LAKELAND ELECTRIC & WATER

(813) 499-6603

Excellence Is Our Goal, Service Is Our Job

Farzie Shelton
CHEMICAL ENGINEER

December 5, 1997

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

1050004-004-AC

Re: Air Construction Permit Application - Lakeland Electric & Water Utilities

PSD-FL-245

Dear Mr. Fancy:

The City of Lakeland, Department of Electric and Water Utilities (Lakeland) proposes to license, construct, and operate a nominal 250-megawatt (MW) (net) simple cycle combustion turbine at its McIntosh Power Plant facility. The project, referred to as Unit No. 5 (501G), will consist of one 250-MW advanced combustion turbine (CT), with dry low-nitrogen oxide (NO_X) burners, and associated equipment. The combustion turbine has a once-through steam generator (OTSG), which will use the waste heat to produce steam for cooling and power augmentation. The primary fuel for the combustion turbines will be natural gas with distillate fuel oil containing a maximum sulfur content of 0.05 percent as backup fuel.

In order to meet electric demand currently experienced by Lakeland, the Unit No. 5 will be initially operated as a base-load unit with a maximum capacity factor of 80 percent. However, it is anticipated that after an initial period of operation (e.g., 5 years) this 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.

Accordingly, on November 24, 1997, a pre air application meeting was conducted between Lakeland's/Golder's representative (Ms. Farzie Shelton, and Mr. Ken Kosky) and Department's representative (Mr. Al Linero, and Mr. Marty Costello) where this project was discussed fully.

As the permitting of Unit No. 5 requires the Departments air construction permit and prevention of significant deterioration (PSD) review approval, Lakeland has contracted Golder Associates Inc. (Golder) to perform the necessary air quality assessments for determining the project's compliance with state and federal new source review (NSR) regulations, including PSD and nonattainment review requirements.

Therefore, in accordance with the Rule 62-210.900(1) F.A.C. requirements Lakeland is submitting to the Department, in quadruplicate, the completed application for Air Permit. Additionally, in accordance with Rule 62-4.050, F.A.C. processing fee for Air Permit application, you will find enclosed a check for the sum of $7500.00.

If you should have any questions, please do not hesitate to contact me at (941) 499-6603.

Sincerely,

Farzie Shelton
Manager of Environmental Permitting & Compliance
Production Division

RECEIVED
DEC 08 1997
BUREAU OF AIR REGULATION

cc: T. Heron, BAR
EPA
NPS
SWD
Polk Co.

Enc.

cc: Al Linero, DEP
Ken Kosky, Golder Associates Inc.

CITY OF LAKELAND
DEPARTMENT OF ELECTRIC AND WATER UTILITIES

AIR PERMIT APPLICATION
AND PREVENTION OF
SIGNIFICANT DETERIORATION (PSD) ANALYSIS

501G PROJECT

Prepared For:

City of Lakeland
Department of Electric and Water Utilities
3030 East Lake Parker Drive
Lakeland, Florida 33805

Prepared By:

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

November 1997
9737594C

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PART I

APPLICATION FOR AIR PERMIT
LONG FORM

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

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

I. APPLICATION INFORMATION

This section of the Application for Air Permit form identifies the facility and provides general information on the scope and purpose of this application. This section also includes information on the owner or authorized representative of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department using ELSA, this section of the Application for Air Permit must also be submitted in hard-copy.

Identification of Facility Addressed in This Application

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility site name, if any; and the facility's physical location. If known, also enter the facility identification number.

1. Facility Owner/Company Name: Lakeland Electric & Water Utilities	
2. Site Name: C.D. McIntosh, Jr. Power Plant	
3. Facility Identification Number: 1050004 [ ] Unknown	
4. Facility Location Information: Street Address or Other Locator: 3030 East Lake Parker Drive City: Lakeland County: Polk Zip Code: 33805	
5. Relocatable Facility? [ ] Yes [x] No	6. Existing Permitted Facility? [x] Yes [ ] No

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	December 8, 1997
2. Permit Number:	1050004-004-AC
3. PSD Number (if applicable):	PSD-FL-245
4. Siting Number (if applicable):	

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 Tomlin 12/04/97
   Signature Date

* Attach letter of authorization if not currently on file.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility. An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit ID		Description of Emissions Unit	Permit Type
Unit #	Unit ID		
7R		McIntosh W501G Combustion Turbine	AC1A
8		Unregulated Emissions	AC1A

See individual Emissions Unit (EU) sections for more detailed descriptions.
Multiple EU IDs indicated with an asterisk (*). Regulated EU indicated with an "R".

Purpose of Application and Category

Check one (except as otherwise indicated):

Category I: All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ____________________

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed: ____________________

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

Current construction permit number: ____________________

Operation permit to be renewed: ____________________

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. Also check Category III.

Operation permit to be revised/corrected: ____________________

____

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

Operation permit to be revised: ____________________

Reason for revision: ____________________

____

Category II: All Air Construction Permit Applications Subject to Processing Under Rule 62-210.300(2)(b),F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): ______________________

____

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: ______________________

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g.; to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ______________________

Reason for revision: ______________________

____

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units.

This Application for Air Permit is submitted to obtain:

[x] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: ______________________

____

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

Current operation permit number(s): ______________________

____

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

Application Processing Fee

Check one:

[ ] Attached - Amount: $ ______________ [x] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Addition of a Westinghouse 501G Combustion Turbine. See Attachment PSD-501G.**
2. Projected or Actual Date of Commencement of Construction : **1 Jun 1998**
3. Projected Date of Completion of Construction : **1 Jun 2000**

Professional Engineer Certification

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

4. Professional Engineer'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.

Thomas F. Kelly

Signature

(seal) 24 Nov 97

24 November 1997

Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact: **Ms. Farzie Shelton, Env. Mgr., Permitting & Compliance**	
2. Application Contact Mailing Address: Organization/Firm: **Lakeland Electric & Water Utilities** Street Address: **501 East Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5079**	
3. Application Contact Telephone Numbers: Telephone: **(941) 499-6603** Fax: **(941) 603-6335**	

Application Comment

See Attachment PSD-501G

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates:
   Zone: 17 East (km): 409.0 North (km): 3106.2

2. Facility Latitude/Longitude:
   Latitude (DD/MM/SS): 28 / 4 / 50 Longitude: (DD/MM/SS): 81 / 55 / 32

3. Governmental Facility Code:	4. Facility Status Code:	5. Facility Major Group SIC Code:	6. Facility SIC(s):
4	A	49	4911

7. Facility Comment (limit to 500 characters):

The McIntosh Power Plant consists of 3 fossil fuel fired-steam generators (FFFSG), 2 diesel powered generators, and 1 gas turbine. FFFSG Units 1 and 2 are fired with No.6 fuel oil and natural gas (distillate oil is used as an ignitor). FFFSG Unit 3 is primarily fired with coal, refuse derived fuel and petroleum coke. This application requests approval of a Westinghouse 501G combustion turbine. See attachment PSD-501G.

Facility Contact

1. Name and Title of Facility Contact:
   Ms. Farzie Shelton, Env. Mgr., Permitting & Compliance

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

3. Facility Contact Telephone Numbers:
   Telephone: **(941) 499-6603** Fax: **(941) 603-6335**

Facility Regulatory Classifications

1. Small Business Stationary Source? [ ] Yes [x] No [ ] Unknown
2. Title V Source? [x] Yes [ ] No
3. Synthetic Non-Title V Source? [ ] Yes, [x] No
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? [x] Yes [ ] No
5. Synthetic Minor Source of Pollutants Other than HAPs? [ ] Yes [x] No
6. Major Source of Hazardous Air Pollutants (HAPs)? [x] Yes [ ] No
7. Synthetic Minor Source of HAPs? [ ] Yes [x] No
8. One or More Emissions Units Subject to NSPS? [x] Yes [ ] No
9. One or More Emissions Units Subject to NESHAP? [ ] Yes [x] No
10. Title V Source by EPA Designation? [ ] Yes [x] No
11. Facility Regulatory Classifications Comment (limit to 200 characters): **501G is subject to NSPS subpart GG. The tank is subject to subpart Kb.**

B. FACILITY REGULATIONS

<u>Rule Applicability Analysis</u> (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

62-212.400 F.A.C.
See Attachment PSD501G

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

Not Applicable

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information:

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hr)	(tons/yr)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

Facility Pollutant Detail Information:

1. Pollutant Emitted:		
2. Requested Emissions Cap:	(lb/hr)	(tons/yr)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters):		

E. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location: [x] Attached, Document ID: PSD-501G [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [x] Attached, Document ID: PSD-501G [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [x] Attached, Document ID(s): PSD-501G [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: ______ [x] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID: ______ [x] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [x] Attached, Document ID: PSD-501G [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt Activities: [ ] Attached, Document ID: ______ [x] Not Applicable
8. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID: ______ [ ] Equipment/Activities On site but Not Required to be Individually Listed [x] Not Applicable
9. Alternative Methods of Operation: [ ] Attached, Document ID: ______ [x] Not Applicable
10. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ______ [x] Not Applicable

11. Identification of Additional Applicable Requirements: [ ] Attached, Document ID: ____________________ [x] Not Applicable
12. Compliance Assurance Monitoring Plan: [ ] Attached, Document ID: ____________________ [x] Not Applicable
13. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency - Verification Attached Document ID: ____________________ [ ] Plan to be Submitted to Implementing Agency by Required Date [x] Not Applicable
14. Compliance Report and Plan [ ] Attached, Document ID: ____________________ [x] Not Applicable
15. Compliance Statement (Hard-copy Required) [ ] Attached, Document ID: ____________________ [x] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

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

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

2. Single Process, Group of Processes, or Fugitive Only? Check one:

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

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

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

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): **McIntosh W501G Combustion Turbine**		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [X] Unknown		
3. Emissions Unit Status Code: C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: 49
6. Emissions Unit Comment (limit to 500 characters): **This emission unit is a Westinghouse 501G combustion turbine operating in a simple cycle. See Attachment PSD-501G.**		

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters): **Dry Low NOx combustion - Natural gas firing**
2. Control Device or Method Code: **25**

B.

1. Description (limit to 200 characters): **Water injection - distillate oil firing**
2. Control Device or Method Code: **28**

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date:	
2. Long-term Reserve Shutdown Date:	
3. Package Unit: Manufacturer: Westinghouse	Model Number: 501G
4. Generator Nameplate Rating:	249 MW
5. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	2,174	mmBtu/hr
2. Maximum Incineration Rate:	lbs/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Operating Capacity Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV) maximum for oil firing is 2, 236 mm BTU/hr (ISO-LHV). Heat Input a function of turbine inlet temperature.**		

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:

hours/day	days/week
weeks/yr	7,008 hours/yr

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II Applications and Category III applications involving non Title-V sources. See Instructions.)

Not Applicable

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

See Attachment 501G-EU1-D for operational requirements **See Attachment PSD-501G for permitting requirements**

ATTACHMENT 501G-EU1-D

Applicable Requirements Listing

EMISSION UNIT ID: EU1 - McIntosh Plan

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	- NSPS Subpart GG
62-204.800(7)(c) (State Only)	- NSPS authority
62-204.800(7)(d)(State Only)	- NSPS General Provisions
62-204.800(12) (State Only)	- Acid Rain Program
62-204.800(13) (State Only)	- Allowances
62-204.800(14) (State Only)	- Acid Rain Program Monitoring
62-204.800(16) (State Only)	- Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	- Circumvention; EUs with control device
62-210.700(1)	- Excess Emissions;
62-210.700(4)	- Excess Emissions; poor maintenance
62-210.700(6)	- Excess Emissions; notification

Acid Rain:

62-214.300	- All Acid Rain Units (Applicability)
62-214.320(1)(a),(2)	- All Acid Rain Units (Application Shield)
62-214.330(1)(a)1.	- Compliance Options (if 214.430)
62-214.340	- Exemptions (new units, retired units)
62-214.350(2);(3);(6)	- All Acid Rain Units (Certification)
62-214.370	- All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	- All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	- CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	- All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	- All Units (Operating Rate; other than CTs;no CT)
62-297.310(3)	- All Units (Calculation of Emission)
62-297.310(4)(a)	- All Units (Applicable Test Procedures;Sampling time)
62-297.310(4)(b)	- All Units (Sample Volume)
62-297.310(4)(c)	- All Units (Required Flow Rate Range-PM/H2SO4/F)
62-297.310(4)(d)	- All Units (Calibration)
62-297.310(4)(e)	- All Units (EPA Method 5-only)
62-297.310(5)	- All Units (Determination of Process Variables)

62-297.310(6)(a)	- All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	- All Units (Sampling Ports)
62-297.310(6)(d)	- All Units (Work Platforms)
62-297.310(6)(e)	- All Units (Access)
62-297.310(6)(f)	- All Units (Electrical Power)
62-297.310(6)(g)	- All Units (Equipment Support)
62-297.310(7)(a)1.	- Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	- FFSG excess emissions
62-297.310(7)(a)3.	- Permit Renewal Test Required
62-297.310(7)(a)4.a	- Annual Test
62-297.310(7)(a)5.	- PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	- PM FFSG semi annual test required if >200 hrs/yr
62-297.310(7)(a)7.	- PM quarterly monitoring if >100 hrs/yr
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(7)(c)	- Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	- Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	- NOx for Electric Utility CTs
40 CFR 60.332(a)(3)	- NOx for Electric Utility CTs
40 CFR 60.333	- SO2 limits
40 CFR 60.334	- Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	- Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	- Notification of Construction
40 CFR 60.7(a)(2)	- Notification of Initial Start-Up
40 CFR 60.7(a)(3)	- Notification of Actual Start-Up
40 CFR 60.7(a)(4)	- Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	- Notification of CEM Demonstration
40 CFR 60.7(b)	- Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	- Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	- Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	- Notification and Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	- Performance Test Requirements
40 CFR 60.8(b)	- Performance Test Notification
40 CFR 60.8(c)	- Performance Tests (representative conditions)
40 CFR 60.8(e)	- Provide Stack Sampling Facilities
40 CFR 60.8(f)	- Test Runs
40 CFR 60.11(a)	- Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	- Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	- Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	- Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	- Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	- Circumvention

40 CFR 60.13(a)	- Monitoring (Appendix B; Appendix F)
40 CFR 60.13(c)	- Monitoring (Opacity COMS)
40 CFR 60.13(d)(1)	- Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2)	- Monitoring (COMS; span, system check)
40 CFR 60.13(e)	- Monitoring (frequency of operation)
40 CFR 60.13(f)	- Monitoring (frequency of operation)
40 CFR 60.13(h)	- Monitoring (COMS; data requirements)
Acid Rain-Permits:	
40 CFR 72.9(a)	- Permit Requirements
40 CFR 72.9(b)	- Monitoring Requirements
40 CFR 72.9(c)(1)	- SO2 Allowances-hold allowances
40 CFR 72.9(c)(2)	- SO2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	- SO2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	- SO2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	- SO2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	- NOx Requirements
40 CFR 72.9(e)	- Excess Emission Requirements
40 CFR 72.9(f)	- Recordkeeping and Reporting
40 CFR 72.9(g)	- Liability
40 CFR 72.20(a)	- Designated Representative; required
40 CFR 72.20(b)	- Designated Representative; legally binding
40 CFR 72.20(c)	- Designated Representative; certification requirements
40 CFR 72.21	- Submissions
40 CFR 72.22	- Alternate Designated Representative
40 CFR 72.23	- Changing representatives; owners
40 CFR 72.24	- Certificate of representation
40 CFR 72.30(a)	- Requirements to Apply (operate)
40 CFR 72.30(b)(2)	- Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	- Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	- Requirements to Apply (submittal requirements)
40 CFR 72.31	- Information Requirements; Acid Rain Applications
40 CFR 72.32	- Permit Application Shield
40 CFR 72.33(b)	- Dispatch System ID;unit/system ID
40 CFR 72.33(c)	- Dispatch System ID;ID requirements
40 CFR 72.33(d)	- Dispatch System ID;ID change
40 CFR 72.40(a)	- General; compliance plan
40 CFR 72.40(b)	- General; multi-unit compliance options
40 CFR 72.40(c)	- General; conditional approval
40 CFR 72.40(d)	- General; termination of compliance options
40 CFR 72.51	- Permit Shield
40 CFR 72.90	- Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	- Authorized account representative
40 CFR 73.35(c)(1)	- Compliance: ID of allowances by serial number

Monitoring Part 75:

40 CFR 75.4	- Compliance Dates;
40 CFR 75.5	- Prohibitions
40 CFR 75.10(a)(1)	- Primary Measurement; SO2;
40 CFR 75.10(a)(2)	- Primary Measurement; NOx;
40 CFR 75.10(a)(3)(iii)	- Primary Measurement; CO2; O2 monitor
40 CFR 75.10(b)	- Primary Measurement; Performance Requirements
40 CFR 75.10(c)	- Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	- Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	- Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	- Primary Measurement; Minimum Recording
40 CFR 75.11(d)	- SO2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	- SO2 Monitoring; Gaseous firing
40 CFR 75.12(a)	- NOx Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	- NOx Monitoring; Determination of NOx emission rate; Appendix F
40 CFR 75.13(b)	- CO2 Monitoring; Appendix G
40 CFR 75.13(c)	- CO2 Monitoring; Appendix F
40 CFR 75.14(c)	- Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	- Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	- Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	- Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	- Recertification Backup/portable monitor
40 CFR 75.20(f)	- Alternate Monitoring system
40 CFR 75.21(a)	- QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	- QA/QC; Calibration Gases
40 CFR 75.21(d)	- QA/QC; Notification of RATA
40 CFR 75.21(e)	- QA/QC; Audits
40 CFR 75.21(f)	- QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	- Reference Methods
40 CFR 75.24	- Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	- General Missing Data Procedures; NOx
40 CFR 75.30(a)(4)	- General Missing Data Procedures; SO2
40 CFR 75.30(b)	- General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c)	- General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d)	- General Missing Data Procedures; SO2 (optional before 1/1/97)
40 CFR 75.30(e)	- General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	- Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	- Monitoring Data Availability for Missing Data
40 CFR 75.33	- Standard Missing Data Procedures
40 CFR 75.36	- Missing Data for Heat Input
40 CFR 75.40	- Alternate Monitoring Systems-General
40 CFR 75.41	- Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	- Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	- Alternate Monitoring Systems-Accessability Criteria
40 CFR 75.44	- Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	- Alternate Monitoring Systems-Daily QA
40 CFR 75.46	- Alternate Monitoring Systems-Missing data

40 CFR 75.47	- Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48	- Alternate Monitoring Systems-Petition
40 CFR 75.53	- Monitoring Plan ; revisions
40 CFR 75.54(a)	- Recordkeeping-general
40 CFR 75.54(b)	- Recordkeeping-operating parameter
40 CFR 75.54(c)	- Recordkeeping-SO2
40 CFR 75.54(d)	- Recordkeeping-NOx
40 CFR 75.54(e)	- Recordkeeping-CO2
40 CFR 75.54(f)	- Recordkeeping-Opacity
40 CFR 75.55(c)	- General Recordkeeping (Specific Situations)
40 CFR 75.55(e)	- General Recordkeeping (Specific Situations)
40 CFR 75.56	- Certification; QA/QC Provisions
40 CFR 75.60	- Reporting Requirements-General
40 CFR 75.61	- Reporting Requirements-Notification cert/recertification
40 CFR 75.62	- Reporting Requirements-Monitoring Plan
40 CFR 75.63	- Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	- Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	- Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	- Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	- Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	- Petitions to the Administrator (if required)
Appendix A-1	- Installation and Measurement Locations
Appendix A-2.	- Equipment Specifications
Appendix A-3.	- Performance Specifications
Appendix A-4.	- Data Handling and Acquisition Systems
Appendix A-5.	- Calibration Gases
Appendix A-6.	- Certification Tests and Procedures
Appendix A-7.	- Calculations
Appendix B	- QA/QC Procedures
Appendix C-1.	- Missing Data; SO2/NOx for controlled sources
Appendix C-2.	- Missing Data; Load-Based Procedure; NOx & flow
Appendix D	- Optional SO2; Oil-/gas-fired units
Appendix F	- Conversion Procedures
Appendix H	- Traceability Protocol

Acid Rain Program-Excess Emissions (these are future requirements):

40 CFR 77.3	- Offset Plans (future)
40 CFR 77.5(b)	- Deductions of Allowances (future)
40 CFR 77.6	- Excess Emissions Penalties (SO2 and NOx;future)

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **See Att. PSD-501G**
2. Emission Point Type Code: [x] 1 [ ] 2 [ ] 3 [ ] 4
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W
6. Stack Height: **85** feet
7. Exit Diameter: **28** feet
8. Exit Temperature: **1,095** °F

9. Actual Volumetric Flow Rate:	3,055,750	acfm
10. Percent Water Vapor:	12.44	%
11. Maximum Dry Standard Flow Rate:	894,739	dscfm
12. Nonstack Emission Point Height:		feet

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 409.0 North (km): 3106.8

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas; for oil 1,051 °F and 3,011,513 ACFM.

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters):

   Distillate (No.2) Fuel Oil

2. Source Classification Code (SCC): **2-01-001-01**

3. SCC Units: **1,000 gallons**

4. Maximum Hourly Rate: **17.8**

5. Maximum Annual Rate: **42,558**

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur: **0.05**

8. Maximum Percent Ash:

9. Million Btu per SCC Unit: **132**

10. Segment Comment (limit to 200 characters):

    MMBtu/SCC=131.5 (rounded to 132). BASIS: Max. hourly=30 deg.F turbine inlet & 7.1 lb/gal; 18,500 Btu/lb LHV; Annual: 59 deg.F, 250 hrs/yr operation. Max. hourly; function of turbine inlet temperature.

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Natural Gas**	
2. Source Classification Code (SCC): **2-01-002-01**	
3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **2.4**	5. Maximum Annual Rate: **16,037**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **950**	
10. Segment Comment (limit to 200 characters): **Max. based on 30 deg.F; 950 Btu/CF LHV. Annual based on 59 deg.F; 7,008 hrs/yr operation. Max. hourly a function of turbine inlet temperature.**	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO2			EL
NOx	026	028	EL
CO			EL
VOC			EL
PM10			EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **139.6** lb/hour **41.3** tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: Reference: **Westinghouse, 1997**
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-501G; Section 2.0; Appendix A.**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, 50% load, 30 degrees F tons/year based on 6,758 hrs/yr gas firing and 250 hrs/yr oil firing; 59 degrees F conditions.**

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 139.6 lb/hr	
4. Equivalent Allowable Emissions: 139.6 lb/hour	41.3 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test; EPA Methods 5 or 17; if < 400 hours	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil firing - 30 degrees F; 50% load; 250 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 9.1 lb/hr	
4. Equivalent Allowable Emissions: 9.1 lb/hour	41.3 tons/year
5. Method of Compliance (limit to 60 characters): VE Test < 20% opacity	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas firing - 30 degrees F, 100% load; 7008 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: SO2

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 126.7 lb/hour 38.4 tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr

6. Emission Factor: See Comment

Reference: Applicant

7. Emissions Method Code:

[ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

See Attachment PSD-501G; Section 2.0; Appendix A.

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

Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil. lb/hr based on oil firing, 100% load, 30 degrees F. Tons/yr based on 6,758 hrs/yr gas firing and 250 hrs/yr oil firing, 59 degrees F conditions.

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.05 % Sulfur Oil
4. Equivalent Allowable Emissions: 126.7 lb/hour 38.4 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Sampling
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Oil firing - 30 degrees F; 50% load; 250 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.

B.

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 1 grain/100 CF
4. Equivalent Allowable Emissions: 7.2 lb/hour 38.4 tons/year
5. Method of Compliance (limit to 60 characters): Fuel Sampling
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Gas firing - 30 degrees F, 100% load; 700% hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: NOx
2. Total Percent Efficiency of Control: %
3. Potential Emissions: 461 lb/hour 863.1 tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: Reference: Westinghouse, 1997
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): See Attachment PSD-501G; Section 2.0; Appendix A.
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): Lb/hr based on oil firing, 50% load, 30 degrees F tons/yr based on 6,758 hrs/yr gas firing and 250 hrs/yr oil firing; 59 degrees F conditions.

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 42 ppmvd	
4. Equivalent Allowable Emissions: 431 lb/hour	863.1 tons/year
5. Method of Compliance (limit to 60 characters): CEM - 30 Day Rolling Average (corrected to 15% Oxygen)	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Requested Allowable Emissions is at 15% O2-100% load. Oil firing; 30°F; 100% load; 250 hrs/year. See Attachment PSD-501G; Section 2.0; Appendix A.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 25 ppmvd	
4. Equivalent Allowable Emissions: 249 lb/hour	863.1 tons/year
5. Method of Compliance (limit to 60 characters): CEM 30 Day Rolling Average (corrected to 15% Oxygen)	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Requested Allowable Emissions and Units is at 15% O2-100% load. Gas firing; 30 degrees F; 100% load, 700% hr/yr; see Attachment PSD-501G; Section 2.0; Appendix A.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **CO**

2. Total Percent Efficiency of Control: %

3. Potential Emissions: **1,244** lb/hour **1,264.4** tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor:

   Reference: **Westinghouse, 1997**

7. Emissions Method Code:

   [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   See Attachment PSD-501G; Section 2.0; Appendix A.

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

   Lb/hr based on oil firing; 50% load; 30 degrees F tons/yr based on 6,758 hrs/yr gas firing and 250 hrs/yr oil firing; 59 degrees F conditions.

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 90 ppmvd	
4. Equivalent Allowable Emissions: 1,244 lb/hour	1,264 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 10; Initial compliance test at high and low loads	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Additional Requested Allowable Emissions and Units information: 100% load/350 ppmvd; 50% load. Oil firing; 30 degrees F; 50% load; 250 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.	

B.

1. Basis for Allowable Emissions Code: OTHER	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 50 ppmvd	
4. Equivalent Allowable Emissions: 1,228 lb/hour	1,264.4 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 10; high and low loads	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): Additional Requested Allowable Emissions and Units information: 100% load/350 ppmvd; 50% load. Gas firing; 30 degrees F; 50% load; 7,008 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **VOC**
2. Total Percent Efficiency of Control: %
3. Potential Emissions: **203** lb/hour **93.7** tons/year
4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
6. Emission Factor: Reference: **Westinghouse, 1997**
7. Emissions Method Code: [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-501G; Section 2.0; Appendix A.**
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, 50% load; 30 degrees F. Tons/yr based on 6,758 hrs/yr gas firing and 250 hrs/yr oil firing; 59 degrees F conditions.**

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 ppmvd**
4. Equivalent Allowable Emissions: **203** lb/hour **93.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Additional Requested Allowable Emissions and Units information: 100% load/100 ppmvd; 50% load. Oil firing; 30 degrees F; 50% load; 250 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.**

B.

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **4 ppmvd**
4. Equivalent Allowable Emissions: **120** lb/hour **93.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Additional Requested Allowable Emissions and Units: 100% load/100 ppmvd; 50% load. Gas firing; 30 degrees F; 50% load; 7008 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.**

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM10**

2. Total Percent Efficiency of Control: %

3. Potential Emissions: **139.6** lb/hour **41.3** tons/year

4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

6. Emission Factor:

   Reference: **Westinghouse, 1997**

7. Emissions Method Code:

   [ ] 0 [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

   See Attachment PSD-501G; Section 2.0; Appendix A.

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

   Lb/hr based on oil firing, 50% load, 30 degrees F tons/year based on 6,758 hrs/yr gas firing and 250 hrs/yr oil firing; 59 degrees F conditions.

Emissions Unit Information Section 1 of 2

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **139.6 lb/hr**	
4. Equivalent Allowable Emissions: **139.6** lb/hour	**41.3** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if < 400 hours**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Oil firing - 30 degrees F; 50% load; 250 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.**	

B.

1. Basis for Allowable Emissions Code: **OTHER**	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: **9.1 lb/hr**	
4. Equivalent Allowable Emissions: **9.1** lb/hour	**41.3** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Gas firing - 30 degrees F, 100% load; 7008 hrs/yr. See Attachment PSD-501G; Section 2.0; Appendix A.**	

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitations: Visible Emissions Limitation 1 of 2

1.	Visible Emissions Subtype: VE20
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: 20. % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4.	Method of Compliance: Annual VE Test EPA Method 9
5.	Visible Emissions Comment (limit to 200 characters):

Visible Emissions Limitations: Visible Emissions Limitation 2 of 2

1.	Visible Emissions Subtype: VE99
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 6 min/hour
4.	Method of Compliance: None
5.	Visible Emissions Comment (limit to 200 characters): FDEP Rule 62-210.700(1). Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Not yet determined Model Number: Serial Number:	
5. Installation Date: 01 Jan 1999	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): NOx CEM proposed to meet requirements proposed in application and requirements of 40CFR part 75.	

Continuous Monitoring System Continuous Monitor 2 of 2

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Monitor Manufacturer: Westinghouse Model Number: Serial Number:	
5. Installation Date: 01 Jan 1999	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): Parameter Code: WTF. Required by 40 CFR part 60; subpart GG; 60.334.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [x] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[x] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:				
	PM	[x] C	[ ] E	[ ] Unknown	
	SO_2	[x] C	[ ] E	[ ] Unknown	
	NO_2	[x] C	[ ] E	[ ] Unknown	
4.	Baseline Emissions:				
	PM	lb/hour	44.7	tons/year	
	SO_2	lb/hour	38.4	tons/year	
	NO_2		863.1	tons/year	
5.	PSD Comment (limit to 200 characters):				
	See Attachment PSD-501G				

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

Supplemental Requirements for All Applications

1.	Process Flow Diagram		
	[X] Attached, Document ID: PSD-501G		
	[ ] Not Applicable	[ ] Waiver Requested	
2.	Fuel Analysis or Specification		
	[X] Attached, Document ID: PSD-501G		
	[ ] Not Applicable	[ ] Waiver Requested	
3.	Detailed Description of Control Equipment		
	[X] Attached, Document ID: PSD-501G		
	[ ] Not Applicable	[ ] Waiver Requested	
4.	Description of Stack Sampling Facilities		
	[X] Attached, Document ID: PSD-501G		
	[ ] Not Applicable	[ ] Waiver Requested	
5.	Compliance Test Report		
	[ ] Attached, Document ID: ________	[X] Not Applicable	
	[ ] Previously Submitted, Date: ________		
6.	Procedures for Startup and Shutdown		
	[ ] Attached, Document ID: ________	[X] Not Applicable	
7.	Operation and Maintenance Plan		
	[ ] Attached, Document ID: ________	[X] Not Applicable	
8.	Supplemental Information for Construction Permit Application		
	[X] Attached, Document ID: PSD-501G	[ ] Not Applicable	
9.	Other Information Required by Rule or Statute		
	[X] Attached, Document ID: PSD-501G	[ ] Not Applicable	

Additional Supplemental Requirements for Category I Applications Only

10.	Alternative Methods of Operation [ ] Attached, Document ID: ____________ [x] Not Applicable
11.	Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: ____________ [x] Not Applicable
12.	Identification of Additional Applicable Requirements [ ] Attached, Document ID: ____________ [x] Not Applicable
13.	Compliance Assurance Monitoring Plan [ ] Attached, Document ID: ____________ [x] Not Applicable
14.	Acid Rain Permit Application (Hard Copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: ____________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: ____________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: ____________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: ____________ [x] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

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

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

2. Single Process, Group of Processes, or Fugitive Only? Check one:

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

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

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

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): **Unregulated Emission Activities - Tank 1.05 million gallons**		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [X] Unknown		
3. Emissions Unit Status Code: **A**	4. Acid Rain Unit? [ ] Yes [x] No	5. Emissions Unit Major Group SIC Code: **49**
6. Emissions Unit Comment (limit to 500 characters): **This emission unit information section addresses a 1.05 mission gallon tank as an unregulated emission unit. NSPS subpart Kb recordkeeping requirements are applicable; there is no emission limiting or work practice standards. See Attachment PSD-501G.**		

Emissions Unit Control Equipment Information

A.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

B.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): No.2 Distillate Oil/Diesel	
2. Source Classification Code (SCC): A2505030090	
3. SCC Units: 1,000 gallons	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: 42,558
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit:	
10. Segment Comment (limit to 200 characters): Annual rate based on inputs to 501G.	

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters):	
2. Source Classification Code (SCC):	
3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit:	
10. Segment Comment (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
VOC			NS

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION (Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and the emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and the source consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and the emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3.	Increment Consuming/Expanding Code:			
	PM	[ ] C	[ ] E	[ ] Unknown
	SO_2	[ ] C	[ ] E	[ ] Unknown
	NO_2	[ ] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lb/hour		tons/year
	SO_2	lb/hour		tons/year
	NO_2			tons/year
5.	PSD Comment (limit to 200 characters):			

PART II

ATTACHMENT PSD-501G

1.0 INTRODUCTION

The City of Lakeland, Department of Electric and Water Utilities proposes to license, construct, and operate a nominal 250-megawatt (MW) (net) simple cycle combustion turbine. The site for the project is located at the City's existing McIntosh Power Plant in the city of Lakeland and Polk County (see Figure 1-1). The project, referred to as 501G, will consist of one 250-MW advanced combustion turbine (CT), with dry low-nitrogen oxide (NO_x) burners, and associated equipment. The combustion turbine has a once-through steam generator (OTSG), which will use the waste heat to produce steam for cooling and power augmentation. The primary fuel for the combustion turbines will be natural gas with distillate fuel oil containing a maximum sulfur content of 0.05 percent as backup fuel.

In order to meet electric demands currently experienced by the City of Lakeland, the 501G Project will be initially operate as a base-load unit with a maximum capacity factor of 80 percent. It is anticipated that after an initial period of operation (e.g., 5 years) 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.

The permitting of the 501G Project in Florida requires an air construction permit and prevention of significant deterioration (PSD) review approval. To assist in performing the necessary licensing activities, the City of Lakeland has contracted Golder Associates Inc. (Golder) to perform the necessary air quality assessments for determining the project's compliance with state and federal new source review (NSR) regulations, including PSD and nonattainment review requirements. The critical aspects of these assessments include the air quality impact analyses performed using an air dispersion model and the best available control technology (BACT) performed to evaluate the selected emission control technology.

The proposed 501G project will be a new air pollution source that will result in increases in air emissions in Polk County. The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review for new or modified sources that increase air emissions above certain threshold amounts. Because the threshold amounts will be exceeded by the proposed project, the project is subject to PSD review. PSD regulations are promulgated under 40 Code of Federal Regulations (CFR) Part 52.21 and implemented through delegation to the FDEP.

Florida's PSD regulations are codified in Rules 62-212.400, F.A.C. These regulations incorporate the EPA PSD regulations.

Based on the emissions from the proposed project, a PSD review is required for each of the following regulated pollutants:

- particulate matter (PM) as total suspended particulate matter (TSP),
- particulate matter with aerodynamic diameter of 10 microns or less (PM10),
- nitrogen dioxide (NO_2),
- carbon monoxide (CO), and
- volatile organic compounds (VOC).

Polk County has been designated as an attainment or unclassifiable area for all criteria pollutants [i.e., attainment: ozone (O_3), PM10, SO_2, CO, and NO_2; unclassifiable: lead] and is classified as a PSD Class II area for PM10, SO_2, and NO_2; therefore, the PSD review will follow regulations pertaining to such designations.

The air permit application is divided into eight major sections.

- Section 2.0 presents a description of the facility, including air emissions and stack parameters.
- Section 3.0 provides a review of the PSD and nonattainment requirements applicable to the proposed project.
- Section 4.0 includes the control technology review with discussions on BACT.
- Section 5.0 discusses the ambient air monitoring analysis (preconstruction monitoring) required by PSD regulations.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the proposed project with ambient air quality standards (AAQS), PSD increments, and good engineering (GEP) stack height regulations.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

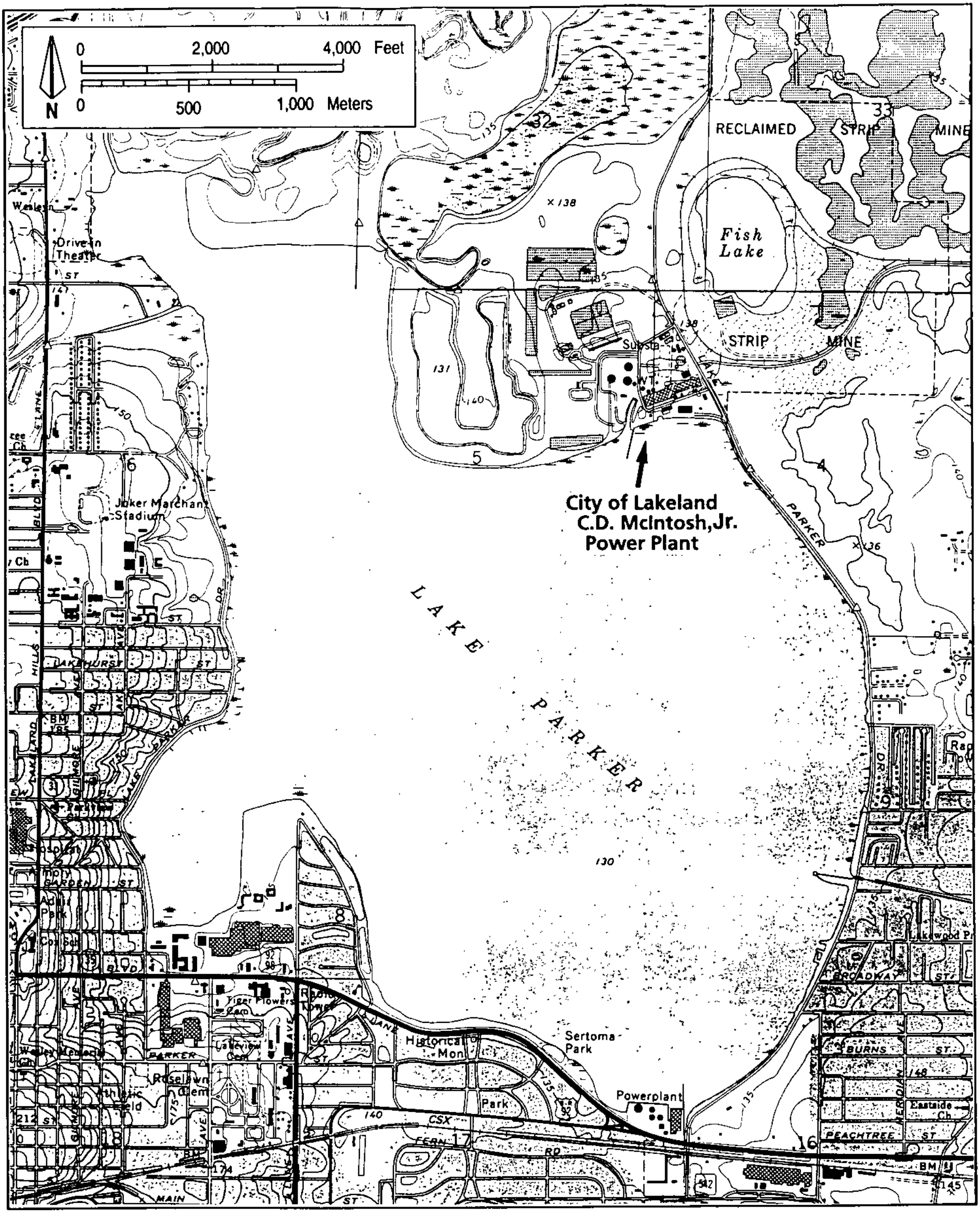


Figure 1-1
Location of McIntosh Plant

Sources: USGS, 1987; Golder, 1997.

Golder Associates

2.0 PROJECT DESCRIPTION

2.1 BACKGROUND

The McIntosh Power Plant consists of 3 fossil fuel-fired steam generators (FFFSG), 2 diesel power generators and 1 simple cycle gas turbine. The size and fuels used by these units are as follows:

Unit 1 - 90-MW FFFSG; No. 6 fuel oil, natural gas
Unit 2 - 115-MW FFFSG; No. 6 fuel oil, natural gas
Unit 3 - 364-MW FFFSG; Coal, petroleum coke, fuel oil, natural gas, refuse derived fuel
Gas Turbine Peaking Unit 1 - 20-MW; distillate oil, natural gas
Diesel Peaking Units 2 and 3 - 3.5-MW (each); distillate oil

The McIntosh Plant has been issued a draft Title V permit (1050004-003-AU) by FDEP that will authorize the facility to operate under specific conditions. Location of the 501G CT at the McIntosh site and selection of the technology will maximize the beneficial use of the site while minimizing environmental, land use, and cost impacts associated with development of a nominal 250-MW power plant at an undeveloped site. The proposed project will utilize a number of the existing facilities, including the water source and discharges, and transmission lines, and will increase the ultimate generating capacity without increasing the overall size of the McIntosh site. The project site boundary located in the McIntosh Plant site is shown in Figure 2-1.

2.2 GENERAL DESCRIPTION

The proposed 501G project consists of a Westinghouse Model 501G advanced CT and associated facilities. The CT has an OTSG which will use the waste heat to produce steam for cooling and power augmentation. The Westinghouse 501G CT is the most efficient 60-hertz industrial turbine in the world. With a net heat rate of 8,725 Btu/kWh (LHV, ISO conditions and gas firing), it is 10 percent more efficient than the nominal 150 MW "F" Class machines (9,600 Btu/kWh LHV, ISO, natural gas-firing). The proposed project will include power augmentation that utilizes steam injection produced from turbine exhaust heat which increases mass flow through the machine and power output. Steam is produced using a OTSG where steam is used for cooling and power augmentation. Electric power production is increased from about 230 MW to about 250 MW using power augmentation with virtually no impact on overall heat rate.

To control NO_x emissions, the turbine will utilize dry low-NO_x combustors. The dry low-NO_x combustor designed for the 501G CT consists of two premixed fuel zones plus a standard diffusion flame pilot burner. Low NO_x levels are achieved by introducing fuel primarily to the pre-mix zones and reducing the amount of fuel being combusted from the pilot nozzle. Water injection will be used to control NO_x when firing oil.

The CT will be capable of both simple cycle and combined cycle operation; the latter is possible by exhausting the turbine exhaust gases through a HRSG anticipated in future years of operation. The CT will use natural gas as the primary fuel and distillate fuel oil with a maximum sulfur content of 0.05 percent as a backup fuel. Fuel oil will be limited to a maximum of 250 hours per year for the CT operating at maximum capacity. Natural gas will be transported to the site via pipeline and fuel oil will be trucked to the site. The facility will connect with a natural gas supply from the existing connection to the Florida Gas Transmission (FGT) system. Fuel oil will be stored onsite in a 1.05-million-gallon aboveground storage tank.

Air emissions control will consist of using state-of-the-art dry low-NO_x burners in the CT when firing natural gas. Water injection will be used for NO_x control when firing distillate fuel oil. The SO_2 emissions will be controlled by the use of low-sulfur fuels. Good combustion practices and clean fuels will also minimize potential emissions of PM, CO, VOC, and other pollutants (e.g., trace metals). These engineering and environmental designs maximize control of air emissions while minimizing economic, environmental, and energy impacts (see Section 4.0 for the BACT evaluation).

2.3 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated maximum hourly emissions and exhaust parameters that are representative of the advanced CT design operating at baseload conditions (100-percent load) and 50-percent load conditions are presented in Tables 2-1 through 2-4. The information is presented in these tables for simple cycle operations based on natural gas combustion (Tables 2-1 and 2-3), and fuel oil combustion (Table 2-2 and 2-4). The data are presented for ambient temperatures of 30, 59, and 90°F. These temperatures represent the range of ambient temperatures that the CT is most likely to experience. Supportive information about the bases of the emission calculations and operating data are presented in Attachment A for operating loads of 100 and 50 percent.

A process flow diagram of the facility operating in simple cycle mode with power augmentation is presented in Figure 2-2. Because of the limited operating history of the proposed turbine, Westinghouse included a margin (increase) in estimating emissions to account for potential analytical inaccuracies. These margins are reflected by the difference between the values labeled "calculated" and "provided" in the tables contained in Appendix A.

Based on a review of the emission rates for natural gas and fuel oil combustion, the highest emission rates for the regulated pollutants generally occur when firing fuel oil. Combustion of natural gas and fuel oil result in slightly different exhaust flow gas rates and stack exit temperatures; however, the differences are minor. As a result of the higher emissions when firing oil, the air modeling analyses were primarily based on determining maximum ground-level impacts with this fuel.

As discussed in Section 6.0, the air modeling analyses that addressed compliance with ambient standards were based on modeling the CT for the operating load and ambient temperature which produced the maximum impacts from the load impact analysis that was performed. Although the highest emission rates occur with low ambient temperatures (i.e., 30°F) and baseload conditions, the lowest exhaust gas flow rates occur with an ambient temperature of 90°F and 50 percent operating load. Since this low exhaust flow condition can result in potentially higher impacts due to lower plume rise (i.e., due to lower exit velocity and temperature), the load analysis included modeling the CT at base and 50 percent operating loads for the two ambient temperatures of 30°F and 90°F.

The maximum potential annual emissions for the proposed facility for regulated air pollutants, based on an ambient temperature of 59°F, are presented in Table 2-5. To produce the maximum annual emissions, the CT is assumed to operate for an entire year firing natural gas for 6,728 hours and fuel oil for 250 hours; emission calculations allow the CT to operate up to 1,000 hours per year of low load operation (50-percent load) when firing gas and 50 hours per year when firing oil.

2.4 SITE LAYOUT, STRUCTURES, AND STACK SAMPLING FACILITIES

A plot plan of the proposed facility is presented in Figure 2-3. The profiles of the buildings and structures are presented in Figure 2-4. The dimensions of the buildings and structures are presented in Section 6.0. Stack sampling facilities will be constructed in accordance to Rule 62-297.310(6) F.A.C.

Table 2-1. Stack, Operating, and Emission Data for the Proposed 501G Combustion Turbine with Dry Low-NO_x Combustors firing Natural Gas-- Base Load for Simple Cycle Operation

Parameter	Operating and Emission Data[a] for Ambient Temperature		
	90°F	59°F	30°F
Stack Data (ft)			
Height	85	85	85
Diameter	28	28	28
Operating Data[b]			
Temperature(°F)	1,128	1,095	1,080
Velocity (ft/sec)	78.8	82.7	85.3
Maximum Hourly Emission Data (lb/hr) per Unit[c]			
SO_2 (1 grain S per 100CF)	6.4	6.9	7.2
PM/PM10	8.5	8.8	9.1
NO_x (25 ppmvd at 15% O_2)	220	237	249
CO (50 ppmvd)	190	211	222
VOC (4 ppmvd)	9	10	10
Sulfuric Acid Mist	0.97	1.05	1.10

[a] Refer to Appendix A for detailed information. Tables A-1 through A-4 provide information on the simple cycle operation at 100% load.
[b] Includes once-through steam generator (OTSG) and power augmentation.
[c] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-2. Stack, Operating, and Emission Data for the Proposed 501G Combustion Turbine with Water Injection Firing Fuel Oil-- Base Load for Simple Cycle Operation

	Operating and Emission Data[a] for Ambient Temperature		
Parameter	90°F	59°F	30°F
Stack Data (ft)			
Height	85	85	85
Diameter	28	28	28
Operating Data[b]			
Temperature(°F)	1,084	1,051	1,037
Velocity (ft/sec)	77.6	81.5	84.1
Maximum Hourly Emission Data (lb/hr) per Unit[c]			
SO_2 (0.05% S Fuel)	111.7	120.9	126.7
PM/PM10	89.4	92.8	95.8
NO_x (42 ppmvd at 15% O_2)	382	413	433
CO (90 ppmvd)	348	386	407
VOC (10 ppmvd)	22	25	26
Lead	0.012	0.013	0.014
Beryllium	0.0004	0.0005	0.0005
Fluoride	0.071	0.076	0.080
Mercury	0.0022	0.0024	0.0025
Sulfuric Acid Mist	17.1	18.5	19.4

[a] Refer to Appendix A for detailed information. Tables A-9 through A-13 provide information on the simple cycle operation at 100% load.

[b] Includes OTSG and power augmentation.

[c] Other regulated pollutants have negligible emissions. These pollutants include reduced sulfur compounds, hydrogen sulfide, asbestos, vinyl chloride, and radionuclides. Emissions of other PSD, HAPs, and non-regulated pollutants are in Appendix A.

Table 2-3. Stack, Operating, and Emission Data for the Proposed 501G Combustion Turbine with Dry Low-NO_x Combustors firing Natural Gas-- 50% Load for Simple Cycle Operation

	Operating and Emission Data[a] for Ambient Temperature		
Parameter	90°F	59°F	30°F
Stack Data (ft)			
Height	85	85	85
Diameter	28	28	28
Operating Data[b]			
Temperature(°F)	984	960	944
Velocity (ft/sec)	56.7	58.4	59.5
Maximum Hourly Emission Data (lb/hr) per Unit[c]			
SO_2	3.9	4.2	4.3
PM/PM10	6.5	6.6	6.7
NO_x (45 ppmvd at 15% O_2)	241	257	287
CO (350 ppmvd)	1,086	1,117	1,228
VOC (60 ppmvd)	106	115	120
Sulfuric Acid Mist	0.60	0.64	0.66

[a] Refer to Appendix A for detailed information. Tables A-5 through A-8 provide information on simple cycle operation at 50% load.

[b] Includes OTSG and power augmentation.

[c] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-4. Stack, Operating, and Emission Data for the Proposed 501G Combustion Turbine with Water Injection Firing Fuel Oil-- 50% Load for Simple Cycle Operation

	Operating and Emission Data[a] for Ambient Temperature		
Parameter	90°F	59°F	30°F
Stack Data (ft)			
Height	85	85	85
Diameter	28	28	28
Operating Data[b]			
Temperature(°F)	968	945	928
Velocity (ft/sec)	56.2	58	59.1
Maximum Hourly Emission Data (lb/hr) per Unit[c]			
SO_2	68.1	72.1	75.8
PM/PM10	135.1	136.9	139.6
NO_x (75 ppmvd at 15% O_2)	415	439	461
CO (350 ppmvd)	1,100	1,193	1,244
VOC (100 ppmvd)	180	195	203
Lead	0.007	0.008	0.008
Beryllium	0.0003	0.0003	0.0003
Fluoride	0.043	0.046	0.048
Mercury	0.0013	0.0014	0.0015
Sulfuric Acid Mist	10.43	11.04	11.61

[a] Refer to Appendix A for detailed information. Tables A-14 through A-18 provide information on simple cycle operation at 50% load.

[b] Includes OTSG and power augmentation.

[c] Other regulated pollutants have negligible emissions. These pollutants include reduced sulfur compounds, hydrogen sulfide, asbestos, vinyl chloride, and radionuclides. Emissions of other PSD, HAPs, and non-regulated pollutants are in Appendix A.

Table 2-5. Summary of Maximum Potential Annual Emissions (tons/year) for 501G Project

Fuel:	Gas	Gas	Oil	Oil	Maximum	Maximum
Load:	100%	50%	100%	50%	Option A	Option B
Hours:	7,008	1,000	250	50	7,008	7,008
<u>Pollutant</u>						
Particulate [PM(TSP), PM10]	30.84	3.30	11.60	3.42	41.34	41.34
Sulfur Dioxide	24.10	2.08	15.11	1.80	38.35	35.77
Nitrogen Dioxide	830.45	128.50	51.63	10.98	852.45	863.10
Carbon Monoxide	739.34	588.50	48.25	29.83	761.22	1264.39
VOCs	35.04	57.5	3.125	4.875	36.92	93.67
Lead	NA	NA	0.002	0.000	0.00	0.00
Sulfuric Acid Mist	3.68	0.32	2.31	0.28	5.86	5.47
Total Fluorides	NA	NA	0.01	0.00	0.01	0.01
Beryllium	NA	NA	5.87E-05	7.01E-06	5.87E-05	5.40E-05
Mercury	6.32E-06	5.45666E-07	2.94E-04	3.51E-05	3.00E-04	2.76E-04

Options (hours/year):	Maximum A	Maximum B
Gas at 100% Load	6,758	5,758
Gas at 50% Load		1,000
Oil at 100% Load	250	200
Oil at 50 % Load		50
Total:	7,008	7,008

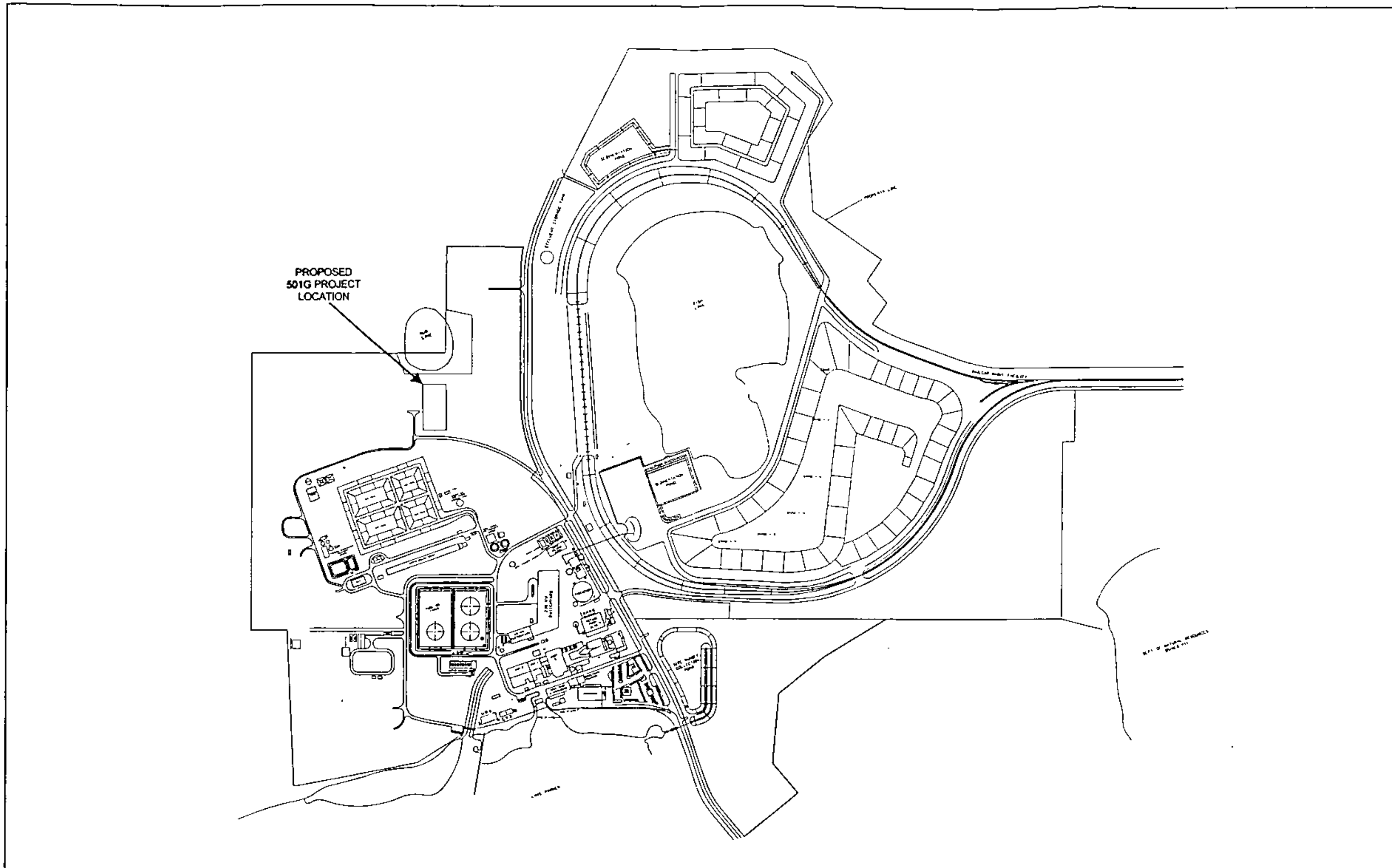
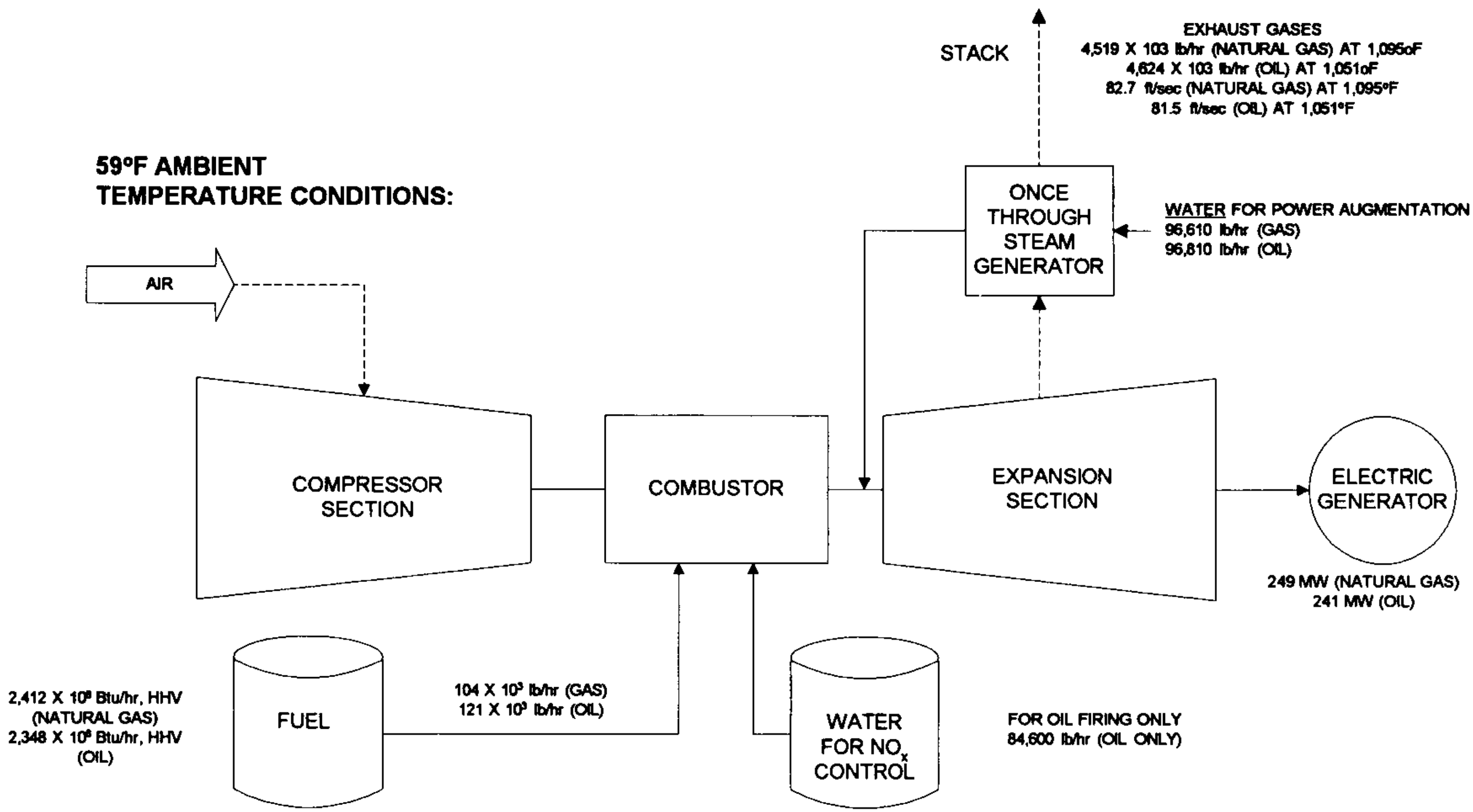


Figure 2-1 McIntosh Plant Boundary and Adjacent Properties Source: City of Lakeland, 1997; Golder, 1997.		*Process Area:* Plant Site Map *Filename:* 9737594C/FIGURES2.VSD (#1) *Latest Revision Date:* 11/25/97

Golder Associates



NOTE: SEE ATTACHMENT A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL. BASED ON FLOW RATES PROVIDED BY WESTINGHOUSE.

Figure 2-2
Simplified Flow Diagram of 501G
City of Lakeland

Process Flow Legend	
Solid/Liquid	———→
Gas	- - - - -→
Steam	··········→

Filename: 9737594C/FIGURES.VSD (#1)
Date: 11/26/97

Golder Associates

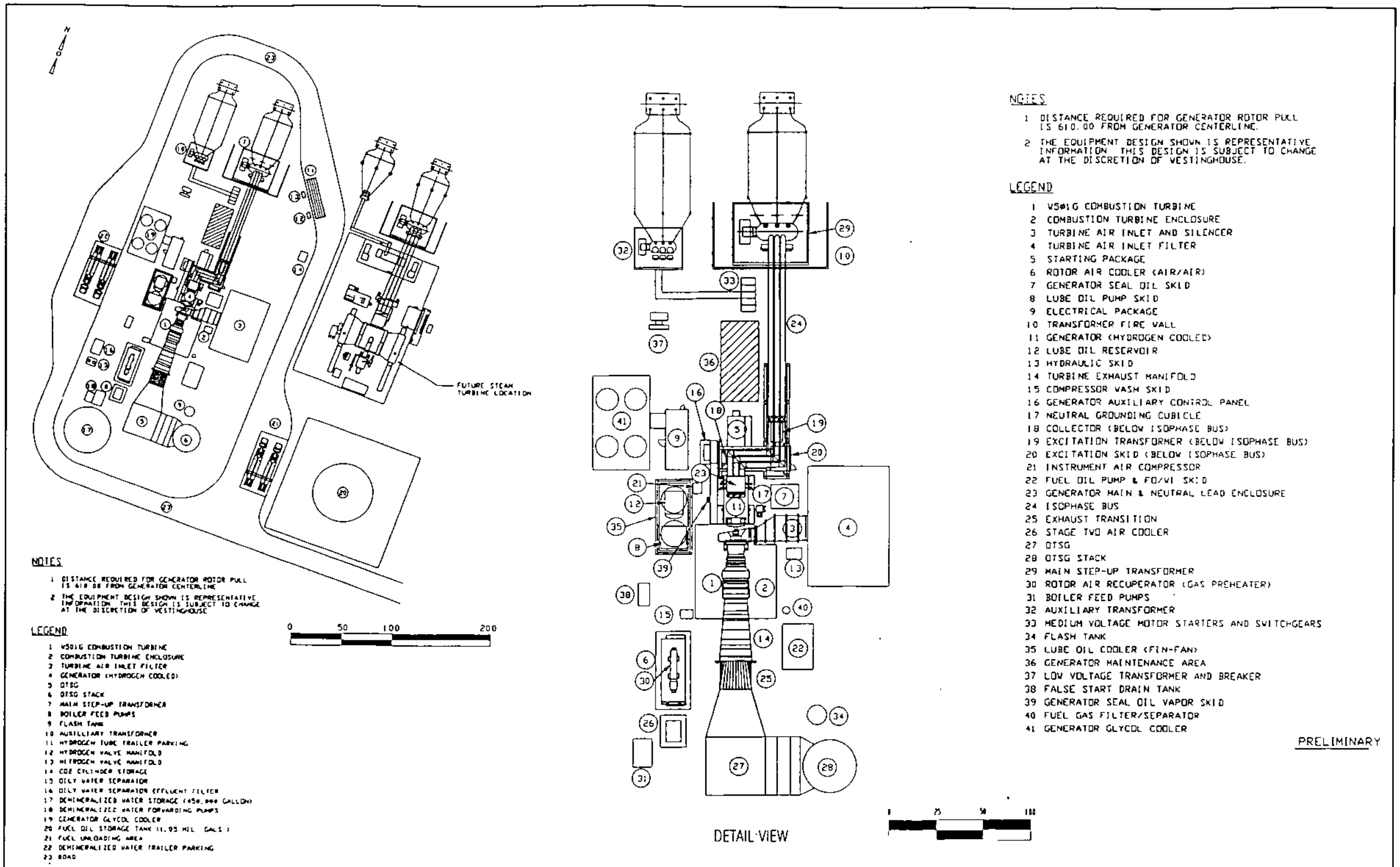
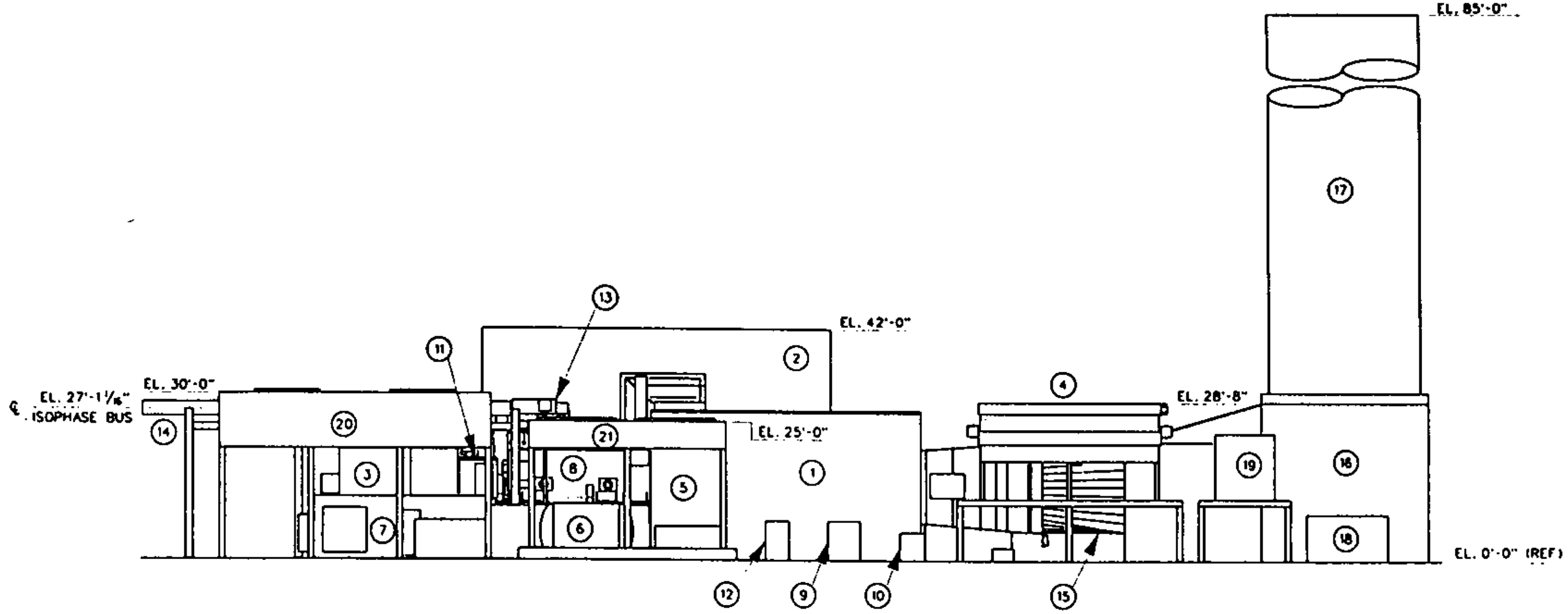


Figure 2-3 501G Plot Plan Source: Westinghouse, 1997.		*Process Area:* 501G Plot Plan *Filename:* 9737594C/FIGURES2.VSD (#2) *Latest Revision Date:* 11/25/97	Golder Associates



LEGEND

1 COMBUSTION TURBINE ENCLOSURE
2 TURBINE AIR INLET FILTER
3 STARTING PACKAGE
4 ROTOR AIR COOLER (AIR/AIR)
5 LUBE OIL PUMP SKID
6 LUBE OIL RESERVOIR
7 ELECTRICAL PACKAGE
8 GENERATOR (HYDROGEN COOLED)
9 HYDRAULIC SKID
10 COMPRESSOR WASH SKID
11 COLLECTOR
12 INSTRUMENT AIR COMPRESSOR
13 GENERATOR MAIN & NEUTRAL LEAD ENCLOSURE
14 ISOPHASE BUS
15 EXHAUST TRANSITION
16 OTSG
17 OTSG STACK
18 BOILER FEED PUMPS
19 STAGE TWO AIR COOLER
20 GENERATOR GLYCOL COOLER
21 LUBE OIL COOLER (FIN-FAN)

NOTES

1 DISTANCE REQUIRED FOR GENERATOR ROTOR PULL IS 610.00 FROM GENERATOR CENTERLINE.
2 THE EQUIPMENT DESIGN SHOWN IS REPRESENTATIVE INFORMATION. THIS DESIGN IS SUBJECT TO CHANGE AT THE DISCRETION OF WESTINGHOUSE.

Figure 2-4
Profile Diagram of 501G Facility
City of Lakeland

Source: Lakeland Electric & Water, 1997.

Filename: 9737594C/FIGURES.VSD (#2)
Date: 11/19/97

Golder Associates

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the proposed 501G facility. These regulations must be satisfied before the proposed CT can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

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

A "major facility" is defined as any one of 28 named source categories that have the potential to emit 100 tons per year (TPY) or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

A "major modification" is defined under PSD regulations as a change at an existing major facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

EPA has promulgated as regulations certain increases above an air quality baseline concentration level of SO_2, PM10, and NO_2 concentrations that would constitute significant deterioration. The

EPA class designations and allowable PSD increments are presented in Table 3-1. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM10, and NO_2 increments.

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

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

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

3.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source (Rule 62-212.410, F.A.C.). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Rule 62-210.200(40), F.A.C., as:

> An emissions limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. If the Department determines that technological or economic limitations on the

> application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the *PSD Workshop Manual* (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

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

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

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

3.2.3 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (Revised). The source impact analysis for criteria pollutants to address compliance with AAQS and PSD Class II increments may be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is above significance levels, as presented in Table 3-1.

The EPA has proposed significant impact levels for Class I areas. The National Park Service (NPS) as the designated agency for oversight in air quality impacts to Class I areas has also recommended significant impact levels for PSD Class I areas. The levels are as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu g/m^3$)	Recommended NPS PSD Class I Significance Level ($\mu g/m^3$)[a]
SO_2	3-hour	1	0.48
	24-hour	0.2	0.07
	Annual	0.1	0.03
PM10	24-hour	0.3	0.27
	Annual	0.2	0.08
NO_2	Annual	0.1	0.03

[a] $\mu g/m^3$ = micrograms per cubic meter.

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

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

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

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

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

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

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

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

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Rule 62-275.700(1)(a), F.A.C.). The minor source baseline for NO_2 has been set as March 28, 1988 (Rule 62-275.700(3)(a), F.A.C). It should be noted that references to PM(TSP) are also applicable to PM10.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

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

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDEP may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (Rule 62-212.400-3, F.A.C.).

3.2.5 SOURCE INFORMATION/GOOD ENGINEERING PRACTICE STACK HEIGHT

Source information must be provided to adequately describe the proposed project. The general type of information required for this project is presented in Section 2.0.

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

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

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,

H = Height of the structure or nearby structure, and

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

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

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

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

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Rule 62-212.400(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Rule 62-212.500, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or if the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Rule 62-2.500(2)(c)2.a., F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of NSR for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The proposed project will be subject to one or more NSPS. The CT will be subject to 40 CFR Part 60, Subpart GG, and the fuel oil storage tank (1.05-million-gallon capacity) will be subject to 40 CFR Part 60, Subpart Kb.

3.4.1.1 Combustion Turbine

The CT will be subject to emission limitations covered under Subpart GG, which limits NO_x and SO_2 emissions from all stationary gas turbines with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired.

NO_x emissions are limited to 75 ppmvd corrected to 15 percent oxygen and heat rate while sulfur dioxide emissions are limited to using a fuel with a sulfur content of 0.8 percent. In addition to emission limitations, these are requirements for notification, record keeping, reporting, performance testing and monitoring. These are summarized below:

40 CFR 60.7 Notification and Record Keeping
- (a)(1) Notification of the date of construction - 30 days after such date.
- (a)(2) Notification of the date of initial start-up - no more than 60 days or less than 30 days prior to date.
- (a)(3) Notification of actual date of initial start-up - within 15 days after such date.
- (a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date.

60.7 (b) Maintain records of the start-up, shutdown, and malfunction quarterly.
- (c) Excess emissions reports - by the 30th day following end of quarter. (required even if no excess emissions occur)
- (d) Maintain file of all measurements for two years.

60.8 Performance Tests
- (a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.
- (d) Notification of Performance tests at least 30 days prior to them occurring.

40 CFR Subpart GG

60.334 Monitoring of Operations
- (a) continuous monitoring system required for water-to-fuel ratio to meet NSPS; system must be accurate within ± 5 percent.
- (b) Monitor sulfur and nitrogen content of fuel.
  Oil - (1): each occasion that fuel is transferred to bul storage tank.
  Gas - (2): daily monitoring required

3.4.1.2 Fuel Oil Storage Tank

The applicable NSPS is 40 CFR Part 60, Subpart Kb--Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984). The storage tank will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb. There are no emission limiting on control requirements under Subpart Kb for the use of distillate fuel oil. The facility, however, must perform record keeping of the type of organic liquid in the tank.

3.4.2 FLORIDA RULES

FDEP regulations for new stationary sources are covered in the F.A.C. The FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(7); subsection (b)38 for stationary gas turbines and (b)15. For volatile organic liquid storage vessels. Therefore, the project is required to meet the same emissions, performance testings, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

3.4.3 FLORIDA AIR PERMITTING REQUIREMENTS

FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.052, 62-4.210, and 62-210.300(1), F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.4 HAZARDOUS POLLUTANT REVIEW

FDEP has promulgated guidelines (FDEP, 1995) to determine whether any emission of a potentially hazardous or toxic pollutant can pose a possible health risk to the public. Maximum concentrations for all regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants are to be compared to ambient reference concentrations (ARCs) for each applicable pollutant. If the maximum predicted concentration for any hazardous pollutant is less than the corresponding ARC for each applicable averaging time, that emission is considered not to pose a significant health risk. However, the ARCs are not environmental standards but, rather, evaluation tools to determine if an apparent threat to the public health may exist.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The project site is located in Polk County, which has been designated by EPA and FDEP as an attainment area for all criteria pollutants. Hillsborough and Pinellas Counties were redesignated by EPA from a moderate ozone nonattainment area to an air quality maintenance area. Polk County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_2. The site is located approximately 90 km (60 miles) from the closest part of the Chassahowitzka National Wilderness Area (NWA), a PSD Class I area.

3.5.2 PSD REVIEW

3.5.2.1 Pollutant Applicability

The proposed project is considered to be a major modification at a major facility because the emissions of several regulated pollutants at the existing facility exceed 100 TPY; therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates. As shown in Table 3-3, potential emissions from the proposed project will be major for PM(TSP), PM10, NO_x, CO, and VOC. Because the proposed project impacts for these pollutants, concentrations are predicted to be below the significant impact levels, a modeling analysis incorporating the impacts from other sources is not required. (Note: EPA has promulgated changes to the PSD Rules to eliminate HAPs from PSD review. FDEP has proposed, October 31, 1997, to adopt these changes. The pollutants vinyl chloride, mercury, asbestos, and beryllium would no longer be evaluated in PSD review when adopted by FDEP.)

As part of the PSD review, a PSD Class I increment analysis is required if the proposed project's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I area to the plant site is the Chassahowitzka NWA located approximately 90 km (60 miles) from the site. Based on the proposed project's predicted SO_2, NO_2, and PM10 impacts in the Class I area (see Section 1), a PSD Class I increment-consumption analysis was not required.

3.5.2.2 Emission Standards

The applicable NSPS for the CTs is 40 CFR Part 60, Subpart GG. The proposed emissions for the turbines will be well below the specified limits (see Section 4.0). The fuel oil storage tank will have a maximum storage capacity of 1.05 million gallons of No. 2 fuel oil. Since the storage tank has a capacity greater than 40 cubic meters (m^3) [approximately 10,568 gallons], the applicable NSPS is 40 CFR Part 60, Subpart Kb. The storage tank will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb, with a true vapor pressure of 0.022 pound per square inch (psi) at 100°F. Because the fuel oil is expected to have a maximum true vapor pressure of less than 3.5 kilopascals (kPa) or 0.51 psi, only the minor monitoring of operating requirements specified in 40 CFR 60 116b(a) and (b) will apply.

3.5.2.3 Ambient Monitoring

Based on the increase in emissions from the proposed plant (see Table 3-4), a preconstruction ambient monitoring analysis is required for PM10, NO_2, CO, and O_3 (based on VOC emissions). If the net increase in impact of other pollutants is less than the applicable *de minimis* monitoring concentration (100 TPY in the case of VOC), then an exemption from the preconstruction ambient monitoring requirement is provided for in the PSD regulations [Rule 62-212.400(3)(e)]. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If preconstruction monitoring data are required to be submitted, data collected at or near the project site can be submitted, based on existing air quality data or the collection of onsite data.

As shown in Table 3-4, the proposed plant's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels for all pollutants. For O_3, the potential VOC emissions are less than the *de minimis* monitoring emission level.

3.5.2.4 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m [213 feet (ft)] high. The stack for the 501G CT will be 85 ft. This stack height does not exceed the GEP stack height. The potential for downwash of the unit's emissions caused by nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.5.3 NONATTAINMENT REVIEW

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

3.5.4 HAZARDOUS POLLUTANT REVIEW

The maximum concentrations of the applicable hazardous air pollutants predicted for the 501G CT are presented in Section 6.4. These maximum concentrations are compared to the FDEP ARCs. The bases and emissions for these pollutants are presented in Attachment A. The ARCs are not environmental standards but, rather, evaluation tools to determine if an apparent threat to the public health may exist.

3.5.5 OTHER CLEAN AIR ACT REQUIREMENTS

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and non-utility units which fall under the program are referred to as affected units. The EPA regulations would be applicable to the proposed project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the later of January 1, 2000, or the date on which the unit begins serving an electric generator (greater than 25 MW).

The permit would provide SO_2 and NO_x emission limitations and the requirement to hold emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT or lowest achievable emission rate (LAER) for new units. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded. For the proposed project, SO_2 allowances will be obtained either from excess allowances from the City's electric system or through the market.

Continuous emission monitoring (CEM) for SO_2 and NO_x is required for gas-fired and oil-fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in

Appendix D, 40 CFR Part 75 (flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_X monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75 Appendices A through I). The CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG. New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation.

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

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

Note: Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year.
[b] Maximum concentrations are not to be exceeded.
[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, PM2.5 standards were introduced with a 24-hour standard of 65 $\mu g/m^3$ (3-year average of 98th percentile) and an annual standard of 15 $\mu g/m^3$ (3-year average at community monitors). Implementation of these standards are many years away. The ozone standard was modified to be 0.08 ppm for 3-hour average; achieved when 3-year average of 99th percentile is 0.08 ppm or less. FDEP has not yet adopted these standards.
[d] 0.12 ppm; achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50.
40 CFR 52.21.
Chapter 62-272, F.A.C.

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

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	[c]	NM
Radionuclides	NESHAP	[c]	NM
Inorganic Arsenic	NESHAP	[c]	NM

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

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

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

Sources: 40 CFR 52.21.
Rule 62-212.400

Table 3-3. Net Increase in Emissions Due to the Proposed 501G Compared to the PSD Significant Emission Rates

	Emissions (TPY)		
Pollutant	Potential Emissions from Proposed Facility	Significant Emission Rate	PSD Review
Sulfur Dioxide	38.4[b]	40	No
Particulate Matter [PM(TSP)]	41.3[a, b]	25	Yes
Particulate Matter (PM10)	41.3[a, b]	15	Yes
Nitrogen Dioxide	863.1[a]	40	Yes
Carbon Monoxide	1264.4[a]	100	Yes
Volatile Organic Compounds	93.7[a]	40	Yes
Lead	<0.1[b]	0.6	No
Sulfuric Acid Mist	5.9[b]	7	No
Total Fluorides	0.01[b]	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Asbestos	NEG	0.007	No
Beryllium	0.00005[b]	0.0004	No
Mercury	0.0003[b]	0.1	No
Vinyl Chloride	NEG	1	No

Note: NEG = Negligible.

[a] Based on emissions from 501G operating at baseload conditions at 59°F; firing natural gas and distillate fuel oil for 5,758 and 1,000 hours per year, respectively; and operating at 50% load firing natural gas and distillate oil for 200 and 50 hours per year, respectively.

[b] Based on baseload conditions at 59°F firing natural gas and distillate oil for 6,758 and 250 hours per year, respectively.

Table 3-4. Predicted Net Increase in Impacts Due To the Proposed 501G Facility Compared to PSD *De Minimis* Monitoring Concentrations

	Concentration ($\mu g/m^3$)	
Pollutant	Predicted Net Increase in Impacts[a]	*De Minimis* Monitoring Concentration
Particulate Matter (PM10)	0.4	10, 24-hour
Nitrogen Dioxide	0.11	14, annual
Carbon Monoxide	8.6	575, 8-hour
Volatile Organic Compounds	93.7 TPY	100 TPY

Note: NA = not applicable.
NM = no ambient measurement method.
TPY = tons per year.

[a] See Section 7.1 for air dispersion modeling results.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_x, CO, VOC, and PM/PM10 (see Section 3.0). The maximum potential annual emissions of these pollutants from the proposed 501G CT are summarized below (see Table 2-5):

Pollutant	Emissions (TPY) 250 MW
NO_x	852 - 863[a]
CO	761 - 1,264[a]
VOC	37 - 94[a]
PM/PM10	41

[a] Maximum emissions include emissions for 1,000 hours (natural gas) and 50 hours (oil) at low load (50%) operation; 5,758 hours (natural gas), 200 hours (oil) at base load operation. Minimum emissions based on base load operation with 6,758 hours (natural gas) and 250 hours (oil).

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring a top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12); and Rule 62-212.200(40), and Rule 62-214.410, F.A.C.]. The analysis must, by definition, be specific to the project (i.e., case-by-case).

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart GG and summarized in Attachment B. The applicable NSPS emission limit for NO_x is 75 parts per million by volume dry (ppmvd) corrected for heat rate and 15 percent oxygen. For the CTs being considered for the project, the NSPS emission limit NO_x with the NSPS heat rate correction is 110.4 parts per million (ppm) on oil and 117.3 ppm on gas (corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent). More information on the NSPS is presented in Attachment B. The proposed NO_x emission limits for the project will be much lower than the NSPS.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

In recent permitting actions, FDEP has established BACT for heavy-duty industrial gas turbines. These decisions have included the use of advanced dry low-NO_x combustors for limiting NO_x and CO emissions and clean fuels (natural gas and distillate oil) for control of other emissions, including SO_2. The BACT proposed for the 501G project is consistent with these FDEP permits. The proposed project will have two modes of operation (see Section 2.3) for which a BACT analysis has been performed. The results of the analysis have concluded the following controls as BACT for the project.

1. Natural Gas Fired. 501G will utilize state-of-the-art dry low-NO_x combustion technology which will achieve gas turbine exhaust NO_x levels of no greater than 25 ppmvd corrected to 15 percent O_2. CO emissions will be limited to 50 ppmvd at base load.
2. Fuel Oil Fired. 501G will utilize water injection to achieve gas turbine exhaust NO_x levels of no greater than 42 ppmvd corrected to 15 percent O_2. CO emissions will be limited to 90 ppmvd at base load.

4.3.1 NITROGEN OXIDES

The BACT analysis was performed for the following alternatives:

1. Advanced dry low-NO_x combustors at an emission rate of 25 ppmvd corrected to 15 percent O_2 when firing gas and 42 ppmvd (corrected) when firing oil.
2. Selective catalytic reduction (SCR) and advanced dry low-NO_x combustors at an emission rate of approximately 7.5 ppmvd corrected to 15 percent O_2 when firing natural gas and 12.6 ppmvd when firing oil.

Attachment B presents a discussion of NO_x control technologies and their feasibility for the project.

Dry low-NO_x combustor technology has recently been offered and installed by manufacturers to reduce NO_x emissions by inhibiting thermal NO_x formation through premixing fuel and air prior to combustion and providing staged combustion to reduce flame temperatures. NO_x emissions ranging from 25 to 9 ppmvd (corrected to 15-percent O_2) has been offered by manufacturers for advanced combustion turbines. Advanced in this context is the larger (over 150 MW) and more efficient (higher initial firing temperatures and lower heat rate) combustion turbines. This technology is truly pollution prevention since NO_x emissions are inhibited from forming.

SCR is a post-combustion process where NO_x in the gas stream is reacted with ammonia in the presence of a catalyst to form nitrogen and water. The reaction occurs typically between 600°F and 750°F, which has limited SCR application to combined cycle units where such temperatures occur in the HRSG. Exhausts from simple cycle operation are in the range of 1,000°F, thus limiting SCR application for this mode of operation. With the higher cost ceramic catalyst, temperatures up to 1,100°F are possible. SCR has been installed and operated on combined cycle facilities generally achieving 9 ppmvd (corrected to 15-percent O_2) or less while burning natural gas.

Applications of SCR with oil firing are limited. Where oil firing has been attempted, catalyst poisoning and ammonium salt formation has occurred. Ammonium salts (ammonium sulfate and ammonium bisulfate) are formed by the reaction of sulfur oxides in the gas stream and ammonia. These salts are highly acidic, and special precautions in materials and ammonia injection rates must be implemented to minimize their formation. Ammonia injected in the SCR system that does not react with NO_x is emitted directly and referred to as ammonia slip. In general, SCR manufacturers guarantee ammonia slip to be no more than 10 ppmvd; however, permitted limits in some applications have exceeded 25 ppmvd. While SCR is technically feasible for the project, SCR has not been applied to a simple cycle advanced combustion turbine of the size proposed for this project or to the amount of oil firing that may occur.

The recent permitting trend for advanced combustion turbines is the use of dry low-NO_x combustors. Indeed, all of the recent projects have been permitted with this technology, including 5 projects in Florida (Florida Power & Light Martin Units 3 and 4; Florida Power Corporation Polk Power Park; and Central Florida Cogeneration Project; Hardee Unit 3 Project, and City of Tallahassee Project), and one in Maryland (Baltimore Gas & Electric Perryman Project).

As discussed in Section 2.1, the CT will be fired primarily with natural gas. Distillate oil will be used as backup fuel not to exceed 250 hours per year. Table 4-1 presents a summary of emissions with dry low-NO_x combustors and with dry low-NO_x combustors and SCR assuming 80 percent operating capacity at an ambient temperature of 59°F. The NO_x removed using SCR would be 596 TPY when firing oil and natural gas. The NO_x removed when firing oil is based on 250 hours per year. The NO_x removed when firing natural gas is based on 6,758 hours of operation.

4.3.1.1 Proposed BACT and Rationale

The proposed BACT for the project is advanced dry low-NO_x combustion technology. The proposed NO_x emissions level using this technology is 25 ppmvd (corrected to 15 percent oxygen and ISO conditions) when firing natural gas under base load conditions. NO_x from oil firing will be controlled using water injection. This combination of control technologies is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds. Table 4-2 summarizes these considerations which favor the dry low-NO_x pollution prevention technology.
2. The estimated incremental cost of SCR ranges from \$5,236 to \$6,156 per ton of NO_x removed. The upper part of the range reflects five years of operation and is similar to cost for other projects that have rejected SCR as being unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered. The cost effectiveness is more than \$8,000 per ton of pollutant removed when the net emissions of all pollutants (exclusive of CO_2) are considered.
3. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary emissions (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst replacement). While NO_x emissions would be reduced by about 600 TPY with SCR, the net emissions reduction would not be as great. There are three additional factors that must be considered:
   a. Ammonia slip would occur, and it may be as high as 96 TPY.
   b. Additional particulate matter may be formed through the reaction of ammonia and sulfur oxides forming ammonium salts. As much as 34 TPY additional particulate matter may be formed.
   c. SCR will require energy for system operation and reduce the efficiency of the combustion turbine. This lost energy would have to be replaced since the proposed project would be an efficient baseload plant while operating. Any power plants replacing this lost energy would be lower on the dispatch list and inevitably more polluting. Conservatively, this lost energy would result in the

emissions of an additional 97.5 TPY of criteria pollutants. Additional emissions of carbon dioxide would also result.

4. The energy impacts of SCR will reduce potential electrical power generation by more than 9.3 million kilowatt hours (kWh) per year. This amount of energy is sufficient to provide the annual electrical needs of 774 residential customers.
5. The proposed BACT (i.e, dry low-NO_x combustion) provides the most cost effective control alternative, is pollution preventing and results in low environmental impacts (less than the significant impact levels). Dry low-NO_x combustion at the proposed emissions levels has been adopted previously in BACT determinations. Indeed, compared to conventional CTs, the proposed BACT will result in 10 percent less NO_x emission from the same amount of generation.

The analyses of economic, environmental, and energy impacts follow.

4.3.1.2 Impacts Analysis

Economic--The total capital costs of SCR for the proposed 501G plant are $7,299,000. The total annualized cost of applying SCR with dry low-NO_x combustion is $3,124,346. Attachment B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the dry low-NO_x combustors and water injection (for oil firing) is estimated to range from $5,236 to $6,156 per ton of NO_x removed.

The cost effectiveness of SCR applied to project for simple cycle is $5,236 per ton of NO_x removed. This cost effectiveness assume operation at 80 percent capacity factor for the life of the project with primary operation on natural gas at 25 ppmvd NO_x. However, as discussed in the project description, the City of Lakeland anticipates that the project would be converted to combined cycle in the near term. Assuming that this conversion takes place within 5 years, the cost effectiveness for this period would be $6,156 per ton of NO_x removed. Moreover, if SCR were installed for simple cycle operation the conversion combined cycle would result in a nearly complete waste of an initial $7 million capital investment and either the installation of further combustion controls, if developed during this period, or the installation of SCR within a HRSG. If SCR were required to meet a lower emission limit during combined cycle operation, an additional $5.8 million of capital investment would be required with an estimated annualized costs of $2.34 million. The 25 percent lower annualized cost for combined cycle operation results in lower catalyst costs for a standard catalyst rather than a "hot" SCR required for simple cycle design. Over a 20 year project life, installing both a "hot" side and standard SCR (i.e., base metal catalyst) systems would result in a cumulative annualized cost of about $30 million higher than if only a standard SCR system were installed (if necessary in future years).

The manufacturer of the combustion turbine, Westinghouse, is involved in a Department of Energy project to develop further advancements to turbine technology. If the combustors can be modified at a future date to lower emissions, than the average cost effectiveness, in simple cycle configuration, would be much higher. If in the 5-year period, the emissions can be lowered to 15 ppmvd while firing gas, then the average cost effectiveness over a 20 year period would be $7,291 per ton of NO_x removed for simple cycle operation. These costs are clearly higher than has been considered unreasonable as BACT for other projects.

This cost effectiveness accounts only for the reduction of NO_x with SCR use and not the potential emissions from ammonia slip or other criteria pollutants that may result. The net cost effectiveness will be much higher. Indeed, it could be more than $8,000 per ton of ammonia and criteria pollutants removed (see Table 4-3; $3,124,346 divided by the net reduction of 370 TPY).

<u>Environmental</u>--The maximum predicted NO_x impacts using the dry low-NO_x technology are all considerably below the PSD Class II increment for NO_x of 25 $\mu g/m^3$, annual average, and the AAQS for NO_x, 100 $\mu g/m^3$. Indeed, the maximum annual impact is 0.11 $\mu g/m^3$, which is about 10 percent of the significant impact level. While additional controls beyond dry low-NO_x combustors (i.e., SCR and SCR with water injection) would reduce emissions, the effect will not be significant and much less than 1 percent of the PSD increment and the AAQS for the project.

The use of dry low-NO_x combustor technology is truly "pollution prevention". In contrast, use of SCR on the proposed 501G project will cause emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate. Ammonia emissions associated with SCR are expected to be up to 10 ppm based on reported experience; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as 96 TPY for the 501G project. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM10; up to 34 TPY could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power from the project. This power, which would otherwise be available to the electrical system, will have to be replaced by other less efficient units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. These "secondary" emissions, coupled with potential emissions of ammonia and ammonium salts, are presented in Table 4-3. This table shows the emissions balance for the project with and without SCR. As shown, the net reduction in emissions with SCR when all criteria pollutants are considered will be 370 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted and were included in Table 4-3. As noted from this table, the emissions including CO_2 would be greater with SCR than that proposed using dry low-NO_x combustion technology.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261). In addition, SCR will require the construction and maintenance of storage vessels of anhydrous or aqueous ammonia for use in the reaction. Ammonia has a number of potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119.

At elevated temperatures, ammonia may contribute to instability and cause containers to burst (ammonia will auto-ignite at a temperature of approximately 100°F). It is incompatible with strong oxidizers, calcium, hypochlorite bleaches, gold, mercury, halogens, and silver. Liquid ammonia will corrode some forms of plastic, rubber, and coatings. Ammonia is a severe irritant of the eyes, especially the cornea, the respiratory tract, and the skin. It is detectable at about 5 ppm and causes respiratory irritation in humans above 25 ppm. The irritating effects of ammonia are less noticeable with chronic exposure.

As a strong alkali, ammonia can cause severe burns of the cornea and the effects are often delayed. Even burns that at the time of injury appear to be mild can go on to opacification, vascularization, and ulceration or perforation. Of all the alkali compounds that cause eye damage, ammonia penetrates the cornea the most rapidly, resulting in potentially severe damage to the cornea. Because ammonia is very soluble in water, it is irritating to the upper respiratory tract. Inhalation of the gas will cause throat and nose irritation and dyspnea as aqueous ammonia is formed. Liquid anhydrous ammonia will cause first and second degree burns on contact with the skin.

Energy--Significant energy penalties occur with SCR. With SCR, the output of the CT may be reduced by about 0.50 percent over that of advanced low-NO_x combustors. This penalty is the result of the SCR pressure drop, which would be about 2.5 inches of water and would amount to about 8,724,960 kWh per yr in potential lost generation. The energy required by the SCR equipment would be about 560,640 kWh per yr. Taken together, the total lost generation and energy requirements of SCR of 9,285,600 kWh per yr could supply the annual electrical needs of about 774 residential customers. To replace this lost energy, an additional 9×10^{10} British thermal units per year (Btu/yr) or about 90 million cubic feet per year (ft^3/yr) of natural gas would be required.

Technology Comparison--The 501G project will use an advanced heavy-duty industrial gas turbine with advanced dry low-NO_x combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design is dry low-NO_x combustors that prevent the formation of air pollutants within the combustion process, thereby eliminating the need for add-on controls that can have detrimental effects on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

An advanced gas turbine is unique from an engineering perspective in two ways. First, the advanced machine is larger and has higher initial firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the selected Westinghouse advanced machine is about 249 MW compared to advanced "F" class machines which are about 150 MW, and from about 70 MW to 120 MW compared to conventional machines. The higher initial firing temperature (i.e., 2,600°F) results in about 20 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines and 10 percent more efficient than "F" class machines. This has the added advantage of producing lower air pollutant emissions (e.g., NO_x, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustor design.

The second unique attribute of the advanced machine is the use of dry low-NO_x combustors that will reduce NO_x emissions to 25 ppmvd when firing natural gas. Thermal NO_x formation is inhibited by using staged combustion techniques where the natural gas and combustion air are premixed prior to ignition. This level of control will result in NO_x emissions of about 0.1 lb/10^6 Btu, which is more than two times lower than emissions from conventional fossil fuel-fired steam generators.

Since the purpose of the project is to produce electrical energy, and CT technology is rapidly advancing, it is appropriate to compare the proposed emissions on an equivalent generation basis to that of a conventional CT. The heat rate of the 501G will be about 8,725 Btu/kWh (LHV) at 59°F. In contrast, the heat rate for an "F" class machine is about 9,600 Btu/kWh (LHV); for the conventional CT, the heat rate is about 11,000 Btu/kWh. Therefore, the amount of total NO_x from the advanced CT will be 10-percent lower than that of a "F" class machine and 20 percent lower than a conventional turbine for the same amount of generation.

The efficiency and project configuration are illustrated by a recently completed simple cycle project located in Gainesville, Florida:

Comparison of Gainesville Regional Utilities (GRU) and Lakeland Simple Cycle Projects

		GRU Permitted[a]	GRU Adjusted[b]	Lakeland Proposed
Operation (hrs/yr)		3,390	7,008	7,008
Generation	(MW)	84	252	249
	(MWhrs)	285,541	1,743,643	1,743,643
NO_x Emissions				
Ton/year		239	1,459	979
lb/hr/MW		1.67	1.65	1.12

Notes: [a] FDEP Permit PSD-FL-212
[b] adjusted based on total generation; 3 turbines

As shown, the emissions as a function of MW approved for the project are lower in the case of Lakeland than for the Gainesville project.

Also, the amount of NO_x control achieved by the dry low-NO_x combustor on an advanced CT is considerably higher than that achieved by a conventional CT. Because of the higher firing initial temperatures, the advanced CT results in greater NO_x emission formation. Since the advanced machine has higher firing temperatures, the NO_x emissions without the use of dry low-NO_x combustion technology are much higher than a conventional CT (greater than 180 ppmvd vs. 150 ppmvd). This results in an overall greater NO_x reduction on the advanced CT.

4.3.2 CARBON MONOXIDE

Emissions of CO are dependent upon the combustion design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected (i.e., for oil firing). The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO as well as NO_x emissions.

For the project, the following alternatives were evaluated as BACT:

1. Combustion controls at 50 ppmvd when firing natural gas (at baseload) and 90 ppmvd when firing oil (at baseload); emissions at 50 percent load are estimated to be 350 ppmvd with maximum annual emissions of 1,264 TPY assuming the following operation: 5,738 hours per year of natural gas at baseload; 1,000 hours per year on natural gas at 50 percent load; 200 hours per year at baseload on oil; and 50 hours per year at 50 percent load on oil; and
2. Oxidation catalyst at 10 ppmvd; maximum annual CO emissions are 535 TPY.

Combined cycle facilities with an oxidation catalyst and combustion controls generally have controlled CO levels of 10 ppm or less as LAER.

4.3.2.1 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission rates for CO will not exceed 50 ppmvd when firing natural gas and 90 ppmvd when firing distillate oil; full load conditions. Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts;
2. The economic impacts are significant (i.e., the capital cost is about $2 million, with an analyzed cost of $980,000 per year; and
3. Recent projects in Florida have been authorized with BACT emission limits of 25 ppmvd on gas and 90 ppmvd on oil.

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable since it will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for similar advanced CTs have set limits in the 30 ppmvd range and higher. Even the Northeast States for Coordinated Air Use Management (NESCAUM) has recognized a BACT level of 50 ppmvd for CO emissions. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

4.3.2.2 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $980,000, resulting in a cost effectiveness of greater than $800 per ton of CO removed. The cost effectiveness is based on 6,758 hours per year on natural gas (including 1,000 hours per year operation at 50 percent load) and 250 hours per year of operation on oil (including 50 hours at 50 percent load), with the maximum emissions controlled to 10 ppmvd. No costs are associated with combustion techniques since they are inherent in the design.

The CO emissions estimate for the 501G is a result of uncertainity associated with maintaining low NO_x emissions while keeping emissions of CO as low as possible over the load range for the machine. Westinghouse in its 501G Application Overview reports CO emissions of 10 ppmvd which would result in emission rates similar to those recently authorized (July 1997) by FDEP in the City of Tallahassee project (draft FDEP Permit PSD-FL-239). In this project, CO emission rates of 25 ppmvd natural gas and 90 ppmvd oil were approved. At emission rates similar to those of the City of Tallahassee, the resultant cost effectiveness would be over $3,000 per ton of CO removed which is higher than those of similar projects.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. Indeed, additional particulate and secondary emissions as a result of an oxidation catalyst would be about 34 TPY. The particulate would result from the conversion of SO_2 to sulfates, and the secondary emissions would result from the heat rate reduction. Moreover, the air quality impacts at the proposed CT emission rate are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 0.1 percent of the applicable ambient air quality standards. There would also be no secondary benefits, such as acidic deposition, to reducing CO.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 3,490,000 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 291 residential customers for a year. To replace this lost energy, about 3.4×10^{10} Btu/yr or about 34 million ft^3/yr of natural gas would be required.

4.3.3 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CT and are a result of incomplete combustion. The proposed BACT for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions will not exceed 4.0 ppmvd when firing natural gas and 10 ppmvd when firing distillate oil. These emission levels are similar to the BACT emission levels established for other similar sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The environmental effect of further reducing emissions would not be significant.

4.3.4 PM/PM10 AND OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The emission of particulates from the CT is a result of incomplete combustion and trace elements in the fuel. Beryllium and inorganic As would be included in the PM/PM10 emissions. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas- or oil-fired CTs.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs {i.e., the grain loading associated with the maximum particulate emissions [about 9.8 pounds per hour (lb/hr) when firing natural gas]} is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

There are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil represent BACT for these pollutants.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas and distillate oil represent BACT because of their inherently low contaminant content.

Table 4-1. NO_x Emission Estimates (TPY) of BACT Alternative Technologies

	Operating Mode[a]		
Alternative BACT Control Technologies	Oil	Gas/PA	Total
NOx Emission (TPY)			
Dry Low-NO_x (DLN) only	51	801	852
DLN with SCR[b]	15	240	255
Reduction	(36)	(561)	(596)
Basis of Emissions (ppmvd)			
DLN only	42	25	
DLN with SCR	12.6	7.5	
Hours of Operation	250	6,758	7,008

Note: Gas/PA = gas with power augmentation.
DLN = Dry low-NO_x.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Emission rates are based on W501G combustion turbine operating at 100-percent capacity and firing fuel oil for 250 hours and natural gas for 6,758 hours, which includes power augmentation. Emission data are based on an ambient temperature of 59°F.

[b] Based on primary emissions with SCR; no account is made for additional emissions (secondary) due to lost energy from heat rate penalty and electrical usage for SCR operation (see Table 4-3).

Table 4-2. 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 oil
Economic Impact[a]		
Capital Costs	included	$7,299,000
Annualized Costs	included	$3,124,346
Cost Effectiveness		
Best Case	NA	$5,236[c]
Expected	NA	$6,156[c]
Environmental Impact[b]		
Total NO_x (TPY)	852	255
NO_x Reduction (TPY)	NA	(596)
Ammonia Emissions (TPY)	0	96
PM Emissions (TPY)	0	34
Secondary Emissions (TPY)	0	97.5
Net Emission Reduction (TPY)	NA	(370)
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 Attachment B for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Tables 4-1 and 4-3.

[c] Best case based on simple cycle for the life of the project. Expected is the cost of simple cycle SCR for five years.

[d] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 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 4-3. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction

	Incremental Emissions (TPY) of Project with SCR		
Pollutants	Primary	Secondary[a]	Total
Particulate	34[b]	5.4	39.4
Sulfur Dioxide	--	60	60
Nitrogen Oxides	(597)[c]	30	(567)
Carbon Monoxide	--	1.8	1.8
Volatile Organic Compounds	--	0.3	0.3
Ammonia	96[d]	0.0	96
Total	(467)	97.5	(370)
Carbon Dioxide[e]	--	9,364	9,364

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 8,760 hours per year operation (0.5% of 24.9 MW per CT plus 0.080 MWh per 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 = 0.55, CO = 0.033, and VOC = 0.005. Example calculation for PM is 1.245 MW x 10,000 Btu/kWh x 1,000 kW/MW x 8,760 hr/yr x 0.1 lb pm/10^6 Btu ÷ 2,000 lb/ton = 5.4 TPY.

[b] Assume 5% SO_2 conversion in catalyst and SO_3 reacts with ammonia; 20.6 TPY SO_3 x 132 (MW of ammonia salt) ÷ 98 (MW of H_2SO_4).

[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 8,760 ÷ 2,000 x 0.80 (capacity factor).

[e] Reflects differential emissions due to lost energy efficiency with SCR (i.e., calculated from total heat input lost; 1.245 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).

5.0 AMBIENT MONITORING ANALYSIS

The CAA requires that an air quality analysis be conducted for each criteria and noncriteria pollutant subject to regulation under the act before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Noncriteria pollutants are those pollutants that may be regulated by emission standards, but no AAQS have been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality.

A major source may waive the ambient monitoring analysis requirement if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de Minimis* concentration levels. The maximum impacts of the proposed source are compared with the PSD *de Minimis* concentrations in Table 3-4. As can be seen from Table 3-4, the proposed plant's maximum air quality impacts will be well below the *de Minimis* concentrations for all applicable pollutants. For O_3, the potential VOC emissions are less than the *de minimis* monitoring emission level. Since the predicted increase in air quality impacts due to the proposed modification are less than the *de minimis* monitoring concentration levels (VOC emission level for O_3), the project can be exempted from preconstruction ambient monitoring requirements.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS APPROACH

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all applicable pollutants that have emission increases that will exceed the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA significant impact levels at any off-plant property areas in the vicinity of the plant.

Generally, if the project undergoing the modification also is within 150 to 200 kilometers of a PSD Class I area, then a significant impact analysis is also performed for the PSD Class I area. Currently, the National Park Service (NPS) has recommended significant impact levels for PSD Class I areas. The recommended levels have not been promulgated as rules. EPA also has proposed PSD Class I significant impact levels that have not been finalized as of this report.

If the project's impacts are above the significant impact levels, then a more detailed air modeling analysis that includes background sources is performed. Current FDEP policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. Based on the screening modeling analysis results, additional modeling refinements with a denser receptor grid are performed, as necessary, to obtain the maximum concentration. Modeling refinements are performed with a receptor grid spacing of 100 meters (m) or less.

6.2 AAQS/PSD MODELING ANALYSIS APPROACH

6.2.1 GENERAL PROCEDURES

For each pollutant for which a significant impact is predicted, a full impact analysis is required. This analysis must consider other nearby sources and background concentrations, and predict concentration for comparison to ambient standards. In general, when 5 years of meteorological data are used in the analysis, the highest annual and the highest, second-highest (HSH) short-term concentrations are compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated for a receptor field by:

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

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

To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two modeling phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

If the original screening analysis indicates that the highest concentrations are occurring in a selected area(s) of the grid, and if the area's total coverage is too vast to directly apply a refined receptor grid, then an additional screening grid(s) will be used over that area. The additional screening grid(s) will employ a greater receptor density than the original screening grid, so refinements can be performed if necessary.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, then those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor at which the maximum concentration was predicted. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements employ an angular spacing between radials of 2 degrees and a distance interval from 100 to 300 m, depending on the concentration gradient in the vicinity of the screening receptor to be refined. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2 degree angular interval and centered on the screening receptor. The domain of the refinement grid will extend to all adjacent screening receptors. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid HSH concentration is obtained. A more detailed description of the model, along with the emission inventory, meteorological data, and screening receptor grids are presented in the following sections.

6.2.2 MODEL SELECTION

The Industrial Source Complex Short-term (ISCST3, Version 96113) dispersion model (EPA, 1996) was used to evaluate the pollutant impacts due to the proposed CT. This model is maintained on the EPA's Technical Transfer Network (TTN) bulletin board service. A listing of ISCST3 model features in presented in Table 6-1. The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights).

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can run in the rural or urban land use mode which affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent land use within a 3-km radius around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on the land-use within a 3-km radius of the City of Lakeland's McIntosh Power Plant site, the rural dispersion coefficients were used in the modeling analysis.

The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. A generic emission rate of 10 grams per second (g/s) was used as emissions for the proposed source. Maximum pollutant-specific air impacts were determined by multiplying the maximum pollutant-specific emission rate in pounds per hour (lb/hr) to the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

6.2.3 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Tampa International Airport and Ruskin, respectively. The 5-year period of meteorological data was from 1987 through 1991. The NWS station at Tampa International Airport, located approximately 59 km (37 miles) west of the proposed plant site, was selected for use in the study because it is the closest primary weather station to the study area that is representative of the plant site.

6.2.4 EMISSION INVENTORY

A summary of the Westinghouse 501G CT's maximum emission rates for all criteria and selected noncriteria pollutants air modeling analysis is presented in Table 6-2. A summary of the criteria and noncriteria emission rates, physical stack and stack operating parameters for the proposed CT are included in Appendix A for three operating loads: baseload, 75, and 50 percent. Emission and stack operating parameters are presented for 30°F, 59°F, 90°F ambient temperatures. In an effort to obtain the maximum air quality impacts for a range of possible operating conditions, the air modeling analysis used a range of emission rates and stack parameter data to predict air quality impacts for natural gas- and fuel oil-firing. For each fuel, four modeling scenarios were considered. The proposed CT was modeled for baseload and 50-percent load conditions with two ambient temperatures, 30°F and 90°F, for each load.

The proposed CT will have a stack height of 85 feet, and an inner stack diameter of 8.5 ft.

6.2.5 RECEPTOR LOCATIONS

For predicting maximum concentrations in the vicinity of the plant, a polar receptor grid comprised of 648 grid receptors was used. These receptors included 36 receptors located on radials extending out from the proposed CT stack location. Along each radial, receptors were located at distances of 0.1, 0.25, 0.5, 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 4.5, 5.0, 6.0, 7.0, 8.0, 9.0, 10.0 and 12.0 km from the proposed CT stack location.

Modeling refinements were performed, as needed, by employing a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of 2 degrees.

For predicting impacts at the Chassahowitzka National Wilderness Class I Area (CNWA), 13 discrete receptors located along the border of the PSD Class I area were used. A listing of the Class I receptors is presented in Table 6-3. Modeling refinements at the Chassahowitzka NWA were not performed due to the distance of the Class I area from the CT plant site.

6.2.6 BUILDING DOWNWASH EFFECTS

The only significant structure in the vicinity of the proposed CT stack is the proposed turbine air filter. This structure is proposed to be 42 ft high and will have horizontal dimensions of 64 ft by 43 ft. For the air modeling analysis, the height of this structure and the building diagonal were entered into the ISCST3 model as the building height and width for each of 36 ten-degree wind sectors.

6.3 AIR MODELING RESULTS FOR SIGNIFICANT IMPACT ANALYSIS

The modeling analysis results for the proposed CT alone in the vicinity of the plant are summarized in Table 6-4. The maximum predicted PM, SO_2, NO_x, and CO impacts due to the proposed CT are all well below the EPA Significant Impact Levels (SIL). Because the proposed source will not have a significant impact upon the air quality in the vicinity of the plant site, more detailed modeling analyses for determining compliance with the AAQS and PSD Class II increments are not required.

The maximum predicted concentrations due to the proposed CT alone at the CNWA are presented in Table 6-5. The maximum predicted impacts are below both the proposed EPA PSD Class I SIL for all applicable pollutants, and the recommended NPS SIL for PM, and NO_x. For SO_2, the maximum impacts are equal to the 24-hour average NPS SIL, but below the annual and 3-hour average SIL. Because all maximum predicted values are at or below the recommended NPS SIL, a PSD Class I modeling analysis at the Chassahowitzka NWA is not required for any emitted pollutant.

6.4 AIR TOXIC MODELING RESULTS

A summary of maximum air toxic impacts due to the proposed CT alone is presented in Table 6-6. The emission rates presented in Table 6-6 are the maximum annual and short-term emission rates for fuel oil firing and base load conditions. Maximum impacts are compared to the Florida ARC for all emitted air toxics. For each averaging time, the ratio of the maximum predicted impact to the Florida ARC is presented for each compound. As shown in Table 6-6, the maximum air toxic impacts are well below the Florida ARCs for all modeled air toxic compounds.

Table 6-1. Major Features of the ISCST3 Model

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

Note: ISCST3 = Industrial Source Complex Short-Term.

Source: EPA, 1995.

Table 6-2. Maximum Pollutant Emission Rates Estimated for City of Lakeland- McIntosh Plant, Westinghouse 501G Combustion Turbine Project

	Maximum Emission Rates (lb/hr) for:			
	Base Load		50 % Load	
Pollutant	90 °F	30 °F	90 °F	30 °F
Natural Gas- Firing				
PM (excludes H2SO4)	8.5	9.1	6.5	6.7
SO2	6.37	7.21	3.89	4.33
NO2	220	249	241	287
CO	190	222	1,086	1228
VOC	9	10	106	120
Arsenic	Neg.	Neg.	Neg.	Neg.
Beryllium	Neg.	Neg.	Neg.	Neg.
Florides	Neg.	Neg.	Neg.	Neg.
Mercury	0.00000167	0.00000189	0.00000102	0.00000114
Sulfuric Acid Mist	0.97	1.1	0.6	0.66
Fuel Oil-Firing				
PM (excludes H2SO4)	89.4	95.8	135	140
SO2	117.3	126.7	68.1	75.8
NO2	382	433	415	461
CO	348	407	1,100	1244
VOC	22	26	180	203
Arsenic	0.00911	0.0103	0.00556	0.00619
Beryllium	0.000434	0.000492	0.000265	0.000295
Fluorides	0.0706	0.0801	0.0431	0.0479
Mercury	0.00217	0.00246	0.00132	0.00147
Sulfuric Acid Mist	17.11	19.4	10.43	11.61

Note: Sulfur content of fuel oil is assumed to be 0.05 percent.

Table 6-3. Chassahowitzka Wilderness Area Receptors Used in the Modeling Analysis

UTM Coordinates	
East (km)	North (km)
340.3	3,165.7
340.3	3,167.7
340.3	3,169.8
340.7	3,171.9
342.0	3,174.0
343.0	3,176.2
343.7	3,178.3
342.4	3,180.6
341.1	3,183.4
339.0	3,183.4
336.5	3,183.4
334.0	3,183.4
331.5	3,183.4

Table 6-4. Maximum Pollutant Concentrations Predicted for City of Lakeland- McIntosh Plant, Westinghouse 501G Combustion Turbine Project

Pollutant	Averaging Time	Maximum Impact (µg/m³)- Natural gas-Firing (1) Base Load 90 °F	Base Load 30 °F	50 % Load 90 °F	50 % Load 30 °F	Maximum Impact (µg/m³)- Fuel oil-Firing (1) Base Load 90 °F	Base Load 30 °F	50 % Load 90 °F	50 % Load 30 °F	EPA PSD Class II Significant Impact Levels (µg/m³)
Specific Pollutant Impacts										
PM	Annual	0.0014	0.0013	0.0016	0.0016	0.0146	0.0146	0.0333	0.0333	1
	24-Hour	0.0173	0.0178	0.0188	0.0188	0.191	0.191	0.398	0.400	5
SO2	Annual	0.0010	0.0010	0.0009	0.0010	0.019	0.019	0.017	0.018	1
	24-Hour	0.0129	0.0141	0.0113	0.0121	0.25	0.25	0.20	0.22	5
	3-Hour	0.064	0.072	0.058	0.064	1.19	1.27	1.01	1.12	25
NO2	Annual	0.0350	0.0358	0.0581	0.0669	0.0625	0.0661	0.102	0.110	1
CO	8-Hour	0.767	0.881	7.54	7.80	1.43	1.62	7.66	8.61	500
	1-Hour	3.93	4.37	34.5	38.7	7.42	8.15	35.0	39.4	2000
Modeled Impacts										
10 g/s	Annual	0.01261	0.01141	0.01914	0.01849	0.01298	0.01211	0.01957	0.01886	NA
	24-Hour	0.16121	0.15521	0.22992	0.22268	0.16939	0.15798	0.23392	0.22658	NA
	8-Hour	0.3202	0.31479	0.55073	0.50423	0.32598	0.31635	0.55282	0.54914	NA
	3-Hour	0.8014	0.79296	1.17365	1.16605	0.80513	0.79716	1.17801	1.17016	NA
	1-Hour	1.64319	1.56325	2.52011	2.49957	1.69303	1.58934	2.52692	2.51492	NA

Note: Sulfur content of fuel oil is assumed to be 0.05 percent; for modeling purposes, oil assumed to be fired for entire year.
NA= not applicable

(1) Concentrations were predicted using the ISCST3 model for 5 years (1987-1991) of meteorological data from National Weather Service station in Tampa. Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 10 g/s. Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

Table 6-5. Maximum Pollutant Concentrations Predicted at the Chassahowitzka National Wilderness Area, PSD Class I Area, for City of Lakeland- McIntosh Plant, Westinghouse 501G Combustion Turbine Project

Pollutant	Averaging Time	Maximum Impact (μg/m³)- Natural gas-Firing (1) Base Load 90 °F	Maximum Impact (μg/m³)- Natural gas-Firing (1) Base Load 30 °F	Maximum Impact (μg/m³)- Natural gas-Firing (1) 50 % Load 90 °F	Maximum Impact (μg/m³)- Natural gas-Firing (1) 50 % Load 30 °F	Maximum Impact (μg/m³)- Fuel oil-Firing (1) Base Load 90 °F	Maximum Impact (μg/m³)- Fuel oil-Firing (1) Base Load 30 °F	Maximum Impact (μg/m³)- Fuel oil-Firing (1) 50 % Load 90 °F	Maximum Impact (μg/m³)- Fuel oil-Firing (1) 50 % Load 30 °F	Proposed EPA PSD Class I Significant Impact Levels (μg/m³)	Recommended NPS Class I Significant Impact Levels (μg/m³)
Specific Pollutant Impacts											
PM	Annual	0.0003	0.0003	0.0003	0.0003	0.0037	0.0038	0.0073	0.0074	0.2	0.08
	24-Hour	0.0057	0.0058	0.0059	0.0059	0.0609	0.0622	0.125	0.126	0.3	0.27
SO2	Annual	0.0003	0.0003	0.0002	0.0002	0.0048	0.0050	0.0037	0.0040	0.1	0.03
	24-Hour	0.0042	0.0046	0.0035	0.0038	0.080	0.082	0.063	0.068	0.2	0.07
	3-Hour	0.0260	0.0283	0.0198	0.0217	0.49	0.51	0.35	0.38	1	0.48
NO2	Annual	0.0088	0.0095	0.0129	0.0150	0.0157	0.0170	0.0225	0.0243	0.1	0.03
Modeled Impacts											
10 g/s	Annual	0.00319	0.00304	0.00424	0.00414	0.00326	0.00311	0.0043	0.00419	NA	NA
	24-Hour	0.05284	0.05047	0.07242	0.07046	0.0541	0.05154	0.07347	0.07148	NA	NA
	8-Hour	0.17605	0.16824	0.22346	0.21885	0.17925	0.17179	0.22579	0.22115	NA	NA
	3-Hour	0.32408	0.31102	0.40449	0.39714	0.32975	0.31734	0.40846	0.40109	NA	NA
	1-Hour	0.55045	0.52473	0.7125	0.69727	0.56114	0.53659	0.72087	0.70555	NA	NA

Note: Sulfur content of fuel oil is assumed to be 0.05 percent; for modeling purposes, oil assumed to be fired for entire year.
NA= not applicable

(1) Concentrations were predicted using the ISCST3 model for 5 years (1987-1991) of meteorological data from National Weather Service station in Tampa. Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 10 g/s. Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

Table 6-6. Maximum Impacts of HAPs and Air Toxic Pollutants for the Proposed 501G Gas Turbine

Pollutant	Emission Rates (1) Maximum (lb/hr)	Emission Rates (1) Annual (TPY)	Maximum Predicted Concentrations (µg/m³) (2) 8-Hour Impact	8-Hour Florida ARC	24-Hour Impact	24-Hour Florida ARC	Annual Impact	Annual Florida ARC	Impact / Florida ARC 8-Hour	Impact / Florida ARC 24-Hour	Impact / Florida ARC Annual	Predicted Impact Complies With Florida ARC?
Antimony	8.62E-02	1.08E-02	3.42E-04	5	1.69E-04	1.2	3.54E-07	0.3	6.84E-05	1.40E-04	1.18E-06	Yes
Arsenic	1.03E-02	1.29E-03	4.10E-05	0.1	2.02E-05	0.02	4.24E-08	0.00023	4.10E-04	1.01E-03	1.84E-04	Yes
Benzene	2.71E-03	3.39E-04	1.07E-05	30	5.30E-06	7	1.11E-08	0.12	3.58E-07	7.57E-07	9.26E-08	Yes
Beryllium	4.92E-04	6.15E-05	1.95E-06	0.02	9.62E-07	0.005	2.02E-09	0.00042	9.76E-05	1.92E-04	4.81E-06	Yes
Cadmium	3.20E-03	4.00E-04	1.27E-05	0.02	6.26E-06	0.005	1.31E-08	0.00056	6.35E-04	1.25E-03	2.34E-05	Yes
Chromium	9.85E-03	1.23E-03	3.91E-05	5	1.93E-05	1.2	4.04E-08	1000	7.81E-06	1.61E-05	4.04E-11	Yes
Chromium (+6)	9.85E-03	1.23E-03	3.91E-05	0.5	1.93E-05	0.1	4.04E-08	0.000083	7.81E-05	1.93E-04	4.87E-04	Yes
Cobalt	9.11E-02	1.14E-02	3.61E-04	0.5	1.78E-04	0.1	3.74E-07	NA	7.23E-04	1.78E-03	NA	Yes
Fluorine (as fluorides)	8.01E-02	1.00E-02	3.18E-04	25	1.57E-04	6	3.29E-07	NA	1.27E-05	2.61E-05	NA	Yes
Formaldehyde	4.92E-02	6.15E-03	1.95E-04	3.7	9.62E-05	0.9	2.02E-07	0.077	5.27E-05	1.07E-04	2.62E-06	Yes
Manganese	3.20E-02	4.00E-03	1.27E-04	50	6.26E-05	12	1.31E-07	0.05	2.54E-06	5.22E-06	2.63E-06	Yes
Mercury	2.46E-03	3.08E-04	9.76E-06	0.5	4.81E-06	0.1	1.01E-08	0.3	1.95E-05	4.81E-05	3.36E-08	Yes
Nickel	4.19E-01	5.23E-02	1.66E-03	10	8.19E-04	2.4	1.72E-06	0.0042	1.66E-04	3.41E-04	4.09E-04	Yes
Phosphorus	7.39E-01	9.23E-02	2.93E-03	1	1.44E-03	0.2	3.03E-06	NA	2.93E-03	7.22E-03	NA	Yes
Selenium	4.92E-03	6.15E-04	1.95E-05	2	9.62E-06	0.5	2.02E-08	NA	9.76E-06	1.92E-05	NA	Yes
Toluene	2.44E-02	3.05E-03	9.67E-05	1880	4.77E-05	448	1.00E-07	400	5.14E-08	1.06E-07	2.50E-10	Yes

Note: Florida ARC= Florida Ambient Reference Concentrations

(1) Maximum short-term annual emission rates based on oil-firing at base load and 30 deg F; annual emission rates assumed hours per year of oil firing = 250

(2) Concentrations were predicted using the ISCST3 model for 5 years (1987-1991) of meteorological data from National Weather Service station in Tampa.
Highest predicted concentrations (µg/m³) for a generic emission rate of 10 g/s (79.365 lb/hr) are :

8-hour average =	0.31479
24-hour average =	0.15521
Annual average =	0.01141

Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 IMPACTS DUE TO DIRECT GROWTH

The proposed project is being constructed to meet current electric demands. Additional growth as a direct result of the additional electric power provided by the project is not expected. The project will be constructed and operated with minimum labor and associated facilities and is not expected to significantly affect growth in the area. As a result, air pollution impacts from additional growth are not anticipated.

7.2 IMPACT ON SOILS, VEGETATION AND WILDLIFE

Because the proposed project's impacts on the local and CNWA air quality are predicted to be less than the significant impact levels for PSD Class II areas and less than the proposed EPA and recommended NPS significant impact levels for PSD Class I areas, the project's impacts on soils, vegetation, and wildlife are also not expected to be significant.

7.3 IMPACTS UPON VISIBILITY

A Level I visibility screening analysis was conducted at the CWNA following the procedures outlined in "Workbook for Estimating Visibility Impairment" (EPA, 1980). The CNWR is located approximately 91 km northwest of the proposed plant site. The Level I screening analysis is designed to provide a conservative estimate (i.e., impacts higher than expected) of plume visual impacts. The EPA model, VISCREEN, was used for this analysis. PM10 and NO_x emissions used for the analysis were based upon the maximum emissions available from fuel oil firing (see Table 6-2).

Model input and output results are presented in Table 7-1. As indicated, the maximum visual impacts caused by the proposed CT will not exceed the screening criteria inside or outside the PSD Class I area. Therefore, the project will not have a significant impact upon visibility of the CWNA.

7.4 REGIONAL HAZE ANALYSIS

7.4.1 GENERAL

A regional haze analysis was conducted to determine if the proposed CT would cause a perceptible degradation in visibility at the CNWR. Visibility is an Air Quality Related Value

(AQRV) at the CNWR. The visibility of an area is generally characterized by either its visual range, V_r (i.e., the greatest distance that a dark object can be seen) or its extinction coefficient, b_{ext} (i.e., the attenuation of light over a distance due to particle scattering and/or gaseous absorption). The visual range and extinction coefficient are related to one another by the following equation:

$$b_{ext} = 3.912 / V_r \quad (km^{-1}) \quad (1)$$

The NPS in coordination with the Fish and Wildlife Service (FWS) uses the Deciview index (NPS, 1992), d_v, to describe an area's change in extinction coefficient. The deciview is defined as:

$$d_v = 10 \ln (b_{ext}/0.01) \qquad (2)$$

where ln represents the natural logarithm of the quantity in parentheses. A change in an area's deciview (NPS, 1995), d_v, of 1 corresponds to an approximate 10 percent changed in extinction, which is considered as a noticeable change in regional haze. The deciview change is defined by:

$$d_v = 10 \ln (1 + b_{exts}/b_{extb}) \quad (3)$$

where b_{exts} and b_{extb} represent the extinction coefficients due to the source (i.e., the proposed project) and for the CNWR background visual range, respectively. Based on recent communications with the NPS, the background visual range for the CNWR is 65 km based on air monitoring data (USFWS, 1995).

7.4.2 CALCULATION OF SOURCE EXTINCTION

The source extinction due to the proposed CT is calculated according to interim recommendations that are provided in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report, Appendix B. The report states that the primary sources of regional visibility degradation are mostly fine particles with diameters of 2.5 m, ammonium bi-sulfate [$(NH_4)_2SO_4$] and ammonium nitrate (NH_4NO_3). The procedures for determining the ambient concentration levels of these compounds due to the proposed project are to:

1. Obtain the maximum hourly sulfur dioxide (SO_2), nitrogen oxides (NO_x), and sulfuric acid (H_2SO_4) mist impacts due to the proposed project from air quality dispersion models such as the ISCST3 or the MESOPUFF II model. For the present analysis, the maximum impacts were provided from the ISCST3 model, a steady state model that was used for the modeling analysis for the PSD increments. Based on verbal communications with Bud Rolofson of the NPS (Golder, 1995), the NPS had changed it's policy of using the hourly maximum impacts to using the highest 24-hour impacts for these pollutants. The maximum 24-hour average impacts are based on the highest predicted concentrations from the ISCST3 model for the 5-year period, 1987 to 1991. The maximum 24-hour average impacts at the CNWR due to the proposed CT only are 0.086, 0.41, and 0.017 ug/m^3 for SO_2, NO_x, and H_2SO_4 mist, respectively.

2. Assume a 100 percent conversion of SO_2 to SO_4 and NO_x to NO_3. Multiplicative factors for this conversion are presented in IWAQM Inset 1, as 1.5 and 1.35, respectively, which are based on the ratios of the molecular weights of the compounds. Based on further discussions with the NPS, a 3 percent per hour conversion rate for SO_2 to SO_4 was used instead of assuming a 100 percent conversion for SO_2 to SO_4. Table 7-2 shows the hourly conversion of SO_2 to SO_4 for a maximum 24-hour average SO_2 concentration of 0.0.086 ug/m^3. For the worst-case 24-hour period, a 24-hour cumulative SO_4 concentration was calculated to be 0.0446 ug/m^3.

3. Calculate maximum concentrations of ammonium sulfate and ammonium nitrate from multiplicative factors 1.375 and 1.29, respectively, from IWAQM, Appendix B.

4. Obtain hourly values of relative humidity (RH). The maximum predicted 24-hour average impacts from the ISCST3 model occurred on December 28, 1989 from the Tampa National Weather Service Station Hourly surface observations for this day indicate an average RH of approximately 78 percent (80 percent was used in the analysis).

5. Calculate the extinction coefficients of ammonium sulfate, ammonium nitrate, and primary fine particulate. The extinction coefficients for each compound are defined by:

$$b_{exts} = 0.003\ (comp)\ f(RH)$$

where (comp) represents the ambient concentration of the compound in question, and f(RH) is the relative humidity factor. From Figure B-1 in Appendix B, a RH of 80 percent corresponds to a RH factor of 3.5. For H_2SO_4 mist (as fine particulate matter), a RH factor of unity (i.e., 1.0) was used per IWAQM recommendations. The total source extinction coefficient value is equal to the sum of the calculated extinction coefficients for each compound.

A summary of the calculations are provided in Table 7-3. The total source extinction coefficient due to the proposed project was determined to be 0.0061. From equation (3) above, the total deciview change due to the proposed project when firing fuel oil is 0.97. It should be noted that fuel oil is the backup fuel for the project. When firing natural gas, which is proposed as the primary fuel, visibility and regional haze impacts are expected to be much lower than those presented for fuel oil-firing.

Based on this analysis, the proposed project will result in less that a 10 percent decrease in visibility to the clearest days observed at the CNWR. Therefore, no adverse impacts upon regional haze is expected to occur due to the proposed CT.

Table 7-1. Visual Effects Screening Analysis for Source: City of Lakeland W501G CT Class I Area: Chassahowitzka NWA

*** Level-1 Screening ***

Input Emissions for:

Particulates	140.00	LB /HR
NOx (as NO2)	461.00	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	11.60	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	91.00 km
Min. Source-Class I Distance:	91.00 km
Max. Source-Class I Distance:	109.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10	84	91.0	84	2.00	1.380	0.05	0.009
SKY	140	84	91.0	84	2.00	0.507	0.05	0.015
TERRAIN	10	84	91.0	84	2.00	0.682	0.05	0.008
TERRAIN	140	84	91.0	84	2.00	0.145	0.05	0.006

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10	40	75.0	129	2.00	1.567	0.05	0.011
SKY	140	40	75.0	129	2.00	0.494	0.05	-0.018
TERRAIN	10	40	75.0	129	2.00	0.883	0.05	0.011
TERRAIN	140	40	75.0	129	2.00	0.210	0.05	0.008

Table 7-2. 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 oF Temperature

Pollutant	Value	Reference
Maximum Emission Rates (lb/hr)		
SO2	126.70	
NOx	433.00	
H2 SO4	19.40	
Highest Predicted 24-Hour Concentrations ($\mu g/m^3$)		
SO2	0.082	(1)
NOx	0.281	(1)
H2 SO4	0.0130	(1)
SO4	0.0638	(2)
NO3	0.3794	(3)
(NH4)2 SO4	0.0877	(4)
NH4 NO3	0.4894	(5)
Average RH (percent)	80	(6)
RH factor, f(RH)	3.5	(7)
Extinction Coefficients (km^{-1})		
Background: (bextb)	0.0602	(8)
Source: (bexts)		
(NH4)2 SO4	0.0009	(9)
NH4 NO3	0.0051	(9)
H2 SO4	0.000039	(10)
Total (bexts)	0.0061	
Deciview Change		
total delta dv =	0.9652	(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) SO4 concentrations based on 3 percent per hour conversion rate from SO2
(3) NO3 = NOx * 1.35 from IWAQM Inset No. 1
(4) (NH4)2 SO4 = SO4 times 1.375 from IWAQM Appendix B
(5) NH4 NO3 = NO3 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.
(8) bextb = 3.912 / 65 where background visual range is 65 km.
(9) values= 0.003 * compound * f(RH) from IWAQM Appendix B
(10) H2 SO4 = 0.003 * compound. f(RH) set = 1 for fine PM
(11) Delta DV = 10 * ln (1 + bexts/bextb)

Table 7-3. Hourly Conversion Rate of 24-hour Average SO_2 Concentration to SO_4 Concentration at the Chassahowitzka National Wilderness Refuge due SO_2 Emissions from the Proposed Westinghouse 501G Combustion Trurbine, City of Lakeland, McIntosh Plant

Hour	Maximum Predicted Concentration (μg/m³)	
	SO_2	SO_4
1	0.0820	0.0037
2	0.0795	0.0036
3	0.0772	0.0035
4	0.0748	0.0034
5	0.0726	0.0033
6	0.0704	0.0032
7	0.0683	0.0031
8	0.0663	0.0030
9	0.0643	0.0029
10	0.0623	0.0028
11	0.0605	0.0027
12	0.0587	0.0026
13	0.0569	0.0026
14	0.0552	0.0025
15	0.0535	0.0024
16	0.0519	0.0023
17	0.0504	0.0023
18	0.0489	0.0022
19	0.0474	0.0021
20	0.0460	0.0021
21	0.0446	0.0020
22	0.0433	0.0019
23	0.0420	0.0019
24	0.0407	0.0018
Total		0.0638

(1) Assumes hourly conversion rate of 0.03 per hour (3%)

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APPENDIX A

DESIGN INFORMATION FOR THE WESTINGHOUSE 501G COMBUSTION TURBINE

Table A-1. Design Information and Stack Parameters for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F
Combustion Turbine Performance			
Net power output (MW) (based on LHV)	223.68	249.09	264.38
Net heat rate (Btu/kWh, LHV)	9,005	8,725	8,620
(Btu/kWh, HHV)	9,995	9,685	9,565
Heat input (MMBtu/hr, LHV)	2,014	2,174	2,279
(MMBtu/hr, HHV)	2,235	2,412	2,529
Fuel heating value (Btu/lb, LHV)	20,904	20,904	20,904
(Btu/lb, HHV)	23,194	23,194	23,194
CT Exhaust Flow			
Mass Flow (lb/hr)	4,166,368	4,518,595	4,725,245
Temperature (°F)	1,128	1,095	1,080
Moisture (% Vol.)	15.35	12.44	11.38
Oxygen (% Vol.)	10.66	11.23	11.4
Molecular Weight	27.65	27.97	28.09
Fuel Usage			
Fuel usage (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	2,014	2,174	2,279
Heat content (Btu/lb, LHV)	20,904	20,904	20,904
Fuel usage (lb/hr)- calculated	96,345	103,999	109,022
(lb/hr)- provided	96,360	103,990	109,040
Stack and Exit Gas Conditions			
Stack height (ft)	85	85	85
Diameter (ft)	28	28	28
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	4,166,368	4,518,595	4,725,245
Temperature (°F)	1,128	1,095	1,080
Molecular weight	27.65	27.97	28.09
Volume flow (acfm)- calculated	2,911,153	3,055,750	3,151,297
(ft3/s)- calculated	48,519	50,929	52,522
(ft3/s)- provided	48,530	50,940	52,550
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Volume flow (acfm)	2,911,153	3,055,750	3,151,297
Diameter (ft)	28	28	28
Velocity (ft/sec)- calculated	78.8	82.7	85.3
(ft/sec)- provided	78.8	82.7	85.3

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft²

Source: Westinghouse, 1997.

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

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F	Optional Annual Operating Hours 59 °F	59 °F
Hours of Operation	7008	7008	7008	6758	5758
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer					
Basis (excludes H_2SO_4), lb/hr	8.5	8.8	9.1		
Emission rate (lb/hr)- provided	8.5	8.8	9.1	8.8	8.8
(TPY)	29.8	30.8	31.9	29.7	25.3
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100					
Fuel density (lb/ft^3)	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 SO_2 /lb S (64/32)	2	2	2		
Emission rate (lb/hr)- calculated	6.4	6.9	7.2	6.9	6.9
(TPY)	22.3	24.1	25.3	23.2	19.8
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% O_2	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	800.8	682.3
(lb/hr)- vendor	220	237	249	237.0	237.0
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	713.0	607.5
(lb/hr)- vendor	190	211	222	211.0	211.0
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	33.8	28.8
(lb/hr)- vendor	9	10	10	10.0	10.0
Lead (lb/hr)= NA					
Emission Rate Basis	NA	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA	NA
(TPY)	NA	NA	NA	NA	NA

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

Source: Westinghouse, 1997; EPA, 1996

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F	Optional Annual Operating Hours 59 °F	59 °F
Hours of Operation	7,008	7,008	7,008	6,758	5,758
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0	0
(TPY)	0	0	0	0	0
Berryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0	0
(TPY)	0	0	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0	0
(TPY)	0	0	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0.000748	0.000748	0.000748		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	1.67E-06	1.80E-06	1.89E-06	1.80E-06	1.80E-06
(TPY)	5.86E-06	6.32E-06	6.63E-06	6.10E-06	5.19E-06
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)					
Fuel Usage (lb/hr)	96,360	103,990	109,040		
Sulfur Content (%)	3.30E-03	3.30E-03	3.30E-03		
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625		
Conversion to H_2SO_4 (%)	10	10	10		
Emission Rate (lb/hr)	0.97	1.05	1.10	1.05	1.05
(TPY)	3.41	3.68	3.86	3.55	3.03

Sources: EPA, 1981; Westinghouse, 1994.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F	Optional Annual Operating Hours 59 °F	59 °F
Hours of Operation	7,008	7,008	7,008	6758	5758
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0.00E+00	0.00E+00
(TPY)	0	0	0	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0.8	0.8	0.8		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	1.79E-03	1.93E-03	2.02E-03	1.93E-03	1.93E-03
(TPY)	6.27E-03	6.76E-03	7.09E-03	6.52E-03	5.56E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0.00E+00	0.00E+00
(TPY)	0	0	0	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0.00E+00	0.00E+00
(TPY)	0	0	0	0.00E+00	0.00E+00
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	34	34	34		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	7.60E-02	8.20E-02	8.60E-02	8.20E-02	8.20E-02
(TPY)	2.66E-01	2.87E-01	3.01E-01	2.77E-01	2.36E-01
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0.00E+00	0.00E+00
(TPY)	0	0	0	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0.00E+00	0.00E+00
(TPY)	0	0	0	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0.00E+00	0.00E+00
(TPY)	0	0	0	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0.00E+00	0.00E+00
(TPY)	0	0	0	0.00E+00	0.00E+00
Selinium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	0	0	0		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	0	0	0	0.00E+00	0.00E+00
(TPY)	0	0	0	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu					
Basis, lb/10^{12} Btu	10	10	10		
Heat Input Rate (MMBtu/hr)	2,235	2,412	2,529		
Emission Rate (lb/hr)	2.24E-02	2.41E-02	2.53E-02	2.41E-02	2.41E-02
(TPY)	7.83E-02	8.45E-02	8.86E-02	8.15E-02	6.94E-02

Sources: EPA,1996 (AP-42,Table 3.1-4)

Table A-5. Design Information and Stack Parameters 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
Combustion Turbine Performance			
Net power output (MW) (based on LHV)	110.99	123.77	131.47
Net heat rate (Btu/kWh, LHV)	11,090	10,620	10,400
(Btu/kWh, HHV)	12,305	11,785	11,540
Heat input (MMBtu/hr, LHV)	1,231	1,315	1,367
(MMBtu/hr, HHV)	1,366	1,459	1,517
Fuel heating value (Btu/lb, LHV)	20,904	20,904	20,904
(Btu/lb, HHV)	23,194	23,194	23,194
CT Exhaust Flow			
Mass Flow (lb/hr)	3,322,052	3,522,381	3,646,193
Temperature (°F)	984	960	944
Moisture (% Vol.)	12.68	9.68	8.61
Oxygen (% Vol.)	12.84	13.37	13.54
Molecular Weight	27.86	28.19	28.31
Fuel Usage			
Fuel usage (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,231	1,315	1,367
Heat content (Btu/lb, LHV)	20,904	20,904	20,904
Fuel usage (lb/hr)- calculated	58,888	62,907	65,394
(lb/hr)- provided	58,880	62,890	65,410
Stack and Exit Gas Conditions			
Stack height (ft)	85	85	85
Diameter (ft)	28	28	28
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	3,322,052	3,522,381	3,646,193
Temperature (°F)	984	960	944
Molecular weight	27.86	28.19	28.31
Volume flow (acfm)- calculated	2,094,759	2,158,484	2,199,524
(ft3/s)- calculated	34,913	35,975	36,659
(ft3/s)- provided	34,925	35,987	36,673
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Volume flow (acfm)	2,094,759	2,158,484	2,199,524
Diameter (ft)	28	28	28
Velocity (ft/sec)- calculated	56.7	58.4	59.5
(ft/sec)- provided	56.7	58.4	59.6

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Source: Westinghouse, 1997.

Table A-6. 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
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
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% 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
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
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
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-7. Maximum Emissions for Other Regulated PSD Pollutants for City of Lakeland- McIntosh Plant
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
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.000748	0.000748	0.000748
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	1.02177E-06	1.09133E-06	1.13472E-06
(TPY)	5.10884E-07	5.45666E-07	5.67358E-07
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (lb/hr)	58,880	62,890	65,410
Sulfur Content (%)	3.30E-03	3.30E-03	3.30E-03
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%)	10	10	10
Emission Rate (lb/hr)	0.60	0.64	0.66
(TPY)	0.30	0.32	0.33

Sources: EPA, 1981; Westinghouse, 1994.

Table A-8. Maximum Emissions for Hazardous Air Pollutants for City of Lakeland- McIntosh Plant
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
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0.0010928	0.0011672	0.0012136
(TPY)	0.0005464	0.0005836	0.0006068
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	34	34	34
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0.046444	0.049606	0.051578
(TPY)	0.023222	0.024803	0.025789
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Selinium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	10	10	10
Heat Input Rate (MMBtu/hr)	1,366	1,459	1,517
Emission Rate (lb/hr)	0.01366	0.01459	0.01517
(TPY)	0.00683	0.007295	0.007585

Source: EPA,1996 (AP-42,Table 3.1-4)

Table A-9. Design Information and Stack Parameters for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Distillate Fuel Oil, Base Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F
Combustion Turbine Performance			
Net power output (MW) (based on LHV)	215.65	241.17	256.02
Net heat rate (Btu/kWh, LHV)	9,585	9,270	9,155
(Btu/kWh, HHV)	10,065	9,740	9,615
Heat Input (MMBtu/hr, LHV)	2,067	2,236	2,344
(MMBtu/hr, HHV)	2,170	2,348	2,462
Fuel heating value (Btu/lb, LHV)	18,500	18,500	18,500
(Btu/lb, HHV)	19,430	19,430	19,430
CT Exhaust Flow			
Mass Flow (lb/hr)	4,258,331	4,624,761	4,833,896
Temperature (°F)	1,084	1,051	1,037
Moisture (% Vol.)	14.99	12.05	11.03
Oxygen (% Vol.)	10.58	11.14	11.3
Molecular Weight	27.90	28.23	28.34
Fuel Usage			
Fuel usage (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat Input (MMBtu/hr, LHV)	2,067	2,236	2,344
Heat content (Btu/lb, LHV)	18,500	18,500	18,500
Fuel usage (lb/hr)- calculated	111,730	120,865	126,703
(lb/hr)- provided	111,710	120,860	126,710
Stack and Exit Gas Conditions			
Stack height (ft)	85	85	85
Diameter (ft)	28	28	28
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	4,258,331	4,624,761	4,833,896
Temperature (°F)	1,084	1,051	1,037
Molecular weight	27.90	28.23	28.34
Volume flow (acfm)- calculated	2,866,635	3,011,513	3,105,774
(ft3/s)- calculated	47,777	50,192	51,763
(ft3/s)- provided	47,762	50,179	51,753
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Volume flow (acfm)	2,866,635	3,011,513	3,105,774
Diameter (ft)	28	28	28
Velocity (ft/sec)- calculated	77.6	81.5	84.1
(ft/sec)- provided	77.6	81.5	84.1

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Source: Westinghouse, 1997.

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

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F	Optional Annual Operating Hours 59 °F
Hours of Operation	250	250	250	200
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	89.4	92.8	95.5	
Emission rate (lb/hr)- provided	89.4	92.8	95.5	92.8
(TPY)	11.2	11.6	11.9	9.3
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO_2 /lb S)				
Fuel Oil (lb/hr)	111,730	120,865	126,703	
Sulfur content (%)	0.05	0.05	0.05	
lb SO_2 /lb S (64/32)	2	2	2	
Emission rate (lb/hr)- calculated	111.7	120.9	126.7	120.9
(TPY)	14.0	15.1	15.8	12.1
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% O_2	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	41.3
(lb/hr)- vendor	382	413	433	413.0
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	38.6
(lb/hr)- vendor	348	386	407	386.0
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	2.5
(lb/hr)- vendor	22	25	26	25.0
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) / 1,000,000 MMBtu/10E+12 Btu				
Basis, lb/10^{12} 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	0.013
(TPY)	0.001	0.002	0.002	0.001

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

Sources: Westinghouse, 1997; EPA, 1996

Table A-11. Maximum Emissions for Other Regulated PSD Pollutants for City of Lakeland- McIntosh Plant Westinghouse 501G Project, Dry Low NOx Combustor, Distillate Fuel Oil, Base Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F	Optional Annual Operating Hours 59 °F
Hours of Operation	250	250	250	200
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	4.2	4.2	4.2	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	9.11E-03	9.86E-03	1.03E-02	9.86E-03
(TPY)	1.14E-03	1.23E-03	1.29E-03	9.86E-04
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.2	0.2	0.2	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	4.34E-04	4.70E-04	4.92E-04	4.70E-04
(TPY)	5.43E-05	5.87E-05	6.16E-05	4.70E-05
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	32.54	32.54	32.54	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	7.06E-02	7.64E-02	8.01E-02	7.64E-02
(TPY)	8.83E-03	9.55E-03	1.00E-02	7.64E-03
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	1	1	1	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	2.17E-03	2.35E-03	2.46E-03	2.35E-03
(TPY)	2.71E-04	2.94E-04	3.08E-04	2.35E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (lb/hr)	111,710	120,860	126,710	
Sulfur Content (%)	0.05	0.05	0.05	
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	
Conversion to H_2SO_4 (%)	10	10	10	
Emission Rate (lb/hr)	17.11	18.51	19.40	18.51
(TPY)	2.14	2.31	2.43	1.85

Sources: EPA, 1981; Westinghouse, 1994.

Table A-12. Maximum Emissions for Hazardous Air Pollutants for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Distillate Fuel Oil, Base Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F	Optional Annual Operating Hours 59 °F
Hours of Operation	250	250	250	200
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	35	35	35	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	7.60E-02	8.22E-02	8.62E-02	8.22E-02
(TPY)	9.49E-03	1.03E-02	1.08E-02	8.22E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	1.1	1.1	1.1	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	2.39E-03	2.58E-03	2.71E-03	2.58E-03
(TPY)	2.98E-04	3.23E-04	3.39E-04	2.58E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	1.3	1.3	1.3	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	2.82E-03	3.05E-03	3.20E-03	3.05E-03
(TPY)	3.53E-04	3.82E-04	4.00E-04	3.05E-04
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	4	4	4	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	8.68E-03	9.39E-03	9.85E-03	9.39E-03
(TPY)	1.09E-03	1.17E-03	1.23E-03	9.39E-04
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	20	20	20	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	4.34E-02	4.70E-02	4.92E-02	4.70E-02
(TPY)	5.43E-03	5.87E-03	6.16E-03	4.70E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	37	37	37	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	8.03E-02	8.69E-02	9.11E-02	8.69E-02
(TPY)	1.00E-02	1.09E-02	1.14E-02	8.69E-03
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	13	13	13	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	2.82E-02	3.05E-02	3.20E-02	3.05E-02
(TPY)	3.53E-03	3.82E-03	4.00E-03	3.05E-03
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	170	170	170	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	3.69E-01	3.99E-01	4.19E-01	3.99E-01
(TPY)	4.61E-02	4.99E-02	5.23E-02	3.99E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	300	300	300	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	6.51E-01	7.04E-01	7.39E-01	7.04E-01
(TPY)	8.14E-02	8.81E-02	9.23E-02	7.04E-02
Selinium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	2	2	2	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	4.34E-03	4.70E-03	4.92E-03	4.70E-03
(TPY)	5.43E-04	5.87E-04	6.16E-04	4.70E-04
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	9.9	9.9	9.9	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	2.15E-02	2.32E-02	2.44E-02	2.32E-02
(TPY)	2.69E-03	2.91E-03	3.05E-03	2.32E-03

Sources: EPA,1996 (AP-42,Table 3.1-4)

Table A-13. Maximum Emissions for Non-Regulated Air Pollutants for City of Lakeland- McIntosh Plant
Westinghouse 501G Project, Dry Low NOx Combustor, Distillate Fuel Oil, Base Load

Parameter	Base Load for Temperature 90 °F	59 °F	30 °F	Optional Annual Operating Hours 59 °F
Hours of Operation	250	250	250	200
Barium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	20	20	20	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	4.34E-02	4.70E-02	4.92E-02	4.70E-02
(TPY)	5.43E-03	5.87E-03	6.16E-03	4.70E-03
Copper (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	1300	1300	1300	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	2.82E+00	3.05E+00	3.20E+00	3.05E+00
(TPY)	3.53E-01	3.82E-01	4.00E-01	3.05E-01
Vanadium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	4.4	4.4	4.4	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	9.55E-03	1.03E-02	1.08E-02	1.03E-02
(TPY)	1.19E-03	1.29E-03	1.35E-03	1.03E-03
Zinc (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	680	680	680	
Heat Input Rate (MMBtu/hr)	2,170	2,348	2,462	
Emission Rate (lb/hr)	1.48E+00	1.60E+00	1.67E+00	1.60E+00
(TPY)	1.84E-01	2.00E-01	2.09E-01	1.60E-01

Sources: EPA,1996 (AP-42,Table 3.1-4)

Table A-14. Design Information and Stack Parameters 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
Combustion Turbine Performance			
Net power output (MW) (based on LHV)	106.95	119.79	127.27
Net heat rate (Btu/kWh, LHV)	11,675	11,140	10,915
(Btu/kWh, HHV)	12,380	11,700	11,575
Heat Input (MMBtu/hr, LHV)	1,248	1,334	1,389
(MMBtu/hr, HHV)	1,324	1,402	1,473
Fuel heating value (Btu/lb, LHV)	18,323	18,500	18,323
(Btu/lb, HHV)	19,430	19,430	19,430
CT Exhaust Flow			
Mass Flow (lb/hr)	3,363,240	3,567,013	3,695,548
Temperature (°F)	968	945	928
Moisture (% Vol.)	11.83	8.78	7.75
Oxygen (% Vol.)	12.86	13.44	13.55
Molecular Weight	28.12	28.46	28.58
Fuel Usage			
Fuel usage (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,248	1,334	1,389
Heat content (Btu/lb, LHV)	18,323	18,500	18,323
Fuel usage (lb/hr)- calculated	68,111	72,108	75,806
(lb/hr)- provided	68,130	72,130	75,800
Stack and Exit Gas Conditions			
Stack height (ft)	85	85	85
Diameter (ft)	28	28	28
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	3,363,240	3,567,013	3,695,548
Temperature (°F)	968	945	928
Molecular weight	28.12	28.46	28.58
Volume flow (acfm)- calculated	2,077,593	2,142,441	2,183,474
(ft3/s)- calculated	34,627	35,707	36,391
(ft3/s)- provided	34,630	35,708	36,396
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Volume flow (acfm)	2,077,593	2,142,441	2,183,474
Diameter (ft)	28	28	28
Velocity (ft/sec)- calculated	56.2	58.0	59.1
(ft/sec)- provided	56.2	58.0	59.1

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Source: Westinghouse, 1997.

Table A-15. 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 H_2SO_4), 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 SO_2 /lb S)			
Fuel Oil (lb/hr)	68,111	72,108	75,806
Sulfur content (%)	0.05	0.05	0.05
lb SO_2 /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
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% O_2	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
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
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
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) / 1,000,000 MMBtu/10E+12 Btu			
Basis, lb/10^{12} 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)	0.0002	0.0002	0.0002

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

Table A-16. Maximum Emissions for Other Regulated PSD 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
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	4.2	4.2	4.2
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	5.56E-03	5.89E-03	6.19E-03
(TPY)	1.39E-04	1.47E-04	1.55E-04
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.2	0.2	0.2
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	2.65E-04	2.80E-04	2.95E-04
(TPY)	6.62E-06	7.01E-06	7.37E-06
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	4.31E-02	4.56E-02	4.79E-02
(TPY)	1.08E-03	1.14E-03	1.20E-03
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1	1	1
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	1.32E-03	1.40E-03	1.47E-03
(TPY)	3.31E-05	3.51E-05	3.68E-05
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (lb/hr)	68,130	72,130	75,800
Sulfur Content (%)	0.05	0.05	0.05
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%)	10	10	10
Emission Rate (lb/hr)	10.43	11.04	11.61
(TPY)	0.26	0.28	0.29

Sources: EPA, 1981; Westinghouse, 1994.

Table A-17. Maximum Emissions for Hazardous Air 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
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	35	35	35
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	4.63E-02	4.91E-02	5.16E-02
(TPY)	1.16E-03	1.23E-03	1.29E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	1.46E-03	1.54E-03	1.62E-03
(TPY)	3.64E-05	3.86E-05	4.05E-05
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.3	1.3	1.3
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	1.72E-03	1.82E-03	1.91E-03
(TPY)	4.30E-05	4.56E-05	4.79E-05
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	4	4	4
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	5.30E-03	5.61E-03	5.89E-03
(TPY)	1.32E-04	1.40E-04	1.47E-04
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	20	20	20
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	2.65E-02	2.80E-02	2.95E-02
(TPY)	6.62E-04	7.01E-04	7.37E-04
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	4.90E-02	5.19E-02	5.45E-02
(TPY)	1.22E-03	1.30E-03	1.36E-03
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	13	13	13
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	1.72E-02	1.82E-02	1.91E-02
(TPY)	4.30E-04	4.56E-04	4.79E-04
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	170	170	170
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	2.25E-01	2.38E-01	2.50E-01
(TPY)	5.63E-03	5.96E-03	6.26E-03
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	300	300	300
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	3.97E-01	4.21E-01	4.42E-01
(TPY)	9.93E-03	1.05E-02	1.10E-02
Selinium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	2	2	2
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	2.65E-03	2.80E-03	2.95E-03
(TPY)	6.62E-05	7.01E-05	7.37E-05
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	9.9	9.9	9.9
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	1.31E-02	1.39E-02	1.46E-02
(TPY)	3.28E-04	3.47E-04	3.65E-04

Sources: EPA,1996 (AP-42,Table 3.1-4)

Table A-18. Maximum Emissions for Non-Regulated Air 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
Barium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	20	20	20
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	2.65E-02	2.80E-02	2.95E-02
(TPY)	6.62E-04	7.01E-04	7.37E-04
Copper (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1300	1300	1300
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	1.72E+00	1.82E+00	1.91E+00
(TPY)	4.30E-02	4.56E-02	4.79E-02
Vanadium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	4.4	4.4	4.4
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	5.83E-03	6.17E-03	6.48E-03
(TPY)	1.46E-04	1.54E-04	1.62E-04
Zinc (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	680	680	680
Heat Input Rate (MMBtu/hr)	1,324	1,402	1,473
Emission Rate (lb/hr)	9.00E-01	9.53E-01	1.00E+00
(TPY)	2.25E-02	2.38E-02	2.50E-02

Sources: EPA,1996 (AP-42,Table 3.1-4)

Fuel Analysis

Natural Gas Analysis

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft. (hhv)	
% sulfur	0.43 grains/CCF [1]	1 grain/100 CF
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data from laboratory analysis

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	0.5	0.5
% 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

Steam cooled 60 Hz W501G generates 230 MW

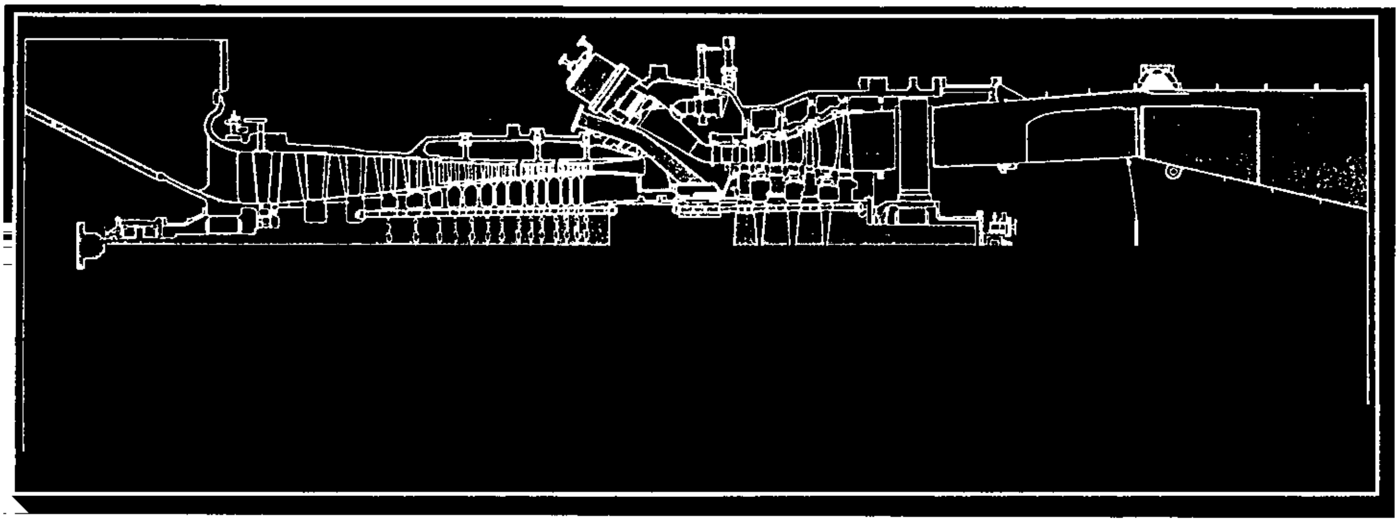

Figure 1. Sectional drawing of the new Westinghouse 501G gas turbine design

A power output of 230 MW from a 60 Hz industrial gas turbine – the Westinghouse W501G – was announced at the ASME Gas Turbine show in the Hague, Netherlands, on 14 June, 1994. With a compression ratio of 19:1, rotor inlet temperature of 1426°C, and steam cooled transition piece, the new machine gives an increase in output of 44 per cent over the previous W501F model from a machine only 4 - 5 per cent longer and costing some ten percent less than the older model.

Staff report

With a power output of some 230 MW from a 60 Hz industrial gas turbine, the 501G gas turbine announced at the ASME Gas Turbine Show in the Hague on 14 June, 1994, promises an increase in performance of more than 50 per cent over most of its current competitors without resorting to intercooling or reheat.

With a simple cycle overall net efficiency of 38.5 per cent and combined cycle efficiency of 58 per cent, the 501G shows some of the benefits of introducing aircraft engine technology, and early influences from the U.S. DOE Advanced Turbine Systems Programme, to make a quantum leap in power generation plant progress.

Many key components have already been developed and tested, and the first unit is due to be shipped to a customer of Mitsubishi in Japan in the second half of 1996. Negotiations are continuing with three potential customers in the USA.

"The 501G is a step above anything else available in the World," said Frank Bakos, President of the Westinghouse Power Generation business unit. "It was developed in collaboration with our tri-lateral technology alliance partners – Mitsubishi Heavy Industries and Fiat Avio, which gave us a real advantage in developing the new design and in compressing the product development schedule," he said.

"Rolls-Royce played an important role in the development of several components," continued Bakos, "and will continue to play a role through the manufacturing of components".

As well as a lower initial cost than the 501F, the new machine is claimed to offer lower overall maintenance costs because it has 15 per cent fewer parts exposed to high temperatures than previous designs.

Major changes

Major features of the 160 MW 501F and the 104.57 MW 501D5 are retained in the new machine. The two bearing rotor, axial exhaust, cold end drive, cannular dry low emissions combustors look very much the same.

On the other hand, the latest aero engine design codes, materials and design concepts, including directionally solidified blade materials and thermal barrier coatings have been applied.

Full three dimensional viscous flow modelling, analysis and optimisation have been carried out on compressor and turbine blading.

Compressor: The compressor is a 17 stage system, but the compression ratio has been raised from 14:1 to slightly higher than 19:1, and it has a transonic first stage.

Gas mass flow exiting the exhaust amounts to some 545 kg/s compared to 437 kg/s for the 501F. Variable inlet guide vanes are still included ahead of the compressor.

Combustors: The cannular dry low emissions combustor design looks very similar to those in the 501F, including – in the drawings shown – the substantial air bypass bleed to maintain low emissions at low power operation. There will be 16 combustor cans in the 501G and 20 in the 701G.

It will, apparently, be a three phase, parallel staged, rich-lean design dual fuel burner with remarkable emissions reduction performance on both gas and liquid fuels.

According to Westinghouse, while the variable air bypass bleed is found to be necessary in Japanese plants, for the 501F machines in Fort Lauderdale, Florida, this facility was not found to be necessary.

Rotor inlet temperature (RIT) has been fixed at 1426°C (2600°F) while maintaining 501F burner outlet temperatures. This is still fairly conservative compared to aircraft engine temperatures, but substantially high-

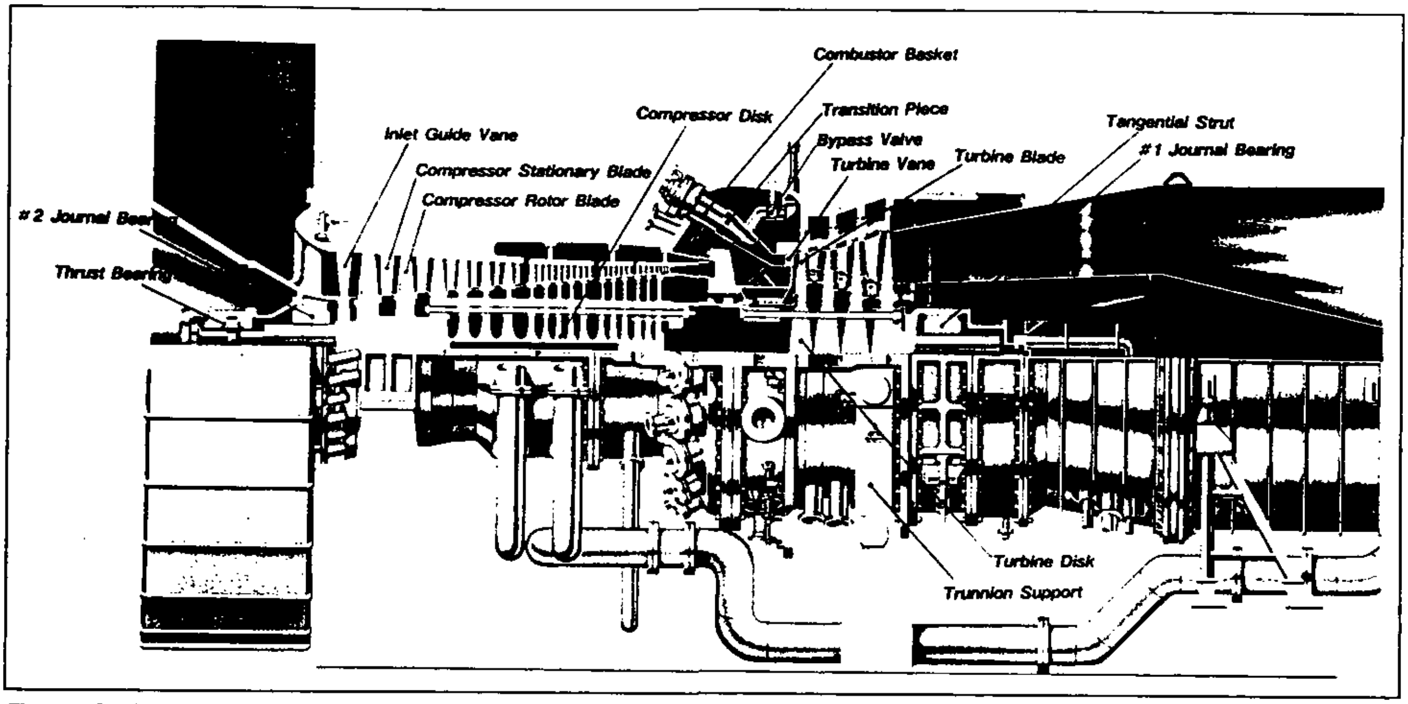

Figure 2. Section through the 701F gas turbine

[illegible]

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Fuel		Gas	Gas	Gas	Gas
Introduction	(year)	1975	1989	1996	1992
Frequency	(Hz)	60	60	60	50
Turbine speed	(r/min)	3600	3600	3600	3000
Power output	(kW)	121 300	163 530	230 000	236 700
	(bhp)	161 909	219 056	307 000	317 420
Combined cycle output[1]	(kW)	169 070	236 149	340 000	325 000
Rotor inlet temp.	(°C)	1171	1350	1426	1350
Compressor ratio		14.4	14.6	19.2	15.6
No. of compressor stages		19	16	17	17
No. of turbine stages		4	4	4	[illegible]
No. of combustor cans		19	16	16	20
Heat rate at lhv	(kJ/kWh)	10 434	9991	9347	9790
	(BTU/kWh)	9890	9470	8860	9280
	(BTU/hph)	7373	7061	6606	6919
Thermal efficiency	(%)	34.50	36.04	38.50	36.78
GTCC efficiency, net[1]	(%)	48.59	53.1	58	52.9
Exhaust flow	(kg/s)	388	449.1	545	669.5
	(kg/kWh)	11.5	9.9	8.5	10.2
	(lb/s)	855.3	990.7	1201.5	1476.0
Exhaust temperature	(°C)	538	580	593	548
	(°F)	1001	1076	1099	1018

1) Single shaft: one GT, one ST, one generator

er than most of the current competition. It is a big jump from the 1350°C of the 501F and the 1170°C of the 501D5.

NO_x levels of less than 25 ppm on natural gas, less than 42 ppm on oil, whilst maintaining CO at less than 10 ppm will be specified for the introductory machines.

Transition piece: The use of steam cooled transitions allows the lower burner temperatures for the same turbine inlet temperature since there is minimal cooling of the burned gases. NO_x generation is a function of burner temperature, thus for the same NO_x level the 501G will have a higher performance level than an air cooled transition.

Using steam cooling for the transition piece will reduce the aerodynamic and thermodynamic losses and additional compressor work involved in the use of combustion air to cool the hot path boundaries.

Turbine: Four stages of turbine, with rotor discs held together by through-bolts as indeed were the latter 15 stages of the compressor, showed sophisticated cooling technology, heat resistant design, and aircraft style tip leakage reduction.

The first two stages are to be made from directionally solidified blade material. Rolls-Royce is currently developing manufacturing techniques for the first two rows of blades, which have complex cooling passages. Only the fourth row does not require air cooling. The designers used air cooling as much as possible in this new design.

The claim is that by using advanced air cooling derived from aircraft engine technology, and by reducing the number of blades and vanes by some 15 per cent, metal temperatures can be maintained at the same or even lower than in the 501F turbines.

Largely achieved by redesigning the aerofoil shapes to produce larger and slightly longer blades according to the results of the three dimensional flow studies, the reduction in the number of blades per disc accounts for a major saving in cooling fluid flow.

Closed loop steam cooling

If the use of steam cooling for the transition piece is a stepping stone to using it for turbine blade and rotor cooling as well, the 501G could at least take a lead in establishing the viability of the technique. It is a technique that most of the major turbine

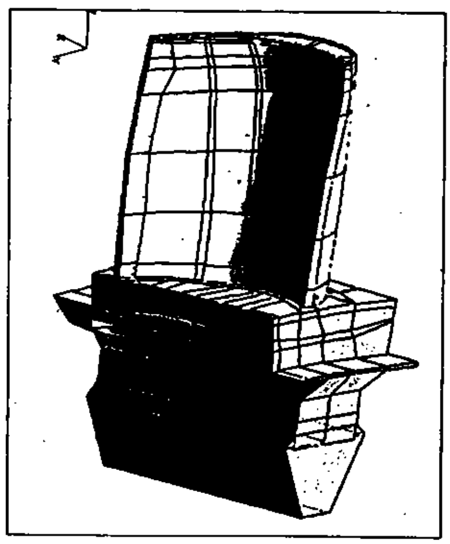

Figure 3. Row 1 turbine blade shape

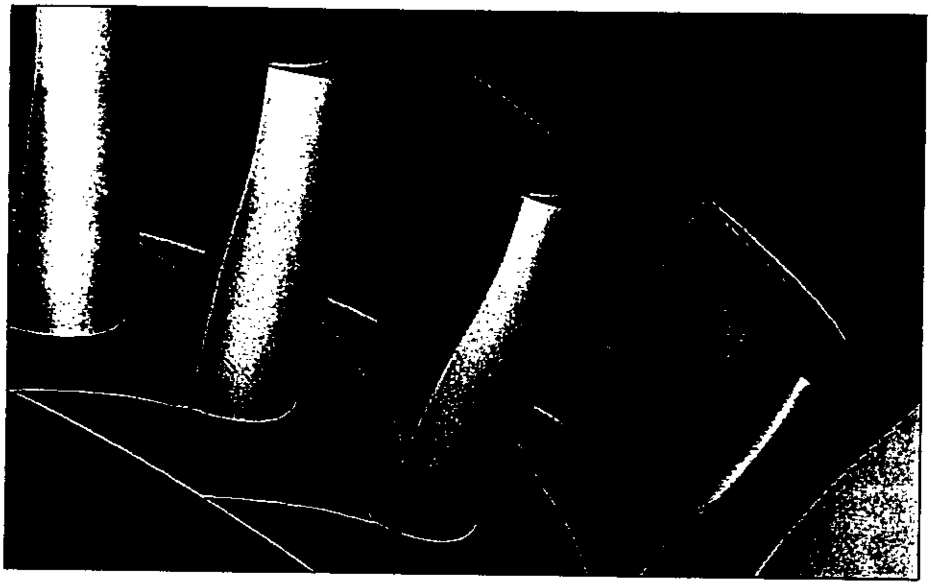

Figure 4. Three dimensional flow field for Row 1 turbine blade

manufacturers are working towards in the immediate future.

Work for the U.S. DOE ATS programme has shown, according to Ronald L. Bannister and others, that air cooling in the turbine blades is a detriment to cycle efficiency in four ways:

- It is ejected from the turbine aerofoils causing a disruption in the surrounding flow field. This increases the aerofoils' irreversible pressure losses and results in a reduction in turbine efficiency.
- Since the cooling air is ejected into the gas path, the resulting mixing of the cooling air into the gas path results in irreversible losses due to the non-ideal mixing of the streams, which have very different velocity factors.
- The reduction in gas path temperature that accompanies the mixing of the cooling air into the gas path reduces the work output of the turbine and compromises efficiency.
- The turbine cooling air must be pumped to pressures significantly higher than that of the gas path pressure at the location where it is injected. While some of this loss is recovered by the turbine, there are internal losses as the cooling air passes from the compressor to the turbine gas path.

Closed-loop steam cooling largely eliminates these loss mechanisms. Steam generated from the gas turbine exhaust gas is fed to the turbine stationary vane casing and the rotor. The steam is passed through passages within the vanes and rotor assemblies and return to the steam generator.

This approach to steam cooling relies solely on convective heat transfer since no steam or cooling fluid is ejected from the aerosols apart from a small amount of leakage through the rotor seals.

Typically the first vane cooling air mixing reduces the gas path temperature by approximately 56 to 83°C. With closed loop steam cooling the reduction in gas path temperature would only be about 6 to 8°C.

In a combined cycle system, the steam would be extracted from the exit of the high pressure steam turbine, and returned to the intermediate pressure turbine as reheat steam. Application of this approach to the ATS "baseline configuration" is reported to yield a 2 per cent increase in combined cycle efficiency.

In a simple cycle machine the steam would be supplied by a small, non-condensing, closed loop steam generator mounted in the gas turbine exhaust duct.

Turbine leakage losses generally account for a bigger efficiency penalty than excessive cooling consumption, but small improvements are less rewarding.

Combined cycle design

The impressive 58 per cent net combined cycle efficiency assumes a three pressure level waste heat recovery boiler with reheat and feed water preheat.

The concept also assumes both gas and steam turbines drive a single shaft with a single high efficiency generator converting the energy rather like the old PACE systems. This should give a massive output of around 350 MW from a very compact single shaft unit with just one gas turbine and one substantial steam turbine.

The relatively high exhaust temperature of 593°C (1100°F) with an exhaust flow of 545 kg/s (1200 lb/s) will be a major contributor to this performance.

Further development

It is interesting to see a major power generating gas turbine manufacturer apparently taking great leaps ahead in technology at a time when growing commercial competition in the utility business is demanding increasingly conservative and well proven equipment.

It is becoming increasingly difficult to find finance for advanced technology projects.

On the other hand, the big increase in performance from the 501G is being achieved with very little that can be clearly identified as new technology.

At the same time, if we compare the 501G with the technology advances planned in the DOE ATS programme, it is even more conservatively rated than the initial baseline configuration starting point.

The ATS baseline configuration assumes a compression ratio of 18:1 and a TIT of 1593°C (2900°F) which would probably give another 10 per cent more output and 1 per cent higher efficiency than the 501G.

What is more significant is that the 501G has clearly been designed to incorporate the technology advances planned in the ATS programme, such as intercooling and reheat, humidification and chemical recuperation, as and when they are good and ready. There is a great wealth of further development potential to come in this type of turbine. □

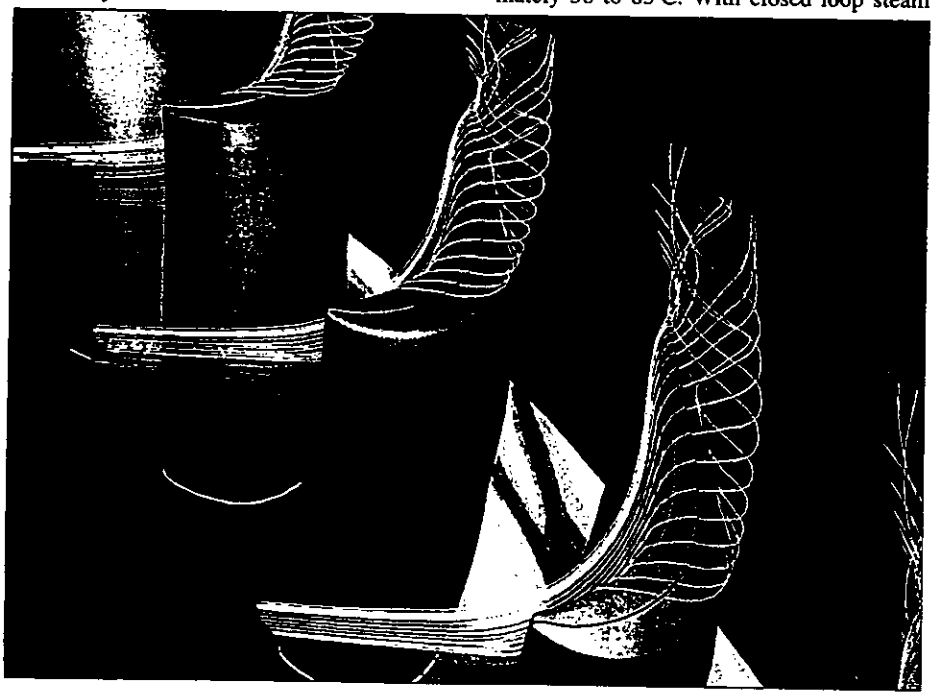

Figure 5. Particle streams — three dimensional flow field for Row 1 turbine blade

City of Lakeland - McIntosh Project

Expected 501G Combustion Turbine Performance
Simple Cycle / Dry Low NOx Combustor
97x166 (45 psi) Hydrogen Cooled Generator (0.90 PF)

CTT-1868C Rev.0
06/06/97

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3
FUEL TYPE	GAS	GAS	GAS
LOAD LEVEL	BASE	BASE	BASE
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,904	20,904	20,904
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,194	23,194	23,194
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	85%	OFF
AMBIENT TEMPERATURE, °F	90.0	59.0	30.0
AMBIENT RELATIVE HUMIDITY, %	90%	60%	60%
COMPRESSOR INLET TEMPERATURE, °F	87.5	52.5	30.0
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696
INLET PRESSURE LOSS, Inches of water (Total)	3.7	4.1	4.3
EXHAUST PRESSURE LOSS, Inches of water (Total)	9.2	10.7	11.6
EXHAUST PRESSURE LOSS, Inches of water (Static)	7.3	8.5	9.2
INJECTION FLUID	STEAM	STEAM	STEAM
INJECTION RATIO, lb Steam / lb Fuel	0.97	0.93	0.89
	PWR AUG	PWR AUG	PWR AUG
COMBUSTION TURBINE PERFORMANCE:			
NET POWER OUTPUT, kW	223,680	249,090	264,380
NET HEAT RATE, Btu/kWh (LHV)	9,005	8,725	8,620
NET HEAT RATE, Btu/kWh (HHV)	9,995	9,685	9,565
FUEL FLOW, lbm/hr	96,360	103,990	109,040
INJECTION RATE, lbm/hr	93,470	96,610	97,370
HEAT INPUT, mmBtu/hr (LHV)	2,014	2,174	2,279
HEAT INPUT, mmBtu/hr (HHV)	2,235	2,412	2,529
EXHAUST TEMPERATURE, °F	1,128	1,095	1,080
EXHAUST FLOW, lbm/hr	4,165,368	4,518,695	4,725,245
EXHAUST FLOW, MACFM	2.91	3.06	3.15
TOTAL PLANT AUXILIARY LOADS, kW	2,180	2,340	2,430
EXHAUST GAS COMPOSITION (BY % VOL):			
OXYGEN	10.66	11.23	11.40
CARBON DIOXIDE	4.03	4.06	4.09
WATER	15.35	12.44	11.38
NITROGEN	69.07	71.36	72.21
ARGON	0.87	0.90	0.91
MOLECULAR WEIGHT	27.65	27.97	28.09
NET EMISSIONS: Based on Westinghouse 21T5620 test method			
NOx, ppmvd @ 15% O2	25	25	25
NOx, lbm/hr as NO2	220	237	249
CO, ppmvd	50	50	50
CO, ppmvd @ 15% O2	36	37	37
CO, lbm/hr	190	211	222
SO2, ppmvd	1	1	1
SO2, ppmvd @ 15% O2	1	1	1
SO2, lbm/hr	2	2	2
VOC, ppmvd as CH4	4	4	4
VOC, ppmvd @ 15% O2 as CH4	3	3	3
VOC, lbm/hr as CH4	9	10	10
PARTICULATES, lbm/hr	8.5	8.8	9.1
OPACITY	<= 10%	<= 10%	<= 10%
OTSG EXHAUST STACK DATA:			
Exhaust Temperature	1,128	1,095	1,080
Exhaust Density, lb/ft^3	0.0238	0.0246	0.0250
Exhaust Volumetric Flow, ft^3/s	48530.23	50940.04	52549.59
Stack Diameter, ft	28.00	28.00	28.00
Exhaust Velocity, ft/s	78.81	82.73	85.34

NOTES:

- Performance based on new and clean condition.
- All data are expected and not guaranteed.
- Net power output is at the generator terminals minus turbine auxiliary loads.
- Exhaust volumetric flow rate is at the exit to the ECONOPAC stack.
- Transition cooling is open loop.
- Gas fuel composition is 95.492% CH_4, 2.461% C_2H_6, 0.36% C_3H_8, 0.065% iC_4H_{10}, 0.16% nC_4H_{10}, 0.009% iC_5H_{12}, 0.002% nC_5H_{12}, 0.036% C_6+, 0.454% N_2, 0.961% CO_2, and 0.2 grains of sulfur per 100 SC
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Gas fuels are heated with rotor waste heat from cooling circuit. The sensible heat of the fuel is not included in the fuel heating values, heat rate, or heat input.
- Auxiliary loads are dependent on the final plant configuration.
- Steam injection is for power augmentation and not for NO_X control.
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per EPA Method 5B (front half only) and exclude H2SO4 mist.
- Maximum gross power is 300 MW.
- Maximum exhaust temperature is 1180 °F for base and part load.

City of Lakeland - McIntosh Project

Expected 501G Combustion Turbine Performance
Simple Cycle / Dry Low NOx Combustor
97x166 (45 psi) Hydrogen Cooled Generator (0.90 PF)

CTT-1388C Rev.0
09/09/97

	CASE 1	CASE 2	CASE 3
SITE CONDITIONS:			
FUEL TYPE	GAS	GAS	GAS
LOAD LEVEL	75%	75%	75%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,904	20,904	20,904
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,194	23,194	23,194
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	85%	OFF
AMBIENT TEMPERATURE, °F	90.0	59.0	30.0
AMBIENT RELATIVE HUMIDITY, %	90%	60%	60%
COMPRESSOR INLET TEMPERATURE, °F	87.5	52.2	30.0
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696
INLET PRESSURE LOSS, Inches of water (Total)	2.5	2.6	2.7
EXHAUST PRESSURE LOSS, Inches of water (Total)	6.3	7.1	7.6
EXHAUST PRESSURE LOSS, Inches of water (Static)	5.0	5.8	6.1
INJECTION FLUID	STEAM	STEAM	STEAM
INJECTION RATIO, lb Steam / lb Fuel	0.91	0.87	0.85
	PWR AUG	PWR AUG	PWR AUG
COMBUSTION TURBINE PERFORMANCE:			
NET POWER OUTPUT, kW	167,420	186,540	198,050
NET HEAT RATE, Btu/kWh (LHV)	9,865	9,500	9,325
NET HEAT RATE, Btu/kWh (HHV)	10,950	10,540	10,350
FUEL FLOW, lbm/hr	79,030	84,770	88,370
INJECTION RATE, lbm/hr	72,150	74,060	74,720
HEAT INPUT, mmBtu/hr (LHV)	1,652	1,772	1,847
HEAT INPUT, mmBtu/hr (HHV)	1,833	1,966	2,050
EXHAUST TEMPERATURE, °F	1,180	1,160	1,141
EXHAUST FLOW, lbm/hr	3,387,856	3,602,271	3,749,369
EXHAUST FLOW, MACFM	2.44	2.54	2.60
TOTAL PLANT AUXILIARY LOADS, kW	1,830	1,950	2,010
EXHAUST GAS COMPOSITION (BY % VOL):			
OXYGEN	10.63	11.06	11.24
CARBON DIOXIDE	4.06	4.15	4.17
WATER	15.24	12.47	11.43
NITROGEN	69.18	71.41	72.23
ARGON	0.87	0.90	0.91
MOLECULAR WEIGHT	27.68	27.98	28.09
NET EMISSIONS: Based on Westinghouse 21T5620 test method			
NOx, ppmvd @ 15% O2	25	25	25
NOx, lbm/hr as NO2	180	193	201
CO, ppmvd	100	100	100
CO, ppmvd @ 15% O2	71	71	72
CO, lbm/hr	309	336	352
SO2, ppmvd	1	1	1
SO2, ppmvd @ 15% O2	1	1	1
SO2, lbm/hr	2	2	2
VOC, ppmvd as CH4	4	4	4
VOC, ppmvd @ 15% O2 as CH4	3	3	3
VOC, lbm/hr as CH4	7	8	8
PARTICULATES, lbm/hr	6.9	7.0	7.2
OPACITY	<= 10%	<= 10%	<= 10%
OTSG EXHAUST STACK DATA:			
Exhaust Temperature	1,180	1,160	1,141
Exhaust Density, lb/ft³	0.0231	0.0237	0.0240
Exhaust Volumetric Flow, ft³/s	40729.10	42297.64	43328.13
Stack Diameter, ft	28.00	28.00	28.00
Exhaust Velocity, ft/s	66.15	68.69	70.37

NOTES:
- Performance based on new and clean condition.
- All data are expected and not guaranteed.
- Net power output is at the generator terminals minus turbine auxiliary loads.
- Exhaust volumetric flow rate is at the exit to the ECONOPAC stack.
- Transition cooling is open loop.
- Gas fuel composition is 95.492% CH_4, 2.461% C_2H_6, 0.36% C_3H_8, 0.065% iC_4H_{10}, 0.18% nC_4H_{10}, 0.009% iC_5H_{12}, 0.002% nC_5H_{12}, 0.036% C_6+, 0.454% N_2, 0.981% CO_2, and 0.2 grains of sulfur per 100 SC
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Auxiliary loads are dependent on the final plant configuration.
- Steam injection is for power augmentation and not for NO_x control.
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per EPA Method 5B (front half only) and exclude H2SO4 mist.
- Maximum gross power is 300 MW.
- Maximum exhaust temperature is 1180 °F for base and part load.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.

City of Lakeland - McIntosh Project

Expected 501G Combustion Turbine Performance
Simple Cycle / Dry Low NOx Combustor
97x186 (45 psi) Hydrogen Cooled Generator (0.90 PF)

CTT-1566C Rev.0
09/09/97

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3
FUEL TYPE	GAS	GAS	GAS
LOAD LEVEL	50%	50%	50%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,904	20,904	20,904
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,194	23,194	23,194
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	85%	OFF
AMBIENT TEMPERATURE, °F	90.0	59.0	30.0
AMBIENT RELATIVE HUMIDITY, %	90%	60%	60%
COMPRESSOR INLET TEMPERATURE, °F	87.5	52.2	30.0
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696
INLET PRESSURE LOSS, inches of water (Total)	2.4	2.6	2.2
EXHAUST PRESSURE LOSS, inches of water (Total)	5.3	5.9	6.3
EXHAUST PRESSURE LOSS, inches of water (Static)	4.2	4.7	5.0
INJECTION FLUID	STEAM	STEAM	STEAM
INJECTION RATIO, lb Steam / lb Fuel	0.91	0.82	0.78
	PWR AUG	PWR AUG	PWR AUG
COMBUSTION TURBINE PERFORMANCE:			
NET POWER OUTPUT, kW	110,990	123,770	131,470
NET HEAT RATE, Btu/kWh (LHV)	11,090	10,620	10,400
NET HEAT RATE, Btu/kWh (HHV)	12,305	11,785	11,540
FUEL FLOW, lbm/hr	58,880	62,890	65,410
INJECTION RATE, lbm/hr	53,700	51,820	50,760
HEAT INPUT, mmBtu/hr (LHV)	1,231	1,315	1,367
HEAT INPUT, mmBtu/hr (HHV)	1,366	1,459	1,517
EXHAUST TEMPERATURE, °F	984	960	944
EXHAUST FLOW, lbm/hr	3,322,052	3,522,381	3,646,193
EXHAUST FLOW, MACFM	2.10	2.16	2.20
TOTAL PLANT AUXILIARY LOADS, kW	1,480	1,560	1,600
EXHAUST GAS COMPOSITION (BY % VOL):			
OXYGEN	12.84	13.37	13.54
CARBON DIOXIDE	3.11	3.17	3.20
WATER	12.68	9.69	8.61
NITROGEN	70.46	72.85	73.71
ARGON	0.88	0.91	0.93
MOLECULAR WEIGHT	27.86	28.19	28.31
NET EMISSIONS: Based on Westinghouse 21T5620 test method			
NOx, ppmvd @ 15% O2	45	45	45
NOx, lbm/hr as NO2	241	257	267
CO, ppmvd	350	350	350
CO, ppmvd @ 15% O2	333	338	339
CO, lbm/hr	1,086	1,177	1,228
SO2, ppmvd	1	1	1
SO2, ppmvd @ 15% O2	1	1	1
SO2, lbm/hr	1	1	1
VOC, ppmvd as CH4	60	60	60
VOC, ppmvd @ 15% O2 as CH4	57	58	58
VOC, lbm/hr as CH4	106	115	120
PARTICULATES, lbm/hr	6.5	6.6	6.7
OPACITY	<= 10%	<= 10%	<= 10%
OTSG EXHAUST STACK DATA:			
Exhaust Temperature	984	960	944
Exhaust Density, lb/ft^3	0.0264	0.0272	0.0276
Exhaust Volumetric Flow, ft^3/s	34924.80	35986.82	36673.43
Stack Diameter, ft	28.00	28.00	28.00
Exhaust Velocity, ft/s	58.72	58.44	59.56

NOTES:

- Performance based on new and clean condition.
- All data are expected and not guaranteed.
- Net power output is at the generator terminals minus turbine auxiliary loads.
- Exhaust volumetric flow rate is at the exit to the ECONOPAC stack.
- Transition cooling is open loop.
- Gas fuel composition is 95.492% CH_4, 2.461% C_2H_6, 0.36% C_3H_8, 0.065% iC_4H_{10}, 0.16% nC_4H_{10}, 0.009% iC_5H_{12}, 0.002% nC_5H_{12}, 0.036% C_6+, 0.454% N_2, 0.981% CO_2, and 0.2 grains of sulfur per 100 SC
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Auxiliary loads are dependent on the final plant configuration.
- Steam injection is for power augmentation and not for NO_x control.
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per EPA Method 5B (front half only) and exclude H2SO4 mist.
- Maximum gross power is 300 MW.
- Maximum exhaust temperature is 1180 °F for base and part load.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.

City of Lakeland - McIntosh Project

Expected 501G Combustion Turbine Performance
Simple Cycle / Dry Low NOx Combustor
97x166 (45 psi) Hydrogen Cooled Generator (0.90 PF)

CTT-1569C Rev.0
09/09/97

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3
FUEL TYPE	OIL	OIL	OIL
LOAD LEVEL	BASE	BASE	BASE
NET FUEL HEATING VALUE, Btu/lbm (LHV)	18,500	18,500	18,500
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	19,430	19,430	19,430
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	85%	OFF
AMBIENT TEMPERATURE, °F	90.0	59.0	30.0
AMBIENT RELATIVE HUMIDITY, %	90%	60%	60%
COMPRESSOR INLET TEMPERATURE, °F	87.7	52.2	30.0
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696
INLET PRESSURE LOSS, inches of water (Total)	3.7	4.1	4.3
EXHAUST PRESSURE LOSS, inches of water (Total)	9.2	10.6	11.5
EXHAUST PRESSURE LOSS, inches of water (Static)	7.2	8.4	9.2
INJECTION FLUID	WATER	WATER	WATER
INJECTION RATIO, lb Water / lb Fuel	0.70	0.70	0.70
INJECTION FLUID	STEAM	STEAM	STEAM
INJECTION RATIO, lb Steam / lb Fuel	0.84	0.80	0.77
	PWR AUG	PWR AUG	PWR AUG
COMBUSTION TURBINE PERFORMANCE:			
NET POWER OUTPUT, kW	215,650	241,170	256,020
NET HEAT RATE, Btu/kWh (LHV)	9,585	9,270	9,155
NET HEAT RATE, Btu/kWh (HHV)	10,065	9,740	9,615
FUEL FLOW, lbm/hr	111,710	120,860	126,710
WATER INJECTION RATE, lbm/hr	78,190	84,600	88,700
STEAM INJECTION RATE, lbm/hr	93,630	96,810	97,820
HEAT INPUT, mmBtu/hr (LHV)	2,067	2,236	2,344
HEAT INPUT, mmBtu/hr (HHV)	2,170	2,348	2,462
EXHAUST TEMPERATURE, °F	1,084	1,051	1,037
EXHAUST FLOW, lbm/hr	4,258,331	4,624,761	4,833,896
EXHAUST FLOW, MACFM	2.87	3.01	3.11
TOTAL PLANT AUXILIARY LOADS, kW	2,710	2,910	3,020
EXHAUST GAS COMPOSITION (BY % VOL):			
OXYGEN	10.58	11.14	11.30
CARBON DIOXIDE	5.42	5.47	5.51
WATER	14.99	12.05	11.03
NITROGEN	68.13	70.44	71.25
ARGON	0.86	0.88	0.89
MOLECULAR WEIGHT	27.91	28.23	28.35
NET EMISSIONS: Based on Westinghouse 21T5620 test method			
NOx, ppmvd @ 15% O2	42	42	42
NOx, lbm/hr as NO2	382	413	433
CO, ppmvd	90	90	90
CO, ppmvd @ 15% O2	63	65	65
CO, lbm/hr	348	386	407
SO2, ppmvd	84	82	81
SO2, ppmvd @ 15% O2	59	59	58
SO2, lbm/hr	704	761	798
VOC, ppmvd as CH4	10	10	10
VOC, ppmvd @ 15% O2 as CH4	7	7	7
VOC, lbm/hr as CH4	22	25	26
PARTICULATES, lbm/hr	89.4	92.8	95.5
OPACITY	<= 20%	<= 20%	<= 20%
OTSG EXHAUST STACK DATA:			
Exhaust Temperature	1,084	1,051	1,037
Exhaust Density, lb/ft^3	0.0248	0.0256	0.0259
Exhaust Volumetric Flow, ft^3/s	47761.70	50178.71	51752.77
Stack Diameter, ft	28.00	28.00	28.00
Exhaust Velocity, ft/s	77.57	81.49	84.05

NOTES:
- Performance based on new and clean condition.
- All data are expected and not guaranteed.
- Net power output is at the generator terminals minus turbine auxiliary loads.
- Exhaust volumetric flow rate is at the exit to the ECONOPAC stack.
- Transition cooling is open loop.
- Oil fuel composition is 87.2% C, 12.5% H, 0.3% S, 0.015% FBN.
- Auxiliary loads are dependent on the final plant configuration.
- Dry Low NO_x injection ratios are estimated. Actual injection will be set at the minimum required to reach specified NO_x levels. Performance will be adjusted according
- Steam injection is for power augmentation and not for NO_x control.
- Particulates are per EPA Method 5B (front half only) and exclude H2SO4 mist.
- Particulates for oil fuel are based on specific gravity and may vary depending on fuel.
- Maximum gross power is 300 MW.

CTPerf.xls

City of Lakeland - McIntosh Project

Expected 501G Combustion Turbine Performance
Simple Cycle / Dry Low NOx Combustor
97x156 (45 psi) Hydrogen Cooled Generator (0.90 PF)

CTT-1568C Rev.0
06/09/97

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3
FUEL TYPE	OIL	OIL	OIL
LOAD LEVEL	75%	75%	75%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	18,500	18,500	18,500
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	19,430	19,430	19,430
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	85%	OFF
AMBIENT TEMPERATURE, °F	90.0	59.0	30.0
AMBIENT RELATIVE HUMIDITY, %	90%	60%	60%
COMPRESSOR INLET TEMPERATURE, °F	87.7	52.4	30.0
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696
INLET PRESSURE LOSS, inches of water (Total)	2.4	2.7	2.7
EXHAUST PRESSURE LOSS, inches of water (Total)	6.2	7.1	7.8
EXHAUST PRESSURE LOSS, inches of water (Static)	4.9	5.6	6.0
INJECTION FLUID	WATER	WATER	WATER
INJECTION RATIO, lb Water / lb Fuel	0.70	0.70	0.70
INJECTION FLUID	STEAM	STEAM	STEAM
INJECTION RATIO, lb Steam / lb Fuel	0.79	0.76	0.74
	PWR AUG	PWR AUG	PWR AUG
COMBUSTION TURBINE PERFORMANCE:			
NET POWER OUTPUT, kW	161,350	180,550	191,720
NET HEAT RATE, Btu/kWh (LHV)	10,425	10,015	9,820
NET HEAT RATE, Btu/kWh (HHV)	10,950	10,520	10,315
FUEL FLOW, lbm/hr	90,920	97,750	101,770
WATER INJECTION RATE, lbm/hr	63,650	68,420	71,240
STEAM INJECTION RATE, lbm/hr	72,010	74,290	74,900
HEAT INPUT, mmBtu/hr (LHV)	1,682	1,808	1,883
HEAT INPUT, mmBtu/hr (HHV)	1,767	1,899	1,977
EXHAUST TEMPERATURE, °F	1,150	1,113	1,095
EXHAUST FLOW, lbm/hr	3,424,973	3,698,460	3,842,227
EXHAUST FLOW, MACFM	2.40	2.51	2.56
TOTAL PLANT AUXILIARY LOADS, kW	2,260	2,410	2,500
EXHAUST GAS COMPOSITION (BY % VOL):			
OXYGEN	10.50	11.07	11.24
CARBON DIOXIDE	5.49	5.53	5.56
WATER	14.94	12.02	10.99
NITROGEN	68.20	70.49	71.30
ARGON	0.86	0.89	0.90
MOLECULAR WEIGHT	27.92	28.25	28.36
NET EMISSIONS: Based on Westinghouse 21T5620 test method			
NOx, ppmvd @ 15% O2	42	42	42
NOx, lbm/hr as NO2	311	334	348
CO, ppmvd	125	125	125
CO, ppmvd @ 15% O2	86	89	89
CO, lbm/hr	389	429	449
SO2, ppmvd	85	83	82
SO2, ppmvd @ 15% O2	59	59	58
SO2, lbm/hr	573	616	641
VOC, ppmvd as CH4	30	30	30
VOC, ppmvd @ 15% O2 as CH4	21	21	21
VOC, lbm/hr as CH4	53	59	62
PARTICULATES, lbm/hr	95.8	98.8	101.1
OPACITY	<= 20%	<= 20%	<= 20%
OTSG EXHAUST STACK DATA:			
Exhaust Temperature	1,150	1,113	1,095
Exhaust Density, lb/ft³	0.0238	0.0246	0.0250
Exhaust Volumetric Flow, ft³/s	40050.38	41781.44	42715.67
Stack Diameter, ft	28.00	28.00	28.00
Exhaust Velocity, ft/s	65.04	67.85	69.37

NOTES:

- Performance based on new and clean condition.
- All data are expected and not guaranteed.
- Net power output is at the generator terminals minus turbine auxiliary loads.
- Exhaust volumetric flow rate is at the exit to the ECONOPAC stack.
- Transition cooling is open loop.
- Oil fuel composition is 87.2% C, 12.5% H, 0.3% S, 0.015% FBN.
- Auxiliary loads are dependent on the final plant configuration.
- Dry Low NO_x injection ratios are estimated. Actual injection will be set at the minimum required to reach specified NO_x levels. Performance will be adjusted according
- Steam injection is for power augmentation and not for NO_x control.
- Particulates are per EPA Method 5B (front half only) and exclude H2SO4 mist.
- Particulates for oil fuel are based on specific gravity and may vary depending on fuel.
- Maximum gross power is 300 MW.

CTPerf5.xls

City of Lakeland - McIntosh Project

Expected 501G Combustion Turbine Performance
Simple Cycle / Dry Low NOx Combustor
97x156 (45 psi) Hydrogen Cooled Generator (0.90 PF)

CTT-1568C Rev.0
09/09/97

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3
FUEL TYPE	OIL	OIL	OIL
LOAD LEVEL	50%	50%	50%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	18,323	18,500	18,323
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	19,430	19,430	19,430
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	85%	OFF
AMBIENT TEMPERATURE, °F	90.0	59.0	30.0
AMBIENT RELATIVE HUMIDITY, %	90%	60%	60%
COMPRESSOR INLET TEMPERATURE, °F	87.7	52.4	30.0
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696
INLET PRESSURE LOSS, inches of water (Total)	2.4	2.6	2.2
EXHAUST PRESSURE LOSS, inches of water (Total)	5.3	5.9	6.3
EXHAUST PRESSURE LOSS, inches of water (Static)	4.2	4.7	5.0
INJECTION FLUID	WATER	WATER	WATER
INJECTION RATIO, lb Water / lb Fuel	0.50	0.50	0.50
INJECTION FLUID	STEAM	STEAM	STEAM
INJECTION RATIO, lb Steam / lb Fuel	0.78	0.72	0.67
	PWR AUG	PWR AUG	PWR AUG
COMBUSTION TURBINE PERFORMANCE:			
NET POWER OUTPUT, kW	108,950	119,790	127,270
NET HEAT RATE, Btu/kWh (LHV)	11,675	11,140	10,915
NET HEAT RATE, Btu/kWh (HHV)	12,380	11,700	11,575
FUEL FLOW, lbm/hr	68,130	72,130	75,800
WATER INJECTION RATE, lbm/hr	34,070	36,070	37,900
STEAM INJECTION RATE, lbm/hr	52,940	52,010	51,090
HEAT INPUT, mmBtu/hr (LHV)	1,248	1,334	1,389
HEAT INPUT, mmBtu/hr (HHV)	1,324	1,402	1,473
EXHAUST TEMPERATURE, °F	968	945	928
EXHAUST FLOW, lbm/hr	3,363,240	3,567,013	3,695,548
EXHAUST FLOW, MACFM	2.08	2.14	2.18
TOTAL PLANT AUXILIARY LOADS, kW	1,750	1,840	1,900
EXHAUST GAS COMPOSITION (BY % VOL):			
OXYGEN	12.86	13.44	13.55
CARBON DIOXIDE	4.22	4.26	4.34
WATER	11.83	8.78	7.75
NITROGEN	70.20	72.59	73.42
ARGON	0.88	0.91	0.92
MOLECULAR WEIGHT	28.13	28.48	28.58
NET EMISSIONS: Based on Westinghouse 21T5620 test method			
NOx, ppmvd @ 15% O2	75	75	75
NOx, lbm/hr as NO2	415	439	461
CO, ppmvd	350	350	350
CO, ppmvd @ 15% O2	327	335	332
CO, lbm/hr	1,100	1,193	1,244
SO2, ppmvd	63	62	62
SO2, ppmvd @ 15% O2	59	59	59
SO2, lbm/hr	429	454	478
VOC, ppmvd as CH4	100	100	100
VOC, ppmvd @ 15% O2 as CH4	93	96	95
VOC, lbm/hr as CH4	180	195	203
PARTICULATES, lbm/hr	135.1	136.9	139.6
OPACITY	<= 50%	<= 50%	<= 50%
OTSG EXHAUST STACK DATA:			
Exhaust Temperature	968	945	928
Exhaust Density, lb/ft³	0.0270	0.0277	0.0282
Exhaust Volumetric Flow, ft³/s	34630.32	35707.73	36396.39
Stack Diameter, ft	28.00	28.00	28.00
Exhaust Velocity, ft/s	56.24	57.99	59.11

NOTES:
- Performance based on new and clean condition.
- All data are expected and not guaranteed.
- Net power output is at the generator terminals minus turbine auxiliary loads.
- Exhaust volumetric flow rate is at the exit to the ECONOPAC stack.
- Transition cooling is open loop.
- Oil fuel composition is 87.2% C, 12.5% H, 0.3% S, 0.015% FBN.
- Auxiliary loads are dependent on the final plant configuration.
- Dry Low NO_x injection ratios are estimated. Actual injection will be set at the minimum required to reach specified NO_x levels. Performance will be adjusted according
- Steam injection is for power augmentation and not for NO_x control.
- Particulates are per EPA Method 5B (front half only) and exclude H2SO4 mist.
- Particulates for oil fuel are based on specific gravity and may vary depending on fuel.
- Maximum gross power is 300 MW.

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501G APPLICATION OVERVIEW

501G Application Overview

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1. Introduction

The 501G ECONOPAC™, nominally rated at 230 MW, is a self-contained, 60-Hz electric power generating system. The design of the ECONOPAC has evolved from over 45-years experience in combustion turbine technology, including virtually all applications. From this background and from a sensitivity to the changing needs of our users, Westinghouse has developed a responsive design philosophy. Westinghouse can supply all equipment and services necessary for an operable power generation plant that will meet your requirements.

The 230-MW 501G is the world's largest, most efficient 60-Hz industrial combustion turbine at 38.5% net simple cycle efficiency. Even at part load, power and efficiency are better than *any* 'F' technology combustion turbine at the 'F' baseload turbine inlet temperatures.

Raising technology to a new level, the 501G represents the latest in the evolutionary cycle that continues a long line of large single-shaft, heavy duty combustion turbines. The 501G engine consists of a 17-stage axial-flow compressor, a combustion chamber equipped with 16 combustors, and a 4-stage reaction-type turbine.

The 501G is a product of Westinghouse's Trilateral Alliance with Mitsubishi Heavy Industries and FiatAvio -- with aero technology infusion from our Rolls-Royce alliance. The 501G will be manufactured in the U.S. by Westinghouse and in Japan by MHI. Deliveries begin in 1996.

The 501G advantage:

- Most efficient combined cycle
- Large power density
- Lower life cycle cost
- Low cost of electricity

- Time-proven, fundamental design concepts
- Advanced aero-engine technology

For the baseload market, the 501G revolutionizes heat recovery applications with expected combined cycle efficiency of over 58% net (60% gross), depending on the steam bottoming cycle chosen. It is also the economic choice for intermediate duty and peaking applications.

The 501G can operate on conventional combustion turbine fuels and a wide range of other fuels. The 501G incorporates the latest in dry low emission combustion technologies to maintain low NO_X, CO, and other emissions without water or steam injection on natural gas. Initially NO_X levels less than 25 ppm will be achieved on natural gas without injection, and less than 42 ppm on distillate oil with water injection for dual-fuel capability.

With its high efficiency and low capital cost, the 501G is ideal for synthetic or coal gas applications, and with completion of the base design, a program is in hand to enable these options to be offered. Additional programs also will allow steam injection for power augmentation to be offered.

Minimizing life cycle costs was an important objective in the design of the 501G. Complementing its low capital cost and low fuel consumption, the 501G has 15 percent fewer hot parts than the 501F, which results in lower maintenance costs. The end result is an unprecedented low cost of electricity -- less than 90% of current technology values.

2. Background

WESTINGHOUSE : A LONG HISTORY OF COMBUSTION TURBINE EXPERTISE

Westinghouse has a long and proud history in the combustion turbine business. We were called upon during World War II to be the Navy's contractor for the development and deployment of the first U.S. designed and manufactured aviation jet engines. This led to our introduction of the first industrial use of combustion turbines in a 2000-hp gas compressor application in 1948.

Our first utility unit, rated at 5,000 kW, was installed for West Texas Utilities in 1952. Since then, there have been many more firsts for Westinghouse combustion turbines. And approximately 1,500 units using Westinghouse technology have been sold by Westinghouse and our family of international affiliates.

The first unit in the 501 series was delivered in 1968. Since then nearly 300 of the 501 units have been sold. The state-of-the-art 501G is the latest in the series. Its heritage derives directly from the Westinghouse 501F and 501D5.

PROVEN TECHNOLOGY FOR DESIGNED-IN RELIABILITY AND LOW LIFE CYCLE COSTS

Designed for reliability and ease of maintenance, the 501G shares the same features that have been well-proven through experience in other Westinghouse combustion turbine models:

- Two-bearing rotor
- Horizontally split casings
- Cold-end generator drive
- Axial exhaust
- Access to critical hot-parts without cover lift
- All flow path components removable without rotor lift
- Roomy walk-around enclosures for turbine and auxiliary packages

- Powerlogic II microprocessor-based unit control, utilizing the highly successful WDPF control system technology

PROJECT CAPABILITIES COMES FROM EXPERIENCE

Westinghouse is experienced in every facet of putting together a successful power project. Our capabilities include:

- Project development
- Total turnkey power plants
- Plant permitting and feasibility studies
- Equipment installation
- Integrated project management
- Plant operation and maintenance

When Westinghouse takes responsibility for your plant, or any portion of it, we take an integrated project management approach to the work at hand. Westinghouse employs the most advanced planning techniques in the industry. Project goals are clearly developed and well communicated. Work packages are created, which include everything from the drawings, to material lists, to sign-off sheets. Personal accountability means a personal commitment to quality. Westinghouse has an impressive record for building reliable plants, and finishing them on schedule and within budget.

TOTAL SERVICE FOR HIGH AVAILABILITY AND LOW OPERATING COSTS

As a major customer commitment, Westinghouse offers a Total Service program for our combustion turbine units. Starting with the technical direction provided during the installation and start-up of your equipment, we work on a continual cooperative effort to ensure that all service needs are met. Whether dealing with a planned inspection outage, or an emergency requiring the quick attention to return the unit to service, Westinghouse is well-equipped, experienced and on-call around the clock, 365 days a year. At your call are expert troubleshooters, field service engineers and well-stocked warehouses, from which critical components can usually be shipped in less than 24 hours to meet emergency needs.

Total Service also means that we pay close attention to trends observed from data provided to us by users of similar units. We analyze this information on a continuing basis, and provide timely reports to all customers. Westinghouse, moreover, regularly provides information related to relevant design improvements and upgrades, as well as notices regarding inspection and maintenance activities. Pre-outage planning is a standard feature of Westinghouse Total Service. Site Operational Audit Reports, prepared by uniquely qualified experts, are also available.

A PROUD TRADITION

Westinghouse is proud of its accomplishments as a leader in the field of combustion turbine technology, project development and management, manufacturing and after-sales service. The 501G is our latest achievement, and we are particularly proud to bring this state-of-the-art combustion turbine to the power generation marketplace for 60-Hz projects worldwide. Regardless of the application, the 501G ECONOPAC is the basic building block for a wide variety of highly efficient, economical power generation systems.

3. 501G Combustion Turbine Summary

Recognized as the heart of the ECONOPAC plant, the 501G combustion turbine consists of three basic elements: axial-flow compressor, combustion system, and turbine. These three elements are combined into a single assembly that ships complete with rotor in place, thereby facilitating field erection. Incorporated into the design are such proven features as a horizontally split and sectionalized casings, two-bearing rotor support, turbine air cooling system, compensating alignment system, and axial-flow exhaust.

COMPRESSOR SECTION

The axial-flow compressor has 17 stages with advanced profile airfoils and a 19.2-to-1 pressure ratio. A single variable inlet guide vane (VIGV) assembly is used for starting to avoid compressor surge, together with opening the compressor bleed valves. The VIGV is also modulated close to improve combined-cycle part load efficiency. The compressor rotor is a bolted construction.

COMBUSTION SECTION

The 501G incorporates 16 dual-fuel dry low NO_X combustors based on the 501F design, with the following initial emission levels less than the following:

	Natural Gas (no injection)	Distillate Oil (water injection)
NO_X, ppm	25	42
CO, ppm	10	90
UHC, ppm	5	20

STEAM-COOLED TRANSITIONS

The transitions, one for each combustor, allow the hot gases to pass from the combustors to the turbine blade path. The transitions are steam cooled to make more air available for primary combustion. During the starting cycle, however, steam is not required until the power output reaches 40% baseload. In combined cycle, the steam is provided by the heat recovery steam generator and can be returned to the intermediate pressure section of the steam turbine. In simple cycle, the steam can be either provided by a packaged boiler or raised by the exhaust energy using a simplified heat recovery system. In each application, steam cooling can be either closed or open loop depending on water costs and application needs. In open cycle, the steam would provide the option for power augmentation.

TURBINE SECTION

The 501G turbine follows previous 501 designs, with curvic clutched discs to transmit torque and a 4-stage turbine to optimize efficiency. The first three stages are air cooled. The latest aero-engine viscous-flow codes were used for the 3-D design of the airfoils. The turbine uses proven aeroderivative advanced materials including directionally solidified castings for the first two turbine rows and the latest development of electron-beam vapor-deposited thermal barrier coatings.

REDUCED HOT PARTS

To lower life cycle costs, the number of critical hot parts has been reduced by over 15% compared to the 501F as shown below:

	501F	501G
Row 1 Vane	32	32
Row 1 Blade	72	54
Row 2 Vane	48	36
Row 2 Blade	66	50
Row 3 Vane	48	42
Row 3 Blade	112	101
Row 4 Vane	56	42
Row 4 Blade	100	90
Total	534	447

4. ECONOPAC Equipment Summary

ECONOPAC SYSTEM

The Westinghouse 501G ECONOPAC is designed and engineered to provide the user with a complete generating system. All components and subsystems are carefully selected and optimized to form a compact plant, housed within enclosures, designed to comply with environmental requirements as well as showing Westinghouse's concern to be aesthetically pleasing. The 501G ECONOPAC provides a small footprint with high power density.

The 501G ECONOPAC features modular construction to facilitate shipment and assembly. The system is pre-assembled to the maximum extent permitted by shipping limitations. Where possible, subsystems are grouped and installed in auxiliary packages to minimize field assembly. These packages are completely factory assembled and wired requiring only interconnection at the site. Pipe rack assemblies are supplied eliminating the need for extensive piping fabrication during construction. Westinghouse, furthermore, provides all interconnecting materials between the standard modules.

In addition to the combustion turbine assembly previously described, the basic bill of material for each ECONOPAC system includes the following equipment and assemblies:

Generator
Static Excitation
Electrical/Control Package
Mechanical Package
Inlet System
Exhaust System
Gas Fuel System
Distillate Fuel Package
Compressor Water Wash
Pipe Packages
Fire Protection

Surge Equipment and Potential Transformer Cubicle
Auxiliary Transformer (Optional)
Isolated Phase Bus (Optional)

Generator

The hydrogen-cooled generator is equipped with integral lube oil and cooler piping, and necessary instrumentation. The design uses a shaft-mounted axial blower for circulating hydrogen through the generator. A solid coupling connects the generator directly to the compressor (the cold end of the combustion turbine).

Static Excitation and Voltage Regulator System

The static excitation and voltage regulator system functions to control the output of the AC generator by direct static excitation of the generator field. Voltage regulation is accomplished by control of thyristor power amplifiers. The excitation may be controlled either manually by a DC regulator adjuster or automatically by the AC voltage regulator in response to the generator terminal voltage.

Electrical/Control Package

The electrical/control package contains equipment necessary for sequencing, control and monitoring of the turbine and generator. This includes the Powerlogic II control system, motor control centers, generator protective relay panels, voltage regulator, fire protection system, battery, and battery charger. The batteries are in an isolated section of the package and are readily accessible from the outside.

Mechanical Package

The mechanical package houses the common lube oil system and reservoir for the combustion turbine and generator, generator seal oil system, instrument air system, and pressure switch and gage cabinet.

Distillate Fuel Package

The distillate fuel package is factory assembled with its own bedplate and enclosure, and contains the mechanical equipment to properly handle and monitor the liquid fuel.

Inlet Filtration

The inlet air filtration system has two stages of renewable pads. The first component consists of a rain louver and screen to stop leaves, birds, and trash. This is followed by a pad-type pre-filter and a final filter. Other inlet filter configurations are available.

Inlet Air and Exhaust Gas Systems

A side-inlet air duct directs flow into the compressor inlet manifold. The manifold is designed to provide an efficient flow pattern of inlet air into the axial-flow compressor. A parallel-baffle silencing configuration is located in the inlet system for sound attenuation.

After expanding through the combustion turbine, the gases pass through the exhaust transition and into the plenum of the exhaust stack. Turning vanes located in the exhaust stack efficiently direct the gases vertically. A parallel-baffle silencer section in the stack attenuates gas-borne noise. For heat recovery applications, the exhaust stack is deleted, and the gases are directed to the heat recovery steam generator.

Gas Fuel System

The main components of the gas fuel system are located on a prepackaged bedplate within the combustion turbine enclosure. A pressure switch and gage panel is provided for local monitoring of the gas system.

Water Injection

The water injection system is used for NO_X control during distillate oil use. The system includes all equipment, valves, piping and instrumentation required to control the flow of water into the combustors. All components of the system are located within the turbine enclosure.

Compressor Water Wash Package

The compressor water wash package is provided for both on-line and off-line compressor cleaning. This package incorporates the required pump, eductor for detergent injection, piping, valving, orifices, and storage tanks.

Piping Packages

Piping for the ECONOPAC is designed and manufactured to minimize field work. Each of the major plant modules is completely factory prepiped, requiring only a few field connections. This is enhanced by the supply of two factory-assembled pipe packages. The turbine pipe package, located adjacent to the combustion turbine in the turbine enclosure, contains piping and valves for the cooling air and lube oil supplies, and return drains. Also located within this package is the rotor cooling-air filter. The generator pipe package, located adjacent to the generator, contains the generator lube oil and seal oil piping.

Fire Protection System

The fire protection system gives visual indication of actuation at the local control panel located in the electrical/control package. Two subsystems are used:

1. An automatically actuated dry chemical type system for the exhaust bearing area of the turbine, consisting of temperature sensing devices, spray horns, dry chemical tank, and interconnecting piping.

2. A CO_2 fire protection system is provided for the mechanical package, turbine enclosure, and the electrical control package. Thermal detectors are provided in the enclosures. A fire in any area initiates the fire protection systems in that area only and shuts down the unit.

Auxiliary Transformers

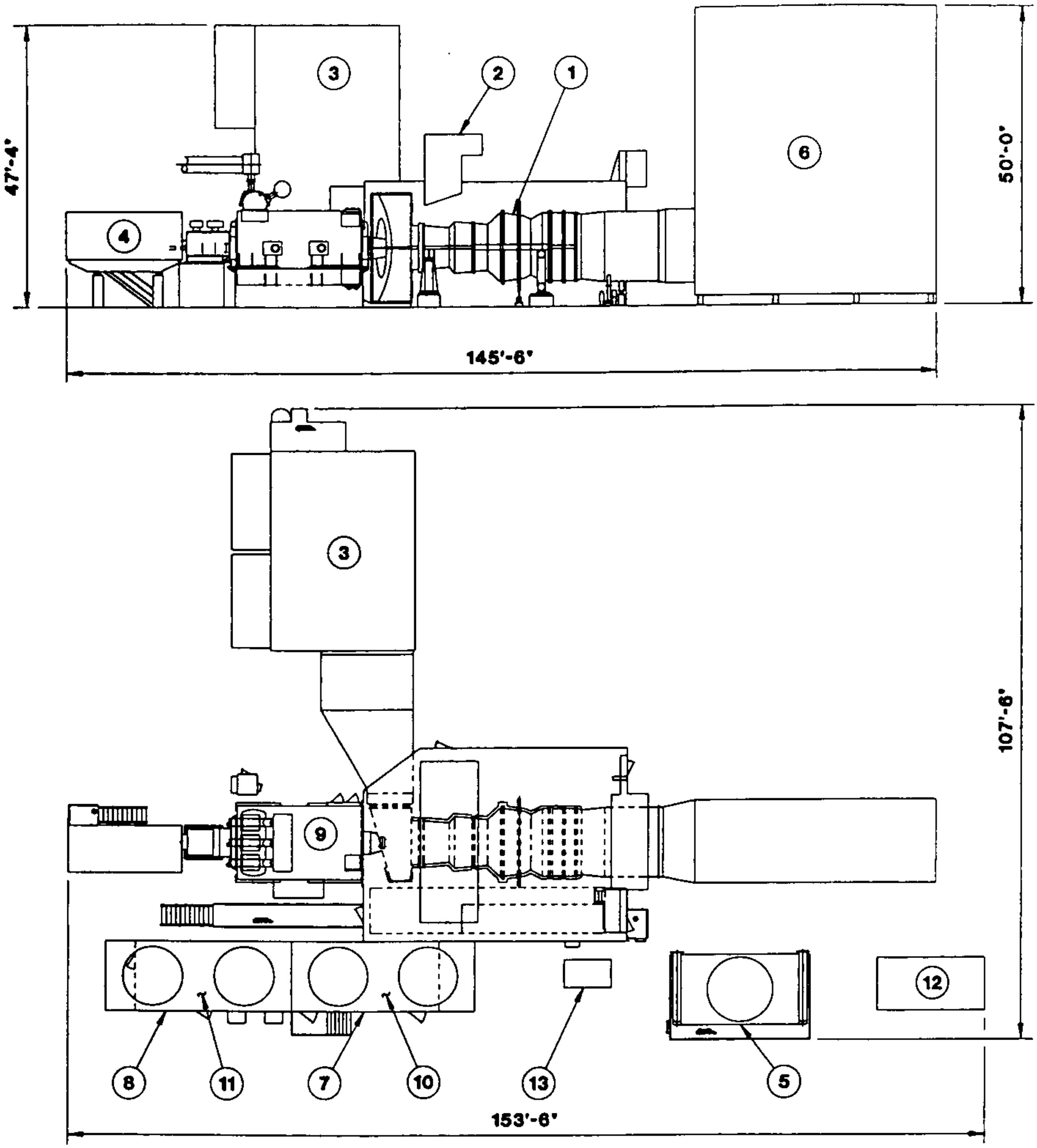
The auxiliary power transformer (optional) may be included as part of the ECONOPAC bill of material. The transformer can be located at any point in the system beyond the isolated phase bus.

Isolated Phase Bus/Surge Protection

Isolated phase bus (optional), located at the starting package end of the plant, carries power from the generator terminals to the customer connection. A surge protection and potential transformer cubicle connects to the bus assembly.

5. 501G ECONOPAC Arrangement

The ECONOPAC arrangement provides a small footprint with high power density encompassing an area 107.5 ft x 153.5 ft (32.8 m x 46.8 m).



LEGEND

1 COMBUSTION TURBINE
2 COMBUSTION TURBINE ENCLOSURE
3 TURBINE AIR INLET FILTER
4 STARTING PACKAGE
5 AIR-TO-AIR COOLER
6 EXHAUST STACK
7 MECHANICAL PACKAGE
8 ELECTRICAL/CONTROL PACKAGE
9 GENERATOR
10 LUBE OIL COOLER
11 GENERATOR GLYCOL COOLER
12 CO_2 FIRE PROTECTION STORAGE
13 COMPRESSOR WASH SKID

6. Technical Data

501G COMBUSTION TURBINE

Compressor	Type	Axial Flow
	Number of Stages	17
	Rotor Speed	3600 rpm
	Pressure Ratio	19.2:1
	Inlet Guide Vanes	Variable
Combustion System	Natural Gas	
	Pressure Required	505 psig
	Combustors	
	Type	Dry Low NO_X
	Configuration	Can-Annular
	Fuel	Dual
	Number	16
	Transitions	
	Cooling Fluid	Steam
	Steam Inlet Conditions	
	Pressure	300 psia
	Temperature	420°F (216°C)
	Total Flow	70,000 lb/hr (31,750 kg/hr)
	Number	16
Turbine	Number of Stages	4
	Number of Cooled Stages	3
	Vane and Blade Design	3-D
Rotor	Bearing-to-Bearing Span	321.4 in. (8164 mm)
	Journal Bearing	
	Type	Tilting Pad
	Number	2
	Thrust Bearing	
	Type	Tilting Pad
	Number	1
	Drive	Cold End

GENERATOR	Manufacturer	Westinghouse
	Type	Hydrogen Cooled
	Model	2-97 x 166
	Ratings:	
	Voltage	20 kV
	Current	9381 amps
	Frequency	60 Hz
	Speed	3600 rpm
	Generator Field Current, Rated	2472 amps
	Generator Field Voltage, Rated	475 volts
Basis of Rating	Hydrogen Pressure	45 psig
	Cold Gas Temperature	97°F (36°C)
Insulation Classes and Temperature Rise	Insulation Class for Stator, Rotor and Exciter	Class F Insulation, Class B Rise
	Maximum Hot Spot Temperature	266°F (130°C)
Impedances and Time Constants:	(325 MVA)	
	X_d	191.1%
	X_q	186.7%
	X'_{dv}	27.6%
	X'_{dl}	31.3%
	X'_{qv}	43.8%
	X'_{ql}	49.8%
	X''_{dv}	22.8%
	X''_{dl}	24.8%
	X''_{qv}	22.6%
	X''_{ql}	24.6%
	X_z	22.7%
	X_o	10.8%
	X_l	19.3%
	r_a	0.12%
	r_o	0.19%
	T'_{do}	6.205 sec
	T'_{qo}	0.689 sec
	T''_{do}	0.042 sec

	T''_{qo}	0.068sec	
	X_p	30.8%	
	Short Circuit Ratio	0.58	
EXCITER	Type	Static	
STARTING TIME	Normal	20 min	
	Fast (Option)	10 min	
RECOMMENDED INSPECTION INTERVALS	Inspection Type	Intervals*	
		Hours	Starts
	Combustor	8,000	400
	Hot Gas Path	24,000	1,200
	Major Overhaul	48,000	2,400

* The hours shown are for a natural gas-fired, baseloaded unit. For operation on oil, multiply the intervals shown by 0.8.

WEIGHTS

Heaviest Piece Lifted During Construction	
Component	Generator
Weight	594,000 lb (269,000 kg)
Heaviest Piece Lifted After Construction	
Component	Bladed Combustion Turbine Rotor
Weight	118,000 lb (53,500 kg)

7. Simple Cycle Performance

This section provides simple cycle baseload performance for a range of ambient temperature. Thermal performance and emission levels are included. Maximum power capability of the 501G is 300 MW at the generator terminals.

GENERIC DATA
DRY LOW NOx COMBUSTOR
EXPECTED 501G COMBUSTION TURBINE PERFORMANCE

CTT-969
05/09/95

SITE CONDITIONS:

FUEL TYPE	GAS	GAS	GAS	GAS	GAS	GAS	GAS
LOAD LEVEL	BASE	BASE	BASE	BASE	BASE	BASE	BASE
FUEL HEATING VALUE, BTU/LB LHV	21520	21520	21520	21520	21520	21520	21520
FUEL HEATING VALUE, BTU/LB HHV	23880	23880	23880	23880	23880	23880	23880
AMBIENT TEMPERATURE, F	0	20	32	59	75	90	100
RELATIVE HUMIDITY	60	60	60	60	60	60	60
BAROMETRIC PRESSURE, PSIA	14.696	14.696	14.696	14.696	14.696	14.696	14.696
INLET PRESSURE LOSS, IN-WATER	4.4	4.3	4.2	4.0	3.8	3.7	3.6
EXHAUST PRESSURE LOSS, IN-WATER	6.3	5.8	5.6	5.0	4.7	4.4	4.2
INJECTION FLUID	NONE	NONE	NONE	NONE	NONE	NONE	NONE
INJECTION RATIO, LB/LB	0	0	0	0	0	0	0
GENERATOR POWER FACTOR	0.9	0.9	0.9	0.9	0.9	0.9	0.9
GENERATOR HYDROGEN PRESSURE, PSIA	30	30	30	30	30	30	30
GENERATOR FRAME (2-97 X 150)							

COMBUSTION TURBINE PERFORMANCE:

NET POWER OUTPUT, KW	284810	265530	254330	230000	216310	204000	196370
HEAT RATE, BTU/KWH LHV	8390	8530	8620	8860	9030	9240	9380
EXHAUST FLOW, LB/HR	4864280	4695420	4590810	4350190	4206670	4069570	3976750
EXHAUST TEMPERATURE, F	1068	1077	1082	1100	1112	1126	1136
FUEL FLOW, LB/HR	111040	105250	101870	94690	90770	87590	85590
INJECTION RATE, LB/HR	0	0	0	0	0	0	0
AUXILIARY LOAD, KW	500	500	500	500	500	500	500
HEAT INPUT, MMBTU/HR (LHV)	2390	2265	2192	2038	1953	1885	1842
HEAT INPUT, MMBTU/HR (HHV)	2652	2513	2433	2261	2168	2092	2044
EXHAUST FLOW, MACFM	3.18	3.09	3.03	2.91	2.85	2.79	2.75

EXHAUST GAS COMPOSITION (BY PCT VOL):

OXYGEN	11.92	12.07	12.13	12.18	12.13	11.97	11.79
CARBON DIOXIDE	4.09	4.02	3.97	3.89	3.85	3.82	3.81
WATER	8.30	8.23	8.29	8.75	9.38	10.38	11.34
NITROGEN	74.73	74.73	74.65	74.22	73.70	72.90	72.14
ARGON	0.94	0.94	0.94	0.93	0.93	0.92	0.91
MOLECULAR WEIGHT	28.42	28.42	28.41	28.36	28.28	28.17	28.06

EMISSIONS:

NOx, PPMVD @ 15% O2	25	25	25	25	25	25	25
NOx, LB/HR	251	238	230	214	205	198	193
CO, PPMVD	10	10	10	10	10	10	10
CO, LB/HR	45	44	43	40	39	37	36
SO2, PPMVD	1	1	1	1	1	1	1
SO2, LB/HR	2	2	2	2	2	2	2
TOTAL UHC, PPMVD	5	5	5	5	5	5	5
TOTAL UHC, LB/HR	13	12	12	12	11	11	10
VOC, PPMVD	4	4	4	4	4	4	4
VOC, LB/HR	10	10	10	9	9	9	8
PARTICULATES (PM10/TSP), LB/HR (TOTAL)	8.7	8.4	8.2	7.8	7.6	7.3	7.2
SOOT, LB/HR	8.4	8.1	7.9	7.5	7.3	7.1	6.9
ASH, LB/HR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H2SO4 MIST, LB/HR	0.4	0.3	0.3	0.3	0.3	0.3	0.3
CO2, PPMVD	45938	45068	44625	43925	43748	43915	44232
CO2, LB/HR	317281	300691	291013	270616	259500	250208	244555
OPACITY, %	<=10	<=10	<=10	<=10	<=10	<=10	<=10

NOTES:
1. The net power output is the power at the generator terminals minus turbine auxiliary loads.
2. The natural gas fuel composition is 100% CH4 and 0.2 grains of sulfur per 100 SCF.
3. Natural gas fuel is heated with rotor waste heat from cooling circuit. The sensible heat of the fuel is not included in the fuel heating values, heat rate, or heat inputs.
4. Exhaust volumetric flow rate is at the exit of ECONOPAC stack.

GENERIC DATA
DRY LOW NOx COMBUSTOR
EXPECTED 501G COMBUSTION TURBINE PERFORMANCE

CTT-969
05/09/95

SITE CONDITIONS:

FUEL TYPE	OIL	OIL	OIL	OIL	OIL	OIL	OIL
LOAD LEVEL	98%	BASE	BASE	BASE	BASE	BASE	BASE
FUEL HEATING VALUE, BTU/LB LHV	18450	18450	18450	18450	18450	18450	18450
FUEL HEATING VALUE, BTU/LB HHV	19680	19680	19680	19680	19680	19680	19680
AMBIENT TEMPERATURE, F	0	20	32	59	75	90	100
RELATIVE HUMIDITY	60	60	60	60	60	60	60
BAROMETRIC PRESSURE, PSIA	14.696	14.696	14.696	14.696	14.696	14.696	14.696
INLET PRESSURE LOSS, IN-WATER	4.2	4.3	4.2	4.0	3.8	3.7	3.6
EXHAUST PRESSURE LOSS, IN-WATER	6.5	6.2	5.9	5.3	5.0	4.6	4.4
INJECTION FLUID	WATER	WATER	WATER	WATER	WATER	WATER	WATER
INJECTION RATIO, LB/LB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
GENERATOR POWER FACTOR	0.9	0.9	0.9	0.9	0.9	0.9	0.9
GENERATOR HYDROGEN PRESSURE, PSIA	30	30	30	30	30	30	30
GENERATOR FRAME (2-97 X 150)							

COMBUSTION TURBINE PERFORMANCE:

NET POWER OUTPUT, KW	298750	286010	273930	248280	233950	220920	212820
HEAT RATE, BTU/KWH LHV	9110	9250	9350	9610	9790	9990	10130
EXHAUST FLOW, LB/HR	5022180	4937110	4825010	4568320	4415880	4271290	4173820
EXHAUST TEMPERATURE, F	1038	1050	1054	1069	1079	1091	1100
FUEL FLOW, LB/HR	147510	143390	138820	129320	124140	119620	116850
INJECTION RATE, LB/HR	206520	200750	194350	181050	173800	167470	163590
AUXILIARY LOAD, KW	1250	1250	1250	1250	1250	1250	1250
HEAT INPUT, MMBTU/HR (LHV)	2722	2646	2561	2386	2290	2207	2156
HEAT INPUT, MMBTU/HR (HHV)	2903	2822	2732	2545	2443	2354	2300
EXHAUST FLOW, MACFM	3.24	3.21	3.15	3.01	2.94	2.88	2.84

EXHAUST GAS COMPOSITION (BY PCT VOL):

OXYGEN	10.15	10.25	10.33	10.40	10.35	10.22	10.06
CARBON DIOXIDE	6.04	5.97	5.92	5.81	5.75	5.71	5.69
WATER	12.26	12.20	12.22	12.60	13.17	14.08	14.97
NITROGEN	70.65	70.67	70.63	70.30	69.83	69.11	68.40
ARGON	0.89	0.89	0.89	0.88	0.88	0.87	0.86
MOLECULAR WEIGHT	28.26	28.26	28.25	28.20	28.13	28.03	27.93

EMISSIONS:

NOx, PPMVD @ 15% O2	42	42	42	42	42	42	42
NOx, LB/HR	495	481	466	434	416	401	392
CO, PPMVD	90	90	90	90	90	90	90
CO, LB/HR	405	398	389	367	354	340	330
SO2, PPMVD	16	15	15	15	15	15	15
SO2, LB/HR	152	148	143	133	128	123	120
TOTAL UHC, PPMVD	20	20	20	20	20	20	20
TOTAL UHC, LB/HR	51	51	49	47	45	43	42
VOC, PPMVD	5	5	5	5	5	5	5
VOC, LB/HR	13	13	12	12	11	11	10
PARTICULATES (PM10/TSP), LB/HR (TOTAL)	82.7	80.9	78.7	73.9	71.0	68.3	66.5
SOOT, LB/HR	43.6	42.8	41.9	39.6	38.1	36.6	35.5
ASH, LB/HR	15.2	14.8	14.3	13.3	12.8	12.3	12.0
H2SO4 MIST, LB/HR	24.0	23.3	22.6	21.0	20.2	19.4	19.0
CO2, PPMVD	70919	70088	69437	68449	68250	68461	68910
CO2, LB/HR	486611	473099	458083	426514	409388	394492	385365
OPACITY, %	<=20	<=20	<=20	<=20	<=20	<=20	<=20

NOTES:
1. The net power output is the power at the generator terminals minus turbine auxiliary loads.
2. The distillate oil fuel composition is 86.425% C, 13.5% H, 0.05% S, 0.015% FBN and 0.01% ash.
3. Exhaust volumetric flow rate is at the exit of ECONOPAC stack.
4. Injection rates are expected and will be adjusted during plant commissioning to meet emissions.
5. Gross power output is limited to 300 MW. Part was achieved by reducing firing temperature and is based on unrestricted CT power output.

8. Performance Correction Curves

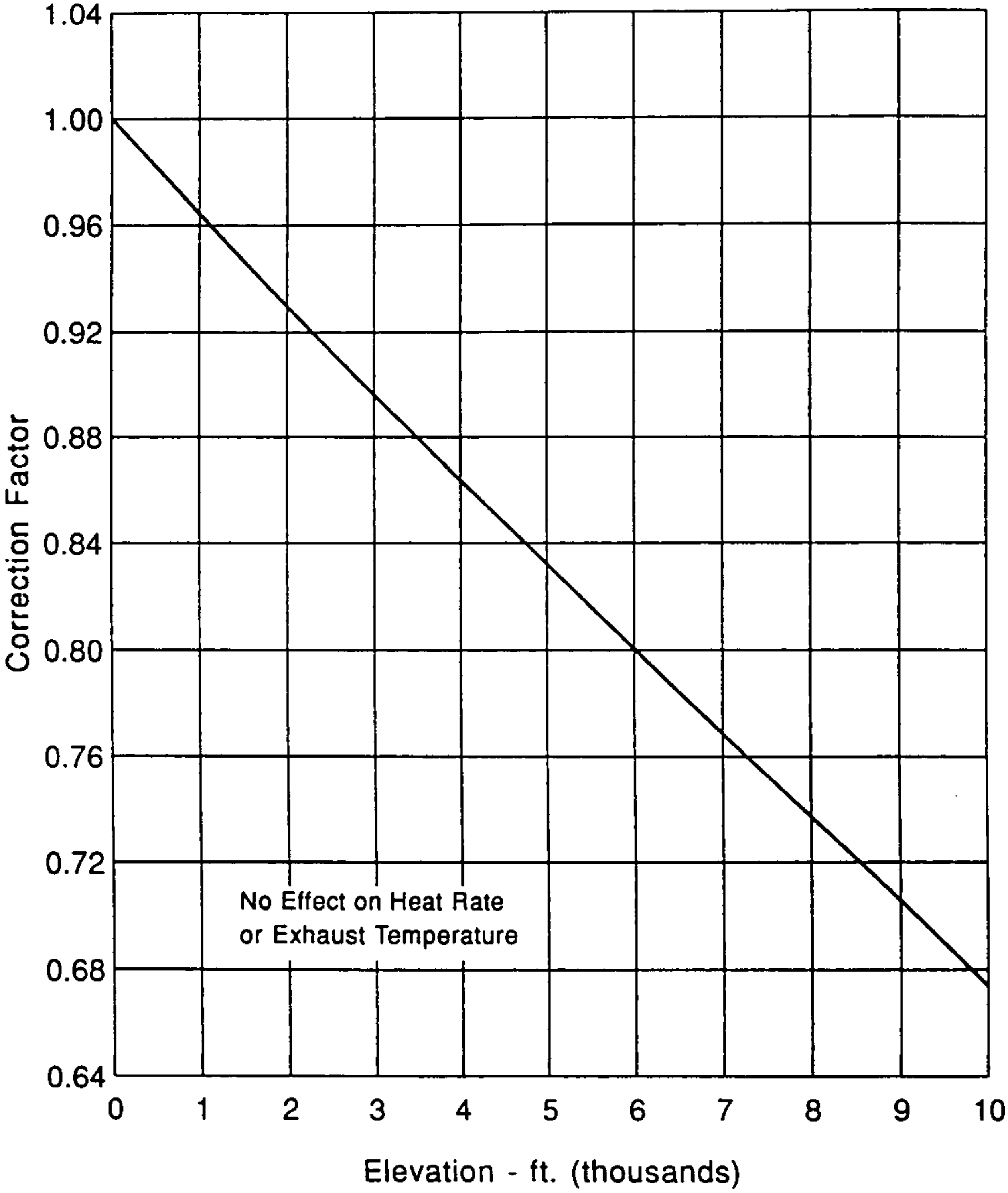
Correction curves are provided to correct the simple cycle performance given in the previous section to site conditions. Correction curves are provided for the following parameters.

- Elevation
- Compressor Inlet Temperature
- Excess Exhaust Loss
- Excess Inlet Loss

501G ECONOPAC SYSTEM PERFORMANCE

Correction to ISO Performance VS. Elevation

Power and Exhaust Flow

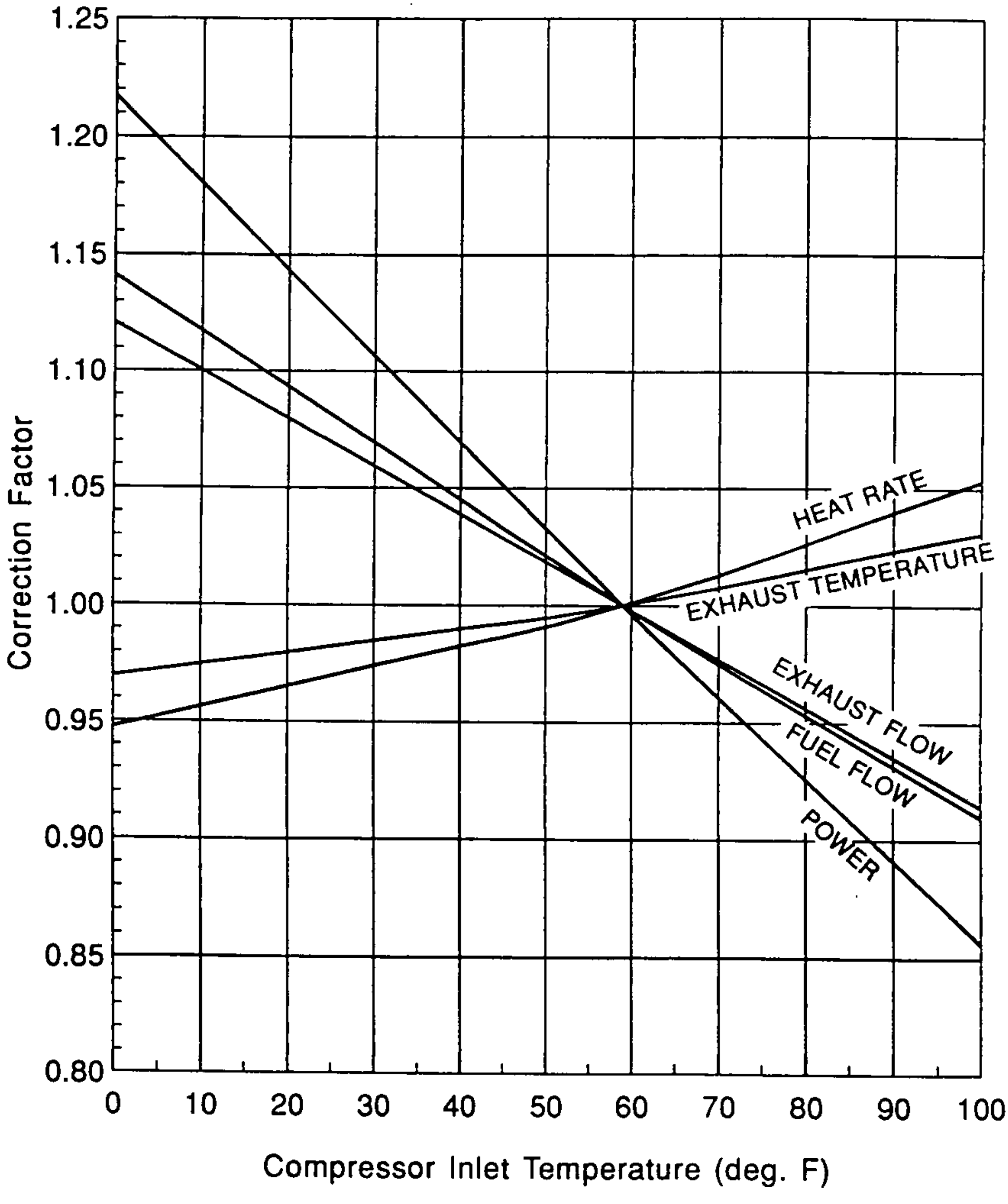


TT-003-501G

05/16/94

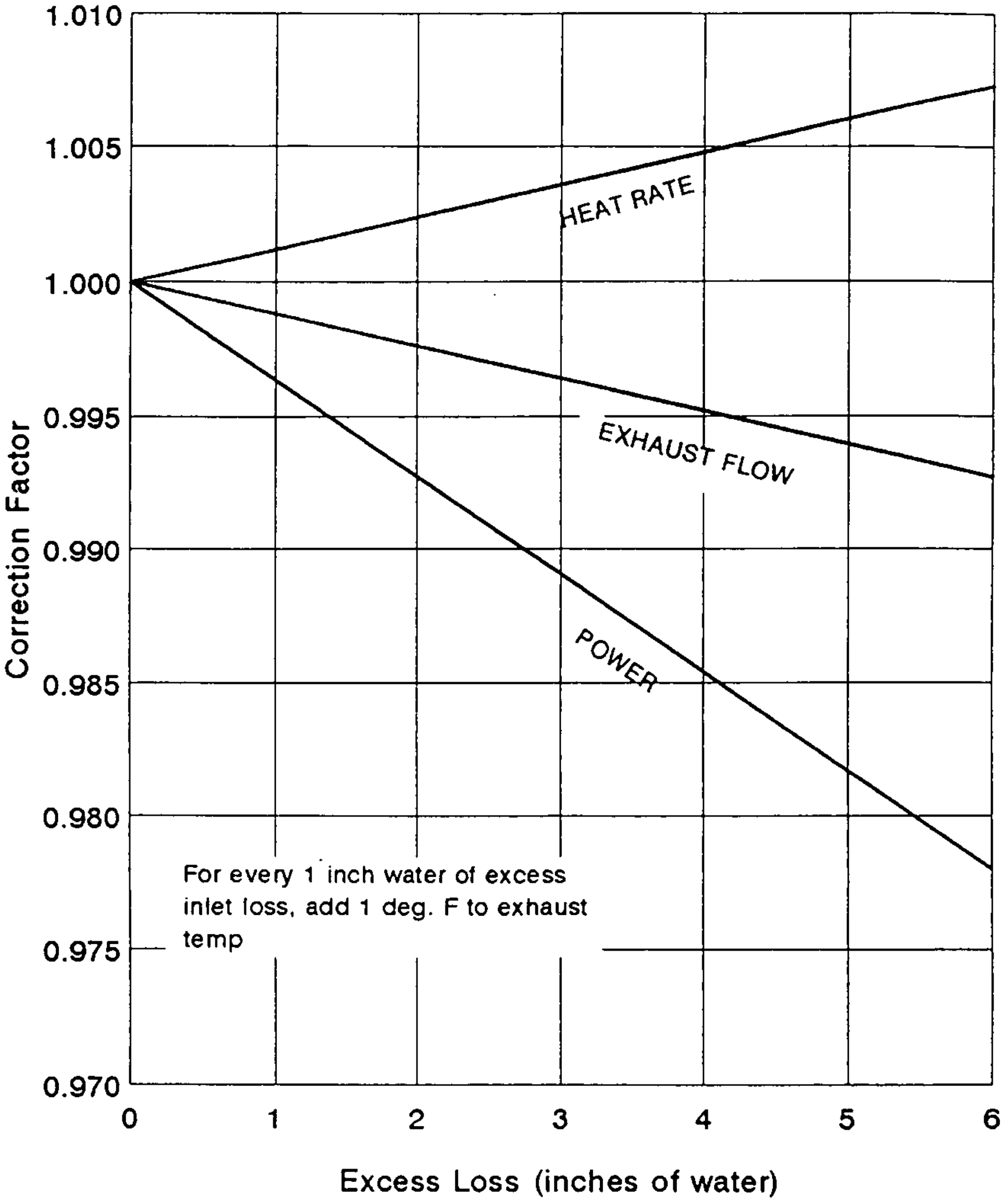
501G ECONOPAC SYSTEM PERFORMANCE

Exhaust Temperature and Correction to ISO Performance VS. Compressor Inlet Temperature



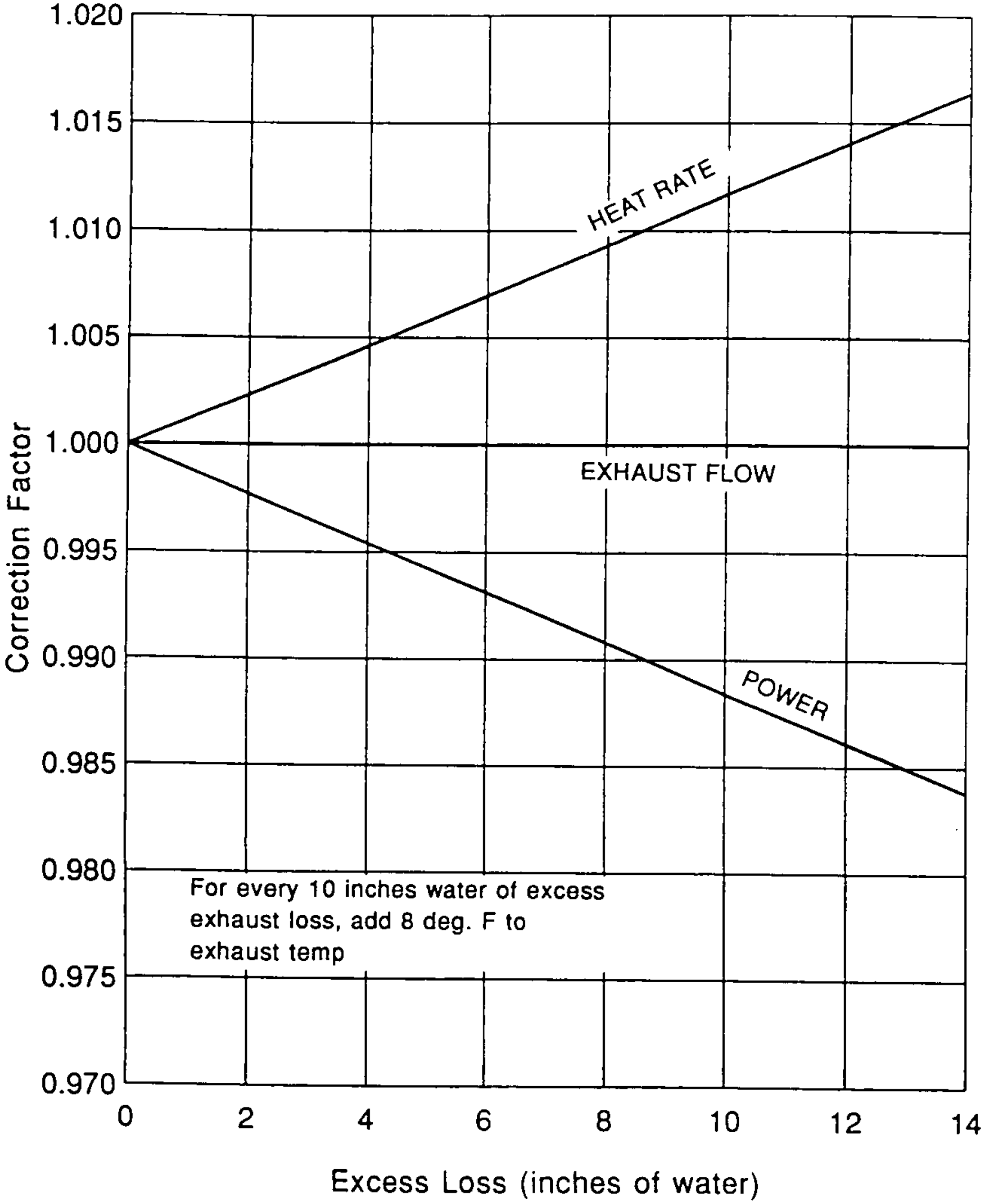
T-004-501G
5/16/94

501G ECONOPAC SYSTEM PERFORMANCE
Correction to ISO Performance for Excess Inlet Loss



TT-002-501G
06/21/94
Rev. 1

501G ECONOPAC SYSTEM PERFORMANCE
Correction to ISO Performance for Excess Exhaust Loss



T-001-501G
5/16/94

9. Combined Cycle Performance

Typical heat balance diagrams are given for 1 x 1 and 2 x 1 combined cycle configurations. Westinghouse should be consulted on your project-specific requirements.

OPERATING CONDITIONS:

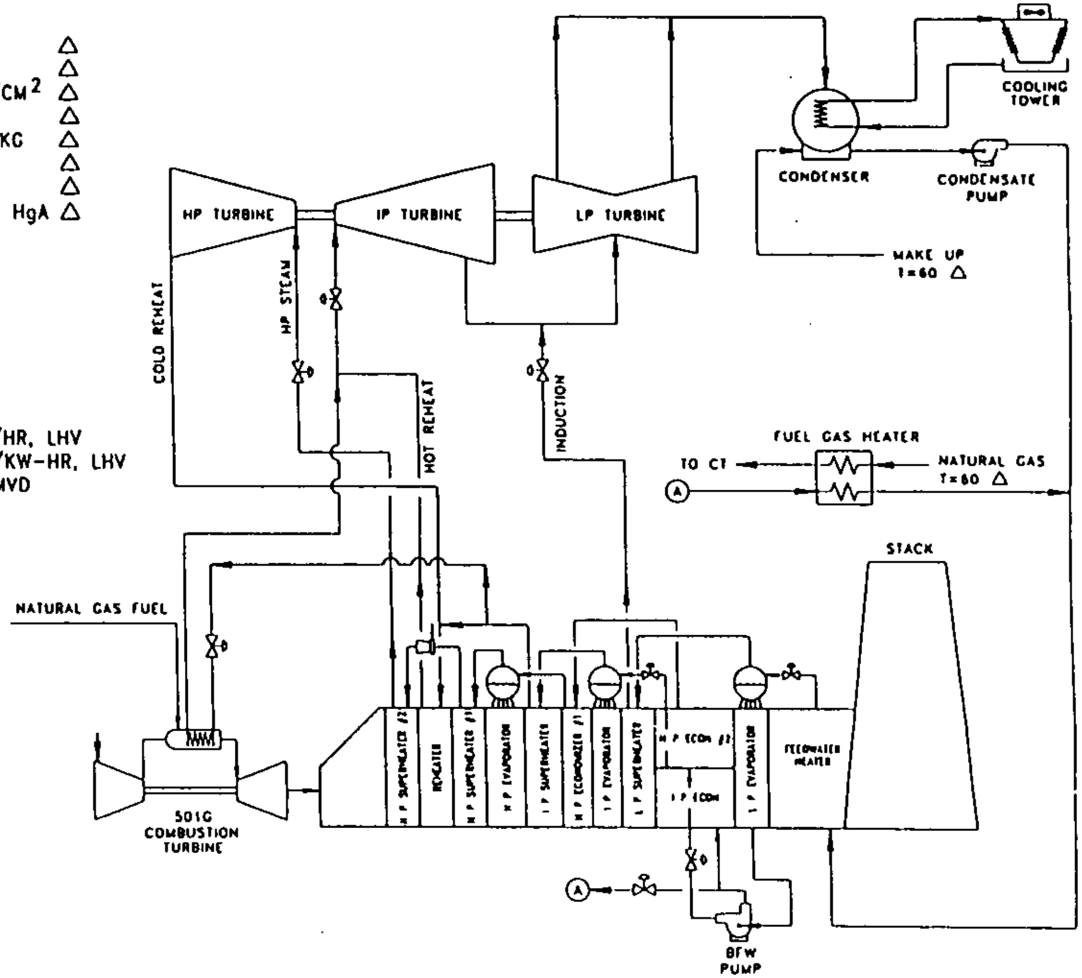
AMBIENT TEMPERATURE	59 °F	15 °C	△
RELATIVE HUMIDITY	60 %	60 %	△
BAROMETRIC PRESSURE	14.696 PSIA	1.033 KG/CM^2	△
FUEL TYPE	NATURAL GAS	NATURAL GAS	△
FUEL HEATING VALUE, LHV	21520 BTU/LB	50056 KJ/KG	△
GENERATOR POWER FACATOR	0.9	0.9	△
FUEL HHV/LHV	1.109	1.109	△
STEAM TURBINE BACKPRESSURE	1.5 in HgA	38.1 mm HgA	△

ESTIMATED PLANT PERFORMANCE:

GROSS CT POWER	229340 KW	229340 KW
GROSS ST POWER	119785 KW	119785 KW
GROSS PLANT POWER	349125 KW	349125 KW
PLANT AUXILIARY LOADS	6635 KW	6635 KW
NET PLANT POWER	342490 KW	342490 KW
CT FUEL INPUT, LHV	2036.68 MMBTU/HR, LHV	2149 GJ/HR, LHV
NET PLANT HEAT RATE, LHV	5947 BTU/KW-HR, LHV	6274 KJ/KW-HR, LHV
STACK NOx EMISSIONS	25 PPMVD	25 PPMVD

NOTES:

1. △ INDICATES PARAMETER WHICH, IF DIFFERENT, RESULTS IN A CORRECTION TO THE CALCULATED PERFORMANCE.
2. PERFORMANCE VALUES ARE FOR NEW AND CLEAN EQUIPMENT.
3. NET PLANT POWER REFERENCED TO THE LOW SIDE OF THE TRANSFORMER. TRANSFORMER LOSSES HAVE NOT BEEN INCLUDED.
4. NOx EMISSIONS ARE BASED ON 15% O_2 AND ISO CONDITIONS.
5. PERFORMANCE BASED ON NATURAL GAS WITH A MAXIMUM SULFUR CONTENT OF 0.2 GRAINS PER 100 SCF.
6. NATURAL GAS FUEL COMPOSITION IS 100% CH_4.



3 PRESSURE, NATURAL CIRCULATION
HEAT RECOVERY STEAM GENERATOR (HRSG)

LEGEND:

P = PRESSURE, PSIA
T = TEMPERATURE, °F
G = FLOW, 1000 LB/HR
H = ENTHALPY, BTU/LB

WESTINGHOUSE 1X1 501G REFERENCE PLANT

DATE 01/03/95 | DRAFTER L. MONROE
ENGINEER S C WILLIS S. Willis
APPROVED BY T S BALDWIN
REV. LEVEL 1 | SALE CODE P
CUST NO. 94506

Westinghouse Electric Corporation
Power Generation Projects Division

1X1 501G REHEAT COMBINED CYCLE
DRY LOW NOx COMBUSTORS
PLANT PERFORMANCE EST

Drawing No. HB2127 5 | SHEET 05 | Page 1 of 1

OPERATING CONDITIONS:

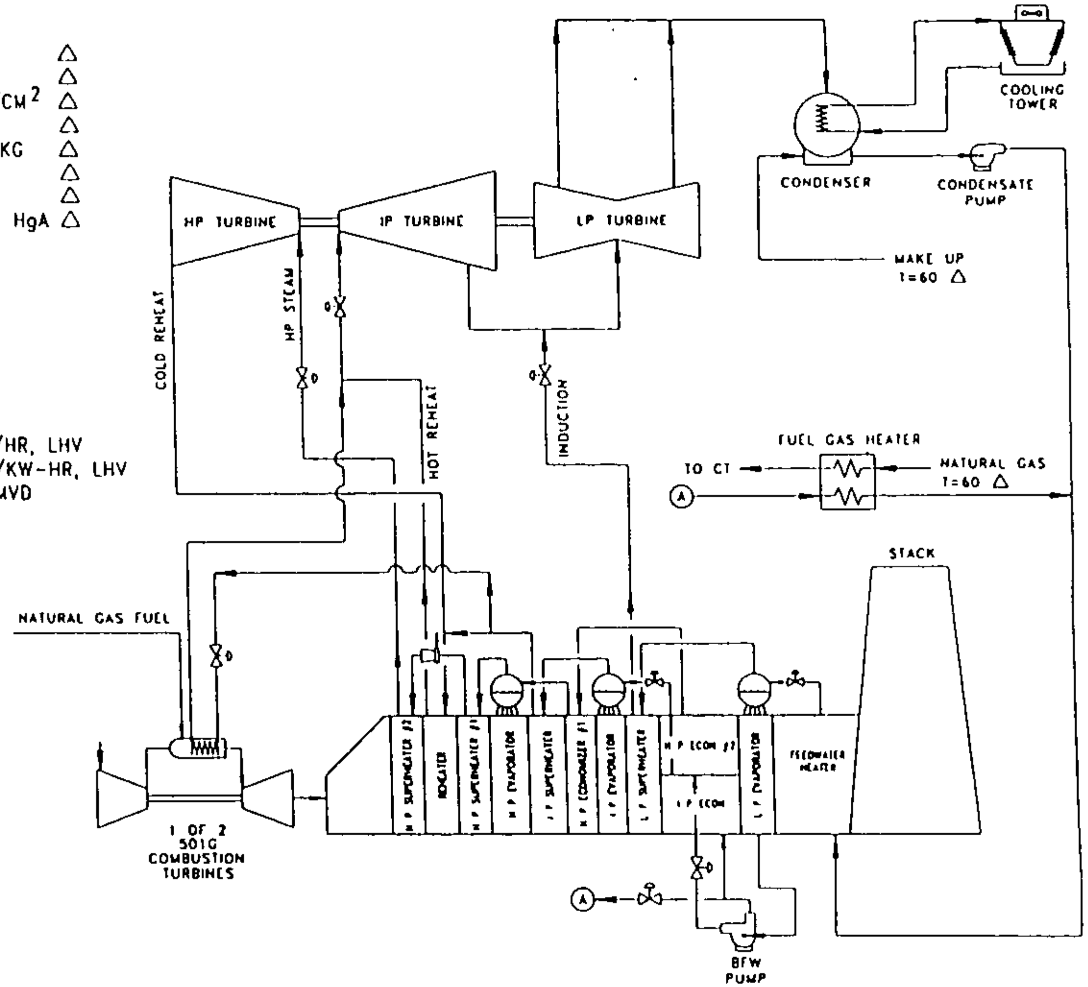
AMBIENT TEMPERATURE	59 °F	15 °C	△
RELATIVE HUMIDITY	60 %	60 %	△
BAROMETRIC PRESSURE	14.696 PSIA	1.033 KG/CM^2	△
FUEL TYPE	NATURAL GAS	NATURAL GAS	△
FUEL HEATING VALUE, LHV	21520 BTU/LB	50056 KJ/KG	△
GENERATOR POWER FACATOR	0.9	0.9	△
FUEL HHV/LHV	1.109	1.109	△
STEAM TURBINE BACKPRESSURE	1.5 in HgA	38.1 mm HgA	△

ESTIMATED PLANT PERFORMANCE:

GROSS CT POWER	458680 KW	458680 KW
GROSS ST POWER	240714 KW	240714 KW
GROSS PLANT POWER	699394 KW	699394 KW
PLANT AUXILIARY LOADS	13290 KW	13290 KW
NET PLANT POWER	686104 KW	686104 KW
CT FUEL INPUT, LHV	4073.4 MMBTU/HR, LHV	4297.4 GJ/HR, LHV
NET PLANT HEAT RATE, LHV	5937 BTU/KW-HR, LHV	6264 KJ/KW-HR, LHV
STACK NOx EMISSIONS	25 PPMVD	25 PPMVD

NOTES:

1. △ INDICATES PARAMETER WHICH, IF DIFFERENT, RESULTS IN A CORRECTION TO THE CALCULATED PERFORMANCE.
2. PERFORMANCE VALUES ARE FOR NEW AND CLEAN EQUIPMENT.
3. NET PLANT POWER REFERENCED TO THE LOW SIDE OF THE TRANSFORMER. TRANSFORMER LOSSES HAVE NOT BEEN INCLUDED.
4. NOx EMISSIONS ARE BASED ON 15% O_2 AND ISO CONDITIONS.
5. PERFORMANCE BASED ON NATURAL GAS WITH A MAXIMUM SULFUR CONTENT OF 0.2 GRAINS PER 100 SCF.
6. NATURAL GAS FUEL COMPOSITION IS 100% CH_4.



1 OF 2
3 PRESSURE, NATURAL CIRCULATION
HEAT RECOVERY STEAM GENERATORS (HRSG)

LEGEND:

P = PRESSURE, PSIA
T = TEMPERATURE, °F
G = FLOW, 1000 LB/HR
H = ENTHALPY, BTU/LB

WESTINGHOUSE PROPRIETARY

WESTINGHOUSE 2X1 501G REFERENCE PLANT

DATE 01/03/95	DRAFTER L. MONROE	Westinghouse Electric Corporation Power Generation Projects Division
ENGINEER S C WILLIS	S. Willis	2X1 501G REHEAT COMBINED CYCLE DRY LOW NOx COMBUSTORS PLANT PERFORMANCE EST
APPROVED BY T S BALDWIN		
REV. LEVEL 1	CALC CODE P	
CUST NO. 94504		Drawing No. HB2128.5 — ISSUE 05 — Page 1 of 1

10. Economics

This section features two exhibits: Relative Annual Cost of Power and Combined Cycle Plant Economic Analysis. The 501G-based combined cycle plant is compared to combined cycle plants using the current 'F' technology combustion turbines.

The Relative Annual Cost of Power displays the expected cost ratio for 501G vs. 'F' technology as a function of capacity factor. Throughout the load range, the 501G has a 10% to 15% advantage over 'F' technology.

The Combined Cycle Plant Economic Analysis compares internal rate of return (IRR) and average debt coverage ratio for the two technology levels.

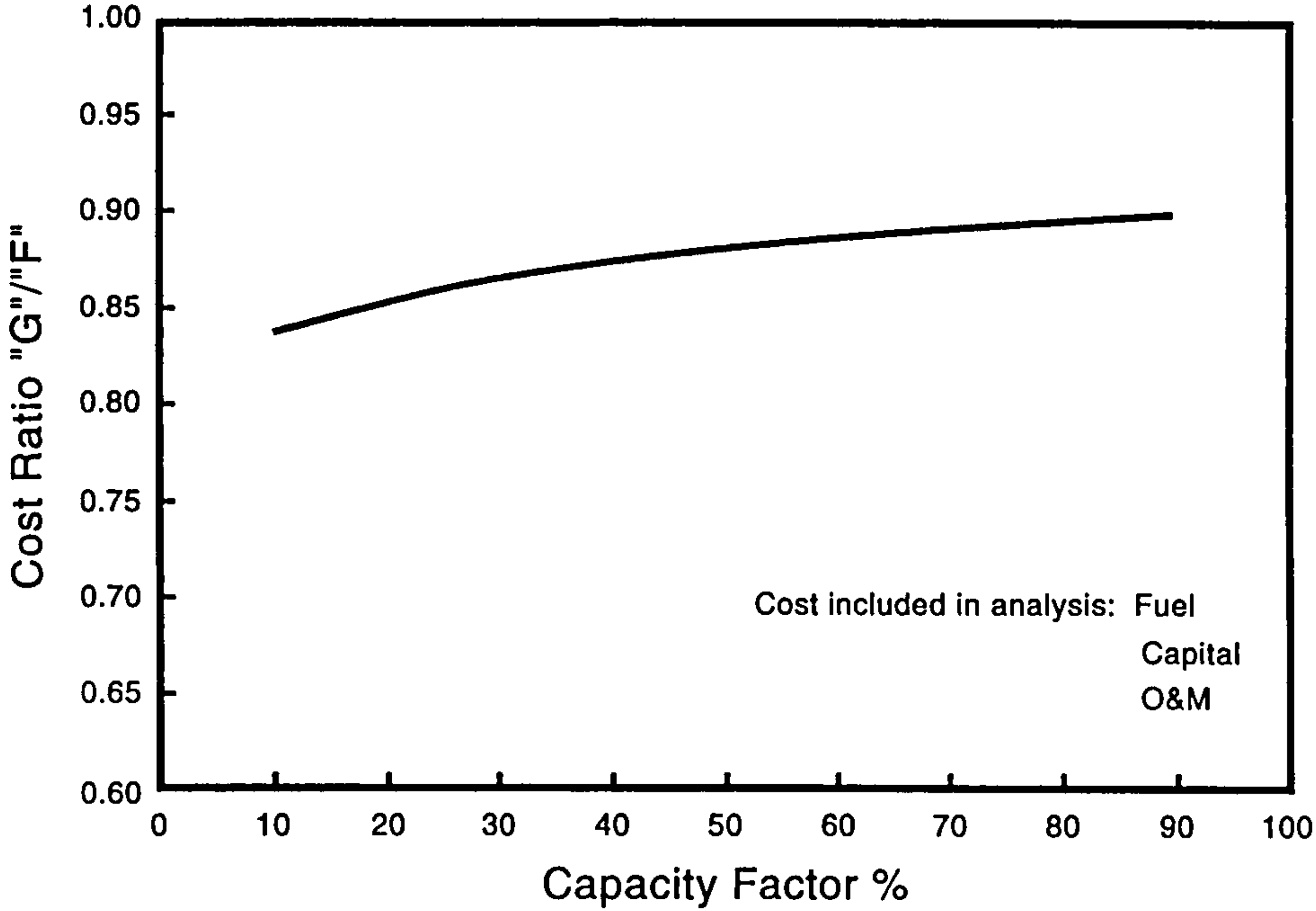
To achieve a pre-defined 20% IRR for 'F' technology, the selling price of electricity, including both capacity payment and energy payment, was varied. Then the 501G IRR was calculated using the same selling price of electricity. Some of the key financial assumptions, shown on a separate page, are conservative. For example, a construction period of 27 months is assumed, even though a 22- to 24-month schedule is more typical.

Whether considering a 90% or 50% capacity factor, the 501G yields a major IRR improvement. Likewise, the average debt coverage ratio, the average ratio of yearly return to debt service, shows the significant financial advantage of the 501G.

The 501G, therefore, offers considerable economic advantage for your project, whether for high or low capacity factors.

Relative Annual Cost of Power

"F" vs "G" Technology - Combined Cycle Plants



92409.36L

Combined Cycle Plant Economic Analysis

Financial Performance for a Non-Utility Generation Project
(Assumes 25 year levelized power rates, includes SCR)

90% Capacity Factor

	Project IRR 25 Years	Average Debt Coverage Ratio
"F" Technology	20.0%	1.52
"G" Technology	35.2%	2.18

50% Capacity Factor

	Project IRR 25 Years	Average Debt Coverage Ratio
"F" Technology	20.0%	1.52
"G" Technology	33.4%	2.11

32408.39L

Financial Analysis Key Assumptions

3% degradation on capacity

2% degradation on heat rate

Fuel cost = $3.00/MMBtu

25 year plant life

4% general escalation rate

No sale to steam host

Base capacity factor = 90%

Construction period = 27 months ("F" & "G" technology)

Owner's contingency = 5% of turnkey cost

Permitting, legal, misc. costs = $5 Million

Federal income tax rate = 34%

State income tax rate = 8%

Debt/Equity = 85/15

Debt term = 15 years

Debt interest rate = 10%

Required debt reserve = 6 months debt service

Levelized power rate set to have "F" Technology IRR = 20%

32409.SOL

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION FOR THE PROPOSED 501G

B.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS regulations (40 CFR, Subpart GG) applicable to gas turbines apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the proposed 501G project and are the most stringent provision of the NSPS. These requirements are summarized in Table B-1 and were considered in the BACT analysis.

As noted from Table B-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.03 percent, the NSPS is increased by 0.0012 percent or 12 parts per million (ppm).

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

B.2.1 NITROGEN OXIDES

Advanced dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is technically feasible for the proposed project. Available information suggests that SCR with dry low-NO_x combustor technology or with wet injection is also technically feasible. For the 501G Project, advanced dry low-NO_x combustor technology is equivalent to the SCR technology and has several important advantages.

B.2.1.1 Identification of NO_x Control Technologies

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table B-2 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines. This table was developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina, (e.g., the California Air Control Board, the South Coast Air Quality Management District, the New Jersey Department of Environmental Protection, and the Rhode Island Department of Environmental Management).

Historically, the most stringent NO_x controls for CTs established as LAER/BACT by state agencies were selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet injection is used initially to reduce NO_x emissions. However, advanced dry low-NO_x technology has only recently been developed and made available for gas turbines. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process.

SCR has been installed or permitted in over 100 projects. The majority of these projects (more than 90 percent) are cogeneration facilities with capacities of 50 MW or less. About 80 percent of the projects have been in California. Of these 109 projects that have either installed SCR or have been permitted with SCR, about 40 percent have been in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest

> achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51, Appendix S.II, A.18).

As noted previously, there are distinct regulatory and policy differences between LAER and BACT.

As discussed in Section 3.0, BACT involves an evaluation of the economic, environmental, and energy impacts of alternative control technologies. In contrast, LAER only considers the technical aspects of control.

All the projects in California have natural gas as the primary fuel, and only 15 of the SCR applications in California have distillate fuel as backup.

The remaining projects with SCR (i.e., about 25 projects) are located in the eastern United States. These projects are located in Vermont, Massachusetts, Connecticut, New Jersey, New York, Rhode Island, and Virginia. A majority of these projects are cogenerators or independent power producers. The size of these projects ranges from 22 MW to 450 MW, with nearly 90 percent less than 100 MW in size. While almost all of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per CT.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80 percent of NO_x in the exhaust gas stream. The most common emission limiting standards associated with SCR are approximately 9 ppm for natural gas firing. However, a few facilities have reported emission limits of about 4.5 ppm. These emission limits were clearly determined to be LAER on CTs using water injection with uncontrolled NO_x levels below 42 ppm.

The installation of SCR has primarily been on combined cycle units where the catalyst is located in the HRSG at the proper temperature range. SCR has been installed on two simple cycle projects in California on machines significantly smaller (less than 25 MW) than the 501G proposed. With smaller turbines, the exhaust as temperature is lower making possible the installation of high temperature catalysts. Without the OTSG on the 501G, temperature would easily exceed the 1,100° F limitation for high temperature catalysts. Even with the OTSG, temperatures will approach 1,100° F and monitoring and control systems will be required to prevent catalyst damage. The high temperature catalyst are more than 2 times more costly than conventional base metal catalysts that are installed in HRSG. While manufacturers guarantee the high temperature catalysts for 3 years, operating experience at temperatures above 1,000° F is limited. Continuous exposure at these elevated temperatures suggest a more limited life of the SCR system.

Wet injection historically has been the primary method of reducing NO_x emissions from CTs. Indeed, this method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when burning natural gas. More recently, however, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) or less when firing natural gas.

In Florida, all of the most recent PSD permits and BACT determinations for gas turbines have required either wet injection or dry low-NO_x technology for NO_x control. The emission limits included in these permits and BACT determinations are primarily in the range of 15 ppmvd to 25 ppmvd (corrected to 15 percent O_2, dry conditions) for future operations on natural-gas firing.

B.2.1.2 Technology Description and Feasibility

Wet Injection--The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

Dry Low-NO_x Combustor--In the past several years, CT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on conventional machines manufactured by Westinghouse, GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. Westinghouse and GE have offered dry low-NO_x combustors on advanced heavy-duty industrial machines. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the CT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level when firing natural gas at baseload conditions is 25 ppmvd (corrected to 15 percent O_2), a level which is guaranteed by the selected vendor (Westinghouse) for the project.

<u>Selective Catalytic Reduction (SCR)</u>--SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined cycle configuration; no simple cycle facilities have SCR. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR with base metal catalysts. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been limited to facilities that burn natural gas or small amounts of fuel oil since SCR catalysts are contaminated by sulfur-containing fuels (i.e., fuel oil). For most fuel-oil-burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience with SCR has not been extensive, certain cost, technical, and environmental considerations have surfaced for units firing both natural gas and oil while using SCR.

Ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required with concomitant cost and technical requirements. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts.

Zeolite and specially designed high temperature catalysts, which are reported to be capable of operating in temperature ranges up to 1,100°F, have become available commercially only recently. Their application with SCR primarily has been limited to internal combustion engines. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800°F to 900°F. At temperatures of 1,100°F and above, the high-temperature catalyst will be irreparably damaged. Application of an SCR system using a zeolite catalyst would be feasible for the project; however, use in simple cycle operation will require monitoring to assure the temperature limits are not exceeded. If temperatures are exceeded then exhaust gas cooling would be required.

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

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

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

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

Disadvantages of the system are as follows:

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

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

1. Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65 percent NO_x reduction,
2. A 600 x 10^6 Btu CO boiler with 60 to 70 percent NO_x reduction, and
3. A 75-MW pulverized coal-fired unit with 65 percent NO_x reduction.

The NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the 501G CT is about 1,000°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

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

The only known commercial applications of Thermal $DeNO_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of material requirements, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal $DeNO_x$ process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of a combustion turbine is typically about 1,000°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

<u>Nonselective Catalytic Reduction</u>--Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

<u>Technology Determination</u>--A technical evaluation of available post-combustion gas controls (i.e., NO_xOUT, Thermal DeNO_x, and NSCR) indicates that these processes have not been applied to CT/HRSG and are technically infeasible for the project because of process constraints (e.g., temperature).

For the BACT analysis, dry low-NO_x combustion technology is technically feasible and SCR in combination with combustion controls is a potentially feasible alternative that can achieve a maximum degree of emission reduction. The advanced dry low-NO_x combustor alone can achieve 25 ppm (corrected) and the SCR with dry low-NO_x combustor is capable of achieving a NO_x emission level of 7.5 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions). When firing oil, the emissions with SCR and wet injection would be about 12.6 ppm (corrected), whereas emissions with wet injection alone would be 42 ppm (corrected). The SCR has a NO_x removal rate of 70 percent based on an associated ammonia slip (i.e., to 10 ppm).

B.2.1.3 <u>SCR Cost Estimates</u>

Tables B-3 and B-4 present the total capital and annualized cost for SCR, respectively. The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993). A vendor estimate was obtained for the SCR system and is contained in this appendix. Standard EPA recommended cost factors were used. For simple cycle operation, a capital recovery period of 10 years was used, since the SCR system would be subjected to temperatures exceeding 1,000°F where considerable wear can take place resulting in lower life of equipment. For combined cycle operation the capital recovery factor was adjusted to account for a 20 year life.

B.2.2 CARBON MONOXIDE

B.2.2.1 Identification of CO Control Technologies

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table B-5 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. For the CTs being evaluated, CO emissions will not exceed 50 ppmvd, corrected to dry conditions when firing natural gas under full load conditions and 90 ppmvd when firing distillate oil.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10 ppm range (corrected to dry conditions).

B.2.2.2 Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required.

For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications primarily have been limited to smaller cogeneration facilities burning natural gas. Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the units likely will require numerous startups, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling.

The lack of demonstrated operation with oil firing suggests rejection of catalytic oxidation as a technically feasible alternative. However, the advent of a second generation catalyst suggests that an oxidation catalyst could be used although none have been placed in actual operation.

B.2.2.3 Oxidation Catalyst Costs

Tables B-6 and B-7 present the capital and annualized cost for an oxidation catalyst. The maximum CO impacts are less than 0.1 percent of the applicable ambient air quality standards. There would also be no secondary benefits, such as acidic deposition, to reducing CO.

Table B-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.

[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-Bound Nitrogen (percent by weight)	Allowed Increase NO_x Percent by Volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

where: N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Mead Coated Board, Inc.	AL	Mar-1997	Combined Cycle Turbine (25 Mw)	568 MMBTU/HR	25.0 PPMVD@ 15% O2 (GAS)	dry low nox combustor design firing gas and dry low nox combustor with water injection firing oil	0	BACT-PSD
Formosa Plastics Corporation, Baton Rouge Plant	LA	Mar-1997	Turbine/Hsrg, Gas Cogeneration	450 MM BTU/HR	9.0 PPMV	dry low nox burner	0	BACT-PSD
Southwestern Public Service Company	NM	Feb-1997	Combustion Turbine, Natural Gas	100 MW	0.0 SEE FACILITY NOTES	dry low nox combustion	0	BACT-PSD
Southern Natural Gas Company	MS	Dec-1996	Turbine, Natural Gas-Fired	9160 HORSEPOWER	110.0 PPMV @ 15% O2, DRY	proper turbine design and operation	0	BACT-PSD
Southern Natural Gas Company-Selma	AL	Dec-1996	9160 Hp Ge Ms3002G Natural Gas Fired Turbine	0	53.0 LB/HR		0	BACT-PSD
Southwestern Public Service Co	NM	Nov-1996	Combustion Turbine, Natural Gas	100 MW	15.0 PPM; SEE FAC. NOTES	dry low nox combustion	0	BACT-PSD
Blue Mountain Power, Lp	PA	Jul-1996	Combustion Turbine With Heat Recovery Boiler	153 MW	4 0 PPM @ 15% O2	dry lnb with scr water injection in place when firing oil. oil firing limits set to 8.4 ppm @15% o2	84	LAER
General Electric Gas Turbines	SC	Apr-1996	I C. Turbine	2700 MMBTU/HR	885.3 LB/HR	good combustion practices to minimize emissions	0	BACT-PSD
Carolina Power & Light	NC	Apr-1996	Combustion Turbine, 4 Each	1908 MMBTU/HR	512.3 LB/HR	water injection; fuel spec: 0 04% n fuel oil	0	BACT-PSD
Carolina Power & Light	NC	Apr-1996	Combustion Turbine, 4 Each	1908 MMBTU/HR	158 0 LB/HR	water injection	0	BACT-PSD
Mid-Georgia Cogen.	GA	Apr-1996	Combustion Turbine (2), Natural Gas	116 MW	9 0 PPMVD	dry low nox burner with scr	0	BACT-PSD
Mid-Georgia Cogen.	GA	Apr-1996	Combustion Turbine (2), Fuel Oil	116 MW	20.0 PPMVD	water injection with scr	0	BACT-PSD
Georgia Gulf Corporation	LA	Mar-1996	Generator, Natural Gas Fired Turbine	1123 MM BTU/HR	25.0 PPMV-CORR. TO 15%O2	control nox using steam injection	0	BACT-PSD
Seminole Hardee Unit 3	FL	Jan-1996	Combined Cycle Combustion Turbine	140 MW	15.0 PPM @ 15% O2	dry lnb staged combustion	0	BACT-PSD
Key West City Electric System	FL	Sep-1995	Turbine, Existing Ct Relocation To A New Plant	23 MW	75 0 PPM @ 15% O2	water injection	0	BACT-PSD
Union Carbide Corporation	LA	Sep-1995	Generator, Gas Turbine	1313 MM BTU/HR	25.0 PPMV CORR. TO 15% O2	dry low nox combustor	0	BACT-PSD
Brooklyn Navy Yard Cogeneration Partners L.P.	NY	Jun-1995	Turbine, Natural Gas Fired	240 MW	3.5 PPM @ 15% O2	scr	0	LAER
Brooklyn Navy Yard Cogeneration Partners L.P.	NY	Jun-1995	Turbine, Oil Fired	240 MW	10.0 PPM @ 15% O2	scr	0	LAER
Panda-Kathleen, L.P.	FL	Jun-1995	Combined Cycle Combustion Turbine (Total 115Mw)	75 MW	15.0 PPM @ 15% O2	dry low nox burner	0	BACT-PSD
Proctor And Gamble Paper Products Co (Charmin)	PA	May-1995	Turbine, Natural Gas	580 MMBTU/HR	55.0 PPM @ 15% O2	steam injection	75	RACT
Pilgrim Energy Center	NY	Apr-1995	(2) Westinghouse W501D5 Turbines (Ep #S 00001&2)	1400 MMBTU/HR	4.5 PPM, 23 6 LB/HR	steam injection followed by scr	0	BACT
Lederle Laboratories	NY	Apr-1995	(2) Gas Turbines (Ep #S 00101&102)	110 MMBTU/HR	42.0 PPM, 18 LB/HR	steam injection	0	BACT-PSD
Gainesville Regional Utilities	FL	Apr-1995	Simple Cycle Combustion Turbine, Gas/No 2 Oil B-Up	74 MW	15.0 PPM AT 15% OXYGEN	dry low nox burners	0	BACT-PSD
Gainesville Regional Utilities	FL	Apr-1995	Oil Fired Combustion Turbine	74 MW	42 0 PPM AT 15% OXYGEN	water injection	0	BACT-PSD
Formosa Plastics Corporation, Louisiana	LA	Mar-1995	Turbine/Hrsg, Gas Cogeneration	450 MM BTU/HR	9 0 PPMV	dry low nox burner/combustion design and control	0	LAER
Lsp-Cottage Grove, L.P.	MN	Mar-1995	Combustion Turbine/Generator	1970 MMBTU/HR	4.5 PPM @ 15% O2 GAS	selective catalytic reduction (scr)	70	BACT-PSD
Marathon Oil Co. - Indian Basin N.G. Plan	NM	Jan-1995	Turbines, Natural Gas (2)	5500 HP	7.4 LBS/HR	lean-premixed combustion technology. dry/low nox	66	BACT-PSD
Kamine/Besicorp Syracuse Lp	NY	Dec-1994	Siemens V84.3 Gas Turbine (Ep #00001)	650 MMBTU/HR	25.0 PPM	water injection	70	BACT
Indeck-Oswego Energy Center	NY	Oct-1994	Ge Frame 6 Gas Turbine	533 LB/MMBTU	42.0 PPM, 75 00 LB/HR	steam injection	53	BACT
Fulton Cogen Plant	NY	Sep-1994	Ge Lm5000 Gas Turbine	500 MMBTU/HR	38.0 PPM, 65 LB/HR	water injection	59	BACT
Fulton Cogen Plant	NY	Sep-1994	Stack Emissions (Gas Turbine And Duct Burner)	610 MMBTU/HR (TOTAL)	36.0 PPM, 69.5 LB/HR	water injection	53	BACT
Carolina Power And Light	SC	Aug-1994	Stationary Gas Turbine	1520 MMBTU/H	25.0 PPMDV @ 15% O2	water injection	30	BACT-PSD
Carolina Power And Light	SC	Aug-1994	Stationary Gas Turbine	1520 MMBTU/H	62.0 PPMDV @ 15% O2	water injection	30	BACT-PSD
Brush Cogeneration Partnership	CO	Jul-1994	Turbine	350 MMBTU/H	25.0 PPM @ 15% O2	dry low nox burner	74	BACT-PSD
Colorado Power Partnership	CO	Jul-1994	Turbines, 2 Nat Gas & 2 Duct Burners	385 MMBTU/H EACH TURBINE	42.0 PPM @ 15% O2	water injection	66	BACT-PSD
Muddy River L.P.	NV	Jun-1994	Combustion Turbine, Diesel & Natural Gas	140 MEGAWATT	303.0 LB/HR	low nox burner	0	BACT-PSD
Csw Nevada, Inc.	NV	Jun-1994	Combustion Turbine, Diesel & Natural Gas	140 MEGAWATT	273.0 LB/HR	dry low nox combustor	0	BACT-PSD
Portland General Electric Co.	OR	May-1994	Turbines, Natural Gas (2)	1720 MMBTU	4.5 PPM @ 15% O2	scr	82	BACT-PSD
Georgia Power Company, Robins Turbine Project	GA	May-1994	Turbine, Combustion, Natural Gas	80 MW	25.0 PPM	water injection, fuel spec: natural gas	0	BACT-PSD
West Campus Cogeneration Company	TX	May-1994	Gas Turbines	75 MW (TOTAL POWER)	200.0 TPY	internal combustion controls	0	BACT-PSD
Fleetwood Cogeneration Associates	PA	Apr-1994	Ng Turbine (Ge Lm6000) With Waste Heat Boiler	360 MMBTU/HR	21.0 LB/HR	scr with low nox combustors	47	BACT-OTHER
Hermiston Generating Co.	OR	Apr-1994	Turbines, Natural Gas (2)	1696 MMBTU	4.5 PPM @ 15% O2	scr	82	BACT-PSD
Florida Power Corporation Polk County Site	FL	Feb-1994	Turbine, Natural Gas (2)	1510 MMBTU/H	12 0 PPMVD @15 % O2	dry low nox combustor	0	BACT-PSD
Florida Power Corporation Polk County Site	FL	Feb-1994	Turbine, Fuel Oil (2)	1730 MMBTU/H	42 0 PPMVD @ 15 %O2	water injection	0	BACT-PSD
Teco Polk Power Station	FL	Feb-1994	Turbine, Syngas (Coal Gasification)	1755 MMBTU/H	25 0 PPMVD @ 15 % O2	dry low nox combustor	0	BACT-PSD
Teco Polk Power Station	FL	Feb-1994	Turbine, Fuel Oil	1765 MMBTU/H	42.0 PPMVD @ 15 % O2	wet injection	0	BACT-PSD

Table B-2. Summary of BACT Determinations for NOx.

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
International Paper	LA	Feb-1994	Turbine/Hrsg, Gas Cogen	338 MM BTU/HR TURBINE	25.0 PPMV 15% O2 TURBINE	dry low nox combustor/combustion control	0	BACT
Kamine/Besicorp Carthage L.P.	NY	Jan-1994	Ge Frame 6 Gas Turbine	491 BTU/HR	42.0 PPM, 76.6 LB/HR	steam injection	63	BACT
Kamine/Besicorp Carthage L.P.	NY	Jan-1994	Stack (Gas Turbine & Duct Burner) **See Note #3**	540 LB/MMBTU	42.0 PPM, 67.4 LB/HR	no controls	0	BACT-OTHER
Orange Cogeneration Lp	FL	Dec-1993	Turbine, Natural Gas, 2	366 MMBTU/H	15.0 PPM @ 15% O2	dry low nox combustor	0	BACT-PSD
Project Orange Associates	NY	Dec-1993	Ge Lm-5000 Gas Turbine	550 MMBTU/HR	25.0 PPM, 47 LB/HR	steam injection, fuel spec, natural gas only	60	BACT
Project Orange Associates	NY	Dec-1993	Stack (Turbine And Duct Burner)	715 MMBTU/HR	26 0 PPM, 69 LB/HR	no controls for nox on stack *see turbine nox data	0	BACT-OTHER
Williams Field Services Co. - El Cedro Compressor	NM	Oct-1993	Turbine, Gas-Fired	11257 HP	42.0 PPM @ 15% O2	solonox combustor, dry low nox technology	66	BACT-PSD
Florida Gas Transmission	FL	Sep-1993	Turbine, Gas	132 MMBTU/H	25 0 PPM @ 15% O2	dry low nox combustor	0	BACT-PSD
Patowmack Power Partners, Limited Partnership	VA	Sep-1993	Turbine, Combustion, Siemens Model V84 2, 3	10 X109 SCF/YR NAT GAS	131 0 LB/HR(GAS); 339 OIL	dry low nox combustor; design, water injection	0	BACT-PSD
Florida Gas Transmission Company	AL	Aug-1993	Turbine, Natural Gas	12600 BHP	0.6 GM/HP HR	air-to-fuel ratio control, dry low nox combustion	71	BACT-PSD
Lockport Cogen Facility	NY	Jul-1993	(6) Ge Frame 6 Turbines (Ep #S 00001-00006)	424 MMBTU/HR	42.0 PPM	steam injection	78	BACT
Anitec Cogen Plant	NY	Jul-1993	Ge Lm5000 Combined Cycle Gas Turbine Ep #00001	451 MMBTU/HR	25.0 PPM, 41 LB/HR	no controls	0	BACT-OTHER
Bank Of America Los Angeles Data Center	CA	Jun-1993	Turbine, Diesel & Generator (See Notes)	0	163.0 PPM @ 15% O2	fuel spec: low nox diesel fuel (see notes)	0	BACT-OTHER
Newark Bay Cogeneration Partnership, L P.	NJ	Jun-1993	Turbines, Combustion, Natural Gas-Fired (2)	617 MMBTU/HR (EACH)	8.3 PPMDV	scr	0	BACT-PSD
Newark Bay Cogeneration Partnership, L P.	NJ	Jun-1993	Turbines, Combustion, Kerosene-Fired (2)	640 MMBTU/H (EACH)	16.0 PPMDV	scr	0	BACT-PSD
Tiger Bay Lp	FL	May-1993	Turbine, Gas	1615 MMBTU/H	15.0 PPM @ 15% O2	dry low nox combustor	0	BACT-PSD
Tiger Bay Lp	FL	May-1993	Turbine, Oil	1850 MMBTU/H	42 0 PPM @ 15% O2	water injection	0	BACT-PSD
Indeck Energy Company	NY	May-1993	Ge Frame 6 Gas Turbine Ep #00001	491 MMBTU/HR	32.0 PPM	steam injection	58	BACT
Phoenix Power Partners	CO	May-1993	Turbine (Natural Gas)	311 MMBTU/HR	22 0 PPM @ 15% O2	dry low nox combustion	0	BACT-OTHER
Lilco Shoreham	NY	May-1993	(3) Ge Frame 7 Turbines (Ep #S 00007-9)	850 MMBTU/HR	55.0 PPM +FBN & HEAT RATE	water injection	30	BACT
Trigen Mitchel Field	NY	Apr-1993	Ge Frame 6 Gas Turbine	425 MMBTU/HR	60.0 PPM, 90 LB/HR	steam injection	20	BACT
Kissimmee Utility Authority	FL	Apr-1993	Turbine, Natural Gas	869 MMBTU/H	15.0 PPM @ 15% O2	dry low nox combustor	0	BACT-PSD
Kissimmee Utility Authority	FL	Apr-1993	Turbine, Fuel Oil	928 MMBTU/H	42.0 PPM @ 15% O2	water injection	0	BACT-PSD
Kissimmee Utility Authority	FL	Apr-1993	Turbine, Natural Gas	367 MMBTU/H	15.0 PPM @ 15% O2	dry low nox combustor	0	BACT-PSD
Kissimmee Utility Authority	FL	Apr-1993	Turbine, Fuel Oil	371 MMBTU/H	42.0 PPM @ 15% O2	water injection	0	BACT-PSD
East Kentucky Power Cooperative	KY	Mar-1993	Turbines (5), #2 Fuel Oil And Nat. Gas Fired	1492 MMBTU/H (EACH)	42.0 PPM @ 15% O2 (OIL)	water injection	46	SEE NOTES
International Paper Co Riverdale Mill	AL	Jan-1993	Turbine, Stationary (Gas-Fired) With Duct Burner	40 MW	0.1 LB/MMBTU (GAS)	steam injection into the turbine	0	BACT-PSD
Oklahoma Municipal Power Authority	OK	Dec-1992	Turbine, Combustion	58 MW	65 0 PPM @ 15% O2	combustion controls	63	BACT-OTHER
Oklahoma Municipal Power Authority	OK	Dec-1992	Turbine, Combustion	58 MW	25.0 PPM @ 15% O2	combustion controls	63	BACT-OTHER
Auburndale Power Partners, Lp	FL	Dec-1992	Turbine,Gas	1214 MMBTU/H	15.0 PPMVD @ 15 % O2	dry low nox combustor	0	BACT-PSD
Auburndale Power Partners, Lp	FL	Dec-1992	Turbine, Oil	1170 MMBTU/H	42.0 PPMVD @ 15 % 02	steam Injection	0	BACT-PSD
Sithe/Independence Power Partners	NY	Nov-1992	Turbines, Combustion (4) (Natural Gas) (1012 Mw)	2133 MMBTU/HR (EACH)	4.5 PPM	scr and dry low nox	0	BACT-OTHER
Kamine/Besicorp Beaver Falls Cogeneration Facility	NY	Nov-1992	Turbine, Combustion (Nat Gas & Oil Fuel) (79Mw)	650 MMBTU/HR	9 0 PPM	dry low nox or scr	0	BACT-OTHER
Kamine/Besicorp Beaver Falls Cogeneration Facility	NY	Nov-1992	Turbine, Combustion (Nat. Gas & Oil Fuel) (79Mw)	650 MMBTU/HR	55.0 PPM	dry low nox or scr	0	BACT-OTHER
Kamine/Besicorp Corning L.P.	NY	Nov-1992	Turbine, Combustion (79 Mw)	653 MMBTU/HR	9 0 PPM	dry low nox or scr	0	BACT-OTHER
Grays Ferry Co. Generation Partnership	PA	Nov-1992	Turbine (Natural Gas & Oil)	1150 MMBTU	9.0 PPMVD (NAT. GAS)*	dry low nox burner, combustion control	0	BACT-OTHER
Goal Line, Lp Icefloe	CA	Nov-1992	Turbine, Combustion (Natural Gas) (42 4 Mw)	386 MMBTU/HR	5.0 PPMVD @ 15% OXYGEN	water injection & scr w/ automatic ammonia inject.	88	BACT-OTHER
Bear Island Paper Company, L.P.	VA	Oct-1992	Turbine, Combustion Gas	474 X10(6) BTU/HR N. GAS	9.0 PPM	selective catalytic reduction (scr)	75	BACT-PSD
Bear Island Paper Company, L.P.	VA	Oct-1992	Turbine, Combustion Gas	488 X10(6) BTU/HR #2 OIL	15 0 PPM	scr	81	BACT-PSD
Bear Island Paper Company, L.P.	VA	Oct-1992	Turbine, Combustion Gas (Total)	0	89.7 TPY	scr	0	BACT-PSD
Gordonsville Energy L P.	VA	Sep-1992	Turbine Facility, Gas	1331 X10(7) SCF/Y NAT GAS	245.0 TOTAL TPY	selective catalytic reduction (scr) w/ water injec	80	BACT-PSD
Gordonsville Energy L.P.	VA	Sep-1992	Turbine Facility, Gas	7 X10(7) GPY FUEL OIL	245 0 TOTAL TPY	selective catalytic reduction (scr)	80	BACT-PSD
Gordonsville Energy L P.	VA	Sep-1992	Turbines (2) [Each With A Sf]	2 X10(9) BTU/HR N GAS	9 0 PPMDV/UNIT @ 15% 02	scr with water injection	80	BACT-PSD
Gordonsville Energy L.P.	VA	Sep-1992	Turbines (2) [Each With A Sf]	1 X10(9) BTU/H #2 OIL	66.0 LBS/HR/UNIT	water injection and scr	80	BACT-PSD
Kamine South Glens Falls Cogen Co	NY	Sep-1992	Ge Frame 6 Gas Turbine	498 MMBTU/HR	42.0 PPM, 76.6 LB/HR	water injection	50	BACT
Pasny/Holtsville Combined Cycle Plant	NY	Sep-1992	Turbine, Combustion Gas (150 Mw)	1146 MMBTU/HR (GAS)*	9.0 PPM	dry low nox	0	BACT-OTHER
Pasny/Holtsville Combined Cycle Plant	NY	Sep-1992	Turbine, Combustion Gas (150 Mw)	1146 MMBTU/HR (GAS)*	42.0 PPM	water injector	0	BACT-OTHER
Wepcu, Paris Site	WI	Aug-1992	Turbines, Combustion (4)	0	25.0 PPM @ 15% O2	good combustion practices	0	BACT-PSD
Wepcu, Paris Site	WI	Aug-1992	Turbines, Combustion (4)	0	65.0 PPM @ 15% O2	good combustion practices	0	BACT-PSD

Table B-2. Summary of BACT Determinations for NOx.

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Florida Power Corporation	FL	Aug-1992	Turbine, Oil	1029 MMBTU/H	42.0 PPMVD @ 15 % O2	wet injection	0	BACT-PSD
Florida Power Corporation	FL	Aug-1992	Turbine, Oil	1866 MMBTU/H	42.0 PPMVD @ 15 % O2	wet injection	0	BACT-PSD
Cng Transmission	OH	Aug-1992	Turbine (Natural Gas) (3)	5500 HP (EACH)	1.6 G/HP-HR*	low nox combustion	0	BACT-OTHER
Saranac Energy Company	NY	Jul-1992	Turbines, Combustion (2) (Natural Gas)	1123 MMBTU/HR (EACH)	9.0 PPM	scr	0	BACT-OTHER
Hartwell Energy Limited Partnership	GA	Jul-1992	Turbine, Gas Fired (2 Each)	1617 M BTU/HR	25.0 PPM @ 15% O2	maximum water injection	0	BACT-PSD
Hartwell Energy Limited Partnership	GA	Jul-1992	Turbine, Oil Fired (2 Each)	1640 M BTU/HR	25.0 PPMVD, FUEL N AFLOW	maximum water injection	0	BACT-PSD
Maui Electric Company, Ltd./Maalaea Generating Sta	HI	Jul-1992	Turbine, Combined-Cycle Combustion	28 MW	42.3 LB/HR	water injection	69	BACT-OTHER
Indeck-Yerkes Energy Services	NY	Jun-1992	Ge Frame 6 Gas Turbine (Ep #00001)	432 MMBTU/HR	42.0 PPM, 74 LB/HR	steam injection	35	BACT
Selkirk Cogeneration Partners, L.P.	NY	Jun-1992	Combustion Turbines (2) (252 Mw)	1173 MMBTU/HR (EACH)	9.0 PPM GAS	steam injection and scr	0	BACT-OTHER
Selkirk Cogeneration Partners, L.P.	NY	Jun-1992	Combustion Turbine (79 Mw)	1173 MMBTU/HR	25.0 PPM GAS	steam injection	0	BACT-OTHER
Narragansett Electric/New England Power Co.	RI	Apr-1992	Turbine, Gas And Duct Burner	1360 MMBTU/H EACH	9.0 PPM @ 15% O2, GAS	scr	0	BACT-PSD
Kentucky Utilities Company	KY	Mar-1992	Turbine, #2 Fuel Oil/Natural Gas (8)	1500 MM BTU/HR (EACH)	42.0 PPM @ 15% O2, N. GAS	water injection	0	BACT-PSD
Bermuda Hundred Energy Limited Partnership	VA	Mar-1992	Turbine, Combustion	1175 MMBTU/H NAT GAS	9.0 PPM @ 15% O2	scr, steam injection	91	BACT-PSD
Bermuda Hundred Energy Limited Partnership	VA	Mar-1992	Turbine, Combustion	1117 MMBTU/H NO2 FUEL OIL	15.0 PPM @ 15% O2	scr, steam inj.	91	BACT-PSD
Bermuda Hundred Energy Limited Partnership	VA	Mar-1992	Turbine, Combustion, 2	0	191.1 T/YR/UNIT		0	BACT-PSD
Thermo Industries, Ltd.	CO	Feb-1992	Turbine, Gas Fired, 5 Each	246 MMBTU/H	25.0 PPM @ 15% O2	dry low nox tech.	0	BACT-PSD
Savannah Electric And Power Co.	GA	Feb-1992	Turbines, 8	1032 MMBTU/H, NAT GAS	25.0 PPM @ 15% O2	max water injection	0	BACT-PSD
Savannah Electric And Power Co.	GA	Feb-1992	Turbines, 8	972 MMBTU/H, #2 OIL	0.0 SEE NOTES	max water injection	0	BACT-PSD
Hawaii Electric Light Co., Inc.	HI	Feb-1992	Turbine, Fuel Oil #2	20 MW	42.3 LB/HR	combustor water injector, water injection	70	BACT-PSD
Kamine/Besicorp Natural Dam Lp	NY	Dec-1991	Ge Frame 6 Gas Turbine	500 MMBTU/HR	42.0 PPM, 80.1 LB/HR	steam injection	35	BACT
Duke Power Co. Lincoln Combustion Turbine Station	NC	Dec-1991	Turbine, Combustion	1247 MM BTU/HR	287.0 LB/HR	multinozzle combustor, maximum water injection	0	BACT-PSD
Duke Power Co. Lincoln Combustion Turbine Station	NC	Dec-1991	Turbine, Combustion	1313 MM BTU/HR	119.0 LB/HR	multinozzle combustor, maximum water injection	0	BACT-PSD
Maui Electric Company, Ltd.	HI	Dec-1991	Turbine, Fuel Oil #2	28 MW	42.0 PPM	water injection	71	BACT-PSD
Kalamazoo Power Limited	MI	Dec-1991	Turbine, Gas-Fired, 2, W/ Waste Heat Boilers	1806 MMBTU/H	15.0 PPMV	dry low nox turbines	0	BACT-PSD
Lake Cogen Limited	FL	Nov-1991	Turbine, Gas, 2 Each	42 MW	25.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Lake Cogen Limited	FL	Nov-1991	Turbine, Oil, 2 Each	42 MW	42.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Orlando Utilities Commission	FL	Nov-1991	Turbine, Gas, 4 Each	35 MW	42.0 PPM @ 15% O2	wet injection	70	BACT-PSD
Orlando Utilities Commission	FL	Nov-1991	Turbine, Oil, 4 Each	35 MW	65.0 PPM @ 15% O2	wet injection	0	BACT-PSD
Southern California Gas	CA	Oct-1991	Turbine, Gas-Fired	48 MMBTU/H	8.0 PPMVD @ 15% O2	high temperature selective catalytic reduction	93	BACT-PSD
Southern California Gas	CA	Oct-1991	Turbine, Gas Fired, Solar Model H	5500 HP	8.0 PPM @ 15% O2	high temp select. cat. reduction	93	BACT-PSD
El Paso Natural Gas	AZ	Oct-1991	Turbine, Gas, Solar Centaur H	5500 HP	84.9 PPM @ 15% O2	lean burn	0	NSPS
El Paso Natural Gas	AZ	Oct-1991	Turbine, Gas, Solar Centaur H	5500 HP	42.0 PPM @ 15% O2	dry low nox combustor	51	BACT-PSD
El Paso Natural Gas	AZ	Oct-1991	Turbine, Gas, Solar Centaur H	5500 HP	85.1 PPM @ 15% O2	fuel spec: lean fuel mix	0	NSPS
El Paso Natural Gas	AZ	Oct-1991	Turbine, Gas, Solar Centaur H	5500 HP	42.0 PPM @ 15% O2	dry low nox combustor	51	BACT-PSD
El Paso Natural Gas	AZ	Oct-1991	Turbine, Nat. Gas Transm., Ge Frame 3	12000 HP	225.0 PPM @ 15% O2	lean burn	0	BACT-PSD
El Paso Natural Gas	AZ	Oct-1991	Turbine, Nat. Gas Transm., Ge Frame 3	12000 HP	42.0 PPM @ 15% O2	dry low nox combustor	80	BACT-PSD
Florida Power Generation	FL	Oct-1991	Turbine, Oil, 6 Each	93 MW	42.0 PPM @ 15% O2	wet injection	0	BACT-PSD
Carolina Power And Light Co.	SC	Sep-1991	Turbine, I.C.	80 MW	292.0 LB/H	water injection	50	BACT-PSD
Enron Louisiana Energy Company	LA	Aug-1991	Turbine, Gas, 2	39 MMBTU/H	40.0 PPM @ 15% O2	h2o inject 0.67 lb/lb	71	BACT-PSD
Algonquin Gas Transmission Co.	RI	Jul-1991	Turbine, Gas, 2	49 MMBTU/H	100.0 PPM @ 15% O2	low nox combustion	0	BACT-OTHER
Charles Larsen Power Plant	FL	Jul-1991	Turbine, Gas, 1 Each	80 MW	25.0 PPM @ 15% O2	wet injection	0	BACT-PSD
Charles Larsen Power Plant	FL	Jul-1991	Turbine, Oil, 1 Each	80 MW	42.0 PPM @ 15% O2	wet injection	0	BACT-PSD
Sumas Energy Inc.	WA	Jun-1991	Turbine, Natural Gas	88 MW	6.0 PPM @ 15% O2	scr	90	BACT-PSD
Saguaro Power Company	NV	Jun-1991	Combustion Turbine Generator	35 MW	16.9 PPH (WINTER)	selective catalytic reduction (scr)	80	BACT-PSD
Florida Power And Light	FL	Jun-1991	Turbine, Gas, 4 Each	400 MW	25.0 PPM @ 15% O2	low nox combustors	0	BACT-PSD
Florida Power And Light	FL	Jun-1991	Turbine, Oil, 2 Each	400 MW	65.0 PPM @ 15% O2	low nox combustors	0	BACT-PSD
Florida Power And Light	FL	Jun-1991	Turbine, Cg, 4 Each	400 MW	42.0 PPM @ 15% O2	low nox combustors	0	BACT-PSD
Granite Road Limited	CA	May-1991	Turbine, Gas, Electric Generation	461 MMBTU/H*	3.5 PPMVD @ 15% O2	scr, steam injection	97	BACT-PSD
Northern Consolidated Power	PA	May-1991	Turbines, Gas, 2	35 KW EACH	25.0 PPM @ 15% O2	steam injection/+scr in 1997	85	OTHER

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Lakewood Cogeneration, L.P.	NJ	Apr-1991	Turbines (Natural Gas) (2)	1190 MMBTU/HR (EACH)	0.0 LB/MMBTU	scr, dry low nox burner	64	BACT-OTHER
Lakewood Cogeneration, L.P.	NJ	Apr-1991	Turbines (#2 Fuel Oil) (2)	1190 MMBTU/HR (EACH)	0.1 LB/MMBTU	scr and water injection	0	BACT-OTHER
Cimarron Chemical	CO	Mar-1991	Turbine #1, Ge Frame 6	33 MW	25 0 PPM @ 15% O2	water injection	0	OTHER
Cimarron Chemical	CO	Mar-1991	Turbine #2, Ge Frame 6	33 MW	9 0 PPM @ 15% O2	scr	0	OTHER
Seminole Fertilizer Corporation	FL	Mar-1991	Turbine, Gas	26 MW	9.0 PPM @ 15% O2	scr	0	BACT-PSD
Florida Power And Light	FL	Mar-1991	Turbine, Gas, 4 Each	240 MW	42.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Florida Power And Light	FL	Mar-1991	Turbine, Oil, 4 Each	0	65 0 PPM @ 15% O2	combustion control	0	BACT-PSD
Commonwealth Atlantic Ltd Partnership	VA	Mar-1991	Turbine, Nat Gas & #2 Oil	1533 MMBTU/H EACH	25.0 PPM @ 15% O2	h2o injection & low nox combustion	0	BACT-PSD
Commonwealth Atlantic Ltd Partnership	VA	Mar-1991	Turbine, Nat Gas & #2 Oil	1400 MMBTU/H	42 0 PPMVD + 400 FBN ALL.	h2o injection, annual stack testing	0	BACT-PSD
Sumas Energy Inc	WA	Dec-1990	Turbine, Gas-Fired	67 MW	9 0 PPM @ 15% O2	selective catalytic reduction (scr)	90	BACT-PSD
Sargent Canyon Cogeneration Company	CA	Nov-1990	Turbine, Gas W/ Heat Recovery Steam Generator	43 MW	240 0 LB/D	turbine dry low nox combust sys w/ scr cntrl sys	0	BACT-PSD
Salinas River Cogeneration Company	CA	Nov-1990	Turbine,Gas, W/ Heat Recovery Steam Generator	43 MW	240.0 LB/D	turbine dry low nox combust sys w/ scr cntrl sys	0	BACT-PSD
Newark Bay Cogeneration Partnership	NJ	Nov-1990	Turbine, Natural Gas Fired	585 MMBTU/HR	0 0 LB/MMBTU	steam injection and scr	94	BACT-PSD
Newark Bay Cogeneration Partnership	NJ	Nov-1990	Turbine, Kerosene Fired	585 MMBTU/HR	0.1 LB/MMBTU	steam injection and scr	94	BACT-PSD
March Point Cogeneration Co	WA	Oct-1990	Turbine, Gas-Fired	80 MW	25 0 PPM @ 15% O2	massive steam injection	80	BACT-PSD
Las Vegas Cogeneration Ltd. Partnership	NV	Oct-1990	Turbine, Combustion Cogeneration	397 MMBTU/H	10 0 PPM @ 15% O2	h2o injection/scr	0	BACT-PSD
Wi Electric Power Co	WI	Oct-1990	Turbines, Combustion, Simple Cycle, 4	75 MW EACH	25 0 PPM @ 15% O2, GAS	h2o injection	0	BACT-PSD
Wi Electric Power Co.	WI	Oct-1990	Turbines, Combustion, Simple Cycle, 4	75 MW EACH	65.0 PPM @ 15% O2, OIL	h2o injection	0	BACT-PSD
Chem Process Incorporated	LA	Sep-1990	Turbine, Natural Gas	219 MMBTU/H	55 0 PPM @ 15% O2	low nox burners	0	OTHER
Commonwealth Gas Pipeline Corporation	VA	Sep-1990	Turbines, Gas Fired, Single Cycle, 5	14 MMBTU/H EACH	0.0	equipment design & operation	0	BACT-PSD
Delmarva Power	DE	Sep-1990	Turbine, Combustion	100 MW	0.1 LB/MMBTU	low nox burner	0	BACT-PSD
Tbg Cogen Cogeneration Plant	NY	Aug-1990	Ge Lm2500 Gas Turbine	215 MMBTU/HR	75 0 PPM + FBN CORRECTION	water injection	60	BACT
Vermont Marble Company	VT	Jul-1990	Turbines, Combustion, Dual Fuel Fired, 2	50 MMBTU/H EACH	42 0 PPM @ 15% O2	h2o injection, gas fuel	0	BACT-PSD
Vermont Marble Company	VT	Jul-1990	Turbines, Combustion, Dual Fuel Fired, 2	50 MMBTU/H EACH	60 0 PPM @ 15% O2	h2o injection, oil fuel	0	BACT-PSD
Doswell Limited Partnership	VA	May-1990	Turbine, Combustion	1261 MMBTU/H	9.0 PPM @ 15% O2	dry combustor to 25 ppm scr to 9 ppm using nat gas	0	OTHER
Doswell Limited Partnership	VA	May-1990	Turbine, Combustion	1261 MMBTU/H	65 0 PPM @ 15% O2	steam injection & fuel spec: use of #2 oil	0	OTHER
Kalaeloe Partners, L P.	HI	Mar-1990	Turbine, Lsfo, 2	1800 MMBTU/H, TOTAL	483 0 LB/H	steam injection at 1.3 to 1 steam to fuel ratio	77	BACT-PSD
Oneida Cogeneration Facility	NY	Feb-1990	Turbine, Ge Frame 6	417 MMBTU/H	32.0 PPM GAS	combustion control	0	OTHER
Pedricktown Cogeneration Limited Partnership	NJ	Feb-1990	Turbine, Natural Gas Fired	1000 MMBTU/HR	0.0 LB/MMBTU	steam injection and scr	93	BACT-PSD
Fulton Cogeneration Associates	NY	Jan-1990	Turbine, Ge Lm5000, Gas Fired	500 MMBTU/H	36 0 PPM GAS FIRING	h2o injection	0	BACT-PSD
Amoco Research Center	IL	Jan-1990	Turbine, Nat Gas Fired	96 MMBTU/H	49 0 PPM @ 15% O2	water injection	0	BACT-PSD
O'Brian California Cogen Ii, Limited	CA	Jan-1990	Turbine, Gas Generator Set W/Duct Burner	50 MW	350.4 LB/D	scr, dry type	0	LAER
Arrowhead Cogeneration Co.	VT	Dec-1989	Turbine, Combustion & Burner, Cogen , 3	282 MMBTU/H, GAS	9 0 PPMVD AT ISO COND &	scr, water injection	80	OTHER
Richmond Power Enterprise Partnership	VA	Dec-1989	Turbine, Gas Fired, 2	1164 MMBTU/H	8 2 PPM @ 15% O2 NAT GAS	scr, steam injection	0	LAER
Sc Electric And Gas Company - Hagood Station	SC	Dec-1989	Internal Combustion Turbine	110 MEGAWATTS	308.0 LBS/HR	water injection	0	BACT-PSD
Peabody Municipal Light Plant	MA	Nov-1989	Turbine, 38 Mw Natural Fas Fired	412 MMBTU/HR	25 0 PPM @ 15% O2	water injection	0	BACT-OTHER
Peabody Municipal Light Plant	MA	Nov-1989	Turbine, 38 Mw Oil Fired	412 MMBTU/HR	40 0 PPM @ 15% O2	water injection	0	BACT-OTHER
Jmc Selkirk, Inc	NY	Nov-1989	Turbine, Ge Frame 7, Gas Fired	80 MW	25 0 PPM GAS FIRING	steam injection	0	BACT-PSD
Oxy Ngl, Inc.	LA	Nov-1989	Turbine, Centaur Gas, 4	29 MMBTU/H	21.6 LB/H	combustion design	0	BACT-PSD
Oxy Ngl, Inc.	LA	Nov-1989	Turbine, Solar Gas	14 MMBTU/H	3.7 LB/H	combustion design	0	BACT-PSD
Oxy Ngl, Inc.	LA	Nov-1989	Turbine, Solar Gas	29 MMBTU/H	21 6 LB/H	combustion design	0	BACT-PSD
Pacific Gas Transmition	OR	Nov-1989	Turbine, Nat Gas	14600 HP	42 0 PPM @ 15% O2	low nox burners	75	BACT-PSD
Badger Creek Limited	CA	Oct-1989	Turbine, Gas Cogeneration	458 MMBTU/H	0.0 LB/MMBTU	scr, steam injection	0	BACT-PSD
Shell Offshore, Inc.	AL	Oct-1989	Turbine, Gas Fired	5000 HP	42.0 PPM	h2o injection	85	BACT-PSD
Capitol District Energy Center	CT	Oct-1989	Engine, Gas Turbine	739 MMBTU/H	42.0 PPM @ 15% O2, GAS	steam injection	0	BACT-PSD
University Of Michigan	MI	Oct-1989	Turbine, Gas, 2 Ea	4 MW	114 8 PPMV, OIL FIRED	h2o injection ratio, w/f=0.3 f.o., 0.5 gas	53	BACT-PSD
Arco Alaska, Inc.	AK	Oct-1989	Turbines, Gas Fired, 3	5400 HP/TURBINE	125.0 PPM @ 15% O2	dry control	0	BACT-PSD
The Dexter Corp.	CT	Sep-1989	Turbine, Nat Gas & #2 Fuel Oil Fired	555 MMBTU/H NAT GAS	42.0 PPM @ 15% O2 GAS	steam injection	0	BACT-PSD
Kingsburg Energy Systems	CA	Sep-1989	Turbine, Natural Gas Fired, Duct Burner	35 MW	6.0 PPM @ 15% O2	scr, steam injection	90	BACT-PSD

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
City Of Anaheim Gas Turbine Project	CA	Sep-1989	Turbine, Gas, Ge Pgim 5000	442 MMBTU/H	90.0 LB/D	scr, steam injection, co reactor	70	BACT-PSD
Panda-Rosemary Corp.	NC	Sep-1989	Turbine, Combustion, #6 Frame	499 MMBTU/H GAS	83.0 LB/H	h2o injection	0	BACT-PSD
Panda-Rosemary Corp.	NC	Sep-1989	Turbine, Combustion, #6 Frame	509 MMBTU/H OIL	134 0 LB/H	h2o injection	0	BACT-PSD
Panda-Rosemary Corp.	NC	Sep-1989	Turbine, Combustion, #7 Frame	1047 MMBTU/H GAS	173 0 LB/H	h2o injection	0	BACT-PSD
Panda-Rosemary Corp	NC	Sep-1989	Turbine, Combustion, #7 Frame	1060 MMBTU/H OIL	277.0 LB/H	h2o injection	0	BACT-PSD
Mobil E & P U.S., Inc.	CA	Sep-1989	Turbine, Gas Fired, 3 Ea	3 MW	2 1 LB/H	scr, catalyst/ammonia injection	0	BACT-PSD
Kamine Syracuse Cogeneration Co.	NY	Sep-1989	Turbine, Gas Fired	79 MW	36 0 PPM, NAT GAS	water injection	0	OTHER
Syracuse University	NY	Sep-1989	Turbine, Gas Fired	79 MW	25 0 PPM, GAS	steam injection	0	OTHER
Megan-Racine Associates, Inc	NY	Aug-1989	Ge Lm5000-N Combined Cycle Gas Turbine	401 LB/MMBTU	42.0 PPMDV @ 15% O2	water injection	60	BACT
Union Oil Co. Of California	AK	Aug-1989	Turbine, Gim Solar Saturn, 4 Ea	1300 MMBTU/H	115 0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, H&H Solar Saturn, 4 Ea	1300 MMBTU/H	115 0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Elect. Generator, 4 Ea	1100 MMBTU/H	115.0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Shipping, Solar Saturn	1100 MMBTU/H	115 0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Centaur West	4400 MMBTU/H	130 0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Saturn, Bingham	4400 MMBTU/H	130 0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Centaur East	4400 MMBTU/H	130 0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Centaur, 2 Ea	4400 MMBTU/H	130 0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Saturn, #1	1300 MMBTU/H	115 0 PPM @ 15% O2		0	BACT-PSD
Union Oil Co Of California	AK	Aug-1989	Turbine, Booster,Solar Saturn	1300 MMBTU/H	115.0 PPM @ 15% O2		0	BACT-PSD
Cimarron Chemical Inc.	CO	Aug-1989	Turbine, 2 Ea	271 MMBTU/H	65 0 PPM @ 15% O2	steam	0	BACT-PSD
Unocal	CA	Jul-1989	Turbine, Gas (See Notes)	0	9.0 PPM @ 15% O2	selective catalytic reduction (scr), water injectn	80	BACT-OTHER
Pratt & Whitney, Utc	CT	Jul-1989	Engine, Gas Turbine	238 MMBTU/H	0.8 LB/MMBTU		0	BACT-PSD
Hawaii Electric Light Co., Inc.	HI	Jun-1989	Turbine, Oil Fired	18 MW	34.8 LB/H	water injection	89	BACT-PSD
Pratt & Whitney, Utc	CT	Jun-1989	Engine, Test Turbine	240 MMBTU/H	0.3 LB/MMBTU GAS FIRING		0	BACT-PSD
Tropicana Products, Inc.	FL	May-1989	Turbine, Gas	45 MW	42.0 PPM @ 15% O2	steam injection	0	BACT-PSD
Empire Energy - Niagara Cogeneration Co.	NY	May-1989	Turbine, Gr Frame 6, 3 Ea	416 MMBTU/H	42.0 PPM GAS FIRING	steam injection	0	BACT-PSD
Megan-Racine Associates, Inc	NY	Mar-1989	Turbine, Lm5000	430 MMBTU/H	42.0 PPM GAS	h2o injection	0	BACT-PSD
Mojave Cogeneration Co., L.P.	CA	Mar-1989	Turbine, Gas	0	10.0 PPM @ 15% O2,DRY,	scr, steam injection	0	BACT-PSD
Indec/Oswego Hill Cogeneration	NY	Feb-1989	Turbine, Gas, Ge Frame 6	40 MW	42.0 PPM @ 15% O2, GAS	h2o injection	0	BACT-PSD
Pawtucket Power	RI	Jan-1989	Turbine/Duct Burner	533 MMBTU/H	9.0 PPM @ 15% O2, GAS	scr	0	BACT-PSD
L & J Energy System Cogeneration	NY	Jan-1989	Turbine, Gas, Ge Lm 5000	40 MW	42.0 PPM @ 15% O2, GAS	steam injection	0	BACT-PSD
Mojave Cogeneration Co.	CA	Jan-1989	Turbine, Gas	490 MMBTU/H	0.0 LB/MMBTU, GAS	fuel spec: oil firing limited to 11 h/d	0	BACT-PSD
Ocean State Power	RI	Dec-1988	Turbine, Gas, Ge Frame 7, 4 Ea	1059 MMBTU/H	9.0 PPM @ 15% O2	scr, h2o injection	0	BACT-PSD
Champion International	AL	Nov-1988	Turbine, Gas, Stationary	35 MW	42.0 PPM @ 15% O2	steam injection	70	BACT-PSD
Indeck - Yerks Energy Services, Inc.	NY	Nov-1988	Turbine, Gas, Ge Frame 6	40 MW	42.0 PPM @ 15% O2, GAS	steam injection	0	BACT-PSD
Texaco-Yokum Cogeneration Project	CA	Nov-1988	Turbine, Gas Fired, 2 Ea	25 MW	190.0 LB/D		0	BACT-PSD
Long Island Lighting Co.	NY	Nov-1988	Turbine, Ge Frame 7, 3 Ea	75 MW	55.0 PPM	water injection	0	BACT-PSD
Amtrak	PA	Oct-1988	Turbine, 2 Ea	20 MW	42.0 PPM @ 15% O2	h2o injection	0	BACT-PSD
Mobil Exploration & Producing Us, Inc.	CA	Sep-1988	Turbine & Burner, Duct	3 MW	91.0 LB/D	scr, catalyst/ammonia injection, h2o injection	65	BACT-PSD
Mobil Oil	CA	Sep-1988	Turbine, 2 Ea, W/Duct Burner	81 MMBTU/H	90.7 LB/D	molecular sieve type catalyst, h2o injection	0	BACT-PSD
Orlando Utilities Commission	FL	Sep-1988	Turbine, 2 Ea	35 MW	42 0 PPM @ 15% O2, GAS	steam injection	70	BACT-PSD
Kamine South Glens Falls	NY	Sep-1988	Turbine, Gas Fired, Ge Frame 6	40 MW	42 0 PPM, GAS	steam injection	0	BACT-PSD
Delmarva Power	DE	Aug-1988	Turbine, Combustion, 2 Ea	100 MW	42 0 PPM	low nox burner, water injection	0	BACT-PSD
Smud/Campbell Soup Co.	CA	Aug-1988	Turbine, Ge Frame 7	80 MW	1734 0 LB/D	steam/h2o injection	0	BACT-PSD
O'Brien Cogeneration	CT	Aug-1988	Turbine, Gas Fired	500 MMBTU/H	39 0 PPM @ 15% O2 GAS	water injection	0	BACT-PSD
O'Brien Cogeneration	CT	Aug-1988	Turbine, Gas Fired	500 MMBTU/H	39 0 PPM @ 15% O2 GAS	water injection	0	BACT-PSD
Continental Energy Assoc.	PA	Jul-1988	Turbine, Nat Gas	785 MMBTU/H	75 0 PPM @ 15% O2 DRY	steam injection	0	BACT-PSD
Marathon Oil Co.	NM	Jul-1988	Turbine, Ge, Gas Fired, 2 Ea	6000 HP	153 0 T/YR EA		0	NSPS
Kamine Carthage	NY	Jul-1988	Turbine, Gas Fired, Ge Frame 6	40 MW	42 0 PPM, GAS	steam injection	0	BACT-PSD

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Trigen	NY	Jul-1988	Turbine, Gas Fired, Ge Frame 6	40 MW	60 0 PPM, GAS	steam injection	0	BACT-PSD
Ada Cogeneration	MI	Jun-1988	Turbine	245 MMBTU/H	42.0 PPM @ 15% O2, 1H	h2o injection	59	BACT-PSD
Ccf-1	CT	May-1988	Turbine, Allison, 2 Ea	110 MMBTU/H GAS FIRED	38 0 PPM @ 15% O2 GAS	water injection	0	BACT-PSD
Merck Sharp & Pohme	PA	May-1988	Turbine	310 MMBTU/H	42 0 PPM @ 15% O2	steam injection	0	BACT-PSD
Virginia Power	VA	Apr-1988	Turbine, Ge,2 Ea	1875 MMBTU/H	42 0 PPM	steam injection w/maximization (nsps subpart gg)	0	LAER
Tbg/Grumman	NY	Mar-1988	Turbine, Gas, 2 Ea	16 MW	75 0 PPM + NSPS CORREC	h2o injection, combustion controls	79	BACT-PSD
Exxon Co , Usa	AL	Mar-1988	Turbine	3120 KW	0 0 PPM	combustion modification	0	BACT-PSD
Exxon Co., Usa	AL	Mar-1988	Turbine	3120 KW	0 0 PPM	combustion modification	0	BACT-PSD
Exxon Co., Usa	AL	Mar-1988	Turbine	3120 KW	0 0 PPM	combustion modification	0	BACT-PSD
Combined Energy Resources	CA	Feb-1988	Engine, Gas Turbine	2 KW	199.0 LB/H	scr, water injection	81	OTHER
Texas Gas Transmission Corp.	KY	Feb-1988	Turbine, Gas	14300 HP	0.0 % BY VOLUME		0	BACT-PSD
Great Lakes Gas Transmission	MI	Feb-1988	Turbine, #1	12500 HP	0.0 SEE NOTES		0	BACT-PSD
Great Lakes Gas Transmission	MI	Feb-1988	Turbine, #2	12500 HP	0.0 SEE NOTES		0	BACT-PSD
Great Lakes Gas Transmission	MI	Feb-1988	Turbine, #3	4000 HP	0 0 SEE NOTES		0	BACT-PSD
Midland Cogeneration Venture	MI	Feb-1988	Turbine, 12 Total	984 MMBTU/H	42 0 PPM @ 15% O2	steam injection	0	BACT-PSD
Midway-Sunset Cogeneration Co.	CA	Jan-1988	Turbine, Ge Frame 7, 3 Ea	75 MW	85.0 LB/H EA, NAT GAS, NO	h2o injection, "quiet combustor"	0	BACT-PSD
Midway-Sunset Cogeneration Co.	CA	Jan-1988	Turbine, Ge Frame 7, 3 Ea	75 MW	140 0 LB/H EA, OIL FIRING,	h2o injection, "quiet combustor"	0	BACT-PSD
Midway-Sunset Cogeneration Co.	CA	Jan-1988	Turbine, Ge Frame 7, 3 Ea	75 MW	243 0 LB/H TOTAL, NOTE 4	h2o injection, "quiet combustor"	0	BACT-PSD
Adm	IL	Jan-1988	Turbine, Gas, 2 Total	34 MW	0.3 LB STEAM/LB FUEL	steam injection, design	0	BACT-PSD
Thermopower & Electric	CO	Jan-1988	Turbine, Gas, 3 Ea	271 MMBTU/H	100 0 PPMV	steam injection	45	BACT-PSD
Cogeneration Resource, Inc.	CA	Nov-1987	Turbine, Dual Fuel, 5 Ea	1 MW	0 1 LB/MMBTU	scr, ammonia reducing agent	92	BACT-PSD
Exxon Co., Usa	CA	Nov-1987	Turbine, Gas, W/Duct Burner	49 MW	16.3 LB/H	low nox burner, scr, steam injection	90	BACT-PSD
Southeast Paper Corp.	GA	Oct-1987	Turbine, Combustion	545 MMBTU/H	100.0 PPM	steam injection	0	BACT-PSD
Chevron Usa, Inc.	CA	Sep-1987	Turbine & Duct Burner, 2 Of Each	99 MW TOTAL	1500.0 LB/D	scr, steam injection	0	BACT-PSD
Downtown Cogeneration Assoc	CT	Aug-1987	Turbine, Gas W/Duct Burner	72 MMBTU/H	42.0 PPM @ 15% O2 GAS	water injection	0	BACT-PSD
Baf Energy	CA	Jul-1987	Turbine, Generator	687 MMBTU/H	9.0 PPM AT 15% 02	scr, steam injection	80	BACT-PSD
Aes Placerita, Inc.	CA	Jul-1987	Turbine & Recovery Boiler	530 MMBTU/H	340.0 LB/D	scr, steam injection	0	BACT-PSD
Aes Placerita, Inc.	CA	Jul-1987	Turbine, Gas	530 MMBTU/H	289.0 LB/D	scr, steam injection	0	BACT-PSD
Power Development Co.	CA	Jun-1987	Turbine, Gas	49 MMBTU/H	36.0 LB/D	scr, h2o injection	0	BACT-PSD
Simpson Paper Co.	CA	Jun-1987	Turbine, Gas	50 MW	233 0 LB/D	scr, steam injection	0	OTHER
San Joaquin Cogen Limited	CA	Jun-1987	Generator, Gas Turbine	49 MW	250.0 LB/D	scr, h2o injection	78	BACT-PSD
Cogen Technologies	NJ	Jun-1987	Turbine, Gas, Ge Frame 6, 3 Ea	40 MW	9 6 PPMVD AT 15% O2	scr, h2o injection	95	OTHER
Trunkline Lng	LA	May-1987	Turbine,Gas, 2 Ea	147102 SCF/H	59.0 LB/H		0	OTHER
Pacific Gas Transmission Co.	OR	May-1987	Turbine, Gas	14000 HP	154.0 PPM	combustion control	0	BACT-PSD
Alaska Electrical Generation & Transmission	AK	Mar-1987	Turbine, Nat Gas Fired	80 MW	75.0 PPMVD AT 15% O2	h2o injection	0	BACT-PSD
U S. Borax & Chemical Corp.	CA	Feb-1987	Turbine, Gas	45 MW	40.0 LB/H	scr, water/steam injection	0	BACT-PSD
Sierra Ltd.	CA	Feb-1987	Turbine, Gas, Ge Lm2500, 2 Total	11 MMCF/D	4.0 LB/H EA	scr, co catalytic converter, steam injection	96	OTHER
California Institute Of Technology	CA	Jan-1987	Turbine/Generator	4 MW	72.0 LB/D	scr, h2o injection	80	BACT-PSD
Midway - Sunset Project	CA	Jan-1987	Turbine, Gas, 3	973 MMBTU/H	113.4 LB/H EA	h2o injection	73	BACT-PSD
City Of Santa Clara	CA	Jan-1987	Turbine, Gas	0	42.0 PPMVD AT 15% O2	water injection	0	BACT-PSD
O'Brien Energy Systems/Merchants Refrigeration Cog	CA	Dec-1986	Turbine, Gas Fired	360 MMBTU/H	30 3 LB/H	duct burner, h2o injection & scr	0	OTHER
California Dept. Of Corrections	CA	Dec-1986	Turbine, Gas, Csc-4500, 2 Net	5 MW	38.0 PPMV AT 15% O2	h2o injection at rate 1lb h2o to 1lb fuel	0	OTHER
Double 'C' Limited	CA	Nov-1986	Turbine, Gas, 2 Ea	25 MW	194 0 LB/D, TOTAL	h2o injection & scr	96	BACT-PSD
Kern Front Limited	CA	Nov-1986	Turbine, Gas, 2 Ea	25 MW	194.0 LB/D, TOTAL	h2o injection & scr	96	BACT-PSD
Arco Alaska Kuparuk Central Prod. Fac. #3	AK	Nov-1986	Turbine, Gas Fired, Comp, 3	14900 HP	115.0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Arco Alaska Kuparuk Central Prod Fac #3	AK	Nov-1986	Turbine, Gas Fired, Inject, 6	4900 HP	115 0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Arco Alaska Kuparuk Central Prod. Fac. #3	AK	Nov-1986	Turbine, Gas Fired, Pwr Gen	33400 HP	100.0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Arco Alaska Lisburne Development Project	AK	Oct-1986	Turbine, Gas Fired, Refrig., 3	5000 HP	115.0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Arco Alaska Lisburne Development Project	AK	Oct-1986	Turbine, Gas Fired, Pwr Gen, 4	12000 HP	115.0 PPMVD AT 15% O2	dry controls	0	BACT-PSD

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Arco Alaska Lisburne Development Project	AK	Oct-1986	Turbine, Gas Fired, Inject, 2	35000 HP	100.0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Amoco Production Co.	TX	Sep-1986	Engine, Turbine	25000 HP	342.0 T/YR		0	BACT-PSD
Pg & E, Station T	CA	Aug-1986	Turbine, Gas, Ge Lm5000	396 MMBTU/H	25.0 PPM AT 15% O2	steam injection at steam/fuel ratio = 1.7/1	75	BACT-PSD
Carolina Cogeneration Co., Inc.	NC	Jul-1986	Turbine, Gas, Peat Fired	416 MMBTU/H	125.0 PPMV	scr	71	BACT-PSD
Wichita Falls Energy Investments, Inc	TX	Jun-1986	Turbine, Gas, 3 Ea	20 MW	684.0 T/YR	steam injection	0	BACT-PSD
Formosa Plastic Corp.	TX	May-1986	Turbine, Gas, Ge Ms 6001	38 MW	640.0 T/YR	steam injection	0	BACT-PSD
Marathon Oil Co., Steelhead Platform	AK	May-1986	Turbine, Gas Fired, Pwr Gen, 3	4454 HP	115.0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Marathon Oil Co., Steelhead Platform	AK	May-1986	Turbine, Gas Fired, Compressor, 3	5278 HP	115.0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Kern Energy Corp	CA	Apr-1986	Turbine, Gas	9 MMCF/D	8.3 LB/H	scr w/nh3 reducing agent & combustor steam inj	87	BACT-PSD
Southeast Energy, Inc.	CA	Apr-1986	Turbine, Gas	8 MMCF/D	8.3 LB/H	scr w/nh3 reducing agent & combustor steam inj	87	BACT-PSD
Moran Power, Inc.	CA	Apr-1986	Turbine, Gas	8 MMCF/D	8.3 LB/H	scr w/nh3 reducing agent & combustor steam inj.	87	BACT-PSD
Monarch Cogeneration	CA	Apr-1986	Turbine & Generator, Steam	92 MMBTU/H	192 5 LB/D	scr	0	BACT-PSD
Monarch Cogeneration	CA	Apr-1986	Turbine & Generator, Steam	92 MMBTU/H	192.5 LB/D	scr	0	BACT-PSD
Babcock & Wilcox, Lauhoff Grain	IL	Mar-1986	Turbine	223 MMBTU/H	0 6 LB/MMBTU	fuel spec: fuel/operation	0	BACT-PSD
Western Power System, Inc.	CA	Mar-1986	Turbine, Gas Fired, Ge Lm2500	27 MW	9.0 PPMVD AT 15% O2	h2o injection & scr	80	OTHER
Aes Placerita, Inc.	CA	Mar-1986	Turbine & Recovery Boiler	519 MMBTU/H	629.0 LB/D	scr, h2o injection	0	BACT-PSD
Union Oil Co.	CA	Mar-1986	Turbine, Gas & Duct Burner	434 MMBTU/H	2.5 PPM AT 15% O2	scr, steam injection	45	BACT-PSD
Shell Ca Production, Inc	CA	Feb-1986	Turbine, Gas Fired, Ge Lm 2500	20 MW	42.0 PPM AT 15% O2 DRY	h2o injection	0	BACT-PSD
Chevron Usa, Inc	CA	Feb-1986	Turbine, Gas, 6 Ea	47 MMBTU/H	19.0 PPMVD AT 3% O2	low nox burner, scr, h2o injection	90	OTHER
Ols Energy	CA	Jan-1986	Turbine, Gas, Ge Lm2500	256 MMBTU/H	9.0 PPMVD AT 15% O2	h2o injection & scr	0	OTHER
Union Cogeneration	CA	Jan-1986	Turbine, Gas W/Duct Burner, 3 Ea	16 MW	25.0 PPMV AT 15% O2	h2o injection & scr	0	OTHER
Pacific Thermonetics, Inc.	CA	Dec-1985	Turbine, Gas, Frame 7, 2 Ea	1015 MMBTU/H	25.0 PPMV AT 15%, NAT. GA	quiet combustor. fuel spec: natural gas, firing limited to 330 h/yr of fuel oil firing	0	BACT-PSD
Energy Reserve, Inc.	CA	Oct-1985	Turbine, Gas Fired	323 MMBTU/H	165.4 LB/D	scr, water injection	93	BACT-PSD
American Cogeneration Technology	CA	Sep-1985	Turbine, Gas, 2 Ea, W/Waste Heat Rec. Boiler	220 MMBTU/H	17.0 PPMV AT 15% O2	h2o injection & scr	60	OTHER
Arco Alaska King Salmon Platform	AK	Sep-1985	Turbine, Gas Fired, Compressor	3950 HP	125 0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Gilroy Energy Co.	CA	Aug-1985	Turbine, Gas, 2	60 MW	25.0 PPMDV AT 15% O2	steam injection, quiet combustor	0	BACT-PSD
Sunlaw/Industrial Park 2	CA	Jun-1985	Turbine, Gas W/#2 Fuel Oil Backup, 2 Ea, Ge Frame	412 MMBTU/H	9.0 PPMVD AT 15% O2	scr, steam injection	80	OTHER
Proctor & Gamble	CA	Jun-1985	Turbine, Gas	217 MMBTU/H	75.0 PPM AT 15% O2, OIL	h2o injection	0	OTHER
Applied Energy Services	LA	May-1985	Turbine/Generator, Steam, Waste Heat	1413 MMBTU/H	414.0 LB/H	steam injection	0	BACT-PSD
Shell California Production Co.	CA	Apr-1985	Turbine, Gas Fired, 2 Ea	22 MW	42.0 PPM AT 15% O2	h2o injection	0	BACT-PSD
Conoco Milne Point	AK	Apr-1985	Turbine, Gas Fired, Total	50000 HP	100.0 PPMVD AT 15% O2		0	BACT-PSD
Willamette Industries	CA	Apr-1985	Turbine, Gas, Ge Lm-2500-33	230 MMBTU/H	15.0 PPMVD AT 15% O2	h2o injection & scr	92	OTHER
Greenleaf Power Co.	CA	Apr-1985	Turbine, Gas, Ge Lm-5000	36 MW	42.0 PPMV AT 15% O2	h2o injection	0	OTHER
Northern California Power	CA	Apr-1985	Turbine-Generator, Ge Frame 5, 2 Ea	26 MW	75.0 PPM, SEE NOTE	h2o injection	0	OTHER
Getty Oil Co.	CA	Mar-1985	Engine, Gas Turbine, 6 Ea	4 MW	7.6 LB/H	h2o injection at 0 8 lb h2o/lb fuel	0	BACT-PSD
Alaska Electrical Generation & Transmission	AK	Mar-1985	Turbine, Gas Fired, Pwr Gen	38 MW	75.0 PPM AT 15% O2	h2o injection	0	BACT-PSD
Champion International Corp.	TX	Mar-1985	Turbine, Gas, 2	1342 MMBTU/H	720.3 T/YR		0	BACT-PSD
Arco Alaska, Inc.	AK	Jan-1985	Turbine, Gas	10 MHP TOTAL	100 0 PPM AT 15% O2, DRY	low nox burners	0	BACT-PSD
Ciba-Geigy Corp.	NJ	Jan-1985	Turbine, Gas W/#2 Oil Backup	4000 HP	11.1 LB/H	h2o injection	55	OTHER
American Cogeneration Co.	CA	Dec-1984	Turbine, Gas/Crude Oil Fired, 5 Ea	1 MW	0.1 LB/MMBTU	scr w/ammonia reducing agent	92	BACT-PSD
Witco Chemical Corp.	CA	Dec-1984	Turbine	350 MMBTU/H	0.2 LB/MMBTU OIL		0	BACT-PSD
Ibm Cogeneration Project	CA	Dec-1984	Turbine, Gas	49 MW	25.0 PPM AT 15% O2	scr, h2o injection	0	LAER
Frito-Lay	CA	Nov-1984	Turbine, Gas Fired	6 MW	13.7 LB/H	h2o/steam injection	0	BACT-PSD
Vulcan Chemicals Co.	LA	Oct-1984	Turbine/Boiler, Nat Gas/Waste Heat, #3-84	196 MMBTU/H	224 7 LB/H	steam injection	0	BACT-PSD
Vulcan Chemicals Co.	LA	Oct-1984	Turbine/Boiler, Nat Gas/Waste Heat, #3-84	196 MMBTU/H	94 0 PPMV	steam injection	0	BACT-PSD
Vulcan Chemicals Co.	LA	Oct-1984	Turbine/Boiler, Nat Gas/Waste Heat, #4-84	196 MMBTU/H	224.7 LB/H	steam injection	0	BACT-PSD
Vulcan Chemicals Co.	LA	Oct-1984	Turbine/Boiler, Nat Gas/Waste Heat, #4-84	196 MMBTU/H	94.0 PPMV	steam injection	0	BACT-PSD
Sohio Alaska Petroleum Corp.	AK	Oct-1984	Turbine, Gas	1000 HP, NOTE #1	100 0 PPM AT 15% O2, DRY	low nox burners	0	BACT-PSD

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Sohio Alaska Petroleum Corp.	AK	Oct-1984	Turbine, Gas	1000 HP, NOTE #2	125.0 PPM AT 15% O2, DRY	low nox burners	0	BACT-PSD
Anchorage Municipal Light & Power	AK	Oct-1984	Turbine	82 MW	75.0 PPM AT 15% O2, DRY	wet controls	0	BACT-PSD
Basf Wyandotte Co.	LA	Sep-1984	Turbine, Nat Gas, #1-84	395 MMBTU/H	330.0 LB/H	combustor design	0	BACT-PSD
Northern California Power Agency	CA	Sep-1984	Turbine, Nat Gas, 2	26 MW	42.0 PPMD AT 15% O2	h2o injection	0	BACT-PSD
Northern California Power Agency	CA	Sep-1984	Turbine, 2, Fuel Oil	26 MW	62.0 PPMD AT 15% O2	h2o injection	0	BACT-PSD
Air Products & Chemicals, Inc.	LA	Jul-1984	Turbine/Boiler, Nat Gas/Waste Heat	203 MMBTU/H	172.0 LB/H	combustor design	0	BACT-PSD
Air Products & Chemicals, Inc.	LA	Jul-1984	Turbine/Boiler, Nat Gas/Waste Heat	203 MMBTU/H	217.0 PPM	combustor design	0	BACT-PSD
Explorer Pipeline Co.	TX	Jun-1984	Turbine, Gas	1100 HP	15.1 T/YR		0	OTHER
Texas Gulf Chemicals Co.	TX	Jun-1984	Turbine, Gas	78 MW	1366.0 T/YR	steam injection	0	NSPS
Texas Petro Chemicals Corp.	TX	Jun-1984	Turbine, Gas, 2 Ea	92 MW	1047.0 T/YR	steam injection	0	NSPS
Getty Oil Co.	CA	May-1984	Turbine, Gas	5000 HP	182.0 LB/D	h2o injection, 0.8-1	60	LAER
Calcogen	CA	Apr-1984	Turbine, Gas	21 MW	42.0 PPM AT 15% O2	water injection	76	BACT-PSD
U.S. Borax & Chemical Corp.	CA	Apr-1984	Turbine, Gas	3855 GAL/H	230.0 LB/H	water injection	70	BACT-PSD
Kissimmee Utilities	FL	Mar-1984	Turbine, Gas	400 MMBTU/H	79.0 PPM GAS FIRED	water injection	40	BACT-PSD
University Co-Generation Ltd., 1983-I	CA	Mar-1984	Turbine, Gas & Boiler, Waste Heat Fired	39 MW	199.0 LB/D	h2o injection, scr	97	OTHER
Amco Chemicals Corp.	TX	Mar-1984	Turbine, Gas	415 MMBTU/H	95.0 PPM	steam injection	37	BACT-PSD
Simpson Cogeneration Project	CA	Jan-1984	Turbine, W/Diesel Standby, Nat Gas Fired	3 MMBTU/H	3264.0 LB/D	see note #1	0	LAER
Tosco Corp.	CA	Dec-1983	Turbine, Gas, 2 Ea	500 MMBTU/H	45.0 PPM AT 15% O2	steam injection	0	OTHER
Dow Chemical, Usa	LA	Nov-1983	Turbine, #Gt-300 & Gt-400, 2 Ea	100 MW	1194.0 LB/H	combustion control	0	NSPS
Champlin Petroleum Co.	WY	Nov-1983	Turbine, 2 Ea	886 HP	150.0 PPM	design	0	BACT-PSD
Cardinal Cogen	CA	Jun-1983	Turbine, Gas	464 MMBTU/H	42.0 PPM AT 15% O2	steam injection	0	BACT-PSD
Southern Calif Edison Co.	CA	Apr-1983	Turbine, Gas, 20	65 MW EA	44.5 PPM	water injection	0	BACT-PSD
Trunkline Lng Co.	LA	Apr-1983	Turbine, Gas, 2	105 MMBTU/H	79.0 LB/H	combustion control, o2 & co monitor	0	NSPS
Kiln-Gas R & D Inc.	IL	Apr-1983	Turbine, Coal Gas Fired	0	75.0 PPM	purification of product gas	0	NSPS
Petro-Tex Chemical Corp	TX	Dec-1982	Turbine, Gas	982 MSCFH	237.9 LB/H	h2o injection	0	NSPS
Liquid Energy Corp.	TX	Nov-1982	Compressor, Turbine Engine, 2 Ea	3200 HP	1.8 G/HP-H		0	BACT-PSD
Simpson Lee Paper Co.	CA	Sep-1982	Turbine, Gas & Boiler, Waste Heat	33 MW	92.0 LB/H ANNUAL AV	h2o injection, continious emis monitor	0	BACT-PSD
Puget Sound Power & Light	WA	Aug-1982	Turbine, Gas, 2	100 MW EA	480.0 LB/H	water injection	0	BACT-PSD
Chugach Electric Association, Unit #4	AK	Aug-1982	Turbine, Gas	26 MW	130.0 LB/H	water injection	0	BACT-PSD
Texas Eastern Transmission Co.	PA	Jul-1982	Turbine, Gas	18500 HP	150.0 PPM	fuel spec: natural gas	0	BACT-PSD
Ibm Corp.	CA	Jun-1982	Turbine	4100 GAL/H	142.0 LB/H	h2o injection - 0.94 lb h2o/lb fuel	80	BACT-PSD
Ibm Corp.	NY	May-1982	Turbine, Gas, 2 Ea	3 MW	0.0	combustion controls	0	BACT-PSD
Algonquin Gas Transmission Co.	CT	Mar-1982	Engine, Turbine Compression	40 BHP	0.0 % BY VOL	manufacturer's guarantee	0	BACT-PSD
Crown Zellerbach, Inc.	CA	Mar-1982	Turbine, Gas	32 MW	42.0 PPM NO2 AT 15% O2	water/steam injection	0	BACT-PSD
Plains Elect. Gen & Trans	NM	Dec-1981	Generator, Turbine, Nat Gas Fired	729 MMBTU/H	270.0 LB/H	h2o injection (water/fuel = 0.5)	43	BACT-PSD
Plains Elect. Gen & Trans	NM	Dec-1981	Generator, Turbine, Oil Standby Fuel	722 MMBTU/H	280.0 LB/H	h2o injection (water/fuel = 0.5)	67	NSPS
Southern Ca Edison Coolwater Station	CA	Dec-1981	Turbine, Gas	100 MW	140.0 LB/H 3H AV	water injection	0	OTHER
Merck & Co., Keko Division	CA	Nov-1981	Turbine, 3	7 MW EA	20.0 LB/H PER TURBINE	water injection	70	BACT-PSD
Fort Howard Paper Co.	OK	Oct-1981	Turbine	400 MMBTU/H	0.3 LB/MMBTU #2 OIL	normal operation	0	BACT-PSD
Fort Howard Paper Co.	OK	Oct-1981	Turbine	400 MMBTU/H	0.2 LB/MMBTU N. GAS	water injection	0	BACT-PSD
Mobil Oil Exploration	AL	Oct-1981	Generator, Turbine, Gas Fired	8 MW	175.0 PPM BY VOL		0	BACT-PSD
Phillips Petroleum Co.	TX	Oct-1981	Turbine, 2	3000 HP EA	0.1 LB/MMBTU GAS	o2 monitoring	0	BACT-PSD
Prudhoe Bay Consortium	AK	Sep-1981	Turbine	303 MHP	150.0 PPM	dry control	0	BACT-PSD
Dow Chemical Co.	LA	Aug-1981	Turbine, Nat Gas Fired, 2 Ea	1203 MMBTU/H	0.4 LB/MMBTU	steam injection	65	NSPS
Gulf States Utility	LA	Jul-1981	Turbine	1390 MMBTU/H	0.3 LB/MMBTU OIL	steam injection	60	NSPS
Gulf States Utility	LA	Jul-1981	Turbine	1361 MMBTU/H	0.3 LB/MMBTU	steam injection	0	NSPS
Vulcan Materials Co	KS	Jul-1981	Turbine, Simple-Cycle, Nat Gas	39 MW	0.0 SEE NOTE	steam injection	0	BACT-PSD
Longview Refin.	TX	May-1981	Turbine, 3	6275 HP	1.3 G/HP-H		0	BACT-PSD
Odessa Natural Corp.	TX	Mar-1981	Turbine	7660 HP	1.3 G/HP-H	air/fuel ratio	0	BACT-PSD

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Northern Alaskan Pipeline	AK	Feb-1981	Turbine, Mainline Compressor	0	150.0 PPM	dry control	0	BACT-PSD
Northern Alaskan Pipeline	AK	Feb-1981	Turbine, Refrigerant Compressor	0	150.0 PPM	dry control	0	BACT-PSD
Northern Alaskan Pipeline	AK	Feb-1981	Turbine, Electric Generator	0	150.0 PPM	dry control	0	BACT-PSD
Gulf States Utility	LA	Jan-1981	Turbine, Combustion, 2	1336 MMBTU/H	334 0 LB/H	steam/water injection	0	NSPS
Gulf States Utility	LA	Jan-1981	Turbine, Combustion, 2	1336 MMBTU/H	362.0 LB/H	steam/water injection	0	NSPS
Florida Power	FL	Jan-1981	Turbine Peaking Units, 4 Ea	63 MW	250 0 LB/H	water injection	0	NSPS
Empire Dist. Elect. Co.	MO	Jan-1981	Turbine, Combustion, Simple-Cyc, Oil Fired, #2	1056 MMBTU/H (MAX)	230 0 PPMV, 15% O2, (ISO)-	design	0	BACT-PSD
Gulf States Utility	LA	Dec-1980	Turbine	1396 MMBTU/H	0.3 LB/MMBTU OIL	water/steam injection	60	NSPS
Prudhoe Bay Consortium	AK	Dec-1980	Turbine, Gas, 10	18 MHP EA	150.0 PPM	dry control	0	BACT-PSD
Nevada Pwr Co., Clark Station Unit #8	NV	Sep-1980	Generator, Combustion Turbine	74 MW	0.3 LB/MMBTU	water injection	0	NSPS
Texaco, Inc.	LA	Aug-1980	Compressor, Turbine, Gas Fired	3300 HP	9 4 LB/H		0	NSPS
Texaco, Inc.	LA	Aug-1980	Turbine, Gas Fired, Compression	3500 HP	1.8 G/HP-H		0	BACT-PSD
Diamond Shamrock Corp.	TX	Jun-1980	Turbine, Gas, 3	960 MMBTU/H EA	403.0 LB/H EA	water injection	0	NSPS
Proctor & Gamble Paper Products Co	CA	Apr-1980	Turbine, Gas	19 MW	0.3 LB/MMBTU FUEL OIL	water injection	0	BACT-PSD
Proctor & Gamble Paper Products Co.	TX	Feb-1980	Turbine, Gas, 2	350 MMBTU/H EA	118 8 LB/H	water injection	0	BACT-PSD
Phillips Petroleum Co.	TX	Jan-1980	Engine, Turbine Compressor	3000 HP EA	1.6 G/HP-H	normal operation	0	BACT-PSD
Nevada Pwr Co., Clark Station Unit #7	NV	Oct-1979	Generator, Gas Turbine	74 MW	0 3 LB/MMBTU	water injection	0	BACT-PSD

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

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

Cost Component	Costs	Basis of Cost Component
Diirect Annual Costs		
Operating Personnel	131,400	24 hours/week at $15/hr
Supervision	19,710	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	72,773	$300 per ton NH3
PSM/RMP Update	5,000	Engineering Estimate
Inventory Cost	151,895	Capital Recovery (16.27%) for 1/3 catalyst
Catalyst Disposal Cost	42,174	$28/1,000 lb/hr mass flow over 3 years; developed from vendor quotes
Contingency	42,295	10% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	465,247	
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	$134,330	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	$732,163	16.27% Capital Recovery Factor of 10% over 10 years times sum of TDCC, TDIC and TInCC
Annualized Total Direct Recurring	$1,125,880	40.21% Capital Recovery Factor of 10% over 3 years times RCC
Total Indirect Annual Costs	$2,065,361	
Total Annualized Costs	$3,124,346	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$5,236	

SUPPLEMENTAL CALCULATIONS RELATED TO SCR AND OPTIONS

Calculations of NOx Emissions Reductions and Ammonia Usage

NOx Emissions on Gas	237	lb/hr @ 50oF Base Load	25 ppmvd @ 15% O_2	142.2 lb/hr at	15 ppmvd @ 15% O_2
NOx Emissions on Oil	413	lb/hr @ 50oF Base Load	42 ppmvd @ 15% O_2		
Percentage of Gas Usage	96.43%	6758.00 hours per year			
Percentage of Oil Usage	3.57%	250.00 hours per year			
Capacity Factor	80%	7,008 hours per year			
NOx Emissions	852.45	tons per year	7.5 ppmvd @ 15% O_2		
NOx Removal Efficiency	70%		12.6 ppmvd @ 15% O_2		
NOx Removed	596.71	tons per year			
Ammonia Required (110% of theoretical)	242.58	tons per year; MW NH3/MW NO2			
Turbine Capacity	249	MW @ 59oF			

Calculations of 5 years only		Capital Recovery Factor at		10%
Total Indirect Costs		Years	Percent	
Overhead	$134,330	5	0.263797	
Property Taxes	$0	3	0.402115	
Insurance	$72,988			
Annualized Total Direct Capital	$1,186,782	151,895	at 10 years	
Annualized Total Direct Recurring	$1,125,880	246,211	at 5 years	
Total	$2,519,980	94,316	delta for 5 to 10 years	
Total Annualized Costs	$3,673,280			
Cost Effectiveness	$6,156			

Ammonia Slip Calculation

Slip	10	ppm	
Flow Rate @ 59oF Gas	3055750	acfm	
Temperature	1095	oF	PV=mRT
Emissions	27.46242867	lb/hr	m=PV/RT
	96.22835006	TPY	

Ammonia Salts

Sulfuric Dioxide	110	tons/year	
SO2 -> H2SO4	8.421875	tons/year	
Sulfuric Acid Mist	25.221875	tons/year	20.58929 tons/year of SO3
Ammonia Salts 2(NH4)* SO4	132	MW	
	33.97232143		

Energy Lost SCR Pressure Drop	8,724,960	kWhr/year
	727.08	residential customers
Energy Usage	560,640	kWhr/year
	46.72	residential customers
Total:	9,285,600	kWhr/year
	774	residential customers
	89,931	mmBtu/year
	90	mmcf/year of gas

Calculation of Going to 15 ppmvd after 5 years

NOx Emissions on Gas	142.2	lb/hr @ 50oF Base Load
NOx Emissions on Oil	413	lb/hr @ 50oF Base Load
Percentage of Gas Usage	0.964326	6758.00 hours per year
Percentage of Oil Usage	0.035674	250.00 hours per year
Capacity Factor	0.8	7,008 hours per year
NOx Emissions	532.12	tons per year
NOx Removal Efficiency	70%	
NOx Removed	372.48	tons per year
Average 20 year NOx Emissions	429	tons per year
Annualized Cost	$3,124,346	
Cost Effectiveness	$7,291	per of NOx removed

Cost Effectiveness of 15 ppmvd at initial

NOx Removed	372.48	tons per year
Annualized Cost	$3,124,346	
Cost Effectiveness	$8,388	

Future Installation of SCR

Installation of SCR in Year 5

Total Indirect Costs					
Overhead	$134,330				
Property Taxes	$0		"Hot" Catalyst Costs	$2,800,000	
Insurance	$72,988		Mass Flow	4,518,595	lb/hr
Annualized Total Direct Capital	$528,163	Adjusted for 20 years	"Hot" Cost	$0.62	per lb/hr mass flow
Annualized Total Direct Recurring	$545,078		Standard Catalyst	$0.30	per lb/hr mass flow
	$1,280,560		Std. Catalyst Cost	$1,355,579	
Annualized Costs	$2,339,544				
NOx Emissions Reduced	596.71				
Cost Effectiveness	$3,921				
Capital Costs	$4,498,837				
	$1,355,579				
	$5,854,415				

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Mead Coated Board, Inc.	AL	Mar-1997	Combined Cycle Turbine (25 Mw)	568 MMBTU/HR	28 0 PPMVD@15% O2 (GAS)	proper design and good combustion practices	0	BACT-PSD
Formosa Plastics Corporation, Baton Rouge Plant	LA	Mar-1997	Turbine/Hsrg, Gas Cogeneration	450 MM BTU/HR	70.0 LB/HR	combustion design and construction	0	BACT-PSD
Southwestern Public Service Company/Cunningham Sta	NM	Feb-1997	Combustion Turbine, Natural Gas	100 MW	0 0 SEE FACILITY NOTES	good combustion practices	0	BACT-PSD
Southwestern Public Service Co/Cunningham Station	NM	Nov-1996	Combustion Turbine, Natural Gas	100 MW	0 0 SEE P2	good combustion practices	0	BACT-PSD
Blue Mountain Power, Lp	PA	Jul-1996	Combustion Turbine With Heat Recovery Boiler	153 MW	3 1 PPM @ 15% O2	oxidation catalyst 18 ppm @ 15% o2 when firing no. 2 oil. at 75% ng limit set to 22.1 ppm	80	OTHER
Portside Energy Corp.	IN	May-1996	Turbine, Natural Gas-Fired	63 MEGAWATT	40 0 LBS/HR	good combustion and emissions not to exceed 40 ppmvd at 15% oxygen.	0	BACT-PSD
Portside Energy Corp.	IN	May-1996	Turbine, Natural Gas-Fired	63 MEGAWATT	12 0 LBS/HR	good combustion and emissions not to exceed 10 ppmvd at 15% oxygen.	0	BACT-PSD
General Electric Gas Turbines	SC	Apr-1996	I.C. Turbine	2700 MMBTU/HR	27169 0 LB/HR	good combustion practices to minimize emissions	0	BACT-PSD
Carolina Power & Light	NC	Apr-1996	Combustion Turbine, 4 Each	1908 MMBTU/HR	81 0 LB/HR	combustion control	0	BACT-PSD
Carolina Power & Light	NC	Apr-1996	Combustion Turbine, 4 Each	1908 MMBTU/HR	80 0 LB/HR	combustion control	0	BACT-PSD
South Mississippi Electric Power Assoc.	MS	Apr-1996	Combustion Turbine, Combined Cycle	1299 MMBTU/HR NAT GAS	26 3 PPM @ 15% O2, GAS	good combustion controls	0	BACT-PSD
Mid-Georgia Cogen	GA	Apr-1996	Combustion Turbine (2), Natural Gas	116 MW	10 0 PPMVD	complete combustion	0	BACT-PSD
Mid-Georgia Cogen.	GA	Apr-1996	Combustion Turbine (2), Fuel Oil	116 MW	30 0 PPMVD	complete combustion	0	BACT-PSD
Georgia Gulf Corporation	LA	Mar-1996	Generator, Natural Gas Fired Turbine	1123 MM BTU/HR	972 4 TPY CAP FOR 3 TURB.	good combustion practice and proper operation	0	BACT-PSD
Seminole Hardee Unit 3	FL	Jan-1996	Combined Cycle Combustion Turbine	140 MW	20 0 PPM (NAT. GAS)	dry lnb good combustion	0	BACT-PSD
Key West City Electric System	FL	Sep-1995	Turbine, Existing Ct Relocation To A New Plant	23 MW	20 0 PPM @ 15% O2 FULL LD	good combustion	0	BACT-PSD
Union Carbide Corporation	LA	Sep-1995	Generator, Gas Turbine	1313 MM BTU/HR	198 6 LB/HR	no add-on control good combustion practice	0	BACT-PSD
Brooklyn Navy Yard Cogeneration Partners L.P.	NY	Jun-1995	Turbine, Natural Gas Fired	240 MW	4 0 PPM @ 15% O2		0	LAER
Brooklyn Navy Yard Cogeneration Partners L P.	NY	Jun-1995	Turbine, Oil Fired	240 MW	5.0 PPM @ 15% O2		0	LAER
Panda-Kathleen, L.P.	FL	Jun-1995	Combined Cycle Combustion Turbine (Total 115Mw)	75 MW	25 0 PPM @ 15% O2	combustion controls standard only applies if ge ct is selected, the abb ct was less than significant emis. incr for co	0	BACT-PSD
Milagro, Williams Field Service	NM	May-1995	Turbine/Cogen, Natural Gas (2)	900 MMCF/DAY	27.6 PPM @ 15% O2		0	BACT-PSD
Pilgrim Energy Center	NY	Apr-1995	(2) Westinghouse W501D5 Turbines (Ep #S 00001&2)	1400 MMBTU/HR	10.0 PPM, 29.0 LB/HR		0	BACT-OTHER
Lederle Laboratories	NY	Apr-1995	(2) Gas Turbines (Ep #S 00101&102)	110 MMBTU/HR	48.0 PPM, 12.6 LB/HR		0	BACT-OTHER
Baltimore Gas & Electric - Perryman Plant	MD	Mar-1995	Turbine, 140 Mw Natural Gas Fired Electric	140 MW	20.0 PPM @ 15% O2	good combustion practices	0	BACT-PSD
Formosa Plastics Corporation, Louisiana	LA	Mar-1995	Turbine/Hrsg, Gas Cogeneration	450 MM BTU/HR	25 8 LB/HR	proper operation	0	BACT-PSD
Marathon Oil Co. - Indian Basin N G. Plan	NM	Jan-1995	Turbines, Natural Gas (2)	5500 HP	13 2 LBS/HR	lean-premixed combustion technology.	66	BACT-PSD
Kamine/Besicorp Syracuse Lp	NY	Dec-1994	Siemens V64.3 Gas Turbine (Ep #00001)	650 MMBTU/HR	9.5 PPM	no controls	0	BACT-OTHER
Indeck-Oswego Energy Center	NY	Oct-1994	Ge Frame 6 Gas Turbine	533 LB/MMBTU	10 0 PPM, 10 00 LB/HR	no controls	0	BACT-OTHER
Fulton Cogen Plant	NY	Sep-1994	Ge Lm5000 Gas Turbine	500 MMBTU/HR	107 0 PPM, 120 LB/HR	no controls	0	BACT-OTHER
Fulton Cogen Plant	NY	Sep-1994	Stack Emissions (Gas Turbine And Duct Burner)	610 MMBTU/HR (TOTAL)	156 0 PPM, 175.0 LB/HR	no controls .	0	BACT-OTHER
Carolina Power And Light	SC	Aug-1994	Stationary Gas Turbine	1520 MMBTU/H	702.0 LB/H	proper operation to achieve good combustion	0	BACT-PSD
Carolina Power And Light	SC	Aug-1994	Stationary Gas Turbine	1520 MMBTU/H	414 0 LB/H	proper operation to achieve good combustion	0	BACT-PSD
Colorado Power Partnership	CO	Jul-1994	Turbines, 2 Nat Gas & 2 Duct Burners	385 MMBTU/H EACH TURBINE	22.4 PPM @ 15% O2		0	BACT-PSD
Muddy River L.P.	NV	Jun-1994	Combustion Turbine, Diesel & Natural Gas	140 MEGAWATT	77.0 LB/HR	fuel spec: natural gas	0	BACT-PSD
Csw Nevada, Inc.	NV	Jun-1994	Combustion Turbine, Diesel & Natural Gas	140 MEGAWATT	83 0 LB/HR	fuel spec: natural gas	0	BACT-PSD
Portland General Electric Co.	OR	May-1994	Turbines, Natural Gas (2)	1720 MMBTU	15 0 PPM @ 15% O2	good combustion practices	0	BACT-PSD
West Campus Cogeneration Company	TX	May-1994	Gas Turbines	75 MW (TOTAL POWER)	300 0 TPY	internal combustion controls	0	BACT
Hermiston Generating Co.	OR	Apr-1994	Turbines, Natural Gas (2)	1696 MMBTU	15 0 PPM @ 15% O2	good combustion practices	0	BACT-PSD
Florida Power Corporation Polk County Site	FL	Feb-1994	Turbine, Natural Gas (2)	1510 MMBTU/H	25 0 PPMVD	good combustion practices	0	BACT-PSD
Florida Power Corporation Polk County Site	FL	Feb-1994	Turbine, Fuel Oil (2)	1730 MMBTU/H	30 0 PPMVD	good combustion practices	0	BACT-PSD
Teco Polk Power Station	FL	Feb-1994	Turbine, Syngas (Coal Gasification)	1755 MMBTU/H	25 0 PPMVD	good combustion	0	BACT-PSD
Teco Polk Power Station	FL	Feb-1994	Turbine, Fuel Oil	1765 MMBTU/H	40 0 PPMVD	good combustion	0	BACT-PSD
International Paper	LA	Feb-1994	Turbine/Hrsg; Gas Cogen	338 MM BTU/HR TURBINE	165 9 LB/HR	combustion control	0	BACT

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Kamine/Besicorp Carthage L.P.	NY	Jan-1994	Ge Frame 6 Gas Turbine	491 BTU/HR	10.0 PPM, 11.0 LB/HR	no controls	0	BACT-OTHER
Kamine/Besicorp Carthage L.P.	NY	Jan-1994	Stack (Gas Turbine & Duct Burner) **See Note #3**	540 LB/MMBTU	23.0 PPM, 28.3 LB/HR	no controls	0	BACT-OTHER
Orange Cogeneration Lp	FL	Dec-1993	Turbine, Natural Gas, 2	368 MMBTU/H	30.0 PPMVD	good combustion	0	BACT-PSD
Project Orange Associates	NY	Dec-1993	Ge Lm-5000 Gas Turbine	550 MMBTU/HR	92.0 LB/HR TEMP > 20F	no controls	0	BACT-OTHER
Project Orange Associates	NY	Dec-1993	Stack (Turbine And Duct Burner)	715 MMBTU/HR	106.4 LB/HR TEMP > 20F	oxidation catalyst	80	BACT
Williams Field Services Co. - El Cedro Compressor	NM	Oct-1993	Turbine, Gas-Fired	11257 HP	50.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Patowmack Power Partners, Limited Partnership	VA	Sep-1993	Turbine, Combustion, Siemens Model V84 2, 3	10 X109 SCF/YR NAT GAS	28.0 LB/HR	good combustion operating practices	0	BACT-PSD
Florida Gas Transmission Company	AL	Aug-1993	Turbine, Natural Gas	12600 BHP	0.4 GM/HP HR	air-to-fuel ratio control, dry combustion controls	0	BACT-PSD
Lockport Cogen Facility	NY	Jul-1993	(6) Ge Frame 6 Turbines (Ep #S 00001-00006)	424 MMBTU/HR	10.0 PPM	no controls	0	BACT-OTHER
Anitec Cogen Plant	NY	Jul-1993	Ge Lm5000 Combined Cycle Gas Turbine Ep #00001	451 MMBTU/HR	36.0 PPM, 33 LB/HR	baffle chamber	80	SEE NOTE #4
Newark Bay Cogeneration Partnership, L.P.	NJ	Jun-1993	Turbines, Combustion, Natural Gas-Fired (2)	617 MMBTU/HR (EACH)	1.8 PPMDV	oxidation catalyst	0	OTHER
Newark Bay Cogeneration Partnership, L.P.	NJ	Jun-1993	Turbines, Combustion, Kerosene-Fired (2)	640 MMBTU/H (EACH)	2.6 PPMDV	oxidation catalyst	0	OTHER
Psi Energy, Inc. Wabash River Station	IN	May-1993	Combined Cycle Syngas Turbine	1775 MMBTU/HR	15.0 LESS THAN PPM	operation practices and good combustion, combined cycle syngas turbine	0	BACT-PSD
Tiger Bay Lp	FL	May-1993	Turbine, Gas	1615 MMBTU/H	49.0 LB/H	good combustion practices	0	BACT-PSD
Tiger Bay Lp	FL	May-1993	Turbine, Oil	1650 MMBTU/H	98.4 LB/H	good combustion practices	0	BACT-PSD
Indeck Energy Company	NY	May-1993	Ge Frame 6 Gas Turbine Ep #00001	491 MMBTU/HR	40.0 PPM	no controls	0	BACT-OTHER
Lilco Shoreham	NY	May-1993	(3) Ge Frame 7 Turbines (Ep #S 00007-9)	850 MMBTU/HR	10 0 PPM, 19 7 LB/HR	no controls	0	BACT-OTHER
Trigen Mitchel Field	NY	Apr-1993	Ge Frame 6 Gas Turbine	425 MMBTU/HR	10.0 PPM, 10 0 LB/HR	no controls	0	BACT-OTHER
Kissimmee Utility Authority	FL	Apr-1993	Turbine, Natural Gas	869 MMBTU/H	54.0 LB/H	good combustion practices	0	BACT-PSD
Kissimmee Utility Authority	FL	Apr-1993	Turbine, Fuel Oil	928 MMBTU/H	65.0 LB/H	good combustion practices	0	BACT-PSD
Kissimmee Utility Authority	FL	Apr-1993	Turbine, Natural Gas	367 MMBTU/H	40.0 LB/H	good combustion practices	0	BACT-PSD
Kissimmee Utility Authority	FL	Apr-1993	Turbine, Fuel Oil	371 MMBTU/H	76.0 LB/H	good combustion practices	0	BACT-PSD
East Kentucky Power Cooperative	KY	Mar-1993	Turbines (5), #2 Fuel Oil And Nat. Gas Fired	1492 MMBTU/H (EACH)	75 0 LBS/H (EACH)	proper combustion techniques	0	BACT-OTHER
International Paper Co. Riverdale Mill	AL	Jan-1993	Turbine, Stationary (Gas-Fired) With Duct Burner	40 MW	22.1 LB/HR	design	0	BACT-PSD
Auburndale Power Partners, Lp	FL	Dec-1992	Turbine,Gas	1214 MMBTU/H	15 0 PPMVD	good combustion practices	0	BACT-PSD
Auburndale Power Partners, Lp	FL	Dec-1992	Turbine, Oil	1170 MMBTU/H	25.0 PPMVD	good combustion practices	0	BACT-PSD
Sithe/Independence Power Partners	NY	Nov-1992	Turbines, Combustion (4) (Natural Gas) (1012 Mw)	2133 MMBTU/HR (EACH)	13.0 PPM	combustion controls	0	BACT-OTHER
Kamine/Besicorp Beaver Falls Cogeneration Facility	NY	Nov-1992	Turbine, Combustion (Nat. Gas & Oil Fuel) (79Mw)	650 MMBTU/HR	9 5 PPM	combustion controls	0	BACT-OTHER
Grays Ferry Co. Generation Partnership	PA	Nov-1992	Turbine (Natural Gas & Oil)	1150 MMBTU	0.0 LB/MMBTU (GAS)*	combustion	0	BACT-OTHER
Bear Island Paper Company, L.P.	VA	Oct-1992	Turbine, Combustion Gas	474 X10(6) BTU/HR N. GAS	11.0 LBS/HR	good combustion	0	BACT-PSD
Bear Island Paper Company, L.P.	VA	Oct-1992	Turbine, Combustion Gas	468 X10(6) BTU/HR #2 OIL	11.0 LBS/HR	good combustion	0	BACT-PSD
Bear Island Paper Company, L.P.	VA	Oct-1992	Turbine, Combustion Gas (Total)	0	48.2 TPY	good combustion	0	BACT-PSD
Gordonsville Energy L.P	VA	Sep-1992	Turbine Facility, Gas	1331 X10(7) SCF/Y NAT GAS	249.9 TOTAL TPY	good combustion practices	0	BACT-PSD
Gordonsville Energy L.P.	VA	Sep-1992	Turbine Facility, Gas	7 X10(7) GPY FUEL OIL	249 9 TOTAL TPY	good combustion practices	0	BACT-PSD
Gordonsville Energy L.P.	VA	Sep-1992	Turbines (2) [Each With A Sf]	2 X10(9) BTU/HR N GAS	57 0 LBS/HR/UNIT	good combustion practices	0	BACT-PSD
Gordonsville Energy L.P.	VA	Sep-1992	Turbines (2) [Each With A Sf]	1 X10(9) BTU/H #2 OIL	68 0 LBS/HR/UNIT	good combustion practices	0	BACT-PSD
Nevada Power Company, Harry Allen Peaking Plant	NV	Sep-1992	Combustion Turbine Electric Power Generation	600 MW (8 UNITS 75 EACH)	152.5 TPY (EACH TURBINE)	precision control for the low nox combustor	0	BACT-PSD
Kamine South Glens Falls Cogen Co	NY	Sep-1992	Ge Frame 6 Gas Turbine	498 MMBTU/HR	9.0 PPM, 11.0 LB/HR	no controls	0	BACT-OTHER
Northern States Power Company	SD	Sep-1992	Turbine, Simple Cycle, 4 Each	129 MW	50 0 PPM FOR GAS	good combustion techniques	0	BACT-PSD
Pasny/Holtsville Combined Cycle Plant	NY	Sep-1992	Turbine, Combustion Gas (150 Mw)	1146 MMBTU/HR (GAS)*	8.5 PPM	combustion control	0	BACT-OTHER
Wepcu, Paris Site	WI	Aug-1992	Turbines, Combustion (4)	0	25 0 LBS/HR (SEE NOTES)		0	BACT-PSD
Florida Power Corporation	FL	Aug-1992	Turbine, Oil	1029 MMBTU/H	54 0 LB/H	good combustion practices	0	BACT-PSD
Florida Power Corporation	FL	Aug-1992	Turbine, Oil	1866 MMBTU/H	79 0 LB/H	good combustion practices	0	BACT-PSD
Cng Transmission	OH	Aug-1992	Turbine (Natural Gas) (3)	5500 HP (EACH)	0.0 G/HP-HR	fuel spec: use of natural gas	0	OTHER
Saranac Energy Company	NY	Jul-1992	Turbines, Combustion (2) (Natural Gas)	1123 MMBTU/HR (EACH)	3.0 PPM	oxidation catalyst	0	BACT-OTHER
Hartwell Energy Limited Partnership	GA	Jul-1992	Turbine, Gas Fired (2 Each)	1817 M BTU/HR	25.0 PPMVD @ FULL LOAD	fuel spec: clean burning fuels	0	BACT-PSD
Hartwell Energy Limited Partnership	GA	Jul-1992	Turbine, Oil Fired (2 Each)	1840 M BTU/HR	25 0 PPMVD @ FULL LOAD	fuel spec: clean burning fuels	0	BACT-PSD
Maui Electric Company, Ltd /Maalaea Generating Sta	HI	Jul-1992	Turbine, Combined-Cycle Combustion	28 MW	26 9 LB/HR	combustion technology/design	0	BACT-OTHER

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Indeck-Yerkes Energy Services	NY	Jun-1992	Ge Frame 6 Gas Turbine (Ep #00001)	432 MMBTU/HR	10.0 PPM, 10 LB/HR	no controls	0	BACT-OTHER
Selkirk Cogeneration Partners, L.P.	NY	Jun-1992	Combustion Turbines (2) (252 Mw)	1173 MMBTU/HR (EACH)	10.0 PPM	combustion controls	0	BACT-OTHER
Selkirk Cogeneration Partners, L.P.	NY	Jun-1992	Combustion Turbine (79 Mw)	1173 MMBTU/HR	25.0 PPM	combustion control	0	BACT-OTHER
Narragansett Electric/New England Power Co.	RI	Apr-1992	Turbine, Gas And Duct Burner	1360 MMBTU/H EACH	11.0 PPM @ 15% O2, GAS		0	BACT-PSD
Kentucky Utilities Company	KY	Mar-1992	Turbine, #2 Fuel Oil/Natural Gas (6)	1500 MM BTU/HR (EACH)	75.0 LB/HR (EACH)	combustion control	0	BACT-PSD
Bermuda Hundred Energy Limited Partnership	VA	Mar-1992	Turbine, Combustion	1175 MMBTU/H NAT. GAS	62.0 LB/H/UNIT	furnace design	91	BACT-PSD
Bermuda Hundred Energy Limited Partnership	VA	Mar-1992	Turbine, Combustion	1117 MMBTU/H NO2 FUEL OIL	62.0 LB/H/UNIT	furnace design	91	BACT-PSD
Bermuda Hundred Energy Limited Partnership	VA	Mar-1992	Turbine, Combustion, 2	0	229.3 T/YR/UNIT		0	BACT-PSD
Thermo Industries, Ltd.	CO	Feb-1992	Turbine, Gas Fired, 5 Each	246 MMBTU/H	25.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Savannah Electric And Power Co.	GA	Feb-1992	Turbines, 8	1032 MMBTU/H, NAT GAS	9.0 PPM @ 15% O2	fuel spec: low sulfur fuel oil	0	BACT-PSD
Savannah Electric And Power Co.	GA	Feb-1992	Turbines, 8	972 MMBTU/H, #2 OIL	9.0 PPM @ 15% O2	fuel spec: low sulfur fuel oil	0	BACT-PSD
Hawaii Electric Light Co., Inc.	HI	Feb-1992	Turbine, Fuel Oil #2	20 MW	26.8 LB/HR @ 100% PEAKLD	combustion design	0	BACT-PSD
Hawaii Electric Light Co., Inc	HI	Feb-1992	Turbine, Fuel Oil #2	20 MW	56.4 LB/H @ 75-<100% PKLD	combustion design	0	BACT-PSD
Hawaii Electric Light Co., Inc.	HI	Feb-1992	Turbine, Fuel Oil #2	20 MW	181.0 LB/H @ 50-<75% PKLD	combustion design	0	BACT-PSD
Hawaii Electric Light Co., Inc.	HI	Feb-1992	Turbine, Fuel Oil #2	20 MW	475.6 LB/H @ 25-<50% PKLD	combustion design	0	BACT-PSD
Kamine/Besicorp Natural Dam Lp	NY	Dec-1991	Ge Frame 6 Gas Turbine	500 MMBTU/HR	0.0 LB/MMBTU, 10 LB/HR	no controls	0	BACT-OTHER
Duke Power Co. Lincoln Combustion Turbine Station	NC	Dec-1991	Turbine, Combustion	1247 MM BTU/HR	60.0 LB/HR	combustion control	0	BACT-PSD
Duke Power Co. Lincoln Combustion Turbine Station	NC	Dec-1991	Turbine, Combustion	1313 MM BTU/HR	59.0 LB/HR	combustion control	0	BACT-PSD
Maui Electric Company, Ltd.	HI	Dec-1991	Turbine, Fuel Oil #2	28 MW	0.0 SEE NOTES	good combustion practices	0	BACT-PSD
Kalamazoo Power Limited	MI	Dec-1991	Turbine, Gas-Fired, 2, W/ Waste Heat Boilers	1806 MMBTU/H	20.0 PPMV	dry low nox turbines	0	BACT-PSD
Lake Cogen Limited	FL	Nov-1991	Turbine, Gas, 2 Each	42 MW	42.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Lake Cogen Limited	FL	Nov-1991	Turbine, Oil, 2 Each	42 MW	78.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Orlando Utilities Commission	FL	Nov-1991	Turbine, Gas, 4 Each	35 MW	10.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Orlando Utilities Commission	FL	Nov-1991	Turbine, Oil, 4 Each	35 MW	10.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Southern California Gas	CA	Oct-1991	Turbine, Gas-Fired	48 MMBTU/H	7.7 PPM @ 15% O2	high temperature oxidation catalyst	80	BACT-PSD
Southern California Gas	CA	Oct-1991	Turbine, Gas Fired, Solar Model H	5500 HP	7.7 PPM @ 15% O2	high temp oxidation catalyst	80	BACT-PSD
El Paso Natural Gas	AZ	Oct-1991	Turbine, Gas, Solar Centaur H	5500 HP	10.5 PPM @ 15% O2	fuel spec: lean fuel mix	0	BACT-PSD
El Paso Natural Gas	AZ	Oct-1991	Turbine, Gas, Solar Centaur H	5500 HP	10.5 PPM @ 15% O2	fuel spec: lean fuel mix	0	BACT-PSD
El Paso Natural Gas	AZ	Oct-1991	Turbine, Nat. Gas Transm., Ge Frame 3	12000 HP	60.0 PPM @ 15% O2	lean burn	0	BACT-PSD
Florida Power Generation	FL	Oct-1991	Turbine, Oil, 6 Each	93 MW	54.0 LB/H	combustion control	0	BACT-PSD
Carolina Power And Light Co.	SC	Sep-1991	Turbine, I C.	80 MW	60.0 LB/H		0	BACT-PSD
Enron Louisiana Energy Company	LA	Aug-1991	Turbine, Gas, 2	39 MMBTU/H	60.0 PPM @ 15% O2	base case, no additional controls	0	BACT-PSD
Algonquin Gas Transmission Co.	RI	Jul-1991	Turbine, Gas, 2	49 MMBTU/H	0.1 LB/MMBTU	good combustion practices	0	BACT-OTHER
Charles Larsen Power Plant	FL	Jul-1991	Turbine, Gas, 1 Each	80 MW	25.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Charles Larsen Power Plant	FL	Jul-1991	Turbine, Oil, 1 Each	80 MW	25.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Sumas Energy Inc.	WA	Jun-1991	Turbine, Natural Gas	88 MW	6.0 PPM @ 15% O2	co catalyst	80	BACT-PSD
Saguaro Power Company	NV	Jun-1991	Combustion Turbine Generator	35 MW	9.0 PPH	converter (catalytic)	90	BACT-PSD
Florida Power And Light	FL	Jun-1991	Turbine, Gas, 4 Each	400 MW	30.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Florida Power And Light	FL	Jun-1991	Turbine, Oil, 2 Each	400 MW	33.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Florida Power And Light	FL	Jun-1991	Turbine, Cg, 4 Each	400 MW	33.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Northern Consolidated Power	PA	May-1991	Turbines, Gas, 2	35 KW EACH	110.0 T/YR	oxidation catalyst	90	OTHER
Lakewood Cogeneration, L.P.	NJ	Apr-1991	Turbines (Natural Gas) (2)	1190 MMBTU/HR (EACH)	0.0 LB/MMBTU	turbine design	0	BACT-OTHER
Lakewood Cogeneration, L.P.	NJ	Apr-1991	Turbines (#2 Fuel Oil) (2)	1190 MMBTU/HR (EACH)	0.1 LB/MMBTU	turbine design	0	BACT-OTHER
Cimarron Chemical	CO	Mar-1991	Turbine #2, Ge Frame 6	33 MW	250.0 T/YR, LESS THAN	co catalyst	0	OTHER
Florida Power And Light	FL	Mar-1991	Turbine, Gas, 4 Each	240 MW	30.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Florida Power And Light	FL	Mar-1991	Turbine, Oil, 4 Each	0	33.0 PPM @ 15% O2	combustion control	0	BACT-PSD
Commonwealth Atlantic Ltd Partnership	VA	Mar-1991	Turbine, Nat Gas & #2 Oil	1533 MMBTU/H EACH	30.0 PPM @ 15% O2	combustion controls, annual stack testing	0	BACT-PSD
Commonwealth Atlantic Ltd Partnership	VA	Mar-1991	Turbine, Nat Gas & #2 Oil	1400 MMBTU/H	30.0 PPM @ 15% O2	combustion control, annual stack testing	0	BACT-PSD
Sumas Energy Inc	WA	Dec-1990	Turbine, Gas-Fired	67 MW	15.0 PPM @ 15% O2	co catalyst	80	BACT-PSD

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Newark Bay Cogeneration Partnership	NJ	Nov-1990	Turbine, Natural Gas Fired	585 MMBTU/HR	0.0 LB/MMBTU	catalytic oxidation	80	BACT-PSD
Newark Bay Cogeneration Partnership	NJ	Nov-1990	Turbine, Kerosene Fired	585 MMBTU/HR	0.1 LB/MMBTU	catalytic oxidation	83	BACT-PSD
March Point Cogeneration Co	WA	Oct-1990	Turbine, Gas-Fired	80 MW	37.0 PPM @ 15% O2	good combustion	0	BACT-PSD
Wi Electric Power Co	WI	Oct-1990	Turbines, Combustion, Simple Cycle, 4	75 MW EACH	0.0 SEE NOTE	good combustion	0	BACT-PSD
Commonwealth Gas Pipeline Corporation	VA	Sep-1990	Turbines, Gas Fired, Single Cycle, 5	14 MMBTU/H EACH	0.0	equipment design & operation	0	BACT-PSD
Delmarva Power	DE	Sep-1990	Turbine, Combustion	100 MW	15.0 PPM @ 15% O2	combustion efficiency	0	OTHER
Formosa Plastics Corporation	LA	Sep-1990	Turbine, Gas-Fired, 2	587 MMBTU/H	70 0 LB/H	combustion control	0	BACT-PSD
Tbg Cogen Cogeneration Plant	NY	Aug-1990	Ge Lm2500 Gas Turbine	215 MMBTU/HR	0.2 LB/MMBTU	catalytic oxidizer	80	BACT
Vermont Marble Company	VT	Jul-1990	Turbines, Combustion, Dual Fuel Fired, 2	50 MMBTU/H EACH	38.0 PPM @ 15% O2	proper design & oper. of cts, gas fuel	0	BACT-PSD
Vermont Marble Company	VT	Jul-1990	Turbines, Combustion, Dual Fuel Fired, 2	50 MMBTU/H EACH	83.0 PPM @ 15% O2	proper design & oper. of cts, oil fuel	0	BACT-PSD
Doswell Limited Partnership	VA	May-1990	Turbine, Combustion	1261 MMBTU/H	25.0 LB/H	combustor design & operation	0	OTHER
Kalaeloe Partners, L.P.	HI	Mar-1990	Turbine, Lsfo, 2	1800 MMBTU/H, TOTAL	0 0 SEE NOTES		0	BACT-PSD
Oneida Cogeneration Facility	NY	Feb-1990	Turbine, Ge Frame 6	417 MMBTU/H	40 0 PPM	combustion control	0	OTHER
Fulton Cogeneration Associates	NY	Jan-1990	Turbine, Ge Lm5000, Gas Fired	500 MMBTU/H	0 0 LB/MMBTU, SEE NOTE	combustion control	0	BACT-PSD
Arrowhead Cogeneration Co.	VT	Dec-1989	Turbine, Combustion & Burner, Cogen , 3	282 MMBTU/H, GAS	50.0 PPMVD AT ISO COND &	design & good combustion techniques	0	OTHER
Sc Electric And Gas Company - Hagood Station	SC	Dec-1989	Internal Combustion Turbine	110 MEGAWATTS	23 0 LBS/HR	good combustion practices	0	BACT-PSD
Peabody Municipal Light Plant	MA	Nov-1989	Turbine, 38 Mw Natural Fas Fired	412 MMBTU/HR	40.0 PPM @ 15% O2	good combustion practices	0	BACT-OTHER
Jmc Selkirk, Inc.	NY	Nov-1989	Turbine, Ge Frame 7, Gas Fired	80 MW	25 0 PPM	combustion control	0	BACT-PSD
Oxy Ngl, Inc.	LA	Nov-1989	Turbine, Centaur Gas, 4	29 MMBTU/H	3.8 LB/H	combustion design	0	BACT-PSD
Oxy Ngl, Inc.	LA	Nov-1989	Turbine, Solar Gas	14 MMBTU/H	4 8 LB/H		0	BACT-PSD
Oxy Ngl, Inc.	LA	Nov-1989	Turbine, Solar Gas	29 MMBTU/H	3.8 LB/H		0	BACT-PSD
Capitol District Energy Center	CT	Oct-1989	Engine, Gas Turbine	739 MMBTU/H	0 1 LB/MMBTU GAS FIRING		0	BACT-PSD
Arco Alaska, Inc	AK	Oct-1989	Turbines, Gas Fired, 3	5400 HP/TURBINE	109 0 LB/MMSCF	not required under bact	0	BACT-PSD
The Dexter Corp	CT	Sep-1989	Turbine, Nat Gas & #2 Fuel Oil Fired	555 MMBTU/H NAT GAS	0 1 LB/MMBTU GAS FIRING		0	BACT-PSD
Virginia Power	VA	Sep-1989	Turbine, Gas	1308 MMBTU/H	26 5 LB/H/UNIT NAT GAS FI		0	BACT-PSD
Panda-Rosemary Corp.	NC	Sep-1989	Turbine, Combustion, #6 Frame	499 MMBTU/H GAS	10 8 LB/H	combustion control	0	BACT-PSD
Panda-Rosemary Corp.	NC	Sep-1989	Turbine, Combustion, #6 Frame	509 MMBTU/H OIL	10.9 LB/H	combustion control	0	BACT-PSD
Panda-Rosemary Corp.	NC	Sep-1989	Turbine, Combustion, #7 Frame	1047 MMBTU/H GAS	23.1 LB/H	combustion control	0	BACT-PSD
Panda-Rosemary Corp.	NC	Sep-1989	Turbine, Combustion, #7 Frame	1060 MMBTU/H OIL	23.0 LB/H	combustion control	0	BACT-PSD
Kamine Syracuse Cogeneration Co.	NY	Sep-1989	Turbine, Gas Fired	79 MW	0.0 LB/MMBTU	combustion control	0	OTHER
Syracuse University	NY	Sep-1989	Turbine, Gas Fired	79 MW	0 2 LB/MMBTU, SEE NOTE	catalytic oxidation	0	OTHER
Megan-Racine Associates, Inc	NY	Aug-1989	Ge Lm5000-N Combined Cycle Gas Turbine	401 LB/MMBTU	0.0 LB/MMBTU, 11 LB/HR	no controls	0	BACT-OTHER
Union Oil Co. Of California	AK	Aug-1989	Turbine, Gtm Solar Saturn, 4 Ea	1300 MMBTU/H	350.0 LB/MMSCF FUEL, AVG		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, H&H Solar Saturn, 4 Ea	1300 MMBTU/H	350 0 LB/MMSCF FUEL		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Elect. Generator, 4 Ea	1100 MMBTU/H	350 0 LB/MMSCF FUEL		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Shipping, Solar Saturn	1100 MMBTU/H	350.0 LB/MMSCF FUEL		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Centaur West	4400 MMBTU/H	109 0 LB/MMSCF FUEL		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Saturn, Bingham	4400 MMBTU/H	109.0 LB/MMSCF FUEL		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Centaur East	4400 MMBTU/H	109 0 LB/MMSCF FUEL		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Centaur, 2 Ea	4400 MMBTU/H	109 0 LB/MMSCF FUEL		0	BACT-PSD
Union Oil Co. Of California	AK	Aug-1989	Turbine, Solar Saturn, #1	1300 MMBTU/H	350 0 LB/MMSCF FUEL		0	BACT-PSD
Union Oil Co Of California	AK	Aug-1989	Turbine, Booster,Solar Saturn	1300 MMBTU/H	350.0 LB/MMSCF FUEL		0	BACT-PSD
Unocal	CA	Jul-1989	Turbine, Gas (See Notes)	0	10.0 PPM @ 15% O2	oxidation catalyst	75	BACT-OTHER
Pratt & Whitney, Utc	CT	Jul-1989	Engine, Gas Turbine	238 MMBTU/H	0.0 LB/MMBTU		0	BACT-PSD
Pratt & Whitney, Utc	CT	Jun-1989	Engine, Test Turbine	240 MMBTU/H	0.1 LB/MMBTU GAS FIRING		0	BACT-PSD
Tropicana Products, Inc.	FL	May-1989	Turbine, Gas	45 MW	10.0 PPM @ 15% O2		0	BACT-PSD
Empire Energy - Niagara Cogeneration Co.	NY	May-1989	Turbine, Gr Frame 6, 3 Ea	416 MMBTU/H	0.0 LB/MMBTU	combustion control	0	BACT-PSD
Megan-Racine Associates, Inc	NY	Mar-1989	Turbine, Lm5000	430 MMBTU/H	0.0 LB/MMBTU OIL	combustion control	0	OTHER
Indec/Oswego Hill Cogeneration	NY	Feb-1989	Turbine, Gas, Ge Frame 6	40 MW	0.0 LB/MMBTU	combustion control	0	BACT-PSD

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Pawtucket Power	RI	Jan-1989	Turbine/Duct Burner	533 MMBTU/H	23 0 PPM @ 15% O2, GAS		0	BACT-PSD
Ocean State Power	RI	Dec-1988	Turbine, Gas, Ge Frame 7, 4 Ea	1059 MMBTU/H	25 0 PPM @ 15% O2		0	BACT-PSD
Champion International	AL	Nov-1988	Turbine, Gas, Stationary	35 MW	9 0 LB/H		0	BACT-PSD
Texaco-Yokum Cogeneration Project	CA	Nov-1988	Turbine, Gas Fired, 2 Ea	25 MW	133 0 LB/D		0	BACT-PSD
Long Island Lighting Co.	NY	Nov-1988	Turbine, Ge Frame 7, 3 Ea	75 MW	10 0 PPM	combustion control	0	OTHER
Amtrak	PA	Oct-1988	Turbine, 2 Ea	20 MW	30 8 LB/H		0	OTHER
Orlando Utilities Commission	FL	Sep-1988	Turbine, 2 Ea	35 MW	10 0 PPM @ 15% O2	combustion control	0	BACT-PSD
Kamine South Glens Falls	NY	Sep-1988	Turbine, Gas Fired, Ge Frame 6	40 MW	0 0 LB/MMBTU	combustion control	0	BACT-PSD
Delmarva Power	DE	Aug-1988	Turbine, Combustion, 2 Ea	100 MW	15.0 PPM	good combustion practices	0	BACT-PSD
Kamine Carthage	NY	Jul-1988	Turbine, Gas Fired, Ge Frame 6	40 MW	0 0 LB/MMBTU	combustion control	0	BACT-PSD
Trigen	NY	Jul-1988	Turbine, Gas Fired, Ge Frame 6	40 MW	0.0 LB/MMBTU	combustion control	0	BACT-PSD
Hopewell Cogeneration Limited Partnership	VA	Jul-1988	Turbine, Nat Gas Fired, 3 Ea	1030 MMBTU/H	25 2 LB/H	steam injection	0	BACT-PSD
Hopewell Cogeneration Limited Partnership	VA	Jul-1988	Turbine, Oil Fired, 3 Ea	1029 MMBTU/H	25 5 LB/H		0	BACT-PSD
Ada Cogeneration	MI	Jun-1988	Turbine	245 MMBTU/H	0.1 LB/MMBTU NAT GAS	h2o injection	0	BACT-PSD
Ccf-1	CT	May-1988	Turbine, Allison, 2 Ea	110 MMBTU/H GAS FIRED	0 6 LB/MMBTU GAS FIRING		0	BACT-PSD
Virginia Power	VA	Apr-1988	Turbine, Ge,2 Ea	1875 MMBTU/H	140 0 LB/H	equipment design	0	LAER
Tbg/Grumman	NY	Mar-1988	Turbine, Gas, 2 Ea	16 MW	0 2 LB/MMBTU	co catalyst	80	BACT-PSD
Exxon Co., Usa	AL	Mar-1988	Turbine	3120 KW	5 0 LB/H	combustion modification	0	BACT-PSD
Exxon Co , Usa	AL	Mar-1988	Turbine	3120 KW	5 0 LB/H	combustion modification	0	BACT-PSD
Exxon Co., Usa	AL	Mar-1988	Turbine	3120 KW	5 0 LB/H	combustion modification	0	BACT-PSD
Great Lakes Gas Transmission	MI	Feb-1988	Turbine, #1	12500 HP	0 0 SEE NOTES		0	BACT-PSD
Great Lakes Gas Transmission	MI	Feb-1988	Turbine, #2	12500 HP	0 0 SEE NOTES		0	BACT-PSD
Great Lakes Gas Transmission	MI	Feb-1988	Turbine, #3	4000 HP	0 0 SEE NOTES		0	BACT-PSD
Midland Cogeneration Venture	MI	Feb-1988	Turbine, 12 Total	984 MMBTU/H	26.0 LB/H	turbine design	0	BACT-PSD
Midway-Sunset Cogeneration Co.	CA	Jan-1988	Turbine, Ge Frame 7, 3 Ea	75 MW	94 0 LB/H EA, NOTE 1	good combustion practices	0	BACT-PSD
Exxon Co., Usa	CA	Nov-1987	Turbine, Gas, W/Duct Burner	49 MW	17.0 LB/H	good combustion practices	0	OTHER
Downtown Cogeneration Assoc.	CT	Aug-1987	Turbine, Gas W/Duct Burner	72 MMBTU/H	0 3 LB/MMBTU OIL FIRING		0	BACT-PSD
Simpson Paper Co.	CA	Jun-1987	Turbine, Gas	50 MW	1302.0 LB/D	combustion controls	0	OTHER
San Joaquin Cogen Limited	CA	Jun-1987	Generator, Gas Turbine	49 MW	1326.0 LB/D	combustion controls	0	BACT-PSD
Cogen Technologies	NJ	Jun-1987	Turbine, Gas, Ge Frame 6, 3 Ea	40 MW	50.0 PPMVD AT 15% O2		0	OTHER
Pacific Gas Transmission Co.	OR	May-1987	Turbine, Gas	14000 HP	6 0 LB/H		0	BACT-PSD
Alaska Electrical Generation & Transmission	AK	Mar-1987	Turbine, Nat Gas Fired	80 MW	109 0 LB/SCF FUEL		0	BACT-PSD
Sycamore Cogeneration Co.	CA	Mar-1987	Turbine, Gas Fired, 4 Ea	75 MW	10 0 PPMV AT 15% O2, 3 H	co oxidizing catalyst, combustion control	0	BACT-PSD
U.S. Borax & Chemical Corp.	CA	Feb-1987	Turbine, Gas	45 MW	23.0 LB/H	good combustion practices	0	BACT-PSD
Arco Alaska Kuparuk Central Prod. Fac. #3	AK	Nov-1986	Turbine, Gas Fired, All	0	109 0 LB/SCF FUEL		0	BACT-PSD
Arco Alaska Lisburne Development Project	AK	Oct-1986	Turbine, Gas Fired, All	0	109.0 LB/SCF FUEL		0	BACT-PSD
Amoco Production Co.	TX	Sep-1986	Engine, Turbine	25000 HP	305 0 T/YR		0	BACT-PSD
Carolina Cogeneration Co , Inc.	NC	Jul-1986	Turbine, Gas, Peat Fired	418 MMBTU/H	34.6 LB/H	proper operation	0	BACT-PSD
Wichita Falls Energy Investments, Inc.	TX	Jun-1986	Turbine, Gas, 3 Ea	20 MW	420.0 T/YR		0	BACT-PSD
Formosa Plastic Corp.	TX	May-1986	Turbine, Gas, Ge Ms 6001	38 MW	32.4 T/YR		0	BACT-PSD
Marathon Oil Co., Steelhead Platform	AK	May-1986	Turbine, Gas Fired, Pwr Gen, 3	4454 HP	109 0 LB/MMSCF FUEL		0	BACT-PSD
Marathon Oil Co , Steelhead Platform	AK	May-1986	Turbine, Gas Fired, Compressor, 3	5278 HP	247 0 LB/MMSCF FUEL		0	BACT-PSD
Babcock & Wilcox, Lauhoff Grain	IL	Mar-1986	Turbine	223 MMBTU/H	200 0 PPM	fuel spec: fuel/operation	0	BACT-PSD
Aes Placerita, Inc.	CA	Mar-1986	Turbine & Recovery Boiler	519 MMBTU/H	103 0 LB/D	oxidation catalyst	80	BACT-PSD
Shell Ca Production, Inc.	CA	Feb-1986	Turbine, Gas Fired, Ge Lm 2500	20 MW	41.0 PPM AT 15% O2 DRY		0	BACT-PSD
Chevron Usa, Inc	CA	Feb-1986	Turbine, Gas, 6 Ea	47 MMBTU/H	32 3 LB/H TOTAL	fuel spec: pipeline gas as fuel, proper operation	0	OTHER
Union Cogeneration	CA	Jan-1986	Turbine, Gas W/Duct Burner, 3 Ea	16 MW	39.0 LB/H	oxidizing catalyst	80	OTHER
Arco Alaska King Salmon Platform	AK	Sep-1985	Turbine, Gas Fired, Compressor	3950 HP	60 0 PPMV		0	BACT-PSD
Sunlaw/Industrial Park 2	CA	Jun-1985	Turbine, Gas W/#2 Fuel Oil Backup, 2 Ea, Ge Frame	412 MMBTU/H	10 0 PPMVD AT 15% O2	mfg guarantee on co emissions	0	OTHER

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emmission Limit	Control Method	Efficiency (%)	Type
Proctor & Gamble	CA	Jun-1985	Turbine, Gas	217 MMBTU/H	32.0 LB/H GAS FIRED		0	OTHER
Applied Energy Services	LA	May-1985	Turbine/Generator, Steam, Waste Heat	1413 MMBTU/H	29.0 LB/H		0	BACT-PSD
Shell California Production Co.	CA	Apr-1985	Turbine, Gas Fired, 2 Ea	22 MW	10.0 PPMV AT 15% O2	good combustion practices	0	BACT-PSD
Conoco Milne Point	AK	Apr-1985	Turbine, Gas Fired, Total	50000 HP	109.0 LB/SCF FUEL		0	BACT-PSD
Greenleaf Power Co.	CA	Apr-1985	Turbine, Gas, Ge Lm-5000	36 MW	20.4 LB/H	good engineering practices	0	OTHER
Getty Oil Co.	CA	Mar-1985	Engine, Gas Turbine, 6 Ea	4 MW	4 5 LB/H		0	BACT-PSD
Champion International Corp.	TX	Mar-1985	Turbine, Gas, 2	1342 MMBTU/H	70.1 T/YR		0	BACT-PSD
Ciba-Geigy Corp.	NJ	Jan-1985	Turbine, Gas W/#2 Oil Backup	4000 HP	9.4 LB/H		0	OTHER
Vulcan Chemicals Co.	LA	Oct-1984	Turbine/Boiler, Nat Gas/Waste Heat, #3-84	196 MMBTU/H	30.6 LB/H		0	BACT-PSD
Vulcan Chemicals Co.	LA	Oct-1984	Turbine/Boiler, Nat Gas/Waste Heat, #4-84	196 MMBTU/H	30 6 LB/H		0	BACT-PSD
Sohio Alaska Petroleum Corp.	AK	Oct-1984	Turbine, Gas	127 MHP TOTAL	109 0 LB/MMSCF FUEL		0	BACT-PSD
Explorer Pipeline Co.	TX	Jun-1984	Turbine, Gas	1100 HP	40 0 T/YR		0	BACT-PSD
Texas Gulf Chemicals Co.	TX	Jun-1984	Turbine, Gas	78 MW	93 8 T/YR		0	BACT-PSD
Texas Petro Chemicals Corp.	TX	Jun-1984	Turbine, Gas, 2 Ea	92 MW	66 8 T/YR		0	BACT-PSD
U.S Borax & Chemical Corp.	CA	Apr-1984	Turbine, Gas	3855 GAL/H	72.0 LB/H		0	BACT-PSD
Dow Chemical, Usa	LA	Nov-1983	Turbine, #Gt-300 & Gt-400, 2 Ea	100 MW	66.0 LB/H		0	BACT-PSD
Champlin Petroleum Co.	WY	Nov-1983	Turbine, 2 Ea	886 HP	2 0 G/HP-H	design	0	BACT-PSD
Getty Oil, Kern River Cogeneration Project	CA	Nov-1983	Turbine, Gas Fired, 4 Ea	825 MMBTU/H	9 0 PPM	good combustion practices	0	BACT-PSD
Southern Calif Edison Co.	CA	Apr-1983	Turbine, Gas, 20	65 MW EA	17.0 LB/H/TURBINE	good combustion practices	0	BACT-PSD
Kiln-Gas R & D Inc.	IL	Apr-1983	Turbine, Coal Gas Fired	0	290 0 LB/H	equipment design	0	BACT-PSD
Petro-Tex Chemical Corp.	TX	Dec-1982	Turbine, Gas	982 MSCFH	15 3 LB/H		0	OTHER
Simpson Lee Paper Co.	CA	Sep-1982	Turbine, Gas & Boiler, Waste Heat	33 MW	43.0 LB/H 1 H AVG	good combustion practices	0	BACT-PSD
Puget Sound Power & Light	WA	Aug-1982	Turbine, Gas, 2	100 MW EA	165.0 LB/H		0	BACT-PSD
Southern Ca Edison Coalwater Station	CA	Dec-1981	Turbine, Gas	100 MW	77 0 LB/H 3H AV	I & m program, co monitors	0	OTHER
Fort Howard Paper Co.	OK	Oct-1981	Turbine	400 MMBTU/H	0.7 LB/MMBTU N. GAS	normal operation	0	BACT-PSD
Fort Howard Paper Co.	OK	Oct-1981	Turbine	400 MMBTU/H	0.8 LB/MMBTU #2 OIL	normal operation	0	BACT-PSD
Phillips Petroleum Co.	TX	Oct-1981	Turbine, 2	3000 HP EA	0 0 LB/MMBTU GAS	o2 monitoring	0	BACT-PSD
Prudhoe Bay Consortium	AK	Sep-1981	Turbine	303 MHP	1.1 LB/MMSCF FUEL	good combustion practices	0	BACT-PSD
Dow Chemical Co.	LA	Aug-1981	Turbine, Nat Gas Fired, 2 Ea	1203 MMBTU/H	0.1 LB/MMBTU	good combustion practices	0	BACT-PSD
Gulf States Utility	LA	Jul-1981	Turbine	1390 MMBTU/H	0.1 LB/MMBTU OIL	good combustion practices	0	BACT-PSD
Gulf States Utility	LA	Jul-1981	Turbine	1361 MMBTU/H	0.1 LB/MMBTU	good combustion practices	0	BACT-PSD
Longview Refin	TX	May-1981	Turbine, 3	6275 HP	0.5 G/HP-H	good combustion practices	0	NSPS
Odessa Natural Corp.	TX	Mar-1981	Turbine	7660 HP	0.5 G/HP-H	air/fuel ratio	0	BACT-PSD
Gulf States Utility	LA	Jan-1981	Turbine, Combustion, 2	1336 MMBTU/H	125.0 LB/H	combustion controls	0	BACT-PSD
Gulf States Utility	LA	Jan-1981	Turbine, Combustion, 2	1336 MMBTU/H	216.0 LB/H	combustion controls	0	BACT-PSD
Florida Power	FL	Jan-1981	Turbine Peaking Units, 4 Ea	63 MW	88.0 LB/H	controlled combustion	0	BACT-PSD
Empire Dist. Elect. Co.	MO	Jan-1981	Turbine, Combustion, Simple-Cyc, Oil Fired, #2	1056 MMBTU/H (MAX)	56.0 LB/H		0	BACT-PSD
Gulf States Utility	LA	Dec-1980	Turbine	1396 MMBTU/H	0.2 LB/MMBTU OIL	efficient design	0	BACT-PSD
Prudhoe Bay Consortium	AK	Dec-1980	Turbine, Gas, 10	16 MHP EA	109 0 LB/MMSCF FUEL	montgomery good combustion practices	0	BACT-PSD
Diamond Shamrock Corp.	TX	Jun-1980	Turbine, Gas, 3	960 MMBTU/H EA	108.1 LB/H EA	good combustion practices	0	BACT-PSD
Nevada Pwr Co., Clark Station Unit #7	NV	Oct-1979	Generator, Gas Turbine	74 MW	0.1 LB/MMBTU		0	BACT-PSD
Mountain Fuel Supply	WY	Aug-1978	Turbine, Gas, 2 Ea	788 HP	0.0 % V AT 0% O2, WET BA	design	0	BACT-PSD

Table B-6. Direct and Indirect Capital Costs for CO Catalyst, City of Lakeland 501G Project, Simple Cycle 9737594C/APPB.XLS 11/29/97

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$235,000	Vendor Quote
Instrumentation	$23,500	10% of SCR Associated Equipment
Sales Tax		6%
Freight		5%
Total Direct Capital Costs (TDCC)	$258,500	
Direct Installation Costs		
Foundation and supports	$86,680	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$151,690	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$43,340	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$21,670	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$10,835	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$10,835	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$0	
Buildings	$0	
Total Direct Installation Costs (TDIC)	$325,050	
Recurring Capital Costs (RCC)	$825,000	Vendor Quote
Total Capital Costs	$1,408,550	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$140,855	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$70,428	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$140,855	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$28,171	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$14,086	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$140,855	10% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$535,249	
Total Direct, Indirect and Recurring Capital Costs (TDIRCC)	$1,943,799	Sum of TCC and TInCC
Mass Flow of Combustion Turbine	4,518,595	lb/hr

Table B-7. Annualized Cost for CO Catalyst, City of Lakeland 501G Project, Simple Cycle

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$43,800	8 hours/week at $15/hr
Supervision	$6,570	15% of Operating Personnel;OAQPS Cost Control Manual
Inventory Cost	$44,755	Capital Recovery (16.27%) for 1/3 catalyst
Catalyst Disposal Cost	$42,174	$28/1,000 lb/hr mass flow over 3 years; developed from vendor quotes
Contingency	$13,730	10% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$151,028	
Energy Costs		
Heat Rate Penalty	$174,499	0.2% of MW output; EPA, 1993 (Page 6-20)
MW Loss Penalty	$59,760	2 days replacement energy costs @ $0.01 kWh each three period
Fuel Escalation	$7,028	Escalation of fuel over inflation; 3% of energy costs
Contingency	$24,129	10% of Energy Costs
Total Energy Costs (TDEC)	$265,416	
Indirect Annual Costs		
Overhead	$30,222	60% of Operating/Supervision Labor and Ammonia
Property Taxes		
Insurance	$19,438	1% of Total Capital Costs
Annualized Total Direct Capital	$182,079	16.27% Capital Recovery Factor of 10% over 10 years times sum of TDCC, TDIC and TInCC
Annualized Total Direct Recurring	$331,733	40.21% Capital Recovery Factor of 10% over 3 years times RCC
Total Indirect Annual Costs	$563,471	
Total Annualized Costs	$979,915	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$867	

SUPPLEMENTAL CALCULATIONS RELATED TO OXIDATION CATALYST AND OPTIONS

Calculations of CO Reduction			lb/hr @ 10 ppmvd	
NOx Emissions on Gas 100% Load	211	lb/hr @ 59oF	42.2	50 ppmvd
NOx Emissions on Gas 50% Load	1177	lb/hr @ 59oF	33.62857	350
NOx Emissions on Oil 100% Load	386	lb/hr @ 59oF	42.88889	90 ppmvd
NOx Emissions on Oil 50% Load	1193	lb/hr @ 59oF	34.08571	350
Percentage of Gas Usage 100% Load	82%	5758.00 hrs/yr	38.20079	
Percentage of Gas Usage 50% Load	14%	1000.00 hrs/yr		
Percentage of Oil Usage 100% Load	3%	200.00 hrs/yr		
Percentage of Gas Usage 50% Load	1%	50.00 hrs/yr		
Capacity Factor	80%	7,008 hrs/yr		
CO Emissions	1264.39	tons per year		
CO Emissions	134	tons/yr		
CO Removed	1130.54	tons per year		
Turbine Capacity	249	MW @ 59oF		
Energy Lost: SCR Pressure Drop	3,489,984	kWhr/year		
	290.832	residential customers		
Energy Usage	0	kWhr/year		
	0	residential customers		
Total:	3,489,984	kWhr/year		
	291	residential customers		
	33,800	mmBtu/year		
	34	mmcf/year of gas		
Calculation based on Purdom Emission Limits				
NOx Emissions on Gas 100% Load	105.5	lb/hr @ 59oF		50 ppmvd
NOx Emissions on Gas 50% Load	1177	lb/hr @ 59oF		350
NOx Emissions on Oil 100% Load	386	lb/hr @ 59oF		90 ppmvd
NOx Emissions on Oil 50% Load	1193	lb/hr @ 59oF		350
Percentage of Gas Usage 100% Load	82%	5758.00 hrs/yr		
Percentage of Gas Usage 50% Load	14%	1000.00 hrs/yr		
Percentage of Oil Usage 100% Load	3%	200.00 hrs/yr		
Percentage of Gas Usage 50% Load	1%	50.00 hrs/yr		
Capacity Factor	80%	7,008 hrs/yr		
CO Emissions at 25 ppmvd gas	960.66	tons per year		
CO Emissions at 50 ppmvd gas	1,264	tons/yr		
CO Removed	303.73	tons per year		
Annualized Cost	$979,915			
Cost Effectiveness	$3,226	per ton NOx removed		

Calculations of 5 years only		Capital Recovery Factor at		0.1
Total Indirect Costs		Years	Percent	
Overhead	$30,222	5	0.263797	
Property Taxes	$0	3	0.402115	
Insurance	$19,438	10	0.162745	
Annualized Total Direct Capital	$295,136			
Annualized Total Direct Recurring	$331,745	$44,755	Inventory at 10 years	
Total	$676,541	$72,544	Inventory at 5 years	
		$27,789	Delta	
Annualized Costs	$1,120,774			
CO Removed	$3,690			

ENGELHARD

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

November 10, 1997

Golder Associates, Inc.
6241 NW 23rd St.
Gainesville, FL 32653

ATTN: Ken Kosky

RE: City of Lakeland - McIntosh
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal 97616

Dear Ken,

We enclose Engelhard Budgetary Proposal 97616 for Engelhard CAMET® CO Catalyst and Engelhard NOxCAT™ ZNX™ High Temperature SCR Catalyst Systems for the above project. This is per our conversation and your FAX of November 3, 1997. This Proposal includes:

- Engelhard CAMET® CO Catalyst System;
- Engelhard NOxCAT™ ZNX™ High Temperature SCR Catalyst System;
  Catalysts are sized: 90% CO and 70% NOx reduction reduction at Full Load (Oil);
- Aqueous Ammonia 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. We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION
PROCESS EMISSION SYSTEMS

Frederick A. Booth

Frederick A. Booth
Sales Engineer

cc: Greer Peters - Proposal Administrator

ENGELHARD

Golder Associates, Inc.
City of Lakeland - McIntosh
CAMET® CO Catalyst System
NOxCAT™ ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal 97616
November 10, 1997

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

Engelhard Corporation ("Engelhard") offers to supply to Buyer the CAMET® CO metal substrate CO system and NOxCAT™ ZNX™ High Temperature Ceramic Substrate SCR system herein.

Scope of Supply

1. Engelhard CAMET® CO metal substrate catalyst modules;
2. Engelhard NOxCAT™ ZNX™ SCR catalyst modules;
3. Internal support structures for catalyst modules; includes all hardware and gaskets for catalyst module installation;
4. Internally insulated Ductwork with stainless steel liner to house CO catalyst, AIG, and SCR catalyst;
5. Ammonia Injection Grid (AIG);
6. External AIG manifold with flow control valves;
7. NH_3 Vaporization / Air dilution skid;
8. Five (5) days (maximum 8 hours/day) field supervision/operator training for catalyst installation and start-up.

BUDGET PRICE: Per Unit	FOB, shipping point	CO and SCR Catalyst Systems	$4,800,000
		Replacement CO Catalyst	$ 825,000
		Replacement SCR Catalyst	$2,800,000

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.*

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.

ENGELHARD

Golder Associates, Inc.
City of Lakeland - McIntosh
CAMET® CO Catalyst System
NOxCAT™ ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal 97616
November 10, 1997

CO and SCR SYSTEM DESIGN BASIS:	
Gas Flow from:	Combustion Turbine
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas and Oil (design for Oil)
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

Performance Data

	GIVEN // CALC. DATA	
	FUEL	Oil
	TURBINE EXHAUST FLOW, lb/hr	4,901,040
	TURBINE EXHAUST FLUE GAS ANALYSIS, % VOL.	
	N_2	71.25
	O_2	11.30
	CO_2	5.51
	H_2O	11.03
	Ar	0.89
	CALCULATED FLUE GAS MOL. WT.	28.35
	TURBINE CO, ppmvd	90
	TURBINE CO, lb/hr	382.3
	TURBINE NOx, ppmvd @ 15%O_2	42
	TURBINE NOx, lb/hr	407.1
	FLUE GAS TEMP. @ CO AND SCR CATALYSTS, F	940
	PERFORMANCE DATA	
CO CATALYST	CO CONVERSION, % - Min.	90.0%
	CO OUT, lb/hr - Max.	38.2
	CO OUT, ppmvd@15%O_2 - Max.	9.0
	CO PRESSURE DROP, "WG - Max.	1.2
SCR CATALYST	NOx CONVERSION, % - Min.	70.0%
	NOx OUT, ppmvd@15%O_2 - Max.	12.6
	NOx OUT, lb/hr - Max.	122.1
	EXPECTED AQUEOUS NH_3 (28% SOL.) FLOW, lb/hr	1023
	NH_3 SLIP, ppmvd@15%O_2 - Max.	10
	PRESSURE DROP - CO and SCR, "WG - Max.	3.7

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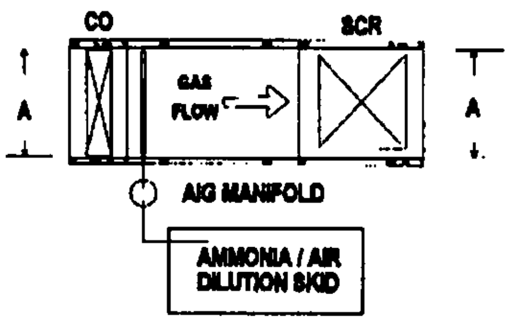
Golder Associates, Inc.
City of Lakeland - McIntosh
CAMET® CO Catalyst System
NOxCAT™ ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal 97616
November 10, 1997

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

- Engelhard CAMET® CO metal substrate catalyst modules;
- 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
Electrical grounding equipment
Utilities
Foundations
Monitors to measure pressure loss and inlet/outlet temperature across the catalyst bed
All other items not specifically listed in Scope of Supply



Dimensions:

Reactor Inside Liner Width	(A) 51'-0"
Reactor Inside Liner Height	(B) 48'-0"
Reactor Depth - Total	(C) 15'-0"