Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

July 16, 2001

0137568

RECEIVED

JUL 18 2001

BUREAU OF AIR REGULATION

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

Attention: Mr. A. A. Linero, P.E., New Source Review Section

RE: TROPICANA PRODUCTS, INC.
DEP FILE NO. 1110004-003-AC (PSD-FL-~~303~~) 303 A

Dear Al:

Attached please find four copies of a permit application for a new steam boiler to be located at Tropicana Products, Inc.'s Fort Pierce Facility. The permit application for this boiler is being submitted as a PSD permit application since the emissions from the new boiler would be contemporaneous with the potential associated with the new juice extractors. The boiler will utilize the latest NO_x combustion controls with natural gas as the primary fuel. When firing oil, the boiler will utilize 0.05-percent sulfur distillate oil. This boiler will be used primarily in lieu of two older boilers, which have much higher emissions using natural gas and residual oil. However, the older boilers will be used as backup and no netting has been assumed.

The impacts of the boiler have been determined to be less than the PSD significant impact levels for both natural gas and distillate oil.

An expeditious review would be appreciated. Please call if you have any questions.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal

KFK/jkw

cc: Joesph Kahn P.E., FDEP
Richard Coyle, Tropicana Products, Inc.
Douglas Foster, Tropicana Products, Inc.
Scott Davis, Tropicana Products, Inc.
J. Baldman, SED
Gregg Worley, EPA
John Bunyak, NPS

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FLORIDA

Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 20, 2001

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Tropicana Products, Inc.
Fort Pierce Facility
DEP File No. 1110004-004-AC, PSD-FL-322

Dear Mr. Worley:

Enclosed for your review and comment is an application for a PSD source submitted by Tropicana Products, Inc.. The proposed project is a new steam boiler at the company's existing facility in Ft. Pierce, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Joe Kahn, review engineer, at 850/921-9509.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa
Enclosure
cc: Joe Kahn

Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 20, 2001

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Tropicana Products, Inc.
Fort Pierce Facility
DEP File No. 1110004-004-AC, PSD-FL-322

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for a PSD source submitted by Tropicana Products, Inc.. The proposed project is a new steam boiler at the company's existing facility in Ft. Pierce, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Joe Kahn, review engineer, at 850/921-9509.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa
Enclosure
cc: Joe Kahn

APPLICATION FOR AIR PERMIT
INSTALLATION OF A PROCESS STEAM BOILER FOR TROPICANA PRODUCTS, INC.
FORT PIERCE CITRUS PROCESSING PLANT

FORT PIERCE, FLORIDA

Prepared For:

Tropicana Products, Inc.
6500 Glades Cutoff Road
Fort Pierce, Florida 34981

Prepared By:

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

June 2001
0137568

DISTRIBUTION:
4 Copies - FDEP
2 Copies - Tropicana Products, Inc.
1 Copy - Golder Associates Inc.

LIST OF TABLES

LIST OF TABLES (CONTINUED)

LIST OF APPENDICES

PART I

APPLICATION FOR AIR PERMIT
LONG FORM

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Tropicana Products, Inc.**	
2. Site Name: **Ft. Pierce Citrus Processing Plant**	
3. Facility Identification Number: **1110004**	[ ] Unknown
4. Facility Location: Street Address or Other Locator: **6500 Glades Cutoff Road** City: **Ft. Pierce** County: **St. Lucie** Zip Code: **34981**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Douglas E. Foster, Manager Environmental Affairs**

2. Application Contact Mailing Address:
Organization/Firm: **Tropicana Products, Inc.**
Street Address: **1001 13th Avenue, East**
City: **Bradenton** State: **FL** Zip Code: **34208**

3. Application Contact Telephone Numbers:
Telephone: **(941) 742 - 2748** Fax: **(941) 742 - 3768**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	7-18-01
2. Permit Number:	1110004-004-AC
3. PSD Number (if applicable):	PSD-FL-322
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number:____________________________________

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

Current construction permit number:____________________________________

Operation permit number to be revised:__________________________________

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

Operation permit number to be revised/corrected:__________________________

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

Operation permit number to be revised:__________________________________

Reason for revision:____

Air Construction Permit Application

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

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

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

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

DESIGNATION OF DOCUMENT SIGNATORY

I, Brock H. Leach, hereby certify that I am the President and Chief Executive Officer of Tropicana Products, Inc., ("Tropicana") and as such I am authorized to designate employees to prepare and sign documents and to certify on behalf of said company the accuracy and completeness of information in such documents.

Pursuant to the power vested in me, I hereby designate the person listed below to prepare and sign documents for submission to federal, state and local government agencies having jurisdiction over environmental, safety and utilities matters, including but not limited to, the United States Environmental Protection Agency, the United States Department of Labor, Occupational Safety and Health, the Florida Department of Environmental Protection, the South Florida Water Management District, and the County of St. Lucie, State of Florida, pertinent to the operation of the Tropicana plant located in Ft. Pierce, Florida.

This designation is effective until revoked in writing.

Designated Signatory

Richard A. Coyle
Director, Ft. Pierce Operations
6500 Glades Cut-Off Road
Ft. Pierce, FL 34981

Brock H. Leach
President and CEO

Dated: 9/27/00

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Richard Coyle, Director of Operators**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Tropicana Products, Inc.** Street Address: **6500 Glades Cutoff Road** City: **Ft. Pierce** State: **FL** Zip Code: **34981**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(561) 465 - 2030** Fax: **(561) 465 - 2855**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [X], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Rich. Coyle — Signature 7-11-01 — Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 336 - 5600** Fax: **(352) 336 - 6603**

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature: [signature] Date: 7/12/2001

(seal) [initials]

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
	Process Steam Boiler	AC1D	

Application Processing Fee

Check one: [X] Attached - Amount: $: 7,500 [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **This application is for a PSD permit for the addition of one 85,000 lb/hr (nominal steam rating) steam boiler to the existing facility. The unit is capable of firing either natural gas or No. 2 fuel oil. The unit includes a low NO_x burner and uses 5% flue gas recirculation (FGR).**	
2. Projected or Actual Date of Commencement of Construction: **1 September 2001**	
3. Projected Date of Completion of Construction: **1 March 2002**	

Application Comment

See Attachment Part II.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **561.0**	North (km): **3028.1**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **27 / 22 / 35**		Longitude (DD/MM/SS): **80 / 23 / 36**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **20**	6. Facility SIC(s): **2033**
7. Facility Comment (limit to 500 characters): **Citrus Processing Plant - consists of two peel dryers with associated evaporators, two pellet mills and coolers, two process steam boilers, a package boiler and associated insignificant emission units. An air construction permit (1110004-003-AC) and Prevention of Significant Deterioration (PSD) approval (PSD-FL-303) were obtained on March 26, 2001 for the addition of 16 juice extractors.**			

Facility Contact

1. Name and Title of Facility Contact: **Scott Davis, Environmental Operations Manager**		
2. Facility Contact Mailing Address: Organization/Firm: **Tropicana Products, Inc.** Street Address: **6500 Glades Cutoff Road** City: **Ft. Pierce**	State: **FL**	Zip Code: **34981**
3. Facility Contact Telephone Numbers: Telephone: **(561) 465 - 2030**	Fax: **(561) 465 - 2855**	

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations

Facility emissions covered under existing Title V permit, no additional facility applicable requirements as a result of the proposed change.	
See Attachment Part II.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location:	[ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan:	[ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s):	[ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter:	[ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification:	[ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application:	[X] Attached, Document ID: Part II [ ] Not Applicable
7. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:_______ [X] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:_______ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:_______ [X] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:_______ [X] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:_______ [X] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:_______) or previously submitted to DEP (Date and DEP Office:_________________) [ ] Plan to be submitted to CEPPO (Date required:_________________) [X] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:_______ [X] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:_______ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

85,000 lb/hr (Steam) Boiler

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**Aug-01**	**49**	[ ]

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

The boiler will fire natural gas and no. 2 distillate fuel oil (backup) and is subject to 40 CFR 60 Subpart Dc.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Low NOx Burner – Gas/Oil 5% Flue Gas Recirculation (FGR) – Gas/Oil
2. Control Device or Method Code(s): 024

Emissions Unit Details

1. Package Unit: Manufacturer: ABCO Industries, Inc. Model Number: D-Type
2. Generator Nameplate Rating: MW
3. Incinerator Information: Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**99.8** mmBtu/hr	
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	24 hours/day		**7** days/week
	52 weeks/year		**8,760** hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input will be up to 99.8 MMBtu/hr for natural gas and 95.7 MMBtu/hr for distillate fuel oil. Maximum operation is requested for both natural gas and fuel oil operation.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment TF-EU1-C	

ATTACHMENT TF-EU1-C

APPLICABLE REQUIREMENTS LISTING

EMISSION UNIT: Process Steam Boiler

FDEP Rules:

Stationary Sources-General:

62-210.650	- Circumvention
62-210.700(1)	- Excess Emissions; malfunction; 2-hrs/24-hrs
62-210.700(2)	- Excess Emissions; FFFSG; startup/shutdown
62-210.700(3)	- Excess Emissions; FFFSG; soot blowing/load change
62-210.700(4)	- Excess Emissions; Excludes poor maintenance
62-210.700(6)	- Excess Emissions; reporting

Stationary Sources-Emission Monitoring:

62-297.310(1)	- Test Runs-Mass Emission
62-297.310(2)(b)	- Operating Rate
62-297.310(3)	- Calculation of Emission
62-297.310(4)(a)1.	- Applicable Test Procedures; Sampling time
62-297.310(4)(b)	- Sample Volume
62-297.310(4)(c)	- Required Flow Rate Range-PM
62-297.310(4)(d)	- Calibration
62-297.310(4)(e)	- EPA Method 5
62-297.310(5)	- Determination of Process Variables
62-297.310(6)(a)	- Permanent Test Facilities - general
62-297.310(6)(c)	- Sampling Ports
62-297.310(6)(d)	- Work Platforms
62-297.310(6)(e)	- Access
62-297.310(6)(f)	- Electrical Power
62-297.310(6)(g)	- Equipment Support
62-297.310(7)(a)1.	- Renewal
62-297.310(7)(a)3.	- Permit Renewal Test Required
62-297.310(7)(a)4.b.	- Annual Test
62-297.310(7)(a)5.	- PM exemption if < 400 hrs/yr
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(8)	- Test Reports

Stationary Sources - BACT Steam Generators < 250 mmBtu/hr

62-296.406(2)	- Particulate Matter
62-296.406(3)	- Sulfur Dioxide

Federal Rules:

NSPS General:

40 CFR 60.7(b)	- Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	- Notification and Recordkeeping (maintain records)

40 CFR 60.8(c)	- Performance Tests (representative conditions)
40 CFR 60.8(e)	- Performance Tests (test facilities required)
40 CFR 60.8(f)	- Performance Tests (test runs)
40 CFR 60.11(a)	- Compliance (ref. S.60.8 Subpart; other than opacity)
40 CFR 60.11(b)	- Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	- Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	- Compliance (maintain air pollution control equipment)
40 CFR 60.11(f)	- Compliance (opacity; ref. S.60.8)
40 CFR 60.12	- Circumvention

NSPS Subpart Dc:

40 CFR 60.42c(d)	- SO_2 Fuel Oil Combustion Limits
40 CFR 60.42c(h)	- Fuel Oil Sulfur Content Certification
40 CFR 60.43c(c)	- Opacity Limits
40 CFR 60.43c(d)	- Opacity Limits during startup, shutdown, or malfunction
40 CFR 60.44c(g)	- Demonstration of compliance with fuel oil sulfur limits
40 CFR 60.45c(a)(7)	- Method 9 testing
40 CFR 60.46c(d)(2)	- Fuel sampling
40 CFR 60.48c(a)	- Notification requirements
40 CFR 60.48c(d)	- Report submittal
40 CFR 60.48c(e)(11)	- Fuel oil supplier certification requirements
40 CFR 60.48c(f)(1)	- Fuel oil supplier certification information
40 CFR 60.48c(g)	- Fuel combustion records

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram?	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **60** feet	7. Exit Diameter: **2.75** feet
8. Exit Temperature: **298** °F	9. Actual Volumetric Flow Rate: **29,325** acfm	10. Water Vapor: **6.7** %

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 Comment (limit to 200 characters): **Stack parameters shown for natural gas firing. See Attachment II**	

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas < 100 MMBtu/hr**		
2. Source Classification Code (SCC): **1-02-006-02**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.098**	5. Maximum Annual Rate: **857**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1020**
10. Segment Comment (limit to 200 characters): **Maximum hourly based on 1,020 Btu/cf (HHV) for the process steam boiler. Maximum annual based on 8,760 hr/yr.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **1-02-005-02**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **0.730**	5. Maximum Annual Rate: **6,392**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **131.1**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC unit = 131.1; based on 6.83 lb/gal; HHV 19,200 Btu/lb, ISO conditions, Maximum annual rate based on a maximum of 8,760 hours of oil firing per year.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			EL
NO_x	024		EL
CO			EL
PM_{10}			

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.4** lb/hour **6.2** tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **Vendor; Golder 2001**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See Attachment Part II.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr and TPY based on oil firing 8,760 hr/yr.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:

   VE < 20% Opacity
4. Equivalent Allowable Emissions:

   1.4 lb/hour **6.2** tons/year
5. Method of Compliance (limit to 60 characters):

   EPA Method 9
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Oil firing; 8,760 hr/yr. See Attachment Part II.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.4** lb/hour **6.2** tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **Vendor; Golder 2001**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):
   See Attachment Part II.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
   Lb/hr and TPY based on oil firing 8,760 hr/yr.

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **VE < 10% Opacity**
4. Equivalent Allowable Emissions: **0.2** lb/hour **0.8** tons/year
5. Method of Compliance (limit to 60 characters):
   EPA Method 9
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
   Gas firing; 8,760 hr/yr. See Attachment Part II.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **5.0** lb/hour **21.8** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Vendor; Golder 2001**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and TPY based on oil firing 8,760 hr/yr.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil maximum**	4. Equivalent Allowable Emissions: **5.0** lb/hour **21.8** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; 8,760 hr/yr. Maximum sulfur content is 0.05% sulfur. See Attachment Part II.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **5.0** lb/hour **21.8** tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **Vendor; Golder 2001**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See Attachment Part II.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr and TPY based on oil firing 8,760 hr/yr.

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:

   See Comment
4. Equivalent Allowable Emissions:

   0.3 lb/hour **1.2** tons/year
5. Method of Compliance (limit to 60 characters):

   Pipeline Natural Gas
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Pipeline natural gas, 1 g/100 cf, 8,760 hr/yr, See Attachment Part II.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: 9.6 lb/hour 41.9 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Vendor; Golder 2001	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Attachment Part II.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr and TPY based on oil firing 8,760 hr/yr.	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.10 lb/MMBtu	4. Equivalent Allowable Emissions: 9.6 lb/hour 41.9 tons/year
5. Method of Compliance (limit to 60 characters): Manufacturer Certification	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Annual allowable emissions based on Oil firing; 8,760 hr/yr. See Attachment Part II.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **9.6** lb/hour **41.9** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Vendor; Golder 2001**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and TPY based on oil firing 8,760 hr/yr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.055 lb/MMBtu**	4. Equivalent Allowable Emissions: **5.5** lb/hour **24.0** tons/year
5. Method of Compliance (limit to 60 characters): **Manufacturer Certification**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Annual allowable emissions based on natural gas firing; 8,760 hr/yr. See Attachment Part II.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **18.4** lb/hour **80.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Vendor; Golder 2001**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **200 ppm at 3% O_2. See Attachment Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and TPY based on maximum natural gas firing of 8,760 hr/yr.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **200 ppm at 3% O_2**	4. Equivalent Allowable Emissions: **17.4** lb/hour **76.3** tons/year
5. Method of Compliance (limit to 60 characters): **Manufacturer Certification**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; 8,760 hr/yr. See Attachment Part II.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **18.4** lb/hour **80.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Vendor; Golder 2001**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **200 ppm at 3% O_2. See Attachment Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and TPY based on maximum natural gas firing of 8,760 hr/yr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **200 ppm at 3% O_2**	4. Equivalent Allowable Emissions: **18.4** lb/hour **80.4** tons/year
5. Method of Compliance (limit to 60 characters): **Manufacturer Certification**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Natural gas firing; 8,760 hr/yr. See Attachment Part II.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.4** lb/hour **6.2** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Vendor; Golder 2001**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and TPY based on oil firing 8,760 hr/yr.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **VE < 20% Opacity**	4. Equivalent Allowable Emissions: **1.4** lb/hour **6.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; 8,760 hr/yr. See Attachment Part II.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.4** lb/hour **6.2** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Vendor; Golder 2001**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and TPY based on oil firing 8,760 hr/yr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **VE < 10% Opacity**	4. Equivalent Allowable Emissions: **0.2** lb/hour **0.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Natural gas firing; 8,760 hr/yr. See Attachment Part II.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **VE of 20% proposed for distillate oil firing. VE of 10% proposed for natural gas firing. Excess opacity based on Rule 62-210-700.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units 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 (limit to 200 characters):	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [X] Not Applicable

PART II

SUPPORTING INFORMATION

1.0 INTRODUCTION

Tropicana Products, Inc. (Tropicana) is proposing to install and operate one steam boiler at the existing Fort Pierce Citrus Processing Plant. The steam boiler will be fired primarily with pipeline quality natural gas, and distillate fuel oil will be used as a backup. Emissions will be controlled by a low NO_x burner and 5% flue gas recirculation.

1.1 EXISTING FACILITY AND PROPOSED PROCESS STEAM BOILER

The Tropicana facility is located at 6500 Glades Cutoff Road, Fort Pierce, Florida. The facility is a citrus processing complex that includes juice extracting, processing, packaging, warehousing, and distribution. Fruit is graded and carried to an extractor room where the juice is removed and pumped to either carton filling, glass filling, plastic filling, block freezing, aseptic storage or to evaporators for concentrate production.

The plant contains two process steam boilers, two citrus peel dryers with waste heat evaporators, two pellet mills and coolers, one package boiler, fifty juice extractors (16 additional extractors planned for 2002), and various unregulated and insignificant emission units (e.g. storage tanks).

The steam boiler will have a nominal steam rating of 85,000 pounds (lb) of steam per hour. The maximum heat input for the boiler will be 99.8 million British thermal units per hour (MMBtu/hr-HHV) when firing natural gas. The primary fuel will be pipeline-quality natural gas with No. 2 fuel oil used as a backup fuel. The fuel oil will contain a maximum of 0.05 percent sulfur. Design drawings of the proposed steam boiler are available in Appendix A.

1.2 PROCESS STEAM BOILER EMISSION ESTIMATION

The estimated hourly and annual criteria pollutant emissions from the steam boiler are provided in Table 1-1. The boiler emissions are based on a heat input rate of 99.8 MMBtu/hr with a maximum fuel usage of 856,848,235 standard cubic feet per year of pipeline quality natural gas and 95.7 MMBtu/hr with a maximum fuel usage of 6,391,508 gallons per year of No. 2 fuel oil with 0.05-percent sulfur.

The steam boiler emissions are based on 8,760 hours per year of operation when firing natural gas. Up to 8,760 hours per year of distillate fuel oil firing is being proposed as the back-up fuel requirements.

The operation of the boiler is proposed to be limited by the equivalent heat input of operating 8,760 hr/yr on natural gas of 874,250 MMBtu/yr (99.8 MMBtu/hr times 8,760 hr/yr). Distillate oil usage is proposed as a backup fuel up to an equivalent of 8,760 hr/yr or 838,350 MMBtu/yr (95.7 MMBtu/hr times 8,760 hr/yr).

The stack will be located above the boiler room building. Parameters for the steam boiler stack are presented in Table 1-2.

Table 1-1. Future Maximum Emissions from the Process Steam Boiler, Tropicana Products, Inc.

Regulated Pollutant	Natural Gas Combustion Emission Factor (lb/10^6 scf)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor[a] (MMBtu/hr)	Hourly Emissions (lb/hr)	Annual Emissions[b] (TPY)	No. 2 Fuel Oil Combustion Emission Factor (lb/1000 gal)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor[a] (MMBtu/hr)	Hourly Emissions (lb/hr)	Annual Emissions[c] (TPY)	Maximum Annual Emissions Due to Any Combination[d] (TPY)
Particulate Matter (PM)	1.9	1.86E-03	1	99.8	0.19	0.81	--	0.015	5	95.7	1.40	6.15	6.15
Particulate Matter (PM_{10})	1.9	1.86E-03	1	99.8	0.19	0.81	--	0.015	5	95.7	1.40	6.15	6.15
Sulfur dioxide (SO_2)	1	grains S/100 scf	2	99.8	0.28	1.22	0.05% sulfur	0.0519	2	95.7	4.97	21.75	21.75
Nitrogen oxides (NO_x)	--	0.055	3	99.8	5.49	24.03	--	0.10	3	95.7	9.57	41.91	41.91
Carbon monoxide (CO)	--	0.18	3	99.8	18.4	80.4	--	0.18	3	95.7	17.4	76.3	80.4
VOC	5.5	0.01	1	99.8	0.54	2.36	--	0.001	5	95.7	0.14	0.61	2.36
Sulfuric acid mist (SAM)	--	3.60E-05	4	99.8	3.59E-03	0.02	--	0.0026	6	95.7	0.25	1.08	1.08
Lead (Pb)		4.90E-07	1	99.8	4.89E-05	2.14E-04	--	9.00E-06	5	95.7	8.61E-04	3.77E-03	3.77E-03
Mercury (Hg)	2.6E-04	2.55E-07	1	99.8	2.54E-05	1.11E-04	--	3.00E-06	5	95.7	2.87E-04	1.26E-03	1.26E-03
Fluorides (Fl)	Neg	--		--	--	--	--	Neg		--	--	--	--

References:
1. Factors for natural gas combustion from AP-42, Tables 1.4-1, 1.4-2 and 1.4-4 (7/98). Factors were converted to lb/MMBtu by dividing by 1,020 Btu/scf.
2. Basis (grains S/100 scf-gas) = 1 and 0.05%S-diesel; typical maximum sulfur content for pipeline natural gas and distillate fuel oil.
3. Proposed emission limits based on emission guarantees from vendor. CO limit is 200 ppm at 3% O_2 (ABCO Industries, Inc., 2001)
4. Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil. 5% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and gaseous sulfate molecular weights (98/80).
5. Factors for No. 2 fuel oil combustion, AP-42 Table 1.3-1, 1.3-3, and 1.3-10 (9/98). A heating value of 136,000 Btu/gal and a maximum sulfur content of 0.05% were used for the No. 2 fuel oil.
6. The emission factor for SO_3 emissions from a No. 2 fuel fired boiler with low NOx burners (5.7S lb/10^3 gal where S is the sulfur content) was multiplied by the ratio of sulfuric acid mist and gaseous sulfate molecular weights (98/80).

Footnotes:

[a] The proposed maximum permitted heat input rate is 99.8 MMBtu/hr for natural gas and 95.7 MMBtu/hr for fuel oil.

[b] Based on maximum proposed operation of 8,760 hours on natural gas.

[c] Based on maximum proposed operation of 8,760 hours on fuel oil.

[d] Maximum emissions predicted for either natural gas combustion only, No. 2 fuel oil combustion only, or a combination of No. 2 fuel oil and natural gas combustion.

Sample Calculations:

Hourly Emissions = Emission Factor x Activity Factor

Annual Emissions = Hourly Emissions x hours of operation (hrs/yr) / 2,000 (lb/ton)

Annual Emissions due to firing both fuels = Annual Emissions due to fuel oil + [(Hourly emissions due to natural gas x (8,760 hrs/yr - 2,880 hrs/yr)/ 2,000 (lb/ton)

Neg = Negligible Concentration

Table 1-2. Summary of Stack Parameters for the Process Steam Boiler, Tropicana Products, Inc.

	Steam Production Rate (lb/hr)	Stack Height (ft)	Stack Diameter (ft)	Gas Firing Parameters			Oil Firing Parameters		
				Flow Rate (acfm)	Velocity (ft/s)	Temperature (deg F)	Flow Rate (acfm)	Velocity (ft/s)	Temperature (deg F)
Process Steam Boiler	85,000	60	2.75	29,325	82	296.0	27,962	78	298.0

Notes:
acfm = actual cubic feet per minute
deg F = degrees Fahrenheit
ft = feet
ft/s = feet per second

2.0 AIR QUALITY REVIEW REQUIREMENTS

Federal and state air regulatory requirements for a major modification to an existing major source of air pollution are discussed in Sections 2.1 to 2.4. The applicability of these regulations to the new steam boiler is presented in Section 2.5. These regulations must be satisfied before the proposed project can be approved.

2.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 2-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

Florida has adopted state AAQS in Rule 62-204.240. These standards are the same as the national AAQS, except in the case of SO_2. For SO_2, Florida has adopted the former 24-hr secondary standard of 260 $\mu g/m^3$, and former annual average secondary standard of 60 $\mu g/m^3$.

2.2 PSD REQUIREMENTS

2.2.1 GENERAL REQUIREMENTS

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

A "major facility" is defined as any one of 28 named source categories that have the potential to emit 100 TPY or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates. The PSD significant emission rates are shown in Table 2-2.

The EPA class designation and allowable PSD increments are presented in Table 2-1. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications are designated based on criteria established in the Clean Air Act Amendments. Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2 increments.

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

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

2.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility exceeds the significant emission rate (see Table 2-2).

BACT is defined in 40 CFR 52.21 (b)(12), as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source of major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determination is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant, which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means, which achieve equivalent results.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978;

1980). Guidelines for the evaluation of BACT can be found in EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the *PSD Workshop Manual* (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with new source performance standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis required the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

2.2.3 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source or major modification subject to PSD review, and for each pollutant for which the increase in emissions exceeds the PSD significant emission rate (Table 2-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments.

Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models* (EPA, 1980).

To address compliance with AAQS and PSD Class II increments, a source impact analysis must be performed for the criteria pollutants. However, this analysis is not required for a specific pollutant if the net increase in impacts as a result of the new source or modification is below significant impact levels, as presented in Table 2-1. The significant impact levels are threshold levels that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance AAQS and PSD increments.

EPA has proposed significant impact levels for Class I areas as follows:

SO_2	3-hour	1 $\mu g/m^3$
	24-hour	0.2 $\mu g/m^3$
	Annual	0.1 $\mu g/m^3$
PM_{10}	24-hour	0.3 $\mu g/m^3$
	Annual	0.2 $\mu g/m^3$
NO_2	Annual	0.1 $\mu g/m^3$

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD review, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the proposed rules concerning the significant impact levels is appropriate in order to assist states in implementing the PSD permit process.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period is normally used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The meteorological data are selected base on an evaluation of measured weather data from a nearby weather station that represents weather conditions at the project site. The criteria used in this evaluation include determining the distance of the project site to the weather station; comparing topographical and land use features between the locations; and determining availability of necessary weather parameters.

The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is important because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

The actual emissions representative of facilities in existence on the applicable baseline date; and

1. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations, and after February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM (TSP), and February 8, 1988, for NO_2.

2.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m), any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 2-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that Florida DEP may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 2-2.

2.2.5 SOURCE INFORMATION/GOOD ENGINEERING PRACTICE STACK HEIGHT

Source information must be provided to adequately describe the proposed project. The information required for this project is presented in Table 1-2.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). The Florida DEP has adopted identical regulations (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 meters (m); or
2. A height established by applying the formula:

   $H_g = H + 1.5L$

where: Hg = GEP stack height,

H = Height of the structure or nearby structure, and

L = Lesser dimension (height or projected width) of nearby structure(s); or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

2.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21(o) and Rule 62-212.400, F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 2-2).

2.3 NONATTAINMENT RULES

Based on the current nonattainment provisions, all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant.

2.4 EMISSION STANDARDS

2.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated." The steam boiler will be subject to NSPS Subpart Dc, New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units.

2.4.2 FLORIDA RULES

FDEP regulations for fossil fuel steam generators with less than 250 MMBtu/hr of heat input are covered in Rule 62-296.406. These rules require that "new" fossil fuel steam generators meet a visible emissions limit of 20 percent opacity, except for either one six-minute period per hour during which opacity does not exceed 27 percent, or one two-minute period per hour during which opacity does not exceed 40 percent. PM and SO_2 emissions from small boilers are subject to BACT as determined by the Department.

2.5 PSD APPLICABILITY

2.5.1 AREA CLASSIFICATION

The project site is located in St. Lucie County, which has been designated by EPA and FDEP as an attainment or maintenance area for all criteria pollutants. St. Lucie County and surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. As a result, the new source review will follow PSD regulations pertaining to such designations, 62-212.400(2)(d)2.a. F.A.C.

2.5.2 PSD REVIEW

Pollutant Applicability

The existing Tropicana facility is considered to be a major by having potential emissions greater than 250 tons/year of any air pollutant regulated under the Clean Air Act (Rule 62-212.400(2)(d)2.a. F.A.C. Therefore, PSD review is required for any pollutant for which the increase in emissions due to the modification is greater than the PSD significant emission rates.

The project itself has potential emissions greater than the PSD thresholds for nitrogen oxides (NO_x) only. However, the facility has applied for an air construction permit in October 2000 for the addition of 16 juice extractors to the existing 50 extractors. The project is contemporaneous with the proposed addition of extractors. PSD analysis is being conducted for all of the criteria pollutants: particulate matter (PM), particulate matter less than 10 microns on diameter (PM_{10}), sulfur dioxide (SO_2), NO_x, carbon monoxide (CO), and volatile organic compounds (VOC).

Source Impact Analysis

A source impact analysis was performed for PM_{10}, NO_x, SO_2 and CO emissions resulting from the proposed project (refer to Section 4.0). As shown in Table 2-4, the predicted increases in impacts due to the proposed steam boiler are predicted to be below the significant impact levels for PM_{10}, NO_x, and CO. As a result, a modeling analysis incorporating the impacts from other sources is not required for these pollutants.

Emission Standards

The process steam boiler is subject to 40 CFR 60, Subpart Dc, the federal NSPS for small boilers. According to the rule, a boiler with less than 100 MMBtu/hr may emit no more than 0.5 pounds/MMBtu of SO_2, or the boiler must burn fuel oil with a maximum sulfur content of 0.50 percent. In addition, the boiler will be subject to a 20-percent opacity limitation, except up to 6 minutes per hour, where the opacity must not exceed 27 percent. The steam boiler will comply with these requirements by testing the fuel oil sulfur content and performing an annual EPA Method 9 test for opacity.

Ambient Monitoring

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate.

Ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

If the net increase in impacts of a pollutant is less than the applicable *de minimis* monitoring concentration, then an exemption from submittal of pre-construction ambient monitoring data may be obtained [40 CFR 52.21(i)(8)]. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Pre-construction monitoring data for SO_2,PM_{10}, NO_x, and CO may be exempted for this project because, as shown in Table 2-4 and in Section 4.0, the proposed modification's impacts are predicted to be below the applicable *de minimis* monitoring concentrations.

GEP Stack Height Impact Analysis

The steam boiler stack will be 60 ft high. This stack height does not exceed the *de minimis* good engineering practice (GEP) stack height of 65 meters (213 ft).

2.5.3 NONATTAINMENT REVIEW

The project site is located in St. Lucie County, which is classified as an attainment or maintenance area for all criteria pollutants. Therefore, nonattainment requirements are not applicable.

Table 2-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels ($\mu g/m^3$)

		AAQS			PSD Increments		
Pollutant	Averaging Time	National Primary Standard	National Secondary Standard	State of Florida	Class I	Class II	Significant Impact Levels[d]
Particulate Matter[a] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum[b]	150[b]	150[b]	150[b]	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[b]	365[b]	NA	260[b]	5	91	5
	3-Hour Maximum[b]	NA	1,300[b]	1,300[b]	25	512	25
Carbon Monoxide	8-Hour Maximum[b]	10,000[b]	10,000[b]	10,000[b]	NA	NA	500
	1-Hour Maximum[b]	40,000[b]	40,000[b]	40,000[b]	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[a]	1-Hour Maximum	235[c]	235[c]	235[c]	NA	NA	NA
	1-Hour Maximum	235	235	NA	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: NA = Not applicable, i.e., no standard exists.

PM_{10} = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

[a] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 $\mu g/m^3$ (3-year average of 98th percentile) and an annual standard of 15 $\mu g/m^3$ (3-year average at community monitors). Implementation of these standards are many years away. The ozone standard was modified to be 0.08 ppm for 8-hour average; achieved when 3-year average of 99th percentile is 0.08 ppm or less. FDEP has not yet adopted these standards.

[b] Short-term maximum concentrations are not to be exceeded more than once per year except for the PM_{10} AAQS (these do not apply to significant impact levels). The PM_{10} 24-hour AAQS is attained when the expected number of days per year with a 24-hour concentration above 150 $\mu g/m^3$ is equal to or less than 1. For modeling purposes, compliance is based on the sixth highest 24-hour average value over a 5-year period.

[c] Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

[d] Maximum concentrations.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978. 40 CFR 50. 40 CFR 52.21. Rule 62-204, F.A.C.

Table 2-2. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	$3.5x10^{-6}$	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.
MWC = Municipal waste combustor.
MSW = Municipal solid waste.

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.
[c] Any emission rate of these pollutants.

Sources: 40 CFR 52.21. Rule 62-212.400, F.A.C.

Table 2-3. Net Emissions Increase from the Tropicana Steam Boiler Addition

Pollutant	Net Increase in Emissions[a] (TPY)	PSD Significant Rate (TPY)
Particulate Matter (PM)	6.15	25
Particulate Matter (PM_{10})	6.15	15
Sulfur Dioxide	21.75	40
Nitrogen Oxides	41.91	40
Carbon Monoxide	80.41	100
Volatile Organic Compounds	2.36	40
Sulfuric Acid Mist	1.08	7
Lead	3.77E-03	0.6
Mercury	1.26E-03	0.1
Fluorides	--	3

[a] The net increase is based on either 8,760 hours of operation on #2 fuel oil or 8,760 hours of operation on natural gas, both at 100% load.

Table 2-4. Impacts of the New Steam Boiler Compared to Class II Significant Impact Levels and Ambient Monitoring *De Minimis* Levels

Pollutant	Averaging Time	Maximum Concentration[a] ($\mu g/m^3$)	EPA Class II Significant Impact Levels ($\mu g/m^3$)	*De Minimis* Monitoring Concentration ($\mu g/m^3$)	Ambient Monitoring Review Applies?
Sulfur Dioxide	Annual	0.43	1	NA	NA
	24-hour	4.80	5	13	No
	3-hour	10.1	25	NA	NA
Particulate Matter (PM_{10})	Annual	0.12	1	NA	NA
	24-hour	1.35	5	10	No
Nitrogen Oxides	Annual	0.85	1	14	No
Carbon Monoxide	8-hour	29	500	575	No
	1-hour	65	2,000	NA	NA

[a] Highest concentration from significant impact analysis (See Section 4.0).
Note: NA = Not Applicable

3.0 CONTROL TECHNOLOGY REVIEW

3.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant emission rates. For the proposed steam boiler, the control technology review requirements have been conducted for emissions of SO_2, PM_{10}, NO_x, and CO (see Sections 2.4.2 and 2.5.2). BACT review for SO_2 and PM_{10} emissions is required pursuant to Florida Rule 62-296 F.A.C. Also, BACT review for NO_x and CO was conducted due to contemporaneous emission increases of these pollutants with the addition of 16 juice extractors.

This section presents the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring a top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12)]. The analysis must, by definition, be specific to the project (i.e., case-by-case). As described in Section 2.2.2, BACT is determined on a case-by-case basis after taking into account the specific energy, environmental and economic impacts and other costs of the project.

Maximum emissions for the steam boiler are based on operating 8,760 hours per year at 99.8 MMBtu/hr heat input for natural gas firing and 95.7 MMBtu/hr heat input for fuel oil firing. Emissions will be controlled by the use of the low-NO_x burners (LNB) and 5% flue gas recirculation (FGR), and by burning very low sulfur No. 2 distillate fuel oil (i.e., 0.05% sulfur or less). Vendor quotes guaranteed a NO_x emission rate of 0.055 lb/MMBtu for natural gas using LNB and 0.10 lb/MMBtu for fuel oil firing with the LNB and FGR system. These technologies result in the best available control technology considering economic, environmental, and energy impacts.

3.2 BACT DETERMINATION FOR SO_2 EMISSIONS

The proposed BACT for SO_2 emissions from the steam boiler is based on burning No. 2 distillate fuel oil with a sulfur content of 0.05% or less. As part of the BACT analysis, a review of previous SO_2 BACT determinations for small industrial boilers listed in the RACT/BACT/LAER

Clearinghouse on EPA's webpage was performed. Summaries of BACT determinations for both fuel oil- and natural gas-fired boilers from this review are presented in Tables 3-1 and 3-2, respectively. From this review, it is evident that SO_2 BACT determinations for small industrial boilers have typically been fuel specifications and good combustion practices.

Since the level of SO_2 emissions is directly related to the amount of sulfur in the fuel, a low sulfur-containing fuel can be used to meet the SO_2 limitation specified by the NSPS regulations for small industrial boilers. Tropicana proposes to use natural gas and 0.05 percent sulfur fuel oil for the operations of the steam boiler and to limit the annual fuel oil usage to 6,391,508 gallons per year. These conditions result in a maximum of 21.8 TPY of SO_2 emissions when operating on fuel oil only. There is no other technology that could achieve lower SO_2 emissions. Therefore, the proposed BACT for SO_2 emissions is to use natural gas and No. 2 fuel oil with a maximum sulfur content of 0.05 percent and limit fuel oil usage to 6,391,508 gallons per year. The resulting emissions are comparable to the emissions resulting from other BACT determinations, and are consistent with previous BACT determinations.

3.3 BACT DETERMINATION FOR PM_{10} EMISSIONS

Maximum PM_{10} emissions from the steam boiler are estimated to be 6.15 TPY. These maximum emissions are due to fuel oil firing only. Tropicana proposes to use natural gas and No. 2 fuel oil with a maximum sulfur content of 0.05 percent. Both of these fuels are clean burning fuels and result in very low PM_{10} emissions.

As part of the BACT analysis, a review of previous PM/PM_{10} BACT determinations for small industrial boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's webpage was performed. Summaries of BACT determinations for both fuel oil- and natural gas-fired boilers from this review are presented in Tables 3-3 and 3-4, respectively.

From the review of previous BACT determination, it is evident that PM/PM_{10} BACT determinations for both oil-fired and natural gas-fired boilers have typically been fuel specifications and good design and operating practices. Proposed maximum PM_{10} emissions from the steam boiler are 0.015 lb/MMBtu when firing No. 2 fuel oil and 0.002 lb/MMBtu for natural gas. These factors are based on the 1998 revisions of AP-42 Tables 1.3.1 and 1.4.2.

The emission limits from the determinations for fuel oil-fired small industrial boilers range from 0.03 lb/MMBtu to 0.08 lb/MMBtu. The proposed BACT for the steam boiler would result in emissions below this range for fuel oil firing. The emission limits from the determinations for natural gas-fired small industrial boilers range from 0.003 lb/MMBtu to 0.20 lb/MMBtu. The proposed BACT for the steam boiler would result in emissions below this range for natural gas firing.

It would not be economical to install any add-on control equipment to decrease PM_{10} emissions any further than what is achievable through burning clean fuels (i.e., natural gas and No. 2 fuel oil with a maximum sulfur content of 0.05%). Therefore, clean fuels are proposed as BACT for PM_{10} emissions.

3.4 BACT DETERMINATION FOR NO_x EMISSIONS

3.4.1 IDENTIFICATION OF NO_x CONTROL TECHNOLOGIES FOR SMALL INDUSTRIAL BOILERS

In this section, the control technologies capable of reducing NO_x emissions produced by small industrial boilers will be evaluated relative to their potential application as BACT for the operation of the steam boiler. All potentially applicable control technologies for stationary external combustion boilers are reviewed. The technologies can be separated into two major groups:

1. Reducing pollutant emissions by boiler modification (i.e., low excess air burner design), and
2. Converting NO_x in the exhaust gas by add-on flue gas treatment devices.

The discussion of each potential NO_x control technology includes a description of the technology and the potential NO_x emission reduction if the technology is concluded to be technically feasible.

<u>Technologies Involving Boiler Modification</u>

Stationary source NO_x emission control technologies originally were developed for use on large, field-erected electric utility boilers since these boilers are the major source of NO_x emissions. As the NO_x control technologies progress and improve, their applications also are extended to smaller industrial and commercial boilers of less than 500 MMBtu/hr heat input. For the steam boiler, the following boiler modification techniques for controlling NO_x formation are applicable: low excess air (LEA) combustion process, low nitrogen oxides (NO_x) burner design, and flue gas recirculation.

Low Excess Air Combustion Process

Formation of NO_x in combustion processes is a result of both oxidation of fuel-bound nitrogen and thermal oxidation of molecular nitrogen in the incoming air. The latter oxidation process occurs at a higher temperature condition than the standard fuel-combustion process. Typically, thermal oxidation accounts for more than 50 percent of NO_x formation in an oil-fired combustion process since the concentration of fuel-bound nitrogen is so small. The principal mechanism of NO_x formation from natural gas combustion is also thermal oxidation. Thus, controlling the amount of excess air will have a significant effect on the NO_x thermal oxidation process.

A low excess air (LEA) combustion process can be achieved either by an oxygen sensor and control feedback process or by the burner design. In standard boilers, reduction of the excess air level usually is accomplished by installing a flue gas oxygen sensory unit that provides feedback to an inlet air automatic controller that regulates the excess air at the desired level. The LEA combustion process, by modifying the boiler inlet air condition, can achieve a maximum of 25 percent NO_x reduction.

In modern boilers, the LEA combustion process is engineered as an integral part of the burner design, which allows a minimum air-to-fuel ratio in the thermal combustion zone. The LEA burner design can achieve better excess air reduction than the LEA system with a flue gas oxygen sensor and control feedback mechanism.

Low NO_x Burner Design

Low NO_x burner design can directly incorporate advanced and higher efficiency combustion techniques that result in low NO_x formation. There are two standard low NO_x burner designs: LEA (single-staging) burners and multi-staging combustion burners.

The LEA (single-staging) burners are designed to operate at the lowest level of excess air by way of an efficient combustion process supported by an optimal air-to-fuel mixture. Compared to the operation of conventional burners (in the range of 3 to 6 percent of flue gas oxygen concentration), the LEA burners are capable of operating at stack gas oxygen concentrations of 0.5 to 1.5 percent. LEA burners were reported to achieve 45 percent reduction in NO_x formation over the conventional burner when burning distillate oil. LEA burners typically are applied in single-burner systems because of the difficulty in maintaining equal air distribution in multiple-burner systems.

The multi-staging low NO_x burners are designed with advanced staged-combustion principles to reduce both fuel NO_x and thermal NO_x. The staged-combustion process allows the overall combustion to be carried out in two separate combustion zones. In the air staging combustion process, the burner design allows 70 percent of stoichiometric air to burn in a fuel-rich, primary combustion zone. Some heat generated by this incomplete combustion is transferred to the boiler tubes. The combustion process is primary combustion zone. Because of the heat transfer within the primary combustion zone, the peak combustion temperature is lowered.

The fuel NO_x formation is reduced as a result of the oxygen-starved condition in the fuel-rich primary combustion zone causing the total fixed nitrogen compounds (such as ammonia, hydrogen cyanide, and hydromonoxide) to form inert molecular nitrogen. The thermal NO_x formation also is reduced because the lowered peak temperature in the secondary burnout zone does not provide a sufficient temperature for thermal oxidation of the triple-bond molecular nitrogen. Overall, the multi-staging combustion burners can achieve 30 to 65 percent NO_x emission reduction over conventional burners.

Both LEA (single-staging) and multi-staging low NO_x burners usually are designed with internal flue gas recirculation in order to enhance NO_x emission reduction. In internal flue gas recirculation, combustion air within the burner is recirculated.

Flue Gas Recirculation

Flue gas recirculation (FGR) involves recycling a portion of the flue gas from the exhaust gas stream to the windbox of the boiler. Usually, the recycled flue gas is mixed with the inlet combustion air at the windbox before being introduced into the combustion chamber. In FGR, the recycled flue gas mainly serves as a dilutant to lower the overall peak combustion temperature. The heat sink effect occurs in FGR because the particulates in the recycled flue gas absorb some heat form the combustion process. These effects result in reductions of thermal NO_x and have negligible change in fuel NO_x. Therefore, FGR is applied only to low nitrogen-content fuel, such as natural gas or distillate oil.

FGR typically can reduce thermal NO_x by 55 to 65 percent based on 10 to 15 percent flue gas recirculation rates, respectively (Coen, 1991). The recirculation rates are limited to below 15 percent for oil-fired boilers because of burner flame instability and emissions of unburned combustibles. An application of FGR usually requires a low NO_x burner that can be either a LEA burner or a multi-stage low NO_x burner. Actual FGR efficiency depends on the boiler type and burner design.

Technologies Involving Exhaust Gas Treatment

In addition to boiler modification technologies, NO_x emissions can be lowered by NO_x reduction reactions by injecting reducing agents (i.e., ammonia or urea) into the flue gas stream. Also, an add-on device can be inserted into the flue gas ductwork to facilitate the NO_x reduction process. A variety of reaction conditions is required depending on the type of reducing agent and catalyst used. For the steam boiler, the following add-on NO_x control devices have been identified: the NO_xOUT selective non-catalytic reduction (SNCR) process, selective catalytic reduction (SCR) with ammonia injection, SCONO$_x$™, and Cannon Technology's Low-Temperature Oxidation (LTO).

NO_xOUT SNCR Process

The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream within the boiler, ideally within a temperature range of 1,600° F to 1,900° F. In the presence of oxygen, the following reaction occurs:

$$CO(NH_2)_2 + 2NO + \tfrac{1}{2} O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech offers a number of catalysts capable of expanding the effective temperature range of the reaction to between 1,000° F and 1,950° F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of using urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. SO_3, if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

There have been several commercial applications of the NO_xOUT process. These applications have been in California, Louisiana, Tennessee, Texas, and Florida (Osceola and Okeelanta cogeneration facilities). The reductions in NO_x emissions have ranged from 25 percent to 75 percent.

Selective Catalytic Reduction with Ammonia Injection

Engelhard Corporation's discovery in 1957 that ammonia reacts selectively with NO_x in the presence of a catalyst and excess oxygen has led to the commercialization of selective catalytic reduction (SCR) technology for industrial boilers of various sizes. The technology has been well developed and applied in Japan, especially for control of emissions from gas-, oil-, and coal-fired utility boilers. It has been applied domestically on gas turbines, engine generators and natural gas-fired industrial boilers.

SCR catalysts consist of two types: metal oxides and zeolite. In the metal oxides catalytic system, either vanadium or titanium is embedded into a ceramic matrix structure; the zeolite catalysts are ceramic molecular sieves extruded into modules of honeycomb shape. The all-ceramic zeolite catalysts are durable and less susceptible to catalyst masking or poisoning than the noble metal/ceramic base catalysts. All catalysts exhibit advantages and disadvantages in terms of exhaust gas temperatures, ammonia/NO_x ratio, and optimum exhaust gas oxygen concentrations. A common disadvantage for all catalyst systems is the narrow window of temperature between 600° F and 900° F within which the NO_x reduction process takes place (Schorr, 1989; Steuler, 1990; Engelhard, 19901; Johnson-Matthey, 1990). Operating outside this temperature range results in catastrophic harm to the catalyst system. Chemical poisoning occurs at lower temperature conditions, while thermal degradation occurs at higher temperature. Reactivity can only be restored through catalyst replacement.

Catalysts are subject to loss of activity over time. Since the catalyst is the most costly component of the SCR system, applications require servicing and cleaning of catalyst surface every 2,000 to 3,000 hours of operation. The cleaning normally consists of blowing the catalyst surfaces with a compressed air gun or water jet. Most catalyst suppliers guarantee a catalyst of 3 years, assuming certain operating conditions. SCR is capable of potentially achieving 70 to 90 percent NO_x reduction.

$SCONO_x$™

This technology was developed by Goal Line Environmental Technologies and distributed by ABB to control NO_x and CO emissions from large gas turbines. CO and NO_x emissions are reduced through the use of specialized potassium carbonate catalyst beds using an oxidation-absorption-regeneration cycle. The required temperature range for use of this system is between 300°F and 700°F, and requires a heat recover steam generator for use with a combined cycle gas turbine. $SCONO_x$™ can achieve a control efficiency greater than 90% but is not feasible for this steam boiler.

Cannon Technology's Low Temperature Oxidation (LTO)

This technology involves injecting ozone into the gas stream at a temperature of approximately 300°F. This injection is done to oxidize CO, NO_x, and SO_2 to carbonates, nitrates, and sulfates, which are then absorbed by a dilute nitric acid solution in a scrubber. The system was developed for steam boilers. Test results show NO_x emissions below 4 ppmvd at 3% oxygen for gas firing. Only units less than 20 MMBtu/hr have been tested with this process. Because the unit operates at 5 times that of the largest unit tested with LTO, this technology was not considered for any further analysis.

3.4.2 SUMMARY OF TECHNICALLY FEASIBLE NO_x CONTROL METHODS

All of the control methods described thus far are considered to be technically feasible. This section examines these control technologies. First, they are ranked according to their total removal effectiveness. Each alternative is then examined with regard to technical issues, environmental effects, energy requirements and impacts, and economic impacts.

This discussion also reviews previous BACT determinations for small industrial fired boilers. Summaries of previous BACT determinations for oil-fired and natural gas-fired small industrial boilers are presented in Tables 3-5 and 3-6, respectively. This information was obtained from the RACT/BACT/LAER Clearinghouse on EPA's website. The types of control equipment from the previous determinations consist of low NO_x Burners, FGR and good combustion practices. The emission limits for the oil-fired boilers range from 0.10 lb/MMBtu to 0.40 lb/MMBtu. The emission limits for the natural gas-fired boilers range from 0.03 lb/MMBtu to 0.32 lb/MMBtu. Tropicana's proposed NO_x emission limits for the steam boiler of 0.055 lb/MMBtu for natural gas and 0.10 lb/MMBtu for fuel oil are within the low portion of the BACT emission limit ranges previously issued. Feasible control technologies for the project are SCR, SNCR, and LNB with FGR.

<u>Ranking of Feasible NO_x Control Methods</u>

The top-down BACT approach requires the ranking of the NO_x emission control alternatives in terms of achievable emission level. Only control options that result in a greater degree of emission reduction than the proposed control technology need to be considered. For the steam boiler, the proposed control technology is a low-NO_x burner with 5% FGR. The potentially more effective options, in order of removal effectiveness, are as follows: first the application of SCR to the boiler modified with low-NO_x burner and FGR; and second, SNCR with low-NO_x burner and FGR. The BACT top-down hierarchy of the feasible control scenarios is presented in Table 3-7. A baseline condition must be established for BACT ranking and economic analysis purposes. The baseline for the proposed steam boiler is the emission rate of 0.10 lb/MMBtu which is guaranteed by the vendor.

Analysis of SCR

Technical Issues

Technical Issues involved in the use of SCR are the narrowing operating temperature range, the potential damage to the catalyst and downstream equipment, and the ammonium bisulfate formation. For the proposed project, a stack gas reheat system would be required to heat the exhaust gases up to the operating temperature of the SCR. This is required since the boiler is of a standard design. Indeed, the boiler exit temperatures, i.e. before the economizer, are < 600 °F and only about 300 °F after the economizer.

The use of ammonia as a reagent for the NO_x reduction reactions may allow excess ammonia to form ammonia bisulfate compounds when firing oil. These compounds can cause damage to metal ductwork downstream. Cleaning consists of blowing the catalyst surfaces with a compressed air gun and vacuuming any soot.

Currently, there is no documented information concerning SCR application on industrial boilers of a similar size and source category as the proposed steam boiler. No other oil-fired or natural gas-fired boilers of a similar capacity undergoing BACT review have been required to use SCR (refer to Table 3-5 and to Table 3-6).

Environmental Effects

The add-on SCR technology will pose other potential adverse environmental impacts, such as accidental spill and release of ammonia, slippage of ammonia by built-in design, and solid waste disposal for the spent catalyst. These issues are described briefly in the following discussion.

The SCR system requires the use of ammonia as reagent to convert to NO_x to molecular nitrogen and water. The main environmental impact centers on the issue of delivery, handling, and storage of ammonia, which poses inherent safety and health risks in the event of accidental releases. The current practice is to use an aqueous ammonia system (normally between 25 to 29 percent ammonia concentration) at installations locations used in populated areas. However, such practice increases the complexity, the size, and the cost of the ammonia system.

Furthermore, ammonia slippage is a normal occurrence during operation of SCR control equipment. NO_x abatement system suppliers generally report an ammonia slippage level of 10 ppm or less.

Energy Requirements and Impacts

The add-on technology of SCR imposes further energy penalties. The additional energy requirements are caused by a power loss as a result of additional back pressure from the SCR, electrical requirements for heating the ammonia solution and operating the injection system, and additional energy necessary for heating the ammonia solution and operating the injection system, and additional energy necessary for heating the exhaust gases from the steam boiler from 300°F up to the SCR operating range of 700°F.

Economic Analysis

This section includes the total capital investment (TCI) and the annualized cost (AC) for SCR applied to the proposed steam boiler. All cost values are calculated from vendor quotes or standard costing procedures based on the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, Fifth Edition (OAQPS, 1996).

In this costing procedure, the basic equipment cost is the basis for other itemized costs that are calculated as fractional costs of the basic equipment cost. The capital cost estimates, the annualized cost estimates, and the cost effectiveness for SCR-natural gas operation are presented in Table 3-8 and Table 3-9 for SCR-fuel oil operation. The basic equipment cost for the SCR was obtained from a vendor for a previous BACT review for Boiler No. 16 at Okeelanta Corporation South Bay Facility and proportioned based on performance as described in *Air Pollution Control: A Design Approach*, Cooper, 1994.

For SCR applied to the proposed steam boiler, with low-NO_x burners and natural gas operation, the TCI is $1.7 million; the annualized cost is $377,460 and the cost effectiveness is $10,794 per ton of NO_x removed. For SCR applied to the proposed steam boiler, with low-NO_x burners and fuel oil operation, the TCI is $1.7 million; the annualized cost is $377,460 and the cost effectiveness is $11,256 per ton of NO_x removed.

Analysis of SNCR

Technical Issues

The SNCR process operates best at temperatures of 1,000°F to 1,950°F. The exhaust temperature of the proposed steam boiler is approximately 600°F and only 300 °F exiting the economizer. Significant modifications to the boiler would have been made to evaluate as injectors can be used to inject the reagent at the proper temperature in the furnace. Given the size of the boiler, SNCR is not feasible.

3.4.3 NO_x BACT SUMMARY AND CONCLUSION

The BACT analysis for NO_x control has identified two feasible control alternatives that achieve greater reduction than low-NO_x burners with FGR alone: ceramic-based SCR and SNCR. This section will consider the overall environmental, energy, and economic impacts of each alternative and eliminate those with adverse impacts. The control alternative not eliminated will be selected as BACT.

Comparison of Technical Issues

Compared to the two alternatives, the low NO_x burner design with FGR is the most reliable option overall for small industrial boiler applications. Add-on control technology such as SCR and SNCR are not appropriate for the proposed boiler.

Comparison of Environmental Effects

The add-on control technology options pose the potential for adverse environmental impacts. SCR poses the potential for toxic impacts as a result of ammonia handling and storage, and ammonia slip. Similarly, SNCR could result in urea emissions from an accidental release. Therefore, the boiler modification process involving both LNB and FGR is the least adverse NO_x control technology for the proposed steam boiler in regard to the environmental effects.

Comparisons of Energy Impacts

The options involving add-on control technology require additional fuel and energy. The low-NO_x burner option does not require additional fuel or electricity to operate. The amount of heat required to convert the gas stream to a temperature appropriate for SCR use is roughly 7.6

MMBtu/hr or 8% of the energy of the boiler. Emission increases from the higher energy requirement are 1.7 TPY SO_2, 3.3 TPY NO_x, 6.1 TPY CO, and 0.50 TPY PM_{10} fuel oil operation and 0.1 TPY SO_2, 3.3 TPY NO_x, 6.1 TPY CO, and 0.1 TPY PM_{10} for natural gas operation. While a heat exchanger could be added to reduce this, it would complicate the system. Therefore, the boiler modification process using the LNB/FGR option is the best NO_x control technology with regard to energy impacts.

Comparison of Economic Analysis

The add-on control technology options involve significant TCI and high cost effectiveness for removal of NO_x. The most cost-effective application of the SCR option is $10,794 per ton of NO_x removal, which is comparable to the cost of adding an SNCR system. The high cost effectiveness of these options deems the add-on control technology options economically infeasible. Therefore, the LNB/FGR option is the best NO_x control technology with regard to economic impacts.

Conclusion

The NO_x top-down BACT analysis in terms of environmental impacts, energy impacts, and economical impacts for the proposed steam boiler is summarized in Table 3-10. The analysis has included two add-on control technologies. The main reasons for eliminating both SCR and SNCR are their technical feasibility and high cost effectiveness. This is consistent with previous BACT determinations for NO_x emissions from small industrial boilers. There are no existing small industrial boilers that have been required to use SCR or SNCR for NO_x control (refer to Tables 3-5 and 3-6). By eliminating both add-on control technology options, the LNB with FGR option is concluded to be BACT for NO_x emissions from the proposed steam boiler.

3.5 BACT DETERMINATION FOR CO EMISSIONS

Maximum CO emissions from the proposed steam boiler are estimated to be 80.4 TPY. Tropicana proposes to use good combustion practices to control CO emissions.

As part of the BACT analysis, a review of previous CO BACT determinations for industrial boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's website was performed. Summaries of the BACT determinations for both fuel oil- and natural gas-fired boilers from this review are presented in Tables 3-11 and 3-12, respectively. The CO emission limits for fuel oil-fired boilers range from 0.03 lb/MMBtu to 0.09 lb/MMBtu. The CO emission limits for natural gas-fired boilers range from 0.02 lb/MMBtu to 0.20 lb/MMBtu. This rather large range of emissions is due to differences in boiler design and operation. From the review of previous BACT determinations, it is evident that CO BACT determinations for both oil-fired and natural gas-fired industrial boilers have typically been good combustion practices and boiler design.

Proposed maximum CO emissions from the proposed steam boiler are 200 ppm at 3% O_2 for both fuel oil and natural gas firing. The emission limits are within the range of previous determinations, and are based on vendor information. No other gas/oil fired boilers have been required to use add-on control for CO emissions. Tropicana proposes to use good combustion practices to control CO emissions from the steam boiler. This level of control is consistent with previous determinations. As seen in the comparison between Tables 3-6 and 3-12, it is noted that in the past, NO_x emission limits have been generally higher than CO emission limits, i.e. the 90 MMBtu/hr boiler at Fulton Cogeneration Associates, permitted in 1990. However, present day standards suggest that the trend is moving towards a lower NO_x emission limit on most equipment, i.e. the 80.8 MMBtu/hr boiler at American Soda Ash, LLP, Parachute Facility, permitted in 1999.

Table 3-1. BACT Determinations for SO_2 Emissions for Fuel Oil-Fired Industrial Boilers, Less Than 100 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits As Provided In LAER/BACT Clearinghouse	Control Equipment/Description	Percent Efficiency
U.S. Navy Base, Northern Division	CT	CT-0009	2/7/90	98 MMBtu/hr	0.53 lb/MMBtu	Fuel Spec: 0.5% S OIL	50
Mansfield Training School	CT	CT-0011	9/14/89	4.8 MMBtu/hr	1.097 lb/MMBtu	Fuel Spec: Fuel Limitation	--
Mansfield Training School	CT	CT-0011	9/14/89	2.9 MMBtu/hr	1.097 lb/MMBtu	Fuel Spec: Fuel Limitation	--
Mansfield Training School	CT	CT-0011	9/14/89	2.9 MMBtu/hr	1.097 lb/MMBtu	Fuel Spec: Fuel Limitation	--
Mansfield Training School	CT	CT-0011	9/14/89	2.2 MMBtu/hr	1.167 lb/MMBtu	Fuel Spec: Fuel Limitation	--
New England Furniture	CT	CT-0081	3/15/88	15.2 MMBtu/hr	0.523 lb/MMBtu	See Notes	--
Mid-Georgia Cogeneration	GA	GA-0063	4/3/96	60 MMBtu/hr	-- --	Fuel Spec: Very Low Sulfur in Fuel	--
Hadson Power II	VA	VA-0165	11/22/89	81.58 MMBtu/hr	0.31 lb/MMBtu	Combustion	--

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001

Table 3-2. BACT Determinations for SO_2 Emissions for Natural Gas-Fired Industrial Boilers, Less Than 100 MMBtu/hr

Company	State	RBLC ID	Permit Date	Heat Input	Emissions: As Provided In LAER/BACT Clearinghouse	Emissions: Converted to lb/MMBtu [a]	Control Equipment/Description
Anniston Army Depot	AL	AL-0139	6/19/97	13.4 MMBtu/hr	0.016 lb/hr	0.0012	Clean Fuel
Anniston Army Depot	AL	AL-0140	6/19/97	11.7 MMBtu/hr	0.014 lb/hr	0.0012	Clean Fuel
Intel Corporation	AZ	AZ-0022	4/10/94	50 MMBtu/hr	-- --	--	Fuel Spec: Natural Gas Primary, .055 Wt. % Sulfur Fuel Oil Backup Only
Orange Cogeneration, L.P.	FL	FL-0068	12/30/93	100 MMBtu/hr	0.003 lb/MMBtu	0.003	Fuel Spec: Low Sulfur Fuel, Gas Fired
Waupaca Foundry - Plant 5	IN	IN-0068	1/19/96	93.9 MMBtu/hr	0.0558 lb/hr	0.0006	--
Transamerican Refining Corporation	LA	LA-0085	1/15/93	1.2 MMBtu/hr	0.001 lb/hr	0.0008	Good Combustion Practices
Fulton Cogeneration Associates	NY	NY-0039	1/29/90	90 MMBtu/hr	0.3 % Sulfur Fuel	--	Fuel Spec: Low Sulfur Fuel

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the heat input rate.

Table 3-4. BACT Determinations for PM/PM_{10} Emissions for Natural Gas-Fired Industrial Boilers, Less Than 100 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput	Emissions As Provided In LAER/BACT Clearinghouse	Emissions Converted to lb/MMBtu [a]	Control Equipment/Description
Intel Corporation	AZ	AZ-0022	4/10/94	50 MMBtu/hr	-- --	--	Fuel Spec: Natural Gas Primary, .055 wt % Sulfur Fuel Oil Backup Only
Mid-Georgia Cogeneration	GA	GA-0063	4/3/96	60 MMBtu/hr	0.005 lb/MMBtu	0.005	Complete Combustion
Nucor Steel	IN	IN-0034	11/30/93	7.3 MMBtu/hr	3 lb/MMcf	0.003	Fuel Spec: Natural Gas Firing
Nucor Steel	IN	IN-0034	11/30/93	34 MMBtu/hr	3 lb/MMcf	0.003	Fuel Spec: Natural Gas Firing
Waupaca Foundry - Plant 5	IN	IN-0068	1/19/96	93.9 MMBtu/hr	1.29 lb/hr	0.014	--
Toyota Motor Corporation Services of N.A.	IN	IN-0069	8/9/96	58 MMBtu/hr	0.2 lb/MMBtu	0.2	Low NOx Burners & Fuel Spec: Use of Natural Gas as Fuel
Transamerican Refining Corporation (TARC)	LA	LA-0085	1/15/93	1.2 MMBtu/hr	0.008 lb/hr	0.007	Good Combustion Practices
Air Liquide America Corporation	LA	LA-0112	2/13/98	95 MMBtu/hr	0.01 lb/MMBtu	0.01	Good Design, Proper Operating Practices, and use Clean Natural Gas as Fuel
Indeck Energy Company	NY	NY-0066	5/12/93	-- MMBtu/hr	0.005 lb/MMBtu	0.005	No Controls
Indek - Yerkes Energy Services	NY	NY-0077	6/24/92	99 MMBtu/hr	0.1 lb/MMBtu	0.1	No Controls
Kamine/Besicorp Corning L.P.	NY	NY-0048	11/5/92	33.5 MMBtu/hr	0.0051 lb/MMBtu	0.0051	Combustion Control
Kamine/Besicorp Syracuse L.P.	NY	NY-0072	12/10/94	33 MMBtu/hr	0.01 lb/MMBtu	0.01	Fuel Spec: Sulfur Content Not to Exceed 0.15% by Weight
Kamine/Besicorp Syracuse L.P.	NY	NY-0072	12/10/94	2.5 MMBtu/hr	0.01 lb/MMBtu	0.01	Fuel Spec: Sulfur Content Not to Exceed 0.15% by Weight
Fulton Cogeneration Associates	NY	NY-0039	1/29/90	90 MMBtu/hr	0.014 lb/MMBtu	0.014	Combustion Control
					AVERAGE	0.03	
					MAXIMUM	0.2	
					MINIMUM	0.003	

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from lb/MMcf, the emission limit was divided by 1,020 MMcf/MMBtu.

Table 3-3. BACT Determinations for PM/PM_{10} Emissions for Fuel Oil-Fired Industrial Boilers, Less Than 100 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput	Emissions As Provided In LAER/BACT Clearinghouse	Control Equipment/Description
U.S. Navy Base, Northern Division	CT	CT-0009	2/7/90	98 MMBtu/hr	0.05 lb/MMBtu	Good Combustion Practices
Mansfield Training School	CT	CT-0011	9/14/89	4.8 MMBtu/hr	0.048 lb/MMBtu	Fuel Spec: Fuel Limitation
Mansfield Training School	CT	CT-0011	9/14/89	2.9 MMBtu/hr	0.048 lb/MMBtu	Fuel Spec: Fuel Limitation
Mansfield Training School	CT	CT-0011	9/14/89	2.9 MMBtu/hr	0.048 lb/MMBtu	Fuel Spec: Fuel Limitation
Mansfield Training School	CT	CT-0011	9/14/89	2.2 MMBtu/hr	0.051 lb/MMBtu	Fuel Spec: Fuel Limitation
New England Furniture	CT	CT-0081	3/15/88	15.2 MMBtu/hr	0.047 lb/MMBtu	--
Mid-Georgia Cogeneration	GA	GA-0063	4/3/96	60 MMBtu/hr	0.028 lb/MMBtu	Complete Combustion
Hadson Power II	VA	VA-0165	11/22/89	81.58 MMBtu/hr	0.03 lb/MMBtu	Combustion Control
Hadson Power II	VA	VA-0165	11/22/89	81.58 MMBtu/hr	0.04 lb/MMBtu	Combustion Control
Kes Chateaugay Project	NY	NY-0055	12/19/94	5 MMBtu/hr	0.03 lb/MMBtu	No Controls
				AVERAGE	0.04	
				MAXIMUM	0.05	
				MINIMUM	0.028	

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001

Table 3-5. BACT Determinations for NO_x Emissions for Fuel Oil-Fired Industrial Boilers, Less Than 100 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput	Emissions As Provided In LAER/BACT Clearinghouse	Control Equipment/Description	% Efficiency
U.S. Navy Base, Northern Division	CT	CT-0009	2/7/90	98 MMBtu/hr	0.2 lb/MMBtu	Low NOx Burners	33
Mansfield Training School	CT	CT-0011	9/14/89	4.8 MMBtu/hr	0.379 lb/MMBtu	Fuel Spec: Fuel Limitation	--
Mansfield Training School	CT	CT-0011	9/14/89	2.9 MMBtu/hr	0.379 lb/MMBtu	Fuel Spec: Fuel Limitation	--
Mansfield Training School	CT	CT-0011	9/14/89	2.9 MMBtu/hr	0.379 lb/MMBtu	Fuel Spec: Fuel Limitation	--
Mansfield Training School	CT	CT-0011	9/14/89	2.2 MMBtu/hr	0.404 lb/MMBtu	Fuel Spec: Fuel Limitation	--
New England Furniture	CT	CT-0081	3/15/88	15.2 MMBtu/hr	0.367 lb/MMBtu	--	--
Mid-Georgia Cogeneration	GA	GA-0063	4/3/96	60 MMBtu/hr	0.15 lb/MMBtu	Dry Low Nox Burner with FGR	--
KES Chateaugay Project	NY	NY-0055	12/19/94	5 MMBtu/hr	0.2 lb/MMBtu	No Controls	--
Hadson Power II	VA	VA-0165	11/22/89	81.58 MMBtu/hr	0.1 lb/MMBtu	Combustion	--
Appleton Paper, Inc.	WI	WI-0065	1/12/93	200000 lbs steam/hr	0.1 lb/MMBtu	Low NOx Burners and Flue Gas Reinductor	75
				AVERAGE	0.27		
				MAXIMUM	0.40		
				MINIMUM	0.10		

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001

Table 3-6. BACT Determinations for NO_x Emissions for Natural Gas-Fired Industrial Boilers, Less Than 100 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput	Emission Limits As Provided In LAER/BACT Clearinghouse	Emission Limits Converted to lb/MMBtu [a]	Control Equipment/Description	% Efficiency
Shell Offshore, Inc.	AL	AL-0045	10/25/89	48.2 MMBtu/hr	4.8 lb/hr	0.100	Low NOx Burners	50
Huls America	AL	AL-0052	8/31/90	38.9 MMBtu/hr	0.075 lb/MMBtu	0.075	Low NOx Burners	--
Champion International Corporation	AL	AL-0066	5/8/91	5.83 MMBtu/hr	0.05 lb/MMBtu	0.05	Flue Gas Recirculation	--
Anniston Army Depot	AL	AL-0139	6/19/97	13.4 MMBtu/hr	0.03 lb/MMBtu	0.03	Low NOx Burners, Clean Fuel	79
Anniston Army Depot	AL	AL-0140	6/19/97	11.7 MMBtu/hr	0.03 lb/MMBtu	0.03	Low NOx Burners, Clean Fuel	79
Intel Corporation	AZ	AZ-0022	4/10/94	50 MMBtu/hr	-- --	--	Low NOx Burners	--
Toma-Tek Inc.	CA	CA-0408	3/1/89	90 MMBtu/hr	3.05 lb/hr	0.034	Low NOx Burners, Good Combustion Practices	--
Sunland Refinery	CA	CA-0513	9/24/92	12.6 MMBtu/hr	0.036 lb/MMBtu	0.036	Low NOx Burner and FGR	--
American Soda, LLP, Parachute Facility	CO	CO-0040	5/6/99	80.8 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Combustion System	--
Orange Cogeneration, L.P.	FL	FL-0068	12/30/93	100 MMBtu/hr	0.13 lb/MMBtu	0.13	Low NOx Burners	--
Mid-Georgia Cogeneration	GA	GA-0063	4/3/96	60 MMBtu/hr	0.1 lb/MMBtu	0.1	Dry Low NOx Burner with FGR	--
Naturalgas Pipeline Company	IL	IL-0043	3/1/89	8.4 MMBtu/hr	0.1 lb/MMBtu	0.1	--	--
Waupaca Foundry - Plant 5	IN	IN-0068	1/19/96	93.9 MMBtu/hr	6.94 lb/hr	0.074	Low NOx Burners	--
I/N Kote	IN	IN-0039	11/20/89	70.8 MMBtu/hr	0.05 lb/MMBtu	0.05	Flue Gas Recirculation and Fuel Selection	--
General Electric Company	IN	IN-0043	9/17/89	93 MMBtu/hr	0.133 lb/MMBtu	0.133	Staged Combustion Air & Low Excess Air	--
Toyota Motor Corporation Services of N.A.	IN	IN-0069	8/9/96	58 MMBtu/hr	0.1 lb/MMBtu	0.1	Low NOx Burners and Fuel Selection	--
Transamerican Refining Corporation (TARC)	LA	LA-0085	1/15/93	1.2 MMBtu/hr	0.14 lb/hr	0.117	Good Combustion Practices	--
Air Liquide America Corporation	LA	LA-0112	2/13/98	95 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Burners	--
Indelk Energy Services of Otsego	MI	MI-0228	3/16/93	99 MMBtu/hr	0.06 lb/MMBtu	0.06	Flue Gas Recirculation	40
Fulton Cogeneration Associates	NY	NY-0039	1/29/90	90 MMBtu/hr	0.14 lb/MMBtu	0.14	Combustion Control	--
Kamine/Besicorp Corning L.P.	NY	NY-0048	11/5/92	33.5 MMBtu/hr	0.32 lb/MMBtu	0.32	Low NOx Burner and FGR	--
Kamine/Besicorp Syracuse L.P.	NY	NY-0072	12/10/94	33 MMBtu/hr	0.035 lb/MMBtu	0.035	Induced Flue Gas Recirculation	70.9
Kamine/Besicorp Syracuse L.P.	NY	NY-0072	12/10/94	2.5 MMBtu/hr	0.12 lb/MMBtu	0.12	No Controls	--
Indek - Yerkes Energy Services	NY	NY-0077	6/24/92	99 MMBtu/hr	0.2 lb/MMBtu	0.2	No Controls	--
CNG Transmission Corporation	WV	WV-0011	5/3/93	10 MMBtu/hr	140 lb/MMcf	0.137	--	--
					AVERAGE	0.09		
					MAXIMUM	0.32		
					MINIMUM	0.03		

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001
FGR = Flue Gas Recirculation

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from lb/MMcf, the emission limit was divided by 1,020 MMcf/MMBtu.

d Industrial Boilers, Less Than 100 MMBtu/hr

Permit Date	Throughput	Emission Limits: As Provided In LAER/BACT Clearinghouse	Emission Limits: Converted to lb/MMBtu [a]	Control Equipment/Description	% Efficiency
10/25/89	48.2 MMBtu/hr	4.8 lb/hr	0.100	Low NOx Burners	50
8/31/90	38.9 MMBtu/hr	0.075 lb/MMBtu	0.075	Low NOx Burners	--
5/8/91	5.83 MMBtu/hr	0.05 lb/MMBtu	0.05	Flue Gas Recirculation	--
6/19/97	13.4 MMBtu/hr	0.03 lb/MMBtu	0.03	Low NOx Burners, Clean Fuel	79
6/19/97	11.7 MMBtu/hr	0.03 lb/MMBtu	0.03	Low NOx Burners, Clean Fuel	79
4/10/94	50 MMBtu/hr	-- --	--	Low NOx Burners	--
3/1/89	90 MMBtu/hr	3.05 lb/hr	0.034	Low NOx Burners, Good Combustion Practices	--
9/24/92	12.6 MMBtu/hr	0.036 lb/MMBtu	0.036	Low NOx Burner and FGR	--
5/6/99	80.8 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Combustion System	--
12/30/93	100 MMBtu/hr	0.13 lb/MMBtu	0.13	Low NOx Burners	--
4/3/96	60 MMBtu/hr	0.1 lb/MMBtu	0.1	Dry Low NOx Burner with FGR	--
3/1/89	8.4 MMBtu/hr	0.1 lb/MMBtu	0.1	--	--
1/19/96	93.9 MMBtu/hr	6.94 lb/hr	0.074	Low NOx Burners	--
11/20/89	70.8 MMBtu/hr	0.05 lb/MMBtu	0.05	Flue Gas Recirculation and Fuel Selection	--
9/17/89	93 MMBtu/hr	0.133 lb/MMBtu	0.133	Staged Combustion Air & Low Excess Air	--
8/9/96	58 MMBtu/hr	0.1 lb/MMBtu	0.1	Low NOx Burners and Fuel Selection	--
1/15/93	1.2 MMBtu/hr	0.14 lb/hr	0.117	Good Combustion Practices	--
2/13/98	95 MMBtu/hr	0.05 lb/MMBtu	0.05	Low NOx Burners	--
3/16/93	99 MMBtu/hr	0.06 lb/MMBtu	0.06	Flue Gas Recirculation	40
1/29/90	90 MMBtu/hr	0.14 lb/MMBtu	0.14	Combustion Control	--
11/5/92	33.5 MMBtu/hr	0.32 lb/MMBtu	0.32	Low NOx Burner and FGR	--
12/10/94	33 MMBtu/hr	0.035 lb/MMBtu	0.035	Induced Flue Gas Recirculation	70.9
12/10/94	2.5 MMBtu/hr	0.12 lb/MMBtu	0.12	No Controls	--
6/24/92	99 MMBtu/hr	0.2 lb/MMBtu	0.2	No Controls	--
5/3/93	10 MMBtu/hr	140 lb/MMcf	0.137	--	--
		AVERAGE	0.09		
		MAXIMUM	0.32		
		MINIMUM	0.03		

Table 3-7. BACT "Top-down" Hierarchy of NO_x Reduction Methods for Proposed Steam Boiler

Fuel Oil

Top-Down Ranking	Technology	Control Effectiveness (%)	Emission Level (lb/MMBtu)	Annual Emissions (TPY)
First	Low-NO_x burner with SCR	92[a]	0.030	8.4
Second	Low-NO_x burner with SNCR	72[b]	0.105	29.3
Third	Low-NO_x burner with FGR	60	0.10[c]	41.9

Natural Gas

Top-Down Ranking	Technology	Control Effectiveness (%)	Emission Level (lb/MMBtu)	Annual Emissions (TPY)
First	Low-NO_x burner with SCR	92[a]	0.030	8.7
Second	Low-NO_x burner with SNCR	72[b]	0.105	30.6
Third	Low-NO_x burner with FGR	60	0.10[c]	43.7

Footnotes:

[a] SCR alone can achieve 80 percent reduction.

[b] SNCR alone can achieve 30 percent reduction.

[c] Proposed steam boiler emission rate for gas and oil firing.

Table 3-8. Cost Effectiveness of SCR, Tropicana Proposed Steam Boiler (Natural Gas Operation)

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
SCR Basic Process	Vendor quote[b,c]	850,000
Ammonia System	See note "d"	36,560
Auxilary Equipment (Reheat)	10% of equipment cost	85,000
Emissions Monitoring	15% of equipment cost	85,000
Structure Support	8% of equipment cost	68,000
Freight	5% of equipment cost	42,500
Taxes	Florida sales tax, 6%	51,000
Total PEC:		1,218,060
Direct Installation	30% of PEC	365,418
Total DCC		1,583,478
INDIRECT CAPITAL COSTS (ICC):		
Engineering	10% of PEC	158,348
Construction and field expenses	5% of PEC	79,174
Contractor Fees	10% of PEC	158,348
Startup	2% of PEC	31,670
Performance test	1% of PEC	15,835
Contingencies	3% of PEC	47,504
Total DCC:		490,878
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	1,708,938
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator	0.5 hr/shift, $16/hr, 8760 hrs/yr	8,760
Supervisor	15% of operator cost	1,314
(2) Maintenance	Vendor quote	10,000
(3) Variable O&M[e,f]	99.8 MMBtu/hr, 8,760 hr/yr	22,196
(4) Catalyst Replacement and disposal[f]	99.8 MMBtu/hr, 8,760 hr/yr, 3 ye	12,119
Total DOC:		54,389
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenanc	12,044
Property Taxes	1% of total capital investment	17,089
Insurance	1% of total capital investment	17,089
Administration	2% of total capital investment	34,179
Total IOC:		80,402
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.142 times TCI (10 yrs	242,669
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	377,460
BASELINE NO_x EMISSIONS (TPY):	0.10 lb/MMBtu, 99.8 MMBtu/hr,	43.7
MAXIMUM NO_x EMISSIONS (TPY):	80% reduction	8.7
REDUCTION IN NO_x EMISSONS (TPY):		35.0
COST EFFECTIVENESS:	$ per ton of NO_x Removed	10,794

Footnotes

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Fifth edition. Cost estimates have been converted from 1988 dollars to 1999 dollars by a ratio of CE Cost Indexes (1988: 342.5, 1999: 400)

[b] Calculated from BACT analysis performed on Okeelanta Corporation, South Bay Modification of Boiler No. 16 employing a ratio of lb/MMBtu of the two units to generate a conservative SCR basic process cost
Source: Formula 2.15: *Air Pollution Control - A Design Approach*, Cooper, 1994.

[c] Vendor quote from 1991 quote for SCR system for Okeelanta Boiler No. 16. Quote has been converted from 1991 dollars to 1999 dollars by a ratio of CE Cost Indexes (1991: 361.3, 1999: 400)

[d] Ammonia vendor's quotation for LaRoche Industries, Inc. for a 3,000-gallon anhydrous ammonia tank, an ammonia evaporator, and a dual-valve pressure regulator. Quote was converted to 1999 dollars from 1991 dollars by a ratio of CE Cost Indexes (1991: 361.3 and 1999: 400).

[e] Includes cost of ammonia, electricity and steam

[f] Based on cost equation and factors from the EPA document titled "New Source Performance Standards, Subpart Db - Technical Support for Proposed Revisions to NOx Standard" (6/97). See Appendix B for equation and factors

Table 3-9. Cost Effectiveness of SCR, Tropicana Proposed Steam Boiler (Fuel Oil Operation)

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
SCR Basic Process	Vendor quote[b,c]	850,000
Ammonia System	See note "d"	36,560
Auxilary Equipment (Reheat)	10% of equipment cost	85,000
Emissions Monitoring	15% of equipment cost	85,000
Structure Support	8% of equipment cost	68,000
Freight	5% of equipment cost	42,500
Taxes	Florida sales tax, 6%	51,000
Total PEC.		1,218,060
Direct Installation	30% of PEC	365,418
Total DCC:		1,583,478
INDIRECT CAPITAL COSTS (ICC).		
Engineering	10% of PEC	158,348
Construction and field expenses	5% of PEC	79,174
Contractor Fees	10% of PEC	158,348
Startup	2% of PEC	31,670
Performance test	1% of PEC	15,835
Contingencies	3% of PEC	47,504
Total DCC:		490,878
TOTAL CAPITAL INVESTMENT (TCI)	DCC + ICC	1,708,938
DIRECT OPERATING COSTS (DOC)		
(1) Operating Labor		
Operator	0.5 hr/shift, $16/hr, 8760 hrs/yr	8,760
Supervisor	15% of operator cost	1,314
(2) Maintenance	Vendor quote	10,000
(3) Variable O&M[e,f]	99.8 MMBtu/hr, 8,760 hr/yr	22,196
(4) Catalyst Replacement and disposal[f]	99 8 MMBtu/hr, 8,760 hr/yr; 3 year life	12,119
Total DOC.		54,389
INDIRECT OPERATING COSTS (IOC)		
Overhead	60% of oper. labor & maintenance	12,044
Property Taxes	1% of total capital investment	17,089
Insurance	1% of total capital investment	17,089
Administration	2% of total capital investment	34,179
Total IOC·		80,402
CAPITAL RECOVERY COSTS (CRC)	CRF of 0.142 times TCI (10 yrs @ 7%)	242,669
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	377,460
BASELINE NO_x EMISSIONS (TPY)	0.10 lb/MMBtu, 95.7 MMBtu/hr; 8,760 hr/yr (fuel oil)	41.9
MAXIMUM NO_x EMISSIONS (TPY) :	80% reduction	8 4
REDUCTION IN NO_x EMISSONS (TPY).		33.5
COST EFFECTIVENESS:	$ per ton of NO_x Removed	11,256

Footnotes·

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Fifth edition. Cost estimates have been converted from 1988 dollars to 1999 dollars by a ratio of CE Cost Indexes (1988· 342 5, 1999 400)

[b] Calculated from BACT analysis performed on Okeelanta Corporation, South Bay Modification of Boiler No 16 employing a ratio of lb/MMBtu of the two units to generate a conservative SCR basic process cost.
Source Formula 2.15. *Air Pollution Control - A Design Approach*, Cooper, 1994

[c] Vendor quote from 1991 quote for SCR system for Okeelanta Boiler No 16 Quote has been converted from 1991 dollars to 1999 dollars by a ratio of CE Cost Indexes (1991. 361.3, 1999: 400)

[d] Ammonia vendor's quotation for LaRoche Industries, Inc for a 3,000-gallon anhydrous ammonia tank, an ammonia evaporator, and a dual-valve pressure regulator. Quote was converted to 1999 dollars from 1991 dollars by a ratio of CE Cost Indexes (1991: 361 3 and 1999: 400).

[e] Includes cost of ammonia, electricity and steam

[f] Based on cost equation and factors from the EPA document titled "New Source Performance Standards, Subpart Db - Technical

Table 3-10. Summary of Top-Down BACT Impact Analysis Results for NO_x

Control Alternative	Total Emission Reduction (TPY)	Technical Feasibility	Potential Environmental Impacts: Toxic Air Impact?	Potential Environmental Impacts: Adverse Environmental Impacts?	Energy Impacts: Incremental Increase Over Baseline? Fuel	Energy Impacts: Incremental Increase Over Baseline? Electricity	Economic Impacts: Annualized Cost ($)	Economic Impacts: Cost Effectiveness ($/ton)
Fuel Oil								
Low-NO_x burner with SCR	33.5	Yes	Yes	Yes	Yes	Yes	377,460	11,256
Low-NO_x burner with SNCR	12.6	No	No	Yes	Yes	Yes	--	--
Low-NO_x burner with FGR	--	Yes	No	No	No	No	--	--
Natural Gas								
Low-NO_x burner with SCR	35.0	Yes	Yes	Yes	Yes	Yes	377,460	10,794
Low-NO_x burner with SNCR	13.1	No	No	Yes	Yes	Yes	--	--
Low-NO_x burner with FGR	--	Yes	No	No	No	No	--	--

Table 3-11. BACT Determinations for CO Emissions for Fuel Oil-Fired Boilers, Less Than 100 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput		Emissions As Provided In LAER/BACT Clearinghouse	Control Equipment/ Description
U.S. Navy Base, Northern Division	CT	CT-0009	2/7/90	98	MMBtu/hr	0.03 lb/MMBtu	Good Combustion Practices
Mansfield Training School	CT	CT-0011	9/14/89	4.8	MMBtu/hr	0.034 lb/MMBtu	Fuel Spec: Fuel Limitation
Mansfield Training School	CT	CT-0011	9/14/89	2.9	MMBtu/hr	0.034 lb/MMBtu	Fuel Spec: Fuel Limitation
Mansfield Training School	CT	CT-0011	9/14/89	2.9	MMBtu/hr	0.034 lb/MMBtu	Fuel Spec: Fuel Limitation
Mansfield Training School	CT	CT-0011	9/14/89	2.2	MMBtu/hr	0.037 lb/MMBtu	Fuel Spec: Fuel Limitation
New England Furniture	CT	CT-0081	3/15/88	15.2	MMBtu/hr	0.033 lb/MMBtu	--
Mid-Georgia Cogeneration	GA	GA-0063	4/3/96	60	MMBtu/hr	0.09 lb/MMBtu	Complete Combustion
Kes Chateaugay Project	NY	NY-0055	12/19/94	5	MMBtu/hr	0.036 lb/MMBtu	No Controls
Hadson Power II	VA	VA-0165	11/22/89	81.58	MMBtu/hr	0.082 lb/MMBtu	Combustion Control
					AVERAGE	0.05	
					MAXIMU	0.09	
					MINIMUM	0.03	

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001

Table 3-12. BACT Determinations for CO Emissions for Natural Gas-Fired Boilers, Less Than 100 MMBtu/hr

Company	State	RBLC ID	Permit Date	Throughput	Emissions: As Provided In LAER/ BACT Clearinghouse	Emissions: Converted to lb/MMBtu [a]	Control Equipment/Description
Champion International	AL	AL-0066	5/8/91	5.83 MMBtu/hr	0.09 lb/MMBtu	0.09	Good Combustion Practices
Quincy Soybean Company of Arkansas	AR	AR-0019	3/4/97	68 MMBtu/hr	10.6 lb/hr	0.156	Good Combustion Practices
American Soda, LLP, Parachute Facility	CO	CO-0040	5/6/99	80.8 MMBtu/hr	0.09 lb/MMBtu	0.09	Good Combustion Practices
Mid-Georgia Cogeneration	GA	GA-0063	4/3/96	60 MMBtu/hr	0.05 lb/MMBtu	0.05	Complete Combustion
Naturalgas Pipeline Company	IL	IL-0043	3/1/89	8.4 MMBtu/hr	0.02 lb/MMBtu	0.02	--
Nucor Steel	IN	IN-0034	11/30/93	7.3 MMBtu/hr	20 lb/MMcf	0.020	--
Nucor Steel	IN	IN-0034	11/30/93	34 MMBtu/hr	35 lb/MMcf	0.034	--
Waupaca Foundry - Plant 5	IN	IN-0068	1/19/96	93.9 MMBtu/hr	19.2 lb/hr	0.204	Low NOx Burner
Transamerican Refining Corporation (TARC)	LA	LA-0085	1/15/93	1.2 MMBtu/hr	0.03 lb/hr	0.025	Good Operating Practice
Air Liquide America Corporation	LA	LA-0112	2/13/98	95 MMBtu/hr	0.06 lb/MMBtu	0.06	Good Design, Proper Operating Practices and 2% Excess O_2
Fulton Cogeneration Associates	NY	NY-0039	1/29/90	90 MMBtu/hr	0.035 lb/MMBtu	0.035	Combustion Control
Kamine/Besicorp Syracuse L.P.	NY	NY-0072	12/10/94	33 MMBtu/hr	0.038 lb/MMBtu	0.038	No Controls
Kamine/Besicorp Syracuse L.P.	NY	NY-0072	12/10/94	2.5 MMBtu/hr	0.152 lb/MMBtu	0.152	No Controls
Indek - Yerkes Energy Services	NY	NY-0077	6/24/92	99 MMBtu/hr	0.038 lb/MMBtu	0.038	No Controls
CNG Transmission Corporation	WV	WV-0011	5/3/93	10 MMBtu/hr	35 lb/MMcf	0.034	--
					AVERAGE	0.07	
					MAXIMUM	0.20	
					MINIMUM	0.02	

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2001

Footnotes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from lb/MMcf, the emission limit was divided by 1,020 MMcf/MMBtu.

4.0 AIR QUALITY IMPACT ANALYSIS

For the proposed project, the net emissions changes are greater than the PSD significant emission rate for NO_x. Also, the proposed project is contemporaneous with the addition of 16 juice extractors over the next two years. As a result, the impacts of all criteria pollutants are analyzed. The following section presents the air modeling approach, including methods and assumptions, and summaries of maximum pollutant concentrations predicted for comparison to PSD Class II significant impact levels.

4.1 AIR MODELING ANALYSIS APPROACH

4.1.1 MODEL SELECTIONS

Significant Impact Analysis

The ISCST3 dispersion model (Version 10100) was used to evaluate the pollutant impacts due to the proposed steam boiler alone. This model is currently available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 4-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

Since the terrain surrounding the Tropicana facility is flat, the modeling analysis assumed that all receptors were at the base elevation of the facility (i.e., flat terrain assumption in ISCST3).

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can run in the rural or urban land use mode, which affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent of the land use within a 3-km radius circle around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on reviews of aerial and U.S. Geological Survey (USGS) topographical maps and a site visit, the land use within a 3-km (1.9-mile) radius of the Tropicana site is considered to be rural (i.e., very little heavy industrial, light-moderate industrial, commercial, or compact residential land use categories). Therefore, the rural mode was used in the air dispersion model to predict impacts from the Tropicana site.

The ISCST3 model was used to predict maximum pollutant concentrations for averaging the annual and 24-hour, 8-hour, 3-hour, and 1-hour averaging periods. The predicted concentrations were then compared to applicable significant impact levels (SILs).

4.1.2 SIGNIFICANT IMPACT ANALYSIS

Site Vicinity

A significant impact analysis is performed for all criteria pollutants. For each pollutant, a significant impact analysis is performed to determine a project's maximum air quality impact and the distance at which the project's impacts are below SIL. If the project's maximum impacts are less than the SIL, no additional modeling with other sources is needed and the impact analysis is complete. However, if the project's impacts are predicted to be greater than the SIL for a particular pollutant, then additional, more detailed modeling analyses are required for that pollutant. The additional analyses include AAQS and PSD increment analyses. Both of these detailed analyses require that the cumulative air quality impacts from other facilities that are in the vicinity of the proposed project's plant be addressed in the impact evaluation.

4.1.3 PSD CLASS I APPLICABILITY

The nearest Class I area to the site is the Everglades National Park (ENP), located about 180 km (113 miles) south southwest of the Tropicana Fort Pierce Plant site. Given the great distance, a PSD Class I analysis was not performed.

4.1.4 METEOROLOGICAL DATA

Significant Impact Analysis

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) office located at the Palm Beach International Airport (PBI). Concentrations were predicted using 5 years of hourly meteorological data from 1987 through 1991. The NWS office in West Palm Beach is the closest primary weather station to the study area with meteorological data representative of the project site. The PBI station meteorological data have been approved by the FDEP and used for numerous air modeling studies submitted as part of air construction permits approved for sources located in Palm Beach County.

In the ISCST3 model, the wind speeds are adjusted from the height at which they are measured (i.e., anemometer height) to the height of each stack considered in the analysis. In this analysis, an anemometer height of 33 ft is used for the modeling analysis.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST3 meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Ruskin using the Holzworth approach (Holzworth, 1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential, hourly meteorological data set (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the EPA RAMMET meteorological preprocessor program.

4.1.5 BUILDING DOWNWASH EFFECTS FOR TROPICANA PLANT

Based on the building dimensions associated with buildings and structures at the Fort Pierce Plant, the proposed steam boiler will comply with the good engineering practice (GEP) stack height regulations. However, the stack is less than GEP height. Therefore, the potential for building downwash to occur was considered in the air modeling analysis for the steam boiler.

Generally, a stack is considered to be within the influence of a building if it is within the lesser of 5 times L, where L is the lesser dimension of the building height or projected width. The

ISCST3 model uses two procedures to address the effects of building downwash. For both methods, the direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector. The H_b is the building height and L_b is the lesser of the building height or projected width. For short stacks (i.e., physical stack height is less than H_b + 0.5 L_b), the Schulman and Scire (1980) method is used. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack height is greater than H_b + 0.5 L_b, but less than GEP, the Huber-Snyder (1976) method is used. Both downwash algorithms affect stacks that are within the influence of a building, without regard for the actual distance the stack or stack's plume from the building. See Appendix B for BPIP input, output, and summary files.

4.1.6 RECEPTOR LOCATIONS

For predicting maximum concentrations in the vicinity of the Fort Pierce Plant, an array of discrete and polar receptors was used. The modeling origin used in the analysis was the northwest corner of the feed mill building. The number of discrete receptors was 49; all of these receptors are located along the property line of the facility. Property line receptors are all 100 m or less between receptors. A polar grid was employed at distances of 0.4, 0.6, 0.8, 1.0, 1.2, 1.4, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 5.0, 6.0, 7.0, 8.0, 9.0, 10.0, 15.0, and 20.0 km. This grid has 36 radials extending out from the origin with these distances.

4.2 AIR MODELING RESULTS

4.2.1 SIGNIFICANT IMPACT ANALYSIS

Site Vicinity

The scenarios modeled for the steam boiler by itself, as the project, were: natural gas and fuel oil operation for baseload, 75% load, and 50% load. A generic emission rate was used in the model of 10 g/s and calculations were performed to determine maximum impacts for the appropriate pollutants and averaging times. The predicted maximum SO_2, PM_{10}, NO_x, and CO concentrations for all loads and fuels are presented in Table 4-2. Based upon the screening analyses, the proposed project was determined to not have a significant impact for any of the modeled pollutants for any scenario. Therefore, no additional detailed modeling analyses are required for these pollutants. Maximum impacts were determined to be within 100 meter spacing from the closest receptor. The ISCST3 input and summary file can be found in Appendix C.

Table 4-1. Major Features of the ISCST3 Model, Version 10100

Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST = Industrial Source Complex Short-Term Model.
Source: EPA, 2000.

Table 4-2. Maximum Predicted Pollutant Impacts From All Scenarios of the Proposed Steam Boiler Compared to EPA Significant Impact Levels

Averaging Time	Concentration[a] (mg/m^3)		Receptor Location[b] Direction (degree)	Receptor Location[b] Distance (m)	Time Period (YYMMDDHH)	EPA Class II Significant Impact Levels (mg/m^3)
SO_2						
Annual	0.36	c	312	499	87123124	1
	0.31	c	144	314	88123124	
	0.37	c	321	429	89123124	
	0.43	c	312	499	90123124	
	0.41	c	305	577	91123124	
HIGH 24-Hour	4.20	c	130	400	87101324	5
	4.62	c	144	314	88020924	
	4.14	c	120	400	89030924	
	4.80	c	333	374	90101024	
	4.78	c	350	400	91030224	
HIGH 3-Hour	10.02	c	130	400	87102903	25
	10.05	c	144	314	88020915	
	9.88	c	144	314	89120312	
	9.94	c	5	334	90022309	
	9.96	c	144	314	91110812	
PM_{10}						
Annual	0.10	c	311.6	498.5	87123124	1
	0.09	c	144	313.6	88123124	
	0.11	c	320.6	429.3	89123124	
	0.12	c	311.6	498.5	90123124	
	0.11	c	305	576.8	91123124	
High 24-Hour	1.18	c	130	400	87101324	5
	1.30	c	144	313.6	88020924	
	1.17	c	120	400	89030924	
	1.35	c	332.5	374.2	90101024	
	1.35	c	350	400	91030224	
NO_x						
Annual	0.70	c	311.6	498.5	87123124	1
	0.60	c	144	313.6	88123124	
	0.72	c	320.6	429.3	89123124	
	0.83	c	311.6	498.5	90123124	
	0.78	c	305	576.8	91123124	
CO						
High 8-Hour	26.93	d	108.5	338.1	87040916	500
	26.81	d	144	313.6	88020916	
	25.44	d	140	400	89121408	
	22.41	d	332.5	374.2	90021608	
	28.46	d	350	400	91120308	
High 1-Hour	48.93	d	108.5	338.1	87040916	2,000
	43.90	d	144	313.6	88020916	
	49.83	d	140	400	89121408	
	45.29	d	332.5	374.2	90021608	
	65.02	d	350	400	91120308	

[a] Based on 5-year meteorological record, West Palm Beach, 1987-91

[b] Relative to Northwest corner of the Feed Mill Building

[c] Maximum is for fuel oil operation

[d] Maximum is for natural gas operation

Legend.

YYMMDDHH = Year, Month, Day, Hour Ending

EPA = Environmental Protection Agency

5.0 REFERENCES

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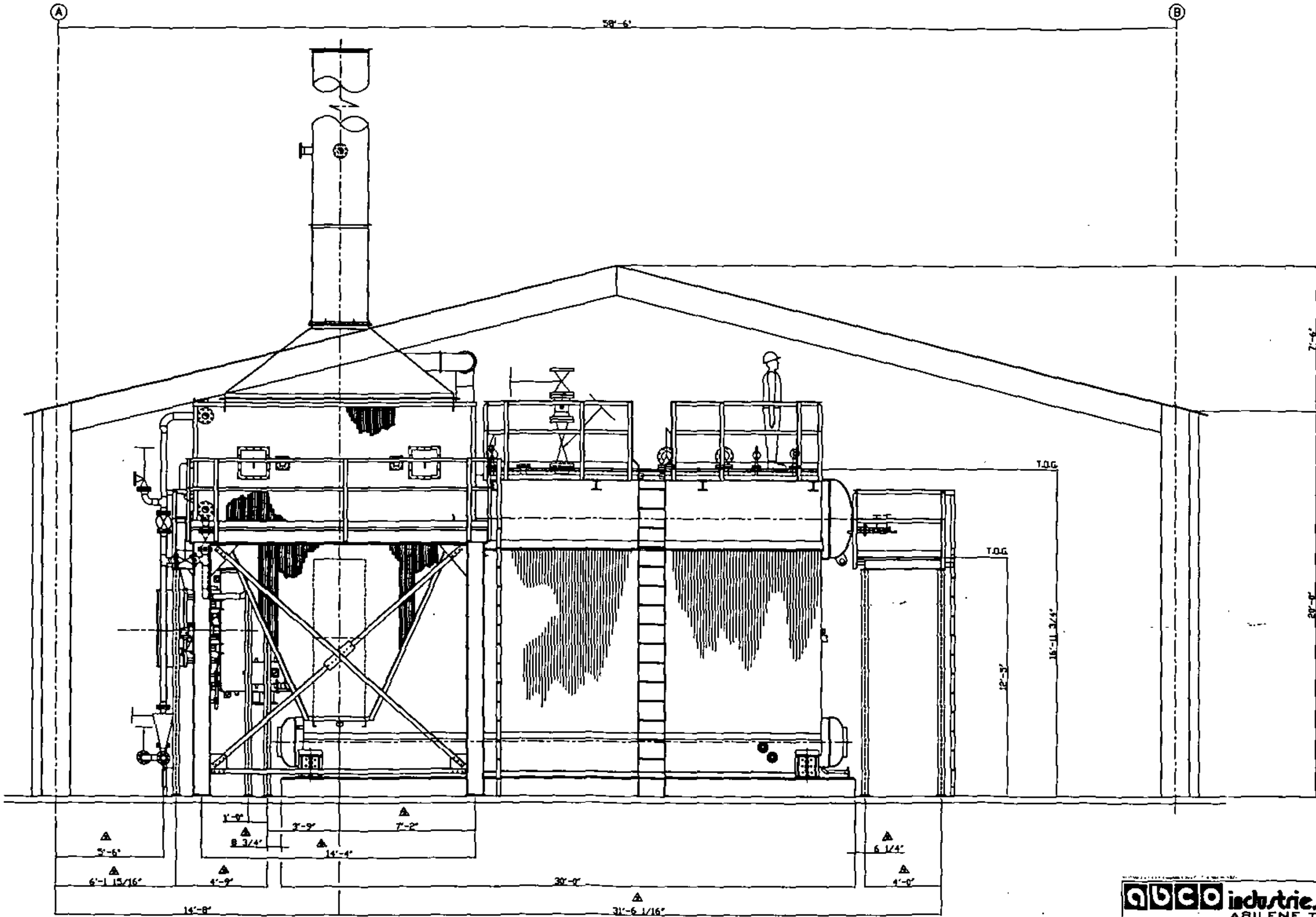
APPENDIX A

ABCO INDUSTRIES, INC.

CLASS D-TYPE BOILER DESIGN DRAWINGS



ELEVATION VIEW

REVISIONS

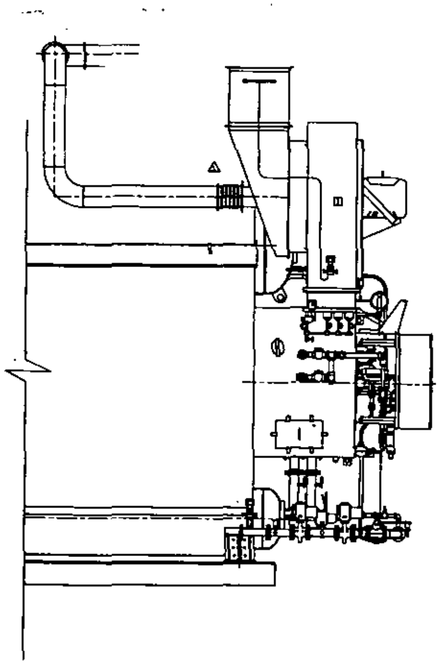
NO.	DATE	DOCUMENT NO.	BY	APPR
1	03/31/01	ADDED FOR DUCT	KF	RRD
2	07/05/01	GENERAL REVISION	RRD	KV
3	-	-	-	-
4	-	-	-	-
5	-	-	-	-
6	-	-	-	-
7	-	-	-	

abco industries, inc.
ABILENE, TEXAS

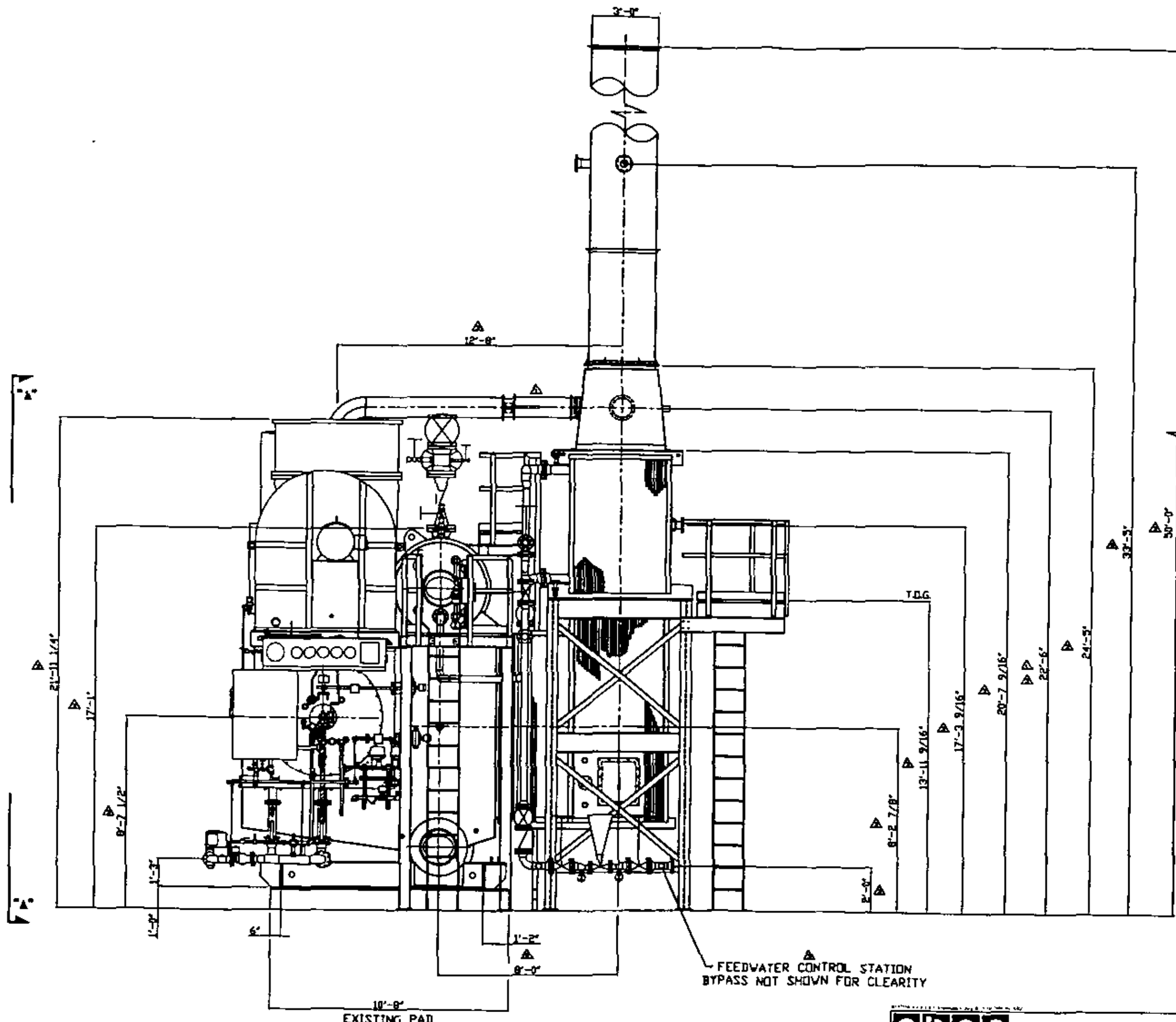
DESCRIPTION: SYSTEM GENERAL ARRANGEMENT (ELEVATION)

CUSTOMER: P.O. No. - [illegible]
TROPICANA PRODUCTS, INC.
FORT PIERCE, FLORIDA

SCALE: 3/8"=1' 0"	DRAWN BY: KF	DRAWING NUMBER	REV
DATE: 03/15/01	APPR. BY: RRD	D-201006-0-03	2



SECTION "A"-"A"



END VIEW

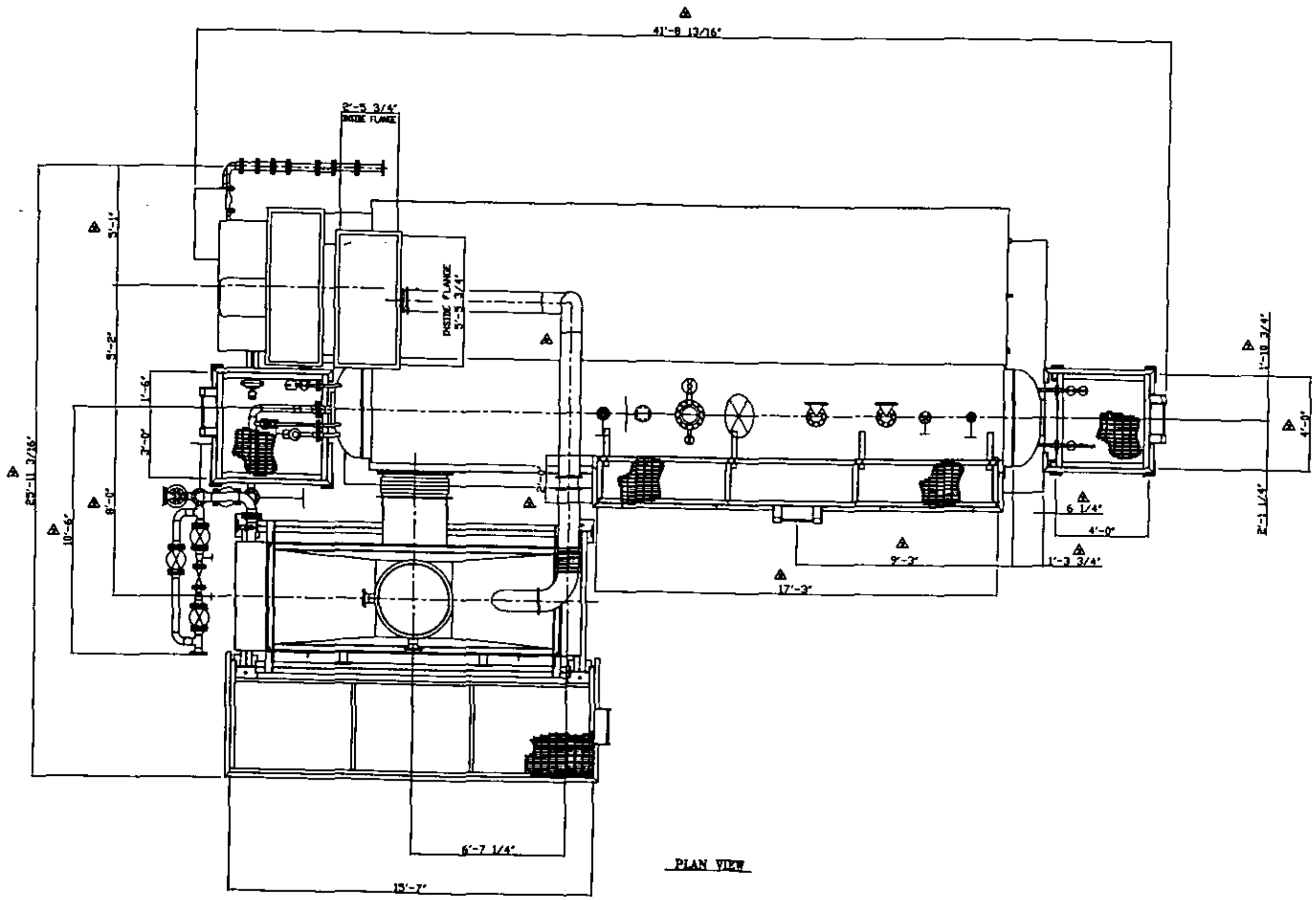
REVISIONS				
NO.	DATE	DOCUMENT NO.	BY	APPR
△	05/31/01	ADDED FOR DUCT	KF	RRD
△	07/05/01	GENERAL REVISION	RRD	MV
△	-	-	-	-
△	-	-	-	-
△	-	-	-	-
△	-	-	-	-
△	-	-	-	

abco industries, inc.
ABILENE, TEXAS

DESCRIPTION: SYSTEM GENERAL ARRANGEMENT (END)

CUSTOMER: P.O. No. - 1803
TROPICANA PRODUCTS, INC.
FORT PIERCE, FLORIDA

SCALE: 3/8"=1' 0"	DRAWN BY: KF	DRAWING NUMBER
DATE: 05/14/01	APPR. BY: RRD	D-201006-0-02



PLAN VIEW

REVISIONS				
NO.	DATE	DOCUMENT NO.	BY	APPR
1	05/15/01	GENERAL REVISION	KF	RRD
2	05/31/01	ADDED FOR DUCT	KF	RRD
3	07/05/01	GENERAL REVISION	RRD	MV
4	-	-	-	-
5	-	-	-	-
6	-	-	-	-
7	-	-	-	-

abco industries, inc.
ABILENE, TEXAS

DESCRIPTION	SYSTEM GENERAL ARRANGEMENT (PLAN)
CUSTOMER	P.O. No. - [illegible] TROPICANA PRODUCTS, INC. FORT PIERCE, FLORIDA
SCALE: 3/8"=1' 0"	DRAWN BY: [illegible]
DATE: 04/19/01	APPR. BY: MV
DRAWING NUMBER	D-201008-0-01
REV.	3

APPENDIX B

TROPICANA PRODUCTS, INC.
FORT PIERCE, FL

BPIP INPUT AND OUTPUT FILES

```
'BPIP-Fort Pierce New Steam Boiler: Tropicana 5/25/2001'
'ST'
'FEET' 0.3048
'UTMN' 0.0
7
'Concrete Tank Farm' 1 0.0
6 29.0
-262    -472
-262    -200
46      -200
46      -386
-110    -386
-110    -472
'Feed Warehouse Left' 1 0.0
4 37.0
-102    128
-102    410
0       410
0       128
'Feed Warehouse Right' 1 0.0
4 37.0
16      128
16      318
118     318
118     128
'WIP Warehouse' 1 0.0
12 39.0
-720    -140
-720    -50
-762    -50
-762    90
-720    90
-720    144
-314    144
-314    62
-262    62
-262    22
-334    22
-334    -140
'Boiler Room' 1 0.0
10 29.0
200     24
200     40
172     40
172     56
200     56
200     98
220     98
220     84
300     84
300     24
'Feed Mill' 1 0.0
8 35.0
0       -122
0       0
200     0
200     -122
110     -122
110     -146
54      -146
54      -122
'Extracting' 1 0.0
10 43.0
100     -324
100     -176
340     -176
340     -200
260     -200
260     -224
236     -224
236     -340
160     -340
160     -324

7
'001'   0.0   95.0    74.0   -70.0
'004'   0.0   95.0   102.0   -70.0
'002'   0.0   60.0   210.0    52.0
```

'003'	0.0	60.0	216.0	38.0SB_App_B.bpp
'006'	0.0	60.0	222.0	56.0
'007'	0.0	55.0	50.0	0.0
'SB'	0.0	60.0	216.0	49.0

DATE : 05/25/01
TIME : 15:11:42
BPIP-Fort Pierce New Steam Boiler: Tropicana 5/25/2001

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

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

Inputs entered in FEET will be converted to meters using a conversion factor of 0.3048. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

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

BPIP-Fort Pierce New Steam Boiler: Tropicana 5/25/2001

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

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
001	28.96	0.00	32.77	65.00
004	28.96	0.00	32.77	65.00
002	18.29	0.00	28.19	65.00
003	18.29	0.00	32.77	65.00
006	18.29	0.00	28.19	65.00
007	16.76	0.00	32.77	65.00
SB	18.29	0.00	28.19	65.00

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

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

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

BPIP (Dated: 95086)

DATE : 05/25/01
TIME : 15:11:42

BPIP-Fort Pierce New Steam Boiler: Tropicana 5/25/2001

BPIP output is in meters

SO BUILDHGT 001	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 001	10.67	10.67	10.67	10.67	13.11	13.11
SO BUILDHGT 001	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 001	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 001	10.67	10.67	10.67	10.67	13.11	13.11
SO BUILDHGT 001	13.11	13.11	13.11	13.11	13.11	10.67
SO BUILDWID 001	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 001	55.79	49.65	44.50	51.55	67.41	75.64
SO BUILDWID 001	67.67	70.60	71.39	70.00	66.49	60.96
SO BUILDWID 001	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 001	55.79	49.65	44.50	51.55	67.41	75.64

SO BUILDWID 001	81.58	85.03	85.91	84.17	79.87	60.96

SO BUILDHGT 004	13.11	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 004	10.67	10.67	10.67	10.67	13.11	13.11
SO BUILDHGT 004	13.11	13.11	10.67	10.67	10.67	10.67
SO BUILDHGT 004	13.11	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 004	10.67	10.67	10.67	10.67	13.11	13.11
SO BUILDHGT 004	13.11	13.11	13.11	13.11	13.11	13.11
SO BUILDWID 004	73.31	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 004	55.79	49.65	44.50	51.55	67.41	75.64
SO BUILDWID 004	81.58	85.03	71.39	70.00	66.49	60.96
SO BUILDWID 004	73.31	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 004	55.79	49.65	44.50	51.55	67.41	75.64
SO BUILDWID 004	81.58	85.03	85.91	84.17	79.87	73.15

SO BUILDHGT 002	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 002	10.67	10.67	8.84	8.84	11.28	11.28
SO BUILDHGT 002	11.28	11.28	11.28	11.28	10.67	10.67
SO BUILDHGT 002	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 002	10.67	10.67	8.84	8.84	8.84	8.84
SO BUILDHGT 002	8.84	8.84	10.67	10.67	10.67	10.67
SO BUILDWID 002	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 002	55.79	49.65	22.56	23.30	65.05	65.70
SO BUILDWID 002	64.35	61.04	55.88	49.02	99.20	60.96
SO BUILDWID 002	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 002	55.79	49.65	22.56	23.30	27.61	31.12
SO BUILDWID 002	35.35	38.51	85.91	91.75	99.20	60.96

SO BUILDHGT 003	13.11	13.11	13.11	10.67	10.67	10.67
SO BUILDHGT 003	10.67	10.67	8.84	8.84	11.28	11.28
SO BUILDHGT 003	11.28	11.28	11.28	11.28	10.67	10.67
SO BUILDHGT 003	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 003	10.67	10.67	8.84	8.84	8.84	8.84
SO BUILDHGT 003	8.84	8.84	13.11	13.11	13.11	13.11
SO BUILDWID 003	73.31	71.24	67.01	70.60	67.67	62.68
SO BUILDWID 003	55.79	49.65	22.56	23.30	65.05	65.70
SO BUILDWID 003	64.35	61.04	55.88	49.02	99.20	60.96
SO BUILDWID 003	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 003	55.79	49.65	22.56	23.30	27.61	31.12
SO BUILDWID 003	35.35	38.51	85.91	84.17	79.87	73.15

SO BUILDHGT 006	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 006	10.67	10.67	8.84	11.28	11.28	11.28
SO BUILDHGT 006	11.28	11.28	11.28	11.28	10.67	10.67
SO BUILDHGT 006	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 006	10.67	10.67	8.84	8.84	8.84	8.84
SO BUILDHGT 006	8.84	8.84	10.67	10.67	10.67	10.67
SO BUILDWID 006	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 006	55.79	49.65	22.56	90.05	65.05	65.70
SO BUILDWID 006	64.35	61.04	55.88	49.02	99.20	103.63
SO BUILDWID 006	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID 006	55.79	49.65	22.56	23.30	27.61	31.12
SO BUILDWID 006	35.35	38.51	85.91	91.75	99.20	103.63

SO BUILDHGT 007	10.67	11.28	11.28	10.67	10.67	10.67
SO BUILDHGT 007	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT 007	11.28	11.28	11.28	11.28	11.28	11.28
SO BUILDHGT 007	11.28	11.28	11.28	10.67	10.67	10.67
SO BUILDHGT 007	10.67	10.67	10.67	10.67	10.67	13.11
SO BUILDHGT 007	13.11	13.11	13.11	13.11	13.11	10.67
SO BUILDWID 007	66.49	92.41	101.05	70.60	67.67	62.68
SO BUILDWID 007	55.79	49.65	44.50	51.55	57.04	62.68
SO BUILDWID 007	85.83	79.07	69.90	49.02	40.67	31.09
SO BUILDWID 007	40.67	49.02	55.88	70.60	67.67	62.68
SO BUILDWID 007	55.79	49.65	44.50	51.55	57.04	75.64
SO BUILDWID 007	81.58	85.03	85.91	84.17	79.87	60.96

SO BUILDHGT SB	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT SB	10.67	10.67	8.84	8.84	11.28	11.28
SO BUILDHGT SB	11.28	11.28	11.28	11.28	10.67	10.67
SO BUILDHGT SB	10.67	10.67	10.67	10.67	10.67	10.67
SO BUILDHGT SB	10.67	10.67	8.84	8.84	8.84	8.84

SO BUILDHGT SB	8.84	8.84	10.67	10.67	10.67	10.67
SO BUILDWID SB	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID SB	55.79	49.65	22.56	23.30	65.05	65.70
SO BUILDWID SB	64.35	61.04	55.88	49.02	99.20	60.96
SO BUILDWID SB	66.49	70.00	71.39	70.60	67.67	62.68
SO BUILDWID SB	55.79	49.65	22.56	23.30	27.61	31.12
SO BUILDWID SB	35.35	38.51	85.91	91.75	99.20	60.96

APPENDIX C

TROPICANA PRODUCTS, INC.
FORT PIERCE, FL

ISCST3 INPUT AND SUMMARY FILES

ISCST3 OUTPUT FILE NUMBER 1 :GENSIG.087
ISCST3 OUTPUT FILE NUMBER 2 :GENSIG.088
ISCST3 OUTPUT FILE NUMBER 3 :GENSIG.089
ISCST3 OUTPUT FILE NUMBER 4 :GENSIG.090
ISCST3 OUTPUT FILE NUMBER 5 :GENSIG.091
First title for last output file is: 1987 Tropicana Fort Pierce Plant SIG ANALYSIS for New Steam Boiler 05/25/01
Second title for last output file is: Palm Beach/Palm Beach Met Data, 1987-91, 10 g/s

AVERAGING TIME	YEAR	CONC (ug/m3)	DIRECTION (degree)	DISTANCE (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASENG				
Annual					
	1987	5.596	305.0	576.8	87123124
	1988	4.771	305.0	576.8	88123124
	1989	5.758	305.0	576.8	89123124
	1990	6.653	305.0	576.8	90123124
	1991	6.271	305.0	576.8	91123124
HIGH 24-Hour					
	1987	64.416	130.	400.	87101324
	1988	70.700	347.7	340.3	88012024
	1989	63.976	340.	400.	89060924
	1990	71.649	332.5	374.2	90101024
	1991	73.700	350.	400.	91030224
HIGH 8-Hour					
	1987	116.404	55.0	472.1	87062716
	1988	115.900	340.	400.	88112716
	1989	109.964	140.	400.	89121408
	1990	96.902	160.	400.	90011316
	1991	123.039	340.	400.	91021916
HIGH 3-Hour					
	1987	153.411	34.3	403.9	87011018
	1988	154.350	350.	400.	88040418
	1989	152.344	340.	400.	89060918
	1990	153.479	350.	400.	90021618
	1991	153.610	34.3	403.9	91030912
HIGH 1-Hour					
	1987	181.775	300.	1000.	87070906
	1988	208.368	130.	600.	88030107
	1989	199.008	232.3	678.5	89111207
	1990	241.130	30.	600.	90071416
	1991	178.078	125.6	310.4	91101614
SOURCE GROUP ID:	BASEFO				
Annual					
	1987	5.796	305.0	576.8	87123124
	1988	4.938	305.0	576.8	88123124
	1989	5.958	305.0	576.8	89123124
	1990	6.890	305.0	576.8	90123124
	1991	6.492	305.0	576.8	91123124
HIGH 24-Hour					
	1987	66.867	130.	400.	87101324
	1988	73.637	347.7	340.3	88012024
	1989	65.919	340.	400.	89060924
	1990	76.452	332.5	374.2	90101024
	1991	76.156	350.	400.	91030224
HIGH 8-Hour					
	1987	118.944	55.0	472.1	87062716
	1988	119.274	340.	400.	88112716
	1989	115.829	140.	400.	89121408
	1990	100.419	140.	400.	90102708
	1991	126.368	340.	400.	91021916
HIGH 3-Hour					
	1987	159.661	34.3	403.9	87011018
	1988	160.091	350.	400.	88040418
	1989	157.411	340.	400.	89060918
	1990	158.368	350.	400.	90021618
	1991	158.692	347.7	340.3	91011115
HIGH 1-Hour					
	1987	185.525	144.0	313.6	87101316
	1988	207.584	130.	600.	88030107
	1989	199.623	232.3	678.5	89111207
	1990	241.713	30.	600.	90071416
	1991	185.257	125.6	310.4	91101614
SOURCE GROUP ID:	LD75NG				
Annual					

	1987	7.548	305.0	576.8	87123124
	1988	6.333	305.0	576.8	88123124
	1989	7.939	311.6	498.5	89123124
	1990	9.020	311.6	498.5	90123124
	1991	8.355	305.0	576.8	91123124
HIGH 24-Hour					
	1987	85.882	130.	400.	87101324
	1988	97.870	144.0	313.6	88020924
	1989	81.145	340.	400.	89060924
	1990	98.197	332.5	374.2	90101024
	1991	95.098	350.	400.	91030224
HIGH 8-Hour					
	1987	140.514	108.5	338.1	87040916
	1988	144.752	340.	400.	88112716
	1989	161.429	140.	400.	89121408
	1990	148.417	332.5	374.2	90021608
	1991	159.006	350.	400.	91120308
HIGH 3-Hour					
	1987	209.817	34.3	403.9	87011018
	1988	204.899	350.	400.	88040418
	1989	206.913	144.0	313.6	89120312
	1990	207.321	140.	400.	90102703
	1991	208.438	144.0	313.6	91110812
HIGH 1-Hour					
	1987	282.954	130.	800.	87042806
	1988	253.888	20.	1000.	88060706
	1989	288.182	40.	600.	89043011
	1990	261.950	34.3	403.9	90071416
	1991	376.045	198.8	442.2	91122611
SOURCE GROUP ID:	LD75FO				
Annual					
	1987	7.556	305.0	576.8	87123124
	1988	6.339	305.0	576.8	88123124
	1989	7.948	311.6	498.5	89123124
	1990	9.030	311.6	498.5	90123124
	1991	8.364	305.0	576.8	91123124
HIGH 24-Hour					
	1987	85.976	130.	400.	87101324
	1988	98.052	144.0	313.6	88020924
	1989	81.217	340.	400.	89060924
	1990	98.283	332.5	374.2	90101024
	1991	95.189	350.	400.	91030224
HIGH 8-Hour					
	1987	140.702	108.5	338.1	87040916
	1988	144.871	340.	400.	88112716
	1989	161.669	140.	400.	89121408
	1990	148.593	332.5	374.2	90021608
	1991	159.182	350.	400.	91120308
HIGH 3-Hour					
	1987	210.065	34.3	403.9	87011018
	1988	205.114	350.	400.	88040418
	1989	207.202	144.0	313.6	89120312
	1990	207.600	140.	400.	90102703
	1991	208.800	144.0	313.6	91110812
HIGH 1-Hour					
	1987	282.948	130.	800.	87042806
	1988	253.859	20.	1000.	88060706
	1989	288.203	40.	600.	89043011
	1990	262.125	34.3	403.9	90071416
	1991	376.037	198.8	442.2	91122611
SOURCE GROUP ID:	LD50NG				
Annual					
	1987	11.034	311.6	498.5	87123124
	1988	10.989	144.0	313.6	88123124
	1989	12.697	320.6	429.3	89123124
	1990	13.308	311.6	498.5	90123124
	1991	11.868	311.6	498.5	91123124
HIGH 24-Hour					
	1987	121.898	125.6	310.4	87101324
	1988	157.440	144.0	313.6	88020924
	1989	121.281	125.6	310.4	89122424
	1990	128.992	332.5	374.2	90101024
	1991	123.677	350.	400.	91030224
HIGH 8-Hour					
	1987	212.710	125.6	310.4	87111208
	1988	224.142	144.0	313.6	88020916
	1989	234.296	140.	400.	89121408
	1990	226.163	332.5	374.2	90021608

	1991	219.772	144.0	313.6	91112608
HIGH 3-Hour					
	1987	314.232	144.0	313.6	87122921
	1988	316.952	144.0	313.6	88020915
	1989	297.818	144.0	313.6	89120312
	1990	303.426	150.	400.	90121403
	1991	324.247	144.0	313.6	91110812
HIGH 1-Hour					
	1987	527.438	120.	400.	87031307
	1988	429.730	350.	800.	88060806
	1989	447.465	130.	400.	89111807
	1990	455.945	30.	600.	90071415
	1991	402.288	340.	400.	91112207
SOURCE GROUP ID:	LD50FO				
Annual					
	1987	10.833	311.6	498.5	87123124
	1988	10.497	144.0	313.6	88123124
	1989	12.445	320.6	429.3	89123124
	1990	13.072	311.6	498.5	90123124
	1991	11.664	311.6	498.5	91123124
HIGH 24-Hour					
	1987	118.957	332.5	374.2	87022724
	1988	152.603	144.0	313.6	88020924
	1989	117.307	125.6	310.4	89122424
	1990	126.869	332.5	374.2	90101024
	1991	121.393	350.	400.	91030224
HIGH 8-Hour					
	1987	205.975	125.6	310.4	87111208
	1988	217.456	144.0	313.6	88020916
	1989	228.376	140.	400.	89121408
	1990	220.930	332.5	374.2	90021608
	1991	212.976	144.0	313.6	91112608
HIGH 3-Hour					
	1987	305.488	144.0	313.6	87122921
	1988	307.872	144.0	313.6	88020915
	1989	290.562	125.6	310.4	89042112
	1990	293.104	150.	400.	90121403
	1991	315.345	144.0	313.6	91110812
HIGH 1-Hour					
	1987	527.313	120.	400.	87031307
	1988	423.896	60.	600.	88022807
	1989	445.115	130.	400.	89111807
	1990	454.563	30.	600.	90071415
	1991	398.455	340.	400.	91112207

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

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CO STARTING\Tropicana\to Janet\Gensig_App_C.i87
CO TITLEONE 1987 Tropicana Fort Pierce Plant SIG ANALYSIS for New Steam Boiler 05/25/01
CO TITLETWO Palm Beach/Palm Beach Met Data, 1987-91, 10 g/s
CO MODELOPT CONC   RURAL DFAULT NOCMPL
CO AVERTIME PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF    .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING
** TROPICANA ORIGIN IS NW CORNER OF FEED MILL
SO LOCATION ORGN     POINT        0.0        0.0       .0
SO SRCPARAM ORGN     0.0      0.0      0.0      0.0      0.0
** TROPICANA SOURCE ID          DESCRIPTION
** ----------------------------------------------------------------
** BASENG                       NATURAL GAS OPERATION AT BASELOAD
** BASEFO                       FUEL OIL OPERATION AT BASELOAD
** LD75NG                       NATURAL GAS OPERATION AT 75% LOAD
** LD75FO                       FUEL OIL OPERATION AT 75% LOAD
** LD50NG                       NATURAL GAS OPERATION AT 50% LOAD
** LD50FO                       FUEL OIL OPERATION AT 50% LOAD
** STACK LOCATIONS
SO LOCATION  BASENG  POINT  65.8     14.8        0.
SO LOCATION  BASEFO  POINT  65.8     14.8        0.
SO LOCATION  LD75NG  POINT  65.8     14.8        0.
SO LOCATION  LD75FO  POINT  65.8     14.8        0.
SO LOCATION  LD50NG  POINT  65.8     14.8        0.
SO LOCATION  LD50FO  POINT  65.8     14.8        0.

** TROPICANA SOURCES
SO SRCPARAM BASENG  10.0  18.29   419.8   25.08   0.84
SO SRCPARAM BASEFO  10.0  18.29   420.9   23.92   0.84
SO SRCPARAM LD75NG  10.0  18.29   410.9   18.35   0.84
SO SRCPARAM LD75FO  10.0  18.29   410.9   18.32   0.84
SO SRCPARAM LD50NG  10.0  18.29   403.2   11.41   0.84
SO SRCPARAM LD50FO  10.0  18.29   402.6   11.95   0.84


SO BUILDHGT BASENG         10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT BASENG         10.67   10.67    8.84    8.84   11.28   11.28
SO BUILDHGT BASENG         11.28   11.28   11.28   11.28   10.67   10.67
SO BUILDHGT BASENG         10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT BASENG         10.67   10.67    8.84    8.84    8.84    8.84
SO BUILDHGT BASENG          8.84    8.84   10.67   10.67   10.67   10.67
SO BUILDWID BASENG         66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID BASENG         55.79   49.65   22.56   23.30   65.05   65.70
SO BUILDWID BASENG         64.35   61.04   55.88   49.02   99.20   60.96
SO BUILDWID BASENG         66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID BASENG         55.79   49.65   22.56   23.30   27.61   31.12
SO BUILDWID BASENG         35.35   38.51   85.91   91.75   99.20   60.96

SO BUILDHGT BASEFO         10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT BASEFO         10.67   10.67    8.84    8.84   11.28   11.28
SO BUILDHGT BASEFO         11.28   11.28   11.28   11.28   10.67   10.67
SO BUILDHGT BASEFO         10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT BASEFO         10.67   10.67    8.84    8.84    8.84    8.84
SO BUILDHGT BASEFO          8.84    8.84   10.67   10.67   10.67   10.67
SO BUILDWID BASEFO         66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID BASEFO         55.79   49.65   22.56   23.30   65.05   65.70
SO BUILDWID BASEFO         64.35   61.04   55.88   49.02   99.20   60.96
SO BUILDWID BASEFO         66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID BASEFO         55.79   49.65   22.56   23.30   27.61   31.12
SO BUILDWID BASEFO         35.35   38.51   85.91   91.75   99.20   60.96

SO BUILDHGT LD75NG         10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT LD75NG         10.67   10.67    8.84    8.84   11.28   11.28
SO BUILDHGT LD75NG         11.28   11.28   11.28   11.28   10.67   10.67
SO BUILDHGT LD75NG         10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT LD75NG         10.67   10.67    8.84    8.84    8.84    8.84
SO BUILDHGT LD75NG          8.84    8.84   10.67   10.67   10.67   10.67
SO BUILDWID LD75NG         66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID LD75NG         55.79   49.65   22.56   23.30   65.05   65.70
SO BUILDWID LD75NG         64.35   61.04   55.88   49.02   99.20   60.96
SO BUILDWID LD75NG         66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID LD75NG         55.79   49.65   22.56   23.30   27.61   31.12
SO BUILDWID LD75NG         35.35   38.51   85.91   91.75   99.20   60.96
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SO BUILDHGT LD75FO          10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT LD75FO          10.67   10.67    8.84    8.84   11.28   11.28
SO BUILDHGT LD75FO          11.28   11.28   11.28   11.28   10.67   10.67
SO BUILDHGT LD75FO          10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT LD75FO          10.67   10.67    8.84    8.84    8.84    8.84
SO BUILDHGT LD75FO           8.84    8.84   10.67   10.67   10.67   10.67
SO BUILDWID LD75FO          66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID LD75FO          55.79   49.65   22.56   23.30   65.05   65.70
SO BUILDWID LD75FO          64.35   61.04   55.88   49.02   99.20   60.96
SO BUILDWID LD75FO          66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID LD75FO          55.79   49.65   22.56   23.30   27.61   31.12
SO BUILDWID LD75FO          35.35   38.51   85.91   91.75   99.20   60.96

SO BUILDHGT LD50NG          10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT LD50NG          10.67   10.67    8.84    8.84   11.28   11.28
SO BUILDHGT LD50NG          11.28   11.28   11.28   11.28   10.67   10.67
SO BUILDHGT LD50NG          10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT LD50NG          10.67   10.67    8.84    8.84    8.84    8.84
SO BUILDHGT LD50NG           8.84    8.84   10.67   10.67   10.67   10.67
SO BUILDWID LD50NG          66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID LD50NG          55.79   49.65   22.56   23.30   65.05   65.70
SO BUILDWID LD50NG          64.35   61.04   55.88   49.02   99.20   60.96
SO BUILDWID LD50NG          66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID LD50NG          55.79   49.65   22.56   23.30   27.61   31.12
SO BUILDWID LD50NG          35.35   38.51   85.91   91.75   99.20   60.96

SO BUILDHGT LD50FO          10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT LD50FO          10.67   10.67    8.84    8.84   11.28   11.28
SO BUILDHGT LD50FO          11.28   11.28   11.28   11.28   10.67   10.67
SO BUILDHGT LD50FO          10.67   10.67   10.67   10.67   10.67   10.67
SO BUILDHGT LD50FO          10.67   10.67    8.84    8.84    8.84    8.84
SO BUILDHGT LD50FO           8.84    8.84   10.67   10.67   10.67   10.67
SO BUILDWID LD50FO          66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID LD50FO          55.79   49.65   22.56   23.30   65.05   65.70
SO BUILDWID LD50FO          64.35   61.04   55.88   49.02   99.20   60.96
SO BUILDWID LD50FO          66.49   70.00   71.39   70.60   67.67   62.68
SO BUILDWID LD50FO          55.79   49.65   22.56   23.30   27.61   31.12
SO BUILDWID LD50FO          35.35   38.51   85.91   91.75   99.20   60.96

SO EMISUNIT    .100000E+07 (GRAMS/SEC)         (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASENG BASENG
SO SRCGROUP BASEFO BASEFO
SO SRCGROUP LD75NG LD75NG
SO SRCGROUP LD75FO LD75FO
SO SRCGROUP LD50NG LD50NG
SO SRCGROUP LD50FO LD50FO
SO FINISHED

RE STARTING
RE GRIDPOLR POL STA
RE GRIDPOLR POL ORIG     0.0     0.0
RE GRIDPOLR POL DIST   1500 2000 2500 3000 3500 4000 5000
RE GRIDPOLR POL DIST   6000 7000 8000 9000 10000 15000 20000
RE GRIDPOLR POL GDIR  36.  10    10.00
RE GRIDPOLR POL END

**  FENCELINE RECEPTORS AT 100-M INTERVALS
RE DISCCART     -1331.7    -399.9
RE DISCCART     -1231.7    -401.4
RE DISCCART     -1131.7    -402.9
RE DISCCART     -1031.7    -404.4
RE DISCCART      -931.7    -405.9
RE DISCCART      -831.7    -407.0
RE DISCCART      -731.7    -405.1
RE DISCCART      -631.8    -403.3
RE DISCCART      -536.7    -415.1
RE DISCCART      -438.3    -406.1
RE DISCCART      -338.3    -404.6
RE DISCCART      -242.8    -416.7
RE DISCCART      -142.8    -418.5
RE DISCCART       -42.8    -420.3
RE DISCCART        47.8    -400.0
RE DISCCART       116.0    -326.9
RE DISCCART       184.2    -253.8
RE DISCCART       252.4    -180.6
RE DISCCART       320.6    -107.5
RE DISCCART       388.8     -34.4
RE DISCCART       457.0      38.8
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RE DISCCART       488.1      106.0ensig_App_C.i87
RE DISCCART       428.3      180.0
RE DISCCART       386.6      270.9
RE DISCCART       327.4      334.2
RE DISCCART       227.4      333.8
RE DISCCART       127.4      333.3
RE DISCCART        27.4      332.9
RE DISCCART       -72.6      332.5
RE DISCCART      -172.6      332.0
RE DISCCART      -272.6      331.6
RE DISCCART      -372.6      331.1
RE DISCCART      -472.6      330.7
RE DISCCART      -572.6      330.2
RE DISCCART      -672.6      329.8
RE DISCCART      -772.6      329.4
RE DISCCART      -872.6      328.9
RE DISCCART      -972.6      328.5
RE DISCCART     -1072.6      328.0
RE DISCCART     -1172.6      327.6
RE DISCCART     -1272.6      327.1
RE DISCCART     -1318.1      266.8
RE DISCCART     -1347.6      171.2
RE DISCCART     -1377.0       75.7
RE DISCCART     -1406.5      -19.9
RE DISCCART     -1425.5     -117.1
RE DISCCART     -1427.2     -217.1
RE DISCCART     -1425.5     -317.1
RE DISCCART     -1366.3     -389.7

** PROPERTY BOUNDARY RECEPTORS WITH ADDITION OFF-SITE RECEPTORS AT
** 1500,2000,2500,and 3000 M, CENTERED ON ORGN
RE DISCPOLR ORGN       400.         10
RE DISCPOLR ORGN       600.         10
RE DISCPOLR ORGN       800.         10
RE DISCPOLR ORGN      1000.         10
RE DISCPOLR ORGN      1200.         10
RE DISCPOLR ORGN      1400.         10
RE DISCPOLR ORGN       400.         20
RE DISCPOLR ORGN       600.         20
RE DISCPOLR ORGN       800.         20
RE DISCPOLR ORGN      1000.         20
RE DISCPOLR ORGN      1200.         20
RE DISCPOLR ORGN      1400.         20
RE DISCPOLR ORGN       400.         30
RE DISCPOLR ORGN       600.         30
RE DISCPOLR ORGN       800.         30
RE DISCPOLR ORGN      1000.         30
RE DISCPOLR ORGN      1200.         30
RE DISCPOLR ORGN      1400.         30
RE DISCPOLR ORGN       600.         40
RE DISCPOLR ORGN       800.         40
RE DISCPOLR ORGN      1000.         40
RE DISCPOLR ORGN      1200.         40
RE DISCPOLR ORGN      1400.         40
RE DISCPOLR ORGN       600.         50
RE DISCPOLR ORGN       800.         50
RE DISCPOLR ORGN      1000.         50
RE DISCPOLR ORGN      1200.         50
RE DISCPOLR ORGN      1400.         50
RE DISCPOLR ORGN       600.         60
RE DISCPOLR ORGN       800.         60
RE DISCPOLR ORGN      1000.         60
RE DISCPOLR ORGN      1200.         60
RE DISCPOLR ORGN      1400.         60
RE DISCPOLR ORGN       600.         70
RE DISCPOLR ORGN       800.         70
RE DISCPOLR ORGN      1000.         70
RE DISCPOLR ORGN      1200.         70
RE DISCPOLR ORGN      1400.         70
RE DISCPOLR ORGN       600.         80
RE DISCPOLR ORGN       800.         80
RE DISCPOLR ORGN      1000.         80
RE DISCPOLR ORGN      1200.         80
RE DISCPOLR ORGN      1400.         80
RE DISCPOLR ORGN       600.         90
RE DISCPOLR ORGN       800.         90
RE DISCPOLR ORGN      1000.         90
RE DISCPOLR ORGN      1200.         90
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RE DISCPOLR ORGN	1400.	
RE DISCPOLR ORGN	400.	100
RE DISCPOLR ORGN	600.	100
RE DISCPOLR ORGN	800.	100
RE DISCPOLR ORGN	1000.	100
RE DISCPOLR ORGN	1200.	100
RE DISCPOLR ORGN	1400.	100
RE DISCPOLR ORGN	400.	110
RE DISCPOLR ORGN	600.	110
RE DISCPOLR ORGN	800.	110
RE DISCPOLR ORGN	1000.	110
RE DISCPOLR ORGN	1200.	110
RE DISCPOLR ORGN	1400.	110
RE DISCPOLR ORGN	400.	120
RE DISCPOLR ORGN	600.	120
RE DISCPOLR ORGN	800.	120
RE DISCPOLR ORGN	1000.	120
RE DISCPOLR ORGN	1200.	120
RE DISCPOLR ORGN	1400.	120
RE DISCPOLR ORGN	400.	130
RE DISCPOLR ORGN	600.	130
RE DISCPOLR ORGN	800.	130
RE DISCPOLR ORGN	1000.	130
RE DISCPOLR ORGN	1200.	130
RE DISCPOLR ORGN	1400.	130
RE DISCPOLR ORGN	400.	140
RE DISCPOLR ORGN	600.	140
RE DISCPOLR ORGN	800.	140
RE DISCPOLR ORGN	1000.	140
RE DISCPOLR ORGN	1200.	140
RE DISCPOLR ORGN	1400.	140
RE DISCPOLR ORGN	400.	150
RE DISCPOLR ORGN	600.	150
RE DISCPOLR ORGN	800.	150
RE DISCPOLR ORGN	1000.	150
RE DISCPOLR ORGN	1200.	150
RE DISCPOLR ORGN	1400.	150
RE DISCPOLR ORGN	400.	160
RE DISCPOLR ORGN	600.	160
RE DISCPOLR ORGN	800.	160
RE DISCPOLR ORGN	1000.	160
RE DISCPOLR ORGN	1200.	160
RE DISCPOLR ORGN	1400.	160
RE DISCPOLR ORGN	400.	170
RE DISCPOLR ORGN	600.	170
RE DISCPOLR ORGN	800.	170
RE DISCPOLR ORGN	1000.	170
RE DISCPOLR ORGN	1200.	170
RE DISCPOLR ORGN	1400.	170
RE DISCPOLR ORGN	600.	180
RE DISCPOLR ORGN	800.	180
RE DISCPOLR ORGN	1000.	180
RE DISCPOLR ORGN	1200.	180
RE DISCPOLR ORGN	1400.	180
RE DISCPOLR ORGN	600.	190
RE DISCPOLR ORGN	800.	190
RE DISCPOLR ORGN	1000.	190
RE DISCPOLR ORGN	1200.	190
RE DISCPOLR ORGN	1400.	190
RE DISCPOLR ORGN	600.	200
RE DISCPOLR ORGN	800.	200
RE DISCPOLR ORGN	1000.	200
RE DISCPOLR ORGN	1200.	200
RE DISCPOLR ORGN	1400.	200
RE DISCPOLR ORGN	600.	210
RE DISCPOLR ORGN	800.	210
RE DISCPOLR ORGN	1000.	210
RE DISCPOLR ORGN	1200.	210
RE DISCPOLR ORGN	1400.	210
RE DISCPOLR ORGN	600.	220
RE DISCPOLR ORGN	800.	220
RE DISCPOLR ORGN	1000.	220
RE DISCPOLR ORGN	1200.	220
RE DISCPOLR ORGN	1400.	220
RE DISCPOLR ORGN	800.	230
RE DISCPOLR ORGN	1000.	230
RE DISCPOLR ORGN	1200.	230
RE DISCPOLR ORGN	1400.	230

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RE DISCPOLR ORGN      1000.       240
RE DISCPOLR ORGN      1200.       240
RE DISCPOLR ORGN      1400.       240
RE DISCPOLR ORGN      1200.       250
RE DISCPOLR ORGN      1400.       250
RE DISCPOLR ORGN      1400.       280
RE DISCPOLR ORGN      1000.       290
RE DISCPOLR ORGN      1200.       290
RE DISCPOLR ORGN      1400.       290
RE DISCPOLR ORGN       800.       300
RE DISCPOLR ORGN      1000.       300
RE DISCPOLR ORGN      1200.       300
RE DISCPOLR ORGN      1400.       300
RE DISCPOLR ORGN       600.       310
RE DISCPOLR ORGN       800.       310
RE DISCPOLR ORGN      1000.       310
RE DISCPOLR ORGN      1200.       310
RE DISCPOLR ORGN      1400.       310
RE DISCPOLR ORGN       600.       320
RE DISCPOLR ORGN       800.       320
RE DISCPOLR ORGN      1000.       320
RE DISCPOLR ORGN      1200.       320
RE DISCPOLR ORGN      1400.       320
RE DISCPOLR ORGN       400.       330
RE DISCPOLR ORGN       600.       330
RE DISCPOLR ORGN       800.       330
RE DISCPOLR ORGN      1000.       330
RE DISCPOLR ORGN      1200.       330
RE DISCPOLR ORGN      1400.       330
RE DISCPOLR ORGN       400.       340
RE DISCPOLR ORGN       600.       340
RE DISCPOLR ORGN       800.       340
RE DISCPOLR ORGN      1000.       340
RE DISCPOLR ORGN      1200.       340
RE DISCPOLR ORGN      1400.       340
RE DISCPOLR ORGN       400.       350
RE DISCPOLR ORGN       600.       350
RE DISCPOLR ORGN       800.       350
RE DISCPOLR ORGN      1000.       350
RE DISCPOLR ORGN      1200.       350
RE DISCPOLR ORGN      1400.       350
RE DISCPOLR ORGN       400.       360
RE DISCPOLR ORGN       600.       360
RE DISCPOLR ORGN       800.       360
RE DISCPOLR ORGN      1000.       360
RE DISCPOLR ORGN      1200.       360
RE DISCPOLR ORGN      1400.       360

RE FINISHED

ME STARTING
ME INPUTFIL P:\MET\PBIPBI87.MET
ME ANEMHGHT    33  FEET
ME SURFDATA  12844      1987     WEST-PALM-BCH
ME UAIRDATA  12844      1987     WEST-PALM-BCH
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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