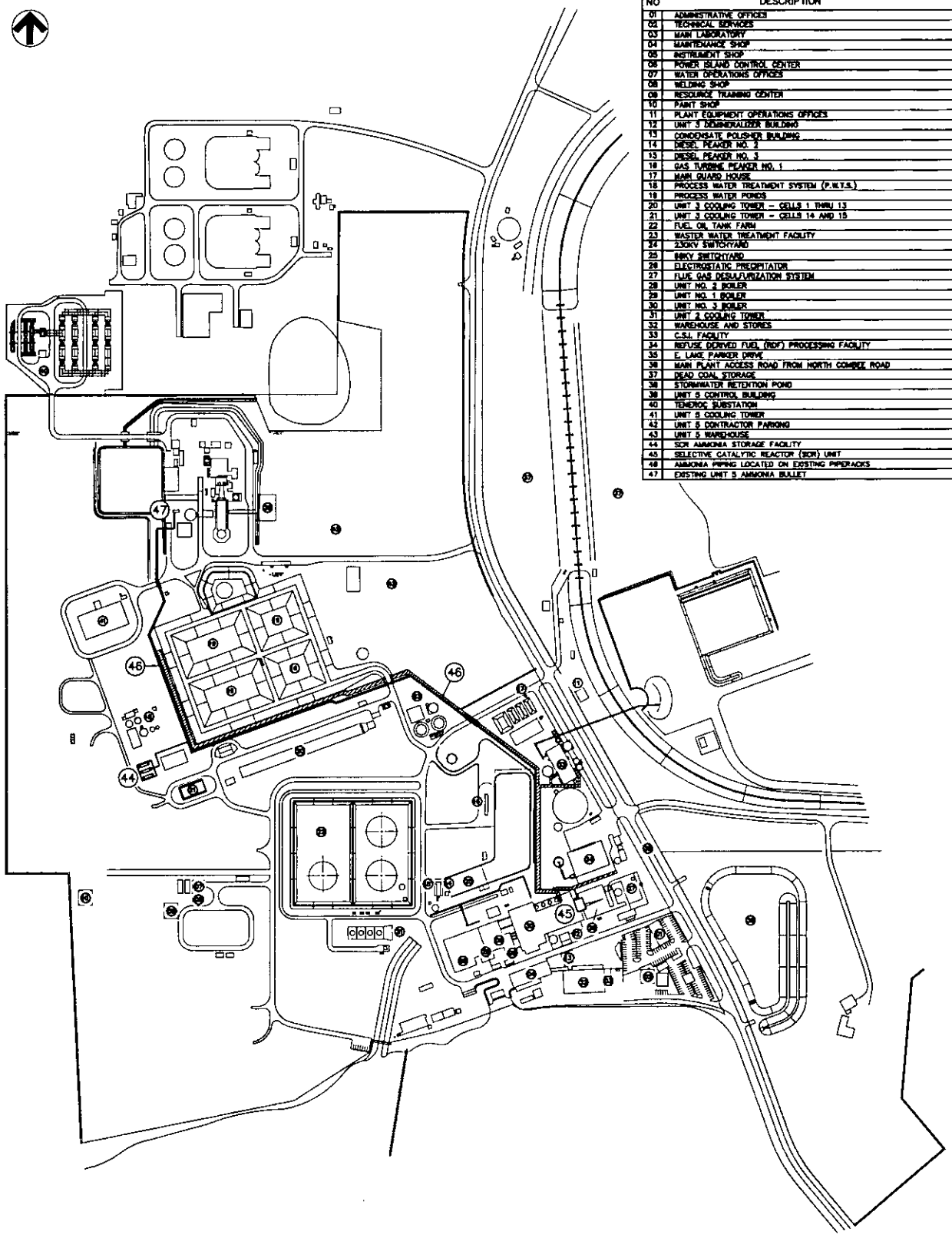


FIGURE 2-3 –SCR General Arrangement



BUILDING AND FACILITIES LEGEND	
NO	DESCRIPTION
01	ADMINISTRATIVE OFFICES
02	TECHNICAL SERVICES
03	MAIN LABORATORY
04	MAINTENANCE SHOP
05	INSTRUMENT SHOP
06	POWER ISLAND CONTROL CENTER
07	WATER OPERATIONS OFFICES
08	WELDING SHOP
09	RESOURCE TRAINING CENTER
10	PAINT SHOP
11	PLANT EQUIPMENT OPERATIONS OFFICES
12	UNIT 3 DEMINERALIZER BUILDING
13	CONDENSATE POLISHER BUILDING
14	DIESEL PEAKER NO. 2
15	DIESEL PEAKER NO. 3
16	GAS TURBINE PEAKER NO. 1
17	MAIN GUARD HOUSE
18	PROCESS WATER TREATMENT SYSTEM (P.W.T.S.)
19	PROCESS WATER PONDS
20	UNIT 3 COOLING TOWER - CELLS 1 THRU 13
21	UNIT 3 COOLING TOWER - CELLS 14 AND 15
22	FUEL OIL TANK FARM
23	WASTER WATER TREATMENT FACILITY
24	230KV SWITCHYARD
25	69KV SWITCHYARD
26	ELECTROSTATIC PRECIPITATOR
27	FLUE GAS DESULFURIZATION SYSTEM
28	UNIT NO. 2 BOILER
29	UNIT NO. 1 BOILER
30	UNIT NO. 3 BOILER
31	UNIT 2 COOLING TOWER
32	WAREHOUSE AND STORES
33	C.S.L. FACILITY
34	REFUSE DERIVED FUEL (RDF) PROCESSING FACILITY
35	E. LAKE PARKER DRIVE
36	MAIN PLANT ACCESS ROAD FROM NORTH COMBEE ROAD
37	DEAD COAL STORAGE
38	STORMWATER RETENTION POND
39	UNIT 5 CONTROL BUILDING
40	TENEROC SUBSTATION
41	UNIT 5 COOLING TOWER
42	UNIT 5 CONTRACTOR PARKING
43	UNIT 5 WAREHOUSE
44	SCR AMMONIA STORAGE FACILITY
45	SELECTIVE CATALYTIC REACTOR (SCR) UNIT
46	AMMONIA PIPING LOCATED ON EXISTING PIPERACKS
47	EXISTING UNIT 5 AMMONIA BULLET

REV. NO.	BY	DATE	CHK. BY	APPR.	REVISION

LAKELAND ELECTRIC

DRAWING TITLE: McINTOSH POWER PLANT OVERALL SITE PLAN

DIVISION: PRODUCTION ENGINEERING
ENGINEER: KOLLER
DRN. BY: MGEIGER
APPR. BY:
DATE: 09-26-01

PROJ. NO.:
PLOT DATE: 09-26-01
DWG. NO.: SK-1
SCALE: NONE
CAD NO.: site1plans
SHT. NO.: - OF -
REV.: 1

SIZE B

3.0 RULE APPLICABILITY

Under Federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. EPA has approved Florida's State Implementation Plan (SIP), which contains PSD regulations. Therefore, PSD approval authority has been granted to the FDEP. For projects approved under the Florida PPSA, the PSD program is delegated.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 tons per year (TPY) or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 Code of Federal Regulations (CFR) 52.21, *Prevention of Significant Deterioration of Air Quality*. The State of Florida has adopted the federal PSD regulations by reference (Rule 62-212.400, FAC). Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

- Control technology review;
- Source impact analysis;
- Air quality analysis (monitoring);
- Source information; and
- Additional impact analyses.

The McIntosh Power Plant is a major facility under FDEP Rules. Because there is a physical change with the addition of LNB, OFA, and SCR and the pollution control exemption in the PSD rules have been vacated, the project is a potential modification as defined in the FDEP Rules in 62-210.200 and under the PSD rules in 62-212.400, FAC. PSD review would be required for the project if there were a significant net increase in emissions. The comparison is made based on the projected future actual

emissions and the baseline actual emissions. The baseline actual emissions for a fossil fuel fired steam electric generating unit are the emissions over a consecutive 24-month period, 5 years immediately preceding the date that a complete application is submitted. The use of different consecutive 24-month periods for each pollutant are allowed. For an existing facility for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates. The net emissions increase is determined using the baseline-to-projected actual test. In this comparison, if the projected actual emissions minus the baseline actual emissions equal or exceed the PSD significant emission rates, then PSD review would apply.

Presented in Table 3-1 is the heat input reported in the Annual Operating Report (AOR) for the period 2001 through 2005. Table 3-2 presents the annual emissions reported in the AORs for the years 2001 through 2005 for CO, PM and SAM. Table 3-2 also presents the average calendar year emissions for each consecutive 2-year period from 2001 through 2005 based on the average calendar year emissions. The use of calendar year dates from the AOR is representative of historic normal operation. The annual average emissions for each consecutive 2-year period are consistent with the definition of baseline actual emissions for fossil fuel fired steam electric generating units. The highest two consecutive 2-year averages in Table 3-2 for the period 2001-2002 are proposed as the basis for future comparisons for CO and SAM emissions and 2003-2002 for PM emissions. Years 2001-2002 also have the highest 2-year average heat input.

Boiler Unit No. 3 operates as a base-load unit, but, for any given year, operation can vary slightly due to electric demand and operational variability due to outages and maintenance. Due to this slight variability, two consecutive years out of the last 5 years are appropriate for any future comparisons.

The proposed conditions for the installation of the LNB/SCR/OFA system with NH_3 control for SAM emissions are presented below:

SCR Systems: The permittee shall construct, tune, operate, and maintain a new LNB, OFA, and SCR system for Units No. 3 to reduce emissions of NO_x as described in the application and the control system shall be operated as necessary to comply with CAIR at Lakeland Electric's discretion.

The applicant shall maintain and submit to the FDEP on an annual basis for a period of 5 years from the date the SCR systems are initially operated, information demonstrating in accordance with 62-212.300(1)(e) F.A.C. that the installation of LNB, OFA and SCR did not result in emission

increases of PM and SAM. The future emissions shall be compared with the baseline actual emissions for the period 2002-2001 for SAM and 2003-2002 for PM as reported in the AORs using EPA Method 5B for PM and Method 8A (controlled condensate) for SAM.

TABLE 3-1
MCINTOSH UNIT 3 ANNUAL HEAT INPUT, 2001-2005

Year	Heat Input (MMBtu/yr)				
	Coal	Oil/Gas	Pet Coke	MSW	Total
2005	24,739,432	88,531	2,202,682	0	27,030,645
2004	18,727,073	149,795	398,533	0	19,275,401
2003	23,556,583	170,380	541,898	62,413	24,331,274
2002	19,914,927	284,194	3,012,015	135,529	23,346,665
2001	22,521,423	480	3,868,418	261,180	26,651,502

Note: Heat Input calculated from Annual Operating Reports based on fuel use and heat content.

TABLE 3-2
MCINTOSH UNIT 3 ANNUAL EMISSIONS REPORTED IN AORS, 2001-2005

Year	Pollutant	Unit 3 (tons)	2-year Average (tons)	2-year Average (period)
2005	CO	136.1	114.6	2005-2004
	PM	264.6	283.3	
	SAM	147.3	125.6	
2004	CO	93.1	111.3	2004-2003
	PM	302.1	394.1	
	SAM	103.9	117.5	
2003	CO	129.5	143.5	2003-2002
	PM	486.0	**438.1**	
	SAM	131.1	128.3	
2002	CO	157.4	**176.6**	2002-2001
	PM	390.1	328.3	
	SAM	125.6	***135.6***	
2001	CO	195.7	-	-
	PM	266.5		
	SAM	145.6		

Note: Data from Annual Operating Reports. Highest 2-year averages indicated in bold format.

4.0 PSD EVALUATION FOR CO

The Project is considered a modification under PSD regulation. A modification under PSD rules would occur if a physical or operational change causes an increase in annual emissions by more than the PSD significant emission rates. The comparison is made based on the projected future actual emissions and the baseline actual emissions. The baseline actual emissions are the emissions over a consecutive 24-month period, 5 years immediately preceeding the date that a complete application and the use of different consecutive 24-month periods for each pollutant are allowed.

For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates. The net emissions increase is determined using the baseline-to-projected actual test. In this comparison, if the projected actual emissions minus the baseline actual emissions equal or exceed the PSD significant emission rates, then PSD review would apply. For the Project, the emissions of CO are projected to exceed the significant emission rate.

4.1 CO BACT Evaluation

There are no applicable new source performance standards (NSPS) requirements for the control of CO from utility boilers. CO emissions result from incomplete combustion of the fuel. CO emissions are controlled by good combustion practices (GCP). The boilers are currently operated for high-combustion efficiency, which will inherently minimize the production of CO. After the implementation of the project, the operation of the boilers will continue to maximize combustion efficiency while reducing CO emissions.

Theoretically, CO emissions can be reduced by passing the flue gas over an oxidation catalyst at a suitable temperature (900 to 1,000°F). In practice, this technology has several unknowns and disadvantages, including the following:

1. No utility pulverized coal-fired boilers are operating with catalytic CO control systems and it would be difficult to locate an oxidation catalyst in the proper temperature zone in a boiler.
2. Oxidation catalyst can convert up to 70 percent of SO_2 to SO_3.
3. There is a lack of experience with large-scale operation of this technology using particulate-laden gases from coal-fired boilers. Oxidation catalysts can be easily eroded and fouled by silica and trace metals in the flue gas.

4. The temperature profile of the flue gas does not match the temperature requirements of typical catalysts which would have to be installed within the boiler make such application extremely difficult.

   a. Use of an undemonstrated catalyst technology would reduce the availability and reliability of the plant (e.g., catalyst plugging).

   b. The high costs to install and operate the system (additional pressure drop, catalyst replacement and disposal, etc.) are without corresponding demonstrated needs or benefits. Design and operation of the boilers to efficiently combust the fuel will minimize CO emissions. The additional costs to further lower emissions are not justified.

A review of the BACT/LAER (best available control technology/lowest achievable emission rate) Clearing house and individual permits from states indicates that BACT emission limits established over the last 5 years range from 0.1 to 0.16 lb/MMBtu for new units. Combustion control is the primary method used to control CO emissions.

Efficiently burning the coal represents BACT for control of CO emissions although Unit 3 is not a new unit. A CO emission rate for the existing Unit 3 pulverized coal boiler of 0.20 lb/MMBtu limit is proposed as BACT. Although recently permitted projects have lower limits the project does not include the construction of a new boiler, but the addition of new burners, OFA and SCR. CO formation is a function of combustion efficiency, boiler design, and residence time and as such the BACT limits of new construction boilers are not directly applicable to the project. As an existing boiler the proposed limit of 0.20 lb/MMBtu limit is proposed as BACT. In addition, air quality impacts of the proposed power plant are not significant.

TABLE 4-1
REPRESENTATIVE PROJECT COMPARISONS FOR RECENTLY PERMITTED PROJECTS

Project	Date	Status	Plant Size MW	Type
Seminole Electric Unit 3 - Flroida	Aug-06	Draft Permit	750	SCPC
Thoroughbred - Kentucky	May-06 (Revision)	Final Permit	1,500	PC
Louisville Gas & Electric - Kentucky	Jan-06 (Revision)	Final Permit	750	SCPC
River Hill Power - Pennsylvania	July - 05	Final Permit	290	CFB -Waste Coal
Prairie State-Illinois	Apr-05	Final Permit	1,500	PC
Elm Road-Wisconsin	Jan-04	Final Permit	1,830	SCPC
Longview-West Virginia	Mar-04	Final Permit	600	PC
City Public Service-Texas	Sep-05	Draft Permit	750	PC
Public Service of Colorado	Jul-05	Final Permit	1,410	PC
Public Service Corp Wausau - Wisconsin	Oct-04	Final Permit	500	SCPC
NRG Energy - Louisiana	Aug-05	Final Permit	675	SCPC
Southwest Springfield - Missouri	Dec-04	Final Permit	275	PC
Omaha Public Power - Nebraska	March-05	Final Permit	660	PC
Municipal Energy Hastings - Nebraska	March-04	Final Permit	220	PC
Xcel Energy - Colorodo	July-05	Final Permit	750	SCPC
Bull Mountain - Montana	July-03	Final Permit	780	PC
Intermountain Power Service - Utah	Oct-04	Final Permit	950	PC
NEVCO Energy - Utah	Oct-04	Final Permit	270	CFB
Springerville Generating Station Units 3 and 4 - Arizona	April-02	Final Permit	800	PC
TS Power Plant - Nevada	May-05	Final Permit	200	PC
Indeck-Elwood LLC - Illinois	Oct-03	Final Permit	660	two CFB
JEA Northside - Florida	May-99	Final Permit	595	CFB
MidAmerican Energy - Iowa	Jun-03	Final Permit	765	SCPC
Sante Cooper - South Carolina	Feb-04	Final Permit	1320	two CFB
Montana Dakota Utilities - North Dakota	Jun-05	Final Permit	220	PC
Newmont - Nevada	May-05	Final Permit	200	PC
Sand Sage - Kansas	Oct-02	Final Permit	660	PC
KCP&L - Missouri	Jan-06	Final Permit	930	PC

TABLE 4-2
COMPARISON OF CO AND VOCS EMISSIONS FROM RECENTLY PERMITTED PROJECTS

Project	Plant Size MW	Heat Input MMBtu/hr	Controlled CO lb/MMBtu	CO lb/MW-hr	Comments
Seminole Electric Unit 3 - Flroida	750	7,500	0.13 0.15	1.30 1.50	Coal Only, Combustion Controls 30-day Average All Fuels
Thoroughbred - Kentucky	1,500	14,886	0.1	0.99	Combustion Controls
Louisville Gas & Electric - Kentucky	750	6,942	0.1/0.5	0.93/4.6	CO 30-day/3-hour average, VOC 3-hr Average, Combustion Controls
River Hill Power - Pennsylvania	290	NA	0.2	NA	>70% Load, Combustion Controls
Prairie State-Illinois	1,500	14,900	0.12	1.19	Combustion Controls
Elm Road-Wisconsin	1,230	12,360	0.12	1.21	Combustion Controls
Longview-West Virginia	600	6,114	0.11	1.12	Combustion Controls
City Public Service-Texas	750	8,000	0.15	1.60	Combustion Controls
Public Service of Colorado	750	7,421	0.13	1.29	Combustion Controls
Public Service Corp Wausau - Wisconsin	500	5176	0.15	1.55	Combustion Controls
NRG Energy - Louisiana	675	6566	0.135	1.31	Combustion Controls
Southwest Springfield - Missouri	275	2725	0.16	1.59	Combustion Controls
Omaha Public Power - Nebraska	660	NA	0.16	NA	Combustion Controls
Municipal Energy Hastings - Nebraska	220	2210.5	0.15	1.51	Combustion Controls
Xcel Energy - Colorodo	750	7421	0.13	1.29	Combustion Controls
Bull Mountain - Montana	780	8026	0.15	1.54	Combustion Controls
Intermountain Power Service - Utah	950	9050	0.15	1.43	Combustion Controls
NEVCO Energy - Utah	270	2531.5	0.115	1.08	Combustion Controls
Springerville Generating Station Units 3 and 4 - Arizona	800	8400	0.15	1.58	VOC limit = 0.06 lb/ton coal combusted, Combustion Controls
TS Power Plant - Nevada	200	2030	0.15	1.52	Combustion Controls
Indeck-Elwood LLC - Illinois	660	5800	0.11	0.97	Combustion Controls
JEA Northside - Florida	595	5528	-	-	CO = 350 lb/hr, 24-hr block average, VOC = 14 lb/hr, Combustion Controls
MidAmerican Energy - Iowa	765	-	0.154	-	Combustion Controls
Sante Cooper - South Carolina	1320	11,100	0.16	1.35	units 2, 3 and 4
Montana Dakota Utilities - North Dakota	220	2,116	0.154	1.48	3-hr average
Newmont - Nevada	200	2,030	0.15	1.52	24-hr rolling
Sand Sage - Kansas	660	6,501	0.15	1.48	Combustion Controls
KCP&L - Missouri	930	7,800	0.16	1.34	Combustion Controls

5.0 AIR QUALITY IMPACT ANALYSIS METHODOLOGY

5.1 Significant Impact Analysis

A significant impact analysis was performed to determine the maximum air quality impacts of the proposed project's CO emission increase. The highest predicted 8-hour and 1-hour CO concentrations were compared to the EPA significant impact levels for CO. If the maximum air quality impacts exceed the significant impact levels, than a detailed cumulative source analysis needs to be performed to demonstrate compliance with the CO ambient air quality standards (AAQS).

5.1.1 AAQS Analysis

In general, when 5 years of meteorological data are used, the highest annual and the highest-second-highest (H2H) short-term concentrations are compared to the applicable CO AAQS. The H2H short-term concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with most air quality standards which permit a short-term average concentration to be exceeded once per year at each receptor.

For the AAQS analysis, the future emissions of the McIntosh Power Plant are to be modeled along with background CO emission facilities. The total air quality concentration is estimated by adding the maximum concentrations from all modeled sources to a non-modeled background concentration. The maximum total air quality concentrations are then compared to the AAQS.

5.1.2 Model Selection

The selection of an air quality model to predict air quality impacts for the proposed project was based on the ability of the model to simulate impacts in the area surrounding the proposed project. The American Meteorological Society and EPA Regulatory Model (AERMOD, Version 04300) was selected for this analysis. The AERMOD dispersion model is available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of the AERMOD model features is presented in Table 3-1.

On November 9, 2005, the EPA implemented AERMOD into its Guideline of Air Quality Models (Appendix W to 40 CFR Part 51) as the recommended model for regulatory modeling applications.

The FDEP is allowing the use of AERMOD for air permitting projects as a replacement for the Industrial Source Complex Short-Term Model (ISCST3) which will no longer be in effect as of December 2006.

The EPA and FDEP recommend that the AERMOD model be used to predict pollutant concentrations at receptors located within 50 km from a source. The AERMOD model calculates hourly concentrations based on hourly meteorological data. The AERMOD model is applicable for most applications since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for averaging times of annual and 24-, 8-, 3-, and 1-hours.

The AERMOD model was used to predict the maximum pollutant concentrations in nearby areas surrounding the McIntosh Power Plant. The EPA regulatory default options were used to predict all maximum impacts.

These options include:

- Final plume rise at all receptor locations,
- Stack-tip downwash,
- Buoyancy-induced dispersion,
- Default wind speed profile coefficients,
- Default vertical potential temperature gradients, and
- Calm wind processing.

5.1.3 Meteorological Data

Meteorological data used in the AERMOD model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) office located at the Tampa International Airport (TPA) and twice-daily upper air soundings collected at Ruskin for the years 2001 through 2005. The NWS office at TPA is located approximately 62 kilometers (km) west-southwest of the McIntosh Power Plant site and is the closest primary weather station to the study area considered to have meteorological data representative of the site. The meteorological data from this NWS station have been used for numerous air modeling

studies for the City of Lakeland. The meteorological data has been obtained and processed by FDEP into a format that is suitable for input to AERMOD using the meteorological preprocessor program AERMET.

5.1.4 Source Data

The Universal Transverse Mercator (UTM) coordinate location and stack parameters for Unit 3 that were used for the modeling analysis are presented in Table 5-2. The Unit 3 stack height is 250 feet. The project's maximum CO emission increase is 800.8 lb/hr.

5.1.5 Building Downwash Effects

The only significant structure in the vicinity of Unit 3's stack is the unit's boiler building, which is 209 feet tall. As the Unit 3 stack height is less than GEP, the potential for building downwash to occur was evaluated in the air modeling analysis for this stack. Direction-specific building parameters were calculated with the Building Profile Input Program (BPIP), Version 04274, which incorporates PRIME algorithms developed by the EPRI.

5.1.6 Receptor Locations

To predict maximum concentrations in the vicinity of the proposed project, a receptor grid was developed in UTM coordinate system, zone 17, North American Datum 1927 (NAD27), and included the following:

- 50-meter intervals along the fence line or restricted property boundary,
- 100-meter intervals beyond the fence line to 1.5 km from the site, and
- 150-meter intervals from 1.5 to 3 km from the site.

The fence line was determined from a plot plan of the site in AutoCad format. For the receptors, elevations and hill scale heights were obtained from 7.5-minute U.S. Geological Survey (USGS) Digital Elevation Model (DEM) data using the AERMOD terrain pre-processor program AERMAP, Version 04300.

5.2 Air Modeling Results

5.2.1 Significant Impact Analysis

A summary of the air modeling results is presented in Table 5-3. The maximum predicted 1- and 8-hour CO impacts are well below their respective significant impact levels. Therefore, additional

cumulative source modeling analyses are not required and the proposed project will be in compliance with the CO AAQS.

TABLE 5-1

MAJOR FEATURES OF THE AERMOD MODEL, VERSION 04300

AERMOD Model Features
• Plume dispersion/growth rates are determined by the profile of vertical and horizontal turbulence, vary with height, and use a continuous growth function.
• In a convective atmosphere, uses three separate algorithms to describe plume behavior as it comes in contact with the mixed layer lid; in a stable atmosphere uses a mechanically mixed layer near the surface.
• Polar or Cartesian coordinate systems for receptor locations can be included directly or by an external file reference.
• Urban model dispersion is input as a function of city size and population density; sources can also be modeled individually as urban sources.
• Stable plume rise: uses Briggs equations with winds and temperature gradients at stack top up to half-way up to plume rise. Convective plume rise: plume superimposed on random convective velocities.
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash.
• Has capability of simulating point, volume, area, and multi-sized area sources.
• Accounts for the effects of vertical variations in wind and turbulence (Brower *et al.*, 1998).
• Uses measured and computed boundary layer parameters and similarity relationships to develop vertical profiles of wind, temperature, and turbulence (Brower *et al.*, 1998).
• Concentration estimates for 1-hour to annual average times.
• Creates vertical profiles of wind, temperature, and turbulence using all available measurement levels.
• Terrain features are depicted by use of a controlling hill elevation and a receptor point elevation.
• Modeling domain surface characteristics are determined by selected direction and month/season values of surface roughness length, Albedo, and Bowen ratio.
• Contains a mechanical and convective mixed layer height, the latter based on the hourly accumulation of sensible heat flux.
• The method of Pasquill (1976) to account for buoyancy-induced dispersion.
• A default regulatory option to set various model options and parameters to EPA-recommended values.
• Contains procedures for calm-wind and missing data for the processing of short term averages.

Note: AERMOD = the American Meteorological Society and Environmental Protection Agency Regulatory Model.

Source: Paine *et al.*, 2004.

TABLE 5-2
CITY OF LAKELAND UNIT 3 STACK PARAMETERS

Source		UTM NAD27		Stack Parameters							
				Physical				Operating			
	Model	East	North	Height		Diameter		Temperature		Velocity	
Description	ID	(m)	(m)	(ft)	(m)	(ft)	(m)	(°F)	(K)	(fps)	(m/s)
Boiler Unit 3	UNIT 3	409364.79	3106270.99	250	76.2	18.0	5.49	125	324.8	91.9	28.02

TABLE 5-3
SIGNIFICANT IMPACT ANALYSIS RESULTS FOR UNIT 3

Averaging Period	Year	Maximum Predicted Impact (mg/m^3)	Receptor Location[a]		Period Ending (YYMMDDHH)	Significant Impact Level (mg/m^3)	Monitoring de Minimis Concentration (mg/m^3)
			East (m)	North (m)			
1-hour High 1st High	2001	145.4	410250	3106450	01121419	2000	--
	2002	155.7	410250	3106350	02102821		
	2003	149.7	410250	3106450	03052601		
	2004	151	410150	3106650	04053124		
	2005	165.2	410250	3106350	05070622		
8-hour High 1st High	2001	62.8	410650	3106350	01071216	500	575
	2002	52.8	408807	3105966	02061116		
	2003	49.3	408850	3105350	03110924		
	2004	57.6	410350	3106450	04011508		
	2005	56.9	410650	3106350	05061716		

Note:

[a] UTM coordinates in Zone 17

YY =Year, MM=Month, DD=Day, HH=Hour