BIG BEND STATION

AIR CONSTRUCTION PERMIT APPLICATION
NO_x POLLUTION CONTROL PROJECTS

RECEIVED
DEC 31 2003
BUREAU OF AIR REGULATION

Prepared for:

TECO
TAMPA ELECTRIC
Tampa, Florida

Prepared by:

ECT
Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 030813-0100

September 2003

INTRODUCTION

Tampa Electric Company (TEC) operates four solid fuel-fired steam boilers (Emission Units ID Nos. 001 through 004) at its Big Bend Station located at Big Bend Road, North Ruskin, Hillsborough County, Florida. In addition to the four solid fuel-fired boilers, the Big Bend Station emission sources include three combustion turbines (Emission Units ID Nos. 005 through 007) and various solid fuel material handing and storage activities (Emission Units ID Nos. 008 through 036). Operation of the Big Bend Station emission units is currently authorized by FINAL Title V Permit Revision No. 0570039-010-AV. FINAL Permit No. 0570039-010-AV was issued with an effective date of January 1, 2001, and expires on December 31, 2004.

TEC has entered into agreements with the U.S. Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP or the Department) concerning the installation of additional air pollution control systems at the Big Bend Station. These agreements (EPA Consent Decree and FDEP Consent Final Judgment) include requirements to install additional nitrogen oxides (NO_x) control systems on Big Bend Station Units 1 through 4. In response to these requirements, TEC has installed low-NO_x burners (LNB) on Units 1 through 4 and plans to install separate overfire air (SOFA) on Unit 4 to further reduce Big Bend Station NO_x emission rates.

The Big Bend Station additional NO_x control systems constitute pollution control projects and, therefore, are not subject to prevention of significant deterioration (PSD) permit review. In correspondence to TEC dated July 30, 2003, the Department requested the submittal of an air construction permit application for the Big Bend Station NO_x pollution control projects. This permit application, using the current version of DEP Form No. 62-210.900(1), A*pplication for Air Permit – Long Form*, is submitted in response the Department's request.

The Department's *Application for Air Permit – Long Form,* DEP Form No. 62-210.900(1), Effective June 16, 2003, follows this introduction. Descriptions of the LNB and SOFA NO_x pollution control projects are provided in Attachment A. A copy of the previously submitted Big Bend Station NO_x Control Plan is provided in Attachment B.

Department of Environmental Protection

Division of Air Resource Management

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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
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

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.

Identification of Facility

1. Facility Owner/Company Name: **Tampa Electric Company**	
2. Site Name: **Big Bend Station**	
3. Facility Identification Number: **0570039**	
4. Facility Location...: Street Address or Other Locator: **Big Bend Road** City: **North Ruskin** County: **Hillsborough** Zip Code: **33572**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Shelly Castro, Associate Engineer – Air Programs**
2. Application Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **6944 U.S. Highway 41 North** City: **Apollo Beach** State: **FL** Zip Code: **33572-9200**
3. Application Contact Telephone Numbers... Telephone: **(813) 641-5033** ext. Fax: **(813) 641-5081**
4. Application Contact Email Address: **sscastro@tecoenergy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	12-31-2003
2. Project Number(s):	0570039-014-AC
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

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

Project consists of the addition of low-NO_x burners (LNB) to emission units (E.U.) 001, 002, 003, and 004. Also, separate overfire air (SOFA) will be added to E.U. 004. These NO_x control systems are being being installed in accordance with agreements between Tampa Electric Company (TEC) and the U.S. Environmental Protection Agency (USEPA Consent Decree) and the Florida Department of Environmental Protection (FDEP Consent Final Final Judgment).

The Big Bend Station NO_x control systems constitute pollution control projects and therefore are exempt from Prevention of Significant Deterioration (PSD) New Source Review (NSR). As requested by the FDEP in correspondence to TEC dated July 30, 2003, this application constitutes TEC's request for an air construction for the Big Bend Station LNB and SOFA NO_x pollution control projects.

FACILITY INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	Unit No. 1 Steam Generator	AC1B	N/A
002	Unit No. 2 Steam Generator	ACIB	N/A
003	Unit No. 3 Steam Generator	AC1B	N/A
004	Unit No. 4 Steam Generator	AC1B	N/A

Application Processing Fee

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

FACILITY INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : **Karen Sheffield, General Manager - Big Bend Station**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **FL** Zip Code: **33601-0111**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(813) 228-4111** ext. Fax: **(813) 630-7121**
4.	Owner/Authorized Representative Email Address: **kasheffield@tecoenergy.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.* Karen A. Sheffield — Signature 12/23/03 — Date

Application Responsible Official Certification N/A

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

FACILITY INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address... Organization/Firm: **Environmental Consulting & Engineering, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **Florida** Zip Code: **32606**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 332-0444** ext. Fax: **(352) 332-6722**
4.	Professional Engineer Email Address: **tdavis@ectinc.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.* Thomas W. Davis 12/22/03 Signature (seal) Date

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **361.9** North (km) **3,075.0**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Karen Zwolak, Senior Environmental Consultant**
2. Facility Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **Big Bend Road** City: **North Ruskin** State: **FL** Zip Code: **33572**
3. Facility Contact Telephone Numbers: Telephone: **(813) 228-4111** ext. Fax: **(813) 630-7121**
4. Facility Contact Email Address: **kozwolak@tecoenergy.com**

Facility Primary Responsible Official N/A

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: **Facility applicable regulations previously submitted with the initial Title V Permit application; reference Big Bend Station Title V Operating Permit Application, Volume II, Attachment A.**			

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	**A** major	**N**
SO2	**A**	**Y**
CO	**A**	**N**
PM10	**A**	**Y**
PM	**A**	**Y**
PM/PM10	**A**	**Y**
SAM	**A**	**N**
VOC	**A**	**N**
PB	**B** facility-regulated not major or synthetic minor	**N**
H106 - HCl	**A**	**N**
H107 - HF	**A**	**N**
H133 - Nickel	**A**	**N**
HAPS	**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
SO2	**N**	**001, 002, 003, 004**		**71,810**	**ESCPSD**
PM/PM10	**N**	**001, 002, 003, 004**		**2,767**	**ESCPSD**

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

Additional SO_2 caps for Units 001, 002, and 003 are 6.5 lb/MMBtu (2-hr average), 31.5 ton/hr (3-hr average), and 25 ton/hr on a 24-hr midnight to midnight block average. In addition, Units 001 and 002 are limited to 16.5 ton/hr (24-hr midnight to midnight block average).

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:___ ☒ 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:___ ☒ 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:___

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: ☐ Attached, Document ID:___ **See Attachment A to this application.**
3. Rule Applicability Analysis: **Facility applicable regulations previously submitted with the initial Title V Permit application; reference Big Bend Station Title V Operating Permit Application, Volume II, Attachment A.** ☐ Attached, Document ID:___
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. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:___ ☒ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID:___ ☒ 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 N/A

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 N/A

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

Addition of NO_x controls does not change prior submittals with respect to facility plot plan, area map, process flow diagrams, exempt emission units, etc.

As requested by the Department, a copy of the TEC Big Bend Station NO_x Control Plan is included as Attachment B to this application.

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:
   Riley Stoker Corporation wet bottom fossil fuel steam boiler

3. Emissions Unit Identification Number: **001**

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	[redacted]	[redacted]	**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **Riley Stoker** Model Number:

10. Generator Nameplate Rating: **445 MW**

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Electrostatic Precipitator (ESP)** **Wet Limestone Injection Flue Gas Desulfurization (FGD)** **Low-NO_x Burners (LNB)**
2. Control Device or Method Code(s): **010, 042, 205**

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: **445 MW**		
3. Maximum Heat Input Rate: **4,037 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:		

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: **CS-001, CS-0W1**	2. Emission Point Type Code: **2**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

N/A

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

001 and 002

5. Discharge Type Code: **V** vertical opening w/ unobstructed opening	6. Stack Height: **490 feet**	7. Exit Diameter: **CS-001 24 feet** **CS-0W1 29 feet**
8. Exit Temperature: **CS-001 294 °F** **CS-0W1 127 °F**	9. Actual Volumetric Flow Rate: **CS-001 3,146,368 acfm** **CS-0W1 2,377,871 acfm**	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment:

Actual flow rates (Field 9) are for both Units 1 and 2 combined. Whenever either unit is fired with petroleum coke, its flue gases are routed from its ESP to the FGD system and then to stack CS-0W1. If petcoke is not fired, the flue gases may bypass the FGD system and stack CS-0W1, and be routed directly from the ESP to stack CS-001.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type): **Coal burned in Unit No. 1.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **183.5**	5. Maximum Annual Rate: **1,607,460**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.71**	8. Maximum % Ash: **10.7**	9. Million Btu per SCC Unit: **22**
10. Segment Comment: **Btu per SCC unit value (Field 9) based on a nominal coal heat content of 11,000 Btu/lb.**		

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type): **No. 2 fuel oil burned in Unit No. 1.**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **N/A**	5. Maximum Annual Rate: **N/A**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **139**
10. Segment Comment: **No. 2 fuel oil burned only during startup, shutdown, flame stabilization, and during the start of a mill.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type): **Petroleum coke burned in Unit No. 1.**			
2. Source Classification Code (SCC): **1-01-008-01**		3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **36.7**	5. Maximum Annual Rate: **321,492**		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6.0**	8. Maximum % Ash: **0.76**		9. Million Btu per SCC Unit: **28**
10. Segment Comment: **Maximum petcoke rates (Fields 4 and 5) based on 20% of coal rates.**			

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type): **Raw coal residual burned in Unit No. 1.**			
2. Source Classification Code (SCC): **1-01-002-01**		3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: *****	5. Maximum Annual Rate: **73,000**		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.43**	8. Maximum % Ash: **57.7**		9. Million Btu per SCC Unit: **6.1**
10. Segment Comment: ***Firing of raw coal residual is limited to 200 tons per day total for Units 1 through 4. Maximum annual coal residual rate (Field 5) is the total for Units 1 through 4.**			

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 5 of 5

1. Segment Description (Process/Fuel Type): **Beneficiated coal residual burned in Unit No. 1.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: *	5. Maximum Annual Rate: **182,500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.45**	8. Maximum % Ash: **35.4**	9. Million Btu per SCC Unit: **17.95**
10. Segment Comment: ***Firing of beneficaiated coal residual is limited to 500 tons per day total for Units 1 through 4. Maximum annual coal residual rate (Field 5 is the total for Units 1 through 4. Sulfur, ash, and heat contents are on a dry basis.**		

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
1 - NOX	**205 (Low NOx Burners)**		**NS**
2 - CO			**NS**
3 - PM	**010 (ESP)**	**042 (FGD)**	**EL**
4 - PM10	**010 (ESP)**	**042 (FGD)**	**NS**
5 - SO2	**042 (FGD)**		**EL**
6 - VOC			**NS**
7 - H106 (HCl)			**NS**
8 - H107 (HF)			**NS**
9 - H133 (Ni)			**NS**
10 - HAPS			**NS**

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:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour 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. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **TEC is not requesting any revisions to currently authorized emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section F1 regarding allowable emissions for Unit No. 1 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

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 ___ 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): **TEC is not requesting any revisions to currently authorized emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section F2 regarding allowable emissions for Unit No. 1 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

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 __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **TEC is not requesting any revisions to currently authorized visible emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section G regarding visible emissions for Unit No. 1 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

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:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Information regarding Unit No. 1 CEMS remains unchanged from the data previously provided to the Department.**	

Continuous Monitoring System: Continuous Monitor __ of __

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: ___ ☒ 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: **Attach A** ☐ 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	

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: ___ ☒ 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: ___ ☒ 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 N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID: ___	
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	

FACILITY INFORMATION

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

Additional Requirements Comment

Addition of NO_x controls does not change prior submittals with respect to process flow diagrams, fuel analyses, startup/shutdown procedures, operation and maintenance plan, etc.

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:
   Riley Stoker Corporation wet bottom fossil fuel steam boiler

3. Emissions Unit Identification Number: **002**

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			**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **Riley Stoker** Model Number:

10. Generator Nameplate Rating: **445 MW**

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Electrostatic Precipitator (ESP)** **Wet Limestone Injection Flue Gas Desulfurization (FGD)** **Low-NO_x Burners (LNB)**
2. Control Device or Method Code(s): **010, 042, 205**

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: **445 MW**	
3. Maximum Heat Input Rate: **4,037 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:	

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: **CS-001, CS-0W1**		2. Emission Point Type Code: **2**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **001 and 002**		
5. Discharge Type Code: **V**	6. Stack Height: **490 feet**	7. Exit Diameter: **CS-001 24 feet** **CS-0W1 29 feet**
8. Exit Temperature: **CS-001 294 °F** **CS-0W1 127 °F**	9. Actual Volumetric Flow Rate: **CS-001 3,146,368 acfm** **CS-0W1 2,377,871 acfm**	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Actual flow rates (Field 9) are for both Units 1 and 2 combined. Whenever either unit is fired with petroleum coke, its flue gases are routed from its ESP to the FGD system and then to stack CS-0W1. If petcoke is not fired, the flue gases may bypass the FGD system and stack CS-0W1, and be routed directly from the ESP to stack CS-001.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type): **Coal burned in Unit No. 2.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **181.6**	5. Maximum Annual Rate: **1,591,135**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.71**	8. Maximum % Ash: **10.7**	9. Million Btu per SCC Unit: **22**
10. Segment Comment: **Btu per SCC unit value (Field 9) based on a nominal coal heat content of 11,000 Btu/lb.**		

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type): **No. 2 fuel oil burned in Unit No. 2.**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **N/A**	5. Maximum Annual Rate: **N/A**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **139**
10. Segment Comment: **No. 2 fuel oil burned only during startup, shutdown, flame stabilization, and during the start of a mill.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type): **Petroleum coke burned in Unit No. 2.**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **36.3**	5. Maximum Annual Rate: **318,227**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6.0**	8. Maximum % Ash: **0.76**	9. Million Btu per SCC Unit: **28**
10. Segment Comment: **Maximum petcoke rates (Fields 4 and 5) based on 20% of coal rates.**		

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type): **Raw coal residual burned in Unit No. 2.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: *	5. Maximum Annual Rate: **73,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.43**	8. Maximum % Ash: **57.7**	9. Million Btu per SCC Unit: **6.1**
10. Segment Comment: ***Firing of raw coal residual is limited to 200 tons per day total for Units 1 through4. Maximum annual coal residual rate (Field 5) is the total for Units 1 through 4.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 5 of 5

1. Segment Description (Process/Fuel Type): **Beneficiated coal residual burned in Unit No. 2.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: *	5. Maximum Annual Rate: **182,500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.45**	8. Maximum % Ash: **35.4**	9. Million Btu per SCC Unit: **17.95**
10. Segment Comment: ***Firing of beneficaiated coal residual is limited to 500 tons per day total for Units 1 through 4. Maximum annual coal residual rate (Field 5 is the total for Units 1 through 4. Sulfur, ash, and heat contents are on a dry basis.**		

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
1 - NOX	**205 (Low NOx Burners)**		**NS**
2 - CO			**NS**
3 - PM	**010 (ESP)**	**001 (FGD)**	**EL**
4 - PM10	**010 (ESP)**	**001 (FGD)**	**NS**
5 - SO2	**001 (FGD)**		**EL**
6 - VOC			**NS**
7 - H106 (HCl)			**NS**
8 - H107 (HF)			**NS**
9 - H133 (Ni)			**NS**
10 - HAPS			**NS**

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:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour 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. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **TEC is not requesting any revisions to currently authorized emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section F1 regarding allowable emissions for Unit No. 2 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

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 ___ 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): **TEC is not requesting any revisions to currently authorized emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section F2 regarding allowable emissions for Unit No. 2 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

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 __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **TEC is not requesting any revisions to currently authorized visible emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section G regarding visible emissions for Unit No. 2 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

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:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Information regarding Unit No. 2 CEMS reamins unchanged from the data previously provided to the Department.**	

Continuous Monitoring System: Continuous Monitor __ of __

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION
Section [2] of [4]

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: ___ ☒ 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: **Attach A** ☐ 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	

FACILITY INFORMATION

EMISSIONS UNIT INFORMATION
Section [2] of [4]

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: ___ ☒ 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: ___ ☒ 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 **N/A**

1. Identification of Applicable Requirements ☐ Attached, Document ID: ___	
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	

FACILITY INFORMATION

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

FACILITY INFORMATION

EMISSIONS UNIT INFORMATION
Section [2] of [4]

Additional Requirements Comment

Addition of NO_x controls does not change prior submittals with respect to process flow diagrams, fuel analyses, startup/shutdown procedures, operation and maintenance plan, etc.

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:
Riley Stoker Corporation wet bottom fossil fuel steam boiler

3. Emissions Unit Identification Number: **003**

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

9. Package Unit:
Manufacturer: **Riley Stoker** Model Number:

10. Generator Nameplate Rating: **445 MW**

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Electrostatic Precipitator (ESP)** **Wet Limestone Injection Flue Gas Desulfurization (FGD)** **Low-NO_x Burners (LNB)**	
2. Control Device or Method Code(s): **010, 042, 205**	

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: **445 MW**	
3. Maximum Heat Input Rate: **4,115 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:	

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: **CS-002**		2. Emission Point Type Code: **2**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **003 and 004 (when operating in FGD integrated mode)**		
5. Discharge Type Code: **V**	6. Stack Height: **490 feet**	7. Exit Diameter: **24 feet**
8. Exit Temperature: **308 °F**	9. Actual Volumetric Flow Rate: **1,389,740 acfm**	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack data is for Unit 3, unscrubbed.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type): **Coal burned in Unit No. 3.**		
2. Source Classification Code (SCC): **1-01-002-01**		3. SCC Units: **Tons Burned**
4. Maximum Hourly Rate: **187.0**	5. Maximum Annual Rate: **1,638,518**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.71**	8. Maximum % Ash: **10.7**	9. Million Btu per SCC Unit: **22**
10. Segment Comment: **Btu per SCC unit value (Field 9) based on a nominal coal heat content of 11,000 Btu/lb.**		

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type): **No. 2 fuel oil burned in Unit No. 3.**		
2. Source Classification Code (SCC): **1-01-005-01**		3. SCC Units: **1,000 Gallons Burned**
4. Maximum Hourly Rate: **N/A**	5. Maximum Annual Rate: **N/A**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **139**
10. Segment Comment: **No. 2 fuel oil burned only during startup, shutdown, flame stabilization, and during the start of a mill.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type): **Petroleum coke burned in Unit No. 3.**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **37.4**	5. Maximum Annual Rate: **327,704**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6.0**	8. Maximum % Ash: **0.76**	9. Million Btu per SCC Unit: **28**
10. Segment Comment: **Maximum petcoke rates (Fields 4 and 5) based on 20% of coal rates.**		

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type): **Raw coal residual burned in Unit No. 3.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: *****	5. Maximum Annual Rate: **73,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.43**	8. Maximum % Ash: **57.7**	9. Million Btu per SCC Unit: **6.1**
10. Segment Comment: ***Firing of raw coal residual is limited to 200 tons per day total for Units 1 through 4. Maximum annual coal residual rate (Field 5) is the total for Units 1 through 4.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

<u>**Segment Description and Rate:**</u> Segment 5 of 5

1. Segment Description (Process/Fuel Type): **Beneficiated coal residual burned in Unit No. 3.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: *	5. Maximum Annual Rate: **182,500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.45**	8. Maximum % Ash: **35.4**	9. Million Btu per SCC Unit: **17.95**
10. Segment Comment: ***Firing of beneficaiated coal residual is limited to 500 tons per day total for Units 1 through 4. Maximum annual coal residual rate (Field 5 is the total for Units 1 through 4. Sulfur, ash, and heat contents are on a dry basis.**		

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
1 - NOX	**205 (Low NOx Burners)**		**NS**
2 - CO			**NS**
3 - PM	**010 (ESP)**	**042 (FGD)**	**EL**
4 - PM10	**010 (ESP)**	**042 (FGD)**	**NS**
5 - SO2	**042 (FGD)**		**EL**
6 - VOC			**NS**
7 - H106 (HCl)			**NS**
8 - H107 (HF)			**NS**
9 - H133 (Ni)			**NS**
10 - HAPS			**NS**

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:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour 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. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **TEC is not requesting any revisions to currently authorized emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section F1 regarding allowable emissions for Unit No. 3 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

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 ___ 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): **TEC is not requesting any revisions to currently authorized emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section F2 regarding allowable emissions for Unit No. 3 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

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 __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **TEC is not requesting any revisions to currently authorized visible emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section G regarding visible emissions for Unit No. 3 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

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:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Information regarding Unit No. 3 CEMS reamins unchanged from the data previously provided to the Department.**	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: ___ ☒ 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: **Attach A** ☐ 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

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: ___ ☒ 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: ___ ☒ 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 N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID: ___	
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

Additional Requirements Comment

Addition of NO_x controls does not change prior submittals with respect to process flow diagrams, fuel analyses, startup/shutdown procedures, operation and maintenance plan, etc.

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:
   Foster Wheeler dry bottom, tangentially fired fossil fuel steam boiler

3. Emissions Unit Identification Number: **004**

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			**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **Foster Wheeler** Model Number:

10. Generator Nameplate Rating: **486 MW**

11. Emissions Unit Comment:

<u>Emissions Unit Control Equipment</u>

1. Control Equipment/Method(s) Description: **Electrostatic Precipitator (ESP)** **Wet Limestone Injection Flue Gas Desulfurization (FGD)** **Low-NO_x Burners (LNB)** **Separate Overfire Air (SOFA)**	
2. Control Device or Method Code(s): **010, 042, 205, 024**	

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: **486 MW**	
3. Maximum Heat Input Rate: **4,330 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:	

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: CS-003	2. Emission Point Type Code: **2**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **003 and 004 (when operating in FGD integrated mode)**	

5. Discharge Type Code: **V**	6. Stack Height: **490 feet**	7. Exit Diameter: **24 feet**
8. Exit Temperature: **127 °F**	9. Actual Volumetric Flow Rate: **2,125,325 acfm**	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack data is for Unit 4, scrubbed.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type): **Coal burned in Unit No. 4.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **196.8**	5. Maximum Annual Rate: **1,724,127**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.71**	8. Maximum % Ash: **10.7**	9. Million Btu per SCC Unit: **22**
10. Segment Comment: **Btu per SCC unit value (Field 9) based on a nominal coal heat content of 11,000 Btu/lb.**		

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type): **No. 2 fuel oil burned in Unit No. 4.**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **N/A**	5. Maximum Annual Rate: **N/A**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **139**
10. Segment Comment: **No. 2 fuel oil burned only during startup, shutdown, flame stabilization, and during the start of a mill.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type): **Petroleum coke burned in Unit No. 4.**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **39.4**	5. Maximum Annual Rate: **344,825**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6.0**	8. Maximum % Ash: **0.76**	9. Million Btu per SCC Unit: **28**
10. Segment Comment: **Maximum petcoke rates (Fields 4 and 5) based on 20% of coal rates.**		

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type): **Raw coal residual burned in Unit No. 4.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: *	5. Maximum Annual Rate: **73,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.43**	8. Maximum % Ash: **57.7**	9. Million Btu per SCC Unit: **6.1**
10. Segment Comment: ***Firing of raw coal residual is limited to 200 tons per day total for Units 1 through 4. Maximum annual coal residual rate (Field 5) is the total for Units 1 through 4.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

<u>Segment Description and Rate:</u> Segment 5 of 5

1. Segment Description (Process/Fuel Type): **Beneficiated coal residual burned in Unit No. 4.**		
2. Source Classification Code (SCC): **1-01-002-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: *	5. Maximum Annual Rate: **182,500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.45**	8. Maximum % Ash: **35.4**	9. Million Btu per SCC Unit: **17.95**
10. Segment Comment: ***Firing of beneficaiated coal residual is limited to 500 tons per day total for Units 1 through 4. Maximum annual coal residual rate (Field 5 is the total for Units 1 through 4. Sulfur, ash, and heat contents are on a dry basis.**		

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
1 - NOX	**205 (Low NO_x Burners)**	**024 (Modified Furnace or Burner Design)**	**EL**
2 - CO			**EL**
3 - PM	**010 (ESP)**	**042 (FGD)**	**EL**
4 - PM10	**010 (ESP)**	**042 (FGD)**	**NS**
5 - SO2	**042 (FGD)**		**EL**
6 - VOC			**NS**
7 - H106 (HCl)			**NS**
8 - H107 (HF)			**NS**
9- HAPS			**NS**

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:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour 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. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **TEC is not requesting any revisions to currently authorized emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section F1 regarding allowable emissions for Unit No. 4 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

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 ___ 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): **TEC is not requesting any revisions to currently authorized emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section F2 regarding allowable emissions for Unit No. 4 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

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 ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **TEC is not requesting any revisions to currently authorized visible emission limits as specified in FINAL Title V Permit No. 0570039-010-AV. The information requested by Section G regarding visible emissions for Unit No. 4 can be found in FINAL Title V Permit No. 0570039-010-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

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:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Information regarding Unit No. 4 CEMS reamins unchanged from the data previously provided to the Department.**	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: ___ ☒ 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: **Attach A** ☐ 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

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: ___ ☒ 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: ___ ☒ 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 N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID: ___	
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	

Additional Requirements Comment

Addition of NO_x controls does not change prior submittals with respect to process flow diagrams, fuel analyses, startup/shutdown procedures, operation and maintenance plan, etc.

ATTACHMENT A

NO_x POLLUTION CONTROL PROJECTS EQUIPMENT DESCRIPTION

UNITS 1 – 3

LOW-NO_x BURNERS (LNB)

Big Bend Station Units 1 through 3 – NO_x Pollution Control Projects

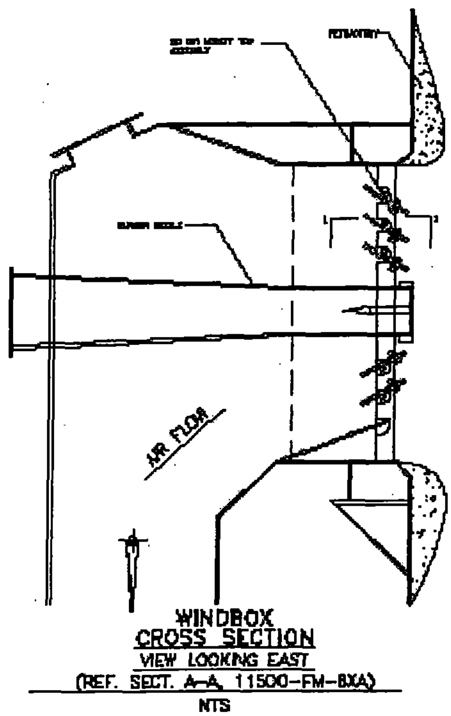
Background –

The Consent Decree entered into between the parties as defined within section IV - Emissions Reductions and Controls–Gannon and Big Bend, subsection B. Big Bend, Paragraph 35 - Early Reductions of NO_x from Big Bend Units 1 through 3, requires that Tampa Electric Company (TEC) attempt to reduce NO_x emissions from Big Bend Units 1 through 3, as referenced against 1998 emission levels. In particular, Big Bend Units 1 and 2 have a target emission reduction of 30 percent, while Big Bend Unit 3 has a target reduction of 15 percent, wherein the baseline emissions rates were 0.86 lb/MMBtu and 0.57 lb/MMBtu for Big Bend Units 1 and 2 and Unit 3, respectively. Furthermore, TEC has agreed to expend up to $3 million project dollars to obtain these objectives. The Consent Decree specifically identified that the methodology to be employed for the NO_x reduction strategy should be based upon "...commercially available combustion optimization technologies, techniques, systems, or equipment, or combinations thereof". Hence, post combustion or pre-conditioning technology assessment was not required or allowed as part of the aforementioned section of the Consent Decree.

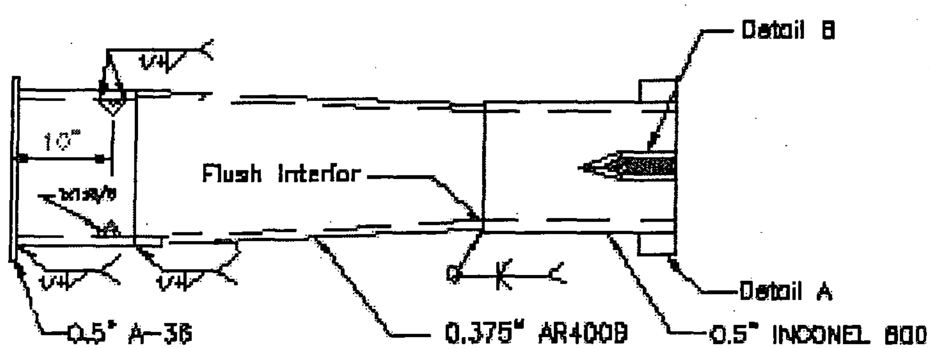
Big Bend Units 1 through 3 are Riley Stoker Turbo®Wet Bottom design, whereby TEC owns and operates the only such units. The application of commercially available technologies for these units is not possible since manufacturers have not invested research and development funds to produce components, which could be applied. Therefore, TEC has primarily relied upon the application of commercially available techniques used by other furnace manufacturers and designs thereof as the basis for compliance with the Consent Decree.

Scope of Work -

Big Bend Units 1 and 2 – TEC contracted with a computation fluid dynamic (CFD) modeling firm who has successfully modeled other facility's coal fired steam generators to reduce NO_x emissions. The modeling effort included local air staging and over-fired air (OFA) configurations to achieve the gaseous emission objective. The results of the modeling indicated that an advanced coal nozzle design in conjunction with local air staging should reduce NO_x emissions to the desired levels. The OFA modeling results proved to be too aggressive for this furnace design. The model predicted that a drop in temperature at the slag tap location would be approximately 600 degrees F, whereby the furnace would be unable to operate. Accordingly, the low NO_x burner (LNB) work for these units included the computer modeling, design, fabrication, installation and optimization of new coal nozzles suitable for low NO_x operation. Other work included modification and redesign of windbox internal components to allow for proper distribution of secondary air for local staging of combustion air. A sketch of the coal compartment is provided.



Typical Windbox Configuration



Typical Coal Nozzle

Big Bend Unit 3 – TEC in conjunction with the CFD modeling performed on Big Bend Units 1 and 2 commissioned burner modifications and OFA investigations of Big Bend 3. Not unlike Big Bend Units 1 and 2, the OFA model produced unacceptable low temperatures at the slag tap, which would prevent operation of the unit. Similar reductions in NO_x were predicted by the use of an advanced coal nozzle design and local air staging. The Big Bend Unit 3 is slightly different in design than Big Bend Units 1 and 2; however the overall concepts used for the nozzle and windbox modifications are identical. The only significant difference between Big Bend Units 1 and 2 nozzles versus Big Bend Unit 3 is that the nozzle cross section for Big Bend Units 1 and 2 is smaller than that for Big Bend Unit 3, which is in accordance with the original design provided by Riley Stoker.

UNIT 4

LOW-NO_x BURNERS (LNB)

SEPARATE OVERFIRE AIR (SOFA)

Big Bend Station Unit 4 – NO_x Pollution Control Projects

Background

Tampa Electric (TEC) and the U.S. Environmental Protection Agency, (EPA) entered into certain agreements to reduce NO_x emissions from the Big Bend coal generated facility as stipulated within the Consent Decree whose effective date was October 4, 2000. One of those stipulations as specified within section VII, paragraphs 50 and 52.C requires TEC to expend funds to ".... (i) demonstrate innovative NO_x control technologies on any of its units or boilers at Gannon or Big Bend not shutdown or on reserve/standby; and/or (ii) reduce the NO_x emission rate for any Big Bend coal-combusting unit below the lowest rate otherwise applicable to it under this Consent Decree." TEC has already petitioned and received approval from the EPA for an innovative NO_x control technology for Big Bend Unit 2, which involves a neural network based intelligent sootblowing system. This innovative NO_x plan describes work for Big Bend Unit 4 which will reduce its NO_x emissions using commercially available techniques years in advance of future requirements. This will provide substantial reductions of NO_x emissions to the environment.

Introduction

Big Bend Unit 4 is a fossil fired steam boiler electric generating system rated at 4,330 MMBtu/hour. It has a Combustion Engineering (CE) "dry" bottom tangentially fired (T-fired) pulverized coal boiler designed for 486 MW generation. The unit began operation in 1985. Big Bend Unit 4 is equipped with five elevations of coal nozzles configured in such a manner that it creates a helical fireball, whereby the coal burners are aimed at the tangential intersection with the fireball. Between each coal nozzle assembly, there is an auxiliary air compartment, which provides the vast majority of combustion air. Big Bend Unit 4 was also originally fitted with two levels of close coupled over-fired air, (CCOFA) and a refuse burner, which are located above the upper most coal nozzle.

The most widely accepted and conventional methods for in-furnace NO_x control involve staging of the combustion process to reduce NO_x emissions. There are several trade names associated with these techniques, depending upon the manufacturer. However, they basically all include the same general principles. Level I primarily consists of replacement of the coal and auxiliary air nozzles designed specifically for NO_x reduction, and the inclusion of CCOFA. Level II systems use Level I techniques, but also include single or multiple levels of separated overfired air (SOFA) ports. The latter levels of NO_x control can involve clustering of coal nozzles, and/or the addition of more SOFA ports. In all cases, the emphasis is to provide a physical separation of varying levels of combustion air from the main combustion zone. Theoretically, increasing the separation and quantities of air diverted from the combustion zone will reduce the level of NO_x generated. There is, however, negative consequences associated with the implementation of these techniques which must be managed as part of the control scheme. These include but are not limited to, water wall wastage, increased unburned carbon, slag formation patterns, and steam temperature impacts.

Scope of Work

Low NO_x Burners with CCOFA - Big Bend Unit 4 was originally fitted with a two level CCOFA system and conventional coal and air nozzles. This arrangement allowed for a NO_x emission rate of 0.45 lb/MMBtu. The upgraded system included Foster Wheeler's (FW) low NO_x designed coal and air nozzles to be used in conjunction with modifications to be made to the CCOFA, which included the addition of one CCOFA port. The work also involved modifications to the lowest air compartment to provide for isolated tile control, which is independent of the main tilt drive system. It is projected that an emission rate of 0.38 lb/MMBtu can be achieved using this system which provides for a 15.5 percent reduction as compared to the 0.45 lb/MMBtu rate.

The specific material scope of supply provided by Foster Wheeler included:

- Twenty FWEC Double Shroud, adjustable coal nozzles for CE T-fired unit complete with nozzle tip pins, seal plates and compartment restrictor plates.
- Windbox tilt kit. Includes internal levers, pins and adjusting links.
- Thirty-two air nozzle tips complete with nozzle tip pins, seal plates and restrictor plates.

This project was completed in the summer of 2001 for a cost of $805,000 and was identified in prior reports to EPA as a candidate for inclusion in TEC's NO_x compliance strategy.

Separated Over Fired Air (SOFA) – As noted above, TEC has already installed a Level I NO_x control system as part of its overall NO_x control strategy in response to the Consent Decree requirements. The next logical step for Big Bend Unit 4 is the installation of a two register SOFA system to allow for deeper staging of the combustion process and further reduction of NO_x emissions. The work involved penetrations into the existing secondary air (SA) duct assembly, the installation of four new duct take-off sections to divert approximately 20 percent of the combustion air to the SOFA system. In addition, pressure part modifications were necessary to allow for the new air nozzles to be installed above the existing windbox. New windbox assemblies were attached to the new boiler tubes along with two air nozzles per corner. The work also involved new and upgraded drive assemblies to modulate air dampers, which regulate the quantity of air delivered to each compartment and additional restrictor plates to help regulate flow. Due to the fact that the Level I system was supplied by Foster Wheeler, TEC has elected to use Foster Wheeler for the Level II upgraded system. TEC expects to achieve an additional 15 percent reduction from the Level I system, or a combined reduction of NO_x emissions from 0.45 lb/MMBtu of approximately 33 percent.

TEC's project schedule was to issue a contract to Foster Wheeler by no later than April 4, 2003, to support the planned outage whose start date was November 1, 2003. This outage concluded December 9, 2003. Due to the specific timing of this project and other work that is being conducted, final tune-up and optimization of the unit is scheduled for January 2004, which should be completed within 3-4 weeks.

The cost of the project is forecasted to be approximately $3,230,000, which includes all material and labor costs associated with providing a fully functional and optimized system. It is further expected that approximately $3,000,000 of this cost will be expended in 2003, and the balance in January 2004 for optimization and any punch list items that may require attention.

Benefits and Conclusion

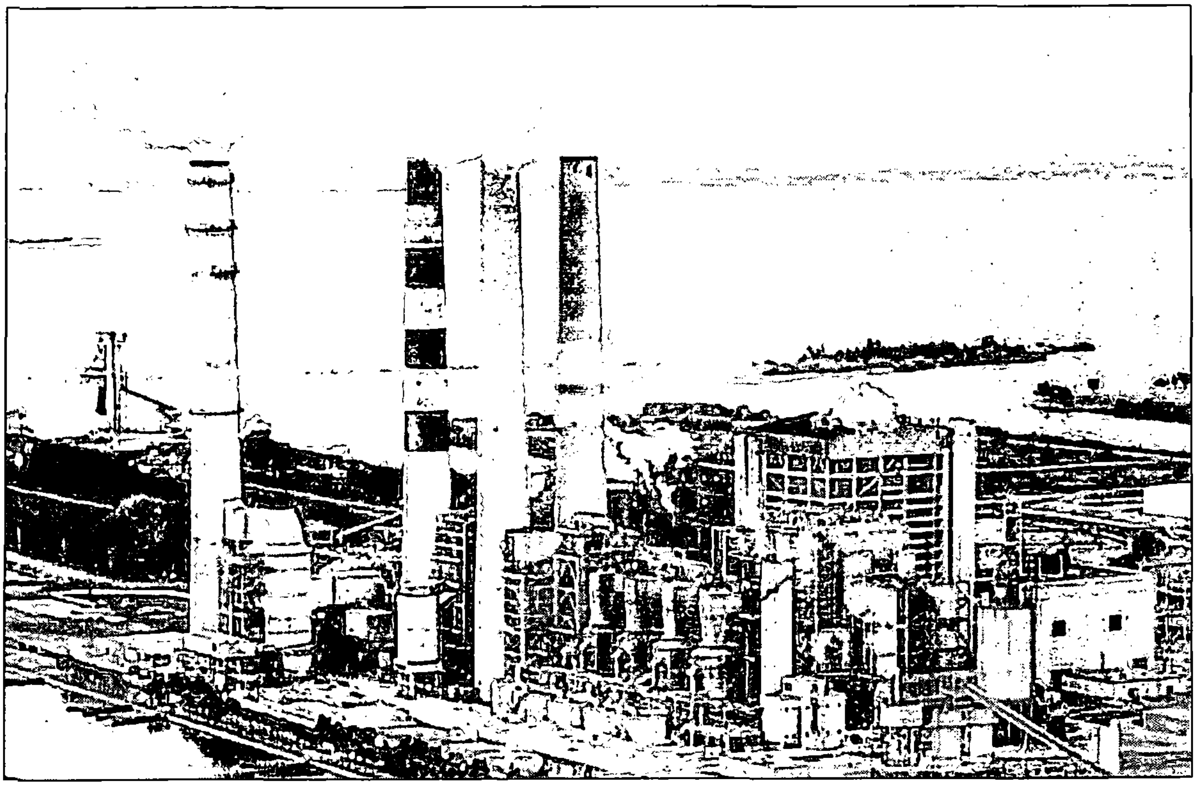
The foregoing projects comply with the stipulations of paragraph 52.C of the Consent Decree which allows TEC to "... reduce the NO_x emission rate for Big Bend coal combusting unit below the lowest rate otherwise applicable to it under this Consent Decree." This is supported by the amendment to the Consent Decree, which allows for the use of either Big Bend Unit 3 or 4 for an early NO_x reduction unit. TEC has elected to use Big Bend Unit 3 as the early NO_x compliance unit, thus allowing for Big Bend Unit 4 to qualify. Additionally, Big Bend Unit 4 is not required to achieve NO_x reduction below its currently permitted level of 0.45 lb/MMBtu until June 1, 2007. The combined impact of these two projects will allow for 33 percent of the required NO_x reductions to occur well in advance of the 2007 date.

In 1998 Big Bend Unit 4 emitted approximately 6,826 tons of NO_x. The NO_x control systems discussed above will provide for a reduction in annual NO_x emissions of approximately 2,252 tons. Additionally, due to the timing of the projects the total emission reduction will be approximately 7,900 tons of NO_x, which otherwise would be released to the environment.

ATTACHMENT B

BIG BEND STATION
NO_x CONTROL PLAN

Tampa Electric Company



Big Bend Station Units 1 through 4
Early NOx Reduction Plan Update Report

TAMPA ELECTRIC

December 2001

1.0 Executive Summary

Pursuant to the requirements set forth in the Consent Decree and subsequent amendment dated September 10, 2001 between the United States Environmental Protection Agency (USEPA) and Tampa Electric Company (TEC), TEC has completed several projects in 2001 with the intent of reducing NO_x emissions from Big Bend Station. Specifically, the Consent Decree requires that TEC perform projects that focus on the reduction of NO_x emissions from Big Bend Station while spending up to $3 million. The early NO_x emissions reduction projects were originally required to be implemented on or before December 31, 2002. However, the amendment to the Consent Decree allows for any modification of Units 3 or 4 to be completed by December 31, 2003. TEC must also submit an Early NO_x Emissions Reduction Plan (Plan) to the EPA on or before December 31, 2001 which describes the technologies which will be used in an effort to achieve the desired reductions. This Plan was submitted to EPA on February 23, 2001 and approved by USEPA on March 8, 2001. The Plan specified that TEC would modify the burners serving Big Bend Unit 1, install a neural network on Big Bend Unit 2, evaluate the impacts of each technology on NO_x emissions, and report the results to USEPA by January 1, 2002. In addition, TEC is required to provide details pertaining to future projects that will be undertaken to reduce NO_x emissions from Big Bend Station as required by paragraph 35 of the Consent Decree and the above mentioned amendment.

Although the Consent Decree limits early NO_x reduction projects to Big Bend Units 1 through 3, TEC believed that Unit 4 had the potential for achieving significant NO_x reductions through the installation of low NO_x burners. This was included as part of the Plan, and the Company elected to implement this project in the spring of 2001. Further, TEC has included this project in the second and third 2001 quarterly Consent Decree reports.

TEC has continually evaluated the effects of the above mentioned NO_x reduction projects on Big Bend Units 1, 2 and 4, and through October 31, 2001, NO_x emissions from Big Bend Units 1 and 4 have been reduced. The Unit 2 neural network system, although installed, requires further tuning and optimization before measurable results can be achieved. TEC will continue with this effort during 2002.

Based on the success of the low NO_x burner projects and the information gained from the tuning of the equipment, TEC plans to implement low NO_x burner modifications on Big Bend Units 2 and 3 as well as install coal and air flow monitoring and control equipment on Unit 1 during 2002. This will allow the Company to approach the NO_x reduction goals of 30%, 30% and 15% below 1998 levels for Big Bend Units 1, 2 and 3, respectively while also achieving NO_x reductions from Big Bend Unit 4.

2.0 Introduction

Paragraph 35 of the EPA Consent Decree requires TEC to attempt to reduce NO_x emissions from Big Bend Units 1 through 3, as referenced against 1998 emission levels. Specifically, Big Bend Units 1 and 2 have a target emission reduction of 30%, while Big Bend Unit 3 has a target emission reduction of 15%. The baseline emission rates are understood by TEC and EPA to be as shown in Table 1 below:

Table 1 - Baseline and Goal Summary

Unit	1998 NO_x Emission Rate [lb/MMBtu]	Early NO_x Reduction Program Emission Rate Goal [lb/MMBtu]
Big Bend Unit 1	0.86	0.60
Big Bend Unit 2	0.86	0.60
Big Bend Unit 3	0.57	0.48

Furthermore, TEC is required to expend up to $3 million on Big Bend Units 1 through 3 in pursuit of this objective, although Big Bend Unit 4 may also be included as a viable candidate for achieving early NO_x reductions as indicated in the amendment dated September 10, 2001. The Consent Decree specifically identifies that the methodology to be employed for the NO_x reduction strategy should be based upon "...commercially available combustion optimization technologies, techniques, systems, or equipment, or combinations thereof."

2.1 Big Bend Station Generating Unit Descriptions

Big Bend Units 1 through 3 each utilize Riley Stoker Turbo® wet bottom design boilers, and TEC owns and operates the only known boilers of this type in existence. Big Bend Unit 1 began commercial operation in October 1970, Big Bend Unit 2 began commercial operation in April 1973, and Big Bend Unit 3 began commercial operation in May 1976. These boilers are different from wall-fired boilers and other firing configurations in that the burners are aligned at a fixed downward angle to maintain high temperatures in the lower furnace to allow the slag to exist in a molten form. This is critical because the slag must be in liquid state in order to flow into a slag tank for collection. Any diversion of heat from this zone could cause the slag to freeze, making the operation of the boiler impossible. The diagram found in Appendix A illustrates the unique characteristics of the Riley Stoker Turbo® wet bottom boiler.

Many of the commercially available NO_x control technologies that are available for other types of boilers are not suited for application on the Riley Stoker Turbo® wet bottom boiler design due to the slag flow issues noted above. Additionally, application of specific commercially available technologies for these units is not possible since manufacturers have not invested research and development funds to produce components which could be adapted to these units and applied for NO_x reduction. Therefore, as the basis for lowering NO_x emissions from Big Bend Units 1 through 3, TEC must rely on NO_x reduction techniques that would not reduce the lower furnace temperature.

Big Bend Unit 4 is Combustion Engineering tangentially fired dry bottom boiler that began commercial operation in February 1985. Unit 4 has a lower NO_x emission rate than Units 1, 2 and/or 3. The Acid Rain limit for a boiler of this type is 0.45 lb NO_x/MMBtu, and Unit 4 typically operates in this range due to differences in design as compared to Big Bend Units 1, 2 and 3. Table 2 provides a summary of the operational characteristics found in Title V permit number 0570039-002-AV of each coal fired generating unit at Big Bend Station.

Table 2 - Description of Big Bend Units 1 through 4

	Firing Configuration	**Full Load Average Heat Input [MMBtu/hr]**	**Full Load Average Gross Generation [MW]**
Unit 1	Turbo	4,037	445
Unit 2	Turbo	3,996	445
Unit 3	Turbo	4,115	445
Unit 4	Tangential	4,330	486

4.0 Alternatives Considered

Pursuant to the requirements and intent of the Consent Decree, TEC evaluated several commercially available NO_x control techniques, although actual industry experience with these technologies on Riley Turbo® wet bottom boilers is non-existent. Most of the technologies evaluated have been implemented on wall- and tangentially-fired units with varying degrees of success. Although the Consent Decree specifies only that combustion optimization techniques should be evaluated, TEC also considered the feasibility of post-combustion techniques, which are considered to be commercially available. These post-combustion NO_x control techniques included Selective Catalytic Reduction (SCR) and Selective Non Catalytic Reduction (SNCR). Based on the review of NO_x control techniques, it was determined that the cost of post combustion NO_x controls would far exceed the cost limitation found in paragraph 35 of the Consent Decree. Therefore, TEC elected to pursue only combustion optimization techniques as viable alternatives for the purpose of satisfying paragraph 35 of the Consent Decree.

TEC's investigations included research of public domain literature, interviews with operators of similar technologies, consultation with various independent consulting firms, and presentations/proposals from various manufacturers and/or suppliers of NO_x reduction equipment and systems. Furthermore, in an effort to effectively comply with the requirements of the Consent Decree, TEC established a team to implement the various technologies described herein, and also monitored the industry for emerging NO_x reduction technologies, which may be applicable to Big Bend Units 1 through 4.

In conducting the evaluation of potential NO_x reduction strategies, the following criteria were considered:

Project Cost –

Evaluated against the early NO_x reduction allocated project cost of up to $3 million expenditure specified by the Consent Decree. The cost is primarily based upon the capital expenditure component for implementation.

Potential NO_x Reduction -

The level of expected NO_x reduction using any particular technology is gauged against the target NO_x reduction levels specified in the Consent Decree. It should be recognized that in many instances the level of NO_x reduction predicted is proportional to other evaluation criteria. Accordingly, the ranking provided is relative to nominal levels of implementation for each technology.

Operating Risk –

This component involves the degree to which the subject technology can adversely impact the normal operation of the unit. Some of the significant areas of concern included: increased safety hazards, boiler slagging/fouling potential, adequate lower furnace temperatures to enable proper slag flow for Units 1 through 3, superheat and reheat steam temperatures, impact on byproduct production and quality, waterwall wastage, impacts on flue gas desulfurization system performance, and impacts on electrostatic precipitator performance.

Performance Risk –

It is generally recognized in the industry that many of the commercially available technologies used to control NO_x inherently create degradation in unit performance, and hence decrease the operating efficiency, capacity or availability of the unit. Some of the typical concerns for these technologies include: increased levels of unburned carbon, which can also adversely impact the marketability of flyash and commercial grade gypsum, increased generation of CO, non-attainment of superheat and reheat steam temperatures, fouling of heat transfer equipment, and accelerated corrosion of equipment.

Environmental Risk –

Whereas the ultimate objective of the program is to reduce the levels of NO_x released to the environment, the selected technology should also create no additional harm, or pose unwarranted risk to do so, relative to other potential emissions. Post combustion technologies such as SCR and SNCR use reagents to drive chemical reactions or react with substrates in an attempt to reduce NO_x emissions. These reagents usually require large bulk storage tanks and have some level of slip, such as ammonia, associated with their usage. Therefore, other air quality emission levels become a concern, as does the disposal of unmarketable combustion byproducts. In addition, spent catalyst is a concern because some spent catalysts are considered hazardous wastes.

Table 3 summarizes the efforts of Tampa Electric's investigations of potential NO_x reduction technologies that could be applied to Big Bend Units 1 through 4, along with relative rankings for selected variables.

Table 3 – Technology Summary

Technology	Cost	Reduction	Operating Risk	Performance Risk	Environmental Risk
Overfired air systems	High	Med	High	High	Low
SCR	High	High	Med	Med	Med
SNCR	High	High	Med	Med	Med
Burners & Air Staging	Med	Med	Low	Med/Low	Low
Fuel/Air Balancing	Med	Med/Low	Low	Low	Low
Reburn	High	Med	High	Med/Low	Low
Neural Networks	Med	Med/Low	Low	Low	Low
Fuel Switch	High	Med/Low	High/Med	Med/Low	Low
Water Tempering	Low	Low	High	High	Low

4.1 Technology Descriptions

Below is a description of each technology evaluated in support of the Early NO_x Reduction Program. The technologies selected for implementation are presented first, followed by the technologies eliminated from consideration. The technologies eliminated from consideration were done so based on potential negative operating impacts and cost. It is worth noting that a technology eliminated from consideration for this program may be reconsidered as an innovative NO_x reduction technology or as an add on NO_x control technology for the purposes of satisfying paragraphs 52.C(3), 34, or 37 of the Consent Decree.

4.1.1 Technologies Selected for Implementation

Neural Networks - The application of a neural network can be a cost-effective method of reducing NO_x emissions from a utility boiler. This technology monitors numerous parameters associated with the combustion process and recommends or automatically adjusts specific parameters to satisfy a NO_x reduction objective. Ideally, the neural network 'learns' over time which conditions produce the lowest NO_x emissions and adjusts the combustion process accordingly. This technology can potentially reduce NO_x emissions while having minimal adverse impacts on operations. This technology was selected for and applied to Unit 2. TEC purchased the neural network from Pegasus and began installation in January 2001. TEC expects to expend approximately $885,000 on this project.

Burners and Air Staging - Modifying burners and staging localized combustion air can be a cost-effective method of achieving NO_x reductions. This technology utilizes a two-fold approach: 1) reduction of peak flame temperatures which lowers thermal NO_x generation; and 2) limiting excess O_2 during the initial stages of the combustion process which reduces fuel NO_x production. Low NO_x burner modifications were selected for and applied to Big Bend Units 1 and 4. On Big Bend Unit 1 TEC had modeling performed by an expert consultant and purchased the new burners from a local fabricator based on the results of the modeling. The Big Bend Unit 1 burners were installed in April 2001 for a project cost of approximately $626,000 through quarter III, 2001. The burner modifications for Big Bend Units 2 and 3 will be installed in 2002, and will be based on Computational Fluid Dynamic (CFD) modeling similar to that performed on Unit 1. The burner modifications on Big Bend Unit 4 were purchased and installed in May 2001. TEC has spent approximately $805,000 on these modifications.

Coal and Air Balancing – Obtaining and maintaining balance between the coal nozzles is necessary to help minimize NO_x emissions. Aside from establishing uniform coal flow between the nozzles, control of the localized stoichiometric ratios during combustion is essential to lower NO_x production. This project provides real-time monitoring of coal and airflow to assist operators in optimizing the combustion process for NO_x control. In addition, other equipment will be installed to balance the coal flow between the coal nozzles. The project is expected to cost approximately $509,000 and will be installed on Big Bend Unit 1 during 2002.

4.1.2 Technologies Eliminated from Consideration

Separated Overfire Air Systems - Separated overfire air technology diverts some of the of combustion air from the burners to air ports above the combustion zone, reducing the oxygen availability at the burners. The reduction in oxygen results in a reduction in NO_x formation. The application of this technology to Big Bend Units 1, 2 and/or 3 would be risky due to the fact that it could change the temperature profile of the furnace floor. As discussed in section 3.0, this could have large negative operational and safety impacts by freezing the slag in the lower furnace, which would cause a unit shutdown due to the inability to remove and collect the combustion byproduct.

Selective Catalytic Reduction (SCR) - Selective Catalytic Reduction removes NO_x from the flue gas stream by reacting ammonia and NO_x in the presence of a catalyst to form molecular nitrogen and water vapor. Although this method of NO_x control can be extremely effective, the cost of installing and operating this technology is much greater than the $3 million project dollar limit found in the Consent Decree. TEC is required to either repower, shutdown, or add NO_x controls to Big Bend Units 1 through 4 beginning in 2007. This technology may be reconsidered as an add on control technology if Big Bend Units 1 through 4 remain coal fired.

Selective Non Catalytic Reduction (SNCR) - Selective Non Catalytic Reduction technology has a chemistry similar to SCR , but uses no catalyst and injects ammonia into specific temperature zones within the boiler. Ammonia is reacted with the NO_x present in the furnace to produce molecular nitrogen and water vapor. Again, the cost for the installation and operation of this technology exceeds the $3 million project dollar limit found in the Consent Decree. TEC is required to either repower, shutdown, or add NO_x controls to Big Bend Units 1 through 4 beginning in 2007. This technology may be reconsidered as an add on control technology if Big Bend Units 1 through 4 remain coal fired.

Reburn - Reburn reduces NO_x emissions by injecting fuel above the original combustion zone with insufficient combustion air; creating a reducing atmosphere. The fuel injected can be natural gas, coal, or another suitable fuel. When the NO_x from the original combustion zone reaches the reburn zone, the oxygen molecules are stripped from the NO_x and used to complete the combustion in the reburn zone. Reburn can result in adverse operational impacts such as increased high carbon content flyash, and a reduction in lower furnace temperatures. The cost for implementing a reburn system far exceeds the $3 million limit found in the Consent Decree.

Fuel Switch – NO_x emissions can be reduced through the firing of high moisture, low heat content coals. However, this fuel can cause adverse impacts on associated fuel handling and combustion systems. For example, high moisture, low heat content fuels tend to be more abrasive than the typical coal fired at Big Bend Station. This causes accelerated degradation in fuel handling systems which, in turn, increases operational and maintenance expenditures at the plant. In addition, slag produced from the combustion of these fuels tend to freeze more readily than the slag produced from firing the current fuel at Big Bend Station, which makes boiler operation impossible. Furthermore, the steam generating boilers at Big Bend Station were designed to accommodate fuels that have a heat content between 10,500 and 12,000 Btu/kwh. These high moisture, low heat content fuels are significantly below this design heat content, which requires more fuel to be fired to generate an equivalent amount of electricity. Due to these potential adverse impacts, TEC determined that switching fuels to reduce NO_x emissions was infeasible.

Water Tempering - Water tempering reduces NO_x emissions by strategically directing a stream of water toward a coal fired flame with the goal of reducing the flame temperature. Since NO_x formation is highly dependent on flame temperature, a reduction in flame temperature results in a reduction of NO_x emissions. Implementation of this technology was deemed to be infeasible due to the physical location of the peak flame temperatures relative to the boiler design geometry.

5.0 Selected Alternatives for Implementation in 2001 and 2002

Based on the above analysis, TEC has implemented low NO_x burners modifications on Units 1 and 4, as well as a neural network and coal and air flow monitoring on Unit 2. The Company evaluated each technology for its impact on NO_x emissions during the second and third quarters of 2001 and found that the low NO_x burners were extremely effective in reducing NO_x emissions on Units 1 and 4, while the neural network is still in the process of being optimized. During 2002, TEC intends to install low NO_x burners on Units 2 and 3, tune the neural network serving Unit 2, and install a coal and air flow monitoring system on Unit 1.

5.1 Big Bend Unit 1

TEC contracted with a CFD modeling firm that has successfully modeled other coal fired steam generators to reduce NO_x emissions. The modeling effort included simulating the effects of installing local air staging and separated over-fire air (SOFA) configurations to achieve the NO_x emissions reduction objective. The results of the modeling indicated that an advanced coal nozzle design in conjunction with local air staging should reduce NO_x emissions to the desired levels. However, the SOFA modeling results proved to be too aggressive for this furnace design. The model predicted that a drop in temperature at the slag tap location would be approximately 600 degrees Fahrenheit, which would make the boiler impossible to operate.

To further augment the modifications to the coal nozzles, TEC contracted with combustion consulting firms to allow for combustion staging without adversely impacting boiler operation. The consultants focused on enhancing the fuel processing and delivery system to help ensure that optimum fuel properties are available to the combustion process. In addition, they optimized the fuel and air mixing and staging process within the furnace, using real-time combustion feedback, to minimize NO_x emissions while providing for safe and reliable boiler operation. As a result, TEC installed the new coal nozzles and burner modifications during the Big Bend Unit 1 outage that concluded in late April of 2001.

5.2 Big Bend Unit 2

In conjunction with the burner modifications installed on Big Bend Unit 1, TEC elected to apply neural network technology to Big Bend Unit 2. In support of this objective, TEC contracted with a consultant to: 1) research the market to determine which neural network systems have the greatest potential for success; 2) prepare a specification for bid; and 3) aid in the technical evaluation of the bids. Upon completion of this process TEC selected a company which has considerable experience with neural network systems in the utility industry and also has prior experience with Riley Turbo® dry bottom units as opposed to TEC's wet bottom units. The neural network was installed in January 2001. Due to operational difficulties associated with the emissions and gas monitoring system, the neural network has not yet been evaluated for its effectiveness in reducing NO_x

emissions. TEC has ordered and installed new process monitors, and intends to optimize the neural network system during the first and second quarters of 2002.

5.3 Big Bend Unit 3

Before installing a NO_x reduction technology on this unit, TEC first wanted to evaluate the effects of the NO_x reduction technologies applied to Units 1 and 2. In conjunction with the CFD modeling performed on Big Bend Unit 1, TEC investigated burner modifications and the application of SOFA to Big Bend Unit 3. Not unlike Big Bend Unit 1, the SOFA model produced unacceptably low temperatures at the slag tap, which would prevent operation of the unit. Similar reductions in NO_x were predicted by the use of an advanced coal nozzle design. Based on this review, TEC will modify the burners serving Unit 3 before or during the second quarter of 2002. This schedule may change as the Unit 3 outage schedule changes.

5.4 Big Bend Unit 4

As noted above, Big Bend Unit 4 is a tangentially fired unit, and several leading manufacturers supply proven NO_x reduction technologies. The most cost-effective technology which provides significant reductions involves the use of modified coal and air nozzles. This system also included the conversion of an existing unused refuse injection port to an air port, thus increasing the effective area of the existing Close Coupled Over-Fired Air, (CCOFA) system. Another innovative design feature included a separate tilting mechanism on the lowest air port which can provide benefits similar to WIR system, but on a smaller scale. This system was installed in May 2001.

6.0 Results and Costs of Applied Technologies

Through the third quarter of 2001, TEC has expended approximately $1.74 million on the Early NO_x Reduction Program at Big Bend Station. In 2002, TEC estimates that the balance of the required $3 million will be spent to install low NO_x burners on Units 2 and 3, complete the air and coal flow balancing project on Unit 1, and to finish the neural network optimization on Unit 2. By the end of 2002, TEC will have satisfied paragraph 35 of the Consent Decree by spending over $3 million on the Early NO_x Reduction Program while achieving significant NO_x reductions from each coal fired generating unit at Big Bend Station. Table 4 summarizes the expenditures through the third quarter of 2001 for each unit in the Early NO_x Reduction Program.

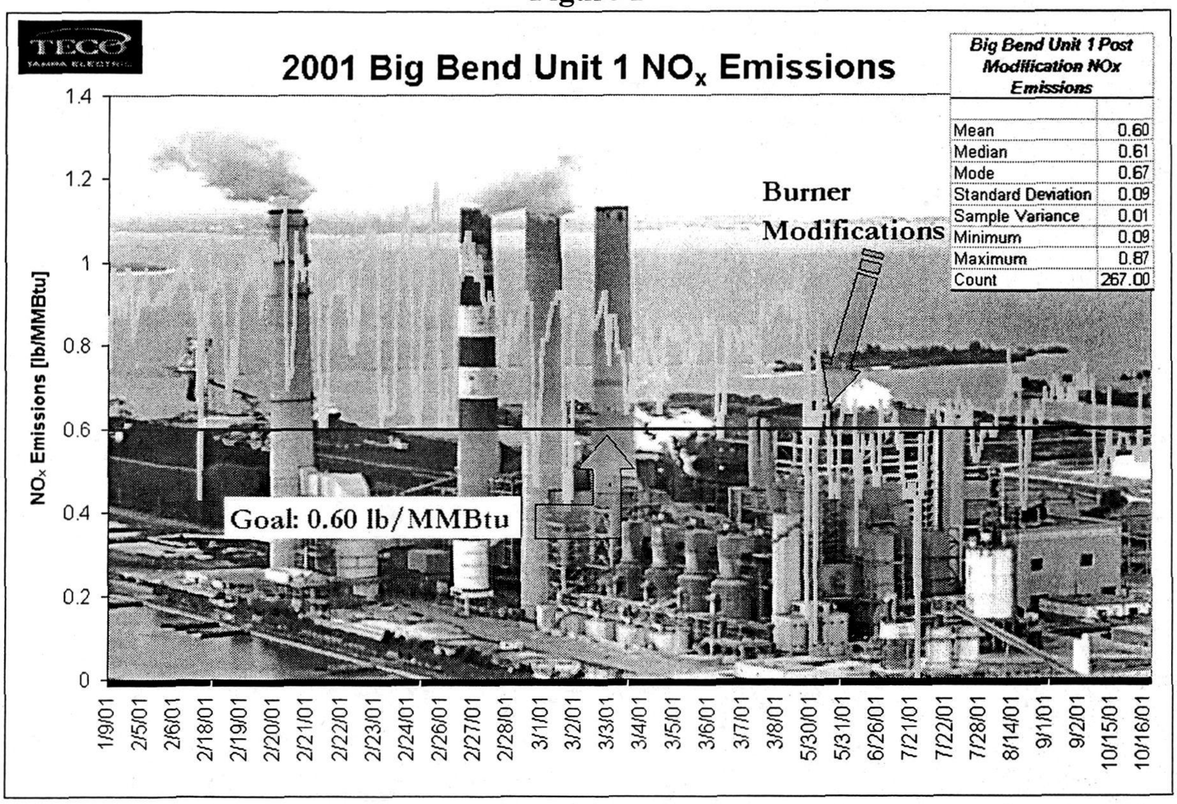
Table 4 - Early NO_x Reduction Program Expenditures

	NO_x Reduction Technology	**Money Spent [Through Quarter 3, 2001]**
Unit 1	Low NO_x Burners	$625,780
Unit 2	Neural Network	$317,486
Unit 4	Low NO_x Burners	$805,983
Total		**$1,749,249**

6.1 Big Bend Unit 1 NO_x Emissions

As mentioned above, low NO_x burners were installed on Big Bend Unit 1 during the spring of 2001. TEC has evaluated the impact on Unit 1 emissions through October 31, 2001, and has found that NO_x emissions have significantly decreased as a result of the operation of the low NO_x burners. TEC is still in the process of tuning the equipment, so NO_x emissions could continue to fluctuate. It is also worth noting that because of operational difficulties not associated with the operation of the low NO_x burners, Unit 1 operated at approximately half of its maximum rated capacity during October 2001. This resulted in artificially low NO_x emissions from the unit because as load is reduced, so are NO_x emissions. Figure 1 displays Unit 1 NO_x emissions before and after the installation of the low NO_x burners. Units 1 and 2 share a common stack. Therefore, this data includes NO_x readings for Unit 1 only during periods when Unit 2 was not operating.

Figure 1



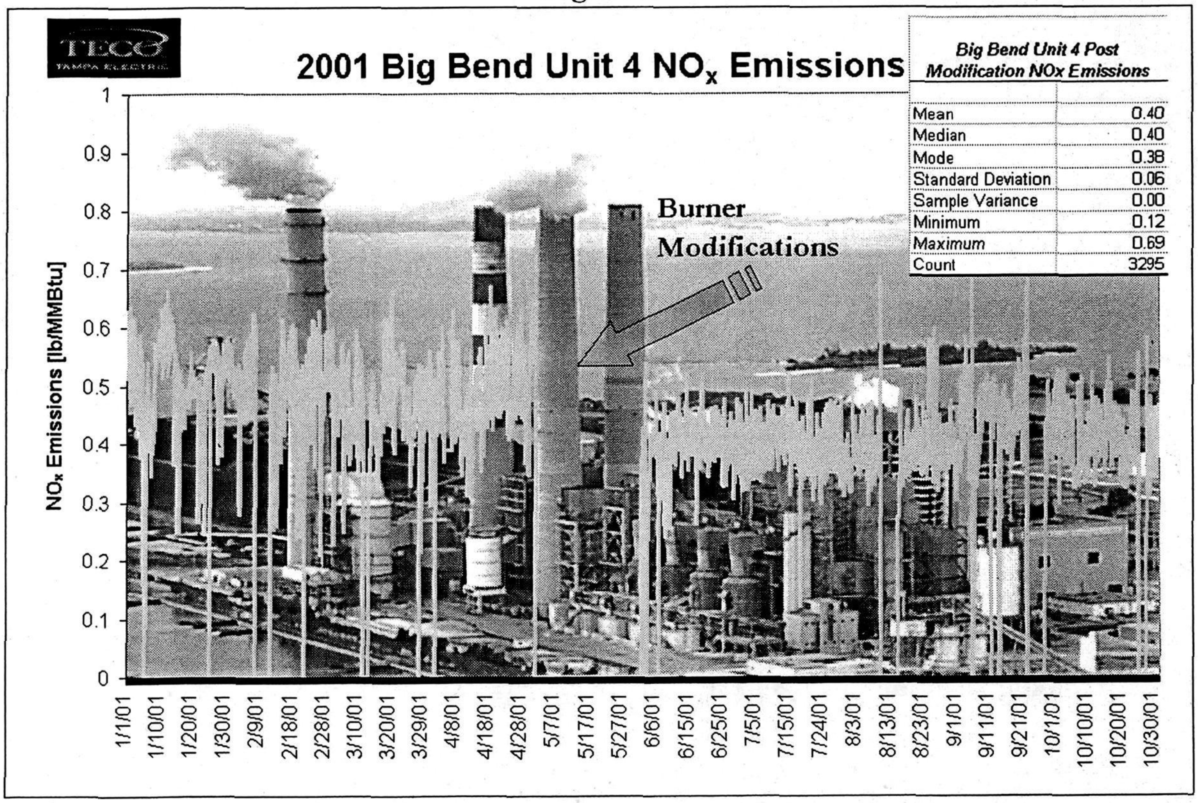
6.2 Big Bend Unit 2 NO_x Emissions

A neural network was installed on Big Bend Unit 2 during January 2001. The purpose of the neural network was to monitor various operating parameters associated with the unit and to "learn" how to optimize specific parameters in an effort to reduce NO_x emissions. TEC is still aggressively pursuing this technology along with the supplier and has recently purchased additional analyzers and monitoring equipment to enhance the performance of the neural network system. Although no NO_x reductions have been achieved to date using this technology, more testing and optimization is scheduled and it is anticipated that the results of this testing will be available by the third quarter of 2002.

6.3 Big Bend Unit 4 NO_x Emissions

Low NO_x burners were also installed on Big Bend Unit 4 during the spring of 2001. TEC has evaluated the impact on Unit 4 emissions through October 31, 2001, and has found that NO_x emissions have decreased as a result of the operation of the low NO_x burners. TEC is still in the process of tuning the equipment, so NO_x emissions could continue to fluctuate. Figure 2 displays Unit 4 NO_x emissions before and after the installation of the low NO_x burners.

Figure 2



7.0 Conclusion

The Early NO_x Reduction program at Big Bend Station has been extremely successful during 2001. TEC has evaluated several NO_x reduction technologies suitable for application to the units at Big Bend Station, and has installed low NO_x burners on Units 1 and 4, and a neural network on Unit 2. Thus far, the low NO_x burners have achieved real reductions, and TEC is confident that the neural network serving Unit 2 is capable of delivering NO_x reductions as well.

To date, TEC has expended approximately $1.74 million on the Early NO_x Reduction Program, and through the implementation of the projects identified in this report, TEC will meet the $3 million threshold requirement for NO_x reduction expenditures found in Paragraph 35 of the Consent Decree and the associated amendment. This will be accomplished while reducing NO_x emissions from all four Units ahead of schedule, rather than being limited to Units 1 through 3. Because of the limited amount of data and the fact that TEC has not completed this plan, it is not known what level of NO_x reductions will be achieved from each unit, but TEC is striving to achieve the goals of 30%, 30% and 15% reduction from Units 1, 2 and 3 respectively with additional NO_x reductions realized from Big Bend Unit 4.

TEC intends to install low NO_x burners on Units 2 and 3 as described above during the planned 2002 outages. In addition, TEC will continue to tune the neural network serving Unit 2 during 2001 and 2002 and will install a real time coal and air balancing system on Unit 1 in 2002. TEC also plans to continue tuning and balancing the airflow and fuel flow on Big Bend Unit 2 in 2002. As mentioned above, the impact of each technology on the NO_x emissions from each Unit will continue to be evaluated during 2001 and 2002, and all NO_x reduction modifications will be complete by December 31, 2002. Finally, TEC will provide EPA with a final report regarding the Early NO_x Reduction Program no later than April 1, 2003 as required by Paragraph 35 of the Consent Decree.

The details found within this update report are subject to change based on NO_x emissions reduction technology availability, unit capability, unit outage schedules, manpower availability and other unit specific operating parameters. In the event that details contained within this Plan change substantially, TEC will notify EPA and revise the Plan within a reasonable time period.