NATIONAL PARK SERVICE AIR RESOURCES DIVISION

P.O. BOX 25287, Denver, CO 80225-0287

FACSIMILE COVER SHEET

Date: April 21, 1998

Telephone: (303) 969-2075
Fax: (303) 969-2822

To: *Al Linero, FDEP, Fax 850-922-6979*

From: *Don Shepherd, Policy, Planning, and Permit Review Branch*

Subject: *Lakeland McIntosh*

Al,

I don't know if you have had any luck with the spreadsheets I sent by e-mail, so we'll try it the "old-fashioned" way. Following are two sets of calculations as you suggested: one set based on a three-year catalyst life (see the "Given/Assumptions" page for "Catalyst Life"); and the other set based on five-year catalyst life. Thanks for your good work on this permit.

Don

Number of Pages: 10 *(Including this cover sheet)*

Office Location: 7333 W. Jefferson, Room 450, Lakewood, CO 80235

(Send Mail to: 12795 W. Alameda Parkway, Lakewood, CO 80228)

Lakeland McIntosh

Plant Data

			Capacity	
Site	FWS Area(s)	Source	(mmBtu/hr)	(MW)
Lakeland, FL	Chassahowitzka	1 CT	2174	250
	St. Marks		each	each

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Lakeland McIntosh

Given/Assumptions

Source	1 CT
Exhaust gas flow (lb/Hr)	4,518,595
Exhaust gas flow (acfm)	3,055,750
Basic Equipment Costs	2,700,000
Ammonia storage cost ($/1,000 lb mass flow)	$35
Uncontrolled Emission rate (TPY)	852
Control efficiency (%)	64%
Operating Hours per Year	7,008
Operating Hours per Shift	8
Operating Shifts per Year	876
Operating Labor Cost ($/hr)	15
Maintenance Labor Cost ($/hr)	15
Electrical Cost ($/kWh)	$0.05
Reagent use (lb/hr @ 28% sol.)	286
Reagent Costs ($/T)	$300
Electrical efficiency	90%
Catalyst replacement	$1,600,000
Catalyst disposal ($/Yr)	$42,174
Catalyst life (Yr)	3
Heat rate penalty (% of MW output)	0.5%
Equipment Life (Yr)	15
Interest Rate (%)	7.00%

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Lakeland McIntosh

Capital Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item		Factor	Cost
Direct Costs			1 CT
Purchased equipment costs			
SCR + auxiliary equipment			$2,700,000
Ammonia storage			$158,151
Total		A	$2,858,151
Sales taxes		0.00 A	$0
Freight		0.05 A	$142,907.54
Purchased equipment cost, PEC	B=	1.05 A	$3,001,058
Direct installation costs			
Foundations & supports		0.08 B	$240,085
Handling & erection		0.14 B	$420,148
Electrical		0.04 B	$120,042
Piping		0.02 B	$60,021
Insulation		0.01 B	$30,011
Painting		0.01 B	$30,011
Direct installation costs		0.30 B	$900,318
Site preparation	As required, SP		$0
Buildings	As required, Bldg.		$0
Total Direct Costs, DC		1.30 B+SP+Bldg	$3,901,376
Indirect Costs (installation)			
Engineering		0.10 B	$300,106
PSM/RMP Plan			$25,000
Construction and field expenses		0.05 B	$150,053
Contractor fees		0.10 B	$300,106
Start-up		0.02 B	$60,021
Performance test		0.01 B	$30,011
Contingencies		0.03 B	$90,032
Total Indirect Cost, IC		0.31 B	$955,328
Total Capital Investment = DC + IC		1.61 B+SP+Bldg	$4,856,704

Annual Costs (OAQPS Control Cost Manual Chapter 3—Catalytic Incinerators)

Cost Item	Factor			Cost
Direct Annual Costs, DC				1 CT
Operating labor				
Operator	0.5 hr/shift			$6,570
Supervisor	15% of operator			$986
PSM/RMP Update				$5,000
Operating materials				
Reagent	286 lb/hr *	7008 hr/yr/2000lb/T*	300 $/T =	$301,106
Maintenance				
Labor	0.5 hr/shift			$6,570
Material	100% of maintenance labor			$6,570
Catalyst replacement				$533,333
Electricity	286 lb/hr *	518.1 Btu/lb*	0.000293 kW*hr/Btu*	
	0.05 $/kWh*	7008 hr/yr*	0.90 ef. =	$13,713
Total DC				$860,135
Energy Costs				
Heat rate penalty	250 MW *	7,008 hr/yr *		
	1000 kW/MW *	0.005 loss *	0.05 $/kWh =	$438,000
Indirect Annual Costs, IC				
Overhead	60% of maintenance costs			$193,081
Administrative charges	2% of Total Capital Investment			$97,134
Property tax	1% of Total Capital Investment			$0
Insurance	1% of Total Capital Investment			$48,567
Capital recovery	0.1098 * [Total Capital Investment-1.08(Cat Cost)]			$469,998
Total IC				$808,780
Total Annual Cost	DC + IC			$2,106,915

Lakeland McIntosh

Cost Effectiveness

Source	1 CT	Units
Pollutant	NOx	
Uncontrolled emissions	852.0	TPY
Control efficiency	64%	
Controlled emissions	306.7	TPY
Pollutants removed	545.3	TPY
Annual cost	$2,106,915	/yr
Annual cost - Emission fees saved	$2,090,556	@ $30/T
Cost/ton	$3,864	/T

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Lakeland McIntosh

Given/Assumptions

Source	1 CT
Exhaust gas flow (lb/Hr)	4,518,595
Exhaust gas flow (acfm)	3,055,750
Basic Equipment Costs	2,700,000
Ammonia storage cost ($/1,000 lb mass flow)	$35
Uncontrolled Emission rate (TPY)	852
Control efficiency (%)	64%
Operating Hours per Year	7,008
Operating Hours per Shift	8
Operating Shifts per Year	876
Operating Labor Cost ($/hr)	15
Maintenance Labor Cost ($/hr)	15
Electrical Cost ($/kWh)	$0.05
Reagent use (lb/hr @ 28% sol.)	286
Reagent Costs ($/T)	$300
Electrical efficiency	90%
Catalyst replacement	$1,600,000
Catalyst disposal ($/Yr)	$42,174
Catalyst life (Yr)	5
Heat rate penalty (% of MW output)	0.5%
Equipment Life (Yr)	15
Interest Rate (%)	7.00%

Lakeland McIntosh

Capital Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item	Factor	Cost
Direct Costs		1 CT
Purchased equipment costs		
SCR + auxiliary equipment		$2,700,000
Ammonia storage		$158,151
Total	A	$2,858,151
Sales taxes	0.00 A	$0
Freight	0.05 A	$142,907.54
Purchased equipment cost, PEC B=	1.05 A	$3,001,058
Direct installation costs		
Foundations & supports	0.08 B	$240,085
Handling & erection	0.14 B	$420,148
Electrical	0.04 B	$120,042
Piping	0.02 B	$60,021
Insulation	0.01 B	$30,011
Painting	0.01 B	$30,011
Direct installation costs	0.30 B	$900,318
Site preparation As required, SP		$0
Buildings As required, Bldg.		$0
Total Direct Costs, DC	1.30 B+SP+Bldg	$3,901,376
Indirect Costs (installation)		
Engineering	0.10 B	$300,106
PSM/RMP Plan		$25,000
Construction and field expenses	0.05 B	$150,053
Contractor fees	0.10 B	$300,106
Start-up	0.02 B	$60,021
Performance test	0.01 B	$30,011
Contingencies	0.03 B	$90,032
Total Indirect Cost, IC	0.31 B	$955,328
Total Capital Investment = DC + IC	1.61 B+SP+Bldg	$4,856,704

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Lakeland McIntosh

Annual Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item	Factor			Cost
Direct Annual Costs, DC				1 CT
Operating labor				
Operator	0.5 hr/shift			$6,570
Supervisor	15% of operator			$986
PSM/RMP Update				$5,000
Operating materials				
Reagent	286 lb/hr *	7008 hr/yr/2000lb/T*	300 $/T =	$301,106
Maintenance				
Labor	0.5 hr/shift			$6,570
Material	100% of maintenance labor			$6,570
Catalyst replacement				$320,000
Electricity	286 lb/hr *	518.1 Btu/lb*	0.000293 kW*hr/Btu*	
	0.05 $/kWh*	7008 hr/yr*	0.90 ef. =	$13,713
Total DC				$646,801
Energy Costs				
Heat rate penalty	250 MW *	7,008 hr/yr *		
	1000 kW/MW *	0.005 loss *	0.05 $/kWh =	$438,000
Indirect Annual Costs, IC				
Overhead	60% of maintenance costs			$193,081
Administrative charges	2% of Total Capital Investment			$97,134
Property tax	1% of Total Capital Investment			$0
Insurance	1% of Total Capital Investment			$48,567
Capital recovery	0.1098 * [Total Capital Investment-1.08(Cat Cost)]			$495,295
Total IC				$834,077
Total Annual Cost	DC + IC			$1,918,878

Lakeland McIntosh

Cost Effectiveness

Source	1 CT	Units
Pollutant	NOx	
Uncontrolled emissions	852.0	TPY
Control efficiency	64%	
Controlled emissions	306.7	TPY
Pollutants removed	545.3	TPY
Annual cost	$1,918,878	/yr
Annual cost - Emission fees saved	$1,902,520	@ $30/T
Cost/ton	$3,519	/T

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McINTOSH POWER PLANT
3030 E. LAKE PARKER DR.
LAKELAND, FLORIDA 33805

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TELECOPY REQUEST/COVER PAGE

Please deliver the following page(s) to:

AL LINERO at DEP

Telecopier Number (850) ~~488~~ - 922-6979

From: FARZIE SHELTON **Telefax Number (FAX) (941) 603-6335**

Date: 4/20/98 **Time:** 3:11 **AM/PM**

Number of Pages (Including Cover Page): 13

For more information or problem assistance, please call your city contact or (941) 499-6600.

Al:

Please Call me.

Thanks

Farzie

PERMITTEE:

City of Lakeland
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Fl 33801-5079

File No.	1050004-004-AC
FID No.	1050004-004
SIC No.	4911
Permit No.	PSD-FL-245
Expires:	December 31, 1999

Authorized Representative:
Ronald W. Tomlin
Assistant Managing Director

PROJECT AND LOCATION:

Permit for the construction of 250 megawatt (MW) simple cycle, gas-fired, stationary combustion turbine (CT), a once-through steam generator, and a 1.05 million gallon storage tank for back-up distillate fuel oil. Conditions are included for possible future conversion to a 350 megawatt combined cycle installation including a heat recovery steam generator provided there are no increases in emissions associated with the conversion. The turbine is designated as Unit No. 5 and will be located at the C.D. McIntosh, Jr., Power Plant, 3030 East Lake Parker Drive, Lakeland, Polk County. UTM coordinates are: Zone 17; 409.0 km E; 3106.2 km N.

STATEMENT OF BASIS:

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

AIR CONSTRUCTION PERMIT PSD-FL-245 (1050004-004-AC)

SECTION I. FACILITY INFORMATION

SUBSECTION A. FACILITY DESCRIPTION

The existing facility includes: two small diesel powered electric generators; one small gas and distillate-fired combustion turbine; one 90 MW gas and fuel oil-fired steam generator; one 115 MW gas and fuel oil-fired steam generator; and one 364 MW multiple (primarily coal) fuel-fired steam. This permit is for the installation of: a 250 MW simple cycle, gas-fired, stationary combustion turbine; a once-through steam generator; a 1.05 million gallon storage tank for back-up (0.05 percent sulfur) distillate fuel oil; and an 85-foot stack. It is possible that in the future the turbine will be converted by the addition of a heat recovery steam generator and a new stack to a 350 MW combined cycle operation without increases in emissions. ~~facilities.~~

Emissions from Unit 5 will be initially controlled by Advanced Dry Low NO_X combustors, steam injection when firing fuel oil, use of inherently clean fuels, and good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions reduced by more sophisticated Ultra Low NO_X burners. Otherwise emissions will be reduced by the addition of a selective catalytic reduction (SCR) system.

SUBSECTION B. EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	250 Megawatt Combustion Turbine and Once Through Steam Generator
002	Fuel Storage	1.05 Million Gallon Fuel Oil Storage Tank

SUBSECTION C. REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications (such as the construction of Unit 5) at the facility resulting in emissions increases greater than 40 TPY of NO_X or SO_2, 25/15 TPY of PM/PM_{10}, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.410, F.A.C.

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

SUBSECTION D. PERMIT SCHEDULE

AIR CONSTRUCTION PERMIT PSD-FL-245 (1050004-004-AC)

SECTION I. FACILITY INFORMATION

- 04/xx/98 Notice of Intent published in the Lakeland ________
- 04/22/98 Distributed Intent to Issue Permit
- 04/04/98 Application deemed complete
- 12/08/97 Received Application

SUBSECTION E. RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on December 8, 1997
- Department's incompleteness letters dated January 5 and 12, 1998
- Comments from the National Park Service dated December 15, 1997, March , 1998, and April , 1998.
- EPA's letter dated February 10, 1998
- City of Lakeland's completeness responses and supplementary letters dated March 4, March 11, and March 31, 1998
- Letters from Westinghouse dated March 30 and March 31, 1998
- Department's Technical evaluation and Preliminary Determination dated April 22, 1998
- Department's Best Available Control Technology Determination dated ~~May xx~~, **<u>April 22</u>**, 1998

AIR CONSTRUCTION PERMIT PSD-FL-245 (1050004-004-AC)

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR) ~~and the Power Plant Siting office~~, Florida Department of Environmental Protection (FDEP) at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District office (DEPSW), 3804 Coconut Palm Drive, Tampa, Florida 33619 and phone number 813/744-6100.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a conversion to combined cycle operation. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

AIR CONSTRUCTION PERMIT PSD-FL-245 (1050004-004-AC)

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

This reassessment will be conducted for this project only if the conversion to combined cycle operation is accompanied by any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, or similar changes. [40 CFR 52.21(j)(4)]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Southwest District office (DEPSW). [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District office by March 1st of each year.

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (7) (c) (1997 version), shall be submitted to the DEP's Southwest District office.

AIR CONSTRUCTION PERMIT PSD-FL-245 (1050004-004-AC)

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

SUBSECTION A. APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

3. Emission Unit 001, Power Generation, consisting of a 250 megawatt combustion turbine with a once-through steam generator shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800, F.A.C.

4. Emission Unit 002, Fuel Storage, consisting of a 1.05 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of performance for Storage Tanks, adopted by reference in Rule 62-204.800, F.A.C.

5. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District office.

SUBSECTION B. GENERAL OPERATION REQUIREMENTS

6. Only pipeline natural gas or maximum 0.05 percent sulfur No. 2 distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

7. ~~Hours of operation~~ **Fuel usage** for the stationary gas turbine ~~and once through steam generator~~ shall not exceed ~~7,008 hours~~ **15.235 X 10 ^{12} Btu (LHV)** per year **while firing gas**. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

8. ~~Hours of operation~~ **Fuel usage** for the stationary gas turbine ~~and once through steam generator~~ shall not exceed ~~250 hours~~ **559.0 X 10 ^{9} Btu (LHV)** per year while firing distillate fuel oil. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

AIR CONSTRUCTION PERMIT PSD-FL-245 (1050004-004-AC)

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

9. The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,174 million Btu per hour (mmBtu/hr) when firing natural gas, nor 2,236 mmBtu/hr when firing No. 2 fuel oil. [Design, Rule 62-210, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Westinghouse Second Generation Advanced Dry Low NO_X (DLN) combustors (or equivalent) shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]

11. The Initial combustors shall be replaced with Westinghouse Ultra Low NO_X (ULN) Piloted Ring Combustors within 36 months after ~~start-up~~ **Initial Performance Test (IPT)** to accomplish further NO_X control unless a high temperature selective catalytic reduction (Hot SCR) system or a low temperature SCR system is installed within 36 months. [Design, Rules 62-4.070 and 62-212.410, F.A.C.]

12. The permittee shall design the stationary gas turbine, ducting, possible future heat recovery steam generator, and stack(s) to accommodate installation of SCR equipment or oxidation catalyst in the event that the ULN technology fails to achieve the NO_X or carbon monoxide (CO) limits given in Specific Condition **16**, within 36 months after ~~start-up~~ **IPT**. [Rule 62-4.070, F.A.C.]

13. A water injection system shall be installed for use when firing No. 2 fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.410, F.A.C.]

~~14. The Advanced DLN and ULN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the Advanced DLN or ULN systems in the diffusion firing mode shall be minimized when firing natural gas. [Rule 62-4.070, F.A.C.]~~

15. During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

AIR CONSTRUCTION PERMIT PSD-FL-245 (1050004-004-AC)

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

SUBSECTION C. EMISSION LIMITS AND STANDARDS

The following emission limits based shall apply upon completion of the initial compliance tests:

16. Best Available Control Technology (BACT). Following is a summary of the BACT determination by DEP. Values for NO_X **and CO** are **ppmvd** corrected to 15% O_2. [Rule 62-212.410, F.A.C.]

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Simple Cycle	25 - NG 42 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Adv. DLN on gas, WI on oil. Applies first 36 months after ~~startup~~ IPT. Clean fuels, good combustion
Simple Cycle	9 - NG 12 - (30 day) 42 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after 36 months ~~operation~~ IPT. Clean fuels, good combustion
Simple Cycle	9 - NG 15 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies after 36 months if 9 ppm NOX not achievable by ULN. Clean fuels, good combustion.
Combined Cycle	7.5 - NG 15 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR if converted to combined cycle, unless 9 ppm is attained by ULN or Hot SCR as described above. Clean fuels, good combustion

17. The following Nitrogen Oxides (NO_X) emissions apply:

- During the first 36 months after ~~start-up~~ IPT ~~(commercial operation)~~, NO_X emissions shall not exceed 25 ppmvd at 15% O_2 when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil **on the basis of a 30-day rolling average** except during periods of startup, shutdown, malfunction or fuel switching, as measured by the continuous emission monitoring system (CEMS). [Rule 62-212.410, F.A.C.]

- Beginning 36 months **after** ~~afetr start-up~~ IPT, ~~achievable short-term NO_X emissions shall be demonsnot during an annual compliance test at baseload not to exceed 9 ppmvd at 15% O_2 when firing natural gas.~~ NO_X emissions shall not exceed 12 ppmvd at 15% O_2 when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. [Rule 62-212.410, F.A.C.]

- If Hot SCR is installed, achievable short-term NO_X emissions shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O_2 when firing natural gas. NO_X emissions shall not exceed 9 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. [Rule 62-212.410, F.A.C.]

- If conventional SCR is installed, achievable short-term at NO_X emissions shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O_2 when firing natural gas. NO_X emissions shall not exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. [Rule 62-212.410, F.A.C.]

- When monitoring data are not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 30 day rolling average.

18. Carbon monoxide (CO) emissions**, at base load,** when firing natural gas shall not exceed 25 ppmvd **corrected to 15% O_2,** ~~when firing natural gas~~ and 90 ppmvd **corrected to 15% O_2** when firing fuel oil as measured by EPA Reference Method 10 test. [Rule 62-212.410, F.A.C.]

19. Sulfur dioxide (SO2) emissions shall not exceed 7.2 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent sulfur distillate fuel oil No. 2 as measured by applicable compliance methods described below. Emissions of SO2 shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review]

20. Visible emissions (VE) shall not exceed 10 percent opacity when firing natural gas or No. 2 fuel oil.

21. Emissions of volatile organic compounds (VOC) when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as measured by EPA Methods 18, 25 or 25 A

SUBSECTION D. EXCESS EMISSIONS

22. Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

23. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C

24. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

SUBSECTION E. COMPLIANCE DETERMINATION

AIR CONSTRUCTION PERMIT PSD-FL-245 (1050004-004-AC)

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

25. The DEP's Southwest District office shall be notified, in writing, at least 30 days prior to the initial ~~compliance~~ **performance** tests and at least 15 days before annual compliance test(s).

26. No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

27. Compliance with the allowable emission limiting standards shall be determined **(IPT)** within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-297, F.A.C.

28. Initial (I) ~~compliance~~ **performance** tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications of air pollution control equipment, including installation of Ultra Low NO_X burners, Hot SCR, or conventional SCR **according to the initial performance schedule in specific condition 27**. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on Unit 5 as indicated. The following reference methods shall be used:

   - EPA Reference ~~Mehtod~~ **Method** 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A); annual on oil if greater than 400 hours of oil firing.
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A) ~~Testing may be conducted at less than capacity.~~
   - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG**. Method 7E or data from RATA for** ~~and~~ short-term NO_X BACT limits.
   - EPA Reference Method 18, 25 or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

29. Continuous compliance with the long-term NO_X emission limits shall be demonstrated with the CEMS system based on a 30 day rolling average. Based on CEMS data, a separate compliance test is conducted at the end of each operating day and a new 30 day average emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. [~~Ruel~~ **Rule** 62-4.070, F.A.C., 40CFR75]

30. Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and the use ~~of no more than 250 hours per year~~ of maximum 0.05 percent sulfur (by weight) distillate No. 2 fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S

limit, fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

31. Compliance with CO emission limit: An initial **performance** test for CO, concurrent with the initial **performance test** NOX test, is required. The initial **performance test** NOX and CO test results shall be the average of three valid one-hour runs. Annual compliance testing may be conducted concurrent with the annual RATA testing required pursuant to 40 CFR 75 (gas only).

32. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, CO emission limit will be employed as surrogate.

33. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-297 F.A.C. Compliance test results shall be submitted to the DEP's Southwest District office no later than 45 days after completion of the last test run.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

34.

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO.

PSD-FL-245

April 15, 1998

RECEIVED

APR 20 1998

BUREAU OF
AIR REGULATION

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the additional information forwarded by your Department for the city of Lakeland's (Lakeland) proposed 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. As you know, in a January 9, 1998, letter and technical review document to you, we recommended that Lakeland be required to meet lower limits than those proposed for nitrogen oxides (NO_X) emissions. In addition, we asked that Lakeland perform a new visibility analysis, using lower NO_X emissions rates to demonstrate that the project's impacts to visibility at Chassahowitzka Wilderness would not be significant.

Lakeland subsequently proposed lower NO_X limits. In addition, they submitted a new visibility analysis. The Air Quality Branch has reviewed this new information and summarized the Fish and Wildlife Service's comments in the enclosed document. Specifically, we again recommend that your Department require Lakeland to meet lower limits on NO_X emissions than those proposed. In addition, we ask that Lakeland use the results from the long-range transport model, MESOPUFF II, to estimate visibility impacts at Chassahowitzka.

If you have any questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at 303/969-2617.

Sincerely yours,

H Dale Hall

For/ Sam D. Hamilton
Regional Director

cc: EPA
SWD
Polk Co.
J. Heron, BAR
K. Kosky, Golder Assoc.
J. Shelton, City of Lakeland

Technical Review of Additional Information
For a 250-Megawatt Simple Cycle Combustion Turbine at
McIntosh Power Plant
Polk County, Florida
PSD-FL-245

by

Air Quality Branch, Fish and Wildlife Service – Denver
April 2, 1998

This review is in response to additional information forwarded to us by the Florida Department of Environmental Protection regarding the City of Lakeland (Lakeland)'s proposal to construct a 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. In a January 9, 1998 letter and technical review document we recommended that Lakeland be required to meet lower limits than those proposed for nitrogen oxides emissions. In addition, we noted that Lakeland's predicted impact on visibility (i.e., regional haze) at Chassahowitzka was significantly higher than the 0.5 deciview value for a single source recommended by the U.S. Fish and Wildlife Service, and therefore unacceptable. We asked that Lakeland propose lower NO_X emissions rates and perform a new regional haze analysis (including PM-10 emissions) to demonstrate that the project's impacts would be less than 0.5 deciview.

Lakeland subsequently proposed lower NO_X limits. In addition, they submitted a new visibility analysis. Our comments on their revised analyses are below.

Best Available Control Technology (BACT) Analysis

Background

As noted above, the City of Lakeland, Florida, proposes to add a 250-megawatt (MW) simple cycle gas and oil fired turbine facility to its existing McIntosh Power Plant. (Note: A simple cycle turbine system provides for only one pass of the combustion gases through a generator and then out of the exhaust stack. A combined cycle turbine (CCT) system is much more efficient and uses the gases passing through the generator with supplementary firing to raise steam temperature and pressure for a steam turbine.) Lakeland's application triggers regulations for the Prevention of Significant Deterioration (PSD) of air quality for particulate matter (PM @ 41 tons per year—TPY), nitrogen oxides (NO_x @ 863 TPY), volatile organic compounds (VOC @ 94 TPY), and carbon monoxide (CO @ 1264 TPY). Any pollutant subject to PSD must be controlled through the use of Best Available Control Technology (BACT). Only NO_x emissions are of concern from a control technology standpoint for this type of application because NO_x emissions are highly dependent upon the combustor type and any add-on controls. Emissions of other pollutants depend primarily on good combustion techniques.

NO_x Controls

Dry Low-NO_x Combustors: Lakeland originally proposed dry low-NO_x (DLN) combustors to meet NO_x limits of 25 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen while burning natural gas, and 42 ppmvd using water injection while burning fuel oil. Lakeland is now proposing to meet a 9-ppm NO_x limit (gas firing) within five years of startup. However, DLN technology is now capable of achieving emission limits well below that proposed by the applicant. A review of the EPA RACT/BACT/LAER clearinghouse data submitted by the applicant found at least 18 examples of gas turbines permitted to start up with NO_x limits in the 9 – 15 ppmvd range, using DLN combustors. This clearly demonstrates that this technology is now capable of much lower emissions than proposed by the applicant. To allow this "advanced" system five years to meet current emission limits would represent significant backsliding.

Selective Catalytic Reduction: Although Selective Catalytic Reduction (SCR) is capable of 70% NO_x removal efficiency, it was rejected by Lakeland on the grounds of economic infeasibility. However, our (enclosed) review of application of SCR to this project resulted in much lower costs; at less than $4,000 per ton of NO_x removed, we believe that SCR is economically feasible. The high costs calculated by Lakeland are due to calculation errors on the part of the applicant. The following comments assume that the applicant used the cost estimation techniques illustrated in Tables 3-8 and 3-10 of the EPA Control Cost Manual:

Experience has shown that other vendors may provide lower SCR quotes.

If the Engelhard estimate covered both NO_x and CO, either the NO_x portion of the cost should be split out or a combined cost effectiveness calculated.

In the DLN-SCR scenario, is the smaller catalyst and ammonia usage resulting from DLN considered?

Because Instrumentation is included in the Engelhard proposal, the addition of $94,000 for this expense appears to be double-counting.

There is no justification for $20,000 for Site Preparation and Building expenses.

The Capital Recovery Factors are too high. Although Lakeland cites the OAQPS Control Cost Manual and city practices as justification for using 10% interest, the current version of the Manual recommends 7%.

Despite Lakeland's argument that addition of SCR to a simple cycle combustion turbine is a unique application, there is now so much experience with SCR on power generation turbines that the high Indirect Contingency cost and addition of Contingency costs to Direct Annual Costs and Energy Costs is no longer justified.

Labor costs are still overestimated.

Ammonia costs and catalyst replacement costs are underestimated, although the latter may be partially addressed by the inclusion of an "Inventory Cost" and a "Catalyst Disposal Cost." Lakeland should check to determine if the catalyst vendor offers free catalyst disposal as part of its replacement service. If additional catalyst is used, either the removal efficiency or catalyst life should be adjusted upward. Lakeland appears to be assuming that all of the catalyst will be replaced every year.

Electrical costs are not documented and appear to be overestimated.

If catalyst replacement is scheduled for some of the 1752 hours that the system will normally be down, there is no need to include a "MW Loss Penalty."

The "Fuel Escalation" cost is not justified.

The use of three and five years to determine the capital recovery factor cannot be allowed absent a firm commitment from Lakeland to go to a Combined Cycle Turbine (CCT) system by installing Heat Recovery Steam Generation (HRSG) in that time. If Lakeland is not committing to install CCT after five years, then it must be assumed that any controls installed now would be used for much longer than five years.

Lakeland states that the $13,000/MW cost is similar to the Commonwealth Chesapeake Corp's costs at $21,000/MW, which did not add controls. Because the cost/MW for Lakeland is less than 70% of the cost for Commonwealth Chesapeake, the two projects are not comparable.

If Lakeland goes from a simple cycle turbine to CCT, it plans to install advanced DLN @ 9-12 ppm and add SCR only if necessary to meet those limits. A review of the RACT/BACT/LAER clearinghouse reveals that permitted NO_x limits for gas CCTs start as low as 3.5 ppm (LAER) and include several BACT determinations in the 5-9 ppm range. (See table.) We have also included a list of CCT projects for which NO_x limits are either pending or not yet entered into the RBLC; it should be noted that all of the limits in the latter set fall into the 3.5-6.0 ppm range. Since it is clear that other similar installations have accepted the combination of DLN combustors and SCR, the applicant should justify why its environmental impacts and costs are uniquely excessive when compared to the others.

Lakeland argues that continued use of a hot catalyst is not good engineering practice, but gives no reasons. Lakeland also argues that Once Through Steam Generation (OTSG) would have to be removed if HRSG were added for efficiency purposes. Even though OTSG would no longer be necessary if HRSG were added, it would not necessarily have to be removed; in fact, Engelhard assumed in its estimate that OTSG would be retained upstream of the SCR. Lakeland's concern for efficiency would be better answered by going to CCT technology immediately.

Conclusions and Recommendations

BACT should be based on the capabilities of gas-fired turbines to meet 5 ppm NO_X or less; use of a less efficient system is not justification for higher emissions. The proposed use of a simple cycle gas turbine to generate electricity represents a less efficient, but lower cost alternative to modern combined cycle systems. By choosing the simple cycle approach, Lakeland has also made it more expensive and difficult to employ the more effective SCR NO_x control system that could be applied to a combined cycle system. Rather than reward an applicant for choosing an electricity generating system that is inherently more difficult to control, emission limits should reflect the end product, not the generation method. (This is essentially the approach proposed by EPA in its New Source Performance Standards for boiler NO_x emissions. Even though the proposed turbine would emit at 0.95 lb/net MW, which is better than the proposed NSPS, addition of SCR would improve these results significantly at a reasonable cost.) It is therefore recommended that NO_x emissions be limited to 5.0 ppmvd during gas firing, and 20 ppmvd for oil firing, which reflects the use of SCR and would result in a NO_x emission reduction of about 680 TPY. (The next alternative would be to limit NO_x emissions to 9.0 ppmvd which reflects the optimal use of the dry low-NO_x combustors proposed and would result in a NO_x emission reduction of about 545 TPY.)

Lakeland argues that use of a high temperature catalyst would delay conversion to CCT. If Lakeland is concerned about schedule and wants to expedite the permitting process, it should propose a CCT and/or improve its control strategy.

Visibility Analysis

Lakeland ran the MESOPUFF II model using the Interagency Workgroup on Air Quality Modeling (IWAQM) protocol to predict the effect of their emissions on nitrate concentrations at Chassahowitzka. The model was also run with the chemical transformation module turned off to predict a nitrogen oxide concentration at Chassahowitzka. By comparing the two concentrations, they estimated a chemical transformation rate of approximately 31% for a 24-hour period. They then multiplied an ISCST-derived nitrogen oxide concentration to estimate the nitrate concentration that was used in the visibility analysis.

Because the proposed source is 91 km from Chassahowitzka, the predicted nitrate concentration value from MESOPUFF II (the long-range transport model) should have been used in the visibility analysis. It is not clear why the applicant did not use the nitrate concentration value predicted by MESOPUFF II in the visibility analysis. The applicant did not report this value. The ISCST model used by the applicant was inappropriate, as it is intended for distances less than 50 km.

The applicant should redo the visibility analysis using the MESOPUFF II nitrate concentration value. If the predicted impact is less than or equal to 0.5 deciview, the impact is considered insignificant and no further analysis is needed. If the predicted impact is greater than 0.5 deciview, the applicant should conduct a cumulative modeling analysis including the new source's proposed emissions and all other increment-consuming emissions. If the cumulative analysis predicts an impact less than or equal to 1.0 deciview, the impact is considered insignificant and no further analysis is needed. If the cumulative impact is greater than 1.0 deciview, a significant increase in haze is possible and FWS will make a case-by-case adverse impact determination regarding the proposed project, considering the predicted frequency, magnitude, and duration of impacts.

The applicant should provide a table of days that the predicted impacts exceed the 0.5 and/or the 1.0 deciview thresholds. Relevant information such as the meteorological data, the predicted ambient concentration, and the deciview value for each day should be listed.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Lakeland McIntosh

Plant Data

			Capacity	
Site	FWS Area(s)	Source	(mmBtu/hr)	(MW)
Lakeland, FL	Chassahowitzka	1 CT	2174	250
	St. Marks		each	each

Lakeland McIntosh

Given/Assumptions

Source	1 CT
Exhaust gas flow (lb/Hr)	4,518,595
Exhaust gas flow (acfm)	3,055,750
Basic Equipment Costs	3,740,000
Ammonia storage cost ($/1,000 lb mass flow)	$35
Uncontrolled Emission rate (TPY)	852
Control efficiency (%)	70%
Operating Hours per Year	7,008
Operating Hours per Shift	8
Operating Shifts per Year	876
Operating Labor Cost ($/hr)	15
Maintenance Labor Cost ($/hr)	15
Electrical Cost ($/kWh)	$0.05
Reagent use (lb/hr @ 28% sol.)	286
Reagent Costs ($/T)	$300
Electrical efficiency	90%
Catalyst replacement	$2,800,000
Catalyst disposal ($/Yr)	$42,174
Catalyst life (Yr)	3
Heat rate penalty (% of MW output)	0.5%
Equipment Life (Yr)	15
Interest Rate (%)	7.00%

Lakeland McIntosh

Capital Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item	Factor	Cost
Direct Costs		1 CT
Purchased equipment costs		
SCR + auxiliary equipment		$3,740,000
Ammonia storage		~~$158,151~~
Total	A	$3,898,151
Sales taxes	0.00 A	$0
Freight	0.05 A	$194,907.54
Purchased equipment cost, PEC	B= 1.05 A	$4,093,058
Direct installation costs		
Foundations & supports	0.08 B	$327,445
Handling & erection	0.14 B	$573,028
Electrical	0.04 B	$163,722
Piping	0.02 B	$81,861
Insulation	0.01 B	$40,931
Painting	0.01 B	$40,931
Direct installation costs	0.30 B	$1,227,918
Site preparation	As required, SP	$0
Buildings	As required, Bldg.	$0
Total Direct Costs, DC	1.30 B+SP+Bldg	$5,320,976
Indirect Costs (installation)		
Engineering	0.10 B	$409,306
PSM/RMP Plan		$25,000
Construction and field expenses	0.05 B	$204,653
Contractor fees	0.10 B	$409,306
Start-up	0.02 B	$81,861
Performance test	0.01 B	$40,931
Contingencies	0.03 B	$122,792
Total Indirect Cost, IC	0.31 B	$1,293,848
Total Capital Investment = DC + IC	1.61 B+SP+Bldg	$6,614,824

Requires recalculation based on revised Engelhard proposal. Advised NPS.
[illegible]

Lakeland McIntosh

Annual Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item	Factor	Cost
Direct Annual Costs, DC		1 CT
Operating labor		
Operator	0.5 hr/shift	$6,570
Supervisor	15% of operator	$986
PSM/RMP Update		$5,000
Operating materials		
Reagent	286 lb/hr * 7008 hr/yr/2000lb/T* 300 $/T =	$301,106
Maintenance		
Labor	0.5 hr/shift	$6,570
Material	100% of maintenance labor	$6,570
Catalyst replacement		$933,333
Electricity	286 lb/hr * 518.1 Btu/lb* 0.000293 kW*hr/Btu* 0.05 $/kWh* 7008 hr/yr* 0.90 ef. =	$13,713
Total DC		$1,260,135
Energy Costs		
Heat rate penalty	250 MW * 7,008 hr/yr * 1000 KW/MW * 0.005 loss * 0.05 $/kWh =	$438,000
Indirect Annual Costs, IC		
Overhead	60% of maintenance costs	$193,081
Administrative charges	2% of Total Capital Investment	$132,296
Property tax	1% of Total Capital Investment	$0
Insurance	1% of Total Capital Investment	$66,148
Capital recovery	0.1098 * [Total Capital Investment-1.08(Cat Cost)]	$615,599
Total IC		$1,007,125
Total Annual Cost	DC + IC	$2,267,259

Requires recalculation. Advised NPS. aafin

*

Note - Not included in costs. Advised NPS + they will send update. aafin

Lakeland McIntosh

Cost Effectiveness

Source	1 CT	Units
Pollutant	NOx	
Uncontrolled emissions	852.0	TPY
Control efficiency	70%	
Controlled emissions	255.6	TPY
Pollutants removed	596.4	TPY
Annual cost	$2,267,259	/yr
Annual cost - Emission fees saved	$2,249,367	@ $30/T
Cost/ton	$3,802	/T

Requires recalculation
They will send update.
A. Linero

Lakeland McIntosh

Environmental Impacts of SCR at 70% removal

NOx removed	596	TPY
Ammonia released	104	TPY @ 10 ppmv

10 ppmvd NOx* E-06 * (20.9/(20.9- 15 % O2)) * 17 MW NH3 * 8740 dscf/mmBtu (fuel input) F-factor(gas)/ 385 scf/lb-mole (vol/mol ratio) = 0.014 lbm/mmBtu

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Formosa Plastics	Mar-97	9.0			
SW PSCo	Nov-96	15.0			
Blue Mtn. Pwr.	Jul-96			4.0	
Mid-Ga. Cogen	Apr-96			9.0	20.0
Seminole Hardee Unit 3	Jan-96	15.0			
Brooklyn Navy Yard Cogen	Jun-95			3.5	10.0
Panda-Kathleen	Jun-95	15.0			
Pilgrim Energy Center	Apr-95			4.5	
Gainesville Regional Utilities	Apr-95	15.0			
Formosa Plastics	Mar-95	9.0			
Lap-Cottage Grove	Mar-95			4.5	
Portland General Elec.	May-94			4.5	
Hermiston Generating	Apr-94			4.5	
Florida Power	Feb-94	12.0			
Orange Cogen	Dec-93	15.0			
Newark Bay Cogen	Jun-93			8.3	16.0
Tiger Bay	May-93	15.0			
Phoenix Power Part.	May-93	22.0			
Kissimmee Utility Authority	Apr-93	15.0			
Kissimmee Utility Authority	Apr-93	15.0			
Auburndale Power Part.	Dec-92	15.0			
Sithe/Independence	Nov-92			4.5	
Kamine/Besicorp	Nov-92	9.0		9.0	
Kamine/Besicorp	Nov-92	9.0		9.0	
Grays Ferry	Nov-92	9.0			
Goal Line	Nov-92			5.0	
Bear Island Paper	Oct-92			9.0	15.0

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Gordonsville Energy	Sep-92			9.0	
Pansy/Holtsville	Sep-92	9.0			
Saranac Energy	Jul-92			9.0	
Selkirk Cogen	Jun-92			9.0	
Narragansett Elec.	Apr-92			9.0	
Bermuda Hundred	Mar-92			9.0	15.0
Kalamazoo Power	Dec-91	15.0			
So. Cal. Gas	Oct-91			8.0	
Sumas Energy	Jun-91			8.0	
Granite Rd. Ltd.	May-91			3.5	
Lakewood Cogen	Apr-91			9.0	
Cimaron Chemical	Mar-91			9.0	
Seminole Fertilizer	Mar-91			9.0	
Sumas Energy	Dec-90			9.0	
Newark Bay Cogen	Nov-90			8.3	
Las Vegas Cogen	Oct-90			10.0	
Doswell Ltd.	May-90			9.0	
Pedricktown Cogen	Feb-90			9.0	
Arrowhead Cogen	Dec-89			9.0	
Richmond Power Enterprise	Dec-89			8.2	
Kingsburg Energy Sys.	Sep-89			6.0	
Unocal	Jul-89			9.0	
Pawtucket Power	Jan-89			9.0	
Ocean State Power	Dec-88			9.0	
Baf Energy	Jul-87			9.0	
Cogen Technologies	Jun-87			9.6	
Western Power Sys.	Mar-86			9.0	
Union Oil	Mar-86			2.5	
Ols Energy	Jan-86			9.0	
American Cogen Tech.	Sep-85			17.0	
Sunlaw	Jun-85			9.0	
Willamette Ind.	Apr-85			15.0	

Permits Pending or Not Yet in RBLC

Facility Name/Location	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Androscoggin Energy				6.0	42.0
Casco Bay Energy				5.0	
Cogen Tech. Linden Venture				3.5	
Rotterdam, N.Y.				4.5	
Dighton, MA				3.5	
Tiverton, RI				3.5	
ARCO Watson Project				5.0	
Bridgeport Energy Project				6.0	

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

April 3, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

Attached are the comments we received by fax from the Air Quality Branch of the Fish and Wildlife Service in response to your March 5, 1998 information addressing our letters dated January 5 and 12, 1998. We will send you a copy of the signed version from the Fish and Wildlife Service when we receive it. Please respond to their comments about the BACT analysis and redo the visibility analysis as requested in their fax.

The Department will continue processing your permit application; however, the application will remain incomplete until the requested information is received and reviewed. If you have any questions regarding this matter, please contact Teresa Heron or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A. A. Linero 4/3

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/ch/t

Enclosure

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

U.S.FISH&WILDLIFE SERVICE
AIR QUALITY BRANCH
P.O. BOX 25287, Denver, CO 80225-0287

FACSIMILE COVER SHEET

Date: April 2, 1998

Telephone: (303) 969-2617
Fax: (303) 969-2822

To: Cleve Holladay

From: Ellen Porter

Subject: Technical Review Document of Lakeland McIntosh Additional Information

Number of Pages: 9
(Including this cover sheet)

Office Location: 7333 West Jefferson Ave, Suite 450, Lakewood, CO 80235

Memorandum

Florida Department of
Environmental Protection

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MR. RONALD TOMLIN
LAKELAND ELECTRIC +
WATER
501. E. LEMON ST
LAKELAND, FL 33801-5079

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PS Form **3811**, December 1994

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PS Form **3800**, April 1995

Technical Review of Additional Information For a 250-Megawatt Simple Cycle Combustion Turbine at McIntosh Power Plant Polk County, Florida PSD-FL-245

by

Air Quality Branch, Fish and Wildlife Service – Denver
April 2, 1998

This review is in response to additional information forwarded to us by the Florida Department of Environmental Protection regarding the City of Lakeland (Lakeland)'s proposal to construct a 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. In a January 9, 1998 letter and technical review document we recommended that Lakeland be required to meet lower limits than those proposed for nitrogen oxides emissions. In addition, we noted that Lakeland's predicted impact on visibility (i.e., regional haze) at Chassahowitzka was significantly higher than the 0.5 deciview value for a single source recommended by the U.S. Fish and Wildlife Service, and therefore unacceptable. We asked that Lakeland propose lower NO_X emissions rates and perform a new regional haze analysis (including PM-10 emissions) to demonstrate that the project's impacts would be less than 0.5 deciview.

Lakeland subsequently proposed lower NO_X limits. In addition, they submitted a new visibility analysis. Our comments on their revised analyses are below.

Best Available Control Technology (BACT) Analysis

Background

As noted above, the City of Lakeland, Florida, proposes to add a 250-megawatt (MW) simple cycle gas and oil fired turbine facility to its existing McIntosh Power Plant. (Note: A simple cycle turbine system provides for only one pass of the combustion gases through a generator and then out of the exhaust stack. A combined cycle turbine (CCT) system is much more efficient and uses the gases passing through the generator with supplementary firing to raise steam temperature and pressure for a steam turbine.) Lakeland's application triggers regulations for the Prevention of Significant Deterioration (PSD) of air quality for particulate matter (PM @ 41 tons per year—TPY), nitrogen oxides (NO_x @ 863 TPY), volatile organic compounds (VOC @ 94 TPY), and carbon monoxide (CO @ 1264 TPY). Any pollutant subject to PSD must be controlled through the use of Best Available Control Technology (BACT). Only NO_x emissions are of concern from a control technology standpoint for this type of application because NO_x emissions are highly dependent upon the combustor type and any add-on controls. Emissions of other pollutants depend primarily on good combustion techniques.

NO_x Controls

Dry Low-NO_x Combustors: Lakeland originally proposed dry low-NO_x (DLN) combustors to meet NO_x limits of 25 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen while burning natural gas, and 42 ppmvd using water injection while burning fuel oil. Lakeland is now proposing to meet a 9-ppm NO_x limit (gas firing) within five years of startup. However, DLN technology is now capable of achieving emission limits well below that proposed by the applicant. A review of the EPA RACT/BACT/LAER clearinghouse data submitted by the applicant found at least 18 examples of gas turbines permitted to start up with NO_x limits in the 9 – 15 ppmvd range, using DLN combustors. This clearly demonstrates that this technology is now capable of much lower emissions than proposed by the applicant. To allow this "advanced" system five years to meet current emission limits would represent significant backsliding.

Selective Catalytic Reduction: Although Selective Catalytic Reduction (SCR) is capable of 70% NO_x removal efficiency, it was rejected by Lakeland on the grounds of economic infeasibility. However, our (enclosed) review of application of SCR to this project resulted in much lower costs; at less than $4,000 per ton of NO_x removed, we believe that SCR is economically feasible. The high costs calculated by Lakeland are due to calculation errors on the part of the applicant. The following comments assume that the applicant used the cost estimation techniques illustrated in Tables 3-8 and 3-10 of the EPA Control Cost Manual:

- Experience has shown that other vendors may provide lower SCR quotes.
- If the Engelhard estimate covered both NO_x and CO, either the NO_x portion of the cost should be split out or a combined cost effectiveness calculated.
- In the DLN-SCR scenario, is the smaller catalyst and ammonia usage resulting from DLN considered?
- Because Instrumentation is included in the Engelhard proposal, the addition of $94,000 for this expense appears to be double-counting.
- There is no justification for $20,000 for Site Preparation and Building expenses.
- The Capital Recovery Factors are too high. Although Lakeland cites the OAQPS Control Cost Manual and city practices as justification for using 10% interest, the current version of the Manual recommends 7%.
- Despite Lakeland's argument that addition of SCR to a simple cycle combustion turbine is a unique application, there is now so much experience with SCR on power generation turbines that the high Indirect Contingency cost and addition of Contingency costs to Direct Annual Costs and Energy Costs is no longer justified.
- Labor costs are still overestimated.
- Ammonia costs and catalyst replacement costs are underestimated, although the latter may be partially addressed by the inclusion of an "Inventory Cost" and a "Catalyst Disposal Cost." Lakeland should check to determine if the catalyst vendor offers free catalyst disposal as part of its replacement service. If additional catalyst is used, either the removal efficiency or catalyst life should be adjusted upward. Lakeland appears to be assuming that all of the catalyst will be replaced every year.
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- The "Fuel Escalation" cost is not justified.

- The use of three and five years to determine the capital recovery factor cannot be allowed absent a firm commitment from Lakeland to go to a Combined Cycle Turbine (CCT) system by installing Heat Recovery Steam Generation (HRSG) in that time. If Lakeland is not committing to install CCT after five years, then it must be assumed that any controls installed now would be used for much longer than five years.
- Lakeland states that the $13,000/MW cost is similar to the Commonwealth Chesapeake Corp's costs at $21,000/MW, which did not add controls. Because the cost/MW for Lakeland is less than 70% of the cost for Commonwealth Chesapeake, the two projects are not comparable.

If Lakeland goes from a simple cycle turbine to CCT, it plans to install advanced DLN @ 9-12 ppm and add SCR only if necessary to meet those limits. A review of the RACT/BACT/LAER clearinghouse reveals that permitted NO_x limits for gas CCTs start as low as 3.5 ppm (LAER) and include several BACT determinations in the 5-9 ppm range. (See table.) We have also included a list of CCT projects for which NO_x limits are either pending or not yet entered into the RBLC; it should be noted that all of the limits in the latter set fall into the 3.5-6.0 ppm range. Since it is clear that other similar installations have accepted the combination of DLN combustors and SCR, the applicant should justify why its environmental impacts and costs are uniquely excessive when compared to the others.

Lakeland argues that continued use of a hot catalyst is not good engineering practice, but gives no reasons. Lakeland also argues that Once Through Steam Generation (OTSG) would have to be removed if HRSG were added for efficiency purposes. Even though OTSG would no longer be necessary if HRSG were added, it would not necessarily have to be removed; in fact, Engelhard assumed in its estimate that OTSG would be retained upstream of the SCR. Lakeland's concern for efficiency would be better answered by going to CCT technology immediately.

Conclusions and Recommendations

BACT should be based on the capabilities of gas-fired turbines to meet 5 ppm NO_X or less; use of a less efficient system is not justification for higher emissions. The proposed use of a simple cycle gas turbine to generate electricity represents a less efficient, but lower cost alternative to modern combined cycle systems. By choosing the simple cycle approach, Lakeland has also made it more expensive and difficult to employ the more effective SCR NO_x control system that could be applied to a combined cycle system. Rather than reward an applicant for choosing an electricity generating system that is inherently more difficult to control, emission limits should reflect the end product, not the generation method. (This is essentially the approach proposed by EPA in its New Source Performance Standards for boiler NO_x emissions. Even though the proposed turbine would emit at 0.95 lb/net MW, which is better than the proposed NSPS, addition of SCR would improve these results significantly at a reasonable cost.) It is therefore recommended that NO_x emissions be limited to 5.0 ppmvd during gas firing, and 20 ppmvd for oil firing, which reflects the use of SCR and would result in a NO_x emission reduction of about 680 TPY. (The next alternative would be to limit NO_x emissions to 9.0 ppmvd which reflects the optimal use of the dry low-NO_x combustors proposed and would result in a NO_x emission reduction of about 545 TPY.)

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Because the proposed source is 91 km from Chassahowitzka, the predicted nitrate concentration value from MESOPUFF II (the long-range transport model) should have been used in the visibility analysis. It is not clear why the applicant did not use the nitrate concentration value predicted by MESOPUFF II in the visibility analysis. The applicant did not report this value. The ISCST model used by the applicant was inappropriate, as it is intended for distances less than 50 km.

The applicant should redo the visibility analysis using the MESOPUFF II nitrate concentration value. If the predicted impact is less than or equal to 0.5 deciview, the impact is considered insignificant and no further analysis is needed. If the predicted impact is greater than 0.5 deciview, the applicant should conduct a cumulative modeling analysis including the new source's proposed emissions and all other increment-consuming emissions. If the cumulative analysis predicts an impact less than or equal to 1.0 deciview, the impact is considered insignificant and no further analysis is needed. If the cumulative impact is greater than 1.0 deciview, a significant increase in haze is possible and FWS will make a case-by-case adverse impact determination regarding the proposed project, considering the predicted frequency, magnitude, and duration of impacts.

The applicant should provide a table of days that the predicted impacts exceed the 0.5 and/or the 1.0 deciview thresholds. Relevant information such as the meteorological data, the predicted ambient concentration, and the deciview value for each day should be listed.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Lakeland McIntosh

Given/Assumptions

Source	1 CT
Exhaust gas flow (lb/Hr)	4,518,595
Exhaust gas flow (acfm)	3,055,760
Basic Equipment Costs	3,740,000
Ammonia storage cost ($/1,000 lb mass flow)	$35
Uncontrolled Emission rate (TPY)	852
Control efficiency (%)	70%
Operating Hours per Year	7,008
Operating Hours per Shift	8
Operating Shifts per Year	876
Operating Labor Cost ($/hr)	15
Maintenance Labor Cost ($/hr)	15
Electrical Cost ($/kWh)	$0.05
Reagent use (lb/hr @ 28% sol.)	286
Reagent Costs ($/T)	$300
Electrical efficiency	90%
Catalyst replacement	$2,800,000
Catalyst disposal ($/Yr)	$42,174
Catalyst life (Yr)	3
Heat rate penalty (% of MW output)	0.5%
Equipment Life (Yr)	15
Interest Rate (%)	7.00%

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Formosa Plastics	Mar-97	9.0			
SW PSCo	Nov-96	15.0			
Blue Mtn. Pwr.	Jul-96			4.0	
Mid-Ga. Cogen	Apr-96			9.0	20.0
Seminole Hardee Unit 3	Jan-96	15.0			
Brooklyn Navy Yard Cogen	Jun-95			3.5	10.0
Panda-Kathleen	Jun-95	15.0			
Pilgrim Energy Center	Apr-95			4.5	
Gainesville Regional Utilities	Apr-95	15.0			
Formosa Plastics	Mar-95	9.0			
Lap-Cottage Grove	Mar-95			4.5	
Portland General Elec.	May-94			4.5	
Hermiston Generating	Apr-94			4.5	
Florida Power	Feb-94	12.0			
Orange Cogen	Dec-93	15.0			
Newark Bay Cogen	Jun-93			8.3	16.0
Tiger Bay	May-93	15.0			
Phoenix Power Part.	May-93	22.0			
Kissimmee Utility Authority	Apr-93	15.0			
Kissimmee Utility Authority	Apr-93	15.0			
Auburndale Power Part.	Dec-92	15.0			
Sithe/Independence	Nov-92			4.5	
Kamine/Besicorp	Nov-92	9.0		9.0	
Kamine/Besicorp	Nov-92	9.0		9.0	
Grays Ferry	Nov-92	9.0			
Goal Line	Nov-92			5.0	
Bear Island Paper	Oct-92			9.0	15.0

Gas Turbine Limits from RBLC

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		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Gordonsville Energy	Sep-92			9.0	
Pansy/Holtsville	Sep-92	9.0			
Saranac Energy	Jul-92			9.0	
Selkirk Cogen	Jun-92			9.0	
Narragansett Elec.	Apr-92			9.0	
Bermuda Hundred	Mar-92			9.0	15.0
Kalamazoo Power	Dec-91	15.0			
So. Cal. Gas	Oct-91			8.0	
Sumas Energy	Jun-91			8.0	
Granite Rd. Ltd.	May-91			3.5	
Lakewood Cogen	Apr-91			9.0	
Cimaron Chemical	Mar-91			9.0	
Seminole Fertilizer	Mar-91			9.0	
Sumas Energy	Dec-90			9.0	
Newark Bay Cogen	Nov-90			8.3	
Las Vegas Cogen	Oct-90			10.0	
Doswell Ltd.	May-90			9.0	
Pedricktown Cogen	Feb-90			9.0	
Arrowhead Cogen	Dec-89			9.0	
Richmond Power Enterprise	Dec-89			8.2	
Kingsburg Energy Sys.	Sep-89			6.0	
Unocal	Jul-89			9.0	
Pawtucket Power	Jan-89			9.0	
Ocean State Power	Dec-88			9.0	
Baf Energy	Jul-87			9.0	
Cogen Technologies	Jun-87			9.6	
Western Power Sys.	Mar-86			9.0	
Union Oil	Mar-86			2.5	
Ols Energy	Jan-86			9.0	
American Cogen Tech.	Sep-85			17.0	
Sunlaw	Jun-85			9.0	
Willamette Ind.	Apr-85			15.0	

Permits Pending or Not Yet In RBLC

Facility Name/Location	Permit Issue Date	NOx Emission Limits < 25 ppm: Dry Lox-NOx Comb. Gas (ppm)	Dry Lox-NOx Comb. Oil (ppm)	SCR Gas (ppm)	SCR Oil (ppm)
Androscoggin Energy				6.0	42.0
Casco Bay Energy				5.0	
Cogen Tech. Linden Venture				3.5	
Rotterdam, N.Y.				4.5	
Dighton, MA				3.5	
Tiverton, RI				3.5	
ARCO Watson Project				5.0	
Bridgeport Energy Project				6.0	

U.S.FISH&WILDLIFE SERVICE
AIR QUALITY BRANCH

P.O. BOX 25287, Denver, CO 80225-0287

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To: Cleve Holladay

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Subject: Technical Review Document of Lakeland McIntosh Additional Information

Number of Pages: 9
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Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Lakeland McIntosh

Plant Data

			Capacity	
Site	FWS Area(s)	Source	(mmBtu/hr)	(MW)
Lakeland, FL	Chassahowitzka	1 CT	2174	250
	St. Marks		each	each

Lakeland McIntosh

Given/Assumptions

Source	1 CT
Exhaust gas flow (lb/Hr)	4,518,595
Exhaust gas flow (acfm)	3,055,750
Basic Equipment Costs	3,740,000
Ammonia storage cost ($/1,000 lb mass flow)	$35
Uncontrolled Emission rate (TPY)	852
Control efficiency (%)	70%
Operating Hours per Year	7,008
Operating Hours per Shift	8
Operating Shifts per Year	876
Operating Labor Cost ($/hr)	15
Maintenance Labor Cost ($/hr)	15
Electrical Cost ($/kWh)	$0.05
Reagent use (lb/hr @ 28% sol.)	286
Reagent Costs ($/T)	$300
Electrical efficiency	90%
Catalyst replacement	$2,800,000
Catalyst disposal ($/Yr)	$42,174
Catalyst life (Yr)	3
Heat rate penalty (% of MW output)	0.5%
Equipment Life (Yr)	15
Interest Rate (%)	7.00%

Lakeland McIntosh

Capital Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item		Factor	Cost 1 CT
Direct Costs			
Purchased equipment costs			
SCR + auxiliary equipment			$3,740,000
Ammonia storage			$158,151
Total		A	$3,898,151
Sales taxes		0.00 A	$0
Freight		0.05 A	$194,907.64
Purchased equipment cost, PEC	B=	1.05 A	$4,093,058
Direct installation costs			
Foundations & supports		0.08 B	$327,445
Handling & erection		0.14 B	$573,028
Electrical		0.04 B	$163,722
Piping		0.02 B	$81,861
Insulation		0.01 B	$40,931
Painting		0.01 B	$40,931
Direct installation costs		0.30 B	$1,227,918
Site preparation	As required, SP		$0
Buildings	As required, Bldg.		$0
Total Direct Costs, DC		1.30 B+SP+Bldg	$5,320,976
Indirect Costs (installation)			
Engineering		0.10 B	$409,306
PSM/RMP Plan			$25,000
Construction and field expenses		0.05 B	$204,653
Contractor fees		0.10 B	$409,306
Start-up		0.02 B	$81,861
Performance test		0.01 B	$40,931
Contingencies		0.03 B	$122,792
Total Indirect Cost, IC		0.31 B	$1,293,848
Total Capital Investment = DC + IC		1.61 B+SP+Bldg	$6,614,824

Lakeland McIntosh

Annual Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item	Factor			Cost 1 CT
Direct Annual Costs, DC				
Operating labor				
Operator	0.5 hr/shift			$6,570
Supervisor	15% of operator			$986
PSM/RMP Update				$5,000
Operating materials				
Reagent	286 lb/hr *	7008 hr/yr/2000lb/T*	300 $/T =	$301,106
Maintenance				
Labor	0.5 hr/shift			$6,570
Material	100% of maintenance labor			$6,570
Catalyst replacement				$933,333
Electricity	286 lb/hr *	518.1 Btu/lb*	0.000293 kW*hr/Btu*	
	0.05 $/kWh*	7008 hr/yr*	0.90 ef. =	$13,713
Total DC				$1,260,135
Energy Costs				
Heat rate penalty	250 MW *	7,008 hr/yr *		
	1000 kW/MW *	0.005 loss *	0.05 $/kWh =	$438,000
Indirect Annual Costs, IC				
Overhead	60% of maintenance costs			$193,081
Administrative charges	2% of Total Capital Investment			$132,296
Property tax	1% of Total Capital Investment			$0
Insurance	1% of Total Capital Investment			$66,148
Capital recovery	0.1098 * [Total Capital Investment-1.08(Cat Cost)]			$615,599
Total IC				$1,007,125
Total Annual Cost	DC + IC			$2,267,259

Lakeland McIntosh

Cost Effectiveness

Source	1 CT	Units
Pollutant	NOx	
Uncontrolled emissions	852.0	TPY
Control efficiency	70%	
Controlled emissions	255.6	TPY
Pollutants removed	596.4	TPY
Annual cost	$2,267,259	/yr
Annual cost - Emission fees saved	$2,249,367	@ $30/T
Cost/ton	$3,802	/T

Lakeland McIntosh

Environmental Impacts of SCR at 70% removal

NOx removed	596 TPY
Ammonia released	104 TPY @ 10 ppmv

10 ppmvd NOx* E-06 * (20.9/(20.9- 15 % O2)) * 17 MW NH3 * 8740 dscf/mmBtu (fuel input) F-factor(gas)/ 385 scf/lb-mole (vol/mol ratio) = 0.014 lbm/mmBtu

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Formosa Plastics	Mar-97	9.0			
SW PSCo	Nov-96	15.0			
Blue Mtn. Pwr.	Jul-96			4.0	
Mid-Ga. Cogen	Apr-96			9.0	20.0
Seminole Hardee Unit 3	Jan-96	15.0			
Brooklyn Navy Yard Cogen	Jun-95			3.5	10.0
Panda-Kathleen	Jun-95	15.0			
Pilgrim Energy Center	Apr-95			4.5	
Gainesville Regional Utilities	Apr-95	15.0			
Formosa Plastics	Mar-95	9.0			
Lap-Cottage Grove	Mar-95			4.5	
Portland General Elec.	May-94			4.5	
Hermiston Generating	Apr-94			4.5	
Florida Power	Feb-94	12.0			
Orange Cogen	Dec-93	15.0			
Newark Bay Cogen	Jun-93			8.3	16.0
Tiger Bay	May-93	15.0			
Phoenix Power Part.	May-93	22.0			
Kissimmee Utility Authority	Apr-93	15.0			
Kissimmee Utility Authority	Apr-93	15.0			
Auburndale Power Part.	Dec-92	15.0			
Sithe/Independence	Nov-92			4.5	
Kamine/Besicorp	Nov-92	9.0		9.0	
Kamine/Besicorp	Nov-92	9.0		9.0	
Grays Ferry	Nov-92	9.0			
Goal Line	Nov-92			5.0	
Bear Island Paper	Oct-92			9.0	15.0

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Gordonsville Energy	Sep-92			9.0	
Pansy/Holtsville	Sep-92	9.0			
Saranac Energy	Jul-92			9.0	
Selkirk Cogen	Jun-92			9.0	
Narragansett Elec.	Apr-92			9.0	
Bermuda Hundred	Mar-92			9.0	15.0
Kalamazoo Power	Dec-91	15.0			
So. Cal. Gas	Oct-91			8.0	
Sumas Energy	Jun-91			8.0	
Granite Rd. Ltd.	May-91			3.5	
Lakewood Cogen	Apr-91			9.0	
Cimaron Chemical	Mar-91			9.0	
Seminole Fertilizer	Mar-91			9.0	
Sumas Energy	Dec-90			9.0	
Newark Bay Cogen	Nov-90			8.3	
Las Vegas Cogen	Oct-90			10.0	
Doswell Ltd.	May-90			9.0	
Pedricktown Cogen	Feb-90			9.0	
Arrowhead Cogen	Dec-89			9.0	
Richmond Power Enterprise	Dec-89			8.2	
Kingsburg Energy Sys.	Sep-89			6.0	
Unocal	Jul-89			9.0	
Pawtucket Power	Jan-89			9.0	
Ocean State Power	Dec-88			9.0	
Baf Energy	Jul-87			9.0	
Cogen Technologies	Jun-87			9.6	
Western Power Sys.	Mar-86			9.0	
Union Oil	Mar-86			2.5	
Ols Energy	Jan-86			9.0	
American Cogen Tech.	Sep-85			17.0	
Sunlaw	Jun-85			9.0	
Willamette Ind.	Apr-85			15.0	

Permits Pending or Not Yet in RBLC

Facility Name/Location	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Androscoggin Energy				6.0	42.0
Casco Bay Energy				5.0	
Cogen Tech. Linden Venture				3.5	
Rotterdam, N.Y.				4.5	
Dighton, MA				3.5	
Tiverton, RI				3.5	
ARCO Watson Project				5.0	
Bridgeport Energy Project				6.0	

U.S.FISH&WILDLIFE SERVICE
AIR QUALITY BRANCH
P.O. BOX 25287, Denver, CO 80225-0287

FACSIMILE COVER SHEET

Date: April 2, 1998

Telephone: (303) 969-2617
Fax: (303) 969-2822

To: Ken Kosky / Cleve Holladay

From: Ellen Porter

Subject: Lakeland Visibility Analysis. These comments will be sent to FDEP.

Lakeland ran the MESOPUFF II model using Interagency Workgroup on Air Quality Modeling (IWAQM) protocol to predict the effect of their emissions on nitrate concentrations at Chassahowitzka. They also ran MESOPUFF II with the chemical transformation module turned off to predict a nitrogen oxide concentration at Chassahowitzka. By comparing the two concentrations, they estimated a chemical transformation rate of approximately 31% for a 24-hour period. They then multiplied the ISCST-derived nitrogen oxide concentration predicted at Chassahowitzka to estimate the nitrate concentration that was used in the visibility analysis.

It is not clear why the applicant did not use the nitrate concentration value predicted by MESOPUFF II model in the visibility analysis. The applicant did not report the predicted MESOPUFF II nitrate value.

Because the proposed source is 91 km from Chassahowitzka, the predicted nitrate concentration value from the long-range transport model (MESOPUFF II) should have been used in the visibility analysis. The ISCST model used by the applicant is intended for distances less than 50 km.

The applicant should redo the visibility analysis using the predicted MESOPUFF II nitrate concentration value. If the predicted impact is less than or equal to 0.5 deciview, the impact is considered insignificant and no further analysis is needed. If the predicted impact is greater than 0.5 deciview, the applicant should conduct a cumulative modeling analysis including the new source's proposed emissions and all other increment-consuming emissions. If the cumulative analysis predicts an impact less than or equal to 1.0 deciview, the impact is considered insignificant and no further analysis is needed. If the cumulative impact is greater than 1.0 deciview, a significant increase in haze is possible and FWS will make a case-by-case adverse impact determination regarding the proposed project, considering the predicted frequency, magnitude, and duration of impacts.

The applicant should provide a table of days that the predicted impacts exceed the 0.5 and/or the 1.0 deciview thresholds. Relevant information such as the meteorological data, the predicted ambient concentration, and the deciview value for each day should be listed.

If you have questions, please call Bud Rolofson at (303) 969-2804.

Number of Pages:2

Office Location: 7333 West Jefferson Ave, Suite 450, Lakewood, CO 80235

U.S.FISH&WILDLIFE SERVICE
AIR QUALITY BRANCH

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If you have questions, please call Bud Rolofson at (303) 969-2804.

Number of Pages:2

Office Location: 7333 West Jefferson Ave, Suite 450, Lakewood, CO 80235

LAKELAND
ELECTRIC & WATER
Excellence Is Our Goal, Service Is Our Job

Farzie Shelton, chE; REM

Manager of Environmental Licensing & Permitting

March 31, 1998

RECEIVED
APR 01 1998
BUREAU OF
AIR REGULATION

Mr. A.A. Linero P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
111 S. Magnolia, Suite 4
Tallahassee, Fl 32301

RE: DEP FileNo. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Al:

On behalf of Lakeland Electric and Water Utilities (Lakeland), I would like to thank you and the staff of the Bureau of Air Regulation who met with us on February 11, 1998 to further discuss and facilitate Unit No. 5 PSD permitting issues. At this meeting it was further emphasized that Lakeland has a unique opportunity to provide savings to its customers while furthering the development of "clean" and "efficient" combustion turbine technology for Florida's future. Towards this goal, Lakeland has proposed a staged emission limit strategy. The proposed strategy would commit Lakeland to lowering NO_X emissions rates when firing natural gas from the proposed 25 ppmvd (corrected to 15 percent oxygen) to 9 ppmvd (corrected to 15 percent oxygen) with 12 ppmvd (corrected to 15 percent oxygen) on thirty days rolling average, no later than 5 years after the initial startup of this unit.

Lakeland's commitment for future compliance with the lower NO_X emission would be accomplished by installing Ultra Low NOx (ULN) combustion technology which is being developed by Westinghouse for the Advanced Turbine System (ATS) program sponsored by the US Department of Energy. At this meeting you proposed to approve Lakeland's application for BACT under the "Innovative Control Technology" pursuant to Rule 62-212.400(4) FAC. To that end you requested Lakeland to provide the Department with manufacturer's (Westinghouse) schedule of development and production of ULN technology and description of Dry Low NO_X (DLN) and ULN technology together with information regarding issues associated with using a high temperature "hot" SCR.

Therefore, enclosed you will find these documents provided to us by the Westinghouse entitled "Ultra Low NO_X Combustion Technology", "DLN and ULN Technology Update - Revision", and "Hot SCR".

City of Lakeland o Department of Electric & Water Utilities
501 East Lemon Street o Lakeland, FL 33801-5050 o (813) 499-6300 o Fax 499-6344 o Message System 499-6592

Mr. A.A. Linero P.E.
Administrator
New Source Review Section
Department of Environmental Protection
March 31, 1998
page 2

As always, we appreciate all the cooperation you have extended to us and we look forward to hear from you at your earliest convenience. However, if you should have any questions or need any additional information, please contact me by telephone at (941) 499-6603; by Fax at (941) 603-6335; or by E-Mail at *fshel@city.lakeland.net*.

Sincerely,

Farzie Shelton

cc: Clair Fancy, FDEP
Howard Rhodes, FDEP
Hamilton Oven, FDEP
Kennard Kosky, Golder Associates
Ron Tomlin
Al Dodd

Enc.

cc: File
EPA
SWD
NPS
Polk Co.

Westinghouse Electric Corporation

Power Generation Business Unit

Generations Systems Divisions

The Quadrangle
4400 Alafaya Trail
Orlando Florida 32826-2399

COL W-COL-0020
File: 042.3

March 30, 1998

Mr. Al Dodd
City of Lakeland, Florida
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5069

**Subject: City of Lakeland Project -McIntosh #5 Project
DLN and ULN Technology Update - Revision**

Dear Al:

We are attaching a revision to the paper (Westinghouse Combustion Technology Update: 501G and Westinghouse Family of Combustion Turbines) previously provided in response to the request from Farzie Shelton and Tim Bachand on 3/24/98. This paper describes the technology for the DLN and ULN technologies as it relates to the 501G product line.

Please advise if you require any additional assistance.

Regards,

Andy Mould

Andy Mould
Project Manager, City of Lakeland

attachment

cc:	Farzie Shelton	COL	
	Tim Bachand	COL	
	Roger Greenwood	MC 560	
	Ben Edwards	MC 565	
	Karen Weaver	MC 590	
	Rick Antos	MC 205	(LO)
	Margery Hilburn	MC 205	
	Kevin Davis	MC 564	

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Westinghouse Combustion Technology Update

501G and Westinghouse Family of Combustion Turbines

Abstract

Westinghouse has aggressively incorporated advanced technologies into the Combustion Turbine family of engines. One area of intense development has been in combustion with a focus on reducing emission levels at increasing firing temperatures while maintaining world class operating reliability and availability. Proactive combustion development programs have resulted in multiple options for achieving dramatic reductions in emissions with Dry Low NOx and Ultra Low NOx combustion systems. This paper presents a description of the program organization, advanced technologies, and results of development efforts to date.

Background

Westinghouse and it's alliance partners have been leaders in the industrial combustion turbine development area for decades. Westinghouse's initial low emission combustion development began in the 1970's (Ref. 1). Westinghouse was also a leader in the early development of catalytic combustion with full scale testing occurring in the 1970's and early 1980's (Refs. 2 and 3). Initial Dry Low NOx systems were installed in MW701D in the early 1980's (Ref. 4). These innovations have provided a strong background facilitating the state of the art Ultra Low NOx systems that are now being implemented into in-service and production engines. The evolutionary approach to new technology introductions has promoted continuing product improvements while maintaining excellent reliability and availability.

Combustor Design Process

The Westinghouse design process (Figure 1) has been tailored for rapid, thorough development using state of the art techniques such as computational fluid dynamics (CFD) analysis and rapid prototype manufacturing utilizing SLA processes, intertwined with strategic use of atmospheric and high pressure test facilities. Inherent in this process is an optimization of operating parameters and a complete verification program including operation in an actual engine. The process is focused on maximizing the benefits of advanced analytical approaches such as CFD with the traditional testing approach.

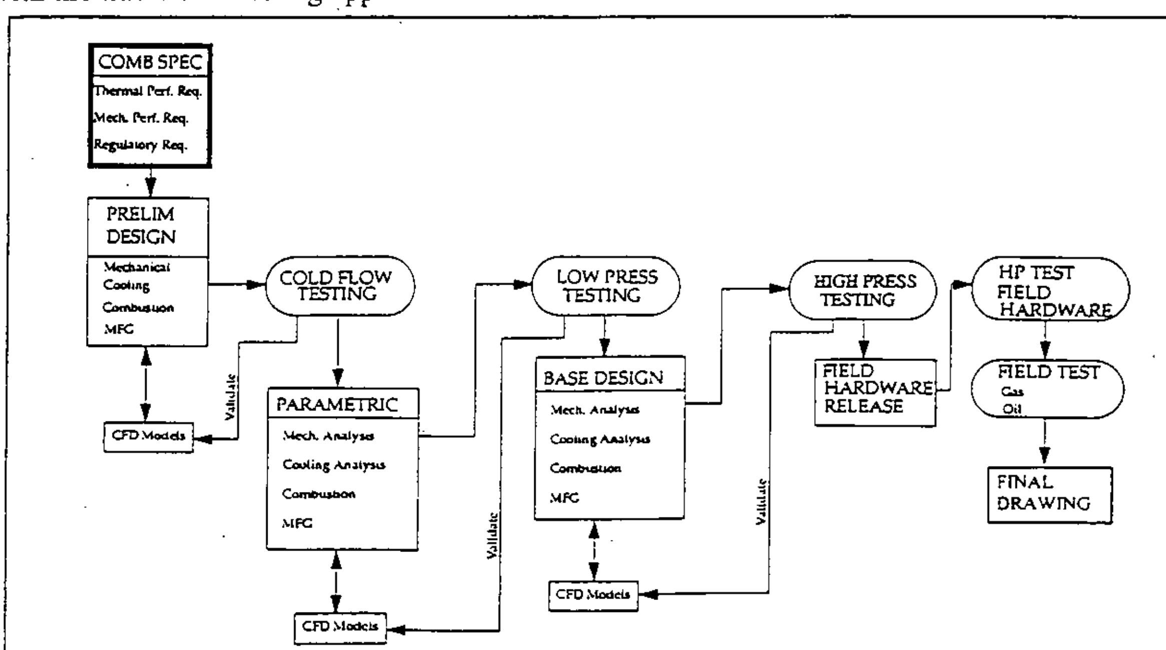

Figure 1 Flowchart Showing Combustor Development Process

CFD Analysis

Computational codes for airfoil flow analysis have been available for many years. However, the added complexity of including combustion reactions along with air and fuel chemistries has traditionally made combustion development a testing-focused technology. More recently though, the development and increased availability of high speed computers and advanced CFD codes have allowed computer modeling to be utilized in the day to day design process of advanced combustion systems. The use of CFD allows for much quicker turnaround in design concept evaluation, less expensive iterations, and most importantly more efficient and productive testing. An example of a CFD model is shown in figure 2. This model is utilized extensively in optimizing the Dry Low NOx design for specific applications.

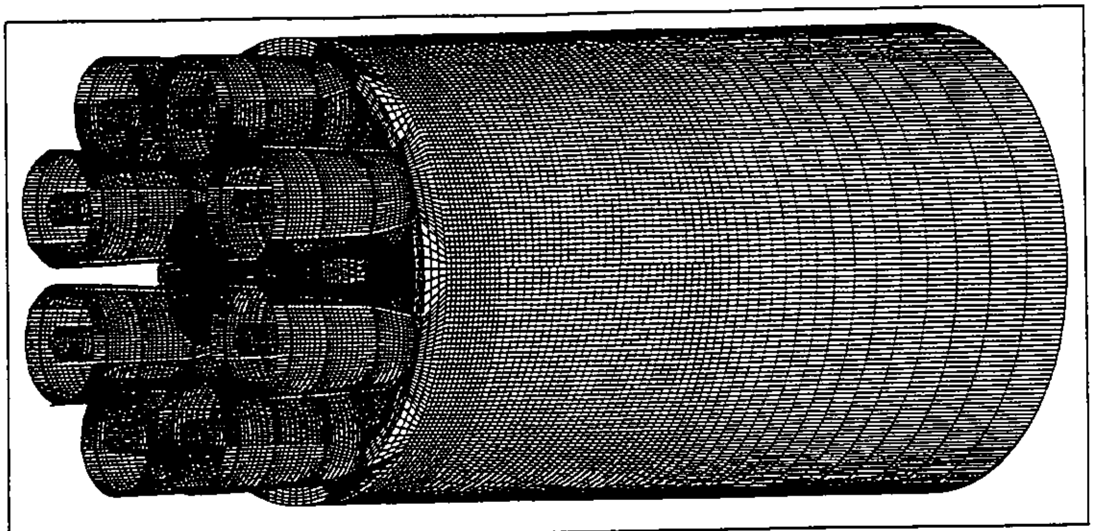

Figure 2. CFD Model

Test Facilities

Westinghouse utilizes a comprehensive array of test facilities to compress the development time and cost of combustion system development. The facilities range from airflow visualization for single combustors and turbine casing annular sectors to full scale, pressure, flow and temperature testing. The majority of these facilities are in the Westinghouse laboratories located near Orlando, Fl. Additionally, Westinghouse also has a full pressure test rig (Figure 3) installed at the Arnold Engineering Development Center in Tullahoma, Tennessee. A photograph of the test rig is shown in Figure 4. This Air Force testing ground provides the high pressure, high flow rates required for engine replication combustor testing (Ref. 5).

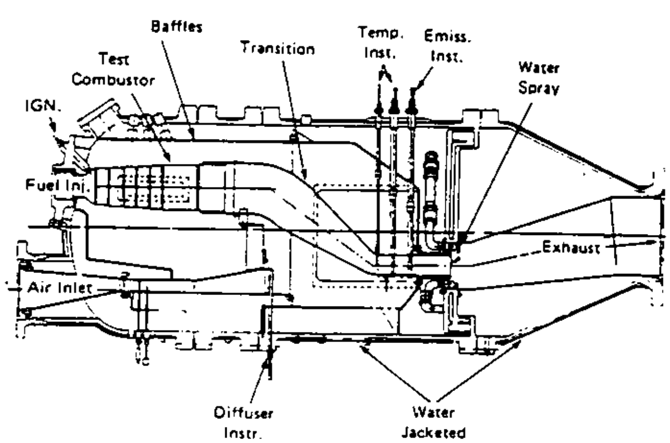

Figure 3. Full Pressure Test Rig

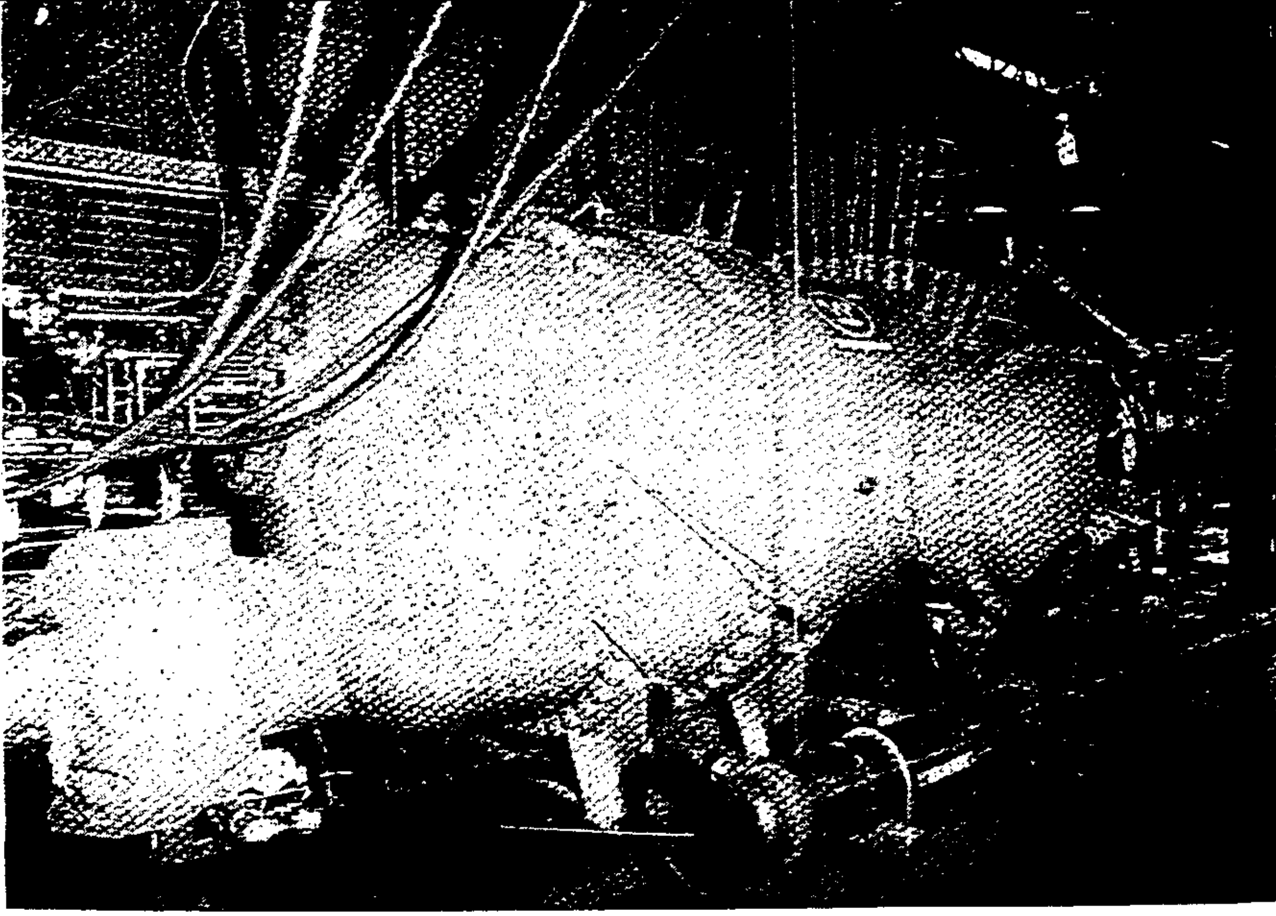

Figure 4 High Pressure Test Rig

Dry Low NOx Design Philosophy

NOx emissions are governed by two primary mechanisms in combustion turbines, the conversion of atmospheric nitrogen at high temperatures (thermal and prompt NOx) and by the conversion of nitrogen in the fuel, called fuel bound nitrogen. Fuel bound nitrogen is typically limited to heavy fuel oils or to coal derived gas fuels. Although this paper will focus on natural gas oriented combustors, Westinghouse is also a leader in developing combustors for fuel bound nitrogen laden gases. The Multi-Annular Swirl Burner combustor utilizes a rich-quench-lean concept that greatly minimizes the fuel bound nitrogen transformation to NOx (Ref. 6). For natural gas fuel the overriding factor in preventing NOx formation is the flame temperature. Flame temperatures in conventional diffusion flames approach 3500F, and in a typical engine would produce about 200ppm of NOx. Dry Low NOx combustors reduce the flame temperature through the partial premixing of fuel and air before ignition (Ref. 7). Figure 5 demonstrates that NOx production is directly related to flame temperature and which in turn is related to the local fuel to air ratio. Premixed combustors operate in a lean fuel/air condition resulting in a lower flame temperature and hence lower NOx. The current DLN system in service is the second generation system that utilizes lean premixed fuel mixing zones surrounding a central pilot. The central pilot provides a stability to the basic system. Third generation ULN systems that utilize fully premixed (no pilot) have been developed and are entering service.

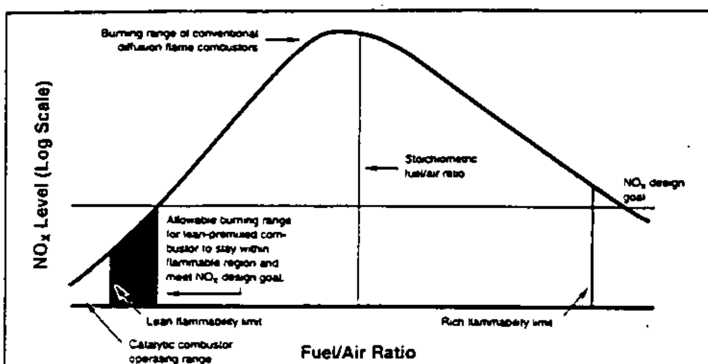

Figure 5 NO_X Formation vs. Fuel Air Ratio

Dry Low NOx Combustion Systems

The second generation dry low NOx combustion system was first introduced into service in 1992 and has an excellent performance record. Lead units now have over 20,000 hours of operation and have not required any shop repairs or replacements. This impressive performance is achieved by maintaining the combustor flame activity in a quiet, stable mode. A Dry Low NOx combustor (Ref. 8) is shown in Figure 6. The design includes the capability of performing on gas or liquid fuel including startup on either fuel as well as fuel transfers in either direction.

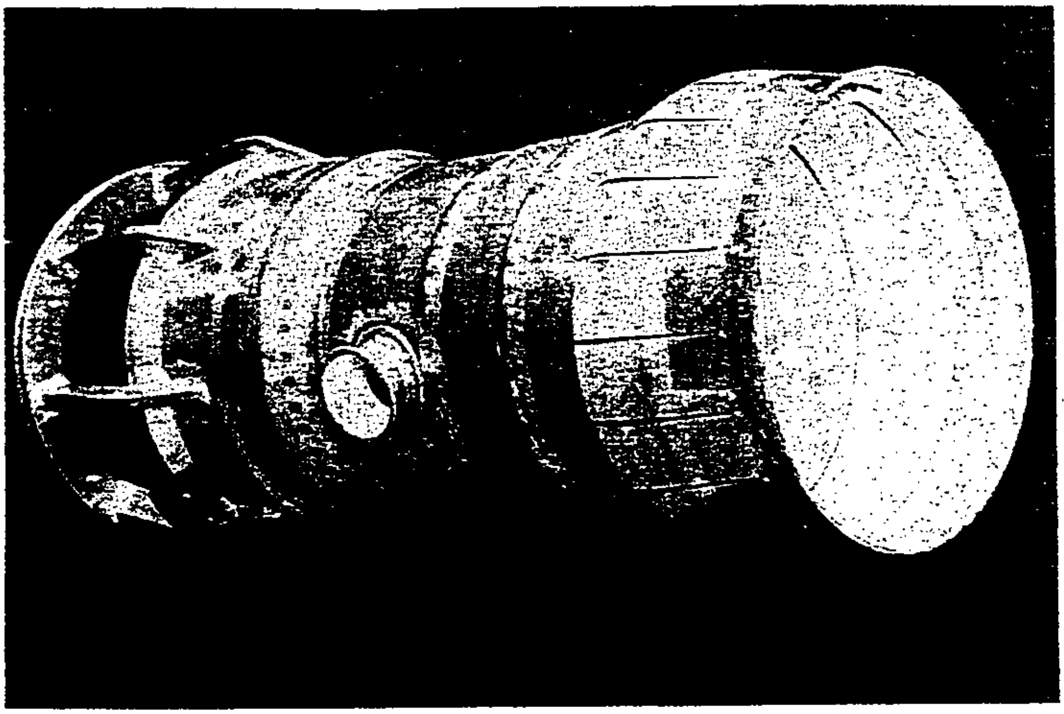

Figure 6

Table 1: Current Westinghouse 60 Hz engines

Engine	Power (MW)	Number of Combustors	Reference Firing Temperature (F)
251B12	48	8	2100
501D5	107	14	2070
501D5A	118	14	2150
501F	167	16	2400
501G	230	16	2583

Continuing the evolutionary design approach (Ref. 9), all current engines utilize can-annular designs that facilitate use of common designs for different engines. Figure 7 shows essentially the same Dry Low Combustor in 501D5, 501D5A,701F, and 501F. This design philosophy allows the experience base for all Dry and Ultra Low NOx combustors to be additive. The 501G is the newest addition to the Westinghouse 60Hz single shaft heavy duty combustion turbine product line (Ref. 10).

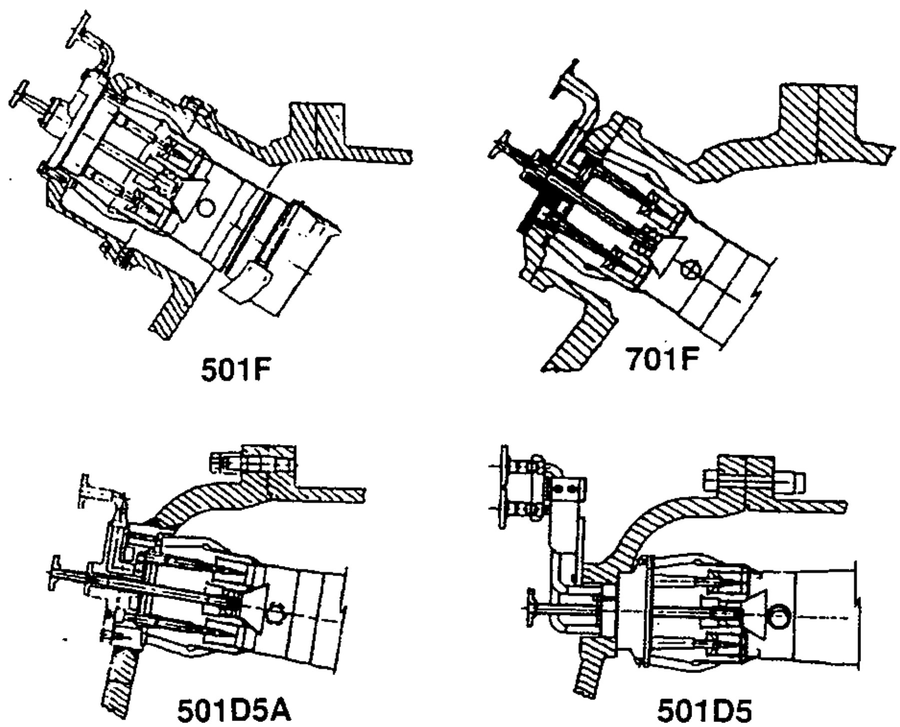

Figure 7. Dry Low NOx Engine Installations

Ultra Low NOx Program

Ultra Low NOx development activities continue on several fronts to positively impact new and existing engines. The comprehensive program includes focused development in advanced premix systems, dry low emission on liquid fuels, active stability enhancement, optical sensor measurements, as well as catalytic combustion.

Relative to premix combustors, Westinghouse has developed a full product line of Ultra Low Emission combustors. Multiple approaches were pursued to provide optimum performance for the wide range of operating conditions required for the fleet of new and operating engines.

Fully Premixed Design - Piloted Ring Combustor

The Piloted Ring Combustor is shown schematically in Figure 8. The combustor consists of two axial stages. The primary stage utilizes two counter rotating swirlers to premix fuel and air and stabilize the primary combustion zone. In the secondary stage a long premixing annulus provides the necessary length to achieve ideal mixing of the natural gas and air before injecting it into the secondary combustion zone. The combustor operates in a fully premixed mode for ultra low emissions, but can also operate in the diffusion mode with natural gas or oil supplied from a center nozzle.

This design has gone through an exhaustive development process including fully integrated cold flow air rig modeling, computational fluid dynamics (CFD), fired atmospheric, mid-pressure, and full pressure rig tests (Ref. 11).

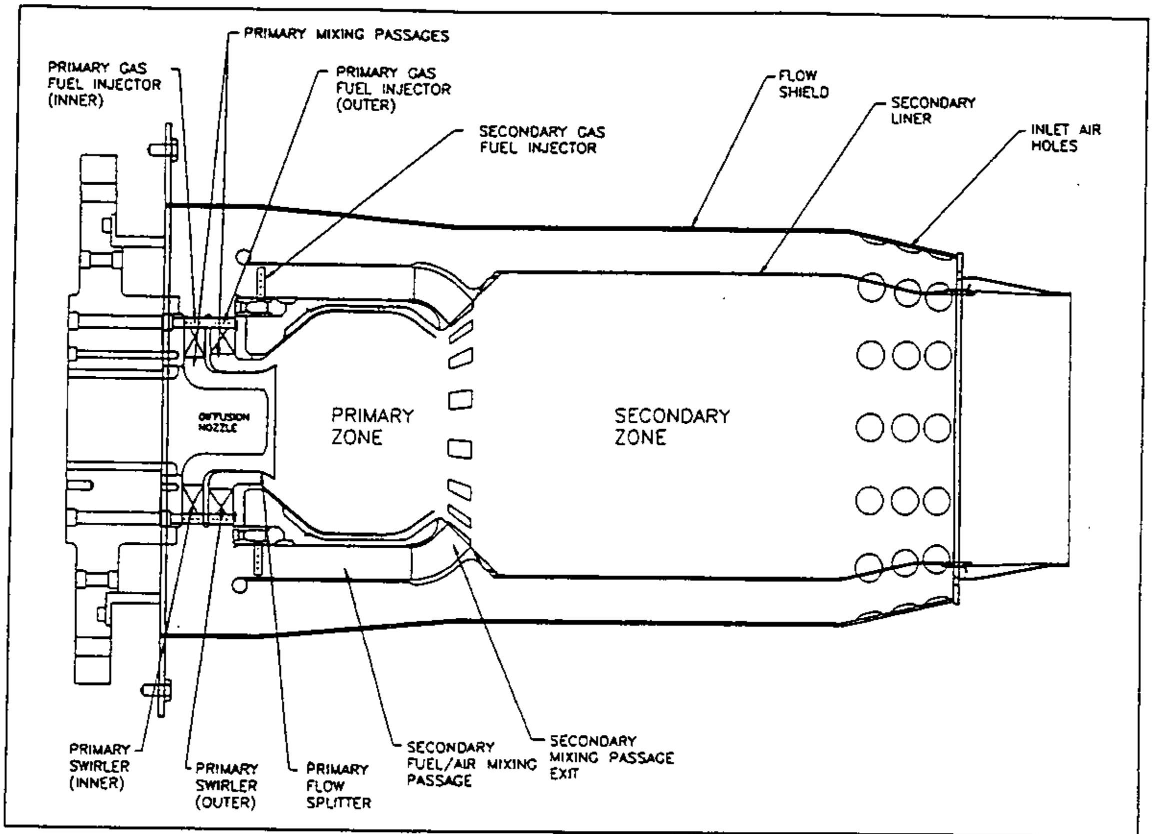

Figure 8 A Westinghouse Ultra Low NO_X Combustor

This design has a heritage as the RB211 DLE combustor (Ref. 12). The piloted ring combustion system shall be utilized in installations in 501F machines such as where the NOx emissions targets are 15 ppm or lower. In the higher fired 501G machine emissions are offered at a NOx rate of 25 ppm with the future potential to produce lower. (See also Table 1.)

501G Combustion Systems - Development Status and Schedule

Two combustion systems are being developed for the 501G combustion turbine. Versions of the DLN and ULN combustion system will be designed and thoroughly tested in full fired combustion test facilities before installation into the first engine. Any combustion development program has many steps to achieve the final desired result of single digit NOx emissions, and so the program schedule must remain flexible. Program target dates will be heavily dependent upon the preceding test results from each phase of the program. Overall, the program as it relates to the 501G ULN program is as follows:

Basic design and lab testing phase	Now through early 1999
Initial field verification testing	Mid 1999
Design modification and retesting	Mid 1999 through mid 2000
Follow up field verification testing	Mid 2000
Additional design changes/tests	Mid 2000 and later
Full commercial application	2001 to 2004

Between each of the lab and verification testing periods, redesign and remanufacture of some of the combustor components is expected. Depending on the component and amount of new design and development which might be required, the time before follow-on testing can be done would be in the order of six months. In addition, there is typically a limited period of time during the year when engines are usually available to Westinghouse for testing (off-peak periods only.)

Summary

Westinghouse's comprehensive program to reduce emission levels from combustion turbines are proceeding toward the ultimate goal of environmentally benign designs. The combined goal to lower emissions with higher performance, higher temperature engines provide a particularly difficult challenge to the combustor designers. Westinghouse is utilizing state of the art tools that include both analytical and testing improvements that make these challenging goals achievable.

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Westinghouse Electric Corporation

Power Generation Business Unit

Generations Systems Divisions

The Quadrangle
4400 Alafaya Trail
Orlando Florida 32826-2399

COL W-COL-0018
File: 042.3

March 26, 1998

Mr. Al Dodd
City of Lakeland, Florida
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5069

Subject: City of Lakeland Project -McIntosh #5 Project Hot SCR

Dear Al:

At a meeting on March 11, 1998 with the Florida Department of Environmental Protection (FDEP), the City of Lakeland and Westinghouse, the FDEP requested information regarding issues associated with using a high temperature "hot" SCR for the proposed City of Lakeland McIntosh Unit No. 5 project. Westinghouse is therefore providing the following for the FDEP's consideration.

Based on Westinghouse's proposed plant design and our research concerning the installation of a high temperature SCR for the McIntosh Unit No. 5, the hot SCR should not be utilized for several reasons, including (1) it would not be used if this unit is converted to a combined cycle design at the end of the permit term, (2) it would add substantial additional design and cost to the project, (3) it would impact operating flexibility of the unit and (4) it has never been installed on a unit even 1/10th the size of the McIntosh Unit No. 5 due to the high exhaust temperature. In addition, the catalyst vendor has indicated to Westinghouse that the hot SCR could only be guaranteed for 7500 hours of operation before replacement would be required.

In previous correspondence with the FDEP in a letter dated January 12, 1998 from the EPA to Mr. Ronald Tomlin of the Lakeland Electric & Water Utilities, it was indicated that the installation of the high temperature SCR for initial use in the simple cycle configuration with subsequent installation and use in a combined cycle configuration would simplify the HRSG design by having a one-piece construction instead of having separate components with a low temperature SCR module in between. Contrary to this, installing the high temperature SCR in the HRSG for the combined cycle phase would not be considered good engineering practice, to our knowledge has never been done, would significantly complicate the HRSG design, would add substantial cost to the project and would impact operating flexibility. Details supporting each of these issues are outlined below.

The location of the catalysts in high temperature SCR applications have been directly in the path of the turbine exhaust. The typical maximum temperatures of these applications have been much less than the maximum temperature limits of high temperature catalysts, i.e., 1,100° F. This temperature limit is adequate for a majority of CT applications. However, the exhaust temperatures for the advanced industrial combustion turbines will exceed this temperature. This is especially true of the Westinghouse 501G. In order to utilize high temperature SCR in a 501G simple cycle application, the catalyst must be installed in a zone of lower flue gas temperature such as downstream of some heat exchange surface. For the City of Lakeland's McIntosh Unit No. 5 Project, a high temperature catalyst would have to be installed downstream of the Once Through Steam Generator (OTSG). The OTSG is several rows of tube banks that provide cooling steam and reduces the flue gas temperature about 100° F. If the Lakeland Project was subsequently converted from simple cycle to combined cycle, the OTSG would not be used in favor of the installation of a Heat Recovery Steam Generator (HRSG). Leaving the OTSG and modifying the HRSG design would, as a minimum, have significant cost and schedule implications for the project and may not be technically feasible. To our knowledge, such a steam cycle design has never been attempted.

Standard practice in the industry for installing SCR in a combined cycle project is to located low temperature catalysts within the proper temperature zone in the HRSG. Significant technical challenges are expected in attempting to install a high temperature SCR system within a HRSG. The first challenge relates to the location of the high temperature catalyst in the proper temperature zone. To achieve the proper temperature range, the high temperature catalyst would be placed upstream of the HP evaporator section, between the superheater and reheater sections. Inserting the space required for catalyst modules at this point would require considerable amount of alloy piping and high temperature resistant duct lining. Such a modified HRSG design would represent a considerable deviation from common practice by HRSG vendor and result in additional design time and uncertainty.

In addition to the technical challenges, there are major financial factors of installing high temperature SCR in the HRSG. For the same NOx removal, the installed capital costs of a high temperature SCR system is more than double that of a traditional SCR system in a combined cycle design. This is principally due to the costs associated with the high temperature catalyst as well as the supporting materials. As provided by the catalyst vendor, the cost of a high temperature catalyst alone is $2.8 million, excluding ductwork, installation, auxiliaries and engineering, for the 501G. If a high temperature SCR system was installed on simple cycle project and then the project was converted to combined cycle, the reduced costs of installing a traditional low temperature SCR system would more than offset the increased design costs, HRSG capital costs and operational costs. The much lower cost of the traditional catalyst would alone result in considerable cost savings when replaced.

If a high temperature SCR was installed in a simple cycle design and components were used for combined cycle, there would be costs associated with unit being unavailable for an extended period of time to accomplish the conversion. The conversion would require the removal and installation of large structural components during which the unit could not be operated.

Impacts on performance could also be significant with a high temperature SCR design. The additional piping in the reheat and HP sections would likely result in increased steam pressure drops and decrease overall combined cycle efficiency.

Based on the above, it is Westinghouse's opinion that a hot SCR, if installed for simple cycle operation, would not be used when the unit is converted to combined cycle configuration. Westinghouse is of the opinion that the best solution for reducing NOx emission from this unit would be to install/retrofit Ultra Low-Nox combustors (ULN), when available, or install a traditional low temperature SCR, if ULN is not available at the time of conversion to a combined cycle configuration. These options provide the lowest cost and most proven methods for NOx reduction. The installation of a high temperature SCR for dual use in the simple cycle and combined cycle plants would add complexity and delays to the construction schedule, it would add significant capital and O&M significant cost to the project, it would increase cost and delivery lead times for the HRSG and OTSG due to first time engineering for the vendors, and reduce operating flexibility and revenues for the City of Lakeland.

Regards,

Andy Mould

Andy Mould
Project Manager, City of Lakeland

cc:	Farzie Shelton	COL
	Roger Greenwood	MC 560
	Ben Edwards	MC 565
	Karen Weaver	MC 590

Westinghouse
Electric Corporation

Power Generation Business Unit
Generation Systems Division
4400 Alafaya Trail MC 550
Orlando, FL 32826
(407) 281-2224

March 25, 1998

Ms. Farzie Shelton
City of Lakeland
501E. Lemon Street
Lakeland, FL 33801

Subject: **Ultra Low NOx Combustion Technology**

Dear Farzie:

Westinghouse is committed to being a leader in advanced combustion turbine technologies in the power generation industry. Under the auspices of the Department of Energy's Advanced Turbine Systems (ATS) program, we are developing new and innovative technologies, including the Ultra Low NOx (ULN) combustion system. The ultimate objective of the ULN system is to achieve NOx emission levels of 9-12 ppmvd (corrected to 15 percent oxygen) for our industrial frame combustion turbine products.

The new ULN combustor is currently undergoing laboratory testing. The first phase of field testing will commence this spring in an operating 501F combustion turbine. The purpose of this test is to verify the lab results. The results will be evaluated and further design improvements and modifications will be incorporated, as required. A second phase of field testing is scheduled to commence in the 4th quarter of 1998. The process will be repeated until successful demonstration of the ULN technology. We fully expect to make the ULN system an available option for the 501G and commercially available for retrofit on the operating 501G fleet after a similar verification program as the one described above for the 501F. Since McIntosh Unit No. 5 is the demonstration project for the 501G, there is a high probability that some verification testing for the ULN combustion system will be performed on the unit.

We are incorporating additional piping and other necessary components on the Lakeland McIntosh Unit No. 5 which will accommodate the future retrofit of the ULN combustion system. We confirm these auxiliary components are included in our contract price.

In summary, Westinghouse fully anticipates having a combustion system available that meets the 9-12 NOx requirements for the McIntosh Unit No. 5 unit within the next four years. We will keep Lakeland fully advised of our progress throughout our entire ULN test program.

Very truly yours,

J. L. Gibson
Regional Marketing Manager

cc: Mr Al Dodd, Project Manager, McIntosh 5

LAKELAND
ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

Hand-delivered by
Farzie Shelton on 3/11/98
aay

March 11, 1998

Mr. A. A. Linero, P.E., Administrator
New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
111 S. Magnolia
Suite 4
Tallahassee, FL 32301

RE: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5
Information in Department's March 9, 1998 Letter

Dear Al:

The City appreciates your expeditious review of the information that we recently submitted. We have review the information contained in your communication dated March 9, 1998 and are submitting the following comments.

We have reviewed the Cataula Generating Company Project and have found that this project is indeed very similar to the Unit 5 Project proposed by the City. This project involves 4 Westinghouse 501G combustion turbines operating in simple cycle firing both natural gas and distillate oil. The permit issued for this project (see attached Permit No. 4911-072-12256; Georgia Department of Natural Resources, Environmental Protection Division) establishes fuel use and emission limits for simple cycle operation without the use of selective catalytic combustion (SCR). The emission limits provided in the permit are very similar for NOx as that being requested by the City of Lakeland (see Conditions 15 and 16). Condition 13 provides for a fuel use of 1.19×10^{13} Btu during any consecutive 12 months for <u>each</u> turbine. At the ISO rating for the 501G machine of about 2,410 mmBtu/hr this is equivalent to 4,940 hours of operation and a capacity factor of 56 percent for the life of the unit. In contrast, the City of Lakeland is requesting a 80 percent capacity factor at those emissions rates for no greater than 5 years after initial operation. After 5 years the City has committed to 12 ppmvd (corrected to 15 percent oxygen) on a 30-day rolling average when firing natural gas. There is no time limit in the Cataula Generating permit. Moreover, Condition 14 provides for a total oil use from all turbines of 2.975×10^7 gallons during any consecutive 12 months which is equivalent to 1,770 hours per year or about 450 hours/year/turbine. The City of Lakeland has proposed only 250 hours/year for emergency conditions only. The NOx emissions provided for in the Cataula Generating Permit is 696 tons/year/turbine. The City is requesting an equivalent 863 tons/year for the first 5 years and about 420 tons/year thereafter. Operating at a capacity factor of 80 percent, the Cataula Generating Project would be allowed to emit 994 tons/year.

Regarding the Commonwealth Chesapeake Project, the reduction in hours would indeed increase the cost effectiveness in the $8,000 per ton of NOx removed. However, the information available on this project clearly indicated that the capital cost for installing SCR on this project was higher than that provided in the application for the Unit No. 5.

The Cambalache Electric Generating Facility located in Puerto Rico is substantially different than the City's proposed project and the suggestion that this is directly comparable is inappropriate. This project involves the use of distillate oil only and there is no limit on the hours of operation (see attached EPA permit). Calculating the cost effectiveness of a 501G on the same basis as the Cambalache Generating Project (i.e., 10 percent oil firing at 8,760 hours/year), the cost effectiveness would indeed be around $2,000 per ton of NOx removed as indicated in your March 9th letter. In contrast, the cost effectiveness for the Lakeland Project is $5,800 to $8,435 per ton of NOx removed based on 5 years initial operation at 25 ppmvd (corrected to 15 percent oxygen) when firing natural gas.

It should be note that the U.S. Generating Project in Massachusetts is a LAER decision required since the facility is located in the Northeast Ozone Transport Region (NOTR). However, as indicated in the original application and our March 4, 1998 response, SCR when installed in on a combined cycle plant would likely be cost effective as determined under BACT.

It is clear that the proposed sequencing of NOx emission limits proposed by the City is appropriate as BACT and would ultimately provide economic and environmental benefits to both the City of Lakeland as well as Florida.

Sincerely,

Farzie Shelton, Manager
Environmental Licensing and Permitting

cc: Ron Tomlin, City of Lakeland
Al Dodd, City of Lakeland
Ken Kosky, Golder Associates

cc: EPA
NPS

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

General Requirements

1. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall to the extent practicable maintain and operate this source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

2. The Permittee shall cause to be conducted a performance test at any specified emission point when so directed by the Division. The test results shall be submitted to the Division within 30 days of the completion of testing. Any tests shall be performed and conducted using methods and procedures which have been previously approved by the Division.

3. The Permittee shall commence construction of the permitted source within 18 months of the effective date of this Permit.

4. The construction of Phase I (source codes T1 and T2) shall be completed by no later than June 1, 2001. In the event that construction of any unit is not completed by the date specified and absent approval by the Division for an extension of the completion date, this Permit shall become null and void with respect to that unit and all units yet to be constructed. The Permit will remain in full force and effect with regard to any units for which construction has been completed by the applicable construction deadline.

5. The construction of Phase II (source codes T3 and T4) shall be completed by no later than June 1, 2004. In the event that construction of any unit is not completed by the date specified and absent approval by the Division for an extension of the completion date, this Permit shall become null and void with respect to that unit and all units yet to be constructed. The Permit will remain in full force and effect with regard to any units for which construction has been completed by the applicable construction deadline.

6. The Permittee shall submit a new BACT proposal for Phase II (source codes T3 and T4) if construction of the first combustion turbine (source code T1 or T2) is completed before beginning of actual construction of Phase II commences. At the request of the Permittee, for good cause shown, the Division may waive the requirement to submit a new BACT proposal.

Performance Testing

7. The Permittee shall provide the Division thirty (30) days prior written notice of the date of any performance test(s) to afford the Division the opportunity to witness and/or audit the test, and shall provide with the notification a test plan in accordance with Division guidelines.

8. The Permittee shall provide performance test ports which comply with criteria approved by the Division.

9. All required continuous monitoring system(s) shall be installed, calibrated and operating when the test(s) are conducted.

10. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up, the Permittee shall conduct the following performance tests on each turbine (source codes T1, T2, T3, and T4) and furnish to the Division a written report of the results of such performance tests:

    a. Performance tests for nitrogen oxides (NO_X) at 100% and below 70% load while burning natural gas and fuel oil in the turbine.

    b. Determination of the sulfur content and nitrogen content of the fuel oil burned.

    c. Performance tests for carbon monoxide (CO) while burning natural gas and fuel oil at 100% load and below 70% load.

    d. Performance test for particulate matter (PM) while burning fuel oil.

    e. Visible emission tests while burning natural gas and fuel oil.

    f. Performance tests for CO, PM, and visible emissions shall be conducted concurrently. The concurrent CO, PM and visible emissions tests will be at 100% load. No PM or visible emissions tests are required for the below 70% load test.

    g. Performance test for formaldehyde while burning natural gas and fuel oil at 100% load for unit 1 only (source code T1).

Performance Testing

11. Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. Specific applicable test methods included in the above reference or as otherwise referenced are as follows:

    a. Method 1 for sample point location.

    b. Method 2 for determination of velocity and gas flow rate.

    c. Method 3A for determination of gas stream molecular weight and excess air correction factor.

    d. Method 5 for emission rate of particulate matter and associated moisture content. For Method 5, the minimum sampling time for each run shall be 120 minutes.

    e. Method 9 and the procedures of Section 1.3 for the determination of opacity.

    f. Method 10 for concentration of carbon monoxide.

    g. ASTM D1072 and D4294 for the determination of fuel sulfur content.

    h. ASTM Method D4629 for the determination of fuel nitrogen content.

    i. Method 20 for the concentration of nitrogen oxides.

    j. Method 0011 for the concentration of formaldehyde.

    Minor modifications of these methods and procedures may be specified or may be approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvements or corrections which in his opinion render those methods and procedures thereof more reliable.

Allowable Emissions

12. The Permittee shall comply with all applicable requirements of 40 CFR Part 60 - Standards of Performance for New Stationary Sources, Subpart A - General Provisions.

13. The Permittee shall limit the burning of fuel(s) in each combustion turbine (source codes T1, T2, T3, and T4) such that the heat input from the burning of all such fuel(s) in each turbine does not exceed $1.19*10^{13}$ Btu during any twelve consecutive months. For purposes of this condition, the heat input of the fuel oil burned in a turbine shall be calculated by multiplying the fuel oil (in gallons) consumed by the turbine by 141,000 Btu per gallon. The heat input of the natural gas burned in a turbine shall be calculated by multiplying the natural gas (in cubic feet) consumed by the turbine by 1022 Btu per cubic foot.

14. The firing of No. 2 fuel oil shall be limited such that the total consumption does not exceed $2.975*10^{7}$ gallons during any twelve consecutive months in any combustion turbine (source codes T1, T2, T3, and T4).

15. The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine (source codes T1, T2, T3, and T4) when burning fuel oil in the turbine any gases which:

    a. contain nitrogen oxides in excess of 75 ppmvd below 70% load and 42 ppmvd at or above 70% load corrected to 15% oxygen, dry basis.

    b. contain carbon monoxide in excess of 150 ppmvd below 70% load and 75 ppmvd at or above 70% load corrected to 15% oxygen, dry basis.

    c. contain particulate matter in excess of 0.03 pounds per million Btu heat input, higher heating value (HHV).

    d. contain volatile organic compounds in excess of 0.01 pounds per million Btu heat input, as methane, higher heating value (HHV).

    e. exhibit greater than 20 percent opacity.

Allowable Emissions

16. The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine (source codes T1, T2, T3, and T4) when burning natural gas in the turbine any gases which:

    a. contain nitrogen oxides in excess of 45 ppmvd below 70% load and 25 ppmvd at or above 70% load corrected to 15% oxygen, dry basis.

    b. contain carbon monoxide in excess of 200 ppmvd below 70% load and 25 ppmvd at or above 70% load corrected to 15% oxygen, dry basis.

    c. contain particulate matter in excess of 0.005 pounds per million Btu heat input, higher heating value (HHV).

    d. contain volatile organic compounds in excess of 0.01 pounds per million Btu heat input, as methane, higher heating value (HHV).

    e. exhibit greater than 10 percent opacity.

17. The Permittee shall not burn in any turbine (source codes T1, T2, T3, and T4) any fuel oil which contains sulfur in excess of 0.05 percent by weight.

18. The Permittee shall comply with the requirements of 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines (for source codes T1, T2, T3, and T4) as follows:

    a. Under 40 CFR 60.334(b), the sulfur content of the natural gas burned in the turbine(s) shall be monitored by the recordkeeping of a semi-annual analysis of the gas as obtained from the supplier. No determination of the nitrogen content of the gas shall be required.

Allowable Emissions

18. (cont.)

b. Under 40 CFR 60.334(c), periods of excess emissions that shall be reported are defined as follows:

1. Nitrogen oxides - Any two consecutive one-hour periods in which the average NO_X concentration exceeds 25 ppmvd when firing natural gas or 42 ppmvd when firing fuel oil at or above 70% load (average over two-hour period) or 45 ppmvd when firing natural gas or 75 ppmvd when firing fuel oil below 70% load (average over two-hour period). NO_X concentrations shall be corrected to 15% oxygen, dry basis.

2. Sulfur dioxide - Any fuel oil shipment in which the sulfur content of the fuel oil burned in the turbine, as indicated by the required sulfur analysis, exceeds 0.05 percent by weight.

19. The Permittee shall not discharge or cause the discharge into the atmosphere from any turbine nitrogen oxide in excess of 696 tons during any 12 consecutive months.

Monitoring Requirements

20. The Permittee shall comply with all applicable requirements of the continuous monitoring rule in 40 CFR 75.

21. The Permittee shall install, certify, operate, and maintain, in accordance with all the requirements of 40 CFR 75.10(a)(2) and 40 CFR 75.12, a NO_X continuous emission monitoring system with the automated data acquisition and handling system for measuring and recording NO_X concentration (in ppmvd, corrected to 15% oxygen, dry basis) and NO_X emission rate (in lb/MMBtu) discharged to the atmosphere for each turbine (source codes T1, T2, T3, and T4).

22. The Permittee shall install, calibrate, operate and maintain on each turbine (source codes T1, T2, T3, and T4) devices for measuring the quantity of fuel oil, in gallons, burned in the turbine, and the quantity of natural gas, in cubic feet, burned in the turbine.

Monitoring Requirements

23. The Permittee shall use the nitrogen oxide emission data required by Condition 21 and fuel usage data required by Condition 22 to determine monthly emissions (tons) of nitrogen oxide. The records shall be in a permanent form suitable and available for inspection. The records shall be retained for at least two years following the date of entry.

24. Within 180 days of the issuance of this Permit, the Permittee shall propose for EPD approval, a method to account for any operating hours for which data is not obtained as required in Condition 21.

25. The Permittee shall monitor the sulfur content and nitrogen content of the fuels being burned in the turbines as follows:

    a. For natural gas, the Permittee shall monitor the sulfur content by the recordkeeping of a semi-annual analysis of the gas as obtained from the supplier. No determination of the nitrogen content shall be required.

    b. For fuel oil, the Permittee shall monitor the sulfur content and nitrogen content of each shipment to the plant.

26. Any monitoring system installed by the Permittee shall be in continuous operation except during calibration checks, zero and span adjustments or periods of maintenance or repair. Maintenance or repair shall be conducted in the most expedient manner to minimize the period during which the system is out of service.

27. The Permittee shall provide and maintain a spare parts inventory for any emission monitoring system installed. A list of parts to be kept in inventory shall be submitted to the Division for approval.

Notification, Reporting and Recordkeeping

28. The Permittee shall furnish the Division written notification as follows:

    a. The anticipated date of initial startup of this source, not more than 60 nor less than 30 days prior to such date.

    b. The actual date of initial startup of this source within 15 days after such date.

    c. Certification that a final inspection has shown that construction has been completed in accordance with the application, plans, specifications and supporting documents submitted in support of this permit.

29. The Permittee shall maintain hourly and monthly records of the amount of fuel oil and natural gas consumed by each of the turbines (source codes T1, T2, T3, and T4). The records shall be in a permanent form suitable and available for inspection. The records shall be retained for at least two years following the date of entry.

30. In accordance with 40 CFR 60.334, the Permittee shall submit a written report of excess emissions, as defined by Condition 18 of this Permit, to the Division for every calendar quarter. If there are no excess emissions during the quarter, the Permittee shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period. All reports shall be postmarked by the 30th day following the end of the reporting period.

Fugitive Emissions

31. The Permittee shall take all reasonable precautions with any operation, process, handling, transportation, or storage facilities to prevent fugitive emissions of air contaminants.

Modifications

32. The Permittee shall give written notification to the Division when there is any modification to this source. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the plant before and after the change; and the anticipated completion date of the change.

Special Conditions

33. The Permittee shall not operate the turbines below 50% of their rated capacity. Periods of startup and shutdown shall be excluded from this limitation.

34. The Permittee shall install and operate, as BACT for NO_X on the combustion turbines (source codes T1, T2, T3, and T4), dry low NO_X combustors for natural gas combustion and water injection for distillate fuel oil combustion .

35. In lieu of a continuous monitoring system as required under Condition 21, the Permittee may apply for an Amendment to this Permit to utilize a parametric and/or alternative monitoring system provided that the monitoring system has been previously approved by the U.S. Environmental Protection Agency to comply with the requirements of 40 CFR 75.

36. At any time that the Division determines that additional control of emissions from the facility may reasonably be needed to provide for the continued protection of public health, safety and welfare, the Division reserves the right to amend the provisions of this Permit pursuant to the Division's authority as established in the Georgia Air Quality Act and the rules adopted pursuant to that Act.

AIR QUALITY PERMIT

Permit No.
4911-072-12256

Effective Date

In accordance with the provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq and the Rules, Chapter 391-3-1, adopted pursuant to or in effect under that Act,

CATAULA GENERATING COMPANY
7500 Old Georgetown Road, Suite 1300
Bethesda, Maryland 20814

is issued a Permit for the following: To construct and operate four Westinghouse 501G simple cycle combustion turbines each nominally rated at 300 MW (at 0 degrees F) capable of firing natural gas or #2 fuel oil in accordance with 40 CFR 52.21.

Facility location: Cataula Generating Station
Hamilton Road
Cataula, Georgia 31811 (Harris County)

This Permit is conditioned upon compliance with all provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq, the Rules, Chapter 391-3-1, adopted or in effect under that Act, or any other condition of this Permit.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above; or for any misrepresentation made in the application(s) dated August 14, 1996, supporting data entered therein or attached thereto, or any subsequent submittals, or supporting data; or for any alterations affecting the emissions from this source. Additional information dated October 23, 1996 and November 20, 1996.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached 9 page(s), which page(s) are a part of this Permit.

Director
Environmental Protection Division

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION II
JACOB K. JAVITS FEDERAL BUILDING
NEW YORK, NEW YORK 10278-0012

DEC 5 1996

Mr. Ismael Brito, P.E.
Project Manager, Construction Division
Puerto Rico Electric Power Authority
Caso Building, 11th Floor
1225 Ponce de León Avenue
San Juan, PR 00936-4267

Re: Prevention of Significant Deterioration of Air Quality: Revision to the July 31, 1995 Permit for the PREPA Cambalache Electric Generating Facility

Dear Mr. Brito:

The purpose of this letter is to issue to the Puerto Rico Electric Power Authority (PREPA) a revised, final Prevention of Significant Deterioration of Air Quality (PSD) permit (Attachment II) for its Cambalache Combustion Turbine Project. This permit revision is the result of a request made by Ove Nymberg of Cambalache Limited Partnership, S.P. (CLP) in a letter dated July 23, 1996.

On July 31, 1995, the United States Environmental Protection Agency (EPA), Region 2 Office, issued a final PSD permit to approve the PREPA Cambalache project. On September 5, 1995, in accordance with the procedures delineated at 40 CFR Part 124, Citizens in Defense of the Environment (CEDDA) filed an administrative appeal on the PREPA Cambalache PSD permit to the Environmental Appeals Board (EAB) in Washington, D.C. This appeal was subsequently denied by the EAB, on December 11, 1995.

The July 23, 1996 request to revise the PREPA Cambalache PSD permit relates to the substitution of a continuous emissions monitoring requirement (reference section XI.1.f of Attachment II). Specifically, CLP, on behalf of PREPA, requested EPA's approval to utilize Method 19 (from 40 CFR Part 60, Appendix A) to measure and record stack gas volumetric flow rate. The July 31, 1995 PSD permit did not specify a particular methodology to measure and record stack gas flow rate; however, the permit required that the continuous monitoring system meet all applicable performance specifications including, but not limited to, 40 CFR Part 52, Appendix E.

Based upon the information submitted by CLP on July 23, 1996, EPA has determined that use of Method 19 is an acceptable alternative to continuously monitor stack gas flow rates. Because the corresponding change to the PREPA Cambalache PSD permit is not a significant change (no increases in emissions or ambient air quality impacts will occur), public review of this PSD permit modification is not required.

This PSD permit revision is a final action under the Clean Air Act (the Act), and is based upon information that CLP submitted on July 23, 1996. This final Agency action can only be challenged by means of a request for judicial review. Under Section 307(b)(1) of the Act, judicial review of this action is available only by the filing of a petition for review in the United States Court of Appeals for the appropriate circuit within 60 days from the date on which the determination is published in the Federal Register. Under Section 307(b)(2) of the Act, this determination is not subject to later judicial review in civil or criminal proceedings for enforcement.

If you have any questions regarding this letter or the PSD permit modification, please call Mr. Steven C. Riva, Chief, Permitting Section, Air Programs Branch, at (212) 637-4074.

Sincerely,

William

Jeanne M. Fox
Regional Administrator

Attachment

cc: Ove Nymberg
Cambalache Limited Partnership, S.P.

Norma Burgos, Chair
Puerto Rico Planning Board

Francisco Claudio, Director
Air Permit Division
Puerto Rico Environmental Quality Board

Paul A. Eisen, Director
Environmental Sciences
SBE Environmental Company

Carl A. Soderberg, Director
Caribbean Field Office
U.S. Environmental Protection Agency

ATTACHMENT I

PREPA Cambalache Combustion Turbine Project
Project Description

GENERAL PROJECT DESCRIPTION: The Puerto Rico Electric Power Authority (PREPA) is proposing to install and operate a 248 megawatt (MW) combustion turbine simple cycle electric generating station on a 52-acre site in Cambalache, in the Municipality of Arecibo. The facility will produce electricity from three ABB GT 11N distillate oil fired combustion turbines, each with a power output of 83 MW. Each combustion turbine will consist of a compressor, combustor and turbine. Energy is generated at each of the combustion turbines by drawing in ambient air with the compressor, heating the air by means of burning fuel oil and expanding the hot combustion gases in a 5-stage turbine. Each combustion turbine will burn No. 2 fuel oil having a maximum sulfur content of 0.15 percent by weight. In addition, the facility will be allowed to operate in a spinning reserve mode (60 percent load) for up to 2,000 hours per year.

PSD-Affected Pollutants Emitted at the PREPA Cambalache Combustion Turbine Project: The facility is classified as a major stationary source because it has the potential to emit more than 250 tons per year of at least one pollutant regulated by the Clean Air Act. The proposed facility is subject to the Prevention of Significant Deterioration of Air Quality (PSD) standards for oxides of nitrogen (NO_x), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), and volatile organic compounds (VOC).

Pollutant	PSD Significant Emission Rate (tons/year)	Projected Facility Emission Rate (tons/year)
Nitrogen oxides (NO_x)	40	460
Sulfur dioxide (SO_2)	40	1,800
Sulfuric acid mist (H_2SO_4)	7	420
Carbon monoxide (CO)	100	515
Particulate matter - total (PM)	25	946
Particulate matter less than 10 microns (PM_{10})	15	946
Volatile Organic Compounds (VOC)	40	180

ATTACHMENT I

PREPA Cambalache Combustion Turbine Project
Project Description

PREPA Cambalache Combustion Turbine Control Equipment: The proposed facility will employ Best Available Control Technology to control the pollutants described above.

Emissions of nitrogen oxides will be controlled by the use of a steam injection system and a Selective Catalytic Reduction (SCR) system. The steam to fuel ratio for each unit shall be established during performance testing and shall be incorporated into the Environmental Quality Board (EQB) operating permit. Each SCR system shall use a zeolite catalyst and shall operate in accordance with the manufacturer's design specifications.

Emissions of sulfur dioxide and sulfuric acid mist shall be controlled by the use of only low sulfur No.2 fuel oil in which the sulfur content may not exceed 0.15% by weight.

Emissions of carbon monoxide, total particulate matter, particulate matter less than 10 microns, and volatile organic compounds will be controlled by implementing good combustion practices. PREPA shall be required to operate each turbine within the designed combustion parameters of the ABB GT 11N distillate oil fired combustion turbine. In addition, PREPA shall be required to monitor the combustion temperature and volumetric flow rate of each turbine, and PREPA shall be required to maintain each turbine in good working order.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

The PREPA Cambalache Combustion Turbine Project as described in Attachment I is subject to the following conditions.

I. Permit Expiration

1. This PSD Permit shall become invalid if construction:

   a. has not commenced (as defined in 40 CFR Part 52.21(b)(9)) within 18 months after the approval takes effect;
   b. is discontinued for a period of 18 months or more; or
   c. is not completed within a reasonable time.

II. Notification of Commencement of Construction and Startup

The Regional Administrator (RA) shall be notified in writing of the anticipated date of initial startup (as defined in 40 CFR Part 60.2) of each combustion turbine not more than sixty (60) days nor less than thirty (30) days prior to such date. The RA shall be notified in writing of the actual date of both commencement of construction and startup of each combustion turbine within fifteen (15) days after such date.

III. Plant Operations

All equipment, facilities, and systems, including the combustion and electric generation units, installed or used to achieve compliance with the terms and conditions of this PSD Permit shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimize air pollutant emissions. The continuous emission monitoring systems required by this permit shall be on-line and in operation 95% of the time when turbines are operating.

IV. Right to Entry

Pursuant to Section 114 of the Clean Air Act (Act), 42 U.S.C. §7414, the Administrator and/or his/her authorized representatives have the right to enter and inspect for all purposes authorized under Section 114 of the Act. The permittee acknowledges that the Regional Administrator and/or his/her authorized representatives, upon the presentation of credentials shall be permitted:

1. to enter at any time upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this PSD Permit;

2. at reasonable times to access and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method required in this PSD Permit; and

4. to sample emissions from the source relevant to this permit.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

V. Transfer of Ownership

In the event of any changes in control or ownership of facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. The applicant shall notify the succeeding owner and operator of the existence of this PSD Permit and its conditions by letter, a copy of which shall be forwarded to the Regional Administrator.

VI. Severability

The provisions of this PSD Permit are severable, and, if any provisions of this PSD Permit are held invalid, the remainder of this PSD Permit shall not be affected thereby.

VII. Operating Requirements

1. Each ABB GT 11N distillate oil fired combustion turbine unit shall be limited to a maximum fuel consumption rate of 6,261 gallons per hour.

2. Each ABB GT 11N distillate oil fired combustion turbine unit shall use No. 2 distillate fuel oil which contains no more than:

   a. 0.15 percent sulfur by weight; and
   b. 0.10 percent nitrogen by weight.

3. Each ABB GT 11N distillate oil fired combustion turbine unit shall be limited to a maximum heat input of 847 million British Thermal Units per hour (MM Btu/hr), based upon lower heating value (LHV).

4. Except for startup and shutdown, each ABB GT 11N distillate oil fired combustion turbine unit shall only be allowed to operate at the following two heat input levels:

   a. base load (847 MM Btu/hr); and
   b. "spinning reserve" mode (581 MM Btu/hr).

5. Each ABB GT 11N distillate oil fired combustion turbine unit shall only be allowed to operate for up to 2,000 hours per year at the "spinning reserve" mode heat input level. Daily compliance shall be determined by adding the total amount of hours operated at the "spinning reserve" mode during each calendar day to the total hours operated at the "spinning reserve" mode in the preceding 364 calendar days.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

VII. Operating Requirements (cont'd)

6. For the purposes of this PSD permit, startup and shutdown shall be defined as:

   a. Startup for each ABB GT 11N distillate oil fired combustion turbine is defined as the period beginning with the initial firing of No. 2 fuel oil in the combustion turbine combustor and ending at the time when the load has increased to the "spinning reserve" mode. The duration of the startup shall not exceed six (6) consecutive hours for any given combustion turbine startup.

   b. Shutdown for each ABB GT 11N distillate oil fired combustion turbine is defined as the period of time beginning with the load decreasing from the "spinning reserve" mode and ending when the cessation of operation of the combustion turbine. The duration of the shutdown shall not exceed six (6) consecutive hours for any given combustion turbine shutdown.

7. At all times, including periods of startup, shutdown, and malfunction, PREPA shall, to the extent practicable, maintain and operate the three ABB GT 11N distillate oil fired combustion turbines including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA and/or EQB which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the plant.

VIII. Emission Limitations For Each ABB GT 11N Combustion Turbine

1. Oxides of Nitrogen (NO_x)

   a. The NO_x emissions shall not exceed 35 pounds per hour (lbs/hr) calculated as NO_2.

   b. The concentration of NO_x in the exhaust gas shall not exceed 10 parts-per-million by volume on a dry basis (ppmdv), corrected to 15% oxygen.

2. Sulfur Dioxide (SO_2)

   a. The SO_2 emissions shall not exceed 137 lbs/hr.

   b. The concentration of SO_2 in the exhaust gas shall not exceed 28 ppmdv, corrected to 15% oxygen.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

VIII. Emission Limitations For Each ABB GT 11N Combustion Turbine (cont'd)

3. **Sulfuric Acid Mist (H_2SO_4)**

   a. The H_2SO_4 emissions shall not exceed 32 lbs/hr.

   b. The concentration of H_2SO_4 in the exhaust gas shall not exceed 4.3 ppmdv, corrected to 15% oxygen.

4. **Carbon Monoxide (CO)**

   a. The CO emissions shall not exceed:

      (i) 104 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 20 lbs/hr at the base load heat input level.

   b. The concentration of CO in the exhaust gas, corrected to 15% oxygen, shall not exceed:

      (i) 71 ppmdv at the "spinning reserve" mode heat input level; and
      (ii) 9 ppmdv at the base load heat input level.

5. **Particulate Matter (PM)**

   a. The PM emissions shall not exceed:

      (i) 55 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 72 lbs/hr at the base load heat input level.

   b. The concentration of PM in the exhaust gas, corrected to 15% oxygen, shall not exceed:

      (i) 0.0191 grains per dry standard cubic feet (gr/dscf) at the "spinning reserve" mode heat input level; and
      (ii) 0.0171 gr/dscf at the base load heat input level.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

VIII. Emission Limitations For Each ABB GT 11N Combustion Turbine (cont'd)

6. Particulate Matter < 10 microns (PM-10)
   a. The PM-10 emissions shall not exceed:

      (i) 55 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 72 lbs/hr at the base load heat input level.

   b. The concentration of PM-10 in the exhaust gas, corrected to 15% oxygen, shall not exceed:

      (i) 0.0191 gr/dscf at the "spinning reserve" mode heat input level; and
      (ii) 0.0171 gr/dscf at the base load heat input level.

7. Volatile Organic Compounds (VOC)
   a. The VOC emissions (as methane) shall not exceed:

      (i) 11 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 13 lbs/hr at the base load heat input level.

   b. The concentration of VOC (as methane) in the exhaust gas, corrected to 15% oxygen, shall not exceed:

      (i) 13 ppmdv at the "spinning reserve" mode heat input level; and
      (ii) 11 ppmdv at the base load heat input level.

8. Lead (Pb):
   a. The Pb emissions shall not exceed:

      (i) 0.016 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 0.023 lbs/hr at the base load heat input level.

   b. The concentration of Pb in the exhaust gas, corrected to 15% oxygen, shall not exceed 5.0 μgr/dscf.

9. Ammonia (NH_4): The concentration of NH_4 in the exhaust gas shall not exceed 10 ppmdv, corrected to 15% oxygen.

10. Opacity limitation: Opacity of emissions, as measured by 40 CFR Part 60, Method 9, shall not exceed 20%, except for one period of not more than six (6) minutes in any thirty (30) minute interval when the opacity shall not exceed 60%.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

IX. Pollution Control Equipment

1. PREPA shall install and shall continuously operate at each ABB GT 11N distillate oil fired combustion turbine the following air pollution controls:

   a. a steam injection system; and
   b. a Selective Catalytic Reduction (SCR) system.

2. The steam to fuel ratio for each unit shall be established during the performance testing. PREPA shall comply with the steam to fuel ratio determined during the performance testing and contained within the written report submitted to EPA.

3. Each SCR system shall continuously use a zeolite catalyst and shall continuously operate in accordance with the manufacturer's design specifications.

4. Each ABB GT 11N distillate oil fired combustion turbine shall continuously use No.2 fuel oil in which:

   a. the sulfur content does not exceed 0.15% by weight; and
   b. the nitrogen content does not exceed 0.10% by weight.

5. Each ABB GT 11N distillate oil fired combustion turbine shall continuously operate in accordance with its designed specified combustion parameters.

X. Fuel Sampling Requirements

1. PREPA shall sample the fuel being fired in the three ABB GT 11N combustion turbines on each occasion that fuel is transferred to the storage tanks at the facility from any other source. The fuel sampling shall include but not be limited to determining the fuel's:

   a. sulfur content (% by weight); and
   b. nitrogen content (% by weight).

2. Compliance with the sulfur content standard shall be determined using the testing methods established in 40 CFR 60.335(d).

3. Compliance with the nitrogen content standard shall be determined using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XI. Continuous Emission Monitoring (CEM) Requirements

1. Prior to the date of startup and thereafter, PREPA shall install, calibrate, maintain, and operate the following continuous monitoring systems in each of the combustion turbine exhaust stack.

   a. A continuous opacity monitoring system (COMS) to measure and record stack opacity levels. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specifications 1).

   b. A continuous emission monitoring system (CEMS) to measure and record stack gas NO_x (as measured as NO_2) concentrations. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specifications 2, and Appendix F).

   c. A CEMS to measure and record stack gas oxygen concentrations. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specifications 3, and Appendix F).

   d. A CEMS to measure and record stack gas carbon monoxide concentrations. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specifications 4, and Appendix F).

   e. A CEMS to measure and record ammonia slip. Upon request of EPA, PREPA shall conduct a performance evaluation of the monitor when testing procedures are formalized by the Agency in the future.

   f. A continuous monitoring system to measure and record stack gas volumetric flow rates. The system shall meet all applicable EPA monitoring performance specifications of 40 CFR Part 60, Appendix A, Method 19.

   g. Continuous monitoring systems to measure and record stack temperatures and steam to fuel ratios. Upon request of EPA, PREPA shall conduct a performance evaluation of the monitor when testing procedures are formalized by the Agency in the future.

2. Not less than 90 days prior to the date of startup of each combustion turbine, PREPA shall submit a written report to EPA of a Quality Assurance Project Plan for the certification of the combustion turbine's monitoring systems. Performance evaluation of the monitoring systems may not begin until the Quality Assurance Project Plan has been approved by EPA.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XI. Continuous Emission Monitoring (CEM) Requirements (cont'd)

3. PREPA shall conduct performance evaluations of the COMS's, CEMS's and continuous monitoring systems during the initial performance testings required under Permit Condition XII of this permit or within 30 days thereafter in accordance with the applicable performance specifications in 40 CFR Part 60, Appendix B, and 40 CFR Part 52, Appendix E. PREPA shall notify the Regional Administrator (RA) 15 days in advance of the date upon which demonstration of the monitoring system(s) performance will commence.

4. PREPA shall submit a written report to EPA of the results of all monitor performance specification evaluations conducted on the monitoring system(s) within 60 days of the completion of the tests. The monitoring systems must meet all the requirements of the applicable performance specification test in order for the monitors to be certified.

XII. Performance Testing Requirements For Each Combustion Turbine

1. Within 60 days after achieving the maximum production rate of the combustion turbine, but no later than 180 days after initial startup as defined in 40 CFR Part 60.2, and at such other times as specified by the EPA, PREPA shall conduct performance tests for SO_2, H_2SO_4, NO_x, PM, PM_{10}, CO, VOCs, Pb and opacity at the combustion turbines. All performance tests shall be conducted at base load conditions, "spinning reserve" mode (60% load) conditions and/or other loads specified by EPA.

2. Three test runs shall be conducted for each load condition and compliance for each operating mode shall be based on the average emission rate of these runs.

3. At least 60 days prior to actual testing, PREPA shall submit to the EPA a Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XII. Performance Testing Requirements For Each Combustion Turbine (cont'd)

4. PREPA shall use the following test methods, or a test method which would be applicable at the time of the test and detailed in a test protocol approved by EPA:

   a. Performance tests to determine the stack gas velocity, sample area, volumetric flow rate, molecular composition, excess air of flue gases, and moisture content of flue gas shall be conducted using 40 CFR Part 60, Appendix A, Methods 1, 2, 3, and 4.

   b. Performance tests for the emissions of NO_x shall be conducted using 40 CFR Part 60, Appendix A, Method 7E.

   c. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60, Appendix A, Method 8.

   d. Performance tests for the emissions of H_2SO_4 shall be conducted using 40 CFR Part 60, Appendix A, Method 8.

   e. Performance tests for the emissions of PM shall be conducted using 40 CFR Part 60, Appendix A, Method 5.

   f. Performance tests for the emissions of PM_{10} shall be conducted using 40 CFR Part 51, Appendix M, Method 201 (exhaust gas recycle) or Method 201A (constant flow rate), and Method 202.

   g. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Appendix A, Method 10.

   h. Performance tests for the emissions of VOCs shall be conducted using 40 CFR Part 60, Appendix A, Method 25A.

   i. Performance tests for the emissions of Pb shall be conducted using 40 CFR Part 60, Appendix A, Method 12.

   j. Performance tests for the visual determination of the opacity of emissions from the stack shall be conducted using 40 CFR Part 60, Appendix A, Method 9 and the procedures stated in 40 CFR Part 60.11.

5. Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance.

6. Additional performance tests may be required at the discretion of the EPA or EQB for any or all of the above pollutants.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XII. Performance Testing Requirements For Each Combustion Turbine (cont'd)

7. For performance test purposes, sampling ports, platforms and access shall be provided by PREPA on each of the combustion turbine units in accordance with 40 CFR Part 60.8(e).

8. PREPA shall submit a written report to EPA of the results of all emission testing within 60 days of the completion of the performance test.

9. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.

XIII. Recordkeeping Requirements

1. Logs shall be kept and updated daily to record the following:

   a. the gallons of No. 2 fuel oil fired on an hourly basis at each ABB GT 11N distillate oil fired combustion turbine;

   b. the hours of operation of each ABB GT 11N distillate oil fired combustion turbine;

   c. the sulfur content of all fuel oil burned;

   d. the amount of steam consumed at each ABB GT 11N distillate oil fired combustion turbine to control NO_x emissions;

   e. the amount of electrical output (MW) on an hourly basis from each ABB GT 11N distillate oil fired combustion turbine;

   f. any adjustments and maintenance performed on each ABB GT 11N distillate oil fired combustion turbine;

   g. any adjustments and maintenance performed on monitoring systems; and

   h. all fuel sampling results obtained pursuant to Condition X of this permit.

2. All monitoring records, fuel sampling test results, calibration test results and logs must be maintained for a period of five years after the date of record, and made available upon request.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XIV. REPORTING REQUIREMENTS

1. PREPA shall submit a written report of all excess emissions to EPA for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each quarter and shall include the information specified below:

   a. The magnitude of excess emissions computed in accordance with 40 CFR Part 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.

   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions for each turbine unit. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted shall also be reported.

   c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

   d. When no excess emissions have occurred or the monitoring systems have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

   e. Results of quarterly monitor performance audits, as required in 40 CFR Part 60, Appendix F.

   f. For the purposes of this PSD Permit, excess emissions indicated by monitoring systems, except during startup or shutdown, shall be considered violations of the applicable emission limits.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XIV. REPORTING REQUIREMENTS (cont'd)

2. Any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner which results in an increase in emissions above any allowable emission limit stated in Permit Condition VIII of this permit and actions taken on any unit must be reported by telephone within 24 hours to:

   Chief, Air Permit Division
   Puerto Rico Environmental Quality Board
   P.O. Box 11488
   Santurce, Puerto Rico 00910
   (809) 767-8071

   In addition, the Regional Administrator (RA) and Puerto Rico Environmental Quality Board (EQB) shall be notified in writing within fifteen (15) days of any such failure. This notification shall include: a description of the malfunctioning equipment or abnormal operation; the date of the initial failure; the period of time over which emissions were increased due to the failure; the cause of the failure; the estimated resultant emissions in excess of those allowed under Condition VIII of this permit; and the methods utilized to restore normal operations. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violations of this permit or of any law or regulations which such malfunction may cause.

XV. OTHER REQUIREMENTS

1. PREPA shall meet all other applicable federal, state and local requirements, including but not limited to those contained in the Puerto Rico State Implementation Plan (SIP), the General Provisions of the New Source Performance Standards (NSPS) (40 CFR Part 60, Subpart A), and the NSPS for Stationary Gas Turbines (40 CFR, Part 60, Subpart GG).

2. All reports and Quality Assurance Project Plans required by this permit shall be submitted to:

   Chief, Air Compliance Branch
   United States Environmental Protection Agency
   Region II
   290 Broadway
   New York, New York 10007-1866

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XV. OTHER REQUIREMENTS (cont'd)

3. Copies of all reports and Quality Assurance Project Plans shall also be submitted to:

   a. Region II CEM Coordinator
   United States Environmental Protection Agency
   Region II
   Monitoring and Assessment Branch
   2890 Woodbridge Avenue - MS - 220
   Edison, New Jersey 08837-3679

   b. Director, Air Permit Division
   Puerto Rico Environmental Quality Board
   P.O. Box 11488
   Santurce, Puerto Rico 00910

ENGELHARD

Westinghouse 501G Turbine - Simple Cycle
NOxCAT™ ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal
April 10, 1998

ENGELHARD CORPORATION
NOxCAT™ ZNX™ HIGH TEMPERATURE SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply the **NOxCAT™ ZNX™** High Temperature Ceramic Substrate SCR system herein.

Scope of Supply
1. Engelhard **NOxCAT™ ZNX™** SCR catalyst modules;
2. Internal support structures for catalyst modules; includes all hardware and gaskets for catalyst module installation;
3. Internally insulated Ductwork with stainless steel liner to house AIG and SCR catalyst;
4. Ammonia Injection Grid (AIG);
5. External AIG manifold with flow control valves;
6. NH_3 Vaporization / Air dilution skid; 28% Aqueous Ammonia to skid

BUDGET PRICE: Per Unit	FOB, shipping point	**SCR Catalyst System**	**$2,700,000**
		Replacement SCR Catalyst	**$1,600,000**

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 18 months after delivery, whichever occurs first.
Performance Guarantee:	Three (3) years of operation* or thirty-six (36)) months after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life.

**Operation is considered to start when exhaust gas is first passed through the catalyst.*

Typical, useful catalyst life is 5 - 7 years.

DOCUMENT / MATERIAL DELIVERY SCHEDULE
Drawings / Documentation - 10 weeks after notice to proceed and receipt of engineering specifications and details

Material Delivery 24 - 30 weeks after approval and release for fabrication

QUALITY ASSURANCE and SAFETY
Engelhard's manufacturing is carried out under strict adherence to published quality control and statistical process control programs. and strict adherence to Corporate safety practices and procedures.

SCR SYSTEM DESIGN BASIS:

Gas Flow from:	Westinghouse 501G Combustion Turbine
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas and Oil (design for Natural Gas)
Gas Flow Rate (At catalyst face):	See Performance Data
Temperature (At catalyst face):	See Performance Data
CO Concentration (At catalyst face):	See Performance Data
NOx Concentration (At catalyst face):	See Performance Data
NH_3 Slip	10 ppmvd @ 15% O_2
Pressure Drop	Nom. 4.0 "WG

ENGELHARD

Westinghouse 501G Turbine - Simple Cycle
NOxCAT™ ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal
April 10, 1998

Performance Data

GIVEN / CALC. DATA			
LOAD	BASE	BASE	BASE
AMBIENT	90	59	30
FUEL	NG	NG	NG
TURBINE EXHAUST FLOW, lb/hr	4,224,240	4,581,360	4,790,880
TURBINE EXHAUST TEMPERATURE, °F	1147	1114	1099
TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	69.07	71.36	72.21
O_2	10.66	11.23	11.40
CO_2	4.03	4.06	4.09
H_2O	15.35	12.44	11.38
Ar	0.87	0.90	0.91
GIVEN: TURBINE NOx, ppmvd @ 15%O_2	25	25	25
GIVEN: TURBINE NOx, lb/hr	220	237	249
CALCULATED FLUE GAS MOL. WT.	27.65	27.97	28.09
GAS TEMP. @ SCR CATALYST, °F (+/-20)	1018	1014	994
DESIGN REQUIREMENTS			
NOx OUT, ppmvd@15%O_2	9	9	9
NH_3 SLIP, ppmvd@15%O_2	10	10	10
SCR PRESSURE DROP, Nom. 4.0 "WG - Max.			
GUARANTEED PERFORMANCE DATA			
NOx CONVERSION, % - Min.	64.0%	64.0%	64.0%
Nox OUT, ppmvd@15%O_2 - Max.	9	9	9
NOx OUT, lb/hr - Max.	79.1	85.4	89.5
EXPECTED AQ. NH_3 (28% SOL.) FLOW, lb/hr	287	310	325
NH_3 SLIP, ppmvd@15%O_2 - Max.	10	10	10
SCR PRESSURE DROP, "WG - Max.	3.5	3.5	3.5

GIVEN / CALC. DATA	
LOAD	BASE
AMBIENT	30
FUEL	OIL
TURBINE EXHAUST FLOW, lb/hr	4,901,040
TURBINE EXHAUST TEMPERATURE, °F	1056
TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	71.25
O_2	11.30
CO_2	5.51
H_2O	11.03
Ar	0.89
GIVEN: TURBINE NOx, ppmvd @ 15%O_2	42
GIVEN: TURBINE NOx, lb/hr	433
CALCULATED FLUE GAS MOL. WT.	28.35
GAS TEMP. @ SCR CATALYST, °F (+/-20)	959
DESIGN REQUIREMENTS	
NOx OUT, ppmvd@15%O_2	ADVISE
NH_3 SLIP, ppmvd@15%O_2	10
SCR PRESSURE DROP, Nom. 4.0 "WG - Max..	
EXPECTED PERFORMANCE DATA	
NOx CONVERSION, % - Min.	69.0%
NOx OUT, ppmvd@15%O_2 - Max.	13
NOx OUT, lb/hr - Max.	134.3
EXPECTED AQ. NH_3 (28% SOL.) FLOW, lb/hr	506
NH_3 SLIP, ppmvd@15%O_2 - Max.	10
SCR PRESSURE DROP, "WG - Max.	3.5

ENGELHARD

Westinghouse 501G Turbine - Simple Cycle
NOxCAT™ ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal
April 10, 1998

Scope of Supply: The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

- Engelhard **NOxCAT™ ZNX™** SCR catalyst modules;
- Internal support structures for catalyst modules; includes all hardware and gaskets for catalyst module installation;
- Internally insulated Ductwork with stainless steel liner to house CO catalyst, AIG, and SCR catalyst;
- Ammonia Injection Grid (AIG);
- External AIG manifold with flow control valves;
- NH_3/Air dilution skid: Pre-piped & wired (including all valves and fittings)
  - Two (2) dilution air fans, one for back-up purposes
  - Panel mounted system controls for:
    - Fans (on/off/flow indicators)
    - System pressure indicators
    - Air/ammonia flow indicator and controller
    - Main power disconnect switch

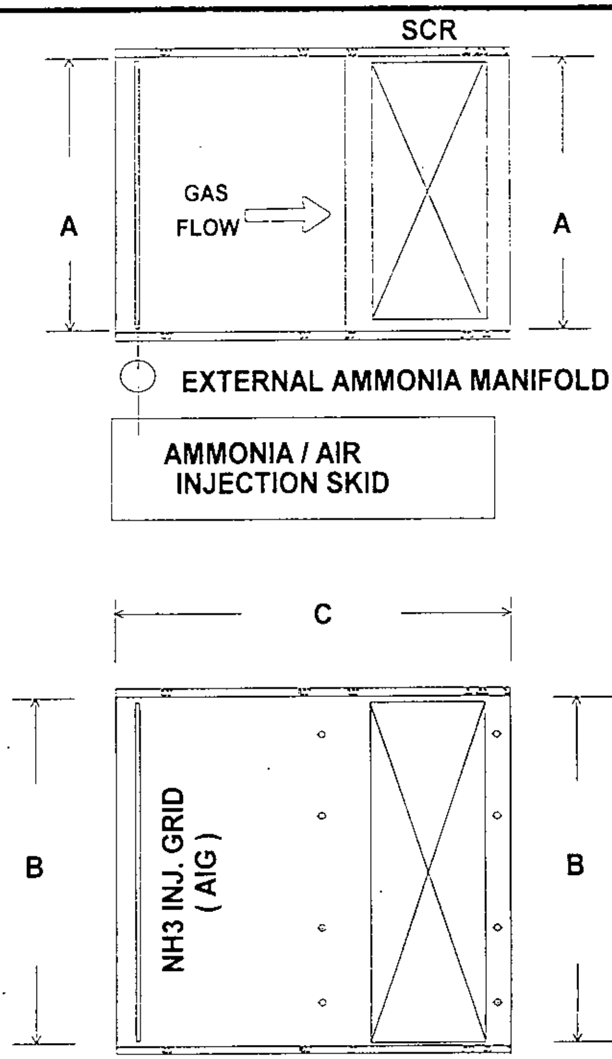
Excluded from Scope of Supply:

Ammonia storage and pumping
Interconnecting field piping or wiring
Inlet and Outlet transitions including any flow models and flow straighteners
Electrical grounding equipment
Utilities
Foundations
All Monitors
All other items not specifically listed in Scope of Supply

Dimensions: Estimated

Reactor Inside Liner Width	(A) 63'-0"
Reactor Inside Liner Height	(B) 37'-0"
Reactor Depth - Total	(C) 12'-0"

Note: Cross section - dimensions can vary due to site



ENGELHARD

ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

April 10, 1998

Florida DEP

ATTN: **Alvaro Linero** via e-mail

RE: **Westinghouse 501G / Simple Cycle**
SCR Catalyst System
Engelhard Budgetary Proposal EPB98154

Dear Mr. Linero,

We enclose Engelhard Budgetary Proposal EPB98154 for Engelhard **NOxCAT™ ZNX™** High Temperature SCR Catalyst System.

This Proposal includes:

- Engelhard **NOxCAT™ ZNX™** High Temperature SCR Catalyst System;
- Catalyst is are sized NOx reduction from 25 ppmvd @ 15%O_2 to 9 ppmvd @ 15%O_2 with ammonia slip of 10 ppmvd @ 15%O_2 for natural gas; performance is estimated during oil firing;reduction at Full Load (Oil);
- Aqueous Ammonia (28% Solution to skid) Delivery System;
- Internally insulated ductwork;
- Guaranteed Performance Data based on the design basis noted;
- Assumed OTSG downstream of gas turbine.
- Dimensions illustrated per enclosed sketches are duct - inside liner dimensions. These dimensions were estimated based on square cross section from OTSG discharge and estimated inlet transitions (2W = 1H) to SCR reactor inlet.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Sales Engineer

cc: Lorraine Pierson - Proposal Administrator

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

March 9, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

We received additional information from the City on March 5 and are reviewing it prior to a scheduled meeting with your staff, consultant, and the manufacturer. We did want to provide you with a first impression on some of the information provided by the City.

References were made to other projects where hot SCR was not employed for comparison with the Lakeland project. The first is a project in Cataula, Georgia, where several 501 G units will be built and for which the State has set a limit of 25 ppm. Our own review indicates that the units will indeed be operated in a simple cycle mode but actually comprise a peaking station. The nature of such operation tends to make hot SCR or any NOx control strategy appear less feasible because the costs are spread out over limited hours of operation. This project is not, therefore, directly comparable with the Lakeland project.

The second project is a 400 MW simple cycle facility planned by CCC in Virginia. The references in the City's submittal indicate that hot SCR was rejected and that the decision was upheld by the EPA Environmental Appeals Board. Reference was made to a cost of $8500 per ton of NOx removed by hot SCR and that the City's cost estimates are well within that value. Our inspection of the decision indicates that the three units will operate no more than 2000 hours per year each. Also they are limited to 500 hours each at full load. Again, the peaking nature of these units inflates the control costs and does not allow a direct comparison with the Lakeland project.

No reference was made to another project mentioned in the same decision. It is for a 248 MW simple cycle base load station in Puerto Rico. In that case EPA required hot SCR and the costs were estimated at $2,200 per ton of NOx removed. Although the installation consists of three small units adding up to 248 MW, that is the project we have found most directly comparable to the Lakeland project (if operated as a simple cycle base loaded unit).

No reference was made to a project by U.S. Generating to build a Westinghouse 501 G combined cycle unit in Massachusetts. In that case, the State set a limit of 3.5 ppm of NOx to be achieved by low temperature SCR. This project is identical to that planned by the City if it operates the facility as a combined cycle project.

We plan to expedite the permitting process to insure that a permit will be issued before the deadline of July 15, 1998. We will need cooperation from all concerned to insure that we have all of the relevant information necessary to justify our final BACT determination. We especially need to know directly from Westinghouse how much time they actually need to develop their dry low NOx technology preferred by the City. We will discuss these and other matters at length with your representatives and Westinghouse at the scheduled meeting. If you have any questions regarding this matter, please contact me at 850/921-9523 or Teresa Heron at 921-9529.

Sincerely,

AA Linero 3/9

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/aal

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ronald W. Jordin
Assistant Managing Dir
Lakeland Electric & Water
501 E. Lemon St.
Lakeland, Fl 33801-5079

4a. Article Number
P 265 659 304

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
3-12-98

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X [signature]

PS Form **3811**, December 1994

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Thank you for using Return Receipt Service.

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Receipt for Certified Mail
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Street & Number Lakeland Electric	
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Special Delivery Fee	
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Return Receipt Showing to Whom & Date Delivered	
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TOTAL Postage & Fees	$
Postmark or Date 3-10-98	

1050004-004-AC
PSD-FL-245

PS Form **3800**, April 1995

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW
ATLANTA, GEORGIA 30303-8909

al

MAR 0 6 1998

RECEIVED

MAR 11 1998

BUREAU OF
AIR REGULATION

4APT-ARB

Mr. Claire H. Fancy, P.E.
Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

SUBJ: PSD Permit Application from City of Lakeland, McIntosh Power Plant, Lakeland, Florida (PSD-FL-245)

Dear Mr. Fancy:

This letter is a follow-up to our February 10, 1998, comment letter regarding the Prevention of Significant Deterioration (PSD) permit application for the above referenced facility. The application is for the construction of a 250 MW simple-cycle combustion turbine (CT) at the existing McIntosh Power Plant. Our initial air quality impact assessment review comments and questions were discussed with Mr. Cleve Holladay of the Florida Department of Environmental Protection on February 23 & 26, 1998. Taking cognizance of these discussions, only the following ambient air impact assessment comment is provided for your consideration. Please note that our review did not include the electronic input and output data records associated with the air quality modeling analyses.

Limitation on Turbine Operation - The modeling ambient air impact analysis has turbine limits on the annual hours of operation (7,008 hours), amount of backup fuel oil burned (maximum of 250 hours per year), and hours of operation at 50 percent load (1,000 hour when burning natural gas and 50 hours when burning fuel oil). These operational limits for the proposed combustion turbine should appear in the permit.

In summary, the ambient impact modeling provided in the PSD application appears appropriate for the proposed operation of the simple-cycle combustion turbine and demonstrates compliance with appropriate PSD increments and NAAQS.

Thank you for the opportunity to review and comment on this application. If you have any questions regarding the contents of this letter, please contact Stan Krivo of my staff at (404)562-9123.

Sincerely yours,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides, and Toxics Management Division

cc: J. Heron, BAR
SWD
Polk Co
NPS
J. Shelton, C of L
K. Kosky, Golder Assoc.

LAKELAND ELECTRIC & WATER

(813) 499-6603

Excellence Is Our Goal, Service Is Our Job

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

March 4, 1998

RECEIVED

MAR 05 1998

BUREAU OF
AIR REGULATION

Mr. A.A. Linero P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
111 S. Magnolia
Suite 4
Tallahassee, Fl 32301

RE: DEP FileNo. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine
Information Addressing Review Comments

Dear Al:

The City of Lakeland Department of Electric and Water Utilities (City) is submitting with this correspondence information addressing the letters dated January 5 and 12, 1998 from the Department, the January 12, 1998 letter from the U.S Department of Interior Fish and Wildlife Service, and the February 10, 1998 letter from the Environmental Protection Agency Region IV Air and Radiation Technology Branch. The information addressing these comment letters is attached along with the appropriate certifications.

Because of the importance of this project to the City of Lakeland, a meeting was held on February 17, 1998 with Mr. Howard Rhodes, Director Division of Air Resource Management and Mr. Clair Fancy, Chief of the Bureau of Air Management to present technical and management perspectives of the project. Also in attendance were Teresa Herron of your Section and FDEP Lawyer Scott Goorland. Representing the City were, Mr. Ronald Tomlin, Assistant Managing Director, Mr. Al Dodd, Project Manager for New Generation, Mr. Ken Kosky of Golder Associates, the engineer-of-record for the permit application, and I.

Much of the information presented herein was discussed at the February meeting. It became apparent during the course of the meeting that the City of Lakeland has a unique opportunity to provide savings to its customers while furthering the development of "clean" and "efficient" combustion turbine technology for Florida's future. Toward this goal, the City proposed, and the Department representatives indicated that they would consider, a staged emission limit strategy. The proposed strategy would commit the City to lowering NOx emissions rates when firing natural gas from the proposed 25 ppmvd (corrected to 15 percent oxygen) to 9 ppmvd (corrected to 15 percent oxygen) with 12

City of Lakeland ⊙ Department of Electric & Water Utilities
.ast Lemon Street ○ Lakeland, FL 33801-5050 ○ (813) 499-6300 ○ Fax 499-6344 ○ Message System 499-6592

March 4, 1998

Mr. A.A. Linero P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
111 S. Magnolia
Suite 4
Tallahassee, Fl 32301

ppmvd (corrected to 15 percent oxygen) on thirty days rolling average no later than 5 years after the initial startup of the Westinghouse 501G (Unit No. 5). This approach has been used by the Department in the development of DLN with much less efficient combustion turbines than Unit No. 5 and in combined cycle configurations where low temperature SCR is both more economic and more technically feasible. Further, the City would commit to firing oil only during emergency conditions as backup to natural gas firing.

The City's commitment for future compliance with the lower NOx emission would be accomplished by installing advanced dry low-NOx combustion technology which is being developed by Westinghouse and GE in the Advanced Turbine System (ATS) program sponsored by the US Department of Energy. The ATS program will be completed in the year 2000 with the expected outcome of producing advanced DLN combustors capable of NOx emission of 9-12 ppmvd (corrected to 15 percent oxygen). The Unit No. 5 retrofit with this ATS NOx control combustor, when available, is the City's first choice in its commitment to the Department.

Additionally, as discussed in the application and as discussed with the Florida Pubic Service Commission, the City anticipates that Unit No. 5 may be converted to combined cycle configuration within 5 years. When this event occurs, the City has two economically viable alternatives. The first and preferred option would be to install the advanced DLN combustion technology which is truly pollution preventing. However, if for any reason the new DLN could not achieve 9-12 ppmvd (corrected to 15 percent oxygen), then the City would install a low temperature SCR on this combined cycle unit. While SCR has environmental drawbacks associated with the use of ammonia, the low temperature SCR technology is well established with known economic consequences.

As discussed at the meeting, the City's opportunity for the project as well as its electric needs are within a relatively short time frame, deadline of July 15, 1998. Therefore, permitting of Unit No. 5 is desired by July 15 of this year if the City is to meet its obligations. Given the importance and schedule, we would like to meet with you and your staff to discuss any remaining questions you may have after the review of the enclosed

March 4, 1998

Mr. A.A. Linero P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
111 S. Magnolia
Suite 4
Tallahassee, Fl 32301

information. It would be desirable to have this meeting within the next two weeks so that we can supply the Department with any further information you may need within your review period. To this end I would endeavor to contact you within the next few days so that we can arrange an amicable meeting date.

As always, your cooperation and assistance is most appreciated.

Sincerely,

Farzie Shelton
Manager of Environmental Permitting/Compliance
Production Division

Enc.

cc: Clair Fancy, FDEP
Howard Rhodes, FDEP
Hamilton Oven, FDEP
Kennard Kosky, Golder Associates
Ron Tomlin
Al Dodd

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:

   Ronald W. Tomlin, Assistant Managing Director

2. Owner/Authorized Representative or Responsible Official Mailing Address:

   Organization/Firm: **Lakeland Electric & Water Utilities**
   Street Address: **501 East Lemon Street**
   City: **Lakeland** State: **FL** Zip Code: **33801-5079**

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:

   Telephone: **(941) 499-6300** Fax: **(941) 499-6344**

4. Owner/Authorized Representative or Responsible Official Statement:

   I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*

   Ronald W. Tomlin
   Signature

   3-4-98
   Date

* Attach letter of authorization if not currently on file.

4. Professional Engineer's Statement:

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

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

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

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

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

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

Kennard F. Kosky   2 March 1998

Signature   Date

(seal)

* Attach any exception to certification statement.

INFORMATION ADDRESSING FDEP, US FISH AND WILDLIFE SERVICE, AND EPA COMMENT LETTERS

Information Addressing the January 5, 1997 FDEP

Lakeland 250 MW Combustion Turbine Project (Westinghouse 501G

Pollutant Emissions

1. Please refer to the attached Tables A-2a, A-6a, A-10a and A-15a which include the lb/mmBtu emission rates. These are calculated by dividing the mass emission rate in lb/hr by the heat input (HHV) in mmBtu/hr. The basis of the calculations for lb/mmBtu is shown on the tables.

2. Table 2-5 presents operation scenarios that envelope the potential emissions from the project. The emissions listed as Maximum Option A reflects 100 percent load with gas-firing at 6,758 hours/year and oil firing at 250 hours/year. The emissions listed as Maximum Option B reflects worst case emissions with 50 percent load operation for 1,000 hours/year when firing gas and 50 hours/year when firing oil. It is intended that the unit could operate under various load conditions reflected by annual emissions encompassed by the emissions in Table 2-5. The emissions presented in Table 2-5 are representative of potential emissions as defined under FDEP regulations (as defined in Rule 62-210.200 F.A.C.).

3. The sulfur content in Fuel Analysis table in Appendix A is a typographical error. This has been corrected on the attached updated table.

Power Augmentation:

4. The term "power augmentation", as used in the permit application, is a misnomer inaccurately describing the primary purpose of the once-through steam generator (OTSG). The purpose of the OTSG is to generate steam needed for cooling the hot section components of the combustor transition. This cooling steam is required at all times when the turbine is operating. After the steam provides cooling, it is injected into the combustor and increases the mass flow of the turbine with an artifact of increasing power by about 19 MW (ISO) when firing gas. Without the OTSG, steam would be required from another source, e.g., an existing boiler, a brand new auxiliary boiler or a heat recovery steam generator (HRSG). The OTSG provides steam without any additional fuel usage. When oil is fired, there is no increase in power, since water must be used for NOx control.

5. Papers describing the Westinghouse DLN technology are attached. The rotor inlet temperature of the 501G is 1,429°C (2,600°F). In contrast, the rotor inlet temperature of the 501F is 1,350°C

(2,460°F). The higher inlet temperatures produce the additional power output and efficiency. Please refer to Appendix A, which provides technical article on the 501G technology.

6. As discussed in the response to Question 4, the purpose of the OTSG is to recover energy from the CT exhaust to produce steam for cooling. The estimated heat recovered from the exhaust is 131 mmBtu/hr (ISO conditions). The steam produced cools the "hot" section components within the CT. The steam will then be vented into the combustion shell, increasing the mass flow and power output (refer to attached diagrams). As described in the application, the vented steam does not reduce the units heat rate; in fact at ISO conditions there is a 1.5 percent decrease in heat rate making the 501G operating in this mode even more efficient. In the event a HRSG were added, the OTSG would no longer be needed since the HRSG could supply steam cooling.

7. This information has already been provided in Appendix A and is described in the 501G Application Overview developed by Westinghouse. The performance and emissions data is for a condition where the steam in not vented through in the combustor. It is possible to vent the steam directly to the atmosphere after it performs the cooling function rather than into the turbine. However, this would result in the waste of useful energy the steam provides and would decrease the units efficiency. The increase in power and efficiency resulting from the discharge of cooling steam in the combustor does not increase the emission rates or heat rate of the 501G, since no additional fuel is used to generate the steam.

8. There is no increase in NO_x emission rates as a result of allowing cooling steam to be discharged with the combustion gases. The primary and only method for NO_x control when firing natural gas is the dry low- NO_x combustor technology. Again, steam cooling is essential for the operation of the unit and must occur continuously whenever the unit is operating. Discharging the steam into the combustor provides useful energy that would otherwise be lost. The decrease in heat rate alone provides for an additional 3.45 MW with the same fuel usage. This amounts to 24,177,600 kilowatt hours per year of additional electrical output. If the steam were required from an additional source, than at least 131 mmBtu/hr would be required to produce the necessary steam. This would result in an additional 46 tons NOx per year and nearly 900 million cubic feet of additional natural gas usage.

9. As described above, cooling steam must be supplied continuously. Rather than wasting the steam's energy, it is used for useful work. Please refer to the information in the response to Questions 6, 7, and 8.

10. The use of the cooling steam results in additional power available at all times when the unit is operating. This additional power is available to the City of Lakeland to meet electric demands. If this power were not available, this lost power would otherwise have to be replaced using older, less efficient, and more polluting technology. Because of the efficiency of the 501G and the useful work the cooling steam provides. Overall NO_x emissions (lb/MW) would decrease with the operation of the 501G. For example, for every pound of NOx emitted from the 501G, there would be 3 less pounds of NOx emitted from other existing plants. The total power produced by the 501G would conservatively result in an annual decrease of 2,485 tons/year of NOx emitted from older units. There would also be a concomitant savings of fuel usage with the 501G. The 501G would conservatively save 1.5 billion cubic feet of natural gas and save $4.23 million per year.

11. The injection of cooling steam into the combustor will be a continuous when the unit is operating. Please also refer to the response to Questions 4, 6, 7, 8 and 10.

Best Available Control Technology:

12. The BACT evaluation was performed using SCR with DLN for natural gas firing (6,758 hours/year) and SCR with wet injection for oil firing (250 hours/year). This design was contrasted with DLN for natural gas firing and wet injection for oil firing as proposed for the project.

13. The City of Lakeland went through a bidding process to obtain information from various power suppliers on the economics and time frames for meeting the City's electric power requirements. This process led to the selection of the 501G as the best alternative to meet the near term load requirements in 1999. While other manufactures may have combustion turbine technologies that have lower NO_x emission rates, they are less efficient. The City's evaluation included consideration of 3 General Electric (GE) Frame 7EA combustion turbines. The attached Table B-8 is an analysis of the GE Frame 7EA at NOx emission rates of 15 ppmvd and 12 ppmvd (corrected to 15 percent oxygen). As shown, the capital cost of the 501G is $49.5 million in contrast to $65 million for 3 GE Frame 7EAs. Moreover, the resulting lower efficiency of the GE Frame 7EA results in an additional annual fuel cost of $7.3 million per year. The cost effectiveness ranges from $25,876 to $33,828 per ton of NO_x

removed. The "F" Class combustion turbine has a nominal rating of about 150 MW, which by itself is insufficient to meet the electric demand requirements. As described in the application, while this class of CT is more efficient than "E" class machines, it is still 10 percent or more less efficient than the proposed 501G. While a combination of two "F" Class machines results in more power than is being requested by the City of Lakeland (i.e., 300 MW for two "F" Class units compared to the 250 MW for the 501G), the cost effectiveness of two "F" Class units were evaluated. The attached Table B-9 is an analysis of two Frame 7F Class combustion turbines at NO_x emission rates of 15 ppmvd and 12 ppmvd (corrected to 15 percent oxygen). As shown, the capital cost of the 501G is $49.5 million in contrast to $61.8 million for 2 Frame 7F Class machines. The lower efficiency of the Frame 7F results in an additional annual fuel cost of $5.8 million per year. The cost effectiveness ranges from $16,216 to $19,770 per ton of NOx removed.

14. The City is aware that for the smaller and less efficient "E" and "F" class combustion turbines, guaranteed NO_x emission rates can be 15 ppmvd (corrected to 15 percent oxygen) and less. Combinations of such machines, as described in the response to Question 13, would be uneconomical. As described in the cover letter, Westinghouse and GE are conducting research on an advanced turbine design that includes the use of dry-low NOx combustors that can achieve levels of 12 ppmvd (corrected to 15 percent oxygen) or less. This research will be completed in the year 2000. The City's first choice is to install advanced combustors developed from this research to achieve an emission level of 12 ppmvd or less no later than 5 years from unit startup.

15. The analysis was performed for the combustion turbine operating at 100 percent load and 80 percent capacity factor. Table 4-1 used capacity to reflect load; it should have indicated 100 percent load rather than 100 percent capacity and has been updated. Updated Table 4-1a has been attached.

16. The catalyst evaluated is a high temperature catalyst design which is available from several vendors. In the context of the specific technology application, there would not be any difference in performance between that proposed and the type of ceramic catalysts cited in the permit application. Conversion of SO_2 to SO_3 may occur even with ceramic catalysts, since fuel metals such as vanadium may deposit on catalyst surfaces and increase activity for catalytic gas reactions. While this may occur, this concept was not considered to be problematic in the BACT analysis. For the type of catalyst evaluated, the primary technology issue is maintaining the temperature below 1,100°F to ensure that thermal damage would not occur. This damage would also occur with ceramic catalysts. The use of

any "hot" SCR catalyst would not even be possible without the OTSG that reduces the temperature below 1,100°F. In any event, sufficient temperature monitoring would have to be installed to insure that the catalyst modules are not damaged. The vendor has guaranteed an ammonia slip rate of 10 ppmvd at 15 percent O_2. Some catalysts may consist of metals that could classify it as a hazardous waste. Since a final vendor was not selected, this may be a possibility if SCR was required. Nonetheless, in this permit application, only a nominal cost was included to account for catalyst disposal.

17. The NO_x emissions at the inlet to the SCR were those proposed for the project without SCR, i.e., 25 ppmvd at 15 percent O_2 for gas firing and 42 ppmvd at 15 percent O_2 for oil firing. These are the emission levels provided by the turbine manufacturer. Please note that DLN and wet injection provide the most cost effective initial NOx control to the proposed emission level and it reduces the catalyst size and ammonia usage. The DLN technology accomplishes this without other potential environmental impacts associated with SCR.

18. Table 4-3 has been adjusted to present a recalculation of ammonium sulfate formed. Table 4-3a is attached and is based on secondary emissions from a relatively efficient (i.e., 10,000 BTU/kWh) steam generating units using 1 percent sulfur oil. This is considered a low-order estimate of emissions, since it assumes that the lost energy caused using SCR would be replaced by more costly but cleaner oil-fired units. This type of unit would be those used for cycling which replace incremental power demands. In reality, secondary emissions could be much higher. Refer to Table 3-3 for proposed SO_2 and SO_3 emission rates.

19. Is not practical to reduce the stack temperature to 600°F to 700°F with dilution air. The stack gas flow is too large to practically reduce the CT exhaust temperature to this level. As discussed above in responses to Questions 4 and 6-10, the OTSG is necessary to supply cooling steam. This reduces temperature to allow installation of a "hot" SCR. Without the OTSG, "hot" SCR would not be possible. At the actual CT exhaust temperatures, the catalyst would be irreparably damaged.

20. The economic analysis of the BACT evaluation was based on the budget estimate provided by Engelhard.

21. All the information provided by Engelhard on the SCR system was included in Appendix B of the application. A budget estimate was also obtained from Mitsubishi Heavy Industries (MHI). This estimate was \$3,590,000 for an SCR system alone compared to the Engelhard estimate of \$3,740,000 for the SCR components alone (\$2.8 million for the catalyst and \$940,400 for associated equipment). MHI did not quote a CO catalyst. The Engelhard budget estimate was used for both the NO_x and CO BACT evaluations, since the cost difference was minor and the combination of the CO catalyst and SCR from one vendor would be a more practical engineering design approach. Please note that the overall capital cost of SCR was estimated to be \$7.3 million which includes considerable modifications to the stack structure to install catalyst modules.

22. A "cold" SCR cannot be applied to simple cycle operation. In the event a HRSG was added, the OTSG would not be used and would allow consideration of adding a "cold" SCR. A "hot" SCR system, if installed for simple cycle, would have to be removed. It could not operate at CT exhaust temperatures without the OTSG. It should be recognized that the "hot" SCR catalyst is substantially higher, i.e., about twice the cost, than the catalyst of a "cold" SCR system (see information addressing January 12, 1998 FDEP letter). This results in lower cost effectiveness for a "cold" SCR system which was estimated to be less than \$4,000 per ton of NO_x removed and included in the permit application.

23. Westinghouse does not offer an emission rate lower than 25 ppmvd corrected to 15 percent O_2 for NO_x. However, as previously discussed, Westinghouse is undergoing research as part of a Department of Energy project to develop an advanced combustion turbine including dry low NOx combustion technology. It is the City's first choice to install a more advanced dry low NO_x combustion system, if available from Westinghouse, no later than 5 years after plant startup.

24. As provided in the response to Question 5, additional information on the dry low NOx combustion technology is being submitted. In addition, a Westinghouse Executive Summary describing the 501G is attached. This information, together with the available information on the performance of the combustion turbine and the SCR has been included in the application. It should be noted that the information provided in the application is consistent with (and in some cases more than) that provided in permit applications for similar projects.

25. The economic analysis involving SCR included 250 hours per year of oil firing. The vendor budget estimate included consideration for 250 hours/year of oil firing.

26. The Capital Recover Factor (CRF) was based on 10 percent as provided in the OAQPS Cost Control Manual (EPA 450/3-90-006). The CRF, as used in the application, reflects all cost associated with financing capital projects including interest expense, allowance for funds used during construction (AFUDC) and financing and carrying charges. The CRF thus takes into account more than just simple interest. The CRF used in the BACT analysis reflects appropriate costs for the City of Lakeland and is identical to that used by the City in its evaluation of alternatives.

27. Increasing the combustion temperatures increases NO_x formation. Since the design process considers the reduction of NO_x through DLN, uncontrolled NO_x levels are only theoretical. It is estimated that the increased firing temperature results in an additional 20 to 30 ppmvd above "F" Class uncontrolled NO_x emission levels (which are estimated at about 180 ppmvd). The DLN technology has been designed to accommodate the higher firing temperatures while limiting NO_x emissions to 25 ppmvd.

28. The cost effectiveness of $5,800 to $8,435 per ton of NO_x removed (see revised Tables 3a and 4a), reflects the cost effectiveness for installation and operation of SCR for 5 years. The cost effectiveness of SCR for 3 year simple cycle operation is $7,000 to $10,200 per ton of NO_x removed (see revised Tables 3b and 4b). As discussed in the response to Question 20, Engelhard Corporation and MHI were contacted to develop the information. Mr. Kennard F. Kosky of Golder Associates, Inc. performed the calculations. A recent decision by the EPA Environmental Appeals Board in the Commonwealth Chesapeake Corp. PSD Appeal found that Virginia Department of Environmental Quality (VDEQ) issuance of a PSD permit not requiring "hot" SCR for three simple cycle combustion turbines was appropriate (1997 WL 94742 EPA; PSD Permit No. 001-00030). In this case, the annualized cost of installing "hot" SCR on three 132.5 MW combustion turbines as $8,308,756 or about $20,900 per MW. The cost effectiveness estimated for the 501G was $13,900 per MW ($3,462,000 divided by 249 MW) for 5 year operation. Clearly, the estimated cost for the 501G is well within other estimates for this technology.

29. The cost effectiveness of $5,800 to $8,435 per ton of NO_x removed, when compared to other projects for which BACT was determined, is similar and higher than values where the Department rejected SCR as BACT. In fact, the Department stated in the City of Tallahassee Site Certification Hearings, that SCR was rejected at a cost effectiveness of $5,200 per ton of NO_x removed. Also,

information was provided on Page 4-9 regarding the Gainesville Regional Utilities (GRU) simple cycle project which was permitted in 1995 (PSD-FL-212) and the most current simple cycle project approved by the Department. In the GRU project, "hot" SCR was evaluated and rejected by the Department as not being cost effective. The BACT determination states: "the incremental cost effectiveness ($/ton) of controlling NO_x is $6,672.58 for this project ($17,333 per MW). These calculated costs are higher than costs previously approved as BACT." As demonstrated in the information provided, the cost effectiveness for this project is clearly in the range and higher when net pollutants are considered, than the cost effectiveness considered inappropriate for the GRU project. Indeed, as shown on Page 4-9, the 501G project compares more favorably than the GRU project when the NO_x emissions per MW are considered. The previous simple cycle projects involved the City of Kissimmee (1992; PSD-182), Florida Power Corporation DeBary Plant (1991; PSD-FL-167), and Florida Power Corporation Intercession City (1992; PSD-FL-180). In all these projects, SCR was rejected and DLN and wet injection were used to control NO_x.

30. Water injection for the 501G will only be used when firing distillate oil for a maximum of 250 hours/year as emergency backup. The City is willing to accept a permit that specifies the use of oil as emergency backup in the event natural gas is curtailed or oil-firing is required for emergency purposes (e.g., forced outages of units, hurricanes, etc.). The cost effectiveness of water injection alone has not been calculated since the appropriate comparison is between SCR and the Westinghouse DLN technology. However, given that uncontrolled NO_x emissions with oil firing would likely exceed 200 ppmvd, the cost effectiveness of water injection is likely to be in the $100s per ton of NO_x removed.

Table A-2a. Maximum Emissions for Criteria Pollutants for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Natural Gas, Base Load (100%)

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F
Hours of Operation	7008	7008	7008
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer			
Basis (excludes H2 SO4), lb/hr	8.5	8.8	9.1
Emission rate (lb/hr)- provided	8.5	8.8	9.1
(TPY)	29.8	30.8	31.9
(MMBtu/hr)	0.0038	0.0036	0.0036
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2 /lb S) /100			
Fuel density (lb/ft3)	0.0432	0.0432	0.0432
Fuel use (cf/hr)	2,230,213	2,407,390	2,523,662
Sulfur content (grains/ 100 cf)	1	1	1
lb SO2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	6.4	6.9	7.2
(TPY)	22.3	24.1	25.3
(MMBtu/hr)	0.0029	0.0029	0.0029
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O2	25	25	25
Moisture (%)	15.35	12.44	11.38
Oxygen (%)	10.66	11.23	11.4
Volume Flow (acfm)	2,911,153	3,055,750	3,151,297
Temperature (°F)	1,128	1,095	1,080
Emission rate (lb/hr)- calculated	206.6	222.6	233.5
(TPY)- vendor	770.9	830.4	872.5
(lb/hr)- vendor	220	237	249
(MMBtu/hr)	0.0984	0.0983	0.0985
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	50	50	50
Moisture (%)	15.35	12.44	11.38
Volume Flow (acfm)	2,911,153	3,055,750	3,151,297
Temperature (°F)	1,128	1,095	1,080
Emission rate (lb/hr)- calculated	178.6	198.0	208.7
(TPY)- vendor	665.8	739.3	777.9
(lb/hr)- vendor	190	211	222
(MMBtu/hr)	0.0850	0.0875	0.0878
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	4	4	4
Moisture (%)	15.35	12.44	11.38
Volume Flow (acfm)	2,911,153	3,055,750	3,151,297
Temperature (°F)	1,128	1,095	1,080
Emission rate (lb/hr)- calculated	8.2	9.1	9.5
(TPY)- vendor	31.5	35.0	35.0
(lb/hr)- vendor	9	10	10
(MMBtu/hr)	0.0040	0.0041	0.0040
Lead (lb/hr)= NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: Westinghouse, 1997; EPA, 1996

Table A-6a. Maximum Emissions for Criteria Pollutants for City of Lakeland- McIntosh Project
Westinghouse 501G, Dry Low NOx Combustor, Natural Gas, 50 Percent Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F
Hours of Operation	1,000	1,000	1,000
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer			
Basis (excludes H_2SO_4), lb/hr	6.5	6.6	6.7
Emission rate (lb/hr)- provided	6.5	6.6	6.7
(TPY)	3.3	3.3	3.4
(MMBtu/hr)	0.0048	0.0045	0.0044
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) /100			
Fuel density (lb/ft3)	0.0432	0.0432	0.0432
Fuel use (cf/hr)	1,363,154	1,456,172	1,513,754
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	3.9	4.2	4.3
(TPY)	1.9	2.1	2.2
(MMBtu/hr)	0.0029	0.0029	0.0029
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2	45	45	45
Moisture (%)	12.68	9.68	8.61
Oxygen (%)	12.84	13.37	13.54
Volume Flow (acfm)	2,094,759	2,158,484	2,199,524
Temperature (°F)	984	960	944
Emission rate (lb/hr)- calculated	226.3	241.4	251.2
(TPY)- vendor	120.5	128.5	143.5
(lb/hr)- vendor	241	257	287
(MMBtu/hr)	0.18	0.18	0.19
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	350	350	350
Moisture (%)	12.68	9.68	8.61
Volume Flow (acfm)	2,094,759	2,158,484	2,199,524
Temperature (°F)	984	960	944
Emission rate (lb/hr)- calculated	1,020	1,106	1,153
(TPY)- vendor	543	589	614
(lb/hr)- vendor	1086	1177	1228
(MMBtu/hr)	0.80	0.81	0.81
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	60	60	60
Moisture (%)	12.68	9.68	8.61
Volume Flow (acfm)	2,094,759	2,158,484	2,199,524
Temperature (°F)	984	960	944
Emission rate (lb/hr)- calculated	100.0	108.3	113.0
(TPY)- vendor	53.0	57.5	60.0
(lb/hr)- vendor	106	115	120
(MMBtu/hr)	0.08	0.08	0.08
Lead (lb/hr)= NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Sources: Westinghouse, 1997; EPA, 1996

Table A-10a. Maximum Emissions for Criteria Pollutants for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Distillate Fuel Oil, Base Load (100%)

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F
Hours of Operation	250	250	250
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer			
Basis (excludes H2SO4), lb/hr	89.4	92.8	95.5
Emission rate (lb/hr)- provided	89.4	92.8	95.5
(TPY)	11.2	11.6	11.9
(MMBtu/hr)	0.041	0.040	0.039
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO2 /lb S)			
Fuel Oil (lb/hr)	111,730	120,865	126,703
Sulfur content (%)	0.05	0.05	0.05
lb SO2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	111.7	120.9	126.7
(TPY)	14.0	15.1	15.8
(MMBtu/hr)	0.051	0.051	0.051
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O2	42	42	42
Moisture (%)	14.99	12.05	11.03
Oxygen (%)	10.58	11.14	11.3
Volume Flow (acfm)	2,866,635	3,011,513	3,105,774
Temperature (°F)	1,084	1,051	1,037
Emission rate (lb/hr)- calculated	359.2	388.5	407.4
(TPY)- vendor	47.8	51.6	54.1
(lb/hr)- vendor	382	413	433
(MMBtu/hr)	0.18	0.18	0.18
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	90	90	90
Moisture (%)	14.99	12.05	11.03
Volume Flow (acfm)	2,866,635	3,011,513	3,105,774
Temperature (°F)	1,084	1,051	1,037
Emission rate (lb/hr)- calculated	327.0	363.1	382.4
(TPY)- vendor	43.5	48.3	50.9
(lb/hr)- vendor	348	386	407
(MMBtu/hr)	0.16	0.16	0.17
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	10	10	10
Moisture (%)	14.99	12.05	11.03
Volume Flow (acfm)	2,866,635	3,011,513	3,105,774
Temperature (°F)	1,084	1,051	1,037
Emission rate (lb/hr)- calculated	20.8	23.1	24.3
(TPY)- vendor	2.8	3.1	3.3
(lb/hr)- vendor	22	25	26
(MMBtu/hr)	0.010	0.011	0.011
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) / 1,000,000 MMBtu/10E+12 Btu			
Basisa , lb/1012 Btu	5.8	5.8	5.8
HIR (MMBtu/hr)	2,067	2,236	2,344
Emission rate (lb/hr)- calculated	0.012	0.013	0.014
(TPY)	0.001	0.002	0.002

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Sources: Westinghouse, 1997; a-EPA, 1996

Table A-15a. Maximum Emissions for Criteria Pollutants for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Distillate Fuel Oil, 50 Percent Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F
Hours of Operation	50	50	50
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer			
Basis (excludes H2SO4), lb/hr	135.1	136.9	139.6
Emission rate (lb/hr)- provided	135.1	136.9	139.6
(TPY)	3.4	3.4	3.5
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO2 /lb S)			
Fuel Oil (lb/hr)	68,111	72,108	75,806
Sulfur content (%)	0.05	0.05	0.05
lb SO2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	68.1	72.1	75.8
(TPY)	1.7	1.8	1.9
(MMBtu/hr)	0.051	0.051	0.051
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O2	75	75	75
Moisture (%)	11.83	8.78	7.75
Oxygen (%)	12.86	13.44	13.55
Volume Flow (acfm)	2,077,593	2,142,441	2,183,474
Temperature (°F)	968	945	928
Emission rate (lb/hr)- calculated	389.4	412.3	433.3
(TPY)- vendor	10.4	11.0	11.5
(lb/hr)- vendor	415	439	461
(MMBtu/hr)	0.31	0.31	0.31
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	350	350	350
Moisture (%)	11.83	8.78	7.75
Volume Flow (acfm)	2,077,593	2,142,441	2,183,474
Temperature (°F)	968	945	928
Emission rate (lb/hr)- calculated	1,033	1,121	1,169
(TPY)- vendor	27.5	29.8	31.1
(lb/hr)- vendor	1,100	1,193	1,244
(MMBtu/hr)	0.83	0.85	0.84
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	100	100	100
Moisture (%)	11.83	8.78	7.75
Volume Flow (acfm)	2,077,593	2,142,441	2,183,474
Temperature (°F)	968	945	928
Emission rate (lb/hr)- calculated	168.7	183.0	190.9
(TPY)- vendor	4.5	4.9	5.1
(lb/hr)- vendor	180	195	203
(MMBtu/hr)	0.14	0.14	0.14
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) / 1,000,000 MMBtu/10E+12 Btu			
Basisa , lb/1012 Btu	5.8	5.8	5.8
HIR (MMBtu/hr)	1,248	1,334	1,389
Emission rate (lb/hr)- calculated	0.007	0.008	0.008
(TPY)	0.000	0.000	0.000

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Sources: Westinghouse, 1997; a-EPA, 1996

Fuel Analysis

No. 2 Fuel Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	6.92 lb/gal	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	0.05	0.05
% nitrogen	0.025 - 0.030	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the fuel procurement specification

Table 4-2a. Comparison of Alternative BACT Control Technologies for NO_x

	Alternative BACT Control Technologies	
	DLN Only	SCR
Technical Feasibility	Feasible	Feasible for gas Not demonstrated for large frame CT
Economic Impact[a]		
Capital Costs	included	$7,299,000
Annualized Costs	included	$4,174,000-3,462,000
Cost Effectiveness[c]		
NO_x Removed (597 TPY)	NA	$5,800-7,000
Net Pollutants Removed (410.5 TPY)	NA	$8,435-10,200
Environmental Impact[b]		
Total NO_x (TPY)	852	256
NO_x Reduction (TPY)	NA	(597)
Ammonia Emissions (TPY)	0	96
PM Emissions (TPY)	0	11.9
Secondary Emissions (TPY)	0	78.3
Net Emission Reduction (TPY)	NA	(410.5)
Energy Impacts[d]		
Energy Use (kWh/yr)	0	9,285,600
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	90,000
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	90

[a] See Tables 3a, 4a, 3b, and 4b for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table 4-3a.

[c] Lower cost effectiveness reflects 5-years operation at proposed emission rates, while higher cost reflects 3-years operation at proposed emission rates.

[d] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 7,008 hours per year. Lost energy is based on 0.5 percent of 249 MW. SCR electrical usage is based on 0.080 MWh per SCR system.

Table 4-3a. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction

	Incremental Emissions (TPY) of Project with SCR		
Pollutants	Primary	Secondary[a]	Total
Particulate	11.9[b]	4.6	16.5
Sulfur Dioxide	--	51.1	51.1
Nitrogen Oxides	(596.7)[c]	20.9	(575.8)
Carbon Monoxide	--	1.5	1.5
Volatile Organic Compounds	--	0.2	0.2
Ammonia	96[d]	0.0	96
Total	(488.8)	78.3	(410.5)
Carbon Dioxide[e]	--	5,073	5,073

Note: Btu/kWh = British thermal units per kilowatt-hour
CT = combustion turbine
MW = megawatt
% = percent
SCR = selective catalytic reduction
TPY = tons per year
-- = no differences in the project's emissions with SCR and without SCR

[a] Lost energy from heat rate penalty and electrical usage for 7,008 hours per year operation (0.5% of 249 MW per CT plus 0.080 MWh for SCR system). Assumes baseloaded oil-fired unit would replace lost energy. EPA emission factors used were (lb/10^6 Btu): PM = 0.1; SO_2 = 1.1; NO_x = 0.45, CO = 0.033, and VOC = 0.005. Example calculation for PM is 1.325 MW x 10,000 Btu/kWh x 1,000 kW/MW x 7,008 hr/yr x 0.1 lb pm/10^6 Btu ÷ 2,000 lb/ton = 4.6 TPY.

[b] Assume 5% SO_2 conversion in catalyst and SO_3 and the SO_3 formed in the combustion process reacts with ammonia to form ammonium sulfate; 38.4 TPY SO_2 x 0.05 = 1.92 TPY SO_2; 1.92 TPY SO_2 x 98 MW of H_2SO_4 ÷ 64 MW SO_2 = 2.94 TPY H_2SO_4; 5.9 TPY H_2SO_4 from combustion for total H_2SO_4 = 8.84 TPY SO_3 x 132 (MW of ammonia salt) ÷ 98 (MW of H_2SO_4) = 11.9 TPY.

[c] Based on the maximum difference between the project's emissions with SCR and without SCR (see Table 4-1).

[d] 10 ppm ammonia slip (ideal gas law): 3,055,750 acfm x (10 ppm ÷ 10^6) x 17 x 2,116.8 ÷ 1,545 ÷ (460 + 1,095) x 60 x 7,008 ÷ 2,000 = 96 TPY.

[e] Reflects differential emissions due to lost energy efficiency with SCR (i.e., calculated from total heat input lost; 1.325 MW times 10,000 Btu/kWh; CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 Btu/lb for 1% sulfur oil).

Table B-3a. Capital Cost for Selective Catalytic Reduction for 501G Project; Simple Cycle Operation Only for 5 Years

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$940,000	Vendor Quote
Ammonia Storage Tank	$158,151	$35 per 1,000 lb mass flow developed from vendor quotes
Instrumentation	$94,000	10% of SCR Associated Equipment
Sales Tax		6% not abblicable to municipality
Freight	47,000	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,239,151	
Direct Installation Costs		
Foundation and supports	$323,132	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$565,481	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$161,566	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$80,783	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$40,392	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$40,392	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$1,231,745	
Recurring Capital Costs (RCC)	$2,800,000	Vendor Quote
Total Capital Costs	$5,270,896	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$527,090	10% of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$25,000	Engineering Estimate
Construction and Field Expense	$263,545	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$527,090	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$105,418	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$52,709	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$527,090	10% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$2,027,941	
Total Direct, Indirect and Recurring Capital Costs (TDIRCC)	$7,298,837	Sum of TCC and TInCC
Mass Flow of Combustion Turbine	4,518,595 lb/hr	

Table B-4a. Annualized Cost for Selective Catalytic Reduction for 501G Project; Simple Cycle Operation Only for 5 Years

Cost Component	Costs		Basis of Cost Component
Diirect Annual Costs			
Operating Personnel	18,720		24 hours/week at $15/hr
Supervision	2,808		15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	72,773		$300 per ton NH3
PSM/RMP Update	5,000		Engineering Estimate
Inventory Cost	246,211		Capital Recovery (26.38%) for 1/3 catalyst
Catalyst Disposal Cost	42,174		$28/1,000 lb/hr mass flow over 3 years; developed from vendor quotes
Contingency	38,769	10%	of Direct Annual Costs
Total Direct Annual Costs (TDAC)	426,454		
Energy Costs			
Electrical	28,032		80kW/h @ $0.05/kWh times Capacity Factor
Heat Rate Penalty	436,248		0.5% of MW output; EPA, 1993 (Page 6-20)
MW Loss Penalty	59,760		3 days replacement energy costs @ $0.01 kWh each three period
Fuel Escalation	15,721		Escalation of fuel over inflation; 3% of energy costs
Contingency	53,976	10%	of Energy Costs
Total Energy Costs (TDEC)	593,737		
Indirect Annual Costs			
Overhead	$56,581	60%	of Operating/Supervision Labor and Ammonia
Property Taxes			Not abblicable for municipality
Insurance	$72,988	1%	of Total Capital Costs
Annualized Total Direct Capital	$1,186,782	26.38%	Capital Recovery Factor of 10% over 5 years times sum of TDCC, TDIC and TInC
Annualized Total Direct Recurring	$1,125,880	40.21%	Capital Recovery Factor of 10% over 3 years times RCC
Total Indirect Annual Costs	$2,442,231		
Total Annualized Costs	$3,462,422		Sum of TDAC, TEC and TIAC
Cost Effectiveness (NOx Removed)	$5,802	596.7	tons per NOx Removed
(Net Pollutants Removed)	$8,435	410.5	tons of net pollutants removed (see Table 4-3a)

Table B-3b. Capital Cost for Selective Catalytic Reduction for 501G Project; Simple Cycle Operation for 3 years

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$940,000	Vendor Quote
Ammonia Storage Tank	$158,151	$35 per 1,000 lb mass flow; developed from vendor quotes
Instrumentation	94,000	10% of SCR Associated Equipment
Sales Tax		6% Not applicable to municipality
Freight	47,000	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,239,151	
Direct Installation Costs		
Foundation and supports	$323,132	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	$565,481	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	$161,566	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping	$80,783	2% of TDCC and RCC; OAQPS Cost Control Manual
Insulation for ductwork	$40,392	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	$40,392	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$1,231,745	
Recurring Capital Costs (RCC)	$2,800,000	Vendor Quote-"Hot" side catalyst
Total Capital Costs	$5,270,896	Sum of TDCC, TDIC and RCC; Hot Side
Indirect Costs		
Engineering	$527,090	10% of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$25,000	Engineering Estimate
Construction and Field Expense	$263,545	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$527,090	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$105,418	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$52,709	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$527,090	10% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$2,027,941	
Total Direct,Indirect and Recurring Capital Costs (TDIRCC)	$7,298,837	Sum of TCC and TInCC

Mass Flow of Combustion Turbine 4,518,595 lb/hr

Table B-4b. Annualized Cost for Selective Catalytic Reduction for 501G Project: Simple Cycle Operation for 3 Years

Cost Component	Costs	Basis of Cost Component
Diirect Annual Costs		
Operating Personnel	18,720	24 hours/week at $15/hr
Supervision	2,808	15% of Operating Personnel
Ammonia	72,773	$300 per ton NH3
PSM/RMP Update	5,000	Engineering Estimate
Inventory Cost	375,307	Capital Recovery (11.74%) for 1/3 catalyst
Catalyst Disposal Cost	42,174	$28/1,000 lb/hr mass flow over 3 years
Contingency	25,839	5% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	542,621	
Energy Costs		
Electrical	28,032	80kW/h @ $0.05/kWh times Capacity Factor
Heat Rate Penalty	436,248	0.5% of MW output
MW Loss Penalty	59,760	3 days replacement energy costs @ $0.01 kWh each three period
Fuel Escalation	15,721	Escalation of fuel over inflation; 3% of energy costs
Contingency	26,988	5% of Energy Costs
Total Energy Costs (TDEC)	566,749	
Indirect Annual Costs		
Overhead	$56,581	60% of Operating/Supervision Labor and Ammonia
Property Taxes		Not applicable to municipality
Insurance	$72,988	1% of Total Capital Costs
Annualized Total Direct Capital	$1,809,049	40.21% Capital Recovery Factor of 10% over 3 years times sum of TDCC, TDIC, TInC
Annualized Total Direct Recurring	$1,125,880	40.21% Capital Recovery Factor of 10% over 3 years times RCC
Total Indirect Annual Costs	$3,064,498	
Total Annualized Costs	$4,173,868	Sum of TDAC, TEC, TIAC and TCCMSC
Cost Effectiveness (NOx Removed)	$6,995	596.71 tons of NOx removed
(Net Pollutants Removed)	$10,168	410.50 tons of net pollutants removed (see Table 4-3a)

Table B-8. Cost Comparison of Lakeland 501G with 3 GE Frame EA Combustion Turbines

Capital Cost of GE Frame 7EA	$65,000,000		
Capital Cost of W501G	$49,500,000		
Difference	$15,500,000		
Annualized Cost	$1,819,700		
Heat Rate for W 501G (Btu/kWh-HHV)	9,688		
Heat Rate for GE Frame 7EA (BTU/kWh-HHV)	11,238		
Differential Heat Rate (BTU/kWh-LHV)	1,397		
Differential Heat Rate (BTU/kWh-HHV)	1,550		
Gas Cost ($/mmBtu)	$2.70		
NOx for GE Frame 7EA (lb/hr)	52.7		42.16 @ 12 ppmvd
Generation (MW)	82.04		82.04
NOx (lb/hr/MW)	0.64		0.51
Heat Input (mmBtu/hr-HHV)	921.97		
NOx for W 501G (lb/hr)	237		
Generation (MW)	249.09		
NOx (lb/hr/MW)	0.95		
Heat Input (mmBtu/hr-HHV)	2413.14		
Generation MW/hr/year	1,745,623		
NOx Emissions (tons/year)			
501G	830		
GE Frame 7EA	561		
Difference	270		
Gas Cost per Year			
501G	$45,660,470		
GE Frame 7EA	$52,966,878		
Difference	$7,306,409		
Toral Annualized Cost	$9,126,109		
Cost Effectiveness (per ton NOx)	$33,828	25 to 15 ppmvd	
Capital Only (per ton of NOx)	$6,745		
Cost Effectiveness (gas cost only)	$27,083	25 to 15 ppmvd	
(gas cost only)	$19,131	25 to 12 ppmvd	
with Capital	$25,876	25 to 12 ppmvd	
Differential Gas Usage (mmBtu)	2,706,077		
(cf/yr)	2,577,216,453		

Note: ISO Conditions used for comparison.

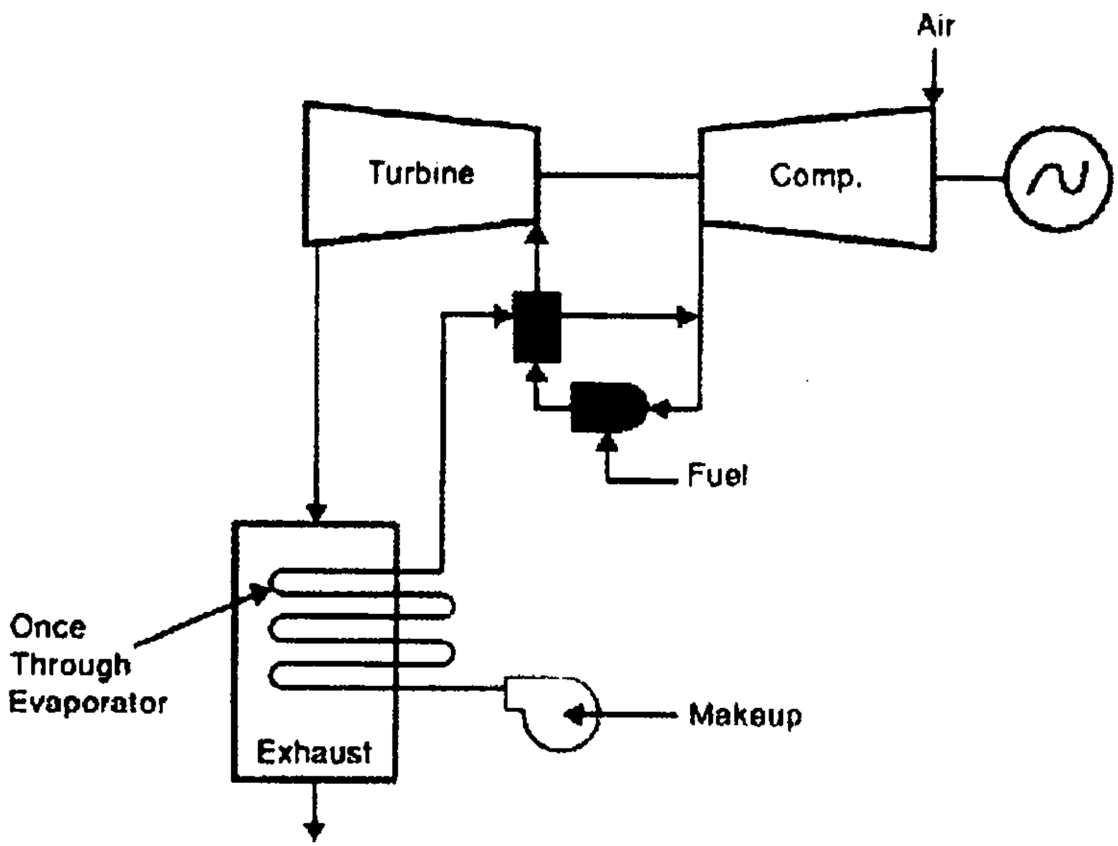
Table B-9. Cost Comparison of Lakeland 501G with 2 Frame F Combustion Turbines

Capital Cost of GE Frame 7F	$61,760,000	
Capital Cost of W501G	$49,500,000	
Difference	$12,260,000	
Annualized Cost	$1,439,324	
Heat Rate for W 501G (Btu/kWh-HHV)	9,688	
Heat Rate for Frame 7F (BTU/kWh-HHV)	10,779	
Differential Heat Rate (BTU/kWh-LHV)	983	
Differential Heat Rate (BTU/kWh-HHV)	1,091	
Gas Cost ($/mmBtu)	$2.70	
NOx for Frame 7F (lb/hr @ 15 ppmvd)	88	70.4 @ 12 ppmvd
Generation (MW)	154.4	154.4
NOx (lb/hr/MW)	0.57	0.46
Heat Input (mmBtu/hr-HHV)	1,664	
NOx for W 501G (lb/hr @ 25 ppmvd)	237	
Generation (MW)	249.09	
NOx (lb/hr/MW)	0.95	
Heat Input (mmBtu/hr-HHV)	2,413	
Generation MW/hr/year	1,745,623	
NOx Emissions (tons/year)		
501G	830	
GE Frame 7F	497	
Difference	333	
Gas Cost per Year		
501G	$45,660,470	
GE Frame 7F	$50,804,371	
Difference	$5,143,902	
Total Annualized Cost	$6,583,226	
Cost Effectiveness (per ton NOx)	$19,770	25 to 15 ppmvd
Capital Only (per ton of NOx)	$4,322	
Cost Effectiveness (gas cost only)	$15,448	25 to 15 ppmvd
(gas cost only)	$11,894	25 to 12 ppmvd
with Capital	$16,216	25 to 12 ppmvd
Differential Gas Usage (mmBtu)	1,905,149	
(cf/yr)	1,814,427,390	

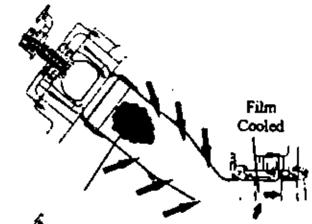
Note: ISO Conditions used for comparison.

STEAM COOLING DIAGRAMS

501G S.C.
Transition Steam Cooling - Open



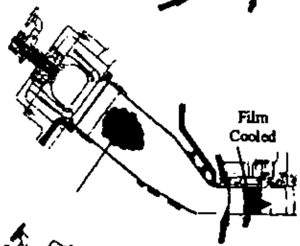
F Technology



BOT 2700°F - 2850°F

RIT 2330°

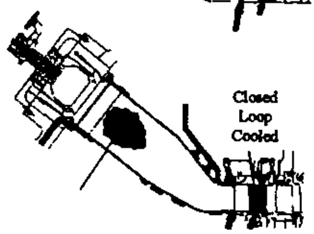
G Technology



BOT 2700°F - 2850°F

RIT 2580°

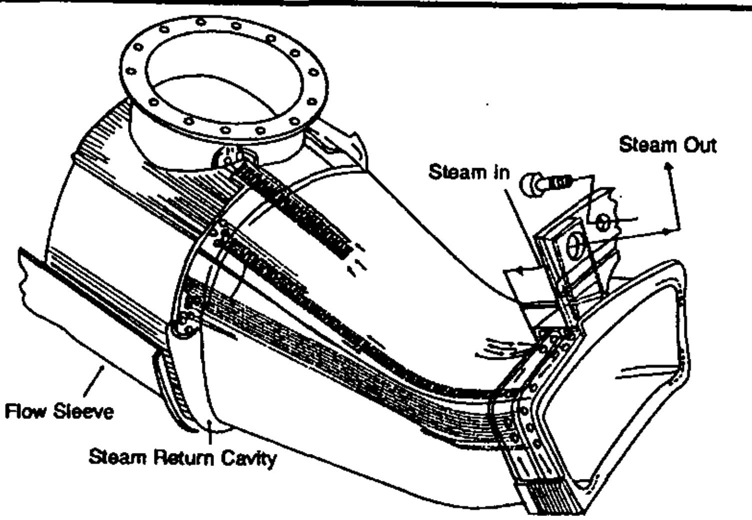
ATS Technology



BOT 2700°F - 2850°F

RIT 2750°

Transition - Steam Cooling



**Information Addressing the January 12, 1998 FDEP Letter
Lakeland 250 MW Combustion Turbine Project (Westinghouse 501G)**

The January 12, 1998 letter from Mr. A.A. Linero, Administrator the FDEP New Source Review Section, to Mr. Ronald Tomlin, Assistant Managing Director, Lakeland Electric & Water Utilities, suggested that the installation of high temperature SCR was an appropriate design in the event the simple cycle combustion turbine was converted in the near term to combined cycle. The FDEP suggested that the high temperature could be installed at start-up and that either advanced dry-low NOx combustion technology or low temperature SCR would not be required. This suggestion was evaluated by Westinghouse and Golder Associates and the following information is provided.

The continued use of a high temperature SCR in a combined cycle configuration for the Westinghouse 501G has technical, schedule and cost implications that make this design inappropriate. Indeed, even if a high temperature SCR were initially installed, its continued use would not be considered good engineering practice and the initial cost could not be recovered. The evaluation concluded that if a "hot" SCR were required it would be discontinued for combined cycle operation. The only equipment that could potentially be used with the low temperature system would be the ammonia tank, dilution and control systems which are not major cost components of the SCR system. All other equipment would be replaced (i.e., catalyst modules, ammonia spray distribution system and catalyst framework). The technical, schedule and cost implications leading to this conclusion are discussed below.

Technical Implications--The exhaust temperature of the advanced 501G is at temperatures exceed that required to install a high temperature. While much smaller conventional and aero-derivative turbines have exhaust temperatures that could accommodate the installation of high temperature catalyst modules (i.e., maximum temperatures of 1,100° F), this in not the case with the 501G or even "F" Class turbines. The potential feasibility of installing a "hot" SCR with the proposed Lakeland 501G project, only comes with the installation of the once through steam generator (OTSG). As discussed in previous responses the OTSG is needed to supply cooling steam required for the 501G. If the project is converted to combined cycle a heat recovery steam generator (HRSG) would be installed to produce steam for a steam electric generator. The HRSG could provide the steam for cooling more efficiently, therefore the OTSG would no longer be needed. Because of the various steam production requirements needed for steam electric turbine and optimizing steam production quality, it is not feasible to place a HRSG after the OTSG.

As noted above, some exhaust temperature reduction is required with a "hot" SCR system. Installing high temperature catalyst modules within the HRSG would require a design that would place catalyst modules between the superheater and reheater sections and up stream of the HP evaporator section. This design has never been done by a HRSG vendor and would involve unique design considerations for piping and materials necessary to accommodate the catalyst framework. In addition, the performance of the HRSG could be affected resulting in lower efficiency. It is likely that the reheat and HP steam pressure would be affected having a concomitant decrease in overall combined cycle efficiency. In contrast, a low temperature catalyst modules can be installed between the HP and LP evaporator sections without significant design or performance considerations. While SCR has not yet been installed in Florida, numerous projects have catalyst spool pieces added to HRGS designs.

Schedule Implications--Conversion from simple cycle to combined cycle configuration can be accomplished with minimum operation time lost for the combustion turbine. When the decision and authorization to proceed with a combined cycle configuration is made, a majority of the construction can be accomplished without affecting the operation of the 501G in simple cycle mode. Without a high temperature configuration, the conversion would simply require a relocation of blanking plates taking several shifts. With a high temperature SCR installed in the HRSG, catalyst modules would have to be relocated within a new framework designed to accommodate the existing catalyst modules. Due to high temperature exposure and the requirement to fit these existing modules into a wider space (assuming these modules were still active), the 501G could not operate for several weeks. During this time, only benefits for operating the 501G in simple cycle mode would be lost.

Cost Implications--The cost of continuing with a high temperature SCR system would be uneconomical if the 501G were converted to combined cycle configuration. The cost of a "hot" SCR catalyst modules is about twice that for a low temperature SCR system. Indeed, the "hot" SCR vendor cost estimate for catalyst modules was \$2.8 million while low temperature catalyst would be about \$1.4 million as indicated in the permit application. Even assuming that the high and low temperature catalysts have the same life (a unlikely situation due to the temperature stress at high temperatures), an additional capital cost of \$9.33 million would occur over 20 years for high temperature catalyst modules alone. This cost is about twice the <u>total</u> cost of new low temperature SCR systems. Moreover, the design and performance implications for the HRSG would likely be significant. The cost of lost operational time for the 501G could also be significant due to replacement of power with higher cost generation.

**Information Addressing the January 6, 1998 US Fish and Wildlife Service Review
Lakeland 250 MW Simple Cycle Combustion Turbine Project (Westinghouse 501G)**

The Air Quality Branch of the US Department of Interior Fish and Wildlife Service (FWS) provided comments to FDEP on the BACT analysis and Air Quality Related Values (AQRV) Analysis for the project. Responses are presented below.

Best Available Control Technology (BACT)

The FWS review suggested that the high costs were due to both the high cost of the high temperature SCR system and some calculation errors. The following information is provided relative to the FWS comments. It should be recognized that the annualized cost of the high temperature SCR system for the Lakeland Project is well within the estimate in the EPA Environmental Appeals Board Commonwealth Chesapeake Corp. case (i.e, $13,900 per MW for Lakeland and $20,900/MW for Commonwealth-see responses to FDEP January 5, 1998 letter) and the GRU BACT determination (i.e., $17,333 per MW; PSD-FL-212).

Contingency for Capital--A contingency of 10 percent was utilized, since the application of a high temperature SCR system has never been performed. This engineering consideration is clearly appropriate based on Vatavuk (1990) the primary author of EPA cost algorithms. Vatavuk suggests a contingency of 9 to 15 percent for designs that have not been established previously. The order of magnitude difference between the 501G and <u>any</u> previous installation requires that at least a 10 percent contingency be applied as good engineering practice.

Operating and Maintenance Labor Costs--These cost have been recalculated along with high temperature SCR for 5 and 3 years as presented in Tables 3a, 4a, 3b and 4b. The adjustment does not affect the conclusion that "hot" SCR is inappropriate for the Lakeland Project for a 3 to 5 year duration.

Ammonia Costs--Ammonia costs used to estimate operational costs was based on $300 per ton delivered to the site. The cost of aqueous ammonia, that specified by the vendor, is about $320 per ton based on quotations received in previous project. It should be noted that the total cost of ammonia affects the cost effectiveness calculation by less than $250 per ton of NOx removed.

Capital Recovery Factor (CRF)--As discussed in the response to the January 5, 1998 FDEP letter, the CRF includes more than simple interest. Indeed, the CRF as defined in the EPA OAQPS Cost Control includes recovery of all capital cost that include financing charges, allowance for funds used during construction (AFUDC) and interest. A CRF of 10 percent is also used by the City of Lakeland in evaluating this project against other projects and is therefore specific to the applicant.

Contingency Cost for Direct Operational/Energy Cost--Similar to the capital costs, the uncertainty associated with an application that has never been performed, requires inclusion of a contingency as good engineering practice.

Heat Rate Penalty--The heat rate penalty is associated with the pressure drop associated with the catalyst modules and the resulting back-pressure on the turbine. An estimate of 0.5 percent was used based on EPA's Alternative Control Techniques Document-- NO_x Emissions from Stationary Gas Turbines (see Page 6-20:EPA 453/R-93-007).

Inventory Cost and Annualized Total Direct Recurring Costs--With all SCR systems, additional catalysts are purchased which are added as replacement or additional modules to insure a high level of NO_x removal. A typical amount of 1/3 of catalyst modules were estimated for the Lakeland project. These additional catalyst modules must be included in the original design to assure continuous system operation. These capital cost occur at the start of a project and must be carried along with all costs. The annualized costs associated with this inventory is recovered (i.e., the CRF) at the same rate as the capital costs. The Annualized Total Recurring Costs are associated with the catalyst modules originally installed with the SCR system. Since the SCR catalyst have a performance life, the capital cost recur over the life of the project. This recurring capital costs are recovered over the guaranteed life of the catalyst (i.e., 3 years).

Reference: Vatavuk, W.M. 1990. Estimating Costs of Air Pollution Control. Lewis Publishers. Chelsea; Michigan.

Air Quality Related Values (AQRV) Analysis

The regional haze analysis predicted for the project's emissions were originally estimated to potentially cause a change of 0.97 deciview at the Chassahowitzka National Wildlife Refuge (CNWR). This analysis was based on maximum sulfur dioxide (SO_2), nitrogen oxides (NO_x), and sulfuric acid (H_2SO_4)

mist impacts (as a surrogate for fine particulate matter) concentrations predicted for the project firing distillate fuel oil. Natural gas is the primary fuel oil for the project while distillate fuel oil is the emergency backup fuel intended to be fired for no more than 10 days a year. These analysis followed the approach recommended by the National Park Service (NPS) in the "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report" (April 1993). These concentrations were conservatively estimated using the Industrial Complex Short-Term model, Version 3 (ISCST3), even though the plant is located about 91 km from the CNWR.

A revised regional haze analysis has been performed which demonstrates that the project's emissions could potentially cause a change of 0.497 deciview at the CNWR. A summary of the input parameters, assumptions, and results is presented in Table 1. This deciview value is less than the revised screening deciview value of 0.5 recommended in guidance developed by the U.S. Fish and Wildlife Service (FWS) in December 1997. This guidance was provided to the project after the air construction permit application was submitted in November, 1997. The 0.5 deciview value is a significant reduction from the 1.0 value previously used to assess air quality related values (AQRV) from emissions for new or modified sources. It should be noted that, although a one-page interim guidance document has been provided by the FWS (see "Interim Visibility Modeling Guidance For Sources Locating or Expanding Near Chassahowitzka Wilderness, Florida, December, 1997), a more detailed, comprehensive guidance document has yet to be issued.

The revised regional haze analysis also followed the IWAQM recommendations but used a more realistic approach to account for the chemical transformation of NO_x to nitrate (NO_3) which then is assumed to convert to ammonium nitrate (NH_4NO_3), a compound used to assess regional haze. Generally, when using a steady state model, like the ISCST3 model, all of the NO_x concentration (100 percent) is assumed to convert to NO_3, a very conservative assumption. In fact, during a 24-hour period, only a fraction of the NO_x emissions and, therefore, concentrations, will convert to NO_3 concentration. To estimate a conversion rate, NO_3 concentrations were predicted for the project at the CNWR using a long range transport model, MESOPUFF II, following the recommended methods by IWAQM. In addition, NOx concentrations were modeled in a separate run without any chemical transformation processes. By comparing the NO_x to NO_3 concentrations, an estimate was made of the chemical transformation rate. Based on the results of using one year of meteorological data (1986) available for the region, the chemical transformation rate of NO_x to NO_3 was estimated to be about 31 percent over a 24-hour period. This conversion rate was based on the average of the ten highest ratios of NO_3 to NO_x concentrations predicted by the model. As a result, the maximum 24-hour average NO_x concentrations predicted by the ISCST3 model was multiplied by 0.31 to obtain the NO_3 concentration for use in the analysis. It should be noted that meteorological data for 1986 were used in the MESOPUFF II model since the necessary data were not readily available for 1987 to 1991, the years for which pollutant concentrations were predicted for the project as submitted in the air construction permit application.

Based on recent discussions with Mr. Bud Rolofson, FWS Air Quality Branch, this analysis also used the PM10 emissions (instead of H_2SO_4) for the project as well as an average relative humidity factor developed from hourly relative humidity data for the day during which the maximum 24-hour average concentrations were predicted at the CNWR by the ISCST3 model.

It must be noted that these results are conservative since:

- the deciview is based on firing fuel oil which is the backup fuel. When firing natural gas, which is the proposed primary fuel, maximum pollutant concentrations are predicted to be lower than those for oil-firing. As a result, the regional haze impacts are also expected to be lower than those for oil-firing;
- the background visual range used in the analysis is based on visual range data for 10 percent of the days having the best visibility. If the median visual range of 40 km were used, the estimated deciview value for the project would be much lower;
- the probability of oil-firing when the best visibility occurs is low due to the expected infrequent use of oil (at most, a maximum of 10 days in a year).

Table 1. Estimated Change in Deciview Due to the City of Lakeland-McIntosh Plant, Proposed Westinghouse 501G Combustion Turbine, Fuel-oil Firing at Baseload Conditions and 30 °F Temperature

Pollutant	Value	Reference
Maximum Emission Rates (lb/hr)		
SO_2	126.70	
NOx	433.00	
PM10	95.50	
Highest Predicted 24-Hour Concentrations (µg/m³)		
SO_2	0.082	(1)
NOx	0.281	(1)
PM10	0.0618	(1)
SO_4	0.0638	(2)
NO_3	0.0871	(3)
$(NH_4)_2\ SO_4$	0.0877	(4)
$NH_4\ NO_3$	0.1124	(5)
Average RH (percent)	74	(6)
RH factor, f(RH)	4.8	(7)
Extinction Coefficients (km^{-1})		
Background: (bextb)	0.0602	(8)
Source: (bexts)		
$(NH_4)_2\ SO_4$	0.0013	(9)
$NH_4\ NO_3$	0.0016	(9)
PM10	0.000185	(10)
Total (bexts)	0.0031	
Deciview Change		
total delta dv =	0.4970	(11)

(1) Highest predicted concentration due CT firing oil using the ISCST3 model with a 5-year meteorological data record from Tampa for 1987-91
(2) SO_4 concentrations based on 3 percent per hour conversion rate from SO_2
(3) NO_3 = NOx * ave. of 10 highest conversion rates of NO2 to NO3 from MESOPUFF (model results- 31% of NO2 converted to NO3 over 24-hour period, 1986)
(4) $(NH_4)_2\ SO_4 = SO_4$ times 1.375 from IWAQM Appendix B
(5) $NH_4\ NO_3 = NO_3$ times 1.29 from IWAQM Appendix B
(6) Based on meteorological data collected at the National Weather Service station in Tampa.
(7) From IWAQM Figure B-1. Based on average relative humidity factor for day (8 3-hr obs.
(8) bextb = 3.912 / 65 where background visual range is 65 km.
(9) values= 0.003 * compound concentration* f(RH) from IWAQM Appendix B
(10) PM10 = 0.003 * compound concentration. f(RH) set = 1 for fine PM
(11) Delta DV = 10 * ln (1 + bexts/bextb)

Information Addressing the February 10, 1998 Letter from EPA

Lakeland 250 MW Simple Cycle Combustion Turbine Project (Westinghouse 501G)

The Air and Radiation Technology Branch, Air, Pesticides, and Toxics Management Division of EPA Region IV provided comments to the FDEP on the Lakeland 501G project. Information addressing these comments is presented below.

1. Combined Cycle Conversion--While the decision to convert to combined cycle has not been made, the City will none the less commit to a lower NOx emission limit of 12 ppmvd (corrected to 15 percent oxygen) no later than 5 years after initial start-up in simple cycle configuration. The City would accept a permit condition that would require lower NOx levels in future years. This approach has been accepted in the past for combined cycle projects; and given the advanced nature of the 501G and the uncertainty and cost associated with the application of "hot" SCR, this approach would be an appropriate BACT decision. The preferred means to provide lower NOx levels would be by either the installation of the Advanced Turbine System (ATS) combustion technology or installation of low temperature SCR system in a combined cycle configuration. For the low temperature SCR system, the cost evaluation in the application suggests that the cost effectiveness for a combined cycle configuration within the range that would make it economically feasible.

2. 5-Year Conversion--Although the City anticipates that converting the 501G to combined cycle at a near term future date may occur, the final decision to convert to combined cycle has not been made by the City. Once the decision is made, the permitting, design and construction for a combined cycle addition would be several years beyond that required to construct the simple cycle configuration. The simple cycle configuration, available in 1999, would provide the City with the additional capacity required while being more efficient than other energy alternatives.

3. Other Projects--The majority of the projects in the RACT/BACT/LAER Clearinghouse are for combined cycle projects with smaller less efficient turbines. The only simple cycle project that have installed SCR have been in much smaller turbines (less than 25 MW) operating in nonattainment areas. Recent PSD decisions in Virginia and Georgia for simple cycle combustion turbine projects have not required high temperature SCR. In addition, the cost effectiveness of other turbines achieving NOx levels of 15 ppmvd (corrected to 15 percent oxygen) or less is well above that considered to be economically feasible, i.e, greater than $15,000 per ton of NO_x removed. (See responses to FDEP

January 6, 1998 Letter.) As discussed in the FDEP responses, the Westinghouse ATS program which will be completed in the year 2000, incorporates research on advanced dry low NOx combustors. The installation of such technology is preferred by the City and the additional time would allow its application. It should be recognized that the 501G is the most efficient combustion turbine in the world. When compared on an output based emission, the NO_x emissions at 25 ppmvd (corrected to 15 percent oxygen) are more than 20 lower than the conventional turbines and more than 10 percent lower than the "F" Class turbines. Moreover, if the project were considered a fossil fuel steam generator, the 501G would meet the proposed Subpart Da New Source Performance Standards (NSPS). These proposed NSPS were promulgated as an output based limit where NO_x emissions are limited to no greater than 1.35 lb per net MW. The NO_x emission rate for the 501G is 0.95 lb per net MW or 30 percent lower than the proposed NSPS.

4. Cost Effectiveness--As discussed in the responses to the January 5, 1998 FDEP letter, the City proposes to meet a NOx limit of 12 ppmvd (corrected to 15 percent oxygen) no later than 5 years after initial start-up in simple cycle configuration. The cost effectiveness for 5 and 3 years have been recalculated and presented in Table 3a, 4a, 3b and 4b.

NSPS Subpart GG--This NSPS is good comparison to demonstrate the efficiency of the 501G. Based on this NSPS for gas turbines, a NOx limit of 117 ppmvd (corrected to 15 percent oxygen) would be allowed. The proposed emission limit for the 501G at 25 ppmvd (corrected to 15 percent oxygen) is 4.7 times lower than the NSPS.

FDEP, US FISH AND WILDLIFE SERVICE, AND EPA COMMENT LETTERS

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 5, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

The Department has conducted a completeness review of the City of Lakeland's application received on December 8, 1997 for installation of a 250 megawatt Westinghouse 501G simple cycle combustion turbine and once-through steam generator to be referred to as Unit No. 5 at the C. D. McIntosh Power Plant. Please provide responses to our comments given below and our questions in the attachment.

Unit 5 will be located at a facility on a site which constitute an electrical power plant and site as defined in the Florida Electrical Power Plant Siting Act. We have forwarded a copy of your application to the Department's Office of Siting Coordination to determine whether or not construction of Unit 5 constitutes a new project or modification with respect to the Act. Please contact Mr. Buck Oven, P.E., at 850/487-0472 regarding the status of that review.

The Department is in the process of modifying the certification for the FPC Hines facility for a 243 MW project consisting of a 165 MW Westinghouse 501 FC combustion turbine and a 78 MW heat recovery steam generator. That project is characterized by a net heat rate of approximately 7000 Btu/kWh and emissions of 12 ppm of nitrogen oxides (NO_X) and 25 ppm of carbon monoxide (CO) while firing gas. The City of Tallahassee is also in the process of obtaining certification for a project with similar power, heat rate, and emissions characteristics to the FPC Hines project. The planned project at C. D. McIntosh exhibits a net heat rate of 8,725 Btu/kWh and emissions of 25 ppm of NO_X and 50 ppm of CO. Therefore, the limits requested by the City of Lakeland appear to be high without sufficient compensating energy, environmental, or economic benefits.

If the City were to include a heat recovery steam generator now, to yield closer to 350 MW, the project characteristics would be on the order of 6000 Btu/kWh and emissions of approximately 10 ppm of NO_X by low temperature selective catalytic reduction (SCR) and 10 ppm CO. This option would yield lower emissions with substantial energy benefits.

The cost calculations indicating that lower NO_X emissions are not economically feasible, and the higher CO emissions from power augmentation, are consequences of the City's plan or need to stage the project. It would be difficult for the Department to conclude that BACT should be less stringent as a result of project staging or uncertain ultimate development plans.

At this time, there is no reasonable assurance that Westinghouse will guarantee emissions less than 25 ppm through Dry-Low NO_X (DLN) combustion. If Westinghouse could guarantee a lower emission rate, it should be achieved at or very soon after start-up. The longer periods of time given to applicants in the early 90's were for the purpose of allowing development of the DLN technology. We do not consider the technology to be experimental anymore. For example, no additional time was provided to FPC or the City of Tallahassee to achieve the 12 ppm NO_X emission rate in their PSD permits.

We expect to receive comments from the Department of Interior and EPA Region IV and will forward them to you as soon as they are received. If you have any questions regarding this matter, please contact Teresa Heron (review engineer) or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A. A. Linero 1/5

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/th

Attachment

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

15. There is a discrepancy between the operating capacity listed on page 4-3, last paragraph, and Table 4-1(80 percent operating capacity vs 100 percent operating capacity). Which one is correct?

16. What type of catalyst was evaluated? Please refer to Section 4.3.1.1.3 and Pages B-5 and 45. Was the ceramic catalyst explored? This system does not promote the conversion of SO_2 to SO_3 and has virtually no catalysis poisoning, plugging or masking problems. The ammonia slip is also limited. In addition the catalyst is not considered a hazardous waste.

17. What will be the actual NO concentrations at the inlet to the SCR system?

18. Evaluate and compare the economic alternatives and the environmental benefits associated with the consumption of No. 2 fuel oil (0.05%) when calculating secondary emissions (Table 4-3, note 3). Show basis of calculations..

19. What other mechanism was considered (i.e. dilution air) to reduce the exhaust temperature to the optimum range of 600-750 degree Fahrenheit. What is the cost associated with use of this technology.

20. Was the economic analysis based on Engelhard quotations only?

21. Submit vendor-supplied design parameters (space velocity, ammonia-to-NO_X mole ratio, pressure drop, catalyst life). How many vendors supplied information.

22. On page 4-5, what is the basis for the values given in the last paragraph when analyzing SCR and combined cycle operation. Is the incremental cost effectiveness of $3,921/ton NOx removed based on combined cycle for the life of the project?

23. What is the possibility of developing more efficient combustors to reduce the emissions to 15 ppmvd by start-up. Application should address the possibility of using "improved combustors" which are capable of limiting NO_X emission to no greater than 15 ppmvd at 15 O_2.

24. Please provide more detailed information for equipment details specifications.

25. Please provide economic of using SCR for oil firing. Molecular sieve catalysts have been proven on oil operations.

26. Provide basis for using capable recovery factor with 12 percent over 20 years for annualized capital cost on Page 23. On Page B-23 Supplemental Calculations Related to SCR and Options: What is the basis of the average 20 years NOx emissions of 429 TPY. Please explain.

27. Page 49, paragraph 1 states that "While the increased firing temperature increases the thermal NO_X generated, this NO increase is controlled through combustion design" How much additional thermal NOx is due to higher temperature?

28. On page 4-4, the estimated cost of SCR is reported to be about $ 6,516 per ton of NOx removed and it exceeds $ 8,000 per ton of pollutant removed when the net emissions of all pollutants (exclusive of CO_2) are considered. Provide us with the names and addresses of all manufacturers that were contacted along with their estimates while developing capital and annualized cost estimates for this project.

29. It appears the cost effectiveness ($/ton removed) presented on using SCR technology is within a reasonable cost range when compared to similar projects. If you don't agree, please expand the BACT analysis for NO_X and CO to demonstrate the contrary. Include a table summarizing the emission reductions, economics, energy and environmental impacts of the control technology chosen (including the BACT limit determined) vs. the SCR technology rejected for different projects in Florida for the last 8 years.

30. What is the cost effectiveness ($/ton NO_X removed) of the proposed water injection technology?

ADDITIONAL COMMENTS - LAKELAND 250 MW COMBUSTION TURBINE PROJECT

POLLUTANT EMISSIONS

1. Show basis of calculations and equivalence in lb/MMBtu emission rate for each one of the pollutants considered in this project.
2. Is it Lakeland's intention to operate Unit 5 under the two options presented in Table 2-5?
3. Please explain the apparent inconsistency between the 0.05 percent (%) maximum sulfur content of the No. 2 fuel oil shown on page 25 and the typical value of 0.5 % sulfur shown on the unnumbered "Fuel Analysis" page following Table A-18 in Appendix A.

POWER AUGMENTATION

4. How much more power output is due to operation in the power augmentation mode and will operation be continuous in that mode?
5. Expand on the details of the Westinghouse DLN burner technology (combustor silo vs. can-annular combustor). What is the firing temperature of this unit?
6. What is the heat input of the once-through steam generator? Describe the primary function of the once-through steam generator? Will this unit be part of the system after the possible installation of the heat recovery steam generator?
7. Submit corresponding data to scenarios presented (Section and Appendix A of the Application) excluding the power augmentation mode.
8. Power augmentation will allow the firing of additional natural gas while injecting steam into the turbine, to produce more megawatts. What is the NO_X emissions increase (ppmvd) during the power augmentation mode? Would power augmentation be the preferred mode of operation . Will power augmentation be during the peak-demand period.
9. Provide a more specific description of the conditions under which operation in the PA mode would be required.
10. Why can't the extra power capacity from the power augmentation be generated under the base load capacity of the CT?
11. Does Lakeland plan to operate in the power augmentation mode as standard operating procedure? Under what circumstances will the power augmentation mode operate (i.e. base load, peaking, etc.)?

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

12. Section B.2., BACT review, indicates that "the available information suggests that SCR with DLN combustor technology or with wet injection is also technically feasible." Was this design evaluated in the BACT analysis?
13. On page B-4 and B-5 it is stated that Westinghouse and GE have offered DLN combustors on advanced heavy-duty industrial machines. Were other manufacturers considered for this project? If so, what was the NO_X pppmv at 15% O_2 and the earliest delivery dates?
14. Are other vendors willing to provide a NO_X emissions limit guarantee less than 15 ppmvd at 15%? What is the cost of converting a CT from a dry low combustor which can initially limit NO_X emissions to 15 ppmvd at 15% O_2 to a combustor which is capable of achieving a 9 ppmvd at 15% during a maintenance period (for example by 2005)?

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 12, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

Attached are the comments we received by Fax from the Air Quality Branch of the Fish and Wildlife Service. We will send you a copy of the signed version when we receive it. Please note their comments regarding the proposed Best Available Control Technology (BACT) nitrogen oxides (NO_X)emission limit of 25 ppm. They also have requested some additional modeling which would might not be necessary if the emissions were lower.

We have reviewed the BACT information in the application in more detail. It appears that it would not be necessary to write off high temperature SCR (installed at start-up) if and when a heat recovery steam generator (HRSG) were installed in the future. Therefore additional costs of future Dry Low-NO_X (DLN) technology and/or low temperature SCR do not need to be summed into the long term cost of pollution control by hot SCR.

High temperature SCR could be installed by start-up. Westinghouse would not then need to attempt to refine its DLN technology (for this project) to achieve lower NO_X emissions at higher temperature and pressure ratios under such challenges as pressure pulsation and lower flame stability. Low temperature SCR might not need to be installed later. In fact, HRSG operation would likely be simplified by one-piece construction instead of having separate components with a low temperature SCR module in-between. This approach would allow the City to proceed with the planned staged project, satisfy BACT requirements for NO_X, and defer the decision on installation of a HRSG until a future date consistent with the PSD application.

We are still awaiting comments from EPA If you have any questions regarding this matter, please contact Teresa Heron (review engineer) or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A A Linero 1/12

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/aal

Attachment

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

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United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

January 15, 1998

RECEIVED

JAN 20 1998

BUREAU OF
AIR REGULATION

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration Application for the city of Lakeland's proposed 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area, administered by the U.S. Fish and Wildlife Service. The technical review comments from our Air Quality Branch are enclosed. Specifically, we recommend that your department require Lakeland to meet lower limits on nitrogen oxides emissions than those proposed. At the proposed limits, Lakeland has predicted that significant visibility degradation will occur in Chassahowitzka. In addition, lower limits would more accurately reflect best available control technology.

We also are enclosing the "Interim Visibility Modeling Guidance for Sources Locating or Expanding Near Chassahowitzka Wilderness, Florida." As you know, we have enclosed this document with other recent comment letters to your department, and we ask that you provide this document to future PSD applicants. Our Air Quality Branch is compiling a more detailed and comprehensive document addressing visibility analyses that will be available in early 1998.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have any questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at 303/969-2617.

cc:
EPA
SWD
Polk Co
J. Shelton, C of L
K. Kosky, Golder

Sincerely yours,

H Dale Hall

for Sam D. Hamilton
Regional Director

CC: T. Heron, BAR

Enclosures

Technical Review of Prevention of Significant Deterioration Permit Application For a 250-Megawatt Simple Cycle Combustion Turbine at McIntosh Power Plant Polk County, Florida

by

Air Quality Branch, Fish and Wildlife Service – Denver
January 6, 1998

The City of Lakeland (Lakeland) is proposing to construct a 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. Lakeland proposes to use natural gas as the primary fuel and low-sulfur (0.05 %) fuel oil as backup fuel for the turbine. Therefore, sulfur dioxide emissions will be minimized and less than significant for Prevention of Significant Deterioration (PSD) Review. However, the project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), particulate matter (PM-10), volatile organic compounds (VOC), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	863
PM-10	41
VOC	94
CO	1264

Best Available Control Technology (BACT) Analysis

Lakeland has proposed a simple cycle turbine system to generate electricity, rather than a more efficient combined cycle system with a heat recovery steam generator. In addition to being a less efficient system, emissions from the simple cycle system are inherently more difficult and expensive to control. We recommend that FDEP set emissions limits that reflect the end product, not the generation method (This is essentially the approach proposed by EPA in its New Source Performance Standards for boiler NO_X emissions.) Specifically, NO_x emissions should be limited to 5.0 parts per million by volume on a dry basis (ppmvd) during gas firing, and 20 ppmvd for oil firing, limits that could be achieved with selective catalytic reduction (a control technology that would be feasible with a combined cycle unit). These limits would result in a NO_x emission reduction of about 680 TPY. A second alternative would be to limit NO_x emissions to 9.0 ppmvd (while gas firing), which reflects the optimal use of the dry low-NO_x combustors proposed and would result in a NO_x emission reduction of about 545 TPY. Our comments on Lakeland's BACT analysis follow.

Lakeland has proposed the use of advanced dry low-NO_x combustors to meet NO_x limits of 25 ppmvd corrected to 15% oxygen (O_2) while burning natural gas. Water injection would be used to meet NO_X limits of 42 ppmvd while burning fuel oil. A review of the EPA RACT/BACT/LAER clearinghouse data submitted by the applicant found at least 18 examples (see enclosed table) of gas turbines using dry low-NO_x combustors permitted with NO_x limits in the 9-15 ppmvd range. In addition, the applicant states, "NO_x emissions ranging from 25 to 9 ppmvd (corrected to 15% O_2) has been offered by manufacturers for advanced combustion turbines." Therefore, this technology is capable of achieving emission limits well below the 25 ppmvd proposed by the applicant.

Even greater NO_X removal efficiency could be achieved by the use of selective catalytic reduction (SCR). SCR is capable of 70% NO_x removal efficiency. The attached table (showing NO_X limits from 43 gas turbines) demonstrates that SCR can achieve emission limits of 2.5-17.0 ppmvd. However, Lakeland has rejected the use of SCR on the grounds of economic unfeasibility. The high costs of SCR ($5,236 - $6,156/ton NO_x removed) are in part due to the high (1000–1100 °F) exhaust temperature of this simple cycle gas turbine which would require the use of high temperature catalyst materials and shorten equipment life. By contrast, a combined cycle system would use the waste heat from the turbine and its exhaust temperature would be lowered into the range at which less expensive SCR systems can function.

The high costs calculated are also due to calculation errors on the part of the applicant. For example:

Contingency costs are overestimated at 10% of Total Direct Capital Cost instead of 3% of the Purchased Equipment Cost.

Operating and maintenance labor costs exceed the costs estimated by EPA (EPA Control Cost Manual).

Ammonia costs appear too high and should be documented.

The Capital Recovery Factors are too high because they are based on a 10% interest rate instead of the 7% rate recommended by EPA.

Contingency costs have arbitrarily been added to Direct Annual Costs and Energy Costs without any justification.

The "Heat Rate Penalty" should be explained and justified.

The inclusion of both an "Inventory Cost" and "Annualized Total Direct Recurring" capital cost appears to be "double-counting" the cost of replacing the catalyst.

Lakeland has also presented SCR economic costs associated with a possible conversion to a combined cycle system in five years. These associated costs should not be considered without a commitment from Lakeland regarding the future conversion.

Air Quality Related Values (AQRV) Analysis

The current information provided by the applicant suggests that, at the proposed NO_X emissions rates, visibility will be unacceptably degraded at Chassahowitzka. Lakeland's regional haze analysis predicted that the project's emissions would cause a change of 0.97 deciview at Chassahowitzka. This is significantly higher than the 0.5 deciview screening value for a single source (see attached *Interim Visibility Modeling Guidance for Sources Locating or Expanding*

Near Chassahowitzka Wilderness, Florida). In addition, the 0.97 deciview value is underestimated because Lakeland did not include potential impacts from their PM-10 emissions in the analysis.

The predicted visibility degradation from Lakeland's new turbine is likely to constitute an adverse impact to visibility at Chassahowitzka, as defined by the federal visibility protection regulations (40 CFR 51.300, *et seq*., 52.27). Therefore, we recommend that FDEP require Lakeland to meet lower NO_X emissions limits to ensure that this project's contribution to regional haze is less than 0.5 deciview. Lakeland should perform a new regional haze analysis (including PM-10 emissions and lower NO_X emissions rates) to demonstrate that the project's impacts are less than 0.5 deciview. Lakeland should perform this analysis according to guidance provided by our office and the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 1 Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility*, EPA-454/R-93-015, April 1993. If Lakeland is unwilling to accept lower NO_X limits, we recommend that FDEP deny the permit on the basis of potential adverse impacts to the Class I area.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Gordonsville Energy	Sep-92			9.0	
Pansy/Holtsville	Sep-92	9.0			
Saranac Energy	Jul-92			9.0	
Selkirk Cogen	Jun-92			9.0	
Narragansett Elec.	Apr-92			9.0	
Bermuda Hundred	Mar-92			9.0	15.0
Kalamazoo Power	Dec-91	15.0			
So. Cal. Gas	Oct-91			8.0	
Sumas Energy	Jun-91			8.0	
Granite Rd. Ltd.	May-91			3.5	
Lakewood Cogen	Apr-91			9.0	
Cimaron Chemical	Mar-91			9.0	
Seminole Fertilizer	Mar-91			9.0	
Sumas Energy	Dec-90			9.0	
Newark Bay Cogen	Nov-90			8.3	
Las Vegas Cogen	Oct-90			10.0	
Doswell Ltd.	May-90			9.0	
Pedricktown Cogen	Feb-90			9.0	
Arrowhead Cogen	Dec-89			9.0	
Richmond Power Enterprise	Dec-89			8.2	
Kingsburg Energy Sys.	Sep-89			6.0	
Unocal	Jul-89			9.0	
Pawtucket Power	Jan-89			9.0	
Ocean State Power	Dec-88			9.0	
Baf Energy	Jul-87			9.0	
Cogen Technologies	Jun-87			9.6	
Western Power Sys.	Mar-86			9.0	
Union Oil	Mar-86			2.5	
Ols Energy	Jan-86			9.0	
American Cogen Tech.	Sep-85			17.0	
Sunlaw	Jun-85			9.0	
Willamette Ind.	Apr-85			15.0	

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Formosa Plastics	Mar-97	9.0			
SW PSCo	Nov-96	15.0			
Blue Mtn. Pwr.	Jul-96			4.0	
Mid-Ga. Cogen	Apr-96			9.0	20.0
Seminole Hardee Unit 3	Jan-96	15.0			
Brooklyn Navy Yard Cogen	Jun-95			3.5	10.0
Panda-Kathleen	Jun-95	15.0			
Pilgrim Energy Center	Apr-95			4.5	
Gainesville Regional Utilities	Apr-95	15.0			
Formosa Plastics	Mar-95	9.0			
Lap-Cottage Grove	Mar-95			4.5	
Portland General Elec.	May-94			4.5	
Hermiston Generating	Apr-94			4.5	
Florida Power	Feb-94	12.0			
Orange Cogen	Dec-93	15.0			
Newark Bay Cogen	Jun-93			8.3	16.0
Tiger Bay	May-93	15.0			
Phoenix Power Part.	May-93	22.0			
Kissimmee Utility Authority	Apr-93	15.0			
Kissimmee Utility Authority	Apr-93	15.0			
Auburndale Power Part.	Dec-92	15.0			
Sithe/Independence	Nov-92			4.5	
Kamine/Besicorp	Nov-92	9.0		9.0	
Kamine/Besicorp	Nov-92	9.0		9.0	
Grays Ferry	Nov-92	9.0			
Goal Line	Nov-92			5.0	
Bear Island Paper	Oct-92			9.0	15.0

Interim Visibility Modeling Guidance
For Sources Locating or Expanding Near
Chassahowitzka Wilderness, Florida
December 1997

This Interim Visibility Modeling Guidance Document has been developed for use by PSD permit applicants seeking to locate or expand near Chassahowitzka Wilderness, a Class I area administered by the U.S. Fish and Wildlife Service (FWS). A more detailed, comprehensive guidance document will be available in early 1998.

Applicants should assume a background visual range of 65 km for Chassahowitzka Wilderness.

Sources less than 50 km from a Class I area:

Sources ***less than 50 km*** from a Class I area should perform an analysis to assess the potential for visible plumes from their emissions at the Class I area. The recommended models are VISCREEN (Levels 1 and 2) as the screening model and PLUVUE II as the more refined model. If the screening or refined modeling predicts an impact less than a delta E of 2.0 and a contrast of 0.05, no plume impact is expected and no further analysis is required. If the modeling predicts an impact equal to or greater than the 2.0 or 0.05 values, the potential for plume impacts is significant and the FLM will determine on a case-by-case basis whether or not those impacts would be adverse, considering predicted frequency, magnitude, duration, and other factors.

Sources greater than or equal to 50 km from a Class I area:

Sources ***greater than or equal to 50 km*** from a model receptor in a Class I area should perform an analysis to assess the potential for a significant increase in uniform (i.e., regional) haze in the Class I area due to the source's emissions. The source may choose to use a screening model (e.g., ISC) or a more refined model (e.g., Mesopuff or Calpuff). If the predicted impact is less than or equal to 0.5 deciview, the impact is considered insignificant and no further analysis is needed. If the predicted impact is greater than 0.5 deciview, the applicant should conduct a cumulative modeling analysis including the new source's proposed emissions and all other increment-consuming emissions. If the cumulative analysis predicts an impact less than or equal to 1.0 deciview, the impact is considered insignificant and no further analysis is needed. If the cumulative impact is greater than 1.0 deciview, a significant increase in haze is possible and FWS will make a case-by-case adverse impact determination regarding the proposed project, considering the predicted frequency, magnitude, and duration of impacts.

Contact: Bud Rolofson, FWS Air Quality Branch (303) 969-2804

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW
ATLANTA, GEORGIA 30303-8909

FEB 10 1998

4APT-ARB

Mr. Claire H. Fancy, P.E.
Chief
Bureau of Air Regulation
Florida Department of Environmental
Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

SUBJ: PSD Permit Application from City of Lakeland, McIntosh Power Plant, Lakeland, Florida (PSD-FL-245)

Dear Mr. Fancy:

This is to acknowledge receipt of an application for a Prevention of Significant Deterioration (PSD) permit for the above referenced facility submitted by a letter dated December 9, 1997, from Mr. Al Linero. The application is for the construction of a 250 MW simple cycle combustion turbine (CT) at the existing McIntosh Power Plant. A Westinghouse Model 501G advanced CT with dry low-NO_x (DLN) burners is proposed. The CT will include a once-through steam generator (OTSG) which will use the waste heat to produce steam for cooling and power augmentation. Electric power production will be increased from about 230 MW to about 250 MW by using power augmentation. The primary fuel for the CT will be natural gas, and distillate fuel oil (maximum sulfur content of 0.05 percent) will be used as a backup fuel.

The proposed combustion turbine will initially operate as a baseload unit, and maximum annual emissions are based on the firing of natural gas for 6,758 hr/yr and the firing of fuel oil for 250 hr/yr. Emission estimates provided by the applicant indicate significance thresholds for the following pollutants will be exceeded, requiring PSD review: CO, NO_x, VOC, PM, and PM_{10}. As stated in the application, after an initial period of operation of approximately five years, it is anticipated that the unit would be modified to operate as a combined cycle unit with the addition of a heat recovery steam generator (HRSG), steam electric generator, and associated equipment.

Based on the applicant's best available control technology (BACT) analysis, NO_x emissions are proposed to be controlled by the use of DLN combustion technology to achieve an emission rate of 25 ppmvd when firing natural gas and the use of water injection to achieve an emission rate of 42 ppmvd when firing fuel oil. The proposed BACT for the control of CO emissions is the use of combustion controls with proposed emission limits at baseload of 50 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil.

Based on our review of the application package, we have the following comments:

(1) Since the facility is anticipated to be converted to a combined cycle system after approximately five years, the initial BACT determination based on simple cycle operation should be subject to revision prior to the conversion to a combined cycle unit. A separate BACT analysis for the combined cycle unit should be conducted regardless of whether the specific changes or modifications associated with the conversion trigger applicability thresholds for PSD review. Also, since there is no definite commitment by the City of Lakeland for the conversion to a combined cycle unit after five years, the BACT analysis for the simple cycle unit should be based on operation in that mode for the life of the project.

(2) Although it isn't an issue in the selection of an appropriate control technology, we are interested in the City of Lakeland's rationale for dividing the project into stages. In particular, why does the facility propose to wait five years to convert the project to a more efficient combined cycle unit which would be less expensive to control?

(3) As indicated in the RACT/BACT/LAER Clearinghouse (RBLC) database, other combustion turbines have been permitted with NO_x emission limits of 15 ppmvd or less with the use of DLN combustion. Also, other turbine models are capable of achieving 15 ppmvd with DLN combustion when using power augmentation. Additional information should be provided concerning the possibility of achieving a NO_x emission rate less than the proposed 25 ppmvd with DLN combustion technology for the proposed CT.

(4) As acknowledged in the permit application, the use of a high temperature selective catalytic reduction (SCR) system is a technically feasible control option, although the estimated costs were considered unreasonable by the City of Lakeland. The cost estimate in the BACT analysis based on simple cycle operation for the life of the project was $5,236/ton. The cost of using the system for only five years, assuming the combined cycle conversion takes place at that time, was calculated to be $6,156/ton. The application also addresses the additional costs associated with the replacement of a high temperature SCR system (used with a simple cycle unit) with another SCR unit if a heat recovery steam generator is later installed. As discussed in the State's January 12, 1998, letter, the use of a high temperature SCR system with the simple cycle operation and following the installation of a HRSG was not addressed in the application, but may be a viable option. The BACT analysis provided in the application for the project does not justify the proposed NO_x emission limit of 25

ppmvd. The feasibility of achieving a lower emission rate should be further investigated.

The NSPS regulations at 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines will be applicable to the new combustion turbine. 40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels will apply to the new 1.05 million gallon fuel oil storage tank.

In addition to the above comments, Mr. Stan Krivo of my staff is reviewing the modeled air quality impact assessment associated with this PSD application. Any significant comments and/or questions associated with this review will be contained in a subsequent letter.

Thank you for the opportunity to review and comment on the application package. If you have any questions, please contact Keith Goff of my staff at (404)562-9137.

Sincerely yours,

for

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides, and Toxics Management Division

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW
ATLANTA, GEORGIA 30303-8909

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RECEIVED

FEB 23 1998

BUREAU OF
AIR REGULATION

4APT-ARB

FEB 10 1998

Mr. Claire H. Fancy, P.E.
Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

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The proposed combustion turbine will initially operate as a baseload unit, and maximum annual emissions are based on the firing of natural gas for 6,758 hr/yr and the firing of fuel oil for 250 hr/yr. Emission estimates provided by the applicant indicate significance thresholds for the following pollutants will be exceeded, requiring PSD review: CO, NO_x, VOC, PM, and PM_{10}. As stated in the application, after an initial period of operation of approximately five years, it is anticipated that the unit would be modified to operate as a combined cycle unit with the addition of a heat recovery steam generator (HRSG), steam electric generator, and associated equipment.

Based on the applicant's best available control technology (BACT) analysis, NO_x emissions are proposed to be controlled by the use of DLN combustion technology to achieve an emission rate of 25 ppmvd when firing natural gas and the use of water injection to achieve an emission rate of 42 ppmvd when firing fuel oil. The proposed BACT for the control of CO emissions is the use of combustion controls with proposed emission limits at baseload of 50 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil.

Based on our review of the application package, we have the following comments:

(1) Since the facility is anticipated to be converted to a combined cycle system after approximately five years, the initial BACT determination based on simple cycle operation should be subject to revision prior to the conversion to a combined cycle unit. A separate BACT analysis for the combined cycle unit should be conducted regardless of whether the specific changes or modifications associated with the conversion trigger applicability thresholds for PSD review. Also, since there is no definite commitment by the City of Lakeland for the conversion to a combined cycle unit after five years, the BACT analysis for the simple cycle unit should be based on operation in that mode for the life of the project.

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In addition to the above comments, Mr. Stan Krivo of my staff is reviewing the modeled air quality impact assessment associated with this PSD application. Any significant comments and/or questions associated with this review will be contained in a subsequent letter.

Thank you for the opportunity to review and comment on the application package. If you have any questions, please contact Keith Goff of my staff at (404)562-9137.

Sincerely yours,

for

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides, and Toxics Management Division

cc: NPS
SWD
Polk Co
J. Shelton, CQL
K. Kosky, Golder Assoc.

Westinghouse
Electric Corporation

Generation Systems Division

The Quadrangle
4400 Alafaya Trail - MC 560
Orlando, Florida 32126-2399

COL W/COL-006
File: 016.1

January 21, 1998

Ms. Farzie Shelton
City of Lakeland, Florida
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

Subject: City of Lakeland Project
McIntosh Unit #5
Air Permitting

Dear Farzie:

Per your request, enclosed are the Westinghouse technical papers describing our combustion technology. This is being provided to support your air permitting efforts.

If we can be of any further assistance, please let us know.

Regards,

Robert O'Boy — for Andy Mould

Andy Mould
Manager, City of Lakeland

enclosure

cc: R. Greenwood MC 560
K. Weaver MC 590

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

January 15, 1998

RECEIVED

JAN 20 1998

BUREAU OF
AIR REGULATION

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration Application for the city of Lakeland's proposed 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area, administered by the U.S. Fish and Wildlife Service. The technical review comments from our Air Quality Branch are enclosed. Specifically, we recommend that your department require Lakeland to meet lower limits on nitrogen oxides emissions than those proposed. At the proposed limits, Lakeland has predicted that significant visibility degradation will occur in Chassahowitzka. In addition, lower limits would more accurately reflect best available control technology.

We also are enclosing the "Interim Visibility Modeling Guidance for Sources Locating or Expanding Near Chassahowitzka Wilderness, Florida." As you know, we have enclosed this document with other recent comment letters to your department, and we ask that you provide this document to future PSD applicants. Our Air Quality Branch is compiling a more detailed and comprehensive document addressing visibility analyses that will be available in early 1998.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have any questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at 303/969-2617.

Sincerely yours,

H Dale Hall
for Sam D. Hamilton
Regional Director

cc:
EPA
SWD
Polk Co
J. Shelton, C of L
K. Kosky, Golder

cc: T. Heron, BAR
C. Holladay, BAR

Enclosures

Technical Review of Prevention of Significant Deterioration Permit Application For a 250-Megawatt Simple Cycle Combustion Turbine at McIntosh Power Plant Polk County, Florida

by

Air Quality Branch, Fish and Wildlife Service – Denver
January 6, 1998

The City of Lakeland (Lakeland) is proposing to construct a 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. Lakeland proposes to use natural gas as the primary fuel and low-sulfur (0.05 %) fuel oil as backup fuel for the turbine. Therefore, sulfur dioxide emissions will be minimized and less than significant for Prevention of Significant Deterioration (PSD) Review. However, the project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), particulate matter (PM-10), volatile organic compounds (VOC), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	863
PM-10	41
VOC	94
CO	1264

Best Available Control Technology (BACT) Analysis

Lakeland has proposed a simple cycle turbine system to generate electricity, rather than a more efficient combined cycle system with a heat recovery steam generator. In addition to being a less efficient system, emissions from the simple cycle system are inherently more difficult and expensive to control. We recommend that FDEP set emissions limits that reflect the end product, not the generation method (This is essentially the approach proposed by EPA in its New Source Performance Standards for boiler NO_X emissions.) Specifically, NO_x emissions should be limited to 5.0 parts per million by volume on a dry basis (ppmvd) during gas firing, and 20 ppmvd for oil firing, limits that could be achieved with selective catalytic reduction (a control technology that would be feasible with a combined cycle unit). These limits would result in a NO_x emission reduction of about 680 TPY. A second alternative would be to limit NO_x emissions to 9.0 ppmvd (while gas firing), which reflects the optimal use of the dry low-NO_x combustors proposed and would result in a NO_x emission reduction of about 545 TPY. Our comments on Lakeland's BACT analysis follow.

Lakeland has proposed the use of advanced dry low-NO_x combustors to meet NO_x limits of 25 ppmvd corrected to 15% oxygen (O_2) while burning natural gas. Water injection would be used to meet NO_X limits of 42 ppmvd while burning fuel oil. A review of the EPA RACT/BACT/LAER clearinghouse data submitted by the applicant found at least 18 examples (see enclosed table) of gas turbines using dry low-NO_x combustors permitted with NO_x limits in the 9-15 ppmvd range. In addition, the applicant states, "NO_x emissions ranging from 25 to 9 ppmvd (corrected to 15% O_2) has been offered by manufacturers for advanced combustion turbines." Therefore, this technology is capable of achieving emission limits well below the 25 ppmvd proposed by the applicant.

Even greater NO_X removal efficiency could be achieved by the use of selective catalytic reduction (SCR). SCR is capable of 70% NO_x removal efficiency. The attached table (showing NO_X limits from 43 gas turbines) demonstrates that SCR can achieve emission limits of 2.5-17.0 ppmvd. However, Lakeland has rejected the use of SCR on the grounds of economic unfeasibility. The high costs of SCR ($5,236 - $6,156/ton NO_x removed) are in part due to the high (1000–1100 °F) exhaust temperature of this simple cycle gas turbine which would require the use of high temperature catalyst materials and shorten equipment life. By contrast, a combined cycle system would use the waste heat from the turbine and its exhaust temperature would be lowered into the range at which less expensive SCR systems can function.

The high costs calculated are also due to calculation errors on the part of the applicant. For example:

Contingency costs are overestimated at 10% of Total Direct Capital Cost instead of 3% of the Purchased Equipment Cost.
Operating and maintenance labor costs exceed the costs estimated by EPA (EPA Control Cost Manual).
Ammonia costs appear too high and should be documented.
The Capital Recovery Factors are too high because they are based on a 10% interest rate instead of the 7% rate recommended by EPA.
Contingency costs have arbitrarily been added to Direct Annual Costs and Energy Costs without any justification.
The "Heat Rate Penalty" should be explained and justified.
The inclusion of both an "Inventory Cost" and "Annualized Total Direct Recurring" capital cost appears to be "double-counting" the cost of replacing the catalyst.

Lakeland has also presented SCR economic costs associated with a possible conversion to a combined cycle system in five years. These associated costs should not be considered without a commitment from Lakeland regarding the future conversion.

Air Quality Related Values (AQRV) Analysis

The current information provided by the applicant suggests that, at the proposed NO_X emissions rates, visibility will be unacceptably degraded at Chassahowitzka. Lakeland's régional haze analysis predicted that the project's emissions would cause a change of 0.97 deciview at Chassahowitzka. This is significantly higher than the 0.5 deciview screening value for a single source (see attached *Interim Visibility Modeling Guidance for Sources Locating or Expanding*

Near Chassahowitzka Wilderness, Florida). In addition, the 0.97 deciview value is underestimated because Lakeland did not include potential impacts from their PM-10 emissions in the analysis.

The predicted visibility degradation from Lakeland's new turbine is likely to constitute an adverse impact to visibility at Chassahowitzka, as defined by the federal visibility protection regulations (40 CFR 51.300, *et seq.*, 52.27). Therefore, we recommend that FDEP require Lakeland to meet lower NO_X emissions limits to ensure that this project's contribution to regional haze is less than 0.5 deciview. Lakeland should perform a new regional haze analysis (including PM-10 emissions and lower NO_X emissions rates) to demonstrate that the project's impacts are less than 0.5 deciview. Lakeland should perform this analysis according to guidance provided by our office and the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 1 Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility*, EPA-454/R-93-015, April 1993. If Lakeland is unwilling to accept lower NO_X limits, we recommend that FDEP deny the permit on the basis of potential adverse impacts to the Class I area.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Gordonsville Energy	Sep-92			9.0	
Pansy/Holtsville	Sep-92	9.0			
Saranac Energy	Jul-92			9.0	
Selkirk Cogen	Jun-92			9.0	
Narragansett Elec.	Apr-92			9.0	
Bermuda Hundred	Mar-92			9.0	15.0
Kalamazoo Power	Dec-91	15.0			
So. Cal. Gas	Oct-91			8.0	
Sumas Energy	Jun-91			8.0	
Granite Rd. Ltd.	May-91			3.5	
Lakewood Cogen	Apr-91			9.0	
Cimaron Chemical	Mar-91			9.0	
Seminole Fertilizer	Mar-91			9.0	
Sumas Energy	Dec-90			9.0	
Newark Bay Cogen	Nov-90			8.3	
Las Vegas Cogen	Oct-90			10.0	
Doswell Ltd.	May-90			9.0	
Pedricktown Cogen	Feb-90			9.0	
Arrowhead Cogen	Dec-89			9.0	
Richmond Power Enterprise	Dec-89			8.2	
Kingsburg Energy Sys.	Sep-89			6.0	
Unocal	Jul-89			9.0	
Pawtucket Power	Jan-89			9.0	
Ocean State Power	Dec-88			9.0	
Baf Energy	Jul-87			9.0	
Cogen Technologies	Jun-87			9.6	
Western Power Sys.	Mar-86			9.0	
Union Oil	Mar-86			2.5	
Ols Energy	Jan-86			9.0	
American Cogen Tech.	Sep-85			17.0	
Sunlaw	Jun-85			9.0	
Willamette Ind.	Apr-85			15.0	

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Formosa Plastics	Mar-97	9.0			
SW PSCo	Nov-96	15.0			
Blue Mtn. Pwr.	Jul-96			4.0	
Mid-Ga. Cogen	Apr-96			9.0	20.0
Seminole Hardee Unit 3	Jan-96	15.0			
Brooklyn Navy Yard Cogen	Jun-95			3.5	10.0
Panda-Kathleen	Jun-95	15.0			
Pilgrim Energy Center	Apr-95			4.5	
Gainesville Regional Utilities	Apr-95	15.0			
Formosa Plastics	Mar-95	9.0			
Lap-Cottage Grove	Mar-95			4.5	
Portland General Elec.	May-94			4.5	
Hermiston Generating	Apr-94			4.5	
Florida Power	Feb-94	12.0			
Orange Cogen	Dec-93	15.0			
Newark Bay Cogen	Jun-93			8.3	16.0
Tiger Bay	May-93	15.0			
Phoenix Power Part.	May-93	22.0			
Kissimmee Utility Authority	Apr-93	15.0			
Kissimmee Utility Authority	Apr-93	15.0			
Auburndale Power Part.	Dec-92	15.0			
Sithe/Independence	Nov-92			4.5	
Kamine/Besicorp	Nov-92	9.0		9.0	
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Grays Ferry	Nov-92	9.0			
Goal Line	Nov-92			5.0	
Bear Island Paper	Oct-92			9.0	15.0

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For Sources Locating or Expanding Near
Chassahowitzka Wilderness, Florida
December 1997

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***Sources less than 50 km from a Class I area*:**

Sources ***less than 50 km*** from a Class I area should perform an analysis to assess the potential for visible plumes from their emissions at the Class I area. The recommended models are VISCREEN (Levels 1 and 2) as the screening model and PLUVUE II as the more refined model. If the screening or refined modeling predicts an impact less than a delta E of 2.0 and a contrast of 0.05, no plume impact is expected and no further analysis is required. If the modeling predicts an impact equal to or greater than the 2.0 or 0.05 values, the potential for plume impacts is significant and the FLM will determine on a case-by-case basis whether or not those impacts would be adverse, considering predicted frequency, magnitude, duration, and other factors.

Sources greater than or equal to 50 km from a Class I area:

Sources ***greater than or equal to 50 km*** from a model receptor in a Class I area should perform an analysis to assess the potential for a significant increase in uniform (i.e., regional) haze in the Class I area due to the source's emissions. The source may choose to use a screening model (e.g., ISC) or a more refined model (e.g., Mesopuff or Calpuff). If the predicted impact is less than or equal to 0.5 deciview, the impact is considered insignificant and no further analysis is needed. If the predicted impact is greater than 0.5 deciview, the applicant should conduct a cumulative modeling analysis including the new source's proposed emissions and all other increment-consuming emissions. If the cumulative analysis predicts an impact less than or equal to 1.0 deciview, the impact is considered insignificant and no further analysis is needed. If the cumulative impact is greater than 1.0 deciview, a significant increase in haze is possible and FWS will make a case-by-case adverse impact determination regarding the proposed project, considering the predicted frequency, magnitude, and duration of impacts.

Contact: Bud Rolofson, FWS Air Quality Branch (303) 969-2804

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 12, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

Attached are the comments we received by Fax from the Air Quality Branch of the Fish and Wildlife Service. We will send you a copy of the signed version when we receive it. Please note their comments regarding the proposed Best Available Control Technology (BACT) nitrogen oxides (NO_X)emission limit of 25 ppm. They also have requested some additional modeling which would might not be necessary if the emissions were lower.

We have reviewed the BACT information in the application in more detail. It appears that it would not be necessary to write off high temperature SCR (installed at start-up) if and when a heat recovery steam generator (HRSG) were installed in the future. Therefore additional costs of future Dry Low-NO_X (DLN) technology and/or low temperature SCR do not need to be summed into the long term cost of pollution control by hot SCR.

High temperature SCR could be installed by start-up. Westinghouse would not then need to attempt to refine its DLN technology (for this project) to achieve lower NO_X emissions at higher temperature and pressure ratios under such challenges as pressure pulsation and lower flame stability. Low temperature SCR might not need to be installed later. In fact, HRSG operation would likely be simplified by one-piece construction instead of having separate components with a low temperature SCR module in-between. This approach would allow the City to proceed with the planned staged project, satisfy BACT requirements for NO_X, and defer the decision on installation of a HRSG until a future date consistent with the PSD application.

We are still awaiting comments from EPA. If you have any questions regarding this matter, please contact Teresa Heron (review engineer) or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A A Linero 1/12

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/aal

Attachment

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

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Assistant Managing Director
Lakeland Electric & Water
501 E. Lemon St.
Lakeland, Fl
33801-5079

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PS Form **3800**, April 1995

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration Application for the City of Lakeland's proposed 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. The technical review comments from our Air Quality Branch are enclosed. Specifically, we recommend that your department require Lakeland to meet lower limits on nitrogen oxides emissions than those proposed. At the proposed limits, Lakeland has predicted that significant visibility degradation will occur in Chassahowitzka. In addition, lower limits would more accurately reflect best available control technology.

In addition, we are enclosing the "Interim Visibility Modeling Guidance for Sources Locating or Expanding Near Chassahowitzka Wilderness, Florida." As you know, we have enclosed this document with other recent comment letters to your department and we ask you to provide this document to future PSD applicants. Our Air Quality Branch is compiling a more detailed and comprehensive document addressing visibility analyses that will be available in early 1998.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ellen Porter of our Air Quality Branch in Denver at (303) 969-2617.

Sincerely,

Sam D. Hamilton
Regional Director

Enclosures

cc: Doug Neeley, Chief
Air and Radiation Branch
U.S. EPA, Region IV
100 Alabama St., SW
Atlanta, Georgia 30303

bcc: FWS-REG. 4: AQC
CHAS: Refuge Manager
AQD-DEN: Ellen Porter
National Park Service - AIR
P.O. Box 25287
Denver, CO 80225

Technical Review of Prevention of Significant Deterioration Permit Application For a 250-Megawatt Simple Cycle Combustion Turbine at McIntosh Power Plant Polk County, Florida

by

Air Quality Branch, Fish and Wildlife Service – Denver
January 6, 1998

The City of Lakeland (Lakeland) is proposing to construct a 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. Lakeland proposes to use natural gas as the primary fuel and low-sulfur (0.05 %) fuel oil as backup fuel for the turbine. Therefore, sulfur dioxide emissions will be minimized and less than significant for Prevention of Significant Deterioration (PSD) Review. However, the project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), particulate matter (PM-10), volatile organic compounds (VOC), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	863
PM-10	41
VOC	94
CO	1264

Best Available Control Technology (BACT) Analysis

Lakeland has proposed a simple cycle turbine system to generate electricity, rather than a more efficient combined cycle system with a heat recovery steam generator. In addition to being a less efficient system, emissions from the simple cycle system are inherently more difficult and expensive to control. We recommend that FDEP set emissions limits that reflect the end product, not the generation method (This is essentially the approach proposed by EPA in its New Source Performance Standards for boiler NO_X emissions.) Specifically, NO_x emissions should be limited to 5.0 parts per million by volume on a dry basis (ppmvd) during gas firing, and 20 ppmvd for oil firing, limits that could be achieved with selective catalytic reduction (a control technology that would be feasible with a combined cycle unit). These limits would result in a NO_x emission reduction of about 680 TPY. A second alternative would be to limit NO_x emissions to 9.0 ppmvd (while gas firing), which reflects the optimal use of the dry low-NO_x combustors proposed and would result in a NO_x emission reduction of about 545 TPY. Our comments on Lakeland's BACT analysis follow.

Lakeland has proposed the use of advanced dry low-NO_x combustors to meet NO_x limits of 25 ppmvd corrected to 15% oxygen (O_2) while burning natural gas. Water injection would be used to meet NO_X limits of 42 ppmvd while burning fuel oil. A review of the EPA

RACT/BACT/LAER clearinghouse data submitted by the applicant found at least 18 examples (see enclosed table) of gas turbines using dry low-NO_x combustors permitted with NO_x limits in the 9-15 ppmvd range. In addition, the applicant states, "NO_x emissions ranging from 25 to 9 ppmvd (corrected to 15% O_2) has been offered by manufacturers for advanced combustion turbines." Therefore, this technology is capable of achieving emission limits well below the 25 ppmvd proposed by the applicant.

Even greater NO_x removal efficiency could be achieved by the use of selective catalytic reduction (SCR). SCR is capable of 70% NO_x removal efficiency. The attached table (showing NO_x limits from 43 gas turbines) demonstrates that SCR can achieve emission limits of 2.5-17.0 ppmvd. However, Lakeland has rejected the use of SCR on the grounds of economic unfeasibility. The high costs of SCR ($5,236 - $6,136/ton NO_x removed) are in part due to the high (1000-1100 °F) exhaust temperature of this simple cycle gas turbine which would require the use of high temperature catalyst materials and shorten equipment life. By contrast, a combined cycle system would use the waste heat from the turbine and its exhaust temperature would be lowered into the range at which less expensive SCR systems can function.

The high costs calculated are also due to calculation errors on the part of the applicant. For example:

- Contingency costs are overestimated at 10% of Total Direct Capital Cost instead of 3% of the Purchased Equipment Cost.
- Operating and maintenance labor costs exceed the costs estimated by EPA (EPA Control Cost Manual).
- Ammonia costs appear too high and should be documented.
- The Capital Recovery Factors are too high because they are based on a 10% interest rate instead of the 7% rate recommended by EPA.
- Contingency costs have arbitrarily been added to Direct Annual Costs and Energy Costs without any justification.
- The "Heat Rate Penalty" should be explained and justified.
- The inclusion of both an "Inventory Cost" and "Annualized Total Direct Recurring" capital cost appears to be "double-counting" the cost of replacing the catalyst.

Lakeland has also presented SCR economic costs associated with a possible conversion to a combined cycle system in five years. These associated costs should not be considered without a commitment from Lakeland regarding the future conversion.

Air Quality Related Values (AQRV) Analysis

The current information provided by the applicant suggests that, at the proposed NO_x emissions rates, visibility will be unacceptably degraded at Chassahowitzka. Lakeland's regional haze analysis predicted that the project's emissions would cause a change of 0.97 deciview at Chassahowitzka. This is significantly higher than the 0.5 deciview screening value for a single source (see attached *Interim Visibility Modeling Guidance for Sources Locating or Expanding Near Chassahowitzka Wilderness, Florida*). In addition, the 0.97 deciview value is underestimated because Lakeland did not include potential impacts from their PM-10 emissions in the analysis.

The predicted visibility degradation from Lakeland's new turbine is likely to constitute an adverse impact to visibility at Chassahowitzka, as defined by the federal visibility protection regulations (40 CFR 51.300, *et seq.*, 52.27). Therefore, we recommend that FDEP require Lakeland to meet lower NO_X emissions limits to ensure that this project's contribution to regional haze is less than 0.5 deciview. Lakeland should perform a new regional haze analysis (including PM-10 emissions and lower NO_X emissions rates) to demonstrate that the project's impacts are less than 0.5 deciview. Lakeland should perform this analysis according to guidance provided by our office and the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 1 Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility*, EPA-454/R-93-015, April 1993. If Lakeland is unwilling to accept lower NO_X limits, we recommend that FDEP deny the permit on the basis of potential adverse impacts to the Class I area.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Formosa Plastics	Mar-97	9.0			
SW PSCo	Nov-96	15.0			
Blue Mtn. Pwr.	Jul-96			4.0	
Mid-Ga. Cogen	Apr-96			9.0	20.0
Seminole [illegible] - Unit 3	Jan-96	15.0			
Brooklyn Navy Yard Cogen	Jun-95			3.5	10.0
Panda-Ka[illegible]n	Jun-95	15.0			
Pilgrim Energy Center	Apr-95			4.5	
Gainesville Regional Utilities	Apr-95	15.0			
Formosa Plastics	Mar-95	9.0			
Lap-Cottage Grove	Mar-95			4.5	
Portland General Elec.	May-94			4.5	
Hermiston Generating	Apr-94			4.5	
Florida Power	Feb-94	12.0			
Orange Cogen	Dec-93	15.0			
Newark Bay Cogen	Jun-93			8.3	16.0
Tiger Bay	May-93	15.0			
Phoenix Power Part.	May-93	22.0			
Kissimmee Utility Authority	Apr-93	15.0			
Kissimmee Utility Authority	Apr-93	15.0			
Auburndale Power Part.	Dec-92	15.0			
Sithe/Independence	Nov-92			4.5	
Kamine/Besicorp	Nov-92	9.0		9.0	
Kamine/Besicorp	Nov-92	9.0		9.0	
Grays Ferry	Nov-92	9.0			
Goal Line	Nov-92			5.0	
Bear Island Paper	Oct-92			9.0	15.0

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Gordonsville Energy	Sep-92			9.0	
Pansy/Holtsville	Sep-92	9.0			
Saranac Energy	Jul-92			9.0	
Selkirk Cogen	Jun-92			9.0	
Narragansett Elec.	Apr-92			9.0	
Bermuda Hundred	Mar-92			9.0	15.0
Kalamazoo Power	Dec-91	15.0			
So. Cal. Gas	Oct-91			8.0	
Sumas Energy	Jun-91			8.0	
Granite Rd. Ltd.	May-91			3.5	
Lakewood Cogen	Apr-91			9.0	
Cimaron Chemical	Mar-91			9.0	
Seminole Fertilizer	Mar-91			9.0	
Sumas Energy	Dec-90			9.0	
Newark Bay Cogen	Nov-90			8.3	
Las Vegas Cogen	Oct-90			10.0	
Doswell Ltd.	May-90			9.0	
Pedricktown Cogen	Feb-90			9.0	
Arrowhead Cogen	Dec-89			9.0	
Richmond Power Enterprise	Dec-89			8.2	
Kingsburg Energy Sys.	Sep-89			6.0	
Unocal	Jul-89			9.0	
Pawtucket Power	Jan-89			9.0	
Ocean State Power	Dec-88			9.0	
Baf Energy	Jul-87			9.0	
Cogen Technologies	Jun-87			9.6	
Western Power Sys.	Mar-86			9.0	
Union Oil	Mar-86			2.5	
Ols Energy	Jan-86			9.0	
American Cogen Tech.	Sep-85			17.0	
Sunlaw	Jun-85			9.0	
Willamette Ind.	Apr-85			15.0	

**Interim Visibility Modeling Guidance
For Sources Locating or Expanding Near
Chassahowitzka Wilderness, Florida
December 1997**

This Interim Visibility Modeling Guidance Document has been developed for use by PSD permit applicants seeking to locate or expand near Chassahowitzka Wilderness, a Class I area administered by the U.S. Fish and Wildlife Service (FWS). A more detailed, comprehensive guidance document will be available in early 1998.

Applicants should assume a background visual range of 65 km for Chassahowitzka Wilderness.

***Sources less than 50 km from a Class I area*:**

Sources ***less than 50 km*** from a Class I area should perform an analysis to assess the potential for visible plumes from their emissions at the Class I area. The recommended models are VISCREEN (Levels 1 and 2) as the screening model and PLUVUE II as the more refined model. If the screening or refined modeling predicts an impact less than a delta E of 2.0 and a contrast of 0.05, no plume impact is expected and no further analysis is required. If the modeling predicts an impact equal to or greater than the 2.0 or 0.05 values, the potential for plume impacts is significant and the FLM will determine on a case-by-case basis whether or not those impacts would be adverse, considering predicted frequency, magnitude, duration, and other factors.

Sources greater than or equal to 50 km from a Class I area:

Sources ***greater than or equal to 50 km*** from a model receptor in a Class I area should perform an analysis to assess the potential for a significant increase in uniform (i.e., regional) haze in the Class I area due to the source's emissions. The source may choose to use a screening model (e.g., ISC) or a more refined model (e.g., Mesopuff or Calpuff). If the predicted impact is less than or equal to 0.5 deciview, the impact is considered insignificant and no further analysis is needed. If the predicted impact is greater than 0.5 deciview, the applicant should conduct a cumulative modeling analysis including the new source's proposed emissions and all other increment-consuming emissions. If the cumulative analysis predicts an impact less than or equal to 1.0 deciview, the impact is considered insignificant and no further analysis is needed. If the cumulative impact is greater than 1.0 deciview, a significant increase in haze is possible and FWS will make a case-by-case adverse impact determination regarding the proposed project, considering the predicted frequency, magnitude, and duration of impacts.

Contact: Bud Rolofson, FWS Air Quality Branch (303) 969-2804

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 5, 1998

Ms. Farzie Shelton
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

Re: McIntosh Unit No. 5

Dear Ms Shelton:

I have reviewed a copy of the Air Construction Permit Application submitted to the Bureau of Air Regulation on December 5, 1997. Based on the description of the project in your transmittal letter and on page 2-1 of the Air Permit Application and PSD Analysis, the Department has determined that this unit will result in an increase in steam-electric generating capacity at a certified power plant site. Because of the increase in steam generating capacity, your utilitiy is required to file an application pursuant to the Florida Electrical Power Plant Siting Act, sections 403.501-519, F.S. The initial $7,500 application fee will be applied against the required $75,000 power plant siting application fee.

Even if there were to be no increase in steam electric generating capacity for this unit, it would still be governed by the PPSA. The addition of Unit 5 at the certified McIntosh site requires that the conditions of certification for Unit 3 be modified. I suggest you review General Condition 1.

If there are any questions concerning this matter, I may be reached at (850) 487-0472.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

cc: Clair Fancy, P.E., BAR ✓
Tom Ballinger, PSC
Scott Goorland, OGC
cc: T. Dixon, BAR

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Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 5, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

The Department has conducted a completeness review of the City of Lakeland's application received on December 8, 1997 for installation of a 250 megawatt Westinghouse 501G simple cycle combustion turbine and once-through steam generator to be referred to as Unit No. 5 at the C. D. McIntosh Power Plant. Please provide responses to our comments given below and our questions in the attachment.

Unit 5 will be located at a facility on a site which constitute an electrical power plant and site as defined in the Florida Electrical Power Plant Siting Act. We have forwarded a copy of your application to the Department's Office of Siting Coordination to determine whether or not construction of Unit 5 constitutes a new project or modification with respect to the Act. Please contact Mr. Buck Oven, P.E., at 850/487-0472 regarding the status of that review.

The Department is in the process of modifying the certification for the FPC Hines facility for a 243 MW project consisting of a 165 MW Westinghouse 501 FC combustion turbine and a 78 MW heat recovery steam generator. That project is characterized by a net heat rate of approximately 7000 Btu/kWh and emissions of 12 ppm of nitrogen oxides (NO_X) and 25 ppm of carbon monoxide (CO) while firing gas. The City of Tallahassee is also in the process of obtaining certification for a project with similar power, heat rate, and emissions characteristics to the FPC Hines project. The planned project at C. D. McIntosh exhibits a net heat rate of 8,725 Btu/kWh and emissions of 25 ppm of NO_X and 50 ppm of CO. Therefore, the limits requested by the City of Lakeland appear to be high without sufficient compensating energy, environmental, or economic benefits.

If the City were to include a heat recovery steam generator now, to yield closer to 350 MW, the project characteristics would be on the order of 6000 Btu/kWh and emissions of approximately 10 ppm of NO_X by low temperature selective catalytic reduction (SCR) and 10 ppm CO. This option would yield lower emissions with substantial energy benefits.

The cost calculations indicating that lower NO_X emissions are not economically feasible, and the higher CO emissions from power augmentation, are consequences of the City's plan or need to stage the project. It would be difficult for the Department to conclude that BACT should be less stringent as a result of project staging or uncertain ultimate development plans.

At this time, there is no reasonable assurance that Westinghouse will guarantee emissions less than 25 ppm through Dry-Low NO_X (DLN) combustion. If Westinghouse could guarantee a lower emission rate, it should be achieved at or very soon after start-up. The longer periods of time given to applicants in the early 90's were for the purpose of allowing development of the DLN technology. We do not consider the technology to be experimental anymore. For example, no additional time was provided to FPC or the City of Tallahassee to achieve the 12 ppm NO_X emission rate in their PSD permits.

We expect to receive comments from the Department of Interior and EPA Region IV and will forward them to you as soon as they are received. If you have any questions regarding this matter, please contact Teresa Heron (review engineer) or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A. A. Linero 1/5

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/th

Attachment

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

ADDITIONAL COMMENTS - LAKELAND 250 MW COMBUSTION TURBINE PROJECT

POLLUTANT EMISSIONS

1. Show basis of calculations and equivalence in lb/MMBtu emission rate for each one of the pollutants considered in this project.
2. Is it Lakeland's intention to operate Unit 5 under the two options presented in Table 2-5?
3. Please explain the apparent inconsistency between the 0.05 percent (%) maximum sulfur content of the No. 2 fuel oil shown on page 25 and the typical value of 0.5 % sulfur shown on the unnumbered "Fuel Analysis" page following Table A-18 in Appendix A.

POWER AUGMENTATION

4. How much more power output is due to operation in the power augmentation mode and will operation be continuous in that mode?
5. Expand on the details of the Westinghouse DLN burner technology (combustor silo vs. can-annular combustor). What is the firing temperature of this unit?
6. What is the heat input of the once-through steam generator? Describe the primary function of the once-through steam generator? Will this unit be part of the system after the possible installation of the heat recovery steam generator?
7. Submit corresponding data to scenarios presented (Section and Appendix A of the Application) excluding the power augmentation mode.
8. Power augmentation will allow the firing of additional natural gas while injecting steam into the turbine, to produce more megawatts. What is the NO_X emissions increase (ppmvd) during the power augmentation mode? Would power augmentation be the preferred mode of operation . Will power augmentation be during the peak-demand period.
9. Provide a more specific description of the conditions under which operation in the PA mode would be required.
10. Why can't the extra power capacity from the power augmentation be generated under the base load capacity of the CT?
11. Does Lakeland plan to operate in the power augmentation mode as standard operating procedure? Under what circumstances will the power augmentation mode operate (i.e. base load, peaking, etc.)?

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

12. Section B.2., BACT review, indicates that "the available information suggests that SCR with DLN combustor technology or with wet injection is also technically feasible." Was this design evaluated in the BACT analysis?
13. On page B-4 and B-5 it is stated that Westinghouse and GE have offered DLN combustors on advanced heavy-duty industrial machines. Were other manufacturers considered for this project? If so, what was the NO_X pppmv at 15% O_2 and the earliest delivery dates?
14. Are other vendors willing to provide a NO_X emissions limit guarantee less than 15 ppmvd at 15%? What is the cost of converting a CT from a dry low combustor which can initially limit NO_X emissions to 15 ppmvd at 15% O_2 to a combustor which is capable of achieving a 9 ppmvd at 15% during a maintenance period (for example by 2005)?

15. There is a discrepancy between the operating capacity listed on page 4-3, last paragraph, and Table 4-1(80 percent operating capacity vs 100 percent operating capacity). Which one is correct?

16. What type of catalyst was evaluated? Please refer to Section 4.3.1.1.3 and Pages B-5 and 45. Was the ceramic catalyst explored? This system does not promote the conversion of SO_2 to SO_3 and has virtually no catalysis poisoning, plugging or masking problems. The ammonia slip is also limited. In addition the catalyst is not considered a hazardous waste.

17. What will be the actual NO concentrations at the inlet to the SCR system?

18. Evaluate and compare the economic alternatives and the environmental benefits associated with the consumption of No. 2 fuel oil (0.05%) when calculating secondary emissions (Table 4-3, note 3). Show basis of calculations..

19. What other mechanism was considered (i.e. dilution air) to reduce the exhaust temperature to the optimum range of 600-750 degree Fahrenheit. What is the cost associated with use of this technology.

20. Was the economic analysis based on Engelhard quotations only?

21. Submit vendor-supplied design parameters (space velocity, ammonia-to-NO_X mole ratio, pressure drop, catalyst life). How many vendors supplied information.

22. On page 4-5, what is the basis for the values given in the last paragraph when analyzing SCR and combined cycle operation. Is the incremental cost effectiveness of $3,921/ton NOx removed based on combined cycle for the life of the project?

23. What is the possibility of developing more efficient combustors to reduce the emissions to 15 ppmvd by start-up. Application should address the possibility of using "improved combustors" which are capable of limiting NO_X emission to no greater than 15 ppmvd at 15 O_2.

24. Please provide more detailed information for equipment details specifications.

25. Please provide economic of using SCR for oil firing. Molecular sieve catalysts have been proven on oil operations.

26. Provide basis for using capable recovery factor with 12 percent over 20 years for annualized capital cost on Page 23. On Page B-23 Supplemental Calculations Related to SCR and Options: What is the basis of the average 20 years NOx emissions of 429 TPY. Please explain.

27. Page 49, paragraph 1 states that "While the increased firing temperature increases the thermal NO_X generated, this NO increase is controlled through combustion design" How much additional thermal NOx is due to higher temperature?

28. On page 4-4, the estimated cost of SCR is reported to be about $ 6,516 per ton of NOx removed and it exceeds $ 8,000 per ton of pollutant removed when the net emissions of all pollutants (exclusive of CO_2) are considered. Provide us with the names and addresses of all manufacturers that were contacted along with their estimates while developing capital and annualized cost estimates for this project.

29. It appears the cost effectiveness ($/ton removed) presented on using SCR technology is within a reasonable cost range when compared to similar projects. If you don't agree, please expand the BACT analysis for NO_X and CO to demonstrate the contrary. Include a table summarizing the emission reductions, economics, energy and environmental impacts of the control technology chosen (including the BACT limit determined) vs. the SCR technology rejected for different projects in Florida for the last 8 years.

30. What is the cost effectiveness ($/ton NO_X removed) of the proposed water injection technology?

Memorandum

Florida Department of
Environmental Protection

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Ronald W. Jonlin AND
Lakeland Electric & Water
501 E. Lemon St.
Lakeland, Fl
33801-5079

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