191876

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR OIL-FIRED BOILER NO. 16 OKEELANTA CORPORATION

Prepared For:

Okeelanta Corporation
P.O. Box 86
South Bay, FL 33493

Prepared By:

KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, FL 32605

January 1991
90121B1

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

$5,000pd.
1-29-91
Recpt #151239

AC50-191896
PSD-FL-169

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Oil-Fired Steam Boiler [X] New¹ [ ] Existing¹

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

COMPANY NAME: Okeelanta Corporation COUNTY: Palm Beach

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) Boiler No. 16

SOURCE LOCATION: Street 6 miles south of South Bay off US 27 City South Bay

UTM: East 17-524.9 North 2940.1

Latitude 26 ° 35' 00 "N Longitude 80 ° 45 ' 00 "W

APPLICANT NAME AND TITLE: Pablo A. Carreno, Director of Mill and Refinery Operations

APPLICANT ADDRESS: P.O. Box 86, South Bay, FL 33493

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Okeelanta Corporation

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

*Attach letter of authorization

Signed:

Pablo A. Carreno, Dir. of Mill and Refinery Operations
Name and Title (Please Type)

Date: 01/29/91 Telephone No. (407) 996-9072

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

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

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

Signed David A. Buff

David A. Buff
Name (Please Type)

KBN Engineering and Applied Sciences, Inc.
Company Name (Please Type)

1034 NW 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

Florida Registration No. 19011 Date: Jan. 28, 1991 Telephone No. (904) 331-9000

SECTION II: GENERAL PROJECT INFORMATION

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

Refer to PSD Report

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

Start of Construction April 1991 Completion of Construction October 1992

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

Low NO_x burners and flue gas recirculation - $200,000

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

None issued

E. Requested permitted equipment operating time: hrs/day 24; days/wk 7; wks/yr 25;
If power plant, hrs/yr ____; if seasonal, describe: 175 days/yr; normally April through October.

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

1. Is this source in a non-attainment area for a particular pollutant? Yes
   - a. If yes, has "offset" been applied? No
   - b. If yes, has "Lowest Achievable Emission Rate" been applied? No
   - c. If yes, list non-attainment pollutants. Ozone
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. No
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. No
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? Yes
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? No
   - a. If yes, for what pollutants? ____
   - b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

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

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

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

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
Not Applicable				

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

1. Total Process Input Rate (lbs/hr): Not Applicable

2. Product Weight (lbs/hr): Not Applicable

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

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
Sulfur Dioxide	105.5	221.6	17-2.600(6)	BACT	105.5	221.6	Boiler
Particulates	11.0	23.1	17-2.600(6)	BACT	11.0	23.1	Boiler
Nitrogen Oxides	36.9	77.5	N/A	N/A	36.9	77.5	Boiler
Carbon Monoxide	41.0	86.1	N/A	N/A	41.0	86.1	Boiler
Vol. Org. Comp.	18.45	38.7	N/A	N/A	18.45	38.7	Boiler

[1] See Section V, Item 2.

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

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated with~~out~~ control (See Section V, Item 3).

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

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Low NO$_x$ burners/flue	NO$_x$	30 - 60%	N/A	Design
gas recirculation				

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Distillate fuel oil	1,083 gal	1,463 gal	205

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

Fuel Analysis: See Table 2-1 of PSD Report

Percent Sulfur:__________ Percent Ash:__________

Density: __________ lbs/gal Typical Percent Nitrogen:__________

Heat Capacity:__________ BTU/lb __________ BTU/gal

Other Fuel Contaminants (which may cause air pollution):__________

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

Annual Average 0 Maximum 0

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

Boiler ash will be properly disposed of on-site.

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

Stack Height: 75 ft. Stack Diameter: 5.0 ft.

Gas Flow Rate: 71,000 ACFM 36,860 DSCFM Gas Exit Temperature: 435 °F.

Water Vapor Content: 12 % Velocity: 60.3 FPS

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type 0 (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Patholog-ical)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Inciner-ated							
Uncon-trolled (lbs/hr)							

Description of Waste ______

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

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

Manufacturer ______

Date Constructed ______ Model No. ______

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

Stack Height: ______ ft. Stack Diameter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

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

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

[ ] Other (specify) ______

Brief description of operating characteristics of control devices:

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

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

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not Applicable
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See PSD Report
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See PSD Report
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
   See PSD Report
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   See PSD Report
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See PSD Report
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See PSD Report
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See PSD Report

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

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

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[X] Yes [ ] No

Contaminant	Rate or Concentration
Sulfer Dioxide	0.5% S fuel oil or 90% reduction
Nitrogen Oxides	0.2 lb/MM Btu

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

[X] Yes [ ] No

Contaminant	Rate or Concentration
See PSD Report	

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

Contaminant	Rate or Concentration
Sulfur Dioxide	0.5% S fuel oil
Nitrogen Oxides	0.18 lb/MM Btu

D. Describe the existing control and treatment technology (if any). Not Applicable

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

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary). See PSD Report

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1] Explain method of determining efficiency.

[2] Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

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

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

F. Describe the control technology selected: See PSD Report

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

---

[1] Explain method of determining efficiency.

[2] Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

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

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

Refer to PSD Report

A. Company Monitored Data

1. ______ no. sites ______ TSP ______ ( ) SO^{2*} ______ Wind spd/dir

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

Other data recorded ______________________

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

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

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling

1. ______ Year(s) of data from ________/____/________ to ________/____/________
month day year month day year

2. Surface data obtained from (location)________________________________

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

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

C. Computer Models Used

1. ______________________________ Modified? If yes, attach description.

2. ______________________________ Modified? If yes, attach description.

3. ______________________________ Modified? If yes, attach description.

4. ______________________________ Modified? If yes, attach description.

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

D. Applicants Maximum Allowable Emission Data

Pollutant	Emission Rate	
TSP	______________________	grams/sec
SO^2	______________________	grams/sec

E. Emission Data Used in Modeling

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

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

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

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

PSD REPORT
OIL-FIRED BOILER NO. 16
OKEELANTA CORPORATION

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ACRONYMS AND ABBREVIATIONS
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AAQS	Ambient Air Quality Standards
BACT	best available control technology
Be	beryllium
Btu/hr-ft^2	British thermal units per hour square foot
CCA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
ENP	Everglades National Park
EPA	U.S. Environmental Protection Agency
F.A.C.	Florida Administrative Code
FDER	Florida Department of Environmental Regulation
FSCL	Florida Sugar Cane League
ft	feet
g/s	grams per second
GEP	good engineering practice
HSH	highest, second-highest
ISC	Industrial Source Complex
ISCLT	Industrial Source Complex Long-Term (Model)
ISCST	Industrial Source Complex Short-Term (Model)
km	kilometer
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
m	meter
MMBtu	million British thermal units
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
PM(TSP)	particulate matter (total suspended particulates)
PM10	particulate matter with an aerodynamic diameter less than or equal to 10 micrometers

ACRONYMS AND ABBREVIATIONS
(Page 2 of 2)

PSD	prevention of significant deterioration
SIA	significant impact area
SIP	State Implementation Plan
SO_2	sulfur dioxide
TPY	tons per year
UNAMAP	Users Network for Applied Modeling of Air Pollution
VOC	volatile organic compound
$\mu g/m^3$	micrograms per cubic meter

1.0 INTRODUCTION

Okeelanta Corporation is proposing to add a new, oil-fired package boiler at its existing sugar cane mill in Palm Beach County. The existing mill is located about 6 miles south of South Bay, Florida, and just west of U.S. 27. Figure 1-1 shows the site location map of the existing facility.

The proposed addition at this location consists of a new 150,000 pounds-per-hour (lb/hr) package boiler firing No. 2 fuel oil. The proposed boiler will be used only during the off-season to supply process steam to the existing sugar refinery at Okeelanta. Under current federal and state air quality regulations, the proposed boiler will constitute a major modification at a major stationary source.

This report addresses the requirements of the prevention of significant deterioration (PSD) new source review procedures pursuant to rules and regulations that implement the Clean Air Act (CAA) amendments of 1977. The Florida Department of Environmental Regulation (FDER) has PSD review and approval authority in Florida. Based on the maximum emissions from the proposed boiler, a PSD review is required for sulfur dioxide (SO_2) and nitrogen oxides (NO_x).

The engineering design for the proposed boiler includes the selection of very low sulfur, No. 2 distillate fuel oil (maximum sulfur content not to exceed 0.5 percent), as well as incorporation of low-NO_x burners and flue-gas recirculation for the control of NO_x emissions. These control aspects are proposed as best available control technology (BACT) for the proposed boiler.

This application contains six other sections. Descriptions of the existing operations at Okeelanta and the proposed oil-fired boiler addition are presented in Section 2.0. The air quality review requirements and source applicability for the proposed boiler are discussed in Section 3.0.

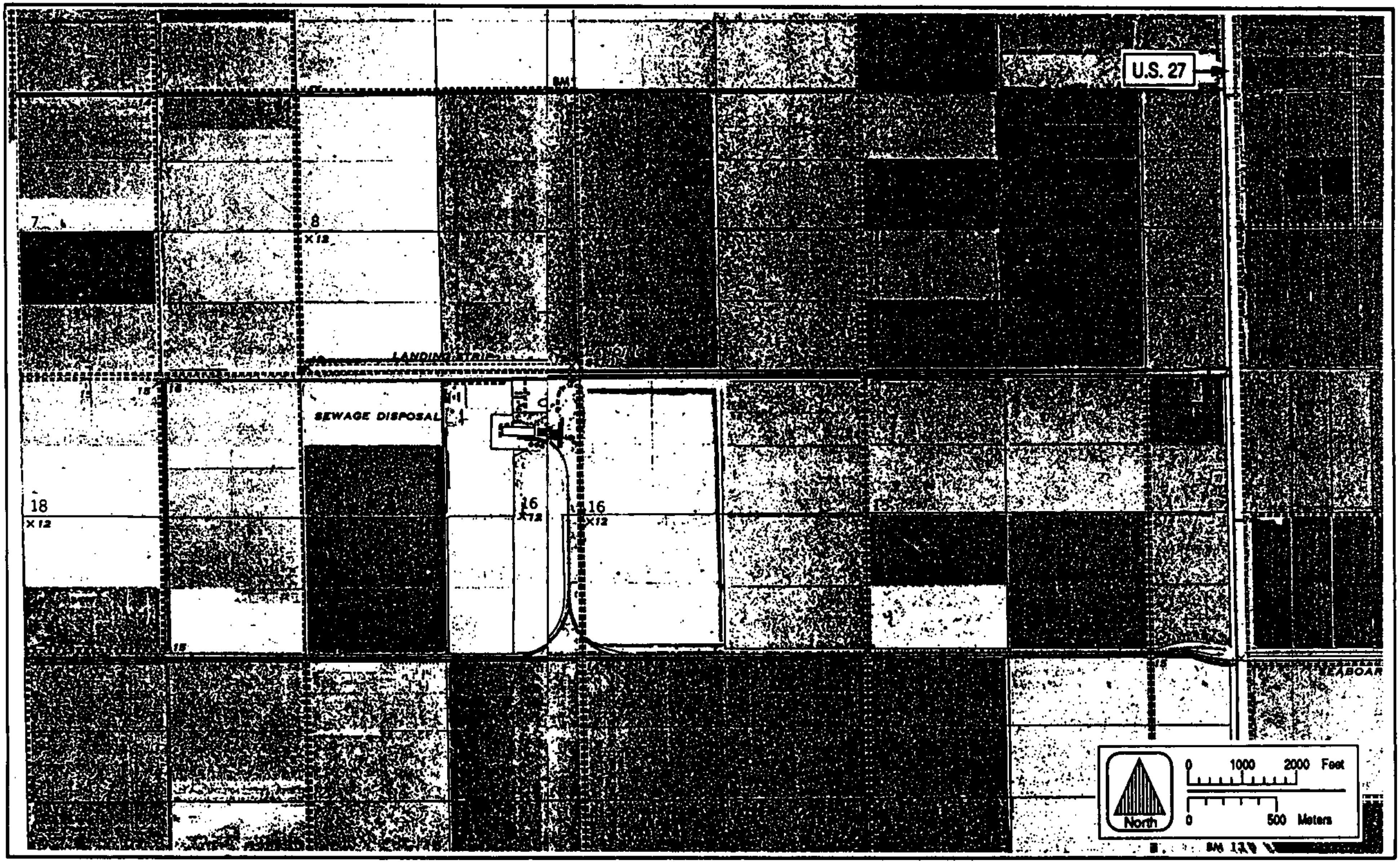

Figure 1-1 LOCATION OF OKEELANTA CORPORATION MILL, SOUTH BAY, FLORIDA

Presented in Section 4.0 is an analysis of ambient monitoring data in the area of the proposed source. The methodology and results of the air dispersion modeling and air quality impact analysis are presented in Section 5.0. The BACT analysis required as part of the PSD permitting process is presented in Section 6.0. Impacts on soils, vegetation, and visibility are summarized in Section 7.0.

2.0 PROJECT DESCRIPTION

2.1 EXISTING OPERATIONS

Okeelanta currently operates a sugar cane processing facility at its mill located just south of South Bay. The mill's air emission sources consist of eight bagasse-/oil-fired boilers, which operate normally November through March (termed the "crop season"). During this period, the mill is harvesting and processing sugar cane into raw sugar. Currently, a raw sugar refinery is operated that processes a portion of the raw sugar into refined sugar.

The processing of the sugar cane produces a solid fuel byproduct, bagasse, which is burned in the boilers to generate steam for the process. The boilers also burn fuel oil during startup and shutdown and at times when bagasse is not available to meet the total steam demands of the facility.

Based on the current annual air emissions from the facility, the facility is classified as an existing major stationary source as defined in the Florida PSD rules.

A location map of the existing sugar mill indicating the plant property boundaries and the existing boilers is presented in Figure 2-1. As shown, Okeelanta owns extensive sugar cane fields surrounding the mill in all directions. A plot plan of the existing mill indicating the existing boilers, stacks, and buildings is presented in Figure 2-2.

2.2 PROPOSED OIL-FIRED BOILER

The proposed oil-fired boiler will be used to provide steam to the Okeelanta sugar refining operations in the off-season only (i.e., during the non-crop season). The other boilers at the mill are shut down during this period. This period generally will run from April through October. The boiler will operate a maximum of 175 days per year and only when the other boilers at the mill are shut down.

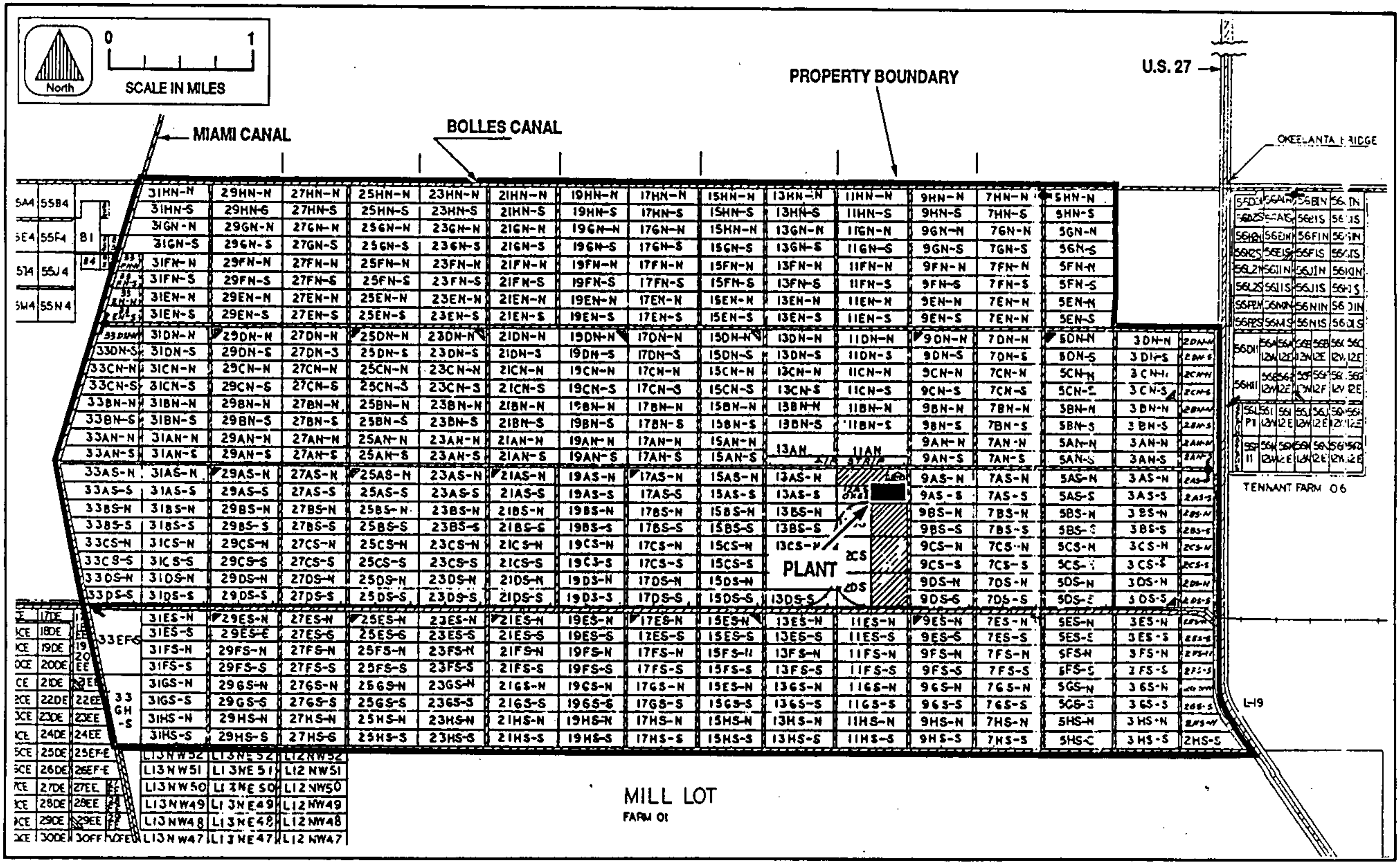

Figure 2-1 OKEELANTA PROPERTY BOUNDARIES

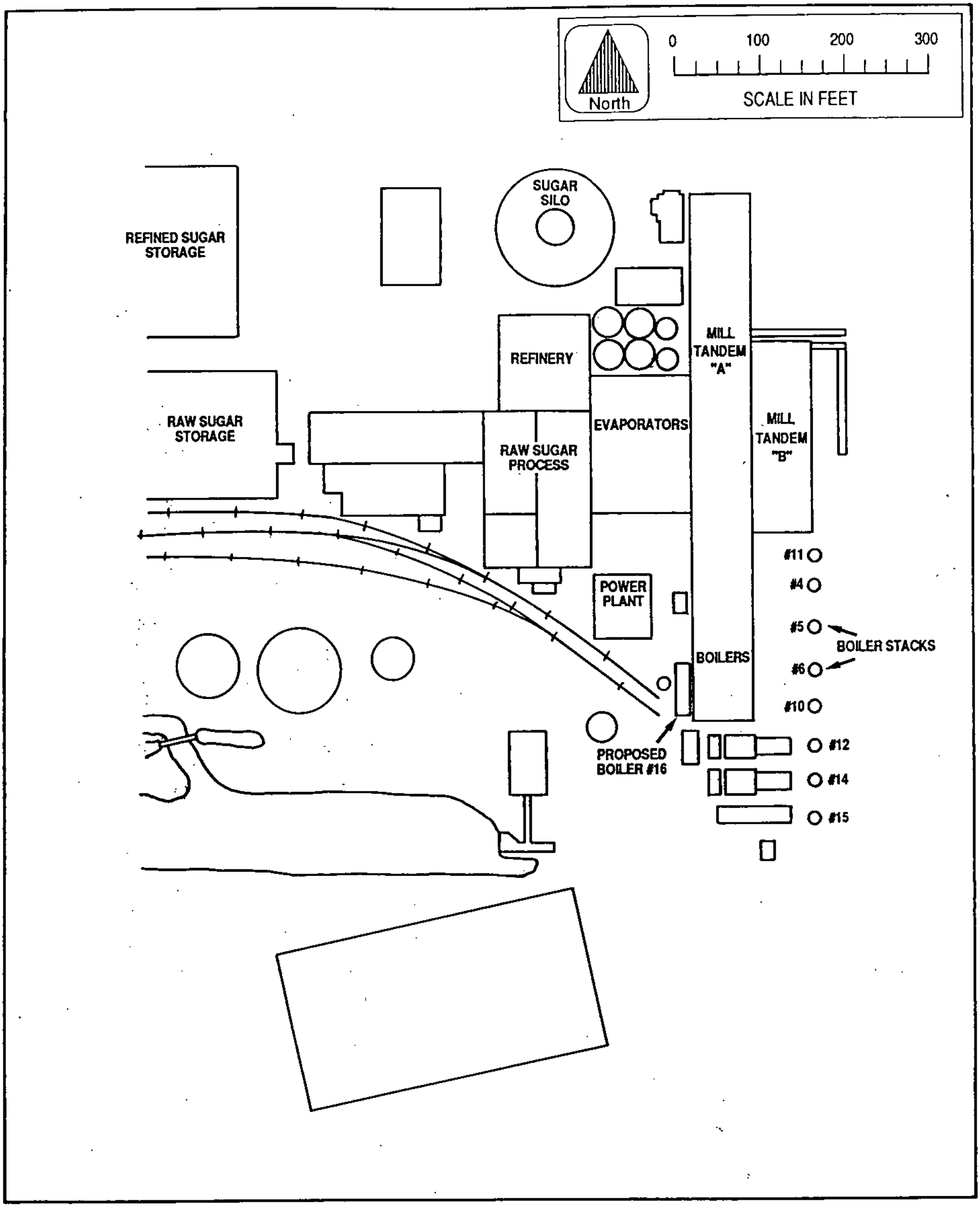

FIGURE 2-2 PLOT PLAN OF OKEELANTA SUGAR MILL

KBN

The design rate of the boiler will be 150,000 lb/hr steam (maximum 24-hour average) at a maximum heat input rate of 205 million British thermal units per hour (MMBtu/hr)(maximum 24-hour average). Fuel fired will be very low sulfur, No. 2 distillate fuel oil, with a maximum sulfur content of 0.5 percent. Specifications for No. 2 distillate fuel oil are shown in Table 2-1.

The proposed boiler will incorporate "low-NO_x" burner technology and flue-gas recirculation, which are control methods for minimizing NO_x emissions from oil-fired boilers. These control methods are discussed in greater detail in the BACT analysis presented in Section 7.0.

Maximum hourly and annual emissions of regulated pollutants from the proposed boiler are presented in Table 2-2. Emissions of total suspended particulate matter [PM(TSP)], particulate matter less than 10 microns in diameter (PM10), NO_x, carbon monoxide (CO), and volatile organic compounds (VOC) are based on boiler design information. Emissions of SO_2 are based on the maximum sulfur content of the fuel and the fuel firing rates. Emissions of other regulated pollutants, including trace elements, are based on emission factors for distillate fuel oil combustion. Emission calculations are presented in Appendix A.

The location of the new boiler and its exhaust stack are shown in Figure 2-2.

Table 2-1. Typical Analyses of No. 2 Fuel Oil

Grade of Fuel Oil	No. 2	
Gravity[a,c]		
Deg API	32	
Specific	0.865	
lb/gal	7.21	
Viscosity[b,c]		
Centistokes @ 100°F	2.5	
SUS @ 100°F	34	
Heating Value		
Btu/gal	140,090	
Btu/lb	19,430	
Ultimate Fuel Analysis		
in weight percent	Vendor[b]	Range[c]
Sulfur	<0.5	0.05-1.0
Hydrogen	12.5	11.8-13.9
Carbon	87.2	86.1-88.2
Nitrogen	0.02	Nil-0.1
Oxygen	Nil	--
Ash	0.001	--
Water, volume %	Nil	0-0.1

[a] Central Oil Company, Inc., Tampa, Florida, 1991.
[b] Perry & Green, Perry's Chemical Engineering Handbook, 6th Ed, 1984.
[c] Babcock & Wilcox, Steam, Its Generation and Use, 1975.

Table 2-2. Maximum Emissions From Okeelanta Corporation's Proposed Boiler No. 16

Pollutant	Emission Factor (lb/MMBtu)	Reference	Maximum Emissions[a] (lb/hr)	(TPY)
Particulate Matter(TSP)	0.054	Design Basis	11.0	23.1
Particulate Matter(PM10)	0.027	AP-42, TB 1.3-4	5.5	11.6
Sulfur Dioxide	0.51	Design Basis	105.5	221.6
Nitrogen Oxides	0.18	Design Basis	36.9	77.5
Carbon Monoxide	0.20	Design Basis	41.0	86.1
VOCs	0.09	Design Basis	18.45	38.7
Trace Metals				
Lead, Pb	8.9×10^{-6}	EPA, 1988[b]	0.0018	0.0038
Mercury, Hg	3.0×10^{-6}	EPA, 1988[b]	0.0006	0.0013
Beryllium, Be	7.9×10^{-7}	EPA, 1989[c]	0.00016	0.00034
Fluoride, F	3.3×10^{-5}	EPA, 1988[b]	0.0082	0.017
Sulfuric Acid Mist	0.013	AP-42, TB 1.3-4	2.6	5.46

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[a] Based on 205 MMBtu/hr heat input rate for the proposed boiler operating at full load capacity.

[b] From Toxic Air Pollutant Emission Factors--A Compilation for Selected Air Toxic Compounds and Sources (EPA-450/2-88-006a, 1988).

[c] From Estimating Air Toxics Emission from Coal and Oil Combustion Sources (EPA-450/2-89-001, 1989).

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to Okeelanta's proposed oil-fired boiler. These regulations must be satisfied before construction can begin on the proposed source.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida ambient air quality standards (AAQS) are presented in Table 3-1. National primary AAQS were promulgated to protect the public health, and national secondary 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.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Federal PSD requirements are contained in the Code of Federal Regulations (CFR), 40, 52.21, Prevention of Significant Deterioration of air quality. The State of Florida has adopted PSD regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)] that essentially are identical to the federal regulations. PSD regulations require that all new major stationary sources or major modifications to existing major sources of air pollutants regulated under CAA be reviewed and a construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by the U.S. Environmental Protection Agency (EPA), and, therefore, PSD approval authority in Florida has been granted to FDER.

A "major facility" is defined under PSD regulations as any one of 28 named source categories that has the potential to emit 100 tons per year (TPY) or more of any pollutant regulated under the CAA, or any other stationary

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

		AAQS					
		National		State of Florida	PSD Increments		Significant Impact Levels
Pollutant	Averaging Time	Primary Standard	Secondary Standard		Class I	Class II	
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum[a]	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4[c]	17[c]	1
	24-Hour Maximum[b]	150	150	150	8[c]	30[c]	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[b]	365	NA	260	5	91	5
	3-Hour Maximum[b]	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum[b]	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum[b]	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum[d]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	15	NA	NA	NA

[a] Maximum concentration not to be exceeded more than once per year.
[b] Achieved when the expected number of exceedances per year is less than 1.
[c] Proposed by EPA in the Federal Register on October 5, 1989.
[d] Achieved when the expected number of days per year with concentrations above the standard is less than 1.

Note: Particulate matter (TSP) = total suspended particulate matter.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
$\mu g/m^3$ = micrograms per cubic meter.
NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50.
40 CFR 52.21.
Chapter 17-2.400, F.A.C.

facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. A "source" is defined as an identifiable piece of process equipment or emissions unit. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant, considering the application of control equipment and any other federally enforceable limitations on the source's capacity. A "major modification" is defined under PSD regulations as a change at an existing major stationary facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Major new facilities and major modifications are required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts:

1. Source information,
2. Control technology review,
3. Source impact analysis,
4. Preconstruction air quality monitoring analysis, and
5. Additional impact analyses.

In addition to these analyses, a new source also must be reviewed with respect to good engineering practices (GEP) stack height regulations. If the proposed new source or modification is located in a nonattainment area for any pollutant, the source may be subject to nonattainment new source review requirements.

Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

The 1977 CAA amendments address the prevention of significant deterioration of air quality. The law specifies that certain increases in air quality concentrations above the baseline concentration level of SO_2 and PM(TSP)

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[a]
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
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour

[a] No de minimis concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

[b] Any emission rate of these pollutants.

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.
NSPS - New Source Performance Standards.
NESHAP - National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ - micrograms per cubic meter.

Source: F.A.C., Rule 17-2.510, Table 500-2.

would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or will have an impact. Congress also directed EPA to evaluate PSD increments for other criteria pollutants and, if appropriate, promulgate PSD increments for such pollutants.

Three classifications were designated, based on criteria established in the CAA amendments. Certain types of areas (international parks, national wilderness areas, memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) were designated as Class I areas. All other areas of the country were designated as Class II. PSD increments for Class III areas were defined, but no areas were designated as Class III. However, Congress made provisions in the law to allow the redesignation of Class II areas to Class III areas.

In 1977, EPA promulgated PSD regulations related to the requirements for classifications, increments, and area designations as set forth by Congress. PSD increments were initially set for only SO_2 and PM(TSP). However, in 1988, EPA promulgated final PSD regulations for NO_x and established PSD increments for nitrogen dioxide (NO_2).

The current federal PSD increments are shown in Table 3-1. As shown, Class I increments are the most stringent, allowing the smallest amount of air quality deterioration, while the Class III increments allow the greatest amount of deterioration. FDER has adopted the EPA class designations and allowable PSD increments for PM(TSP), SO_2, and NO_2. The Florida NO_2 increments were adopted in August 1990.

On October 5, 1989, EPA proposed PSD increments for PM10. Those proposed increments are shown in Table 3-1. The PM10 increments as proposed are somewhat lower in magnitude than the current PM(TSP) increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a fictitious concentration level corresponding to a specified baseline date and certain additional baseline sources. In reference to the baseline concentration, the baseline date actually includes three different dates:

1. The major source 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 source baseline date, which is the earliest date after the trigger date on which a major stationary source or major modification subject to PSD regulations submits a complete PSD application; and
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

By definition in the PSD regulations, 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:

1. The actual emissions representative of sources in existence on the applicable minor source baseline date; and
2. The allowable emissions of major stationary facilities that began construction before January 6, 1975, for SO_2 and PM(TSP) sources, or February 8, 1988, for NO_x sources, but which 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 representative of a major stationary source on which construction began after January 6, 1975, for SO_2 and PM(TSP) sources, and after February 8, 1988, for NO_x sources; and
2. Actual emission increases and decreases at any stationary facility occurring after the major source baseline date that result from a

physical change or change in the method of operation of the facility.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.). The minor source baseline date for NO_2 has been set as March 28, 1988, for all of Florida.

3.2.3 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 [Chapter 17-2.500(5)(c), F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Chapter 17-2.100(25), F.A.C. as:

> An emissions limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines 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. If the Department 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.

The requirements for BACT were promulgated within the framework of PSD 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 requires 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 judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program including the adoption of a new "top-down" approach to BACT decisionmaking.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limits that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990a).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Chapter 17-2.500(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 (see Table 3-2).

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).

Under the exemption rule, FDER 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 3-2 [Chapter 17-2.500(3)(e), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). 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, 1987b). The source impact analysis for criteria pollutants can be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is below significance levels, as presented in Table 3-1.

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. 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 significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor must normally be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSES

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analysis 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; Chapter 17-2.500(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts from 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 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

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, 1985). Identical regulations have been adopted by FDER [Chapter 17-2.270, 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: H_g = 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 kilometers (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 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. Because the terrain in the vicinity of the Okeelanta sugar mill is flat, plume impaction was not considered in determining the GEP stack height.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant, or if the modification results in a significant net emission increase of the nonattainment pollutant.

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 PSD REVIEW

3.4.1.1 Pollutant Applicability

The Okeelanta sugar mill is located in Palm Beach County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants except ozone. As such, VOC emissions are not subject to PSD review. Palm Beach County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_2. The site is located within 100 km of the nearest PSD Class I area, the Everglades National Park, located about 90 km south.

The Okeelanta sugar mill is considered to be an existing major facility because potential emissions of any regulated pollutant exceed 100 TPY. As a result, PSD review is required for the proposed modification for each pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., a major modification).

The maximum annual emissions from the proposed oil-fired boiler are compared to the PSD significant emission rates in Table 3-3. As shown, potential emissions of SO_2 and NO_x from the boiler will exceed the PSD significant emission rate. Therefore, the proposed expansion project is subject to PSD review for SO_2 and NO_x.

Table 3-3. Maximum Potential Emissions From Proposed Oil-Fired Boiler

Pollutant	Maximum Potential Emissions From Proposed Boiler (TPY)	Significant Emission Rate (TPY)	PSD Review Applies?
Particulate Matter (TSP)	23.1	25	No
Particulate Matter (PM10)	11.6	15	No
Sulfur Dioxide	221.6	40	Yes
Nitrogen Oxides	77.5	40	Yes
Carbon Monoxide	86.1	100	No
Votatile Organic Compounds (non-methane)	38.7	40	No
Lead	0.0038	0.6	No
Sulfuric Acid Mist	5.46	7	No
Total Fluorides	0.017	3	No
Total Reduced Sulfur	0	10	No
Reduced Sulfur Compounds	0	10	No
Hydrogen Sulfide	0	10	No
Asbestos	0	0.007	No
Beryllium	0.00034	0.0004	No
Mercury	0.0013	0.1	No
Vinyl Chloride	0	1	No

3.4.1.2 Ambient Monitoring

Based upon the increase in emissions from Okeelanta's proposed boiler, a PSD preconstruction ambient monitoring analysis is required for SO_2 and NO_x. However, if the increase in impacts of a pollutant is less than the de minimis monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement may be granted for that pollutant. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

The maximum 24-hour average SO_2 impact associated with the new boiler is predicted to be 18 micrograms per cubic meter ($\mu g/m^3$), and the maximum annual average NO_2 impact is predicted to be 0.33 $\mu g/m^3$. The methodology used to predict these impacts is presented in Section 5.0, along with the impact analysis results. The de minimis concentration level for SO_2 is 13 $\mu g/m^3$, 24-hour average, and the de minimis level for NO_2 is 14 $\mu g/m^3$, annual average.

The maximum 24-hour SO_2 impacts are greater than the de minimis level, and, therefore, an ambient monitoring analysis is required for SO_2. The monitoring analysis is presented in Section 4.0. Since the maximum impact of NO_2 is less than the de minimis concentration level, the proposed project can be exempted from the PSD preconstruction ambient monitoring requirement for NO_x.

3.4.1.3 GEP Stack Height Analysis

The GEP stack height regulations allow any stack to be at least 65 m [213 (ft)] high. The proposed stack for the new boiler will be 75 ft high and therefore does not exceed the GEP stack height. The potential for downwash of the boiler's emissions as a result of nearby structures is discussed in Section 5.0, Source Impact Analysis.

3.4.2 NONATTAINMENT REVIEW

The Okeelanta mill is located in Palm Beach County, which has been designated as a nonattainment area for ozone. As a result, nonattainment review applies if the proposed boiler will emit greater than 40 TPY of VOC. As shown in Table 3-3, the proposed increase in VOC will be less than 40 TPY. As a result, nonattainment new source review does not apply to the proposed project.

3.4.3 NEW SOURCE PERFORMANCE STANDARDS

Based on the maximum heat input to the proposed boiler and the type of fuel burned, the boiler will be subject to the federal NSPS for industrial boilers (40 CFR 60, Subpart Db). The Subpart Db standards are summarized in Table 3-4. The NSPS for SO_2 require that either the boiler meet an emission limit of 0.8 pound per million British thermal units (lb/MMBtu) heat input and achieve 90 percent reduction in SO_2 emissions or burn very low sulfur fuel oil. Very low sulfur fuel oil is defined as distillate fuel with a maximum sulfur content of 0.5 percent by weight, or a fuel oil with an equivalent SO_2 emission rate of 0.5 lb/MMBtu or less. The proposed boiler will comply with the NSPS for SO_2 by burning very low sulfur distillate fuel oil with a maximum sulfur content of 0.5 percent.

The NSPS for NO_x is 0.2 lb/MMBtu heat input for an industrial boiler firing distillate oil and having a high heat release rate [i.e., greater than 70,000 British thermal units per hour per square foot (Btu/hr-ft^2)]. The proposed boiler will fall into this source category. The proposed maximum NO_x emission rate for the boiler is 0.18 lb/MMBtu, which is lower than the NSPS.

There is no particulate matter emission limit for industrial boilers firing very low sulfur fuel oil. There is an opacity limitation of 20 percent, as shown in Table 3-4.

Table 3-4. NSPS for Oil-Fired, Steam-Generating Units With Heat Input Between $100x10^6$ Btu/hr and $250x10^6$ Btu/hr (40 CFR 60, Subpart Db)

Pollutant	Annual Capacity Factor On Oil (%)	Standard
Sulfur Dioxide	31-100 on oil	0.80 lb/10^6 Btu; 90% reduction[a]
	0-30	0.50 lb/10^6 Btu[b]
Particulate Matter	0-100	Conventional or emerging SO_2 control technology used: 0.10 lb/10^6 Btu; SO_2 control technology not used: No PM limit
	0-100	20% opacity, except 27% for one 6-minute period per hour
Nitrogen Oxides	11-100	Distillate oil only: Low heat release rate --0.10 lb/10^6 Btu High heat release rate--0.20 lb/10^6 Btu Duct burner in combined cycle --0.20 lb/10^6 Btu
		Residual oil only: Low heat release rate --0.30 lb/10^6 Btu High heat release rate--0.40 lb/10^6 Btu Duct burner in combined cycle --0.40 lb/10^6 Btu
	0-10	Residual oil with %N ≤0.3, distillate oil or natural gas: - No NO_x standard

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[a] Percentage reduction requirement does not apply if burning very low sulfur oil (<0.50 lb/10^6 Btu).

[b] Also applies if oil is fired in a duct burner of a combined cycle unit and 30% or less of the heat input to the steam-generating unit is from oil combustion in the duct burner.

4.0 PRECONSTRUCTION AMBIENT MONITORING ANALYSIS

As discussed in Section 3.3, Source Applicability, a preconstruction ambient monitoring analysis is required for SO_2. The preconstruction monitoring analysis is presented in this section.

Guidelines concerning the requirements for PSD preconstruction monitoring are given in the document entitled "Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD)" (EPA, 1987). The guidelines cover the collection of new data to fulfill the requirements, as well as the use of existing representative air quality data. To determine if existing data are "representative", the major considerations are monitor location, quality of the data, and currentness of data.

The Florida Sugar Cane League (FSCL) has operated an ambient monitoring network in the sugar cane growing area for several years. The network contains one continuous ambient SO_2 monitor, located at the Florida Celery Exchange in Belle Glade. This site is about 15 km northeast of the Okeelanta sugar mill. Data collected from the station are summarized in Table 4-1 for the period April 1988 through June 1990.

The first criteria in determining if existing data are representative is monitor location. According to the PSD guidelines, a "regional" monitoring site may be used if the proposed source will be located in an area that is generally free from the impact of other points and area sources associated with human activities. The regional site must be located in an area of similar terrain and represent the air quality across a broad region. The SO_2 monitoring site in Belle Glade meet this criteria since, during the time the proposed boiler will operate (i.e., off-season), there are very few stationary air pollution sources in the sugar cane area that are operating. All of the sugar mills in the area, which have bagasse/oil-fired boilers, are shutdown during the off-season.

Table 4-1. SO_2 Concentrations Measured at the Monitoring Station in Belle Glade

Site Number	Location	Period	Number of Observations	Measured Concentration ($\mu g/m^3$) 3-Hour Highest	3-Hour Second Highest	24-Hour Highest	24-Hour Second-Highest	Annual
3420-017-J02	Belle Glade: Duda Rd, 1 mile south of Old SR 80	Apr - Sept 1988	3,614	17	17	8	7	3
		Jan - Dec 1989	5,974	50	42	19	19	8
		Jan - June 1990	3,895	66	64	24	18	9

The second criteria relates to the quality of the monitoring data (i.e., the data must meet all PSD quality assurance requirements). The FSCL monitoring network has had full PSD approval for several years and meets the PSD requirements.

The third criteria states that the data must be current. Generally, this means the data must not be more than 3 years old. The data presented in Table 4-1 were collected within the past 3 years and therefore meet the PSD criteria.

In summary, the continuous SO_2 data collected at the monitoring site in Belle Glade fulfills the PSD preconstruction monitoring criteria. The data therefore should satisfy the preconstruction monitoring requirements for SO_2.

5.0 AIR QUALITY MODELING APPROACH

5.1 GENERAL MODELING APPROACH

The general modeling approach followed EPA and FDER modeling guidelines for determining compliance with AAQS and PSD increments. In general, when model predictions are used to determine compliance with AAQS and PSD increments, current policies stipulate that the highest annual average and highest, second-highest short-term (i.e., 24 hours or less) concentrations be compared to the applicable standard when 5 years of meteorological data are used. The highest, second-highest concentration (HSH) is calculated for a receptor field by:

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

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

To develop the maximum short-term concentrations for the proposed mill, the general modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. The basic difference between the two phases is the receptor grid used when predicting concentrations, the number of emission points, and the number of meteorological periods evaluated. In general, concentrations for the screening phase were predicted using a coarse receptor grid, limited number of major sources, and a 5-year meteorological record.

After a final list of HSH short-term concentrations was developed, the refined phase of the analysis was conducted by predicting concentrations for a refined receptor grid centered on the receptor at which the HSH concentration was produced from the screening phase. The air dispersion model was executed for the meteorological periods during which both the highest and second-highest concentrations were predicted to occur at that receptor, based on the screening phase results. This approach was used to ensure that valid HSH concentrations were obtained. More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

5.2 MODEL SELECTION

The selection of an appropriate air dispersion model was based on the model's ability to simulate impacts in areas surrounding the Okeelanta mill. Within 50.0 km of the mill, the terrain can be described as simple, i.e., flat to gently rolling. As defined in the EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex ISC short-term (ISC) dispersion model (EPA, 1988a) was used to evaluate the pollutant emissions from the Okeelanta mill and other existing major facilities. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1988b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

The ISC model consists of two sets of computer codes which are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISC Short-Term (ISCST) model, is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term and annual averaging periods. For example, a 24-hour average concentration is based on 24 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

The second model code within the ISC model is the ISC Long-Term (ISCLT) model. The ISCLT model uses joint frequencies of wind direction, wind speed, and atmospheric stability to calculate seasonal and/or annual average ground-level concentrations. Because the input wind directions are for 16 sectors, with each sector defined as 22.5 degrees, the model calculates concentrations by assuming that the pollutant is uniformly distributed in the horizontal plane within a 22.5-degree sector.

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output. In general, the ISCST model will produce higher annual average concentrations as compared to the ISCLT model.

Major features of the ISCST model are presented in Table 5-1. Concentrations due to stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground level concentrations. The criteria used to determine when the rural

Table 5-1. Major Features of the ISCLT Model

ISCLT Model Features

- Polar or Cartesian coordinate systems for receptor locations
- Rural or one of three urban options that affect windspeed profile exponent, dispersion rates, and mixing height calculations
- Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs)
- Procedures suggested by Huber and Snyder (1976), Huber (1977), Schulmann and Hanna (1986), and Schulmann and Scire (1980) for evaluating building downwash and wake effects
- Procedures suggested by Briggs for evaluating stack-tip downwash
- Separation of multiple point sources
- Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
- Capability of simulating point, line, volume, and area sources
- Capability to calculate dry deposition
- Variation of windspeed with height (windspeed-profile exponent law)
- Concentration estimates for annual average
- Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm
- Receptors located above local terrain (i.e., "flagpole" receptors)
- 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)

Source: EPA, 1988a.

or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by EPA (1987a) and are referred to as the regulatory options in the ISCST model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO_2 concentration emitted by 50 percent for every 4 hours of plume travel time).

In this analysis, the EPA regulatory options were used to address maximum impacts. Based on a review of the land use around the Okeelanta mill, the rural mode was selected based on the degree of residential, industrial, and commercial development within 3 km of the site.

5.3 METEOROLOGICAL DATA

Meteorological data used in the ISCST 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) stations at Palm Beach International Airport. The 5-year period of meteorological data was from 1982 through 1986. The NWS station at West Palm Beach, located approximately 67 km to the east of the

Okeelanta site, was selected for use in the study because it is the closest primary weather station to the study area which is representative of the plant site.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST 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 with the radiosonde data using the Holzworth (1972) approach. 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 series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions were 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 by using the EPA RAMMET meteorological preprocessor program.

In order to simulate the operation of the proposed boiler during the off-season, the 245-day period from March 1 through October 31 (Day 60 through Day 304) was simulated in the ISCST model. The boiler will operate for a maximum of 175 days per year during the off-season. However, the off-season can vary from year to year and can start as early as March 1 and end as late as October 31. As a result, the entire 245-day period was modeled to determine maximum short-term impacts. To determine the annual average impact, the 245-day average concentration was multiplied by the ratio of 245/365, or 0.67.

5.4 EMISSION INVENTORY

5.4.1 PROPOSED OKEELANTA BOILER

Stack and operating parameters and emission rates for the proposed boiler at Okeelanta are presented in Table 5-2. A generic emission rate of 10 grams per second (g/s) [79.37 pounds per hour (lb/hr)] was used for modeling the proposed boiler. The final results were then converted to SO_2 and NO_x concentrations using the proposed emission rates of 105.5 and 36.9, respectively.

5.4.2 OTHER AIR EMISSION SOURCES

The results of the modeling analysis show that maximum NO_2 impacts as a result of the proposed boiler are less than significance levels (see Section 5.8). As a result, SO_2 is the only pollutant requiring further modeling analysis. Therefore, an emission inventory for SO_2 was developed from available databases. All other sugar mill PSD sources do not operate at the same time as the proposed boiler. Based on the modeling analysis results, the significant impact area (SIA) for SO_2 extends out 14 km from the Okeelanta mill (See Section 5.8.1). The proposed boiler is the only SO_2 source within the SIA.

The nearest PSD Class I area to the Okeelanta mill is the Everglades National Park (ENP), located about 90 km south of the mill. The closest edge of the ENP comes within 100 km of the mill directly to the south and also to the southwest at the western edge of the park. All major PSD SO_2 sources located within 100 km of the ENP were included for the modeling analysis. This included only sources on the east coasts of Dade and Broward Counties, since the other increment consuming sugar mill sources will not be operating at the same time as the proposed boiler. The stack, emission and operation data for the east coast PSD sources were obtained from prior PSD applications and modeling analyses conducted for that area (KBN, 1990).

Table 5-2. Summary of Source Parameters Used in the Modeling Analysis

Modeled Source Number	Stack Dimensions (m)		Operating Parameters		Generic Emissions
	Height	Diameter	Temperature (K)	Velocity (m/s)	(g/s)
1	22.90	1.52	497	18.38	10.0

Note: The maximum SO_2 emission rate is 105.5 lb/hr (13.29 g/sec).
The maximum NO_x emission rate is 36.9 lb/hr (4.65 g/sec).
The maximum Be emission rate is 0.00051 lb/hr (0.000064 g/s).

5.5 RECEPTOR LOCATIONS

The plant property boundaries surrounding the Okeelanta mill are shown in Figure 5-1. To the east, U.S. 27 is the nearest public access. This road is bounded by canals that prevent access into the cane fields. There are a few roads leading from U.S. 27 onto Okeelanta property; these roads either have gates or signs posted as no trespassing. To the north, the entire property is bounded by the Bolles canal. There is a public road that is located immediately to the north of the canal; however, there are no roads or bridges across the canal. To the west, the property is bounded by the Miami Canal, with limited roads extending across the canal. Although there are generally only sugar cane fields located to the west of the Miami Canal and the public would not be present in these areas, the roads across the canal will be posted to limit public access across the canal.

To the south, the property is bounded by a public road that runs west off of U.S. 27. The public access to the cane fields to the north of this road will be restricted by posted signs.

In addition to the physical barriers and visual warning signs described above, Okeelanta maintains security patrols of the cane fields on an around-the-clock basis. The security personnel routinely travel the property area. Any unauthorized persons found on the Okeelanta property are promptly removed from the property.

For the screening analysis, a polar grid and discrete receptors were used. The discrete receptor grid consisted of 36 property boundary receptors representing the <u>minimum</u> boundary distance from the proposed boiler within every 10-degree direction interval. These receptor distances are presented in Table 5-3. Additional discrete receptors were entered off of plant property at distances of 5,000, 7,000, and 9,000 meters to fill in gaps between plant property and the receptor grid ring distances of 11,000 and 14,000 meters from the proposed boiler, respectively.

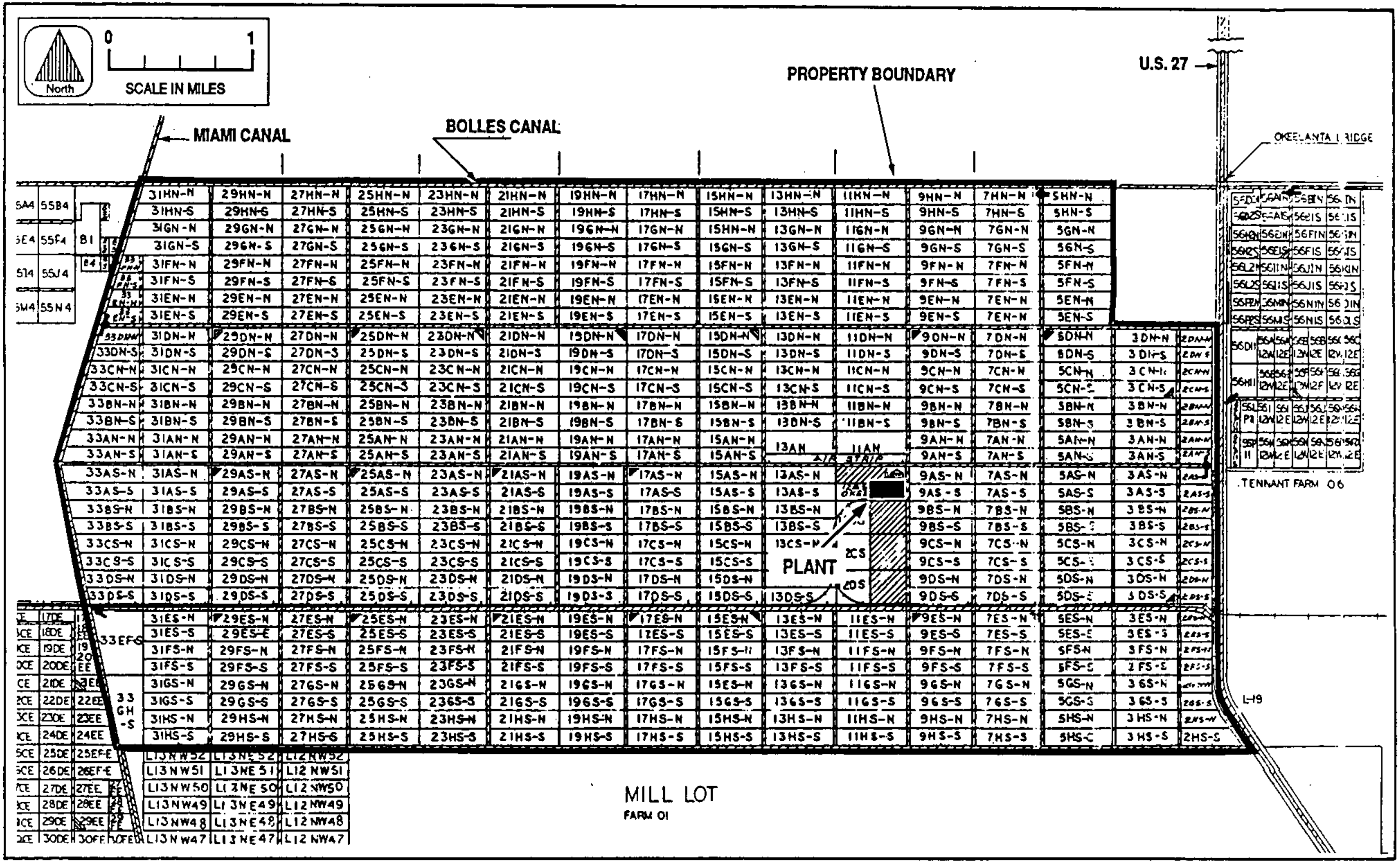

FIGURE 5-1 OKEELANTA PROPERTY BOUNDARIES

Table 5-3. Discrete Plant Boundary Receptors, Okeelanta Mill

Distance[a] (m)	Direction (°)	Distance[a] (m)	Direction (°)
3,616	10	2,758	190
3,742	20	2,854	200
4,002	30	3,052	210
3,621	40	3,391	220
3,268	50	3,949	230
3,597	60	4,906	240
3,976	70	6,744	250
3,855	80	9,269	260
3,840	90	9,349	270
3,862	100	9,339	280
3,995	110	8,510	290
4,273	120	6,271	300
3,879	130	5,086	310
3,349	140	4,391	320
3,027	150	3,968	330
2,840	160	3,724	340
2,754	170	3,610	350
2,743	180	3,597	360

[a] Relative to the proposed stack located at (0,0) meters.

All modeled concentration maximums occurred at the plant property boundary. The refinement phase of the modeling used all <u>actual</u> plant property distances located every 2 degrees within 10 degrees on either side of the maximum screening receptor. To ensure that the highest, second-highest concentration calculated with the refined grid was correct, concentrations were predicted for the entire year with the refined grid receptors.

5.6 BUILDING DOWNWASH CONSIDERATIONS

The proposed boiler will have a stack height below Good Engineering Practice, and as such, the modeling analysis must address the potential effects of aerodynamic downwash on the proposed stack. To determine the potential for downwash to occur, the following buildings were analyzed from a site layout map of the mill:

	Height(ft)
Mill Tandems A & B	55
South Evaporator Building	75
North Evaporator Building	65
Power Plant Building	46
Tank	80
Refinery Building	90

A plot plan of the mill showing the major buildings is presented in Figure 5-2. Downwash was determined for every 1 degree within each 10-degree direction sector. A tiering analysis was performed for all buildings located within 1L of each other (where L represents the lesser dimension of the height and width of the building). Based on this analysis, direction-specific building heights and widths were determined and included for the proposed boiler. A summary of all building parameters used is presented in Table 5-4.

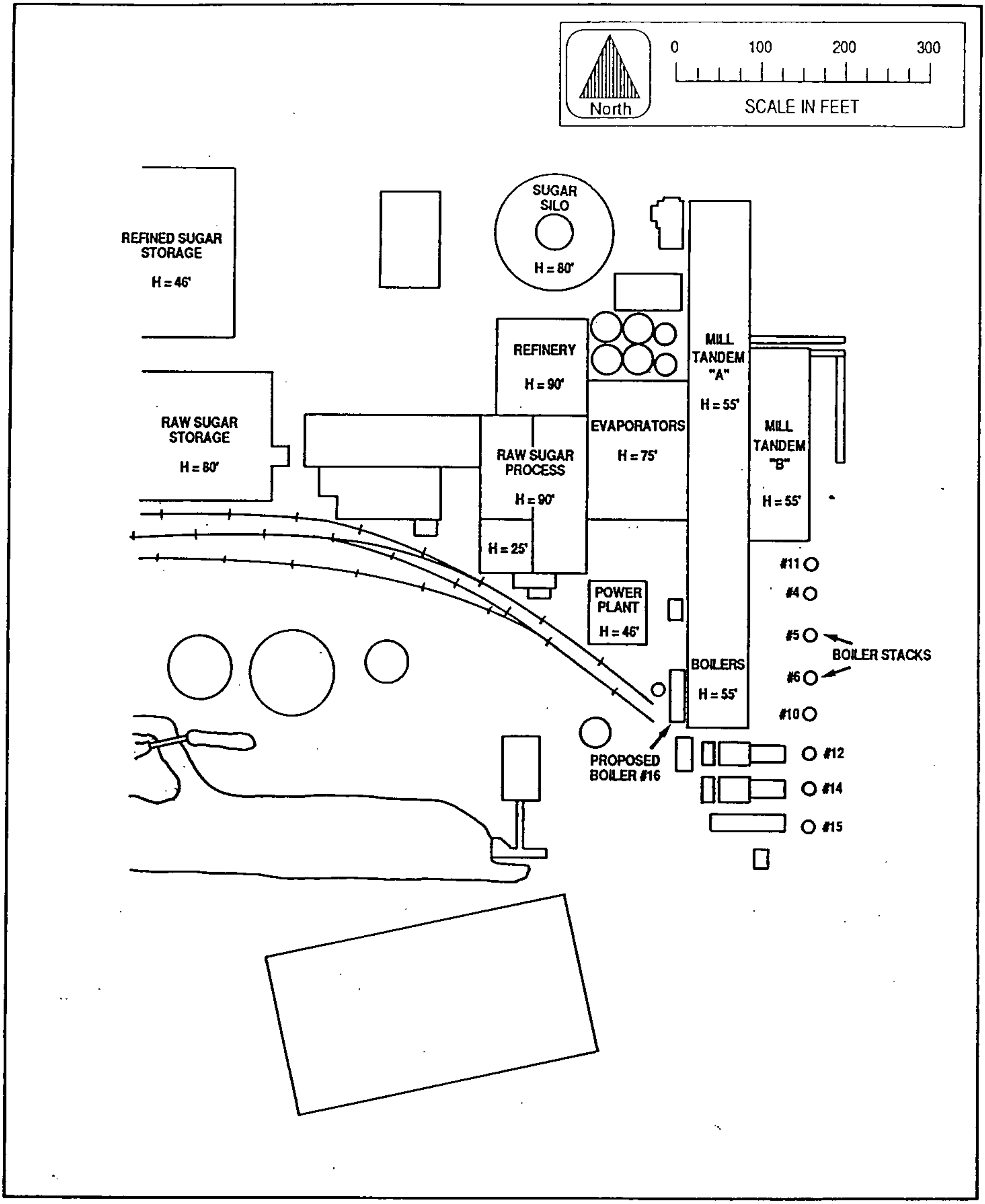

FIGURE 5-2 BUILDING HEIGHTS, OKEELANTA SUGAR MILL

Table 5-4. Building Dimensions Used in the Modeling Analysis

Building	Actual Building Dimensions[a] Height (m)	Length (m)	Width (m)
Mill Tandems A & B	16.85	135.0	42.6
South Evaporators	22.86	22.9	12.2
North Evaporators	19.81	22.9	38.4
Power Plant	14.02	21.3	21.9
Tank	24.38	—	71.8[b]
Refinery	27.43	91.5	36.5

[a] For modeling, all buildings within 1L of each other were combined, where L is the lesser dimension of the building height or width of each building.

[b] Tank diameter.

5.7 BACKGROUND

A background SO_2 concentration (i.e., impacts from sources not modeled in the analysis) must be added to the maximum predicted concentration from modeled sources to produce a total concentration for comparison to the SO_2 AAQS. Background concentrations were developed from ambient monitoring data available from the FSCL, as described in Section 4.0.

As presented in Section 4.0, there is one monitor that measured SO_2 concentrations in Belle Glade during 1988, 1989, and 1990. A summary of the maximum SO_2 concentrations measured at this site was presented in Table 4-1.

During the crop season, when the proposed boiler is not operating, the monitoring site is located close to a major source of SO_2 in Belle Glade (i.e., Sugar Cane Growers Cooperative), and therefore the concentrations would overestimate representative background levels during the off-season. SO_2 concentrations measured during the crop season would be higher based on operation of this SO_2 source. In order to develop a conservative estimate of the SO_2 background for the off-season, the second-highest 3-hour, 24-hour, and highest annual average concentrations measured at the monitor during the entire monitoring period (1988-1990) was used as the background SO_2 concentration. These concentrations are 64 $\mu g/m^3$, 3-hour; 19 $\mu g/m^3$, 24-hour; and 9 $\mu g/m^3$, annual average.

5.8 AIR QUALITY MODELING RESULTS

5.8.1 SIGNIFICANT IMPACT ANALYSIS

The maximum impacts of the proposed boiler are presented in Table 5-5 (screening) and Table 5-6 (refined) based on the generic emission rate of 10 g/s. Based on the actual SO_2 emission rate of 105.5 lb/hr (13.3 g/s), the results indicate that the maximum predicted SO_2 concentrations will be above the significant impact levels for all averaging times. Therefore, further modeling analysis is required for this pollutant to demonstrate compliance with PSD increments and AAQS.

Table 5-5. Maximum Predicted Impacts for Okeelanta's Proposed Boiler: Screening Analysis With an Emission Rate of 10 g/s

Averaging Time	Year	Concentration (μg/m³)	Dir. (deg)	Dist. (m)	Significant Impact Level (μg/m³)
Annual[a]	1982	1.04	320	4,391	1
	1983	0.92	320	4,391	
	1984	1.10	320	4,391	
	1985	0.84	320	4,391	
	1986	0.74	360	3,597	
3-Hour	1982	56	330	3,968	25
	1983	65	170	2,754	
	1984	53	160	2,840	
	1985	50	170	2,754	
	1986	39	130	3,879	
24-Hour	1982	13	160	2,840	5
	1983	11	170	2,754	
	1984	11	320	4,391	
	1985	10	360	3,597	
	1986	9	360	3,597	

[a] Reflects a 245-day average.

Table 5-6. Maximum Predicted Generic Impacts for Okeelanta's Proposed Boiler: Refined Analysis

Averaging Time		Concentration ($\mu g/m^3$)	Dir. (deg)	Dist. (m)	Day	Period
Annual[a]	1982	0.99	318	4,840	—	—
	1984	1.05	318	4,840	—	—
3-Hour	1982	54	330	4,153	205	8
	1983	64	170	2,786	300	7
24-Hour	1982	13.7	162	2,884	267	—
	1983	13.9	168	2,804	300	—
	1984	10.7	320	4,695	117	—

[a] Reflects 245-day average.

Based on the actual NO_x emission rate of 36.9 lb/hr (4.65 g/s) and the adjustment for the 245-day operation (0.67), the maximum predicted NO_x concentration is 0.33 $\mu g/m^3$, annual average, which is below the significant impact level of 1 $\mu g/m^3$, annual average. Therefore, the proposed modification is not significant for NO_x, and further modeling analysis is not required for that pollutant. For SO_2, the maximum significant impact distance of the proposed boiler is 14 km, which is also the furthest ring distance included in the screening analysis.

5.8.2 PSD CLASS II ANALYSIS

Refined modeling analysis results for the proposed boiler are presented in Table 5-7. The proposed boiler is the only PSD increment consuming source within its significant impact distance. The proposed boiler also operates only in the off-season. The results presented in Table 5-7 are therefore indicative of the total PSD Class II increment consumption to be expected in the vicinity of the mill from the operation of the proposed boiler. The maximum SO_2 annual impact of 0.94 $\mu g/m^3$ is below the allowable PSD Class II increment of 20 $\mu g/m^3$. Similarly, the maximum 3-hour and 24-hour SO_2 impacts of 85 and 18.5 $\mu g/m^3$, respectively, are below the allowable increments of 512 and 91 $\mu g/m^3$ for those averaging times. These maximum impacts are less than 25 percent of the allowable Class II increments.

5.8.3 PSD CLASS I ANALYSIS

The maximum SO_2 PSD Class I screening results are presented in Table 5-8. These results reflect the impacts from all PSD-increment-consuming sources. The maximum PSD Class I refined results are presented in Table 5-9. The maximum annual, 3-hr, and 24-hr concentrations are 0.4, 17.3, and 3.8 $\mu g/m^3$, respectively. These impacts are below the allowable PSD Class I increments of 2, 25, and 5 $\mu g/m^3$, respectively.

The predicted maximum impacts of the proposed boiler only on the Class I area are summarized in Table 5-10. As shown, the impacts are very low, being 0.03 $\mu g/m^3$, annual average; 2.2 $\mu g/m^3$, 3-hour average; and 0.4 $\mu g/m^3$,

Table 5-7. Maximum Predicted Impacts for Okeelanta's Proposed Boiler: Refined Analyis

Averaging Time		Concentration ($\mu g/m^3$)	Dir. (deg)	Dist. (m)	Day	Period
Sulfur Dioxide						
Annual[a]	1984	0.94	318	4,840	–	–
3-Hour	1983	85	170	2,786	300	7
24-Hour	1983	18.5	168	2,804	300	–
Nitrogen Oxides						
Annual[a]	1984	0.33	318	4,840	–	–

[a] Adjusted to 365-day average by multiplying the generic impact times 0.67.

Note: Refined concentrations based on generic concentration times ratio of actual emission rate to generic emission rate for each pollutant.

Table 5-8. Maximum Predicted SO_2 PSD Class I Impacts Due to All Sources: Screening Analysis

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor X (m)	Receptor Y (m)
Annual	1982	0.40	8,500	-91,400
	1983	0.40	8,500	-91,400
	1984	0.35	8,500	-91,400
	1985	0.40	8,500	-91,400
	1986	0.37	8,500	-96,400
3-Hour	1982	9.8	8,500	-91,400
	1983	16.8	8,500	-96,400
	1984	10.3	8,500	-91,400
	1985	12.2	8,500	-91,400
	1986	12.1	8,500	-91,400
24-Hour	1982	3.3	8,500	-91,400
	1983	3.7	5,000	-91,400
	1984	3.0	8,500	-91,400
	1985	3.3	8,500	-96,400
	1986	3.6	8,500	-96,400

Table 5-9. Maximum Predicted SO_2 PSD Class I Impacts Due to All Sources: Refined Analysis

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor X (m)	Receptor Y (m)	Class I Increment ($\mu g/m^3$)
Annual	1982	0.40	8,500	-91,400	2
	1983	0.40	8,500	-91,400	
	1985	0.40	8,500	-91,400	
3-Hour	1983	17.3	8,500	-97,300	25
24-Hour	1986	3.8	7,600	-91,400	5

Note: The proposed boiler does not contribute to any of the above 3-hour and 24-hour concentrations.

Table 5-10. Maximum Predicted SO_2 PSD Class I Impacts for Proposed Boiler Only

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor X (m)	Receptor Y (m)
Annual	1982	0.01	-5,000	-91,400
	1983	0.03	0	-91,400
	1984	0.01	5,000	-91,400
	1985	0.01	0	-91,400
	1986	0.01	-61,000	-79,400
3-Hour	1982	2.2	5,000	-91,400
	1983	2.2	0	-91,400
	1984	1.8	-10,000	-106,400
	1985	1.8	8,500	-91,400
	1986	1.8	-10,000	-106,400
24-Hour	1982	0.3	5,000	-91,400
	1983	0.4	0	-91,400
	1984	0.3	0	-91,400
	1985	0.3	5,000	-91,400
	1986	0.4	10,000	-101,400

24-hour average. These impacts are less than 9 percent of the allowable increments.

5.8.4 AAQS ANALYSIS

Because the proposed boiler will only operate in the off-season, the results presented in Table 5-7 are indicative of the total mill impact, excluding background. With the estimated annual background value of 9 $\mu g/m^3$ (see Section 5.7), the maximum SO_2 annual impact of 10 $\mu g/m^3$ is well below the State of Florida AAQS of 60 $\mu g/m^3$. Similarly, with the maximum 3-hour and 24-hour background values of 64 $\mu g/m^3$ and 19 $\mu g/m^3$, respectively, the maximum total 3-hour and 24-hour SO_2 impacts of 149 $\mu g/m^3$ and 38 $\mu g/m^3$, respectively, are below the AAQS of 1,300 and 260 $\mu g/m^3$ for those averaging times. These maximum impacts are less than 20 percent of the AAQS. Therefore, all AAQS are expected to be met with the addition of the proposed boiler.

6.0 BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION

The potential emissions of SO_2 and NO_x from the proposed boiler will exceed their assigned PSD significant emission rates as shown in Table 3-3; therefore, BACT analyses for these two pollutants are required. A general description of industrial boilers is presented in Section 6.1. Sections 6.2 and 6.3 address BACT determinations for SO_2 and NO_x, respectively. The complete "top-down" BACT evaluation of SO_2 includes the identification of SO_2 control technologies for industrial boilers (Section 6.2.1); the environmental, energy, and economic impact evaluations of all technically feasible methods (Section 6.2.2); and the BACT analysis summary (Section 6.2.3). Similar BACT evaluation of NO_x will be discussed in Sections 6.3.1, 6.3.2, and 6.3.3.

6.1 GENERAL DESCRIPTION OF INDUSTRIAL BOILERS

Okeelanta Corporation's proposed boiler is the No. 16 oil-fired boiler to be constructed at the applicant's sugar manufacturing facility in Palm Beach County. The proposed boiler will be the only boiler fired during the 175-day off-season period to produce 150,000 lb/hr of steam needed for general plant processing. The proposed boiler is intended to be operated during the off-season of the sugar cane crop harvest; therefore, a replacement fuel for bagasse is required to provide the heat input for the boiler. Based on the amount of steam required, the boiler will be a medium-sized industrial boiler rated at 205 MMBtu/hr. Clean fuel oil such as distillate oil will be used as the fuel source as a result of readily available supply and low SO_2 and NO_x emissions.

Typically, standard oil-fired industrial boilers vary in sizes ranging from 50 MMBtu/hr to 300 MMBtu/hr and are available as shop-assembled package boilers to reduce the high cost of field-erected boiler. Modern boiler design uses a watertube type boilers which can generate higher capacity and pressure steam with the advantage of design flexibility. Advanced burner designs and total internal furnace wall cooling are recent developments that further enhance boiler efficiency while reducing pollutant emission.

The Okeelanta Corporation's proposed boiler will be a watertube type package boiler with high combustion efficiency of above 80 percent. The proposed boiler will include the most advanced boiler modification techniques to minimize potential emissions.

6.2 BACT DETERMINATION FOR SULFUR DIOXIDE (SO_2) EMISSIONS

6.2.1 IDENTIFICATION OF SO_2 EMISSION CONTROL TECHNOLOGIES FOR INDUSTRIAL BOILERS

In this discussion, the available control technologies capable of reducing SO_2 emissions produced from industrial boilers will be evaluated with regard to their potential application as BACT for the proposed 205-MMBtu/hr distillate-oil-fired boiler.

SO_2 emissions are produced in industrial boilers by the fossil fuel combustion process in which complete oxidation of the fuel-bound sulfur occurs. The amount of SO_2 emissions is directly proportional to the sulfur content in the fuel. Therefore, low sulfur oil also is being considered as an available means to control SO_2 emissions. Reducing SO_2 emissions by boiler modification is not considered technically feasible because the firing mechanism does not affect SO_2 emissions. Generally, complete oxidation of sulfur in fuel is readily achieved before the complete combustion of the primary carbon fuel element in fossil fuel. Typically, SO_2 emission reduction is accomplished by treating the flue gas with a variety of flue gas desulfurization (FGD) processes. Standard FGD processes for industrial boilers are add-on SO_2 scrubbers that include wet lime/limestone scrubbers, spray dryer FGD scrubbers, and sodium solution scrubbing processes.

The discussion of each potential SO_2 control technology includes a description of the technology and the potential SO_2 emission reduction if it is concluded that the technology is technically feasible.

6.2.1.1 Low Sulfur Fuel

Any of the standard fossil fuels, such as natural gas and distillate and residual oils derived from petroleum crude and coal, can be used as heat input sources in industrial boilers. The heating values of these fuels range from 20,000 to 23,200 Btu/lb for natural gas; 17,500 to 19,400 Btu/lb for residual oils; 19,200 to 19,900 Btu/lb for distillate oils; and 10,000 to 14,000 Btu/lb for typical coals. The variations in sulfur content in the fuel are inversely proportional to the heating values for each fuel ranging from nil for natural gas, 0.01 to 0.5 percent for distillate oil, 0.20 to 3.5 percent for residual oil, and 0.05 to 3.0 for coal. 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 industrial boilers.

Natural gas was first considered as a fuel source for the proposed 205-MMBtu/hr boiler. However, there is currently neither an existing natural gas pipeline nor an expansion plan for a pipeline to the site in the near future. Thus, the option of using natural gas is eliminated because of unavailability.

The fuel with the next lowest sulfur content is distillate oils. The total amount of SO_2 emissions calculated for burning distillate oils is based on the maximum sulfur content of 0.5 percent as determined by the American Petroleum Institute (API) standard. Under current NSPS regulations for industrial boilers (40 CFR Subpart Db), low sulfur fuel oils of up to 0.5 percent sulfur content offer a viable option for reducing SO_2 emissions. Also, No. 2 distillate oil is readily available by tank truck to the site. Therefore, No. 2 fuel oil is considered the best available low sulfur fuel for the proposed boiler. For Okeelanta Corporation's proposed boiler, the equivalent SO_2 emission factor is calculated to be 0.51 lb/MMBtu (refer also to Table 2-1).

6.2.1.2 <u>Wet Lime/Limestone Scrubber</u>

The wet lime or limestone FGD process uses either hydrated lime [$(Ca(OH)_2$] or calcium carbonate ($CaCO_3$) to absorb SO_2 compounds from the flue gas. Either $Ca(OH)_2$ or $CaCO_3$ reagent is added to water to make a solution, and then sprayed into the flue gas inside a wet scrubber. Upon contact, the SO_2 compounds react with the reagents to form calcium sulfite ($CaSO_3 \bullet \frac{1}{2}H_2O$) initially, then calcium sulfate ($CaSO_4 \bullet 2H_2O$) with further oxidation.

The calcium sulfite and calcium sulfate precipitate as crystals at the bottom of the wet scrubber or in a holding tank that is downstream from the scrubber and designed to receive the precipitated solids and liquid solution. The solids from the holding tank will be separated from the system by way of a solid-liquid separator. The liquids from the solid-liquid separator are returned to the holding tank where they are combined with the effluent and recycled through the scrubber to absorb additional SO_2.

Both lime and limestone FGD processes are proven technology capable of removing more than 90 percent of the SO_2 from flue gas. Theoretically, higher efficiencies of up to 95 percent may be achievable by adding adipic acid to the liquid scrubbing solution because the reactions between the lime and limestone with SO_2 are more favorable at lower pH conditions.

6.2.1.3 Spray Dryer FGD Scrubber

In a spray drying FGD process, the flue gas entering the scrubber contacts a sprayed slurry of either wet lime or sodium carbonate (Na_2CO_3) sorbent. Sufficient contact is maintained in this scrubber, which is designed with prolonged residence time (5 to 10 seconds), allowing the absorbing reactions and the drying process to be completed. The SO_2 compounds are absorbed by the alkaline slurry to form pseudo liquid-solid phase salts that are dried into crystals by the heat of the flue gas with approximately 1 percent free moisture.

The exact mechanisms for the absorption of SO_2 and formation of alkaline salts are not clear. Overall, the SO_2 reacts with lime or sodium sorbent to form initially either calcium sulfite ($CaSO_3 \bullet \frac{1}{2}H_2O$) or sodium sulfite ($Na_2SO_3$). Upon further oxidation or SO_2 absorption enhanced by the drying process, the sulfite salts will transform into calcium sulfate ($CaSO_4 \bullet 2H_2O$) or sodium sulfate solids. Generally, the spray dry FGD process requires a particulate control device downstream because the byproducts are dry crystalline sulfate salts.

The removal efficiency of the spray dry FGD system varies between 50 to 80 percent average for industrial boilers. Higher removal efficiencies of up to 90 percent can be achieved by maintaining an optimum ratio of either lime- or sodium-based sorbent and SO_2 gas. Furthermore, the type of particulate removal device used may enhance SO_2 removal efficiency. By using a fabric filter instead of an electrostatic precipitator (ESP), the slurry collected on the filter bag surfaces can absorb an additional 5 percent of total SO_2 emissions. A 95 percent SO_2 removal efficiency can be achieved with a lime spray dryer/FGD scrubber and baghouse particulate control combination.

6.2.1.4 Sodium Solution Scrubbing Process

The sodium scrubbing process uses a liquid solution of caustic soda (NaOH) or sodium carbonate (Na_2CO_3) to absorb SO_2 from the flue gas. The overall mechanisms are vapor-liquid reactions in which the flue gas SO_2 reacts with either sodium hydroxide or sodium carbonate solution to form sodium sulfite ($NaSO_3$) droplets. Instantaneously, the sodium sulfite will react with absorbed oxygen from the flue gas to produce a sodium sulfate solution. The final scrubber effluent is a mixture of sodium alkaline salt liquor.

This process is capable of achieving high SO_2 removal efficiencies over a wider range of SO_2 concentrations. Overall, this process can be more effective than both the lime- or sodium-based sorbent in the pseudo liquid-solid phase because the scrubbing liquid can contain higher concentrations of sodium reagent. Also, reactivity is higher between liquid and vapor phases than between the pseudo liquid-solid (i.e., calcium- or sodium-based slurry) and vapor phases. However, the sodium solution scrubbing process consumes a premium chemical (caustic soda or sodium carbonate) to produce a high alkaline waste liquor that requires proper disposal. The sodium solution scrubbing process can achieve an SO_2 removal efficiency of 95 percent.

6.2.2 EVALUATION OF TECHNICALLY FEASIBLE SO_2 CONTROL METHODS

This section examines all the technically feasible SO_2 control methods identified in the previous discussion. A summary of the feasible options is given in Table 6.2-1. All four SO_2 reduction methods are ranked according to their total removal effectiveness. Each alternative is then further examined with regard to its technical issues, environmental effects, energy requirements and impacts, and economic impacts.

The most currently available information on permitting requirements for oil-fired industrial boilers similar to Okeelanta Corporation's proposed boiler was used to derive the baseline SO_2 emission level. Presented in Table 6.2-2 is a summary of all BACT determinations for SO_2 emissions from the oil-fired external combustion stationary sources rated between 10 MMBtu/hr to 250 MMBtu/hr heat input issued since 1980. These sources generally are referred to as oil-fired industrial boilers. This information was obtained from BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse documents by way of the BACT/LAER Informational System (BLIS) database through EPA's National Computer Center located at Research Triangle Park in North Carolina.

6.2.2.1 Ranking of Feasible Control Technologies

The top-down BACT approach requires the ranking of the SO_2 emission control alternatives according to their achievable emission levels applied to the proposed boiler. Of the four alternatives being considered for the project, three alternatives are identified as the add-on FGD processes that can be designed to achieve similar SO_2 removal efficiency of 95 percent. The next highest removal efficiency is therefore the low sulfur oil firing alternative. This alternative can be identified as a process modification by switching to No. 2 distillate oil with 0.5 percent sulfur content.

The design criteria that determine SO_2 removal efficiency for add-on FGD processes are independent of the type of fuels specified for a boiler. The achievable SO_2 emission rates for cases where low sulfur oil (i.e., No. 2

Table 6.2-1. Summary of Technical Feasibility of SO2 Emission Controls for the Proposed Oil-fired Boiler

Control Technology	SO2 Controlled Emission Rate+	Technical Feasibility	Comments
<u>Process Modification</u>			
Low Sulfur Fuel (No. 2 Distillate Oil, 0.5% S)	0.51 lb/MMBtu	YES	As specified by NSPS option of using 0.5 % sulfur No. 2 distillate oil.
<u>Add-on FGD Technology*</u>			
Wet Lime/Limestone Scrubber			
No. 6 Residual Oil, 1.0% S	0.05 lb/MMBtu	YES	Minimum 90 percent efficient, up to 95% efficiency may be achieved by addition of adipic acid to maintain the system's pH level.
No. 2 Distillate Oil, 0.5% S	0.03 lb/MMBtu	YES	
Spray Dryer FGD Scrubber			
No. 6 Residual Oil, 1.0% S	0.05 lb/MMBtu	YES	Up to 95% efficiency; requires baghouse installed downstream as particulate control device.
No. 2 Distillate Oil, 0.5% S	0.03 lb/MMBtu	YES	
Sodium Solution Scrubbing Process			
No. 6 Residual Oil, 1.0% S	0.05 lb/MMBtu	YES	Highest SO2 removal efficiency among all FGD processes; 95 percent.
No. 2 Distillate Oil, 0.5% S	0.03 lb/MMBtu	YES	

\+ Baseline emission rate was assumed from firing No. 6 residual oil (with 1% sulfur) in conventional industrial boilers. The corresponding emission level is 1.03 lbs of SO2/MMBtu (see emission calculation in Appendix B, Part ID).

* For the proposed boiler, each FGD process can be designed to achieve equal removal efficiency of 95 percent.

Table 6.2-2 Summary of BACT Determinations for SO2 Emissions from Oil-fired External Industrial Boilers

Company Name	State	Permit Number	Permit Issued Date	Boiler Size (MMBtu/hr)	SO2 Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	Control Method	Control Efficiency (%)
Owens-Illinois Inc.	OH	04-367	26-Nov-86	10.3	0.52	5.36	23.5	Nat. Gas & #2 Oil Firing	UD
Exeter Energy Limited Partners	CT	176-0004	28-Aug-89	11.2	0.229	2.56	0.5	Undetermined	UD
Northeast Utilities, NNECO	CT	199-0001	23-Sep-88	28.3	0.22	6.23	2.7	Limit 0.5% S to #2 Oil	UD
Berry Holding Company	CA	4016014A & 015B	02-Oct-85	31.5	0.036	1.12	UD	Caustic Scrubber, Pack Tower	96.5%
same as above	CA	4016022 & 023	02-Oct-85	62.5	0.036	2.23	UD	Caustic Scrubber, Pack Tower	96.5%
Petro-Lewis Corporation	CA	SJ 83-09	07-Aug-84	50.0	0.052	2.60	UD	2-Stage Ventury Scrubber	95.0%
Angus Petrotech	CA	4132002-004	29-Nov-83	62.5	0.04	2.56	11.2	Sodium Based Scrubber	UD
Hopco	CA	4099002-013	04-Dec-84	62.5	0.03	2.10	9.2	Undetermined	UD
Georgia-Pacific Corporation	OH	14-1043	01-Dec-85	118.0	1.06	125.08	547.9	Limit 1.0% S in #6 Oil	NA
Delco Moraine Div., GMC	OH	08-654	01-Jul-85	144.0	1.3	187.20	UD	Undetermined	UD
Wisconsin Tissue Mills, Inc.	WI	88-DLJ-024	10-Oct-88	146.4	1.10	161.04	705.4	Limit 1.0% S in #6 Oil	NA
Houston Lighting & Power	TX	PSD-TX-209	16-Jan-80	185.0	0.50	92.50	405.2	Limit <0.5% S in #2 Oil	UD

UD = Undetermined, indicates that information was either unavailable or insufficient to determine.
NA = Not Applicable
Source: BACT/LAER Clearinghouse information on BACT/LAER Information System (BLIS) database at the EPA National Computer Center, RTP, NC.

distillate oil with 0.5 percent sulfur) is fired in boilers equipped with FGD processes are shown in Table 6.2-1. Therefore, the combination of low sulfur firing together with FGD scrubber also is considered a viable SO_2 reduction method. In term of removal efficiency, this combined option can achieve higher SO_2 reduction than either individual process.

A baseline emission level must be established as the basis for BACT ranking and economic analysis purposes. The baseline is defined as the uncontrolled rate of a process being reviewed. In the BACT determinations of SO_2 emissions from industrial boilers shown in Table 6.2-2, the highest SO_2 emission levels are 1.06 lb/MMBtu and 1.10 lb/MMBtu for two boilers (i.e., Georgia-Pacific Corporation and Wisconsin Tissue Mills, Inc., respectively) permitted with 1.0 percent sulfur oil as the only documented requirement. These SO_2 emission levels that associate with the firing of 1 percent sulfur fuel oil will be used as the baseline emission level. For the proposed boiler, the baseline emission level was calculated as 211.0 lbs/hr of SO_2, determined by multiplying the heat input rate of 205 MMBtu/hr by the equivalent SO_2 emissions of 1.03 lb/MMBtu for 1.0 percent sulfur fuel.

By virtue of their similar design efficiencies, analyzing any one type of the three FGD scrubbers is sufficient for the detailed analysis of the FGD process. Thus, the further analysis based on the top-down BACT approach will combine the sodium solution scrubbing processes, the spray dry scrubbers, and the wet scrubbers into a single section. Therefore, there are only three SO_2 emission control methods overall, and their rankings in BACT top-down hierarchy are as follows: the most effective process is the combination of low sulfur oil firing, together with an FGD scrubber for 97 percent removal efficiency (from the baseline) or an equivalent SO_2 emission level of 0.03 lb/MMBtu SO_2 emission level; the second best control method is a process that uses any one of the three FGD scrubbers to reach overall 95 percent removal efficiency or an equivalent SO_2 emission level of 0.05 lb/MMBtu; and the third best SO_2 control method is firing No. 2

distillate oil with 0.5 percent sulfur content for 50 percent reduction or an equivalent SO_2 emission level of 0.51 lb/MMBtu.

Presented in Table 6.2-3 is the BACT top-down hierarchy of the technically feasible SO_2 reduction methods, their general ranges of control effectiveness, and their designed control efficiencies applied to the proposed boiler. In the following detail analyses, the add-on FGD processes are discussed first, followed by the discussions of the low sulfur oil firing process and the combined process of both SO_2 reduction techniques.

6.2.2.2 Analysis of Add-On FGD Process

Technical Issues--The sodium-based solution scrubbing process is the most effective of the three FGD processes, particularly for oil firing that produces very low particulate concentration. Overall reliability of sodium scrubbing systems applied to industrial boilers is also high. In a well-designed system, sodium scrubbing processes do not present any outstanding technical problems neither in application nor operation limitations. Applicability is only limited by waste liquor disposal issue that will be addressed in later discussions. Operation limitations are mainly caused by erosion and corrosion problems. Other operational issues are the handling of highly alkaline or caustic solutions containing sodium hydroxide and sodium carbonate.

The lime spray dryer FGD process has the least favorable status for application to oil-fired boiler because of the additional particulates control equipment generally required with its application. Since the distillate oil contains a negligible amount of ash content, the particulate control is entirely for the benefit of removing the lime or limestone reagent used in the SO_2 removing process. (Lime spray dryer FGD scrubbers are more frequently applied to coal-fired utility boilers where particulates are a major component in the flue gas.) From the operating standpoint, a narrow operating temperature window has to be strictly

Table 6.2-3. BACT "Top-down" Hierarchy of SO2 Reduction Methods for the Proposed Boiler.

Top-down Ranking	Technology	Range of Control Effectiveness (%)	Control level for BACT Analysis (%)	SO2 Emission Level** (lb/MMBtu)	SO2 Annual Emissions (TPY)
First	Low Sulfur Oil with a FGD Scrubber (0.5% S Distillate Oil with Sodium Scrubber)	97	97	0.03	12.9
Second	FGD Scrubbers (1.0% S No.6 Residual Oil)				
	Sodium Solution Scrubbing Process	80-97	95	0.05	21.5
	Wet Lime/Limestone Scrubber	80-95+	95	0.05	21.5
	Spray Dryer Scrubber	80-95++	95	0.05	21.5
Third	Low Sulfur Oil (0.5% S No.2 Distillate Oil)	50	50	0.51	219.6
Baseline*	1.0% Sulfur No.6 Residual Oil	--	--	1.03	443.4

* SO2 emission level from firing No. 6 residual oil with 1.0 percent sulfur content is considered as the baseline emission level for this analysis. The corresponding emission level for this baseline is 1.03 lb of SO2/MMBtu.

** Calculated based on baseline emission level.

\+ Higher range can be achieved by addition of adipic acid to the process materials.

++ Higher range can be achieved by further SO2 removal by sorbent layer collected on baghouse filter bags.

adhered to in order to avoid either potential excessive heating or condensation in downstream particulates collection equipment. Its long-term reliability is not sufficiently proven for oil-fired industrial boiler applications. However, its mechanical operation is less complex than the wet lime or sodium-based scrubbing systems.

The wet lime or limestone scrubber requires a larger auxiliary system or equipment for various processes such as raw materials preparation, solid and liquid separation, other mixing and aeration operation, and waste handing system. Its applicability is generally limited by plant physical limitation because it is a nonregenerable process that usually associates with high processing volume.

The fatal technical issue for applying the wet scrubber process are stipulated by Okeelanta Corporation's intended schedule of operation for the proposed boiler. The intended 175-day operation occurs during the off-season period. Okeelanta does not operate its bagasse-fired boilers (with scrubbers) during the off-season and currently has no provisions for handling scrubber wastewater during this time. Okeelanta is prohibited from discharging from its wastewater ponds during the off-season. This period is coincidental with the high rain season, and the combination of scrubber wastewater and high rainfall could result in an unauthorized discharge from these ponds. As a result, it is not feasible to handle scrubber wastewater in the off-season without construction of additional wastewater handling facilities.

<u>Environmental Effects</u>--The sodium-based chemicals (Na_2CO_3 and NaOH) used in the sodium scrubbing process are highly water soluble making their waste liquor disposal a difficult problem. Disposal options include treating the waste liquor in the existing wastewater treatment facilities or using it for another process feed stream. Those disposal options are also limited by the timing of the actual operation of the proposed boiler when the other boiler scrubbers are shut down (see discussion under Technical Issues).

Other disposal methods such as deep-well injection and off-site disposal by licensed waste processors are cost prohibitive. Safety of plant operating personnel is also a major concern in handing of caustic solutions.

A wet scrubber also has the disadvantage of requiring a water source. The add-on FGD options would require between 5.4 million and 11.0 million gallons per year. This is a significant environmental effect in south Florida, which is experiencing declining water levels.

There are no major environmental issues concerning the use of the lime spray dryer process, except plant safety procedures for handling particulate solid wastes and the solid waste disposal issue.

The primary environmental concern of the wet lime/limestone system is the process wastewater and solid waste generated. These waste streams would require proper disposal. As discussed above, disposal of wastewater in the off-season is of particular concern.

Energy Requirements and Impacts--In general, all of the wet FGD systems will require electricity to drive various mechanical equipment and pumps. The estimated electricity requirements are 404,400 kilowatt-hours (kW-hr) and 461,400 kW-hr for the sodium-based scrubber and the spray dryer scrubber, respectively. This estimated value is calculated for a total of 175 days of annual operation. Methods of calculation are included in the next section. The wet lime/limestone system would require higher energy than the other two systems.

Economic Analysis--Generally, the sodium based scrubber will have the lowest annual costs of the three add-on FGD systems, while the spray dryer will have the highest. Therefore, these two systems will be analyzed for economic impact to illustrate the range of costs for the add-on FGD system.

This section presents the total capital investment (TCI) and the annualized cost (AC) of both FGD processes for the proposed 205 MMBtu/hr boiler. All analyses were based on an EPA-developed cost algorithm for determining costs of emission control equipment on fossil-fuel-fired industrial boilers (EPA, 1982). The cost estimate for each FGD process is obtained from a separate subroutine. The input values such as boiler flue gas flow rate and SO_2 removal efficiency accounted for the sizing of the equipment. Two subroutines in the cost algorithm are attached in Appendix B. The final cost values are adjusted to reflect the most current 1990 costs by multiplying with an escalation factor obtained from the ratio of the Chemical Engineering (CE) Plant Cost Index in 1990 to that in 1978.

The cost estimates for the sodium-based solution scrubbing process are tabulated in Table 6.2-4. The calculation basis or specific reference for each cost item is also given in the table. The total capital investment (TCI) is $1,190,997. The total direct operating cost (DOC) and indirect operating cost (IOC) are $185,147 and $135,547, respectively. The capital recovery cost (CRC) is $193,775. The calculated annualized cost for the sodium-based scrubber system is $514,470.

The cost estimates for the lime spray dryer FGD scrubbing system are tabulated in Table 6.2-5. The total capital investment (TCI) is $2,985,099. The total direct operating cost (DOC) and indirect operating cost (IOC) are $196,260 and $216,617, respectively. The capital recovery cost (CRC) is $485,676. The calculated annualized cost for the lime spray dryer scrubber is $898,554. The higher annualized cost for the spray dryer system also reflects the additional cost for the particulate control system.

Since all of the FGD processes have a similar SO_2 removal efficiency, the economic comparison in Section 6.2.3.4 will use the lower annualized cost calculated for the sodium-based solution scrubbing process.

Table 6.2-4. Cost Estimates for Sodium Solution Scrubbing Process

Cost Items	Basis	Costs for Caustic FGD
TOTAL CAPITAL INVESTMENT (TCI):		
(1) Direct & Indirect Costs	TDI in NATH Cost Algorithm	$397,133
(2) Turnkey Cost	(1.48 TDI + 112,800) x EF[2]	$1,144,710
(3) Working Capital	25% of total DOC[2]	$46,287
TCI	(2) + (3)	$1,190,997
DIRECT OPERATING COSTS (DOC):		
(4) Operating Labor		
Operator	DL in NATH Cost Algorithm[2]	$82,260
Supervisor[1]	15% of operator cost	$12,339
(5) Maintenance	8% of TDI[2] x EF	$51,913
(6) Replacement Parts[1]		
(include freight & tax)	Equiv. to oper. cost of 350 hours	$7,770
(7) Chemicals		
(a) Sodium Carbonate	SC in NATH Cost Algorithm[2]	$9,700
(8) Utilities		
(a) Electricity	ELEC in NATH Cost Algorithm[2]	$17,047
(b) Water	WTR in NATH Cost Algorithm[2]	$2,687
(9) Waste Disposal		
(a) Solid Wastes	SW in NATH Cost Algorithm[2]	$938
(b) Liquid Wastes	LW in NATH Cost Algorithm[2]	$494
Total DOC		$185,147
INDIRECT OPERATING COSTS (IOC):		
(10) Overhead[1]	60% of oper. labor & maint.	$87,907
(11) Property Taxes[1]	1% of total capital investment	$11,910
(12) Insurance[1]	1% of total capital investment	$11,910
(13) Administration[1]	2% of total capital investment	$23,820
Total IOC		$135,547
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	$193,775
ANNUALIZED COST (AC):	DOC + IOC + CRC	$514,470

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition, 1990.

[2] The EPA's NATH cost algorithm is given in EPA-450/3-82-021, 1978 (see Attachment B). All final cost values are corrected to reflect the most current 1990 cost values by multifying with EF.
EF is the "escalation factor" calculated from the Chemical Engineering Plant Cost Index, the composite annual index.
EF = 1990 CE cost index/1978 CE cost index = 357.5/218.8 = 1.634.

Table 6.2-5. Cost Estimates for Lime Spray Dryer FGD Process

Cost Items	Basis	Costs for Lime Spray Dryer FGD
TOTAL CAPITAL INVESTMENT (TCI):		
(1) Direct & Indirect Costs	TDI in DS Cost Algorithm	$1,123,024
(2) Turnkey Cost	1.60 TDI x EF[2]	$2,936,034
(3) Working Capital	25% of total DOC[2]	$49,065
TCI	(2) + (3)	$2,985,099
DIRECT OPERATING COSTS (DOC):		
(4) Operating Labor		
Operator	DL in DS Cost Algorithm[2]	$82,260
Supervisor[1]	15% of operator cost	$12,339
(5) Maintenance	MANT is DS Cost Algorithm[2]	$67,424
(6) Replacement Parts[1] (include freight & tax)	Equiv. to oper. cost of 350 hours	$7,770
(7) Chemicals		
(a) Lime	Lime in DS Cost Algorithm[2]	$1,556
(8) Utilities		
(a) Electricity	ELEC in DS Cost Algorithm[2]	$19,450
(b) Water	WTR in DS Cost Algorithm[2]	$1,332
(9) Waste Disposal		
(a) Solid Wastes	SW in DS Cost Algorithm[2]	$4,130
Total DOC		$196,260
INDIRECT OPERATING COSTS (IOC):		
(10) Overhead[1]	60% of oper. labor & maint.	$97,214
(11) Property Taxes[1]	1% of total capital investment	$29,851
(12) Insurance[1]	1% of total capital investment	$29,851
(13) Administration[1]	2% of total capital investment	$59,702
Total IOC		$216,617
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	$485,676
ANNUALIZED COST (AC):	DOC + IOC + CRC	$898,554

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition, 1990.

[2] The EPA's DS cost algorithm is given in EPA-450/3-82-021, 1978 (see Attachment B). All final cost values are corrected to reflect the most current 1990 cost values by multiplying with EF.
EF is the "escalation factor" calculated from the Chemical Engineering Plant Cost Index, the composite annual index.
EF is the escalation factor = 1990 CE cost index/1978 CE cost index = 357.5/218.8 = 1.634.

6.2.2.3 Analysis of Low Sulfur Fuel Oil

Technical Issues--Firing low sulfur fuel oil does not require any additional change in the standard boiler setup. Since low sulfur oil is considered as "cleaner" fuel because of less ash content and higher heating value per pound of fuel, its use will enhance other mechanical integrities (i.e., the firing mechanism of the boiler, etc.) and reduce the normal maintenance requirements.

Environmental Effects--Low sulfur content oil such as No.2 distillate oil also contains lower amount of nitrogen concentration; therefore, firing low sulfur fuel oil will also reduce the fuel NO_x emission level. The NSPS limitation for NO_x for industrial boilers is reduced from 0.4 lb/MMBtu for residual oil to 0.2 lb/MMBtu for firing distillate oil. Therefore, one of the main reasons for using low sulfur fuel oil is the significant reduction in NO_x emissions. In addition, the trace element concentration of distillate oil is less than that of residual oil, reducing trace element emissions.

Energy Requirements and Impacts--There is no additional energy-related requirement from using a lower sulfur fuel. Theoretically, a better fuel economy is resulted because of the slightly higher heating value per pound of fuel when switching to low sulfur fuel oil. Comparing the average heating value of 18,200 Btu/lb for No. 6 residual oil to 19,430 Btu/lb for the No. 2 distillate oil proposed for the project, an average of 1,230 Btu more heat is produced per pound of fuel. However, because the low sulfur fuel oil has a lower fuel gravity value, it will require approximately an additional 300,000 gal of fuel per year for the proposed boiler.

Economic Analysis--There is significant increase in fuel cost when switching from residual oil to distillate oil. The increase of fuel cost is a result of the higher volume consumption of 298,200 gal/yr and the higher cost of distillate oil. Central Oil Company listed its prices of \$33.42 per barrel for 1.0 percent sulfur oil and \$40.53 per barrel for 0.5

percent sulfur oil. The total net increase of fuel cost is calculated to be approximately $1,277,600 annually, based on the total fuel requirement of 5,846,400 gal/yr for No. 6 fuel oil, and 6,144,600 gal/yr for No. 2 fuel oil.

6.2.3 SO_2 BACT SUMMARY AND CONCLUSION

The BACT analysis for SO_2 control has identified three feasible control alternatives: the low sulfur oil firing, the addition of an add-on FGD scrubber, and the combination of both alternatives. This section will consider the overall environmental, energy, and economic impacts of each alternative and eliminate the one with the most adverse impacts. The control alternative not eliminated will be selected as BACT.

6.2.3.1 Comparison of Technical Issues

Of the three alternatives, the option of firing low sulfur oil is the simplest option because there is no additional operating procedure requirements, nor any additional equipment is required. Firing low sulfur oil will also mean less frequent maintenance is needed because of better combustion process from using "cleaner" fuel. On the other hand, an addition of any FGD process stipulates that additional operating and maintenance will be required for the boiler on top of the labor requirements for the control device and its auxiliary processes such as raw materials or chemicals preparation, separation processes, and wastes handling processes. The wet SO_2 control methods using sodium-based chemicals are also subjected to corrosion and erosion problems.

The solids and liquor wastes handling aspect is the main technical reason for eliminating all alternatives involving the use of any FGD process. Since the operation of the proposed boiler will take place only during the off-season, applying either the sodium-based solution scrubbing process or the wet lime/limestone scrubber presents severe difficulties because there are no provisions to process the wastewater during the off-season.

Wastewater discharges during the off-season are limited due to site conditions, weather, and permit limitations.

The option of installing a lime spray dryer scrubber also presents difficulties because of the requirement for a particulate control system. The plant is not equipped to handle the lime solid waste. Thus, using low sulfur fuel to reduce SO_2 emission is the best control alternative since it poses the fewest technical concerns.

6.2.3.2 Comparison of Environmental Effects

All of the add-on FGD processes create additional environmental concerns because reagents are required and byproducts are produced in each process. Of all the FGD processes, the most adverse environmental impacts could be from the application of the caustic solution scrubbing process, which produces a sodium-based waste liquor. This waste liquor would have to be disposed of by Okeelanta during the off-season operation, when treatment options are limited. Therefore, the option of using this process is the least favorable in term of environmental effects.

Other lime scrubbing processes (i.e., wet lime scrubber and lime spray dryer scrubber) produce solid/slurry waste and particulate solids, respectively, that require additional processing prior to disposal in landfills.

All the add-on FGD options have an associated water use. This is a negative environmental impact in south Florida where water is becoming scarce.

Using low sulfur fuel will also result in NO_x reduction. Based on the NSPS limits, NO_x emissions would decrease from 155 TPY to 77.5 TPY. The potential amount of NO_x emission will be reduced by up to 50 percent by using a "cleaner" fuel for the proposed boiler. The most favorable aspect of using low sulfur oil is that there is no adverse environmental issues involved for this SO_2 reduction alternative; therefore, using low sulfur fuel is the best option for the environment.

6.2.3.3 Comparison of Energy Impacts

All of the FGD processes require additional electricity to operate various pumps and mechanical mixers. For example, it requires about 404.4 and 461.4 megawatts-hr annually to operate either the sodium-based solution scrubbing system or the lime spray dryer scrubber, respectively. The best alternative will be the low sulfur oil firing in view of the energy impact analysis because it does not require any additional energy.

6.2.3.4 Comparison of Economic Analysis

The economic analysis is based on the cost effectiveness of the control method. The economic impact is determined by its total and incremental values. Comparing the total cost effectiveness of all three SO_2 control alternatives: the combination of low sulfur oil firing equipped with an additional FGD scrubber has the cost effectiveness value of $4,162 per ton of SO_2 removed; the sodium solution scrubbing process is the lowest with $1,219 per ton of SO_2 removed. The low sulfur fuel firing has a total cost effectiveness value of $5,707 per ton of SO_2 removed.

The incremental cost effectiveness values for the combination SO_2 removal method is $148,371 per ton of SO_2 removed. The low sulfur oil firing shows an incremental cost effectiveness of $5,707 per ton of SO_2 removed; while the incremental cost for the sodium-based solution scrubbing process with 1-percent sulfur fuel oil is -$3,853.

6.2.3.5 Conclusion

The top-down BACT analysis in terms of environmental impacts, energy impacts and economic impacts for Okeelanta Corporation's proposed project is summarized in Table 6.2-6. The combination of low sulfur oil firing equipped with sodium-based (or any of the other two) FGD processes is eliminated primarily based on the technical issues concerning the lack of

Table 6.2-6 Summary of Top-Down BACT Impact Analysis Results for SO2.

			Environmental Impacts		Energy Impacts	Economic Impacts			
Control Alternative	Total Emission Reduction (TPY)*	Incremental Emission Reduction (TPY)**	Potential toxic air impact?	Potential adverse enviromental impacts?	Additional Electricity Requirement (kW-hr/yr)	Total Annualized Cost ($/yr)	Incremental Annualized Cost ($/yr)	Total Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Low Sulfur Oil (0.5% S No.2 Oil) with Sodium-based Scrubber	430.5	8.61	Yes	Yes	404,400	$1,791,945	$1,277,475	$4,162	$148,371
Sodium Scrubbing Process (1.0% S No.6 Oil)	421.9	198.0	Yes	Yes	404,400	$514,470	-$763,005	$1,219	-$3,853
Low Sulfur Oil (0.5% S No.2 Oil)	223.9	223.9	No	No	0	$1,277,475	$1,277,475	$5,707	$5,707
Baseline (1.0% S No.6 Oil)	----	----	--	--	----	----	----	----	----

* Total emission reduction, total annualized cost, and total cost effectiveness are calculated based on similar baseline parameter values.

** Incremental values are based on the next lower control technology's parameter values.

wastewater disposal options during the off-season operation of the proposed boiler. Also, the incremental cost effectiveness for using this combination alternative is economically infeasible at $148,371 per ton removal.

The technical issue concerning the lack of wastewater disposal options during the off-season also eliminates the second best removal alternative of using an FGD process to control SO_2 emissions along with high sulfur fuel oil. In addition, add-on FGD control technologies have additional energy and water requirements along with creating potential adverse environmental impacts, such as the disposal of caustic waste liquor. NO_x emissions may double by the use of higher sulfur fuel oil.

By eliminating both FGD-related options, the low sulfur oil firing (0.5 percent distillate oil) is BACT for SO_2 emission for the proposed boiler. This is consistent with current BACT determinations for SO_2 emissions shown in Table 6.2-2 for boiler sizes greater than 100 MMBtu/hr. The Wisconsin Tissue Mills, Inc., was permitted in 1988 for a 146.4-MMBtu/hr boiler with twice the emission level (1.1 lb/MMBtu) as the proposed boiler with much higher annual SO_2 emissions.

Although the incremental cost effectiveness for the chosen SO_2 control alternative is $5,707 per ton of SO_2 removed, the firing of low sulfur oil does not generate any additional wastes or require any additional energy. Best of all, it is the simplest technology to apply. The high incremental cost is justified because of its simplicity and its ability to meet the NSPS for SO_2. The Kern County Air Control Pollution Board in California is currently considering low sulfur oil to be an appropriate SO_2 emission control alternative for industrial boilers rated up to 250 MMBtu/hr when such low sulfur firing process is an essential technique for controlling NO_x emission simultaneously.

Furthermore, the Okeelanta Corporation's proposed boiler has an insignificant SO_2 impact, its modeling result shows a low SO_2 impact of less than 1 $\mu g/m^3$, annual average, to the surrounding rural area. Therefore, firing of No. 2 distillate oil of 0.5 percent sulfur is concluded to be BACT for SO_2 emission control from the proposed 205-MMBtu/hr package boiler.

6.3 BACT DETERMINATION FOR NITROGEN OXIDES (NO_x EMISSIONS)

6.3.1 IDENTIFICATION OF NO_x CONTROL TECHNOLOGIES FOR INDUSTRIAL BOILERS

In this section, the control technologies capable of reducing NO_x emissions produced by industrial boilers will be evaluated relative to their potential application as BACT for the proposed 205-MMBtu/hr 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.

6.3.1.1 Technologies Involving Boiler Modification

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 stationary 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 proposed 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 in oil is small. Thus, controlling the amount of excess air will have a significant effect on the NO_x thermal oxidation process.

A standard boiler normally operates at greater than 40 percent excess air at full-load condition. This amount of excess air is equivalent to 3 to 6 percent in stack gas oxygen concentration depending on individual boiler design. Some test results have shown that the NO_x formation can be reduced 10 to 15 percent when the boiler stack gas oxygen concentration is lowered to between 3 to 5 percent from its normal combustion condition [South Coast Air Quality Management District (SCAQMD), 1987]. State-of-the-art low thermal NO_x boiler design limits the amount of excess air to a maximum level of between 15 to 20 percent.

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 control 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 completed in the secondary burnout zone situated downstream from the 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 of NO_x emission reduction over conventional burners.

Both LEA (single-staging) and multi-staging low NO_x burners usually are designed with flue gas recirculation in order to enhance NO_x emission reduction.

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 oxygen concentration of the combustion air and as a heat sink to lower the peak combustion temperature. The heat sink effect occurs in FGR because the particulates in the recycled flue gas absorb some heat from 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 fuels, 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, 1990). 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 an LEA burner or a multi-stage low NO_x burner. Actual FGR efficiency depends on the boiler type and burner design. For the proposed boiler, FGR can reduce 50 percent of NO_x emissions at a 12.5 percent recirculation rate (McBurney Corporation, 1991).

6.3.1.2 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. Generally, an add-on device is inserted into the flue gas duct work 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 proposed oil-fired boiler, the following add-on NO_x control devices have been identified: the NO_xOUT process, Exxon's Thermal DeNO_x, and selective catalytic reduction with ammonia injection.

<u>NO_xOUT Process</u>--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, ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction occurs:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \dashrightarrow 2N_2 + CO_2 + 2H_2O$$

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 claims to have a number of proprietary 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.

Commercial application of the NO_xOUT system is limited to three reported cases:

1. Trial demonstration on a 62.5-TPH stoker-fired, wood waste boiler with 60 to 65 percent NO_x reduction,
2. A 600-MMBtu/hr gas-fired CO boiler with 60 to 70 percent NO_x reduction, and
3. A 75-MW pulverized-coal-fired boiler with 65 percent NO_x reduction.

The NO_xOUT process is not technically feasible for the proposed lean-burn engine because of the high application temperature of 1,000°F to 1,950°F. The exhaust gas temperature of the proposed boiler is 435°F. Raising the exhaust temperature to the required temperature level essentially would require the installation of an auxiliary duct burner system. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

<u>Thermal DeNO$_x$</u>--Thermal DeNO$_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO$_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications of Thermal DeNO$_x$ are on large utility boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There was a single recorded application of Thermal DeNO$_x$ in a 62.5-MMBtu/hr boiler for a crude oil production facility in Kern County, California (refer to Section 6.3.2 for a summary of BACT determinations for NO_x emissions). It was installed as a demonstrated technology; however, the entire operation has been inactive for some time according to a staff engineer of the Kern County Air Pollution Control Board. Therefore, application of Thermal $DeNO_x$ for industrial boilers is still being considered as an unproven technology.

From the application standpoint, temperatures of 1,800°F require alloy construction materials with large size piping and components since the exhaust gas volume would be increased several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of engineered materials meeting high-temperature construction specifications, the additional duct burner system required, and extra fuel consumption. The overall uncontrolled emissions would increase because of the additional fuel consumed in the auxiliary duct burner system.

Thus, the Thermal $DeNO_x$ process will not be considered for the proposed project because its high application temperature makes it technically infeasible.

<u>Selective Catalytic Reduction with Ammonia Injection</u>--The NO_x abatement technology for oil- and gas-fired combustion sources that is currently receiving considerable attention is the selective catalytic reduction (SCR) process 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 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 combustion sources that generate large quantities of NO_x, such as gas turbines.

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, 1990; 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 temperatures. 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 the 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 life of 3 years, assuming certain operating conditions.

Technically, SCR is potentially applicable to further reduce the already low NO_x emissions (0.18 lb/MMBtu) from the proposed boiler. SCR is capable of achieving 70 to 90 percent NO_x reduction. For the proposed oil-fired boiler, with already low NO_x concentration in the exhaust gases, vendors guarantee a removal rate of 80 percent. This would result in an NO_x emission rate of 0.04 lb/MMBtu.

6.3.1.3 Summary of Technically Feasible NO_x Control Methods

In summary, there are two basic alternatives for reduction of NO_x emissions from the proposed boiler: boiler modification and add-on control technology. Presented in Table 6.3-1 is a summary of the technical

Table 6.3-1. Summary of Technical Feasibility of NOx Emission Controls for the Proposed Oil-fired Boiler

Control Technology	NOx Controlled Emission Rate+	Technical Feasibility	Comments
Boiler Modification Alternatives			
Low Excess Air (LEA) Firing	0.30 lb/MMBtu	YES	Lowest emission rate achievable by modification of boiler inlet air condition, maximum 25% NOx reduction.
Low NOx Burner (LNB) Design	0.22 lb/MMBtu	YES	Approx. 45% of NOx reduction for the proposed boiler
Flue Gas Recirculation (FGR)	0.20 lb/MMBtu	YES	Maximum 50% of NOx reduction for the proposed boiler.
Low NOx Burner with FGR	0.18 lb/MMBtu*	YES	Maximum 55% of NOx reduction for the proposed boiler.
Add-on Control Technology			
NOxOUT Process	Not Applicable	NO	Technically infeasible (1000-1600°F), cost prohibitive for high temperature auxiliary equipment.
THERMAL DeNOx	Not Applicable	NO	Technically infeasible (above 1000°F), cost prohibitive for high temperature auxiliary equipment.
Selective Catalytic Reduction**			
Conventional Boiler	0.08 lb/MMBtu	YES	Technically, SCR can achieve 80 percent NOx reduction from the flue gas from either conventional or modified boiler.
Boiler with LNB and FGR	0.04 lb/MMBtu	YES	

\+ Baseline emission rate from conventional industrial boiler firing No.6 residual oil is 0.40 lb/MMBtu (Source: BACT Clearinghouse information, 1991).

* Guaranteed NOx emission rate from the boiler vendor (Source: The McBurney Corporation, 1991).

** The range of emission rate was calculated from 80 percent reduction based on the conventional boiler and a boiler equipped with low NOx burner and FGR.

evaluation of NO_x emission control methods applicable to industrial boilers.

In the boiler modification category, all three processes (LEA firing, low NO_x burner design, and FGR) are applicable to the proposed boiler. In the add-on control technology category, only the SCR with ammonia injection is considered technically feasible. There are two scenarios that SCR can be applied to: a conventional boiler and a boiler modified with low NO_x burner design and FGR technique. The other two methods, such as NO_xOUT and Thermal DeNO_x, are considered technically infeasible.

6.3.2 EVALUATION OF TECHNICALLY FEASIBLE NO_x CONTROL METHODS

This section examines all the technically feasible NO_x control methods identified in the previous discussion. First, all four remaining control alternatives and the additional scenario of applying SCR to boilers modified with low NO_x burner and FGR 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.

The discussion also reviews current permitting practices for applications similar to Okeelanta Corporation's proposed project. Presented in Table 6.3-2 is a summary of all BACT determinations for NO_x emissions from oil-fired, stationary external combustion boilers issued since 1980. The information was obtained from BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse information stored in the BACT/LAER Information System (BLIS) database via EPA's National Computer Center at Research Triangle Park in North Carolina.

6.3.2.1 Ranking of Feasible Control Technologies

The top-down BACT approach requires the ranking of the NO_x emission control alternatives in terms of achievable emission level. The five options, in order of removal effectiveness, are as follows: first, the application of

Table 6.3-2 Summary of BACT Determinations for NOx Emissions from Oil-fired External Industrial Boilers

Company Name	State	Permit Number	Permit Issued Date	Boiler Size (MMBtu/hr)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	Control Method	Control Efficiency (%)
Owens-Illinois Inc.	OH	04-367	26-Nov-86	10.3	0.15	1.49	6.5	None	UD
Exeter Energy Limited Partners	CT	176-0004	28-Aug-89	11.2	3.43	38.46	7.7	Undetermined	UD
Northeast Utilities, NNECO	CT	199-0001	23-Sep-88	28.3	3.26	92.26	40.0	None	UD
Berry Holding Company	CA	4016014A & 015B	02-Oct-85	31.5	0.20	6.26	UD	Low NOx Burner, FGR	61.8%
same as above	CA	4016022 & 023	02-Oct-85	62.5	0.12	7.50	UD	Low NOx Burner, FGR	70.0%
Angus Petrotech	CA	4132002-004	29-Nov-83	62.5	0.13	8.29	36.3	Low NOx Burner	67.5%
Hopco*	CA	4099002-013	04-Dec-84	62.5	0.12	7.40	32.4	THERMAL DeNOx	70.0%
Georgia-Pacific Corporation	OH	14-1043	01-Dec-85	118.0	0.30	35.40	155.1	LEA Firing	25.0%
Delco Moraine Div., GMC	OH	08-654	01-Jul-85	144.0	UD	UD	UD	Undetermined	UD
Wisconsin Tissue Mills, Inc.	WI	88-DLJ-024	10-Oct-88	146.4	0.38	55.63	243.7	LEA Firing	5.0%
Houston Lighting & Power	TX	PSD-TX-209	16-Jan-80	185.0	0.30	55.50	243.1	Low NOx Burner	25.0%

* Source has been inactive for sometime.

UD = Undetermined, indicates that information was either unavailable or it was insufficient to determine.

SCR to a boiler modified with low NO_x burner and FGR; second, the ceramic-based SCR; third, the low NO_x burner with FGR; fourth, the FGR technology; and, fifth, the LEA firing process. The low NO_x burner was combined with FGR as a single option because this combination is a preferred commercial practice.

A baseline condition must be established for BACT ranking and economic analysis purposes. The baseline is defined as the uncontrolled rate of a process being reviewed. Therefore, the baseline condition for the control technologies involving industrial boilers would be a conventional boiler with an NO_x emission level of 0.40 lb/MMBtu. This emission level was derived from the correlations between the reported NO_x emissions levels and the associated NO_x control efficiency in current BACT determinations (see Table 6.3-2). This is also the highest NO_x emission rate allowed under NSPS.

Presented in Table 6.3-3 is the BACT top-down hierarchy of five technically feasible NO_x emission control scenarios, their corresponding NO_x emission levels in pound per MMBtu heat input, and their control efficiencies calculated from the baseline emission level. In the following analyses, the ceramic-based SCR system is discussed first, followed by discussions of the low NO_x burner (LNB) with FGR, the combined option of applying both SCR and LNB-FGR, the FGR technology, and the LEA firing process.

6.3.2.2 Analysis of Ceramic-Based SCR System

Technical Issues--As the most effective NO_x abatement process in terms of removal efficiency, SCR has been examined closely for NO_x emission sources. However, the reliability of SCR's performance on industrial boilers has not been demonstrated. Data on sustained NO_x reduction performance for both stationary external combustion and internal combustion processes are very limited.

Table 6.3-3. BACT "Top–down" Hierarchy of NOx Reduction Methods for the Proposed Boiler.

Top-down Ranking	Technology	Range of Control Effectiveness (%)	Control level for BACT Analysis (%)	Emission Level** (lb/MMBtu)	Annual Emission (TPY)
First	SCR with LNB/FGR Dual Option	90	90	0.04	17.2
Second	Ceramic-based SCR	70-85	80	0.08	34.4
Third	Low NOx Burner with FGR (a.k.a. LNB/FGR Dual Option)	50-65	55	0.18	77.5
Fourth	Flue Gas Recirculation (FGR)	45-65	50	0.20	86.1
Fifth	Low Excess Air (LEA) Firing	10-25	25	0.30	129.2
Baseline*	Conventional Boiler	--	--	0.40	172.2

* NOx emission level for a conventional industrial boiler is used as the baseline emission level for this analysis. The term "conventional" refers to boilers that have not been modified with either low excess air, low NOx burner (LNB) design, and/or flue gas recirculation. This emission level of 0.40 lb NOx/MMBtu is also the NSPS limit for firing 1% sulfur residual oil.

** Calculated based on baseline emission level and control level.

Technical issues involved in the use of SCR are the narrow operating temperature range, the potential damage to the catalyst and downstream equipment, and the ammonium bisulfate formation. A stack gas reheat system would be required to heat the exhaust gases up to the operating temperature of the SCR (see further discussion under Energy Requirements and Impacts). This further complicates an already complex operation consisting of SCR components and an ammonia handling system. The use of ammonia as a reagent for the NO_x reduction reactions may allow excess ammonia to form ammonium bisulfate compounds under irregular operating conditions. These compounds can serve as catalyst poisoning agents and also cause damage to metal ductwork downstream. Thus, SCR application requires a strict maintenance service schedule. It is expected that the SCR system may require manual cleaning every 2,000 to 2,500 hours of operation (Steuler, 1990). 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 boiler. Application of SCR systems to much larger utility boilers or smaller internal combustion engines is still being considered as experimental technology. No other oil-fired boilers undergoing BACT review have been required to use SCR (refer to Table 6-3.2).

Environmental Effects--The add-on SCR technology for NO_x control 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 NO_x to molecular nitrogen and water. The main environmental impact centers around the issue of delivery, handling, and storage of ammonia, which poses inherent safety and health risks in the event of accidental releases. In proposing NO_x abatement regulations for stationary gas turbines, California's South Coast Air Quality Management District (SCAQMD) has performed a risk assessment study on spill handling and storage of ammonia. The study has concluded that this aspect of SCR operation realistically could present serious consequences and recommended further consideration of potential impacts and mitigation measures (SCAQMD, 1979). The current practice is to use an aqueous ammonia system (normally between 25 to 29 percent ammonia concentration) at installations located 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.

Energy Requirements and Impacts--The add-on technology of SCR imposes further energy penalties. The additional energy requirements are caused by 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 reheating the proposed engine exhaust gases from 435°F up to the SCR operating range of 700°F. [SCR manufacturers specify a typical operating temperature window between 600°F to 900°F (Engelhard, 1990; and Steuler, 1990)]. A minimum of 16.19 MMBtu/hr is required for stack gas reheating or 67,998 MMBtu/yr calculated for the total of 4,200 hours of annual operation. Also, an addition of 8.6 megawatt-hours is required for the operation of the ammonia vaporizer and injection system.

Economic Analysis--This section presents the total capital investment (TCI) and the annualized cost (AC) of the SCR NO_x control system for the proposed boiler. Capital and annualized cost estimates were prepared for an SCR system offered by Engelhard Corporation. The Engelhard NO_x abatement system uses an all-ceramic honeycomb catalyst and can achieve an NO_x reduction efficiency of 80 percent on the proposed boiler.

Capital costs for the SCR system are tabulated in Table 6.3-4. The vendor's equipment quote for the Engelhard SCR system is $760,000. The direct capital cost of the system is calculated to be $1,679,652, and the indirect capital cost is calculated to be $924,446. The total capital investment is $2,604,098. The annualized costs for this NO_x abatement systems are given in Table 6.3-5. The calculation basis for cost items also is given in the table. The annualized cost for the Engelhard SCR system is $1,008,477.

6.3.2.3 Analysis of Low NOx Burner Design with FGR Technology

Technical Issues--Of the two types of low NO_x burner (LNB) design, the single-staging LEA burner is more reliable than the multi-staging low NO_x burner because of its simple mechanical design. The term "single-staging" refers to the design of a single air staging process; therefore, the LEA burner requires controlling only one inlet air stream feeding into the single combustion zone in the burner. The term "multi-staging" refers to the design of separating the incoming air into two air staging processes. By design, the multi-staging burner is a more precision controlling equipment that requires "staging" or splitting the total inlet air into two portions for distribution to two internal combustion zones: 70 percent of inlet air for the primary combustion zone and 30 percent for the secondary combustion zone. The main design objective for "staging" the inlet air is to create a fuel-rich combustion process in order to minimize fuel NO_x formation in the primary combustion zone and to lower the flame temperature in the secondary combustion zone to minimize thermal NO_x formation.

The "staging" controls are built into each burner; therefore, either design can be applied to the proposed boiler with similar mechanical or structural requirements. Furthermore, the proposed use of low sulfur fuel oil (with low fuel-bound nitrogen content) technically will reduce the fuel NO_x formation. Thus, both burner designs can achieve equally low NO_x emission levels since the use of a multi-staging burner does not have any advantage over the LEA burner when firing low sulfur distillate oil.

Table 6.3–4 Capital Cost Estimates for a Typical SCR System for NOx Emission Control.

Cost Items	Cost Factors	Ceramic-based SCR System
DIRECT CAPITAL COSTS (DCC):		
(1) Purchased Equipment		
(a) SCR Basic Equipment	Vendor Quote	$760,000
(b) Ammonia System	See Note 1	$20,000
(c) Auxiliary Equipment (Reheat)*	0.10 x (1a)	$76,000
(d) Emission Monitoring	0.15 x (1a)	$114,000
(e) Structure Support	0.10 x (1a-1d)	$97,000
(f) Instrumentation & controls	0.10 x (1a-1d)	$97,000
(g) Freight[1]	0.05 x (1a-1f)	$58,200
(h) Sales Tax (Florida)	0.06 x (1a-1f)	$69,840
(i) Subtotal	(1a-1h)	$1,292,040
(2) Direct Installation[1]	0.30 x (1i)	$387,612
Total DCC:	(1) + (2)	$1,679,652
INDIRECT CAPITAL COSTS (ICC):		
(3) Indirect Installation		
(a) Engineering & Supervision[1]	0.10 x (DCC)	$167,965
(b) Construction & Field Expenses[1]	0.05 x (DCC)	$83,983
(c) Contruction Contractor Fee[1]	0.10 x (DCC)	$167,965
(d) Contigencies[2]	0.25 x (DCC)	$419,913
(4) Other Indirect Costs		
(a) Startup & Testing[1]	0.03 x (DCC)	$50,390
(b) Working Capital	30-day DOC**	$34,231
Total ICC:	(3) + (4)	$924,446
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$2,604,098

* Duct burner system to reheat the exhaust gas from 435°F up to 700°F.

** 30 days of direct operating costs, calculated from the annualized cost Table 6.3-5 (i.e., total DOC/12 months).

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

[2] Guaranteed efficiency and operation for the installation of SCR on industrial boilers. Such application is not considered as well-proven technology.

Note 1: Ammonia vendor's quotation from LaRoche Industries, Inc. for a 3,000-gallon anhydrous ammonia tank, an ammonia evaporator, and a dual-valve pressure regulator.

Table 6.3-5 Annualized Cost Estimates for a Typical SCR System for NOx Emission Control.

Cost Items	Basis	Ceramic-based SCR System
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator[2]	2,800 hr/yr @ $20/hr	$56,000
Supervisor[1]	15% of operator cost	$8,400
(2) Maintenance[2]	5% of direct capital cost	$52,033
(3) Replacement Parts (include freight & tax)		
(a) Catalyst	(Part+Labor)xCRF; See Note 1	$53,881
(4) Utilities		
(a) Electricity	0.30 MW-hr/ton NH3; $85/MW-hr	$731
(b) Fuel for stack reheat	$3.42/MMBtu; See Note 2	$232,553
(5) Ammonia	0.37 lb NH3/lb NOx; $250/ton NH3	$7,169
Total DOC		$410,767
INDIRECT OPERATING COSTS (IOC):		
(7) Overhead[1]	60% of operating labor & maintenance	$69,860
(8) Property Taxes[1]	1% of total capital investment	$26,041
(9) Insurance[1]	1% of total capital investment	$26,041
(10) Administration[1]	2% of total capital investment	$52,082
Total IOC		$174,023
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	$423,687
ANNUALIZED COST (AC):	DOC + IOC + CRC	$1,008,477

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

[2] Based on no existing installation of SCR on industrial boilers: 5.33 hours per shift are devoted to the NOx emission control system operation and maintenance.

Note 1: Ceramic-based catalyst replacement part cost is $120,000 with a service life of 3 years.
Combined freight and tax factor is 11%; and CRF for a 3-year recovery period and 10% interest rate is 0.4021.
Replacement labor cost is $50 per hour for two 8-hour days. Total cost includes both material and labor costs.

Note 2: Assumed heat transfer efficiency of 80%, heat input required to raise exhaust temperature to 700°F is:
Q = (187,940 lb/hr)(0.26 Btu/lb°F for air)(700°F-435°F)/(0.8) = 16.19 MMBtu/hr.
Annual heat input equals 16.19 MMBtu/hr times 4,200 hr/yr = 67,998 MMBtu/yr.
Fuel cost is $3.42 per MMBtu of low sulfur fuel delivered to site. The $3.42 figure is averaged from estimated low sulfur fuel delivered price for two power plants located in closeby regions in Florida.

In modern burner design, internal FGR usually is integrated into the design of the burner. The FGR option is available to both burner design concepts described above. The combination of LNB design and internal FGR can achieve 55 percent of NO_x emission reduction, which is at least 5 percent better than applying either technology individually.

For the proposed watertube boiler, a single burner system using either an LEA or a multi-staging low NO_x burner along with FGR (subsequently to be referred to as the LNB/FGR dual option) can be assembled as a package boiler to produce the 150,000 lb/hr of required steam. The use of the single burner system will allow greater control of ambient air input in order to maintain the low NO_x combustion process. There is no technical difficulty associated with the use of the LNB/FGR dual option in the proposed boiler.

Environmental Effects--There is no adverse environmental effect in using the combination of LNB design and FGR because there is no waste produced. As mentioned, at least 5 percent of NO_x emission level is reduced by applying this LNB/FGR dual option. Potentially, emissions of particulates and volatile organic compounds (VOC) are reduced by further thermal degradation from being recirculated back through the combustion zone. Assuming equal spatial distribution of all components in the flue gas stream and a recirculation rate of 12 percent, FGR can reduce up to 12 percent of combustible components in the flue gas exhaust from the boiler.

Energy Requirements and Impacts--The LNB/FGR dual option allows for combustion at low excess oxygen levels, in turn resulting in fuel savings. The actual amount of fuel savings is not quantified for this report.

Economic Analysis--This section includes the total capital investment (TCI) and the annualized cost (AC) for all three boiler modifications (i.e., LNB design, FGR, and LEA firing) applied to the proposed 205-MMBtu/hr boiler. All cost values are calculated from standard costing procedure based on the

Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (OAQPS, 1990).

In this costing procedure, the basic equipment cost is the basis for all itemized costs that are calculated as fractional costs of the basic equipment cost. Tables 6.3-6 and 6.3-7 show the capital cost estimates and the annualized cost estimates for all boiler modifications. The basic equipment costs either were obtained from the vendor (i.e., for the low NO_x burner) or estimated from an EPA-developed cost algorithm (EPA, 1982) for control equipment (i.e., for the FGR and LEA firing systems). The capital cost and annualized cost estimates for the proposed boiler also are given in these tables.

For the individual low NO_x burner design and FGR, the total capital investments (TCI) are $113,740 and $65,244, respectively; the annualized costs (AC) are $28,949 and $16,761, respectively. For the LNB/FGR dual option, the TCI and AC are the sum of their individual cost items or $178,984 and $45,710, respectively.

6.3.2.4 Analysis of SCR System Applied to Boiler Modified with LNB Design and FGR Technology

Technical Issues--The technical issues concerning this NO_x emission control scenario are similar to those already discussed for each individual alternative in Sections 6.3.2.2 and 6.3.2.3. In general, reliability of SCR application remains questionable for the proposed boiler because of its being considered as an unproven technology for an industrial boiler. In addition, a boiler modified with both low NO_x burner design and FGR has lower flue gas temperature than the exhaust gas from the conventional boiler; however, the LNB/FGR dual option does not have any significant technical effects on the overall process.

Environmental Effects--Similar to the issue discussed in Section 6.3.2.2, potential adverse environmental effects are related to SCR operation, such le 6.3-6. Capital Cost Estimates for Boiler and Boiler Modification Systems for NOx Control

Cost Items	Cost Factors	Costs for Proposed Boiler	Costs for Low-NOx Burner	Costs for FGR System (see Note 1)	Costs for LEA System (see Note 2)
DIRECT CAPITAL COSTS (DCC):					
(1) Purchased Equipment					
(a) Basic Equipment	Vendor Quote	$940,000	$50,000	---	---
(b) Boiler Modification	EF = 1.634*	---	---	$28,678	$18,984
(c) Structure Support	0.10 x (1a-1b)	$94,000	$5,000	$2,868	$1,898
(d) Instrumentation & controls[1]	0.10 x (1a-1b)	$94,000	$5,000	$2,868	$1,898
(e) Freight[1]	0.05 x (1a-1d)	$56,400	$3,000	$1,721	$1,139
(f) Sales Tax (Florida)	0.06 x (1a-1d)	$67,680	$3,600	$2,065	$1,367
(g) Subtotal	(1a-1f)	$1,252,080	$66,600	$38,199	$25,286
(2) Direct Installation[1]	0.30 x (1g)	$375,624	$19,980	$11,460	$7,586
Total DCC:	(1) + (2)	$1,627,704	$86,580	$49,658	$32,872
NDIRECT CAPITAL COSTS (ICC):					
(3) Indirect Installation					
(a) Engineering & Supervision[1]	0.10 x (DCC)	$162,770	$8,658	$4,966	$3,287
(b) Construction & Field Expenses[1]	0.05 x (DCC)	$81,385	$4,329	$2,483	$1,644
(c) Contruction Contractor Fee[1]	0.10 x (DCC)	$162,770	$8,658	$4,966	$3,287
(d) Contigencies[1]	0.03 x (DCC)	$48,831	$2,597	$1,490	$986
(4) Other Indirect Costs					
(a) Startup & Testing[1]	0.03 x (DCC)	$48,831	$2,597	$1,490	$986
(b) Working Capital	30-day DOC**	$6,014	$320	$192	$122
Total ICC:	(3) + (4)	$510,602	$27,160	$15,586	$10,312
OTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$2,138,306	$113,740	$65,244	$43,184

EF is the escalation factor = 1990 CE cost index/1978 CE cost index = 357.5/218.8 = 1.634. The escalation factor is used to find he most recent 1990 cost value for the FGR and LEA systems.

30 days of direct operating costs, calculated from the annualized cost Table 6.3-7 (i.e., total DOC/12 months).

Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

e 1: From FGR Cost Algorithm in EPA-450/3-82-021, EQUIP = EF x (44.72 Q + 8383) = $28,678

e 2: From LEA Cost Algorithm in EPA-450/3-82-021, EQUIP = EF x (31.38 Q + 5185) = $18,984 le 6.3–7. Annualized Cost Estimates for Boiler and Boiler Modification Systems for NOx Control

Cost Items	Basis	Costs for Proposed Boiler	Costs for Low NOx Burner	Costs for FGR System	Costs for LEA System
DIRECT OPERATING COSTS (DOC):					
(1) Operating Labor					
Operator[2]	2,800 hr/yr @ $20/hr	$56,000	$2,979	$1,787	$1,132
Supervisor[1]	15% of operator cost	$8,400	$447	$268	$170
(2) Maintenance[1]	Included in (1)	---	---	---	---
(3) Replacement Parts[1] (include freight & tax)	Equ. to 350 hours of oper. cost	$7,770	$413	$248	$157
Total DOC		$72,170	$3,839	$2,303	$1,459
NDIRECT OPERATING COSTS (IOC):					
(7) Overhead[1]	60% of oper. labor & maint.	$38,640	$2,055	$1,233	$781
(8) Property Taxes[1]	1% of total capital investment	$21,383	$1,137	$652	$432
(9) Insurance[1]	1% of total capital investment	$21,383	$1,137	$652	$432
(10) Administration[1]	2% of total capital investment	$42,766	$2,275	$1,305	$864
Total IOC		$124,172	$6,605	$3,843	$2,508
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	$347,902	$18,505	$10,615	$7,026
ANNUALIZED COST (AC):	DOC + IOC + CRC	$544,245	$28,949	$16,761	$10,993

Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

Based on off-season operation which will require a worker for two 8-hour shifts to man the equipment.

as: accidental spill and release of ammonia, regular slippage of ammonia by built-in design, and disposal of spent catalyst. The advantages such as lower particulate and VOC emission rates contributed by the boiler modification process are insignificant in conjunction with an SCR application.

Energy Requirements and Impacts--The additional heat input requirement for stack gas reheat is 67,998 MMBtu/yr. Also, the addition of 8.6 megawatt-hours is required for the operation of the ammonia vaporizer and injection system. As mentioned, the boiler modified with low NO_x burner design and FGR has lower flue gas temperature than that coming from a conventional boiler; therefore, the total fuel requirement for duct burner reheat may be higher because of lower flue gas temperature.

Economic Analysis--The cost estimates for the combined SCR option and the LNB/FGR dual option are obtained as a sum of the individual SCR option (from Tables 6.3-4 and 6.3-5) and the LNB/FGR dual option (from Tables 6.3-6 and 6.3-7). Therefore, the total capital cost investment of the combined option is $2,783,082. The annualized cost for this combined option is $1,008,477 from the SCR, plus $28,949 from the LNB design, and $16,761 from the FGR, or a total of $1,054,187.

6.3.2.5 Analysis of FGR Technology

Technical Issues--There are no major technical issues associated with application of FGR.

Environmental Effects--There is no additional waste generated from the boiler by modifying it with FGR. Potentially, emissions of particulates and volatile organic compounds (VOC) are reduced by further thermal degradation from being recirculated back through the combustion zone in the burner. Assuming equal spatial distribution of all components in the flue gas stream and a recirculation rate of up to 15 percent, FGR can reduce up to the same percentage of combustible components in the flue gas exhaust as that of a similar size conventional boiler.

Energy Requirements and Impacts--There is no additional energy requirement from applying FGR to the boiler. Theoretically, FGR allows for combustion at low excess oxygen levels, thereby resulting in fuel savings. The actual amount of fuel savings is not quantified for this report.

Economic Analysis--The economic analysis for FGR is given in Tables 6.3-6 and 6.3-7. The total direct capital cost (DCC) and indirect capital cost (ICC) are $49,658 and $15,586, respectively. The total capital investment cost (TCI) is $65,244; and annualized cost (AC) for the FGR application is $16,761.

6.3.2.6 Analysis of LEA Firing

Technical Issues--Similar to the FGR application, the main technical concern involves the installation of the flue gas oxygen monitor that automatically provides the control feedback signal to the inlet air flow controller, which maintains the excess air at the desired level. Therefore, maintaining the flue gas oxygen monitor in good operating condition is essential for LEA firing application. For the proposed boiler, the low flue gas temperature at 435°F will not have a detrimental effect on the service life of the oxygen monitoring device.

Environmental Effects--There is no additional waste generated from the boiler associated with LEA firing.

Energy Requirements and Impacts--There is no additional energy requirement associated with using LEA firing in the proposed boiler. Theoretically, LEA firing allows for combustion at low excess oxygen levels, thereby resulting in fuel savings. The actual amount of fuel savings is not quantified for this report.

Economic Analysis--The economic analyses for LEA firing are also given in Tables 6.3-6 and 6.3-7. The total direct capital cost (DCC) and indirect capital cost (ICC) are \$32,872 and \$10,312, respectively. The total capital investment cost (TCI) is \$43,184; and annualized cost (AC) for the FGR application is \$10,993.

6.3.3 NO_x BACT SUMMARY AND CONCLUSION

The BACT analysis for NO_x control has identified five feasible control alternatives: the combination of SCR option and LNB/FGR dual option, the ceramic-based SCR, the LNB/FGR dual option, the FGR, and the LEA firing. 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.

6.3.3.1 Comparison of Technical Issues

Of the five alternatives, the low NO_x burner (LNB) design with FGR is the most reliable option overall for industrial boiler application and provides the best NO_x emission reduction among the boiler modification techniques. Other boiler modification techniques, such as FGR and LEA firing, also are reliable technically; however, their NO_x reduction capabilities are less effective than the LNB/FGR dual option.

Add-on control technology such as SCR application on either a conventional or modified boiler will further complicate the entire boiler operation. These potential complications are a result of significant routine maintenance and unscheduled downtime because of malfunction or failure of SCR components. Also, the seasonal operating schedule intended for the proposed boiler is not the best operation for an SCR application. Prolonged shutdown period, when the boiler stays inactive during normal plant operation, of an SCR unit will require extensive shutdown and startup operations.

Conversely, the boiler equipped with the LNB/FGR dual option is highly reliable, requiring low maintenance and minimal attention during continuous operation. With the additional advantage of firing "clean" fuel (i.e., low sulfur distillate oil), the startup and shutdown of the boiler is an automatic turnkey procedure. Therefore, the LNB/FGR dual option is the best NO_x control technology for the proposed boiler. Table 6.3-8 contains a summary of the operating parameters for the proposed boiler from Babcock & Wilcox or an equivalent boiler.

6.3.3.2 Comparison of Environmental Effects

Of the five alternatives, the two options using SCR pose the greatest potential for toxic impacts as a result of ammonia handling and storage, and ammonia slip. Comparing potential adverse environmental impacts, the boiler modifications do not contribute any adverse byproducts to the atmosphere.

Comparison among the three modification processes shows that none causes a significantly worse environmental impact than the others. However, the LNB/FGR dual option yields the lowest NO_x emission rate and theoretically can reduce potential particulates and VOC emissions. Therefore, the boiler modification process using the LNB/FGR dual option is the best NO_x control technology for the proposed boiler in regard to the environmental effects. This option results in low NO_x emissions (77.5 TPY) and low air quality impacts (0.33 $\mu g/m^3$, annual average).

6.3.3.3 Comparison of Energy Impacts

The options involving the use of SCR will require 67,998 MMBtu/yr of heat input for the auxiliary duct burner system. In addition, 8.6 MW-hr/yr of electricity is required for the operation of the ammonia vaporizer and injection system. Conversely, all boiler modifications do not require additional fuel or electricity; therefore, boiler modification is the better energy savings alternative. Potentially, the option of using the LNB/FGR dual option is the best fuel savings option because of its lowest

Table 6.3-8. Summary of the Operating Parameters for the Proposed Boiler No. 16.

Parameter	Design Specification*
Make	Babcock & Wilcox
Type	Package Boiler
Model	FM 120-97
Modifications (2)	1) Coen's LO-NOx Burner 2) FGR
Air/Fuel Ratio	16.32
Excess Air Flow	15 percent, maximum
Flue Gas Recirculation Rate	12 percent
Exhaust Flue Gas	
Mass Flow Rate	187,940 lb/hr
Volume Flow Rate	71,300 acfm
Temperature	435°F

* The actual installed boiler may be obtained from a different boiler maker; however, the final boiler design specifications will be equivalent to those listed below.

Source: McBurney Corporation (1991).

excess combustion process by design. Therefore, the boiler modification process using the LNB/FGR dual option is the best NO_x control technology for the proposed boiler with regard to energy requirements and impacts.

6.3.3.4 Comparison of Economic Analysis

Economic analysis is based on the cost effectiveness of the control method. For a typical control device, such economic impact is determined by its total and incremental cost effectiveness values. These values for all five NO_x control options are tabulated in Table 6.3-9.

The two SCR-related options have the first and second highest total cost effectiveness values of $6,802 and $7,321 per ton of NO_x removed for the combination of SCR plus LNB/FGR dual option and the ceramic-based SCR, respectively. Among the boiler modification techniques, the total cost effectiveness values are $483 per ton of NO_x removed for the LNB/FGR dual option, $195 per ton of NO_x removed for the FGR option, and $255 per ton of NO_x removed for the LEA firing option. Comparing the total cost effectiveness of the two add-on SCR options to the three non-SCR boiler modification alternatives, the difference between the SCR group and the non-SCR group is a factor of at least 14.

The incremental cost effectiveness values for the SCR-related options are $2,654 per ton of NO_x removed for the combination of SCR plus LNB/FGR dual option and $22,364 per ton of NO_x removed for the ceramic-based SCR. The incremental cost effectiveness values for the boiler modification techniques are $3,362, $134, and $255 per ton of NO_x removed for the LNB/FGR dual option, the FGR, and the LEA firing, respectively.

Overall, the alternative of using either one of the SCR-related NO_x control methods is economically infeasible. The SCR-related option is at least 14 times more expensive than any boiler modification technique in terms of total cost effectiveness. In addition, the incremental cost between the

Table 6.3-9 Summary of Top-Down BACT Impact Analysis Results for NOx.

			Environmental Impacts		Energy Impacts Incremental increase over baseline		Economic Impacts			
Control Alternative	Total Emission Reduction (TPY)*	Incremental Emission Reduction (TPY)**	Potential toxic air impact?	Potential adverse enviromental impacts?	No. 2 Fuel Oil (MMBtu/yr)	Electricity (MW-hr/yr)	Total Annualized Cost ($/yr)	Incremental Annualized Cost ($/yr)	Total Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
SCR and LNB/FGR Dual Option	155.0	17.2	Yes	Yes	67,998	8.6	$1,054,187	$45,710	$6,802	$2,654
Ceramic-based SCR	137.8	43.1	Yes	Yes	67,998	8.6	$1,008,477	$962,767	$7,321	$22,364
Low NOx Burner with FGR (a.k.a. LNB/FGR Dual Option)	94.7	8.6	No	No	0	0	$45,710	$28,949	$483	$3,362
FGR	86.1	43.1	No	No	0	0	$16,761	$5,768	$195	$134
Low Excess Air (LEA) Firing	43.1	43.1	No	No	0	0	$10,993	$10,993	$255	$255
Baseline (conventional boiler)	----	----	--	--	----	--	----	----	----	----

* Total emission reduction, total annualized cost, and total cost effectiveness are calculated based on similar baseline parameter values.

** Incremental values are based on the next lower control technology's parameter values.

least expensive SCR-related option and the highest cost boiler modification technique is $22,364.

Of the three boiler modification options, the LNB/FGR dual option has the highest total and incremental cost effectiveness. Since these values are within the reasonable cost estimates while providing the best NO_x emission reduction rate, the LNB/FGR dual option is BACT for NO_x emissions from the proposed boiler.

6.3.3.5 Conclusion

The NO_x top-down BACT analysis in terms of environmental impacts, energy impacts, and economic impacts for Okeelanta Corporation's proposed project is summarized in Table 6.2-9. The analysis has considered two SCR-related control options and three boiler modification options. The main reasons for eliminating both SCR-related options are their high cost effectiveness and their being an unproven technology for industrial boilers. The seasonable operation intent for the proposed boiler also is considered an inappropriate operation for any SCR application. This is consistent with current BACT determinations for NO_x emissions from oil-fired industrial boilers. There are no existing oil-fired boilers that have been required to use SCR for NO_x control (see Table 6.3-2).

By eliminating both SCR-related options, one of the boiler modification techniques must be chosen as BACT for NO_x emissions from the proposed boiler. Compared to the NSPS NO_x limitation for industrial boilers burning distillate oil, only the LNB/FGR dual option (of 0.18 lb/MMBtu) and the FGR technology (of 0.20 lb/MMBtu) are able to meet the NSPS limit of 0.20 lb/MMBtu. The LNB/FGR dual option has the highest cost effectiveness values among the three boiler modifications; however, it also is the best option in terms of providing the highest NO_x emission reduction rate.

Although the incremental cost effectiveness of $3,362 per ton of NO_x removed for the LNB/FGR dual option is much higher than the $134 per ton of

NO_x removed for the next applicable technology, Okeelanta Corporation is willing to bear this reasonably higher incremental cost effectiveness in order to achieve the better NO_x emission reduction. Therefore, the LNB/FGR dual option is concluded to be BACT for NO_x emission control from the proposed 205-MMBtu/hr package boiler.

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 IMPACTS ON SOILS AND VEGETATION

As described in the air quality impact analysis (Section 5.0), the maximum predicted SO_2 concentrations in the vicinity of the Okeelanta mill as a result of the proposed boiler are predicted to be well below the AAQS for SO_2 and below the significance level for NO_2. As a result, no detrimental effects on soils or vegetation should occur in this area. The primary crop in the area is sugar cane, which routinely is exposed to higher air concentrations in the crop season with no detrimental effects.

The analysis also demonstrated that PSD increment consumption in the Everglades National Park Class I area will be well below the Class I increments for SO_2. The maximum increment consumption is 76 percent of the allowable increment (predicted for the 24-hour SO_2 increment), primarily as a result of other PSD increment-consuming sources. Annual increment consumption in the Class I area is predicted to be 0.4 $\mu g/m^3$, which is well below the PSD increment of 1.0 $\mu g/m^3$. The maximum SO_2 impacts on the Class I area as a result of the proposed boiler only are 2.2 $\mu g/m^3$, 3-hour; 0.4 $\mu g/m^3$, 24-hour; and 0.03 $\mu g/m^3$, annual average. These maximum impacts are less than 9 percent of any of the Class I increments. As a result, no significant effect on soils or vegetation should occur in the Class I area because of the proposed boiler.

7.2 IMPACTS ON VISIBILITY

The visibility analysis required by PSD regulations is directed primarily toward Class I areas. The CAA amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory PSD Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration caused by various pollutants. The only Class I area within 100 km of the proposed facility is the Everglades National Park, located about 90 km from the Okeelanta facility.

A level-1 visibility screening analysis was performed to determine the potential adverse visibility effects using the approach suggested in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1988). The level-1 screening analysis is designed to provide a conservative estimate of plume visual impacts (i.e., impacts higher than expected). The EPA model, VISCREEN, was used for this analysis. Model input and output results are presented in Table 7-1. The projected increase in emissions caused by the proposed boiler, as presented in Table 2-2, was used as input to the model. As indicated, the maximum visibility impacts caused by the proposed boiler do not exceed the screening criteria inside or outside the Class I area. As a result, there is no significant impact upon visibility predicted for the Class I areas.

7.3 IMPACTS DUE TO ASSOCIATED POPULATION GROWTH

There will be a small increase in the number of temporary construction workers during construction. There will be a minimal increase in permanent employment at Okeelanta as a result of adding the oil-fired boiler. As a result, there will be no significant impacts on air quality caused by associated population growth.

Table 7-1. Results of Visibility Screening Analysis

```
                 Visual Effects Screening Analysis for
                   Source: OKEELANTA MILL PROPOSED
                   Class I Area: EVERGLADES NAT. PARK

                   ***   Level-1 Screening   ***
          Input Emissions for

             Particulates     23.10  TON/YR
             NOx (as NO2)     77.50  TON/YR
             Primary NO2        .00  TON/YR
             Soot               .00  TON/YR
             Primary SO4       5.50  TON/YR

              **** Default Particle Characteristics Assumed

                       Transport Scenario Specifications:

              Background Ozone:                   .04 ppm
              Background Visual Range:          25.00 km
              Source-Observer Distance:         91.40 km
              Min. Source-Class I Distance:     91.40 km
              Max. Source-Class I Distance:    140.00 km
              Plume-Source-Observer Angle:      11.25 degrees
              Stability:   6
              Wind Speed:   1.00 m/s

                                   R E S U L T S

          Asterisks (*) indicate plume impacts that exceed screening criteria

                 Maximum Visual Impacts INSIDE  Class I Area
                  Screening Criteria ARE NOT Exceeded
                                                  Delta E      Contrast
                                                -----------  -----------
          Backgrnd Theta Azi Distance Alpha Crit  Plume  Crit  Plume
          -------- ----- --- -------- ----- ----  -----  ----  -----
           SKY       10.  84.   91.4    84.  2.00  .008   .05   .000
           SKY      140.  84.   91.4    84.  2.00  .002   .05   .000
           TERRAIN   10.  84.   91.4    84.  2.00  .001   .05   .000
           TERRAIN  140.  84.   91.4    84.  2.00  .000   .05   .000

                 Maximum Visual Impacts OUTSIDE Class I Area
                  Screening Criteria ARE NOT Exceeded
                                                  Delta E      Contrast
                                                -----------  -----------
          Backgrnd Theta Azi Distance Alpha Crit  Plume  Crit  Plume
          -------- ----- --- -------- ----- ----  -----  ----  -----
           SKY       10.  70.   86.9    99.  2.00  .009   .05   .000
           SKY      140.  70.   86.9    99.  2.00  .002   .05  -.000
           TERRAIN   10.  65.   85.3   104.  2.00  .002   .05   .000
           TERRAIN  140.  65.   85.3   104.  2.00  .000   .05   .000
```

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APPENDIX A

EMISSION CALCULATIONS
PROPOSED OIL-FIRED BOILER
OKEELANTA CORPORATION

I. BOILER DESIGN DATA

A. HEAT INPUT

Maximum steam rate - 150,000 lb/hr (24-hr average)

Enthalpy change - 1,153.46 Btu/lb steam

Boiler efficiency - 84.4%

Maximum 24-hr average heat input

- 150,000 lb/hr x 1,153.46 Btu/lb + 0.844 - 205x10^6 Btu/hr

Operating time (maximum) - 175 days/yr - 4,200 hr/yr

Annual heat input - 205x10^6 Btu/hr x 4,200 hr/yr

- 8.61x10^{11} Btu/yr

B. FUEL ANALYSIS

No. 2 fuel oil only will be burned in boiler

Density - 7.21 lb/gal

Maximum sulfur content - 0.5% S

Heating value - 140,090 Btu/gal

- 19,430 Btu/lb

C. FUEL USAGE

Maximum hourly - 205x10^6 Btu/hr + 140,090 Btu/gal - 1,463 gal/hr

Maximum annual - 1,463 gal/hr x 4,200 hr/yr - 6,144,600 gal/yr

II. EMISSION CALCULATIONS

A. PARTICULATE MATTER (TSP)

1. Maximum Hourly

Particulate emissions can be estimated from the AP-42 emission factor (Table 1.3-1) of 2 lb/10^3 gal for distillate oil.

1,463 gal/hr x 2 lb/10^3 gal - 2.9 lb/hr

To be conservative, estimate maximum PM(TSP) emissions as 11.0 lb/hr

2. Maximum Annual

11.0 lb/hr x 4,200 hr/yr + 2,000 lb/ton - 23.1 TPY

B. PARTICULATE MATTER (PM10)

1. Maximum Hourly

AP-42 states that 50% of PM emissions from an uncontrolled industrial boiler firing distillate oil are PM10 (Table 1.3-4).

11.00 lb/hr x 0.50 = 5.50 lb/hr

2. Maximum Annual

5.50 lb/hr x 4,200 + 2,000 = 11.55 TPY

C. SULFUR DIOXIDE (SO_2)

1. Maximum Hourly

Based on 100% conversion of sulfur in fuel oil to SO_2:

1,463 gal/hr x 7.21 lb/gal x 0.005 x 2 lb SO_2/lb S = 105.5 lb/hr

2. Maximum Annual

105.5 lb/hr x 4,200 + 2,000 = 221.6 TPY

D. NITROGEN OXIDES

1. Maximum Hourly

Emissions will be limited to 0.18 lb/10^6 Btu based on burner design.

205x10^6 Btu/hr x 0.18 lb/10^6 Btu = 36.9 lb/hr

2. Maximum Annual

36.9 lb/hr x 4,200 + 2,000 = 77.5 TPY

E. CARBON MONOXIDE

1. Maximum Hourly

Maximum emissions will be 0.20 lb/10^6 Btu based on good combustion practices.

205x10^6 Btu/hr x 0.20 lb/10^6 Btu = 41.0 lb/hr

2. Maximum Annual

   41.0 lb/hr x 4,200 ÷ 2,000 = 86.1 TPY

F. VOLATILE ORGANIC COMPOUNDS

1. Maximum Hourly

   Maximum emissions will be 0.09 lb/10^{6} Btu

   205x10^{6} Btu/hr x 0.09 lb/10^{6} Btu = 18.45 lb/hr

2. Maximum Annual

   18.45 lb/hr x 4,200 ÷ 2,000 = 38.7 TPY

G. TRACE METALS

Emission factors obtained from "Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources," EPA-450/2-88-006a, unless otherwise noted.

1. Lead

   Distillate oil combustion in industrial boilers:

   8.9 lb/10^{12} Btu (uncontrolled)

   Maximum hourly: 205x10^{6} Btu/hr x 8.9 lb/10^{12} Btu

   = 0.0018 lb/hr

   Annual : 0.0018 lb/hr x 4,200 ÷ 2,000 = 0.0038 TPY

2. Mercury

   Distillate oil-fired boiler, uncontrolled: 3.0 lb/10^{12} Btu

   Maximum hourly: 205x10^{6} Btu/hr x 3.0 lb/10^{12} Btu

   = 0.00062 lb/hr

   Annual: 0.00062 lb/hr x 4,200 ÷ 2,000 = 0.0013 TPY

3. Beryllium

   Based on "Estimating Air Toxics Emission from Coal and Oil Combustion Sources," EPA-450/2-89-001 (1989). Beryllium uncontrolled emission factor for distillate oil-fired boilers is 0.79 lb/10^{12} Btu. This value is an average of 3 stack test results ranging from 0.52 to 1.2 lb/10^{12} Btu.

   Maximum hourly: 205x10^{6} Btu/hr x 0.79 lb/10^{12} Btu

   = 0.00016 lb/hr = 0.00016

   Annual: 0.00016 lb/hr x 4,200 ÷ 2,000 = 0.00034 TPY

4. Fluorides

Based on "Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources," EPA-600/7-81-003, and "Health Impacts, Emissions and Emission Factors for Noncriteria Pollutants Subject to DeMinimis Guidelines and Emitted from Stationary Conventional Combustion Processes," EPA-450/2-80-074: 14 pg/J (32.7 lb/10^{12} Btu) for distillate oil-fired boilers, uncontrolled

Maximum hourly: 205x10^{6} Btu/hr x 32.7 lb/10^{12} Btu = 0.0082 lb/hr

Annual: 0.0082 lb/hr x 4,200 ÷ 2,000 = 0.017 TPY

H. SULFURIC ACID MIST

From AP-42, Table 1.3-1, SO_3 emission factor is 2.9 S lb/10^{3} gal

Maximum hourly SO_3 = 1,463 gal/hr x [2.9(0.5)] lb/10^{3} gal
= 2.12 lb/hr

Convert to H_2SO_4: 2.12 lb/hr x 98/80 = 2.60 lb/hr

Annual: 2.60 lb/hr x 4,200 ÷ 2,000 = 5.46 TPY

APPENDIX B

EPA COST ALGORITHM FOR CONTROL EQUIPMENT

EPA-450/3-82-021

Costs of Sulfur Dioxide, Particulate Matter, and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers

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Contract No.: 68-02-3058

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1982

1-a

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-450/3/82-021	2.	3. RECIPIENT'S ACCESSION NO. PB83 119438
4. TITLE AND SUBTITLE Costs of Sulfur Dioxide, Particulate Matter, and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers		5. REPORT DATE August 1982
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Office of Air Quality Planning and Standards U.S. Environmental Protection Agency Research Triangle Park, North Carolina 27711		10. PROGRAM ELEMENT NO.
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12. SPONSORING AGENCY NAME AND ADDRESS DAA for Air Quality Planning and Standards Office of Air, Noise, and Radiation U.S. Environmental Protection Agency Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED Final
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15. SUPPLEMENTARY NOTES		

16. ABSTRACT

This report is a resource document for the development of Federal standards of performance for control of sulfur dioxide, particulate matter and nitrogen oxides emissions from new industrial boilers. It gives capital and annualized costs for a variety of control technologies that can be applied to gas, oil, and coal fired industrial boilers. In addition to control costs for 30, 75, 150, and 400 million Btu per hour size model boilers, cost algorithms and a computer program are given in detail to allow for automated cost data development.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Boilers, Industrial Costs, Capital and Annualized Air Pollution Control Costs		

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TABLE A-21. COST EQUATIONS[4] FOR SODIUM THROWAWAY FGD SYSTEMS[a]

Routine Code: NATH

Capital Costs:[b]

$$TDI = 44{,}000\ (FLW)^{0.62} + 20{,}600\ (S1)^{0.427}$$

$$TK = 1.48\ TDI + 74{,}400 \qquad \text{if } Q \leq 58.6$$

$$= 1.48\ TDI + 112{,}800 \qquad \text{if } Q > 58.6$$

Annual Costs:[b,c]

DL = 105,000

SPRV = 21,000

MANT = 0.08 TDI

ELEC = 8,760 CF ELECR [4.26 (FLW) - 2.56] [0.65 + 0.31 S1]

WTR = 8,760 CF WTRR [0.776 (FLW) - 0.720] [0.213 + 0.684 S1]

SW = 8,760 CF SWDR [0.16 + 4.53 S2]

SC = 8,760 CF SASHR [8.03 + 3.5 S2]

LW = 8,760 CF LWDR (0.0860 S2)

---

[a] FGD algorithms use metric units as noted in Table A-2.

[b] S1 = S * EFFSO2 * 100/H

[c] S2 = S1 * Q/3.6

TABLE A-22. COST EQUATIONS[5] FOR LIME SPRAY DRYING FGD SYSTEMS WITH PM REMOVAL[a]

Routine Code: DS

Capital Costs:[c]

$\text{TDI} = 55{,}600\ (\text{FLW})^{0.51} + 21{,}600\ (\text{S2})^{0.40} + 33{,}327\ (\text{FLW})^{0.89}$

$\text{TK} = 1.48\ \text{TDI} + 110{,}400$ if $Q \le 58.6$

$1.60\ \text{TDI}$ if $Q > 58.6$

Annual Costs:[b,c]

$\text{DL} = 105{,}000$

$\text{SPRV} = 21{,}000$

$\text{MANT} = 0.08\ [55{,}600\ (\text{FLW})^{0.51} + 21{,}600\ (\text{S2})^{0.40}] + 14{,}840 + 1.23\ Q^2 + 578\ (\text{FLW})^{0.997}$

$\text{ELEC} = 8{,}760\ \text{CF} * \text{ELECR}\ [6.14\ (\text{FLW})^{0.82}]$

$\text{WTR} = 8{,}760\ \text{CF} * \text{WTRR}\ [0.144\ (\text{FLW})]$

$\text{SW} = 8{,}760\ \text{CF} * \text{SWDR}\ [(0.035 * \text{EFFSO2} + 3.02)\ (\text{S2}) + \text{UNCPM} * \text{EFFPM}/100]$?

$\text{LIME} = 8{,}760\ \text{CF} * \text{ALIMER}\ (1.88\ \ln(\text{EFFSO2}) - 5.3)\ \text{S2}$?

---

[a] FGD costs use metric units as noted in Table A-2.

[b] $\text{S1} = \text{S1} * \text{EFFSO2} * 100/\text{H}$

[c] $\text{S2} = \text{S1} * Q/3.6$