Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

January 11, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Farzie Shelton, Manager Environmental Affairs
City of Lakeland Department of Electric Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-013-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Ms. Shelton:

Following our discussions regarding the startup activities at Lakeland, we reviewed the information provided in the letter dated October 11, 2001 describing the conversion of the simple cycle unit to combined cycle. The permit modification dated November 21, 2001 addressed only low load operation related to continuous steam blowing required to achieve clean key steam pathways and surfaces and achieve steam purity requirements.

Your letter and its attachments described additional activities related to commissioning activities that also require low load operation. These were not included in the permit modification. Since the time we issued the permit modification, EPA Region IV's expert on the New Source Performance Standards advised Lakeland that the clock for initial performance testing can be reset if major changes are made to an affected facility after it starts up (reference communication McNeal to Shelton, dated December 27, 2001). We understand that the conversion is also behind the schedule outlined in the October 11 letter.

The previously issued permit modification is hereby amended as follows:

NEW SPECIFIC CONDITION No. 47 (Revised)

Commissioning of the Combined Cycle Phase: The following excess emissions periods are applicable only during the commissioning of the conversion project from simple cycle to combined cycle operation ~~at the end of construction and exceed a total of 60 days (1440 hours)~~:

- Emissions of CO, VOC, PM and NO_X from the combustion turbines (CTs), in excess of the BACT limit established in Specific Conditions 20-25, resulting from ~~steam blow~~ activities associated with bringing the heat recovery steam generator and the steam turbine-electrical generator into operation shall be permitted provided that best operational practices are adhered to and that ~~the Subpart GG NSPS~~ NO_X emissions do not exceed ~~limit of~~ 75 ppmvd @15% O_2 (110 ppmvd adjusted for efficiency) on a 24 hour rolling average ~~is not exceeded~~. The period during which such excess emissions are authorized shall occur prior to May 1 ~~February 29~~, 2002 ~~and shall not exceed a total of 60 days (1440 hours)~~. The applicant shall record the periods of startup for each operating mode. Excess emissions during the periods of startup shall be reported to the FDEP Southwest District office within 30 days. {Applicant Request}

Please note that regardless of the time it takes to convert the unit to combined cycle, the permit requires that the unit meet the NO_X limitation of 7.5 ppmvd by selective catalytic reduction (9 ppmvd if achieved by Dry Low NO_X or hot SCR technology) by May 1, 2002. Compliance is also required with all applicable New Source Performance Standards in 40CFR60 as affected by the resetting of the initial performance test clock.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

Any party to this permitting decision (order) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Any party to this permitting decision (order) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/15/02 to the person(s) listed:

Farzie Shelton, City of Lakeland*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Jeff Spence, Polk County, ESD
Hamilton Oven, DEP PPSO

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Friday 1/15/02
(Clerk) (Date)

LAKELAND ELECTRIC

Farzie Shelton, chE; REM

Manager of Environmental Affairs

July 20, 2001

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

RE: DEP File No. 1050004-004-AC (PSD-FL-245) – Certification PA 74-06SR2
McIntosh Unit No. 5 Combustion Turbine Combined Cycle

Dear Al:

In accordance with our application and PSD permit condition, Lakeland Electric (Lakeland) is proceeding with the construction of the heat recovery steam generator for the above referenced unit. Lakeland anticipates conversion to the combined cycle to be completed sometimes in November/December 2001. Therefore, Lakeland anticipates start-up of this unit and shake down period to commence around November/December 2001 for which Lakeland will provide the Department with necessary notification in accordance with the Section II Emission Unit(s) General Requirements condition No. 5 of our permit.

Today, we are writing to confirm our understanding of our permit condition in connection with the start-up of this combined cycle. In accordance with Section III Emission Unit(s) Specific Conditions, condition No. 30, Lakeland will have a period not to exceed 100 days for shake down period (start up period) for which time excess emission is permissible prior to performing initial compliance tests. Additionally, during this 100 days Lakeland intend to relocate the Continuous Emission Monitoring (CEM) equipment on the new stack and perform the necessary certification of these equipment in accordance with the 40 CFR Part 75 of the Clean Air Act.

Therefore, we appreciate if you would confirm that condition No. 30 does provide us with the 100 days start-up period. However, if you should decide otherwise, Lakeland with this letter, is requesting modification of Unit No. 5 PSD permit to allow the necessary start-up period for commissioning of this combined cycle.

As always your cooperation and help in this matter is greatly appreciated. If you should have any questions, please do not hesitate to contact me.

Sincerely

Farzie Shelton

Cc: Mr. Hamilton Oven P.E.

City of Lakeland ® Department of Electric Utilities

501 East Lemon Street ® Lakeland, Fl 33801-5050 ® (863) 834-6603 ® Fax (863) 834-8187 ® Message System 834-6592

farzie.shelton@lakelandgov.net

To: Farzie Shelton

From: Steve Marshall
Tom Trickey

Date: July 10, 2001

Subject: Request for permit variance - for commissioning of combined-cycle conversion
McIntosh Unit 5, PA 741-06SR2, Permit No. PSD-FL-245

McIntosh Unit 5 is a 501G 250 MW combustion turbine that was manufactured by Siemens-Westinghouse Power Corporation (SWPC) and is currently operating in simple cycle configuration. In this configuration, the combustion turbine currently meets all air permit requirements.

Unit 5 will be converted to combined cycle operation in 2001. The simple cycle combustion turbine will be rendered inoperable on September 15, 2001 in order to complete the conversion to combined cycle configuration. The unit will be "mechanically complete" on or about November 8, 2001 at which time the commissioning phase of the project will begin. The unit will not be returned to commercial operation until commissioning is complete.

The 501G-Series uses steam, instead of air, to cool the metal of the transition pieces between the combustors and the first-row turbine blades at operating loads above 20% of maximum capacity; air is used for cooling when operating below 20%. Steam cooling is new combustion turbine technology that improves performance. However, the steam purity requirement for transition cooling steam is much greater than the purity requirement of steam for powering a steam turbine. This purity requirement presents some significant problems during the initial startup of the 501G combined-cycle unit.

During first-start of any new steam cycle system, time is needed to check-out the equipment, get control of the systems enough to run, and then tune the controls. This period is recognized as the shakedown period in the permit, for which 100 days was originally allowed. Also, metals and other contaminants from the surfaces of tubes, piping, and vessels in contact with the water and steam are either dissolved or picked up in suspension.

This is much worse during a first start. It takes time to blow-down the system in order to purge those contaminants. The 501G combustion turbine can not operate above 20% load until the purity of the steam needed for transition cooling is achieved. During initial startup phase, we anticipate several intermittent days of no-load operation followed by two or more weeks of non-continuous combustion turbine operation at 20% load before achieving steam purity requirements allowing transfer to steam cooling and ramping up load. These expected events may cause the combustion turbine to produce emission levels that unavoidably exceed allowable limits.

Realizing that 501G combustion turbines are tuned for full-load operation and usually have excess emissions during startup/shutdown cycles, the permit appropriately allows for excess emissions during normal startups and shutdowns. However, the permit limits the duration of those startup excess emissions to 4 hours. This limit is acceptable for a commissioned unit, but not for the first-start of a new combined cycle unit.

It is estimated that the startup, shakedown, and commissioning phases will last no longer than 100 days. It is also estimated that the initial startup phase, during which the combustion turbine will operate at 20% load or less, will take an estimated continuous maximum duration of 21 days to purge contaminants. The stack-gas emissions will probably exceed our permit limitations for most of the entire duration of running in the initial startup phase. There may also be periods of excess emissions that last longer than our permitted 4 hour duration during the shakedown and commissioning phases. Commissioning of the combined cycle unit can not be completed without exceeding the allowable emission limits.

Please confirm that a second commissioning period for the combined cycle conversion that allows for excess emissions has not been provided in the existing permit. If you concur that a second commissioning period has not been provided, then please take whatever steps are necessary to obtain as soon as possible a 100 day time frame that will allow commissioning the combined cycle unit.

Time is of the essence so please consider this request to be of very high priority and keep us informed of your progress. Thank you for your support and assistance.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 21, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Farzie Shelton, Manager
Environmental Affairs
City of Lakeland
Department of Electric Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

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

Dear Ms. Shelton:

The Department reviewed your letter dated July 20, 2001 requesting confirmation that a 100 day period of excess emissions is allowed during the commissioning of the combined cycle phase of the project.

When the initial permit was issued, the City submitted comments to the effect that "shakedown" has no regulatory meaning and 100 days seems arbitrary. In our response in the Final Determination, we explained our rationale. The 100 day period was not related to commissioning of combined cycle, but rather to insure that tests were conducted within a reasonable time after installation of control equipment to meet BACT emissions limits set forth in the permit. For example, a complete change out of combustors to meet the 9 ppm NOx limit by Dry Low NOx technology would trigger a 100 day period to conduct the BACT test. It would not trigger 100 days of excess emissions, especially with relation to the applicable New Source Performance Standard, Subpart GG.

We consider the letter, therefore to be a request to modify the conditions to allow for excess emissions during the commissioning of the combined cycle phase. The application is incomplete and the following information is required to process it:

1. The request needs to be signed by a professional engineer.

2. We need the startup characteristic curves that will show gas turbine speed and load with respect to time during a startup as well as steam turbine speed and load with respect to time.

3. We need the steady-state emissions characteristics such as NOx and CO concentrations with respect to load. We are particularly interested in the 20 percent load case during which contaminants will be purged.

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

[redacted]

Ms. Fernie Shelton
LAKELAND FL 33801

Postage	$ $0.34
Certified Fee	$2.10
Return Receipt Fee (Endorsement Required)	$1.50
Restricted Delivery Fee (Endorsement Required)	$0.00
Total Postage & Fees	$ $3.94

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Recipient's Name *(Please Print Clearly) (to be completed by mailer)*
City of Lakeland

Street, Apt. No.; or PO Box No.
501 East Lemon St.

City, State, ZIP+4
Lakeland, FL 33801-5050

PS Form 3800, February 2000 — See Reverse for Instructions

7000 0600 0026 4129 8115

LAKELAND ELECTRIC

Farzie Shelton, chE; REM

Manager of Environmental Affairs

October 11, 2001

RECEIVED
OCT 12 2001
BUREAU OF AIR REGULATION

Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

RE: DEP File No. 1050004-004-AC (PSD-FL-245) – Certification PA 74-06SR2
McIntosh Unit No. 5 Combustion Turbine Combined Cycle

Dear Mr. Fancy:

We are in receipt of your letter dated August 21, 2001 in response to our letter of July 20, 2001. In our letter, Lakeland Electric (Lakeland) had requested the Department to modify the conditions of the above referenced permit to allow for excess emissions during the commissioning of the combined cycle phase of its united No. 5 at McIntosh Power Plant. Accordingly, we requested Mr. Steve Marshall (Unit No. 5 combined cycle project manager) to address the Department's questions and requested information.

Therefore, enclosed please find Mr. Marshall's response (signed and sealed) together with the necessary supporting document. As you will note Mr. Marshall is of the opinion that a minimum of 1,440 operating hours is necessary for starting and commissioning this unit commencing early November 2001.

Therefore, we appreciate if you would process our request at your earliest convenience. As always your cooperation and help in this matter is greatly appreciated. If you should have any questions, please do not hesitate to contact me.

Sincerely

Farzie Shelton

Enc.

Cc: Mr. Hamilton Oven P.E.
J. Heron ✓
B. Thomas, SWD ✓
G. Worley, EPA ✓
D. Bunyak, NPS ✓

City of Lakeland ● Department of Electric Utilities

501 East Lemon Street ● Lakeland, Fl 33801-5050 ● (863) 834-6603 ● Fax (863) 834-8187 ● Message System 834-6592

farzie.shelton@lakelandgov.net

LAKELAND ELECTRIC

October 9, 2001

Farzie Shelton, Manager of Environmental Affairs
Lakeland Electric
Larsen Power Plant
2002 E. Hwy. 92
Lakeland, FL 33801

Subject: DEP File No. 1050004 (PSD-FL-245)
McIntosh Unit No. 5 Combined Cycle Conversion

Dear Farzie:

In response to the Florida Department of Environmental Protection Agency's letter (Exhibit 1) dated August 21, 2001 requesting additional information, the city of Lakeland submits following information. The numbers shown below correspond to the questions in the referenced letter and numbers that are skipped do not require a specific response.

(2) Please see Exhibit 2. Steam turbine-generator (STG) output will "follow" the combustion turbine (CT) and the corresponding amount of steam that is sent to the STG versus being directed straight to the condenser thus bypassing the STG. This enables the STG to "trip" without the CT also tripping. The plant operators can then correct the problem and bring the STG back on line sooner.

(3) Please see Exhibit 3. Lakeland has contacted Siemens-Westinghouse Power Corporation (SWPC) to obtain the requested information pertaining to the 20% load case. SWPC has indicated in its letter dated September 28, 2001 that it currently does not have the requested startup data for a 501G combustion turbine (CT). However, similar data from a 501F CT is included for reference and SWPC speculates that the 501G CT will have lower emissions than a 501F CT due to its more advanced design.

In lieu of the requested information that is unavailable from SWPC, please consider this additional explanation in order to address the department's concerns.

The SWPC 501G CT utilizes "steam cooling" in order to achieve its higher operating efficiency and this is the significant difference (other than size) between a 501G and 501F. The heat recovery steam generator (HRSG) in combined cycle configuration will produce cooling steam for the CT and it must be extremely pure.

When the 501G CT first starts, it utilizes "air" for cooling instead of "steam" and it switches from air to steam when the CT output is in the 10% to 20% range and the steam being produced meets the specified purity requirements. If the steam

501 E. Lemon St. ✦ Lakeland, Florida 33801
Phone: 941.499.6300 ✦ Fax: 941.499.6344

does not meet the purity requirements, then the combined cycle would continue to operate in the 10% to 20% output range and be continuously "blowing down" steam to remove contaminants from the system until the continuously monitored steam purity measurements indicate that the steam purity is now within acceptable limits. As soon as the steam purity is acceptable, then the 501G "switches" to steam cooling and then moves into its "design operating range." The SWPC "ramp rate curves" and attachments indicate the exact sequence of events and expected time durations.

It should be understood that the SWPC ramp rate curves represent a "normal" starting sequence that logically assumes:

(1) The HRSG is clean and will quickly produce the high purity steam required, and

(2) All of the plant controls are properly functioning.

Commissioning a new unit following at the end of construction involves a different and more challenging set of circumstances that Lakeland must contend with:

(1) The HRSG has just been assembled, chemically cleaned, and air blown (using large rented compressors) through its steam lines to remove debris. However, the combined cycle plant has not been operated yet and no steam blown down to remove any remaining contaminants.

(2) The combined cycle controls have been installed and some control loops verified. However, many of the control loops cannot be tuned unless the combined cycle plant is operating. This will involve the combined cycle plant starting and stopping many times as Lakeland and its contractor (S&B Engineers & Constructors, Ltd.), works through the various problems that arise until safe and reliable control of the plant is ultimately attained.

Lakeland and S&B are currently targeting November 15, 2001 for the "first attempt" to test run the newly constructed combined cycle unit. It is typical in the industry to combine the activities of "debugging" and tuning the plant controls with the initial operation of the combined cycle power plant. In fact, the combined cycle power plant will probably see many "starts" and "stops" as part of the commissioning process.

It is also unknown and impossible to predict how long the combined cycle power plant will have to operate with the CT on "air cooling" and the HRSG continuously blowing down steam in order to remove contaminants and attain the specified cooling steam purity. However, experience at a couple of other 501G combined cycle plants elsewhere in the United States has indicated that this can be expected to take two (2) or more days until steam purity is attained. During this time of unavoidable sustained "low load operation" (<20%), the 501G CT is expected to produce higher emissions than the air permit currently allows. Lakeland must again emphasize that this is an unavoidable operating scenario that is a vital part of the commissioning process.

(4) Regarding a protocol to minimize emissions, both Lakeland and S&B are very motivated to complete all commissioning activities as rapidly as is possible, thereby minimizing emissions.

Lakeland's contractor (S&B) is contractually obligated to complete all commissioning activities such that the combined cycle power plant can be declared available for commercial operation by December 15, 2001. Commissioning will take place on a daily round-the-clock schedule and concludes with successfully demonstrating combined cycle operation on both natural gas and distillate fuel and meeting plant performance and emissions requirements.

Lakeland is motivated to complete all commissioning activities as rapidly as possible for several reasons. Since September 15, 2001, the conversion from simple to combined cycle has caused Lakeland to lose the ability to operate and dispatch its 249 MW simple cycle 501G CT due to construction activities. Lakeland must now replace that power when needed by either operating less efficient units in its fleet or purchasing replacement power from other utilities.

It is also very costly for Lakeland to operate the 501G (> $5,000/hour) during commissioning activities. Lakeland will therefore strive to minimize the amount of time that the 501G CT is operated and to maximize the benefit obtained when it is run. For example, steam will be blown down to remove contaminants at the same time that some of the control loops are being debugged. As many activities as is possible will be completed simultaneously in order to meet schedule deadlines, performance specifications, and emissions requirements.

Please request that the department modify the conditions in the subject permit to grant a total of 1,440 operating hours to commission the newly constructed combined cycle power plant during which excess emissions <u>may</u> occur. Currently, it is my belief that the requested 1,440 operating hours represent a conservative estimate within which the commissioning of the combined cycle unit can be completed. It is clearly understood by Lakeland that excess emissions shall be kept to an absolute minimum and under no circumstances will Lakeland exceed the requested 1,440 operating hour allotment without the department's prior approval.

Please advise at your earliest convenience regarding the status of this request or if any additional information is required.

Sincerely,

Steven D. Marshall

Steven D. Marshall, P.E. (FL #44733)
Project Manager
Unit 5 Combined Cycle Conversion Project

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Farzie Shelton
Manager Environmental Affairs
City of Lakeland Dept. of
Electrical Services
501 East Lemon St.
Lakeland, FL 33801-5079

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) Bonnie Brenner

B. Date of Delivery 1-17-02

C. Signature

X Bonnie Brenner

☐ Agent
☒ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (*Extra Fee*) ☐ Yes

2. Article Number (*Copy from service label*)
7000 2870 0000 7028 3130

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 2870 0000 7028 3130

Ms. Farzie Shelton

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To
City of Lakeland Electrical Services

Street, Apt. No.; or PO Box No.
501 East Lemon St.

City, State, ZIP+ 4
Lakeland, FL 33801-5079

PS Form 3800, May 2000 See Reverse for Instructions

JAN-4-2002 09:03A FROM:

TO:918509226979829384 P:1

LAKELAND ELECTRIC

ENVIRONMENTAL AFFAIRS
FAX COVER PAGE

Please deliver the following page(s)

To: AL LINERO

Company:

Telephone number:

Fax number: 850-922-6979

From: Farzie Shelton – Manager of Environmental Affairs

Telephone number: (863) 834-6603

Fax number: (863) 834-8187

Date: Time: a.m. / p.m.

Number of pages (including cover page):

For information or problems regarding this fax, please call Jeanette Otto at (863) 834-8191.

Comments:

Al:

I am faxing this in case you do not get it via e-mail.

Thanks Farzie

Shelton, Farzie

From: William B. Shelton [farzie@gte.net]
Sent: Friday, January 04, 2002 8:32 AM
To: Shelton, Farzie
Subject: from Bill

Hope this info is helpful, call me if you need further assistance.

Bill Shelton

William B. Shelton, PE - Florida Regional Engineer
Rinker Hydro Conduit - Florida Engineering Office
4504 Sydney Road,
Plant City FL 33567

Tel: (813) 752 5138 (800) 881-1144 [FL-Watts] Fax: (813) 752 2720

Cell: (813) 924 1944 Home: (813) 254 3998

E-Mail: [<mailto:farzie@gte.net>] or [<mailto:wshelton@rinker.com>]

-----Original Message-----
From: DHMCNEAL@aol.com [mailto:DHMCNEAL@aol.com]
Sent: Thursday, December 27, 2001 10:24 AMfor
To: farzie@gte.net
Cc: mitchell.kenneth@epa.gov
Subject: (no subject)

Farzie:

A May 10, 1999, determination that I wrote regarding a paper mill boiler would support the idea that the clock for initial performance testing resets if major changes are made to an affected facility after it starts up. This particular determination was for a natural gas-fired boiler that was modified so that it could also burn wood waste, wastewater treatment plant sludge, and tire derived fuel. The letter indicated that the deadline for starting an initial performance test on the boiler would be 30 days after reaching maximum production, but no later than 180 days following the restart of the unit after the completion of the modifications. Tying the deadline for testing to the date the unit restarted constituted a reset of the clock for initial performance testing in this case.

The easiest way to get a copy of the determination would be to search it by date (May 10, 1999) on the Applicability Determination Index at the following web site:

http://esdev.sdc-moses.com/oeca/oc/adi/

David McNeal
EPA Region 4
404/562-9102

A May 10, 1999, determination that I wrote regarding a paper mill boiler would support the idea that the clock for initial performance testing resets if major changes are made to an affected facility after it starts up. This particular determination was for a natural gas-fired boiler that was modified so that it could also burn wood waste, wastewater treatment plant sludge, and tire derived fuel. The letter indicated that the deadline for starting an initial performance test on the boiler would be 30 days after reaching maximum production, but no later than 180 days following the restart of the unit after the completion of the modifications. Tying the deadline for testing to the date the unit restarted constituted a reset of the clock for initial performance testing in this case.

The easiest way to get a copy of the determination would be to search it by date (May 10, 1999) on the Applicability Determination Index at the following web site:

http://esdev.sdc-moses.com/oeca/oc/adi/

David McNeal
EPA Region 4
404/562-9102

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 21, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Farzie Shelton, Manager Environmental Affairs
City of Lakeland Department of Electric Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-013-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Ms. Shelton:

We received your letters dated July 20 and October 11 requesting a period of excess emissions during steam blows associated with the commissioning of the combined cycle phase of McIntosh Unit 5. We understand that the "steam blows" are an unavoidable part of commissioning of the combined cycle phase. Performing them at low load will minimize wastage of water and reduce exhaust. However, concentrations of the regulated pollutants will increase in the exhaust.

We distributed an Intent to Issue a Permit Modification on October 31. The City published the Notice in the Lakeland Ledger on November 2. We received no comments during the 14-day public comment period.

The referenced permit is hereby modified as follows:

NEW SPECIFIC CONDITION No. 47

Commissioning of the Combined Cycle Phase: The following excess emissions periods are applicable only at the end of construction and shall not exceed a total of 60 days (1440 hours):

- Emissions of CO, VOC, PM and NO_X from the combustion turbines (CTs), in excess of the BACT limit established in Specific Conditions 20-25, resulting from steam blow activities associated with bringing the heat recovery steam generator into operation shall be permitted provided that best operational practices are adhered to and that the Subpart GG NSPS NO_X limit of 75 ppmvd @15% O_2 (110 ppmvd adjusted for efficiency) is not exceeded. The period during which such excess emissions are authorized shall occur prior to February 29, 2002 and shall not exceed a total of 60 days (1440 hours). The applicant shall record the periods of startup for each operating mode. Excess emissions during the periods of startup shall be reported to the FDEP Southwest District office within 30 days. {Applicant Request}

Please note that regardless of the time it takes to convert the unit to combined cycle, the permit requires that the unit meet the NO_X limitation of 7.5 ppmvd under combined cycle operation by selective catalytic reduction (9 ppmvd if achieved by Dry Low NO_X or hot SCR technology) by May 1, 2002.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

Any party to this permitting decision (order) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11/28/01 to the person(s) listed:

Farzie Shelton, City of Lakeland*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Jeff Spence, Polk County, ESD
Hamilton Oven, DEP PPSO

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson 11/28/01
(Clerk) (Date)

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Farzie Shelton, Manager Environmental Affairs
City of Lakeland Department of Electric Utilities
501 E. Lemon Street
Lakeland, FL 33801-5079

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* D Mullis
B. Date of Delivery 11-30-01

C. Signature
X Diane Mullis ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 2942

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

7000 2870 0000 7028 2942

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To Farzie Shelton

Street, Apt. No.; or PO Box No. 501 E. Lemon Street

City, State, ZIP+ 4 Lakeland, FL 33801-5079

PS Form 3800, May 2000 **See Reverse for Instructions**

LAKELAND ELECTRIC

Farzie Shelton, chE; REM

Manager of Environmental Affairs

RECEIVED

NOV 08 2001

BUREAU OF AIR REGULATION

Via Federal Express

November 7, 2001

Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Re: Draft Air Construction Permit No. 1050004-013-AC (PSD-FL-245)
McIntosh Power Plant Unit No. 5 – Affidavit of publication

We are in receipt of your letter dated October 31, 2001 and attached Drafts Air Construction Permit, Intent to Issue Air Construction Permit Modification, and Public Notice of Intent to Issue Air Construction Permit Modification.

Pursuant to Section 403.815, Florida Statutes and DEP Rule 62-103.150, F.A.C., on November 2, 2001 we published the "Notice of Intent to Issue Air Construction Permit Modification " in the Lakeland Ledger. Therefore, enclosed please find Affidavit of Publication confirming publication of the Department's notice.

If you should have any questions, please do not hesitate to contact me.

Sincerely

Farzie Shelton

Enclosure

cc: J. Kleon
B. Thomas, SWD

City of Lakeland ® Department of Electric Utilities

501 East Lemon Street ● Lakeland, Fl 33801-5050 ● (863) 834-6603 ● Fax (863) 603-5670 ● Message System 834-6592

farzie.shelton@lakelandgov.net

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared Ken Holtzinger, who on oath says that he is the Classified Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

Public Notice of Intent

in the matter of Air Construction Permit Modification

in the ....

Court, was published in said newspaper in the issues of 11-2; 2001

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed K Holtz
Ken Holtzinger
Classified Manager
Who is personally known to me.

Sworn to and subscribed before me this 2nd
day of November A.D. 20 01
Patricia Ann Rouse
Notary Public

PATRICIA ANN ROUSE

(Seal) PATRICIA ANN ROUSE MY COMMISSION # CC 976018 EXPIRES: October 17, 2004 Bonded Thru Notary Public Underwriters

My Commission Expires..........

454511 F996 City of Lakeland Sue Trout

Attach Notice Here

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 1050004-013-AC (PSD-FL-245)
City of Lakeland Electric and Water Utilities Department
C.D. McIntosh, Jr. Power Plant - Unit No. 5
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to The City of Lakeland Electric & Water Utilities Department. The modification is to temporarily allow excess nitrogen oxides emissions period during the conversion of the simple cycle combustion turbine (Unit 5) to combined cycle mode at the C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. A Best Available Control Technology (BACT) determination was not required pursuant to Rules 62-212.400 and 410, F.A.C. and 40 CFR 52.21. The applicant's name and address are The City of Lakeland Electric and Water Utilities Department, 501 East Lemon Street, Lakeland, Florida 33801-5079.

The nominal 250 megawatt (MW) simple cycle combustion turbine-electrical generator was commissioned in 1999. It was tested for initial compliance while firing natural gas and then operated in simple cycle mode. The unit achieves a nitrogen oxides (NO_X) limit of 25 parts per million by volume, dry, at 15 percent oxygen (ppmvd).

The previously noticed and approved conversion to combined cycle is nearing completion. Under this phase, the hot exhaust gases will be recovered in a waste heat boiler that will raise sufficient steam to produce another 100 MW, thus increasing the capacity of the unit to 350 MW (nominal). The previously permitted NO_X emissions will be 7.5 ppmvd, to be achieved by selective catalytic reduction (SCR).

During the integration phase of the steam cycle, there will be times when it will be necessary to steam clean ("steam blows") the piping system for the waste heat boiler of dirt and debris accumulated during construction. This steam will be vented rather than used to make electricity. Emissions during steam blows will be higher than presently allowed by the simple cycle or combined cycle permits because the burners will not operate in full lean premixed mode at low load.

Although greater nitrogen oxides emissions are expected during the steam blows, concentrations will not exceed the NO_X limit of 40 CFR, Subpart GG of approximately 110 ppmvd at 15 % O_2 for efficient large frame units. Steam blows will occur intermittently during a period of 60 days (tentatively during November - January 2002). It is estimated that the total duration of low load operation will not exceed several hundred hours. An upper limit of 1440 hours of excess emissions will be permitted by this action. Excess emissions due to "steam blows" will be allowed until February 29, 2002.

The Department will issue the FINAL permit modification with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of fourteen (14) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit Modification." Written comments and requests for a public meeting should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit modification and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S.; before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida, 32301 Telephone: (850)488-0114 Fax: (850)922-6979	Florida Department of Environmental Protection Southwest District Office 3804 Coconut Drive Tampa, Florida 33619-8218 Telephone: (813)744-6100 Fax: (813)744-6084	City of Lakeland Electric and Water Utilities Attention: Ms. Farzie Shelton 501 East Lemon Street Lakeland, Florida 33801-5079 Telephone: (941)499-6603 Fax: (941)603-6335

The complete project file includes the application, technical evaluations, Draft Permit Modification, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

F996 - 11-2; 2001

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

October 31, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: DEP File No. 1050004-013-AC (PSD-FL-245)
250 Megawatt Combustion Turbine

Dear Mr. Tomlin:

Enclosed is one copy of the Draft Air Construction Permit Modification at the C. D. McIntosh, Jr Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. The Department's Intent to Issue Air Construction Permit Modification and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION" are also included.

The "PUBLIC NOTICE" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please call Ms. Teresa Heron at 850/921-9529 or Mr. Linero at 850/921-9523.

Sincerely,

AA Linero P.E.

for C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/th

Enclosures

SENDER: ***COMPLETE THIS SECTION***

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Farzie Shelton
Manager Environmental Affairs
City of Lakeland Electric &
Water Utilities
501 East Lemon Street
Lakeland, FL 33801-5079

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Bonnie Brennan
B. Date of Delivery 11-2-01

C. Signature
X Bonnie Brennan ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 2775

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

7000 2870 0000 7028 2775

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To
Farzie Shelton
Street, Apt. No.; or PO Box No.
501 E. Lemon St.
City, State, ZIP+ 4
Lakeland, FL 33801-5079

PS Form 3800, May 2000 **See Reverse for Instructions**

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Bonnie Brennan

B. Date of Delivery 11-2-01

C. Signature
X Bonnie Brennan
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 2782

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

7000 2870 0000 7028 2782

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To
Ronald W. Tomlin
Street, Apt. No.; or PO Box No.
501 E. Lemon St.
City, State, ZIP+ 4
Lakeland, FL 33801-5079

PS Form 3800, May 2000 **See Reverse for Instructions**

In the Matter of an
Application for Permit Modification by:

Ms. Farzie Shelton, Manager Environmental Affairs
City of Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

DEP File No. 1050004-013-AC
Permit No. PSD-FL-245
C.D. McIntosh, Jr. Power Plant, Unit No. 5
Polk County

____/

INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification (copy of DRAFT permit modification attached) for the proposed project, detailed in the application specified above for the reasons stated below.

The applicant, City of Lakeland Electric & Water Utilities, applied on July 20, 2001 to the Department for an air construction permit modification to temporarily allow excess nitrogen oxides emissions period during the conversion of the simple cycle combustion turbine (Unit 5) to combined cycle mode at the C.D. McIntosh, Jr. Power Plant, located at 3030 East Lake Parker Drive, Lakeland, Polk County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit modification is required to allow the excess emissions from the described work. The Department intends to issue this air construction permit modification based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit Modification. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit modification. Failure to publish the notice and provide proof of publication may result in the denial of the permit modification pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit modification with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue Air Construction Permit Modification. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit modification and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

A A Linn P.E.
for C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION (including the PUBLIC NOTICE and the DRAFT permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10/31/01 to the person(s) listed:

Farzie Shelton, City of Lakeland*
Brian Beals, EPA
John Bunyak, NPS
Thomas, SWD
Buck Oven, DEP
Jeff Spence, Polk County ESD, Polk County

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson 10/31/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050004-013-AC (PSD-FL-245)

City of Lakeland Electric and Water Utilities Department
C.D. McIntosh, Jr. Power Plant - Unit No. 5
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to The City of Lakeland Electric & Water Utilities Department. The modification is to temporarily allow excess nitrogen oxides emissions period during the conversion of the simple cycle combustion turbine (Unit 5) to combined cycle mode at the C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. A Best Available Control Technology (BACT) determination was not required pursuant to Rules 62-212.400 and 410, F.A.C. and 40 CFR 52.21. The applicant's name and address are The City of Lakeland Electric and Water Utilities Department, 501 East Lemon Street, Lakeland, Florida 33801-5079.

The nominal 250 megawatt (MW) simple cycle combustion turbine-electrical generator was commissioned in 1999. It was tested for initial compliance while firing natural gas and then operated in simple cycle mode. The unit achieves a nitrogen oxides (NO_X) limit of 25 parts per million by volume, dry, at 15 percent oxygen (ppmvd).

The previously noticed and approved conversion to combined cycle is nearing completion. Under this phase, the hot exhaust gases will be recovered in a waste heat boiler that will raise sufficient steam to produce another 100 MW, thus increasing the capacity of the unit to 350 MW (nominal). The previously permitted NO_X emissions will be 7.5 ppmvd, to be achieved by selective catalytic reduction (SCR).

During the integration phase of the steam cycle, there will be times when it will be necessary to steam clean ("steam blows") the piping system for the waste heat boiler of dirt and debris accumulated during construction. This steam will be vented rather than used to make electricity. Emissions during steam blows will be higher than presently allowed by the simple cycle or combined cycle permits because the burners will not operate in full lean premixed mode at low load.

Although greater nitrogen oxides emissions are expected during the steam blows, concentrations will not exceed the NO_X limit of 40 CFR, Subpart GG of approximately 110 ppmvd at 15 % O_2 for efficient large frame units. Steam blows will occur intermittently during a period of 60 days (tentatively during November – January 2002). It is estimated that the total duration of low load operation will not exceed several hundred hours. An upper limit of 1440 hours of excess emissions will be permitted by this action. Excess emissions due to "steam blows" will be allowed until February 29, 2002.

The Department will issue the FINAL permit modification with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of fourteen (14) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit Modification." Written comments and requests for a public meeting should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit modification and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of
Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: (850)488-0114
Fax: (850)922-6979

Florida Department of
Environmental Protection
Southwest District Office
3804 Coconut Drive
Tampa, Florida 33619-8218
Telephone: (813)744-6100
Fax: (813)744-6084

City of Lakeland
Electric and Water Utilities
Attention: Ms. Farzie Shelton
501 East Lemon Street
Lakeland, Florida 33801-5079
Telephone: (941)499-6603
Fax: (941)603-6335

The complete project file includes the application, technical evaluations, Draft Permit Modification, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

November XX, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Farzie Sheton, Manager Environmental Affairs
City of Lakeland Department of Electric Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-013-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Ms. Shelton:

We received your letters dated July 20 and October 11 requesting a period of excess emissions during steam blows associated with the commissioning of the combined cycle phase of McIntosh Unit 5. We understand that the "steam blows" are an unavoidable part of commissioning of the combined cycle phase. Performing them at low load will minimize wastage of water and reduce exhaust. However concentrations of the regulated pollutants will increase in the exhaust.

The PSD/Air Construction is hereby modified as follows:

NEW SPECIFIC CONDITION No. 47

Commissioning of the Combined Cycle Phase: The following excess emissions periods are applicable only at the end of construction and shall not exceed a total of 60 days (1440 hours):

- Emissions of CO, VOC, PM and NO_X from the combustion turbines (CTs), in excess of the BACT limit established in Specific Conditions 20-25, resulting from steam blow activities associated with bringing the heat recovery steam generator into operation shall be permitted provided that best operational practices are adhered to and that the Subpart GG NSPS NOx limit of 75 ppmvd @15% O_2 (110 ppmvd adjusted for efficiency) is not exceeded. The period during which such excess emissions are authorized shall occur prior to February 29, 2002 and shall not exceed a total of 60 days (1440 hours). The applicant shall record the periods of startup for each operating mode. Excess emissions during the periods of startup shall be reported to the FDEP Central District office within 30 days. {Applicant Request}

Please note that regardless of the time it takes to convert the unit to combined cycle, the permit requires that the unit meet the NO_X limitation of 7.5 ppmvd under combined cycle operation by selective catalytic reduction (9 ppmvd if achieved by Dry Low NO_X or hot SCR technology) by May 1, 2002.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

Any party to this permitting decision (order) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

____
Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on ______________ to the person(s) listed:

Farzie Shelton, City of Lakeland*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Jeff Spence, Polk County, ESD
Hamilton Oven, DEP PPSO

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

________________________ ______________
(Clerk) (Date)

LAKELAND ELECTRIC

FAX COVER PAGE

Please deliver the following page (s)

To: Teresa Heron

Company: DEP

Fax Number: 850-922-6979

From: Farzie Shelton

Telephone Number: 863-834-6603

Date: 8/13/01 Time: 10:20 a.m./ p.m.

Number of Pages (including cover page): 4

For information or problems regarding this fax, please call (863) 834-8191.

Comments:

FAXED: JULY 20, 2001 Letter
JULY 10, 2001 memo

EXHIBIT 1

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 21, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

RECEIVED
AUG 2 4 2001

Ms. Farzie Shelton, Manager
Environmental Affairs
City of Lakeland
Department of Electric Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

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

Dear Ms. Shelton:

The Department reviewed your letter dated July 20, 2001 requesting confirmation that a 100 day period of excess emissions is allowed during the commissioning of the combined cycle phase of the project.

When the initial permit was issued, the City submitted comments to the effect that "shakedown" has no regulatory meaning and 100 days seems arbitrary. In our response in the Final Determination, we explained our rationale. The 100 day period was not related to commissioning of combined cycle, but rather to insure that tests were conducted within a reasonable time after installation of control equipment to meet BACT emissions limits set forth in the permit. For example, a complete change out of combustors to meet the 9 ppm NOx limit by Dry Low NOx technology would trigger a 100 day period to conduct the BACT test. It would not trigger 100 days of excess emissions, especially with relation to the applicable New Source Performance Standard, Subpart GG.

We consider the letter, therefore to be a request to modify the conditions to allow for excess emissions during the commissioning of the combined cycle phase. The application is incomplete and the following information is required to process it:

1. The request needs to be signed by a professional engineer.
2. We need the startup characteristic curves that will show gas turbine speed and load with respect to time during a startup as well as steam turbine speed and load with respect to time.
3. We need the steady-state emissions characteristics such as NOx and CO concentrations with respect to load. We are particularly interested in the 20 percent load case during which contaminants will be purged.

4. Please submit a protocol describing the measures to be taken to minimize emissions during the low load conditions described.

If you have any questions regarding this matter, please contact Teresa Heron at 850/921-9529 or Al Linero at 850/921-9523.

Sincerely,

A A Linero P.E.

for C. H. Fancy, Chief, P.E.
Bureau of Air Regulation

CHF/th

Attachment

cc: Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, SWD

LAKELAND ELECTRIC

ENVIRONMENTAL AFFAIRS
FAX COVER PAGE

Please deliver the following page(s)

To: Steve Marshall

Company: Energy Supply

Telephone number:

Fax number: 6488

From: Farzie Shelton – Manager of Environmental Affairs

Telephone number: (863) 834-6603

Fax number: (863) 834-8187

Date: 8/27/01 Time: 9:45 a.m. /

Number of pages (including cover page): 3

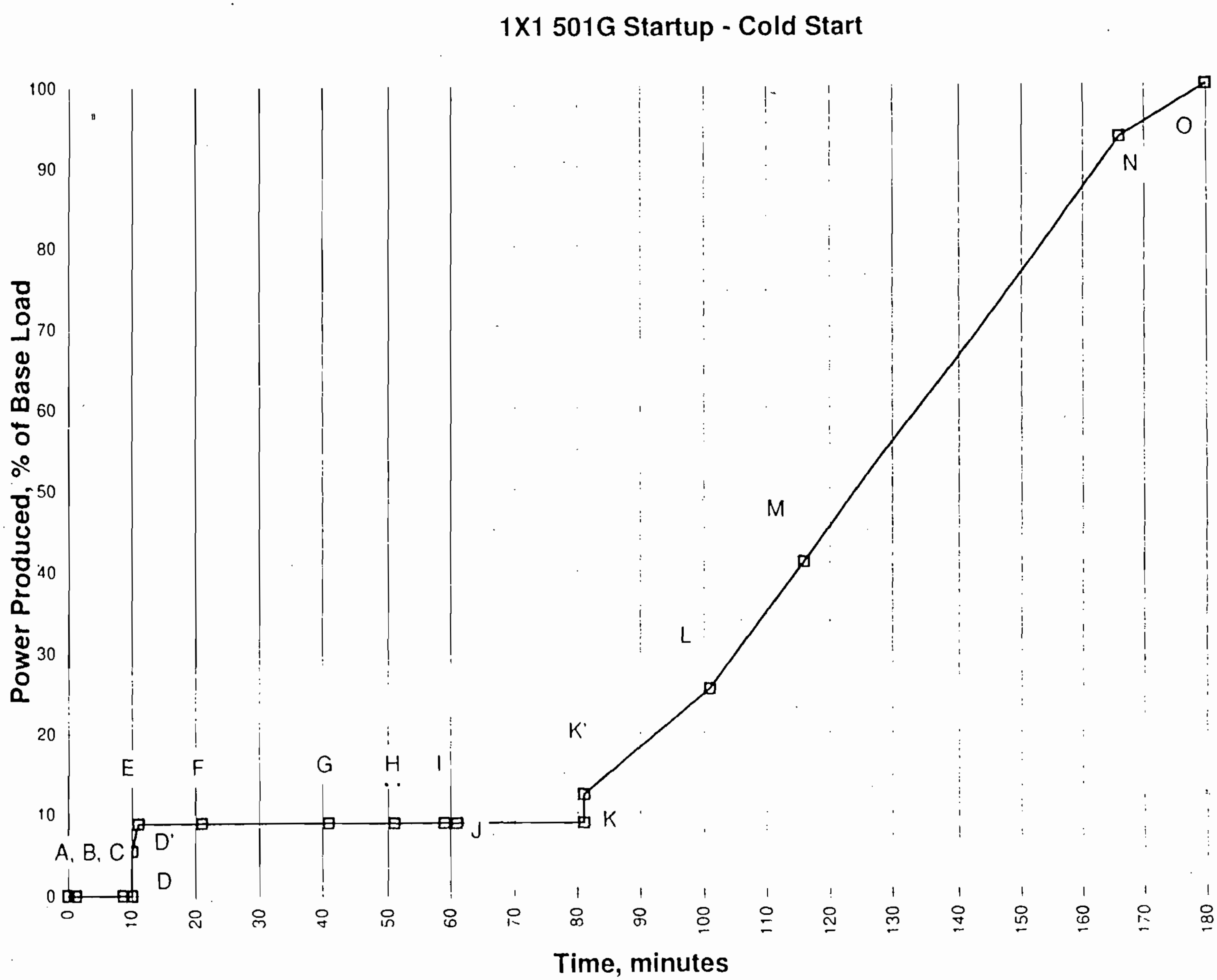
For information or problems regarding this fax, please call Jeanette Otto at (863) 834-8191.

Comments:

EXHIBIT 2

Ramp Rates

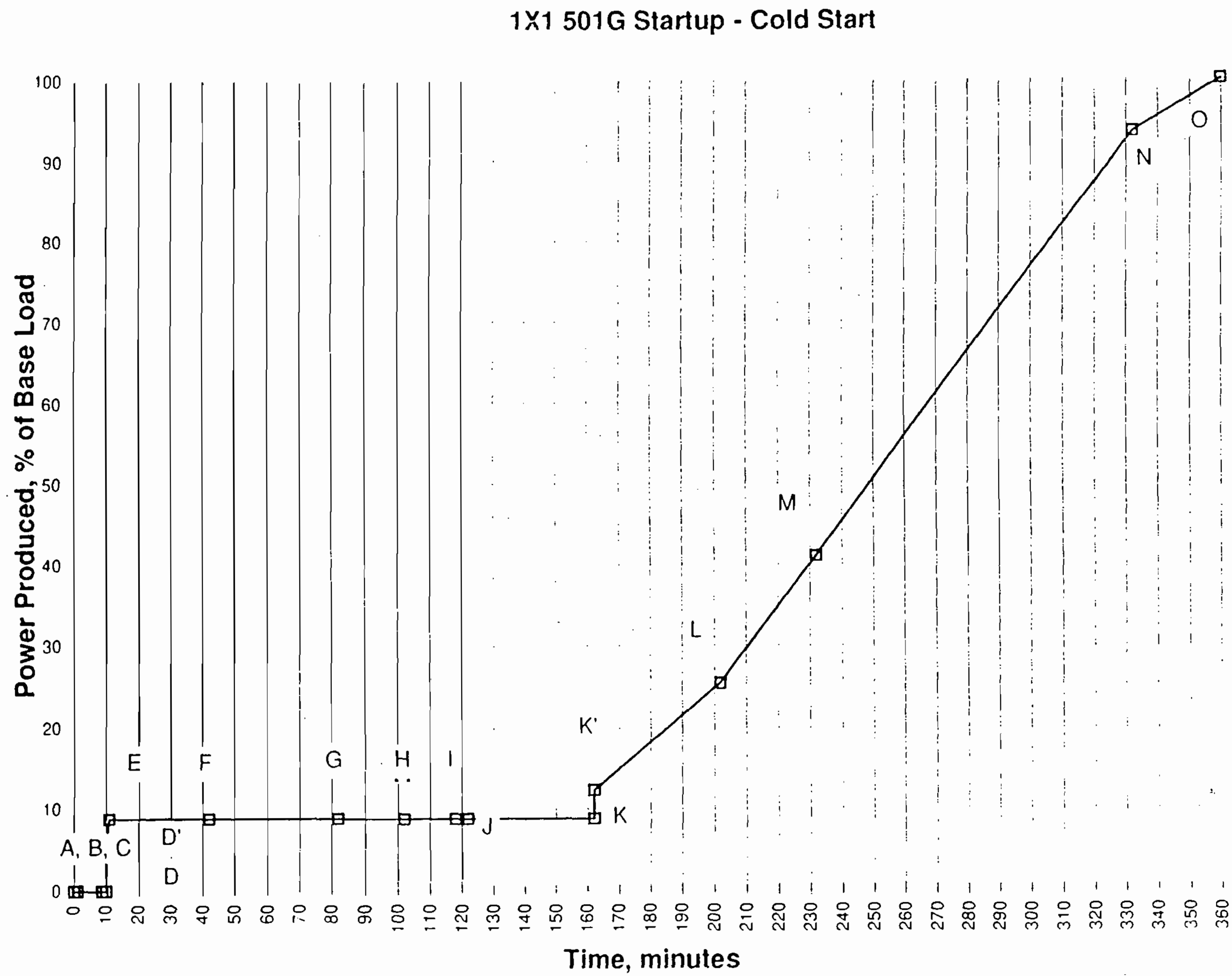
Unit Design Parameters



1X1 501G Startup - Cold Start
Power Produced, % of Base Load
0
10
20
30
40
50
60
70
80
90
100
Time, minutes
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
A, B, C
D
D'
E
F
G
H
I
J
K
K'
L
M
N
O

Point	Description
A	Start CT
B	Ignite Combustors, CT
C	Disengage CT Starting Motor
D	Synchronize CT
D'	CT at min Load point
E	CT at 15% Load, Hold
F	Gland seal steam to ST, Start Hogger
G	Open IP to CRH bypass / close IP Startup vent
H	Condenser Vacuum at 10" HgA, Bypass steam to condenser
I	Initiate stm cooling of CT transitions
J	Cond. Vacuum at 5" HgA, Start ST roll
K	Synchronize ST
K'	ST at 10% Load, Hold
L	CT at 35% load, Hold, begin ST Loading
M	CT at 50% Load
N	CT Base Loaded
O	ST Base Loaded

Unit Operating Parameters


1X1 501G Startup - Cold Start
Power Produced, % of Base Load
Time, minutes
A, B, C
D'
D
E
F
G
H
I
J
K
K'
L
M
N
O

Point	Description
A	Start CT
B	Ignite Combustors, CT
C	Disengage CT Starting Motor
D	Synchronize CT
D'	CT at min Load point
E	CT at 15% Load, Hold
F	Gland seal steam to ST, Start Hogger
G	Open IP to CRH bypass / close IP Startup vent
H	Condenser Vacuum at 10" HgA, Bypass steam to condenser
I	Initiate stm cooling of CT transitions
J	Cond. Vacuum at 5" HgA, Start ST roll
K	Synchronize ST
K'	ST at 10% Load, Hold
L	CT at 35% load, Hold, begin ST Loading
M	CT at 50% Load
N	CT Base Loaded
O	ST Base Loaded

501G STARTUP PROFILE

FIGURE 1

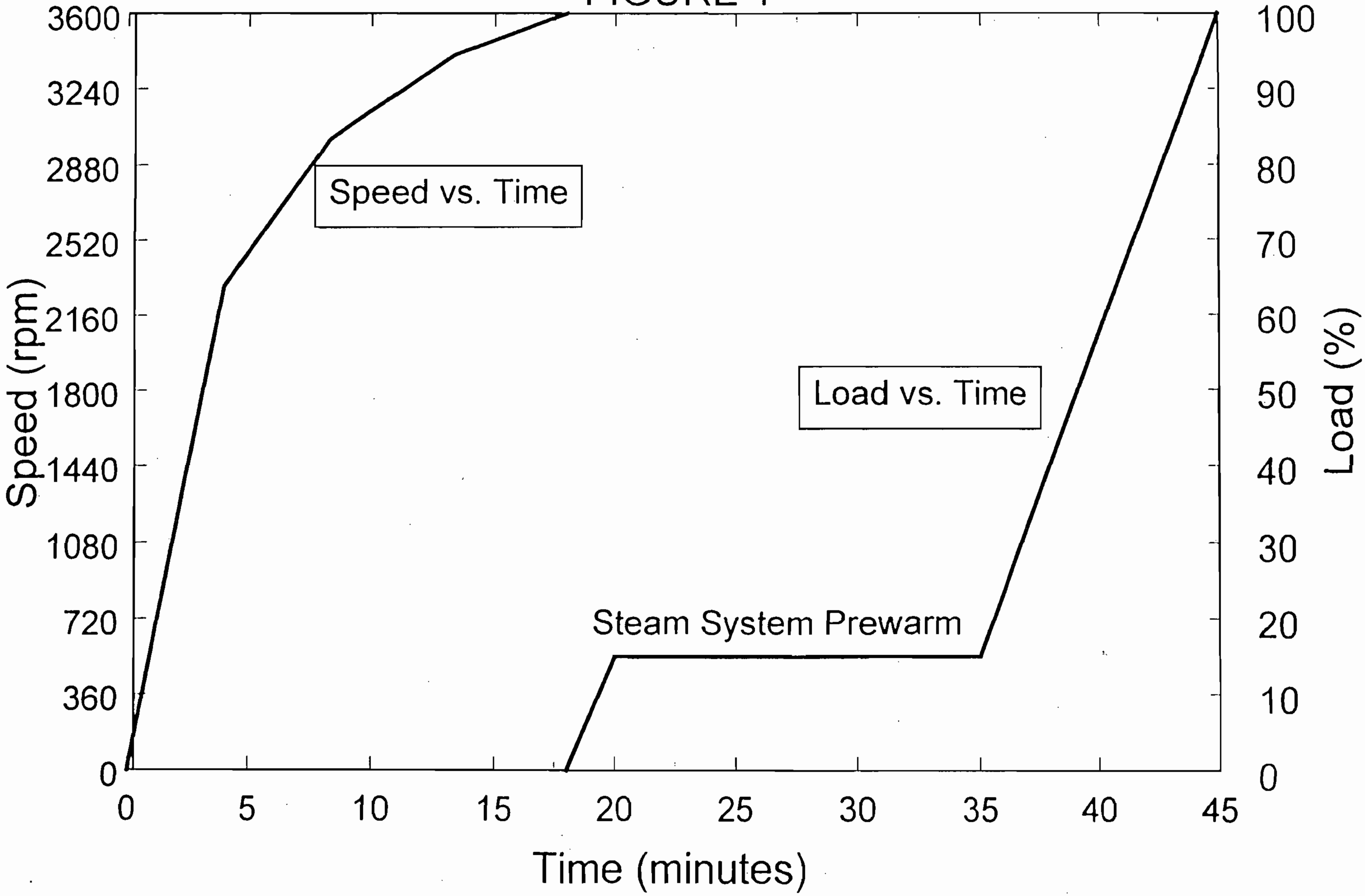


EXHIBIT 3
STEVE MARSHALL

SIEMENS
Westinghouse

September 28, 2001

SW-LCC-0112
File: 042

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

Subject: City of Lakeland - McIntosh #5 Combined Cycle Project
Part Load Emissions Estimates during Combined Cycle Commissioning

Dear Steve:

This is in response to the e-mail request (Mr. Tom Trickey dated 9/14/01) for part load (20%) emissions data for W501G Combustion Turbine at the McIntosh #5 facility.

At this time, we do not have good start-up emissions data for a W501G. However, we can provide part load (20%) emission data (estimated) on a W501 F as follows:

Parameter	Concentration, ppmvd @ 15% O_2
NOx	45
CO	4000
VOC	665
Particulate Matter	Not available

Please note that this data is estimated and is not guaranteed and we are unable to determine if the data is directly applicable for a W501G installation. However, the data provided is higher and more reliable than the data we do have from the Lakeland SC where the NOX meter pegged at 1,000 at the lower load points.

We are hopeful, however, that the data provided will allow you to proceed with your emissions variance request to the FDEP.

Please feel free to call us if additional discussion is required.

Regards,

Andy Mould
Andy Mould
Project Manager

Siemens Westinghouse Power Corporation
A Siemens Company

4400 Alafaya Trail
Orlando, FL 32826-2399

BEST AVAILABLE COPY

Department of Environmental Protection

Jeb Bush
Governor

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

August 21, 2001

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Ms. Farzie Shelton
LAKELAND FL 33801

Postage	$ $0.34
Certified Fee	$2.10
Return Receipt Fee (Endorsement Required)	$1.50
Restricted Delivery Fee (Endorsement Required)	$0.00
Total Postage & Fees	$ $3.94

Postmark Here
AUG 22 2001
08/22/2001

Recipient's Name (Please Print Clearly) (to be completed by mailer)
City of Lakeland
Street, Apt. No.; or PO Box No.
501 East Lemon St.
City, State, ZIP+4
Lakeland, FL 33801-5050

7000 0600 0026 4129 8115

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Farzie Shelton, Manager
Environmental Affairs
City of Lakeland
Department of Electric Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

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

Dear Ms. Shelton:

The Department reviewed your letter dated July 20, 2001 requesting confirmation that a 100 day period of excess emissions is allowed during the commissioning of the combined cycle phase of the project.

When the initial permit was issued, the City submitted comments to the effect that "shakedown" has no regulatory meaning and 100 days seems arbitrary. In our response in the Final Determination, we explained our rationale. The 100 day period was not related to commissioning of combined cycle, but rather to insure that tests were conducted within a reasonable time after installation of control equipment to meet BACT emissions limits set forth in the permit. For example, a complete change out of combustors to meet the 9 ppm NOx limit by Dry Low NOx technology would trigger a 100 day period to conduct the BACT test. It would not trigger 100 days of excess emissions, especially with relation to the applicable New Source Performance Standard, Subpart GG.

We consider the letter, therefore to be a request to modify the conditions to allow for excess emissions during the commissioning of the combined cycle phase. The application is incomplete and the following information is required to process it:

1. The request needs to be signed by a professional engineer.
2. We need the startup characteristic curves that will show gas turbine speed and load with respect to time during a startup as well as steam turbine speed and load with respect to time.
3. We need the steady-state emissions characteristics such as NOx and CO concentrations with respect to load. We are particularly interested in the 20 percent load case during which contaminants will be purged.

4. Please submit a protocol describing the measures to be taken to minimize emissions during the low load conditions described.

If you have any questions regarding this matter, please contact Teresa Heron at 850/921-9529 or Al Linero at 850/921-9523.

Sincerely,

A A Linero P.E.

for C. H. Fancy, Chief, P.E.
Bureau of Air Regulation

CHF/th

Attachment

cc: Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, SWD

LAKELAND ELECTRIC

Farzie Shelton, chE; REM
Manager of Environmental Affairs

RECEIVED
JUL 23 2001
BUREAU OF AIR REGULATION

July 20, 2001

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

RE: DEP File No. 1050004-004-AC (PSD-FL-245) – Certification PA 74-06SR2 McIntosh Unit No. 5 Combustion Turbine Combined Cycle

Dear Al:

In accordance with our application and PSD permit condition, Lakeland Electric (Lakeland) is proceeding with the construction of the heat recovery steam generator for the above referenced unit. Lakeland anticipates conversion to the combined cycle to be completed sometimes in November/December 2001. Therefore, Lakeland anticipates start-up of this unit and shake down period to commence around November/December 2001 for which Lakeland will provide the Department with necessary notification in accordance with the Section II Emission Unit(s) General Requirements condition No. 5 of our permit.

Today, we are writing to confirm our understanding of our permit condition in connection with the start-up of this combined cycle. In accordance with Section III Emission Unit(s) Specific Conditions, condition No. 30, Lakeland will have a period not to exceed 100 days for shake down period (start up period) for which time excess emission is permissible prior to performing initial compliance tests. Additionally, during this 100 days Lakeland intend to relocate the Continuous Emission Monitoring (CEM) equipment on the new stack and perform the necessary certification of these equipment in accordance with the 40 CFR Part 75 of the Clean Air Act.

Therefore, we appreciate if you would confirm that condition No. 30 does provide us with the 100 days start-up period. However, if you should decide otherwise, Lakeland with this letter, is requesting modification of Unit No. 5 PSD permit to allow the necessary start-up period for commissioning of this combined cycle.

As always your cooperation and help in this matter is greatly appreciated. If you should have any questions, please do not hesitate to contact me.

Sincerely

Farzie Shelton

Cc: Mr. Hamilton Oven P.E.

City of Lakeland ⊕ Department of Electric Utilities

501 East Lemon Street ⊕ Lakeland, Fl 33801-5050 ⊕ (863) 834-6603 ⊕ Fax (863) 834-8187 ⊕ Message System 834-6592

farzie.shelton@lakelandgov.net

To: Farzie Shelton

From: Steve Marshall
Tom Trickey

Date: July 10, 2001

Subject: Request for permit variance - for commissioning of combined-cycle conversion
McIntosh Unit 5, PA 741-06SR2, Permit No. PSD-FL-245

McIntosh Unit 5 is a 501G 250 MW combustion turbine that was manufactured by Siemens-Westinghouse Power Corporation (SWPC) and is currently operating in simple cycle configuration. In this configuration, the combustion turbine currently meets all air permit requirements.

Unit 5 will be converted to combined cycle operation in 2001. The simple cycle combustion turbine will be rendered inoperable on September 15, 2001 in order to complete the conversion to combined cycle configuration. The unit will be "mechanically complete" on or about November 8, 2001 at which time the commissioning phase of the project will begin. The unit will not be returned to commercial operation until commissioning is complete.

The 501G-Series uses steam, instead of air, to cool the metal of the transition pieces between the combustors and the first-row turbine blades at operating loads above 20% of maximum capacity; air is used for cooling when operating below 20%. Steam cooling is new combustion turbine technology that improves performance. However, the steam purity requirement for transition cooling steam is much greater than the purity requirement of steam for powering a steam turbine. This purity requirement presents some significant problems during the initial startup of the 501G combined-cycle unit.

During first-start of any new steam cycle system, time is needed to check-out the equipment, get control of the systems enough to run, and then tune the controls. This period is recognized as the shakedown period in the permit, for which 100 days was originally allowed. Also, metals and other contaminants from the surfaces of tubes, piping, and vessels in contact with the water and steam are either dissolved or picked up in suspension.

This is much worse during a first start. It takes time to blow-down the system in order to purge those contaminants. The 501G combustion turbine can not operate above 20% load until the purity of the steam needed for transition cooling is achieved. During initial startup phase, we anticipate several intermittent days of no-load operation followed by two or more weeks of non-continuous combustion turbine operation at 20% load before achieving steam purity requirements allowing transfer to steam cooling and ramping up load. These expected events may cause the combustion turbine to produce emission levels that unavoidably exceed allowable limits.

Realizing that 501G combustion turbines are tuned for full-load operation and usually have excess emissions during startup/shutdown cycles, the permit appropriately allows for excess emissions during normal startups and shutdowns. However, the permit limits the duration of those startup excess emissions to 4 hours. This limit is acceptable for a commissioned unit, but not for the first-start of a new combined cycle unit.

It is estimated that the startup, shakedown, and commissioning phases will last no longer than 100 days. It is also estimated that the initial startup phase, during which the combustion turbine will operate at 20% load or less, will take an estimated continuous maximum duration of 21 days to purge contaminants. The stack-gas emissions will probably exceed our permit limitations for most of the entire duration of running in the initial startup phase. There may also be periods of excess emissions that last longer than our permitted 4 hour duration during the shakedown and commissioning phases. Commissioning of the combined cycle unit can not be completed without exceeding the allowable emission limits.

Please confirm that a second commissioning period for the combined cycle conversion that allows for excess emissions has not been provided in the existing permit. If you concur that a second commissioning period has not been provided, then please take whatever steps are necessary to obtain as soon as possible a 100 day time frame that will allow commissioning the combined cycle unit.

Time is of the essence so please consider this request to be of very high priority and keep us informed of your progress. Thank you for your support and assistance.

LAKELAND ELECTRIC

Farzie Shelton, chE; REM

Manager of Environmental Affairs

October 11, 2001

RECEIVED

OCT 12 2001

BUREAU OF AIR REGULATION

Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

RE: DEP File No. 1050004-004-AC (PSD-FL-245) – Certification PA 74-06SR2
McIntosh Unit No. 5 Combustion Turbine Combined Cycle

Dear Mr. Fancy:

We are in receipt of your letter dated August 21, 2001 in response to our letter of July 20, 2001. In our letter, Lakeland Electric (Lakeland) had requested the Department to modify the conditions of the above referenced permit to allow for excess emissions during the commissioning of the combined cycle phase of its united No. 5 at McIntosh Power Plant. Accordingly, we requested Mr. Steve Marshall (Unit No. 5 combined cycle project manager) to address the Department's questions and requested information.

Therefore, enclosed please find Mr. Marshall's response (signed and sealed) together with the necessary supporting document. As you will note Mr. Marshall is of the opinion that a minimum of 1,440 operating hours is necessary for starting and commissioning this unit commencing early November 2001.

Therefore, we appreciate if you would process our request at your earliest convenience. As always your cooperation and help in this matter is greatly appreciated. If you should have any questions, please do not hesitate to contact me.

Sincerely

Farzie Shelton

Enc.

Cc: Mr. Hamilton Oven P.E.
J. Heron ✓
B. Thomas, SWD ✓
G. Worley, EPA ✓
J. Bunyak, NPS ✓

City of Lakeland ● Department of Electric Utilities

501 East Lemon Street ● Lakeland, Fl 33801-5050 ● (863) 834-6603 ● Fax (863) 834-8187 ● Message System 834-6592

farzie.shelton@lakelandgov.net

LAKELAND ELECTRIC

October 9, 2001

Farzie Shelton, Manager of Environmental Affairs
Lakeland Electric
Larsen Power Plant
2002 E. Hwy. 92
Lakeland, FL 33801

Subject: DEP File No. 1050004 (PSD-FL-245)
McIntosh Unit No. 5 Combined Cycle Conversion

Dear Farzie:

In response to the Florida Department of Environmental Protection Agency's letter (Exhibit 1) dated August 21, 2001 requesting additional information, the city of Lakeland submits following information. The numbers shown below correspond to the questions in the referenced letter and numbers that are skipped do not require a specific response.

(2) Please see Exhibit 2. Steam turbine-generator (STG) output will "follow" the combustion turbine (CT) and the corresponding amount of steam that is sent to the STG versus being directed straight to the condenser thus bypassing the STG. This enables the STG to "trip" without the CT also tripping. The plant operators can then correct the problem and bring the STG back on line sooner.

(3) Please see Exhibit 3. Lakeland has contacted Siemens-Westinghouse Power Corporation (SWPC) to obtain the requested information pertaining to the 20% load case. SWPC has indicated in its letter dated September 28, 2001 that it currently does not have the requested startup data for a 501G combustion turbine (CT). However, similar data from a 501F CT is included for reference and SWPC speculates that the 501G CT will have lower emissions than a 501F CT due to its more advanced design.

In lieu of the requested information that is unavailable from SWPC, please consider this additional explanation in order to address the department's concerns.

The SWPC 501G CT utilizes "steam cooling" in order to achieve its higher operating efficiency and this is the significant difference (other than size) between a 501G and 501F. The heat recovery steam generator (HRSG) in combined cycle configuration will produce cooling steam for the CT and it must be extremely pure.

When the 501G CT first starts, it utilizes "air" for cooling instead of "steam" and it switches from air to steam when the CT output is in the 10% to 20% range and the steam being produced meets the specified purity requirements. If the steam

501 E. Lemon St. ✦ Lakeland, Florida 33801
Phone: 941.499.6300 ✦ Fax: 941.499.6344

does not meet the purity requirements, then the combined cycle would continue to operate in the 10% to 20% output range and be continuously "blowing down" steam to remove contaminants from the system until the continuously monitored steam purity measurements indicate that the steam purity is now within acceptable limits. As soon as the steam purity is acceptable, then the 501G "switches" to steam cooling and then moves into its "design operating range." The SWPC "ramp rate curves" and attachments indicate the exact sequence of events and expected time durations.

It should be understood that the SWPC ramp rate curves represent a "normal" starting sequence that logically assumes:

(1) The HRSG is clean and will quickly produce the high purity steam required, and

(2) All of the plant controls are properly functioning.

Commissioning a new unit following at the end of construction involves a different and more challenging set of circumstances that Lakeland must contend with:

(1) The HRSG has just been assembled, chemically cleaned, and air blown (using large rented compressors) through its steam lines to remove debris. However, the combined cycle plant has not been operated yet and no steam blown down to remove any remaining contaminants.

(2) The combined cycle controls have been installed and some control loops verified. However, many of the control loops cannot be tuned unless the combined cycle plant is operating. This will involve the combined cycle plant starting and stopping many times as Lakeland and its contractor (S&B Engineers & Constructors, Ltd.), works through the various problems that arise until safe and reliable control of the plant is ultimately attained.

Lakeland and S&B are currently targeting November 15, 2001 for the "first attempt" to test run the newly constructed combined cycle unit. It is typical in the industry to combine the activities of "debugging" and tuning the plant controls with the initial operation of the combined cycle power plant. In fact, the combined cycle power plant will probably see many "starts" and "stops" as part of the commissioning process.

It is also unknown and impossible to predict how long the combined cycle power plant will have to operate with the CT on "air cooling" and the HRSG continuously blowing down steam in order to remove contaminants and attain the specified cooling steam purity. However, experience at a couple of other 501G combined cycle plants elsewhere in the United States has indicated that this can be expected to take two (2) or more days until steam purity is attained. During this time of unavoidable sustained "low load operation" (<20%), the 501G CT is expected to produce higher emissions than the air permit currently allows. Lakeland must again emphasize that this is an unavoidable operating scenario that is a vital part of the commissioning process.

(4) Regarding a protocol to minimize emissions, both Lakeland and S&B are very motivated to complete all commissioning activities as rapidly as is possible, thereby minimizing emissions.

Lakeland's contractor (S&B) is contractually obligated to complete all commissioning activities such that the combined cycle power plant can be declared available for commercial operation by December 15, 2001. Commissioning will take place on a daily round-the-clock schedule and concludes with successfully demonstrating combined cycle operation on both natural gas and distillate fuel and meeting plant performance and emissions requirements.

Lakeland is motivated to complete all commissioning activities as rapidly as possible for several reasons. Since September 15, 2001, the conversion from simple to combined cycle has caused Lakeland to lose the ability to operate and dispatch its 249 MW simple cycle 501G CT due to construction activities. Lakeland must now replace that power when needed by either operating less efficient units in its fleet or purchasing replacement power from other utilities.

It is also very costly for Lakeland to operate the 501G (> $5,000/hour) during commissioning activities. Lakeland will therefore strive to minimize the amount of time that the 501G CT is operated and to maximize the benefit obtained when it is run. For example, steam will be blown down to remove contaminants at the same time that some of the control loops are being debugged. As many activities as is possible will be completed simultaneously in order to meet schedule deadlines, performance specifications, and emissions requirements.

Please request that the department modify the conditions in the subject permit to grant a total of 1,440 operating hours to commission the newly constructed combined cycle power plant during which excess emissions may occur. Currently, it is my belief that the requested 1,440 operating hours represent a conservative estimate within which the commissioning of the combined cycle unit can be completed. It is clearly understood by Lakeland that excess emissions shall be kept to an absolute minimum and under no circumstances will Lakeland exceed the requested 1,440 operating hour allotment without the department's prior approval.

Please advise at your earliest convenience regarding the status of this request or if any additional information is required.

Sincerely,

Steven D. Marshall

Steven D. Marshall, P.E. (FL #44733)
Project Manager
Unit 5 Combined Cycle Conversion Project

Steven D. Marshall
10/9/01

SENDER: *COMPLETE THIS SECTION*

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1. Article Addressed to:

Ms. Farzie Shelton
Manager Environmental Affairs
City of Lakeland Dept. of
Electrical Services
501 East Lemon St.
Lakeland, FL 33801-5079

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C. Signature
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1. Article Addressed to:

Ms. Farzie Shelton, Manager Environmental Affairs
City of Lakeland Department of Electric Utilities
501 E. Lemon Street
Lakeland, FL 33801-5079

COMPLETE THIS SECTION ON DELIVERY

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C. Signature
X Diane Mullis
☐ Agent
☐ Addressee

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City, State, ZIP+ 4 Lakeland, FL 33801-5079

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AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared Ken Holtzinger, who on oath says that he is the Classified Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

Public Notice of Intent

Air Construction Permit Modification
in the matter of...

in the...

Court, was published in said newspaper in the issues of.......................

11-2; 2001

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed K Holtz.......................
Ken Holtzinger
Classified Manager
Who is personally known to me.

Sworn to and subscribed before me this 2nd ....

day of November .... A.D. 20 01 ....

Patricia Ann Rouse
Notary Public

PATRICIA ANN ROUSE

PATRICIA ANN ROUSE
MY COMMISSION # CC 976018
EXPIRES: October 17, 2004
Bonded Thru Notary Public Underwriters

(Seal)

My Commission Expires............

454511 F996 City of Lakeland Sue Trout

Attach Notice Here

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 1050004-013-AC (PSD-FL-245)
City of Lakeland Electric and Water Utilities Department
C.D. McIntosh, Jr. Power Plant - Unit No. 5
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification to The City of Lakeland Electric & Water Utilities Department. The modification is to temporarily allow excess nitrogen oxides emissions period during the conversion of the simple cycle combustion turbine (Unit 5) to combined cycle mode at the C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. A Best Available Control Technology (BACT) determination was not required pursuant to Rules 62-212.400 and 410, F.A.C. and 40 CFR 52.21. The applicant's name and address are The City of Lakeland Electric and Water Utilities Department, 501 East Lemon Street, Lakeland, Florida 33801-5079.

The nominal 250 megawatt (MW) simple cycle combustion turbine-electrical generator was commissioned in 1999. It was tested for initial compliance while firing natural gas and then operated in simple cycle mode. The unit achieves a nitrogen oxides (NO_X) limit of 25 parts per million by volume, dry, at 15 percent oxygen (ppmvd).

The previously noticed and approved conversion to combined cycle is nearing completion. Under this phase, the hot exhaust gases will be recovered in a waste heat boiler that will raise sufficient steam to produce another 100 MW, thus increasing the capacity of the unit to 350 MW (nominal). The previously permitted NO_X emissions will be 7.5 ppmvd, to be achieved by selective catalytic reduction (SCR).

During the integration phase of the steam cycle, there will be times when it will be necessary to steam clean ("steam blows") the piping system for the waste heat boiler of dirt and debris accumulated during construction. This steam will be vented rather than used to make electricity. Emissions during steam blows will be higher than presently allowed by the simple cycle or combined cycle permits because the burners will not operate in full lean premixed mode at low load.

Although greater nitrogen oxides emissions are expected during the steam blows, concentrations will not exceed the NO_X limit of 40 CFR, Subpart GG of approximately 110 ppmvd at 15 % O_2 for efficient large frame units. Steam blows will occur intermittently during a period of 60 days (tentatively during November - January 2002). It is estimated that the total duration of low load operation will not exceed several hundred hours. An upper limit of 1440 hours of excess emissions will be permitted by this action. Excess emissions due to "steam blows" will be allowed until February 29, 2002.

The Department will issue the FINAL permit modification with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of fourteen (14) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit Modification." Written comments and requests for a public meeting should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit modification and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida, 32301 Telephone: (850)488-0114 Fax: (850)922-6979	Florida Department of Environmental Protection Southwest District Office 3804 Coconut Drive Tampa, Florida 33619-8218 Telephone: (813)744-6100 Fax: (813)744-6084	City of Lakeland Electric and Water Utilities Attention: Ms. Forzie Shelton 501 East Lemon Street Lakeland, Florida 33801-5079 Telephone: (941)499-6603 Fax: (941)603-6335

The complete project file includes the application, technical evaluations, Draft Permit Modification, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

F996 - 11-2; 2001

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1. Article Addressed to:

Ms. Farzie Shelton
Manager Environmental Affairs
City of Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, FL 33801-5079

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1 Article Addressed to:

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

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TECHNOLOGY DEVELOPMENT PROGRAMS FOR THE ADVANCED TURBINE SYSTEMS ENGINE

I. S. DIAKUNCHAK, Combustion Turbine Engineering
R. L. BANNISTER, D. J. HUBER
Emerging Products & Technologies
D. F. ROAN, Materials Engineering

EMERGING PRODUCTS & TECHNOLOGIES
TECHNOLOGY DIVISION

Technical Paper TP-96173

September 3, 1996

UNRESTRICTED
WORL-TP-96173

TECHNOLOGY DEVELOPMENT PROGRAMS FOR THE ADVANCED TURBINE SYSTEMS ENGINE

I. S. DIAKUNCHAK, Combustion Turbine Engineering
R. L. BANNISTER, D. J. HUBER
Emerging Products & Technologies
D. F. ROAN, Materials Engineering

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Technical Paper TP-96173

September 3, 1996

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THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
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96-GT-5

TECHNOLOGY DEVELOPMENT PROGRAMS FOR THE ADVANCED TURBINE SYSTEMS ENGINE

Ihor S. Diakunchak Ronald L. Bannister

David J. Huber D. Frank Roan

Westinghouse Electric Corporation
4400 Alafaya Trail
Orlando, Florida 32826-2399

ABSTRACT

This paper describes the technologies that are being developed or extended beyond the current state-of-the-art to achieve Advanced Turbine Systems (ATS) Program goals. The Westinghouse ATS plant is an advanced closed-loop cooled combined cycle, based on an advanced gas turbine engine incorporating novel design concepts and enhancements of existing technologies. The ATS engine is a fuel-flexible design operating on natural gas with provisions for future conversion to coal or biomass fuels. It is based on proven concepts employed in 501F and 501G engines. To achieve the required performance and reliability the engine will include closed-loop steam cooling, advanced materials and coatings, and enhanced component performance. To minimize NOx emissions, an ultra-low NOx combustion system will be incorporated. To ensure technical success, development programs are being conducted on the following: closed-loop steam cooling, advanced materials and coatings, component aerodynamic performance, flow visualization, optical diagnostics, combustion generated noise, and catalytic combustion.

INTRODUCTION

The U. S. Department of Energy, Office of Fossil Energy ATS Program is an ambitious program to develop the necessary technologies, which will result in a significant increase in natural gas-fired power generation plant efficiency, a decrease in cost of electricity and a decrease in airborne pollutants. In Phase 1 of the ATS Program, preliminary investigations on different gas turbine cycles demonstrated that net plant efficiencies greater than 60% could be achieved (Little et al., 1993). The more promising cycles were evaluated in more detail during Phase 2 in order to select the cycle that would achieve all of the program goals (Briesh et al., 1994). The closed-loop cooled combined cycle was selected because it offered the best solution, with the least risk, for exceeding the ATS Program goals of net plant efficiency, emissions, cost of electricity, reliability, availability, and maintainability (RAM), and commercialization in the year 2000.

The Westinghouse ATS plant is based on an advanced gas turbine design combined with an advanced steam turbine and a high efficiency generator. To promote achievement of the challenging performance, emissions, and RAM goals, current technologies are being extended and new technologies developed (Bannister et al., 1995). The attainment of the ATS performance goal necessitates advancements in aerodynamics, sealing, cooling, coatings, and materials technologies. To reduce emissions to the required levels demands a development effort in the following technologies: pre-mixed ultra low NOx combustion, catalytic combustion, combustion instabilities, and optical diagnostics. To achieve the RAM targets requires the utilization of proven design features, with quantified risk analysis, and advanced materials, coatings, and cooling technologies. Phase 2 research and development projects currently in progress, as well as those planned for Phase 3, will result in advances in gas turbine technology and greatly contribute to ATS Program success.

The ATS engine is the next frame in the series of successful utility turbines developed by Westinghouse over the last 50 years. During that time, Westinghouse engineers made significant contributions in advancing gas turbine technology as applied to heavy-duty industrial and utility engines (Scalzo et al., 1994). Some of the innovations included single-shaft, two-bearing engine design, cold-end drive, axial exhaust, cooled turbine airfoils, and tilting pad bearings. Today, these features are incorporated by all major gas turbine manufacturers in their designs. In the

Presented at the International Gas Turbine and Aeroengine Congress & Exhibition

st, enhancements in Westinghouse gas turbine -formance and mechanical reliability were made in ntinuous steps (see Figure 1). The evolution of large gas bines started with the introduction of the 45 MW 501A gine in 1968. Continuous enhancements in performance re made up to the 100 MW 501D5 introduced in 1981. e next engine developed was the 160 MW 501F roduced in 1991 (Scalzo et al., 1988, Entenmann et al., 90, Entenmann et al., 1992). The 230 MW 501G, the est engine in the 501 series, is the initial step in ATS gine development (Southall and McQuiggan, 1995). Each cessive engine design was based on the proven concepts d in the previous design (see Table 1).

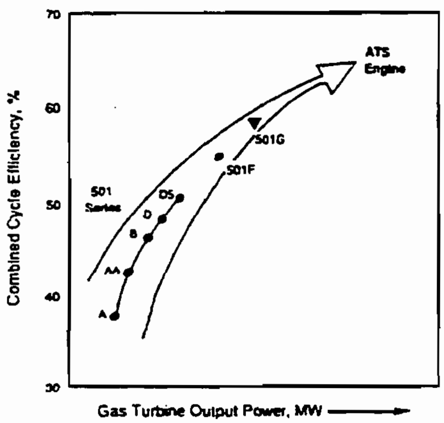

Figure 1. Evolution of Large Westinghouse Gas Turbines

Table 1. Proven Design Features

Feature	501D	501F	501G	ATS
earing Rotor	X	X	X	X
tage Turbine	X	X	X	X
. Combustors	X	X	X	X
riz. Split Casing	X	X	X	X
d End Drive	X	X	X	X
gle Row 1 Vanes	X	X	X	X
oling	AC	AC	AC/SC	AC/SC
lk-in Enclosure	X	X	X	X

: = Air Cooling SC = Steam Cooling

The 501F produces 160 MW at a simple cycle iciency of 36%. Its combined cycle net efficiency is about %. This performance level was achieved by proximately 110°C (200°F) increase in firing temperature, mpared to the previous engine, advanced compressor and bine design, advanced airfoil cooling design, and proved materials.

The current production engine, 501G, introduced in the ring of 1994, produces 230 MW. Its combined cycle net iciency is 58%. This engine incorporates further vancements in materials, cooling technology, and mponent aerodynamic design. The 19:1 pressure ratio mpressor uses advanced profile high efficiency airfoils. e combustion system incorporates 16 dry low NOx combustors. The combustor design is similar to the 501F with the same flame temperature and hence the same low NOx emission. The four-stage turbine uses full 3-D design airfoils and proven aeroderivative materials and coatings.

Achieving the ATS Program's challenging goals will require breakthroughs in several key technologies as well as advances in a broad range of current technologies. At the ATS performance level, the key issues are turbine component cooling, coating systems, and emissions control. Of almost equal importance in achieving the ATS Program goals will be the advances in component aerodynamic performance, scaling technology, and materials. To mitigate the key technical issues and to bring about the necessary advances in the supporting technologies, several development programs were proposed for ATS Phase 2. These programs include developments in combustion, emissions, cooling, aerodynamics, sealing, coating, and materials technologies.

Westinghouse's strategy to exceed the ATS Program goals is to build on the proven technologies used in the successfully operating fleet of its utility gas turbines, such as the 501F, to extend the technologies developed for the 501G and to overcome the identified technical barrier issues through a concerted development effort in ATS Phases 2 and 3 (see Figure 2).

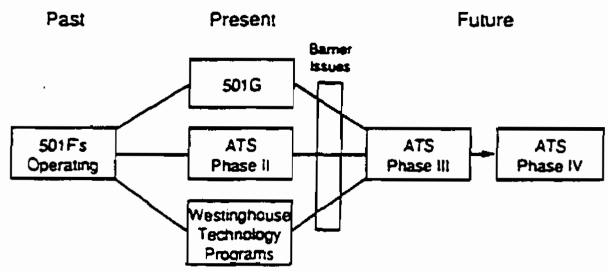

Figure 2. ATS Technology Development

The objectives of the ATS Program Phase 2 were to select the ATS cycle and to enhance or develop technologies required to achieve the ATS Program goals. This paper describes progress on the different technology development programs being conducted by Westinghouse in support of the ATS Program.

ATS DESCRIPTION

The ATS plant is based on the advanced combined cycle. The gas turbine, generator, and steam turbine will be connected together in an in-line arrangement with a clutch located between the generator and the steam turbine.

The gas turbine exhaust gases will pass through the three-pressure level heat recovery steam generator (HRSG) before being exhausted through the stack. The steam turbine will employ advanced 3-D aerodynamic design methods. The 60-Hz two-pole generator will be an extension of the Westinghouse hydrogen-cooled modular design concept.

The ATS engine is an advanced 300 MW class design incorporating many proven design features used in previous Westinghouse gas turbines and new design features and technologies required to achieve the ATS Program goals. The compressor design philosophy is based on that used in the advanced 501G compressor. The aerodynamic design uses 3-D viscous codes, controlled diffusion airfoils and reduced airfoil thicknesses. Variable stators are incorporated in the front stages to improve starting and part-load operation.

The combustion system has 16 combustors of lean-premixed multistage design. To limit NOx emissions to less than 10 ppmv, nearly all of the compressor delivery air is premixed with the fuel. Therefore, closed-loop steam cooling is used to cool the combustors and transitions.

The four-stage turbine is an extension of the advanced 501G turbine design. The design is based on 3-D design philosophy and advanced viscous analysis codes. The airfoil loadings are optimized to enhance aerodynamic performance while minimizing airfoil solidity. The reduced solidity results in reduced cooling requirements and increased efficiency. To further enhance plant efficiency, the following features are included: turbine airfoil closed-loop cooling, active blade tip clearance control on the first two stages, improved rotor sealing, and optimum circumferential alignment of airfoils.

Preliminary ATS engine and plant designs were completed and design reviews were held to verify the design concepts.

CONVERSION TO COAL-FIRED ATS

A number of advanced, coal-fired power generation technologies have been under development that could be applied to a natural gas-fired ATS. These include a broad range of coal gasification technologies (fixed bed, fluid bed, and entrained bed), second generation pressurized fluidized bed combustion (PFBC), and direct coal-fired turbine. Two advanced, coal-fueled technologies have been selected for consideration as coal-fired ATS: air-blown integrated gasification combined cycle (IGCC) with hot gas cleaning based on the KRW fluidized bed gasifier, and second generation PFBC (Newby et al., 1995).

The selection of a coal-fired reference system for the conversion of the natural gas-fired ATS to a coal-fired ATS was based on performance potential (power conversion and emissions), cost potential, and status of development. Estimated thermal conversion performance, cost potential, and the status of development of several advanced, coal-fueled technologies that could achieve the desired turbine inlet conditions were considered. Comparisons were made to natural gas-fired turbine cycles, as well as to conventional coal-fired power plants, atmospheric pressure fluidized bed combustion, and pulverized coal combustion boilers with flue gas desulfurization. The air-blown IGCC technologies with hot gas cleaning and second generation PFBC appeared to have the greatest thermal performance and cost potential with combined cycle efficiencies in the range of 51 to 53%. Their respective status of development is categorized as early demonstration which is suitable for the ATS Program.

PHASE 2 COMPONENT DEVELOPMENT PROJECTS

To resolve the identified technical barrier issues and achieve ATS Program goals, an extensive R&D program is in progress in the fields of combustion, cooling, aerodynamics, leakage control, coatings, and materials.

COMBUSTION

Due to the strict emissions requirements for the ATS engine, combustion development will be one of the critical areas requiring significant effort. To address this issue the following development programs were initiated: combustor flow visualization, combustor cylinder flow mapping, optical diagnostics probe development, combustion instability/noise investigation, and catalytic combustion component development. In addition, several dry ultra low NOx combustor development programs are in progress. The combustor verification tests are being performed in the full-scale, high pressure test facility located at the Arnold Engineering Development Center, Arnold AFB, Tennessee (Pillsbury et al., 1995).

Flow Visualization.

Air flows inside the combustor cylinder and into the combustors are very complicated. These flows have a significant effect on the losses, and hence on engine performance, and on the flow distribution inside the combustors and hence on the combustion processes. The latter effect is especially critical in the dry ultra low NOx lean-premix combustors, which rely on the correct fuel/air ratios within a very narrow tolerance band, for low NOx production and operational flame stability. Flow tests are being carried out on plastic models of the ultra low NOx baskets in the single-can rig and the sector rig at Westinghouse Casselberry Labs. Flow visualization, detail flow mapping tests and effective flow area measurements are being performed. Hot wire anemometry, as well as other conventional measurement techniques, are employed.

Combustion Cylinder Flow Mapping

Flow mapping and flow visualization tests are in progress on a half-scale plastic model of a combustion cylinder at Clemson University. Higher order effects inside the combustor are being investigated. Detailed measurements of pressures, velocities and flow angles inside the combustion cylinder, and especially around the

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combustor baskets, are being obtained. Included in this investigation is the effect of struts, cooling air return pipes, op-bat length increase and cooling air extraction. In ddition to studying and optimizing the flow around the ombustors, the objectives of these tests are to optimize the erformance of the compressor exit diffuser, reduce the iffuser exit dump loss, and hence improve the ATS engine erformance. In support of the experimental program, a FD analysis of the combustion cylinder flow field was arried out.

ptical Diagnostics Probe Development

Optical diagnostics allow measurement of pertinent rameters, such as the composition and concentration of mbustion products, in addition to velocities and flow gles, without disturbing the main flow. A laser-induced iorescence fibre optic probe is being developed. Probe aluation at high pressures and temperatures is in progress. is probe will be a very useful tool in enhancing mbustion development productivity. It will be used in ld flow and fired tests.

›mbustion Instability Investigation

Lean-premix combustion system will be employed to hieve the NOx emissions goals. The lean combustion with inherent flame instability results in more combustion nerated noise, and hence, in vibration problems in the mbustion system as well as in the downstream mponents. A program to develop the theoretical ckground for combustion instabilities, to carry out periments to aid in the understanding of the problem, to velop a generalized analysis procedure, and to develop bility criteria is under way.

An active noise control system is being developed to minate combustion instabilities. It consists of a sensor to tect the combustion instabilities, signal processor, dback algorithm generator and a fuel modulation valve d controller (see Figure 3).

tra Low NOx and Catalytic Combustion Development

Westinghouse is developing several ultra low NOx mbustors (Foss et al., 1994) in order to achieve single git NOx emissions (see Figure 4). The ATS combustor ll be based on the most successful candidate. Catalytic mbustion is expected to play an important role in hieving ultra low NOx emissions at the ATS engine firing nperature. The catalyst allows ultra lean-premix mbustion without flame instability and flame outs. ierefore, NOx production is restricted to low single digits ATS firing temperature with stable operation. velopment is in progress to gain theoretical understanding catalytic combustion, to design a catalytic combustion stem and to develop a practical catalytic combustor. A talyst coated pilot has been tested in an ultra low NOx combustor with excellent results. A catalytic combustor with exhaust gas recirculation to preheat the catalyst to the required temperature is being designed.

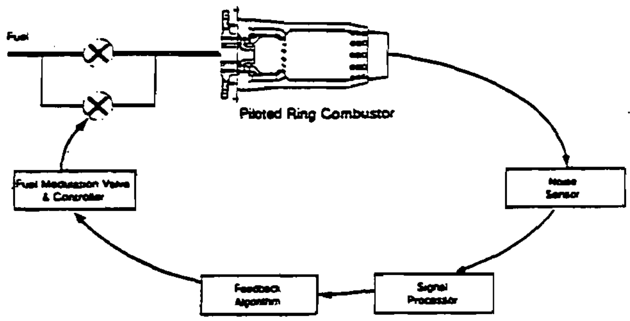

Figure 3. Active Noise Control Loop

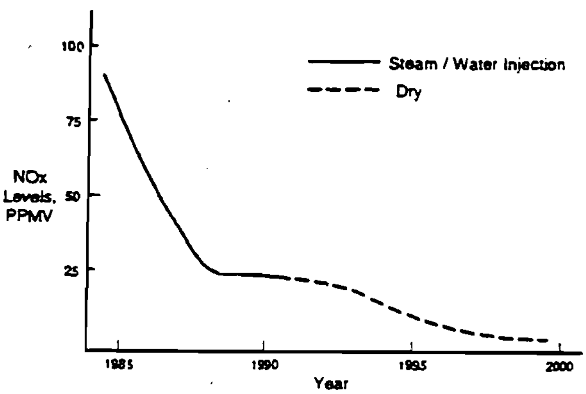

Figure 4. NOx Emission Levels

COOLING

Closed-Loop Steam Cooling

The one concept that will result in the greatest increase in the ATS plant cycle efficiency is closed-loop steam cooling. There are several challenges to a successful closed-loop steam cooling system. These include maintaining airfoil surface metal temperatures without outside film cooling, limiting wall temperature gradients, preventing corrosion and fouling of internal components over long periods of time, bringing coolant to and out of rotating components, leakage control, and cold start before steam from the downstream HRSG is available.

The major contributor to plant efficiency increase with closed-loop steam cooling is the elimination of cooling air injection into the turbine flow path. This results in an increase in gas temperature downstream of the first stage vane and hence an increase in gas energy level during the expansion process. A secondary contributor is the elimination of mixing losses associated with cooling air ejection. The combination of these effects results in a significant increase in ATS plant efficiency. In addition, NOx emissions will decrease because more air is available for the lean-premix combustor at the same burner outlet temperature. Achieving acceptable blade metal temperatures in a closed-loop cooling design is a challenge due to the absence of cooling air film to shield the turbine airfoil and shroud wall, and no shower-head or trailing edge ejection to provide enhanced cooling in the critical leading and trailing edge regions. To produce an optimized closed-loop cooling design, the following approaches are utilized: (1) airfoil aerodynamic design tailored to provide minimum gas side heat transfer coefficients, (2) minimum coolant inlet temperature, (3) thermal barrier coating applied on airfoil and end wall surfaces to reduce heat input, (4) maximized cold side surface area, (5) turbulators to enhance cold side heat transfer coefficients, and (6) minimum outside wall thicknesses to reduce wall temperature gradients and hence the internal heat transfer coefficients required to cool the airfoil.

Preliminary investigation was carried out on the following turbine airfoil closed-loop cooling concepts: thin wall shell/spar (see Figure 5), thin wall casting, and peripheral spanwise cooling hole. More detailed calculations will be carried out to select the final ATS airfoil cooling design.

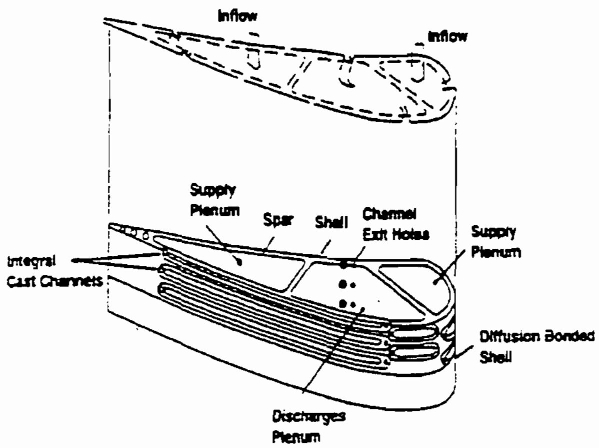

Figure 5. Conceptual Design of Shell/Spar Vane

Shroud Cooling

The airfoil end walls or shrouds present a cooling challenge. The combination of flat burner outlet temperature profiles and uncertainty in the end wall heat transfer coefficients make it difficult to arrive at an optimized shroud cooling design analytically. To address this issue, plastic model tests are in progress to optimize first stage turbine vane shroud film cooling design (see Figure 6). The thermochromic liquid crystal technique is being used to measure the surface temperatures, and hence, the heat transfer coefficients.

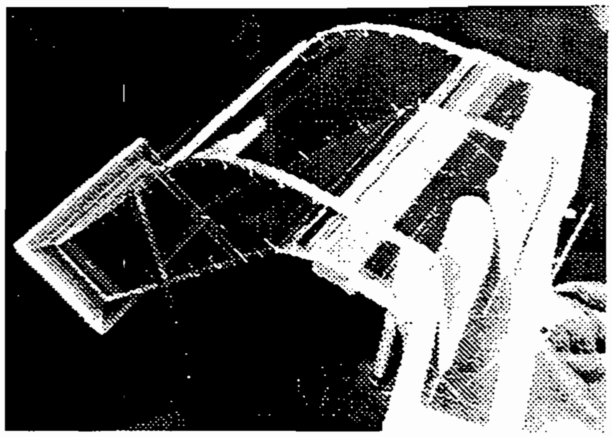

Figure 6. Vane Cascade

Serpentine Channel Cooling

To maintain low blade metal temperatures, complicated multipass serpentine cooling schemes are being developed. Plastic model tests are being conducted to verify and optimize the design prior to incorporation into the engine. Two models are being tested: one model simulating the multipass mid chord region of the blade and the second model representing the trailing edge portion of the blade. Tests are being carried out at different cooling air flow rates. The internal heat transfer coefficients and pressure losses are being measured. Tests on the trailing edge model have been completed, and testing on the mid chord model is in progress.

Integral Shroud Cooling

Turbine blades in the rear stages are designed with an integral interlocked tip shroud to enhance performance and to improve mechanical integrity by providing vibration damping. Metal temperatures and stress levels on these blades may necessitate cooling not only the airfoil, but also the tip shroud. A new approach is required in the cooling design, casting, and machining to cool the shrouds with cooling air, which will heat up through the blade before reaching the tip shroud. To effectively cool the tip shroud, alternative cooling schemes and manufacturing processes were investigated. An optimized shroud cooling design was developed. This cooling concept consists of a cast cavity in the bottom portion of the blade and a mid chord radial hole to supply tip shroud cooling air. The velocities and internal heat transfer coefficients in this hole are low. Therefore, the cooling air heat pick-up is minimized before the cooling air enters the cooling holes machined in the shroud.

AERODYNAMICS

High Efficiency Compressor

High efficiency compressor design is being developed for the ATS engine. The ATS compressor design philosophy is based on that used for the advanced 501G compressor. The aerodynamic design uses 3-D viscous codes, reduced number of stages, controlled diffusion airfoil design, reduced airfoil thickness and advanced sealing. An optimization study was carried out to optimize each stage efficiency individually so as to maximize the efficiency for the design pressure ratio with the minimum number of stages. Compressor performance at off-design conditions was investigated to ensure adequate surge margin over the entire operating range. Blade and stator profile definition is in aerodynamic/mechanical design iteration. All airfoils are custom shaped using controlled diffusion design process. The design objective is to satisfy all mechanical constraints with minimum airfoil thickness so as to optimize efficiency.

LEAKAGE CONTROL

Active Blade Tip Clearance Control

Turbine blade tip clearance has a significant effect on the performance of highly loaded front stages. For each one percent tip clearance increase (based on blade height), the stage efficiency may decrease by up to 2 percent. Even if the initial cold blade tip clearances are set at minimum values, during transients, such as rapid starts and emergency shutdowns, the blade tips are ground off. This results in increased hot running blade tip clearances, which get progressively worse with time. To optimize turbine efficiency, an active tip clearance control system is being developed. The objective of such a scheme is to maintain large tip clearances on start-up and to reduce them to minimum acceptable values when the engine has reached steady-state operating condition (see Figure 7). A conceptual design of an active tip clearance control system is in progress.

Brush Seals

To reduce air leakage, as well as hot gas ingestion into turbine disc cavities, brush seals, which have the potential to reduce leakage by up to 90%, will be incorporated in appropriate locations in the turbine and compressor (see Figure 8). This will enhance engine efficiency as well as mechanical integrity of the turbine components. To incorporate an effective, reliable, and long-lasting brush seal system into a heavy-duty industrial gas turbine, a development program was initiated. Preliminary investigation was carried out to evaluate the benefits, potential seal locations, and validation testing required to apply brush seals to industrial gas turbine engines. Conceptual seal design at one engine location was carried out. Tribopair tests were carried out on five different bristle alloys, two rotor materials, and two rotor surface finishes to determine which tribopair results in minimum wear. The optimum tribopair was selected for seal leakage testing.

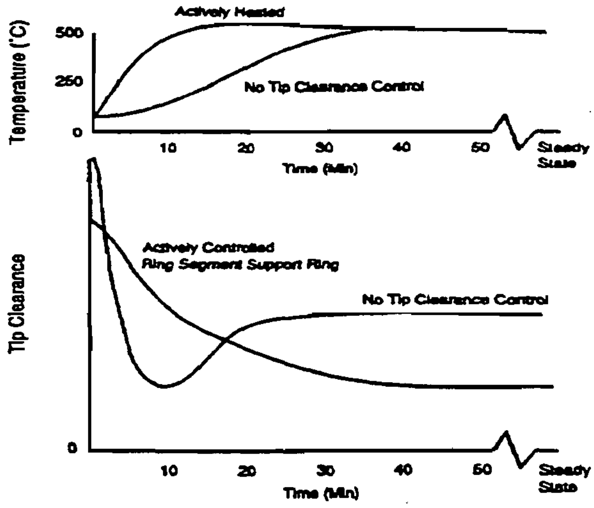

Figure 7. Support Ring Temperature and Tip Clearance with and without Active Control

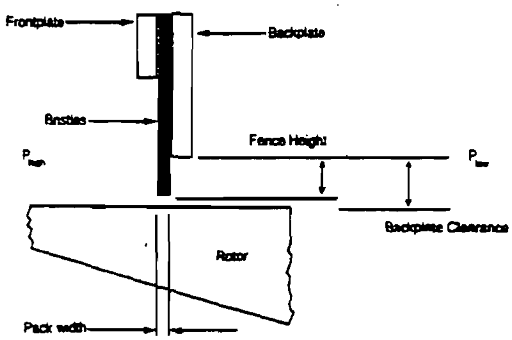

Figure 8. Brush Seal Schematic and Terminology

COATINGS

Thermal Barrier Coatings

Ceramic thermal barrier coatings (TBC) are important to the success of the ATS program. TBC low thermal conductivity effectively insulates the metal substrate and provides up to 11°C (20°F) metal temperature reduction per .025 mm (.001 in.) coating thickness. While TBCs have been used widely on stationary components, use on rotating components has been limited. Field testing of coated blades must be carried out to determine comparative coating longevity and effectiveness of air plasma spray (APS) and physical vapor deposition (PVD) thermal barrier coatings. Three batches of first stage turbine blades coated with APS TBC, PVD TBC, and with only the metallic overlay coating were installed in an operating engine. During engine inspections, these blades will be examined insitu or removed for coating performance evaluation.

Advanced Coating Development

The ATS engine turbine component coatings must be capable of operation for 24,000 hours. To ensure this, a program is in progress to develop an advanced coating system. Different bond coats are being evaluated under accelerated oxidation test conditions. New candidate ceramic coating materials are undergoing testing. The objective of this program is to combine the optimum bond coat with the best performing TBC to provide a coating system with maximum service life at the ATS operating conditions.

MATERIALS

Single Crystal Blade Development

To enhance performance and reliability, single crystal (SC) blades will be incorporated in the ATS engine. A casting development program was carried out to demonstrate castability of large industrial turbine blades in CMSX-4 material. Existing 501F engine blade tooling was used to cast single crystal blades. The castings were evaluated by grain etching, selected NDE methods and dimensional inspection methods to determine their metallurgical acceptability. After several trials, excellent results were obtained on a solid and a cored stage 3 shrouded blade, thus demonstrating that SC blades are castable in CMSX-4 alloy. Further process development is still needed to improve the yield.

A development program is in progress to optimize post-cast heat treatment, evaluate effects of grain defects, generate SC material design data, and further develop the casting process.

Ceramic Components

Ceramic components have potential for reducing cooling requirements, enhancing engine performance and improving turbine component reliability. Investigations are being carried out into the applicability of ceramic components, such as combustors, transitions, and ring segments into large industrial gas turbines. A conceptual design of turbine ring segments using ceramic matrix composite material is in progress.

FUTURE ACTIVITIES

The Phase 2 technology development efforts have progressed sufficiently to demonstrate that the ATS program goals are obtainable in the 5-year time frame. The Phase 2 technology developments currently under way and those planned for Phase 3 should resolve the identified technical barrier issues, so that the performance, emissions, and RAM objectives may be achieved. A concerted combustion development effort will be initiated to provide the ATS engine with an environmentally benign combustion system limiting NOx emissions to single digits, while achieving stable, reliable, long service life operation. The cooling program will lead to optimized cooling designs which should result in enhanced performance, mechanical integrity, and reliability. The advanced coating systems and materials development programs will make a significant contribution to enhanced turbine component reliability as well as increased performance. The aerodynamics and advanced sealing developments are intended to ensure that the ATS program thermal performance goal of greater than 60% net plant efficiency will be achieved. Significant technological advancements have already been achieved in Phase 2. The technology development programs planned for Phase 3 will build upon these successes and advance the gas turbine state-of-the-art, thus making a major contribution to the success of the Westinghouse ATS Program.

ACKNOWLEDGMENTS

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..AB-This paper describes the technologies that are being developed or extended beyond the current state-of-the-art to achieve Advanced Turbine Systems (ATS) Program goals. The Westinghouse ATS plant is an advanced closed-loop cooled combined cycle, based on an advanced gas turbine engine incorporating novel design concepts and enhancements of existing technologies. The ATS engine is a fuel-flexible design operating on natural gas with provisions for future conversion to coal or biomass fuels. It is based on proven concepts employed in 501F and 501G engines. To achieve the required performance and reliability the engine will include closed-loop steam cooling advanced materials and coatings, and enhanced component performance. To minimize NOx emissions, an ultra-low NOx combustion system will be incorporated. To ensure technical success, development programs are being conducted on the following: closed-loop steam cooling, advanced materials and coatings, component aerodynamic performance, flow visualization, optical diagnostics, combustion generated noise, and catalytic combustion.

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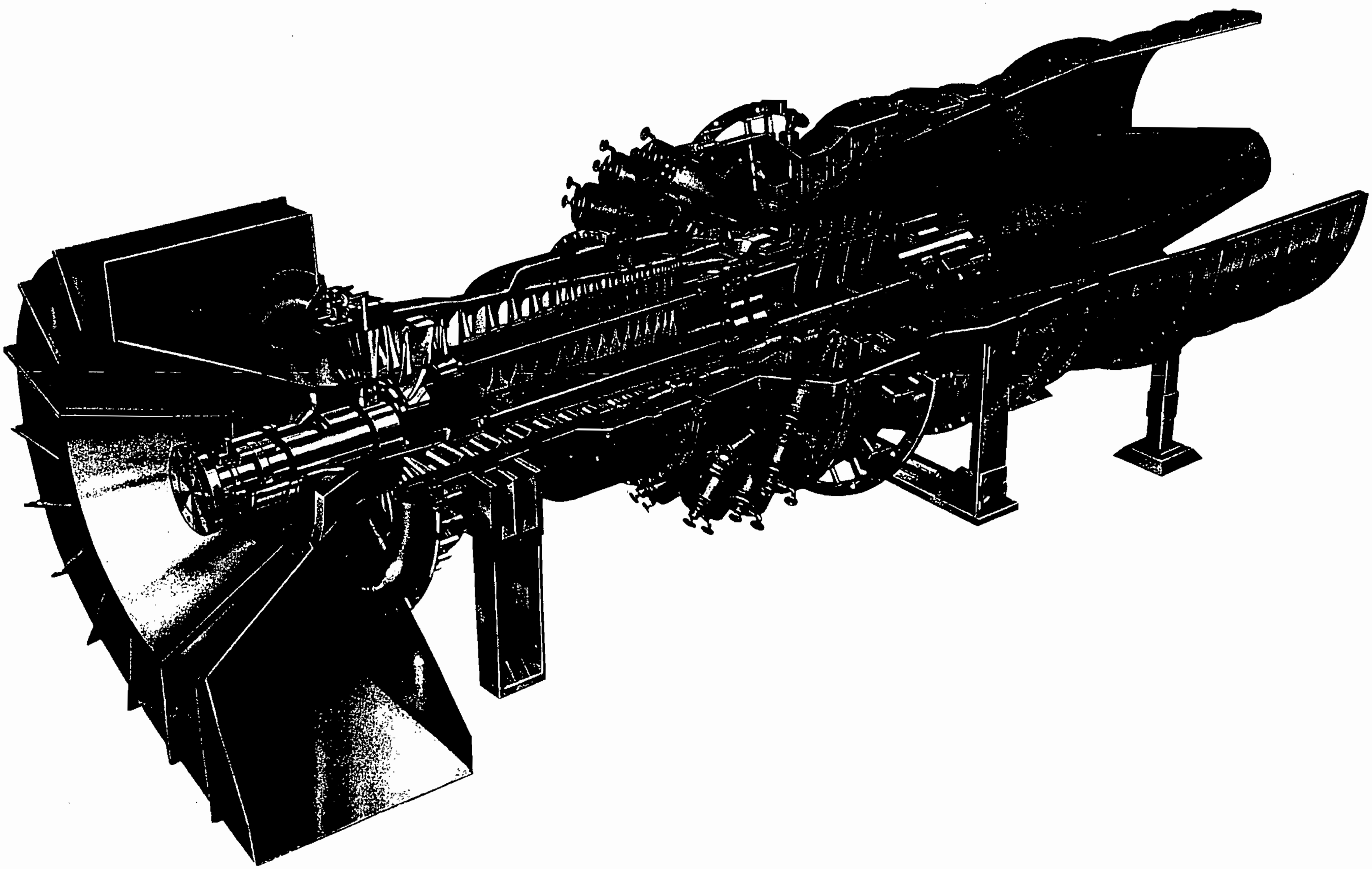
RAISING COMBUSTION TURBINE TECHNOLOGY

501G

EXECUTIVE OVERVIEW

501G Overview



501G Major Design Goals

- High efficiency
- Largest Power Density
- Low cost of electricity
- Proven advanced design concepts
- High reliability
- Low life cycle costs

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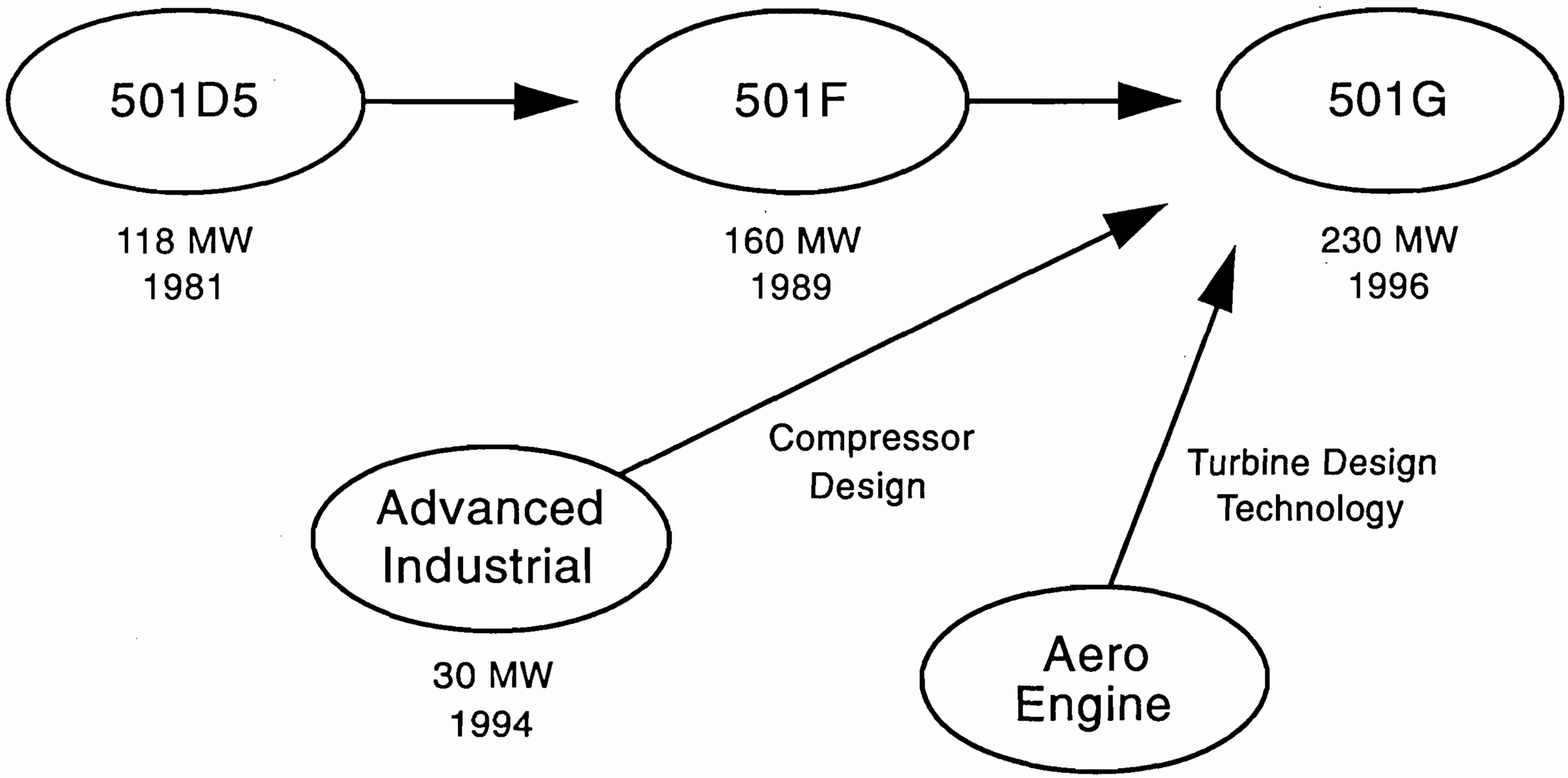
501G Design Approach

- Capitalize on Alliance strengths and resources
  - MHI, FiatAvio
  - Rolls-Royce
- Maintain time-proven fundamental design
- Utilize state-of-the-art technologies
  - Aero computer design codes
  - Advanced materials including thermal barrier coatings
- Aggressive concurrent engineering
  - Engineering / Manufacturing / Vendors
- Independent Design Oversight Board

501G Heritage



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501G Design Approach

- Maintain metal temperatures within proven experience
- Comprehensive component verification programs
  - Complete compressor
  - High Temperature Demonstration Unit
- 3-D flowfield analysis for optimum efficiencies
- RAM and Risk Analysis programs for maximum reliability
- Manufacturing considerations a primary objective
- Low emissions program to satisfy world-wide needs

501G: World Leader in Performance

	Simple Cycle	Combined Cycle*
Power, MW	230	345
Efficiency, (LHV)	38.5%	58%
Heat rate - Btu/kWh	8,860	5,883
Airflow, Lb/Sec	1,200	
Exhaust Temp., °F	1,100	

* Mature Rating

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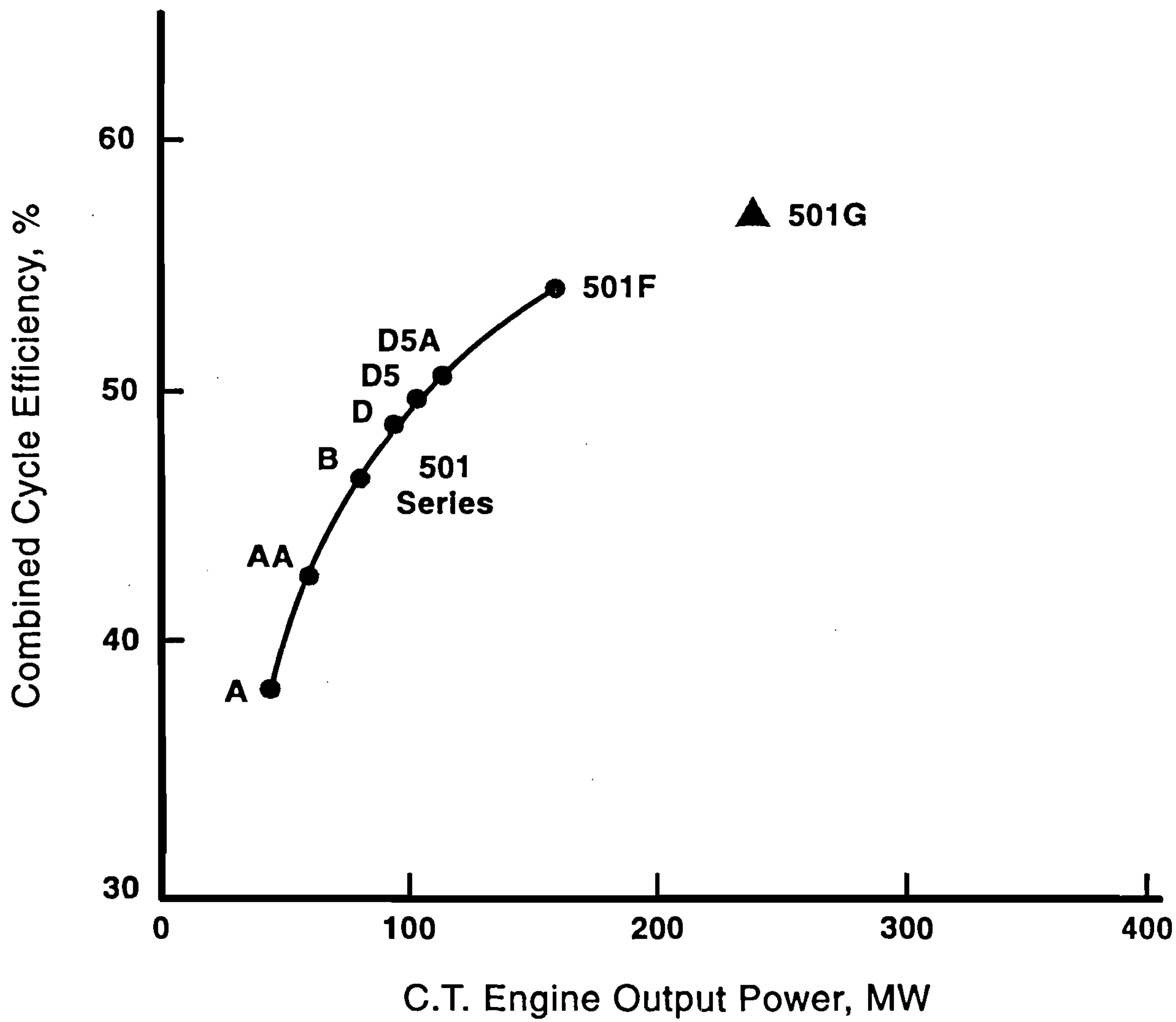
501G Evolution
World Leader in Performance



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501G Emissions for 1996 Shipment

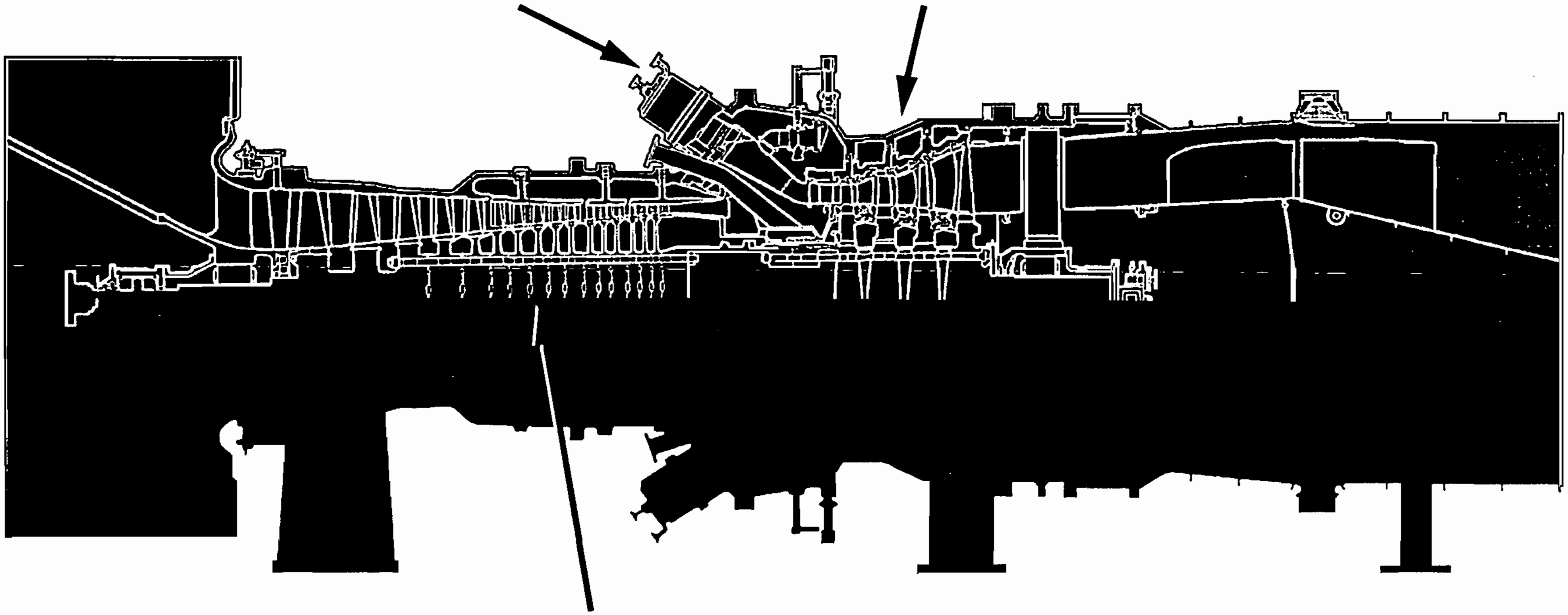
	Natural Gas (Dry)	Oil (Water Injection)
• NOx	< 25 ppm	< 42 ppm
• CO	< 10 ppm	< 25 ppm
• UHC	< 10 ppm	< 15 ppm

36951.04L

501G Design Features

- 16 Can-Annular Dry Low NOx Combustors
- 2600 °F Class Turbine
- Steam Cooled Transitions
- By-pass Valve for Part Load Stability

- 4 Stages of Full 3-D Blades and Vanes
- 15% Fewer Blades and Vanes than 501FA
- 3-Stages Air Cooled
- Aeroderivative Proven Materials and Coatings



- 17 Stage Advanced Profile Airfoils
- 19.2 to 1 Pressure Ratio
- Bolted Rotor Construction
- One Variable-IGV to Maintain Part Load Performance

501 Evolution

Engine	501A	501B	501D	501D5	501D5A	501F	501G
Commercial Operation	1968	1973	1976	1982	1995	1992	1997
Power, MW	45	80	95	107	119	162	230
Rotor Inlet Temp., ° F	1615	1819	2005	2070	2150	2350	2583
Air Flow, Lb/Sec	548	746	781	790	832	961	1200
Pressure Ratio	7.5	11.2	12.6	14	14.2	15	19.2
No. Comp. Stages	17	17	19	19	19	16	17
No. Turbine Stages	4	4	4	4	4	4	4
No. Cooled Rows	1	3	4	4	4	6	6
Exhaust Temp., ° F	885	907	956	981	1004	1083	1100
Heat Rate (Btu/kWh)							
LHV - ISO Gas							
Simple	12,600	11,600	10,925	10,040	9,930	9,550	8,860
Combined	9,000	7,350	7,280	7,055	7,024	6,250	5,883

36951.14L

501G Proven Design Features

- Compressor-end drive
- Two-bearing rotor
- Axial exhaust
- Tilting pad bearings

Proven Design Features

Feature	251	501D	501F	501G
2-bearing rotor	✓	✓	✓	✓
4-stage turbine		✓	✓	✓
Individual combustors	✓	✓	✓	✓
Horizontal split casing	✓	✓	✓	✓
Cold end drive	✓	✓	✓	✓
Single Row 1 vanes	✓	✓	✓	✓
Cooled & filtered rotor air	✓	✓	✓	✓
Walk-in enclosure	✓	✓	✓	✓

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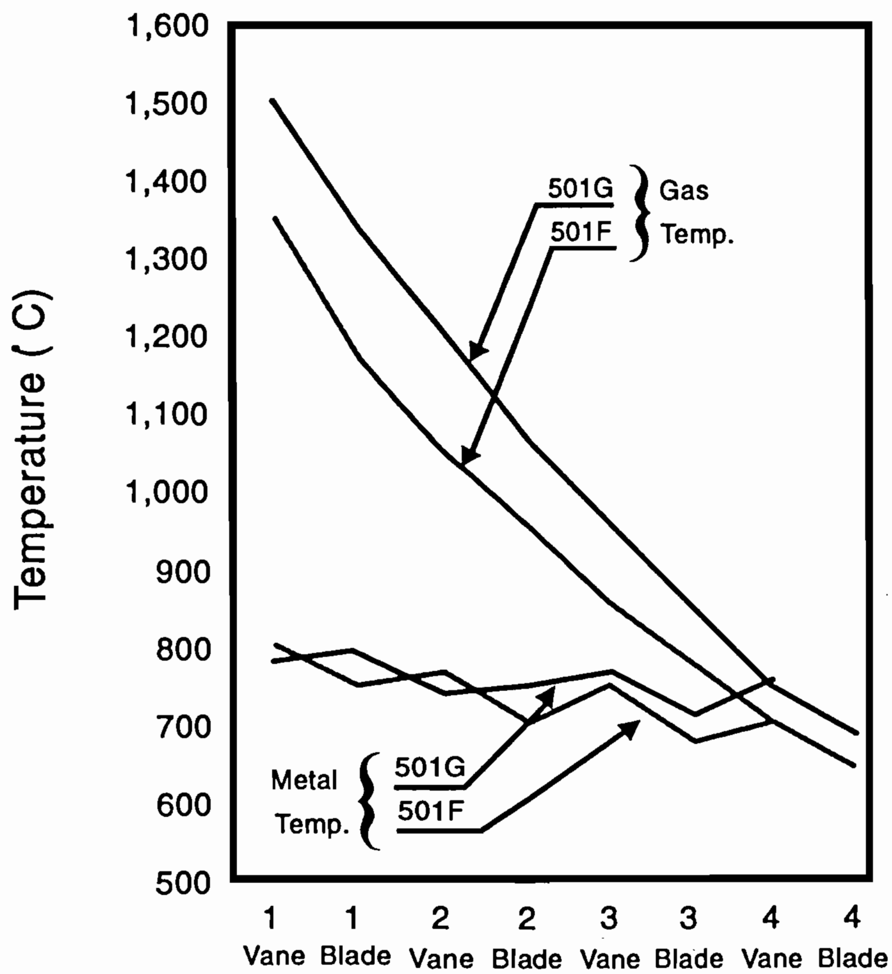
Proven Blade and Vane Metal Temperatures



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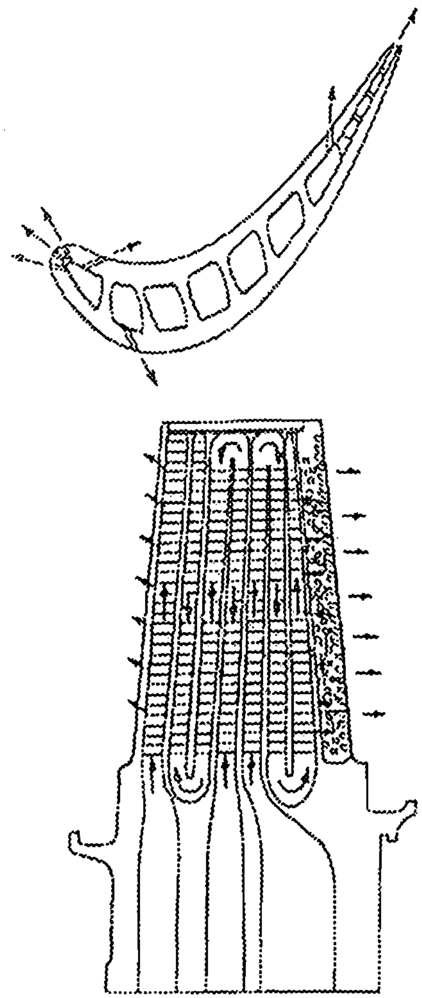
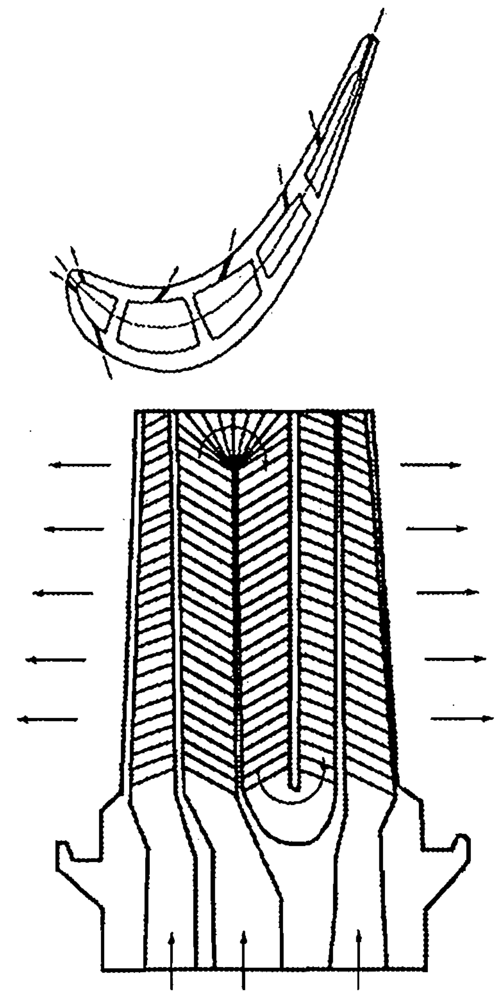
Row 1 Blade Evolution



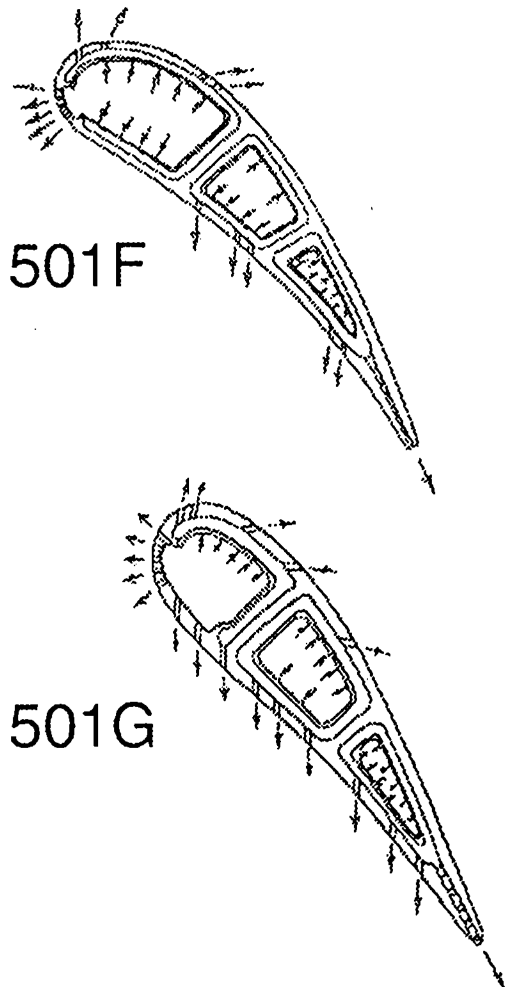
501F



501G

36970.02M

Row 1 Vane Evolution



501F

501G

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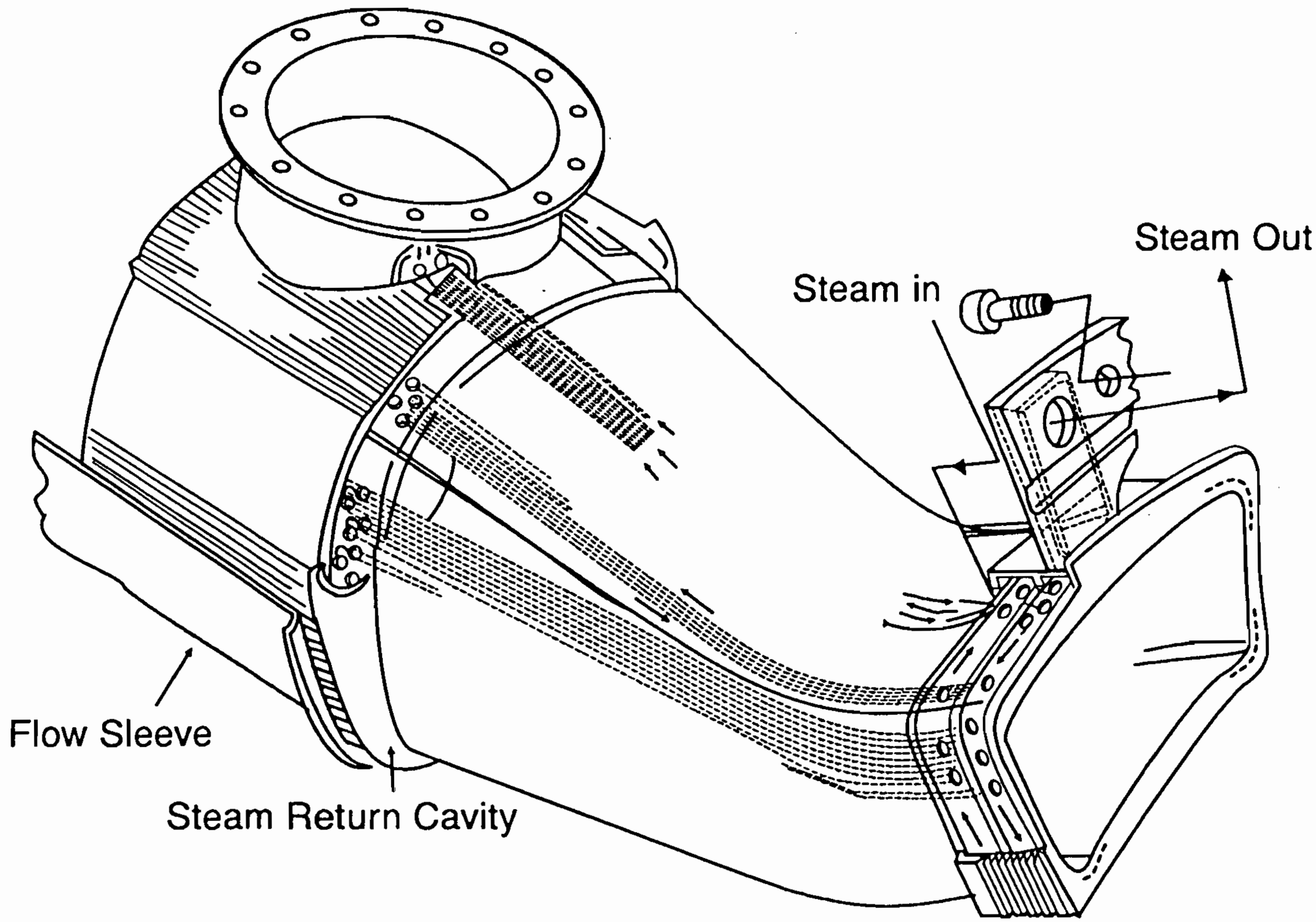
Transition - Steam Cooling



501G Lowest Life Cycle Costs

Number of Critical Parts

	501F	501G
Combustors	16	16
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 Blades & Vanes	534	447
Total Cooled Blades & Vanes	378	315

36951.08L

501G Inspection Intervals

Inspection Type	Hours	Starts
Combustor	8,000	400
Turbine	24,000	1,200
Major	48,000	2,400

Gas Fuel

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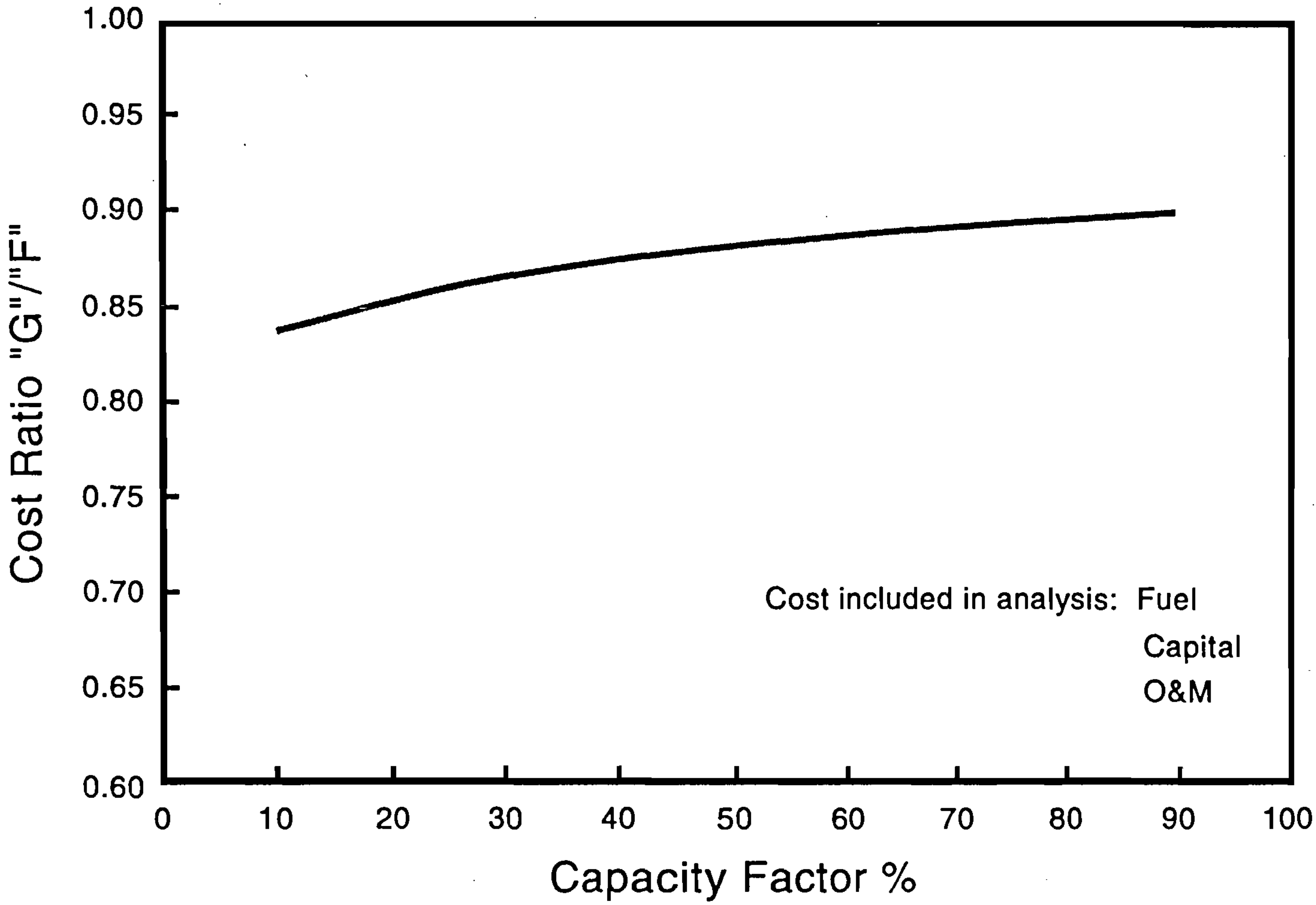
Relative Annual Cost of Power

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



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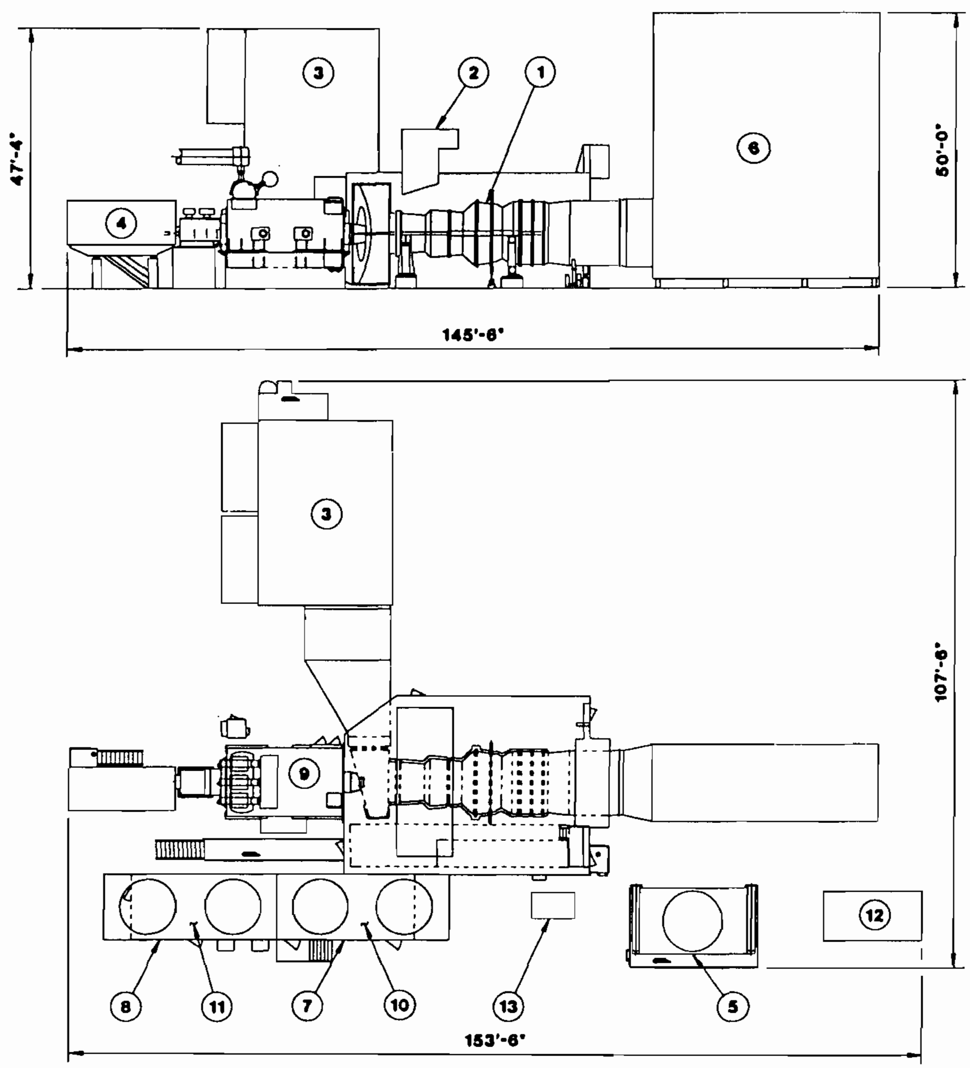
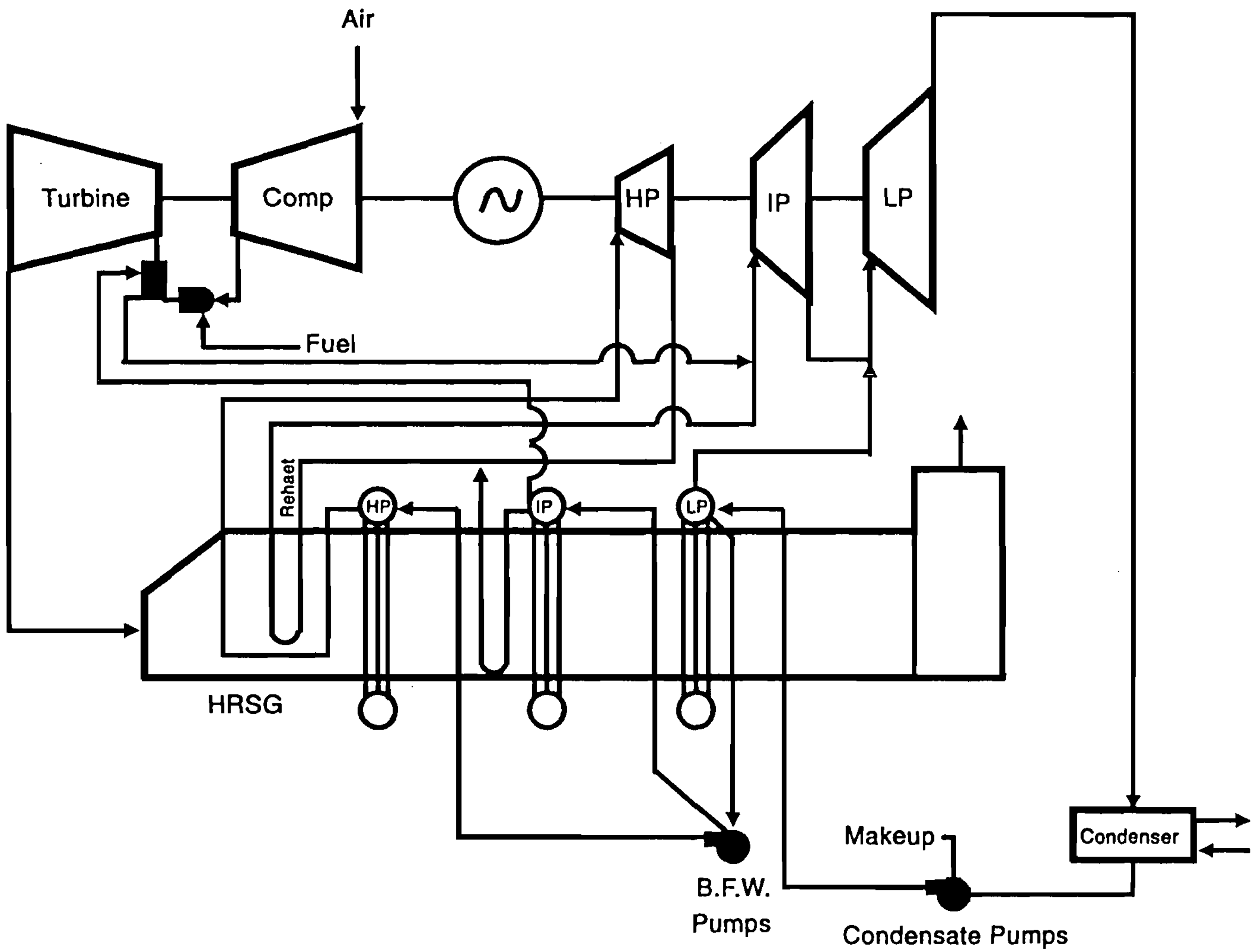
501G EconoPac - Standard Configuration



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

501G 1X1 Reference Plant



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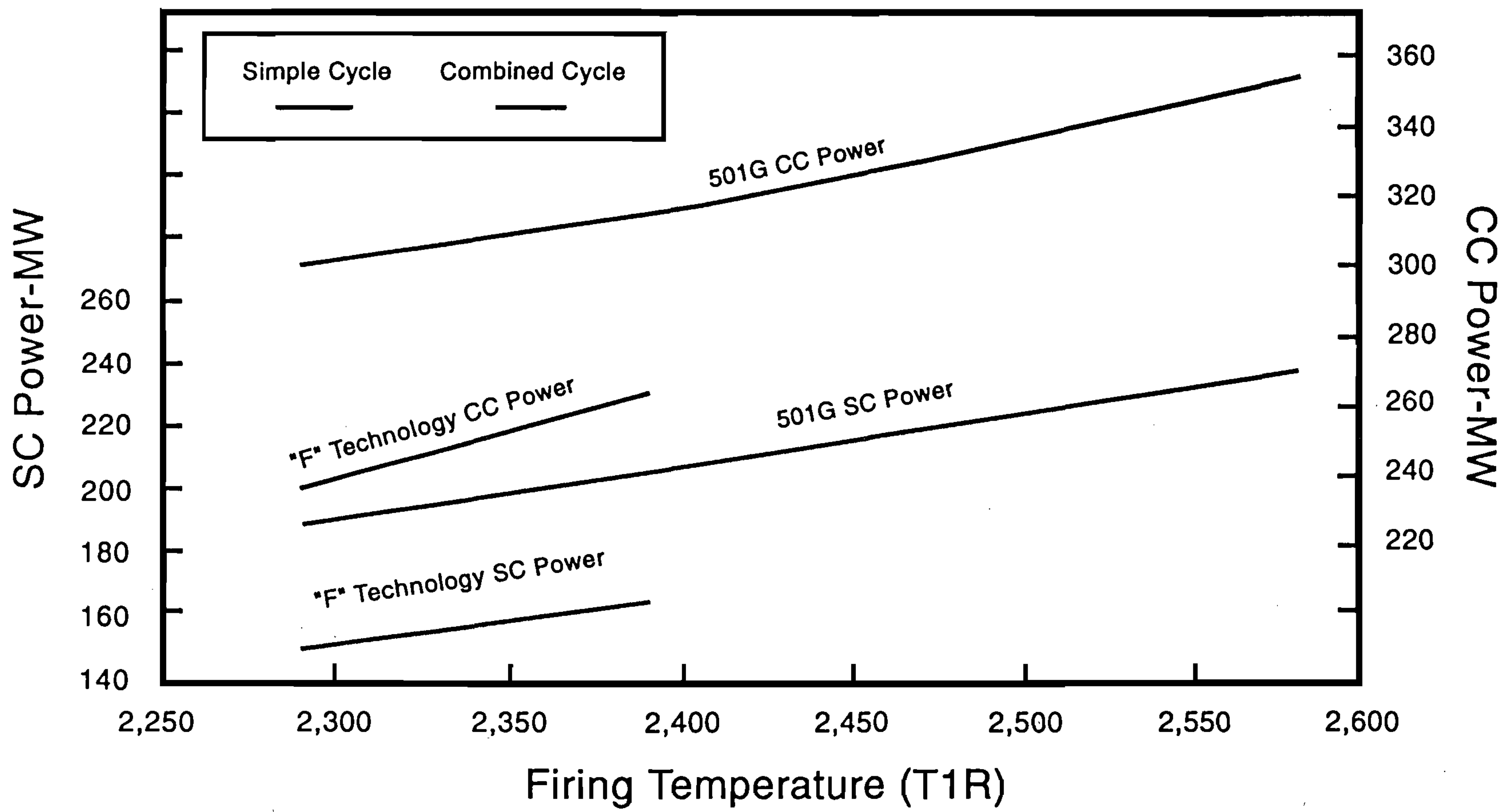
501G Power vs Firing Temperature



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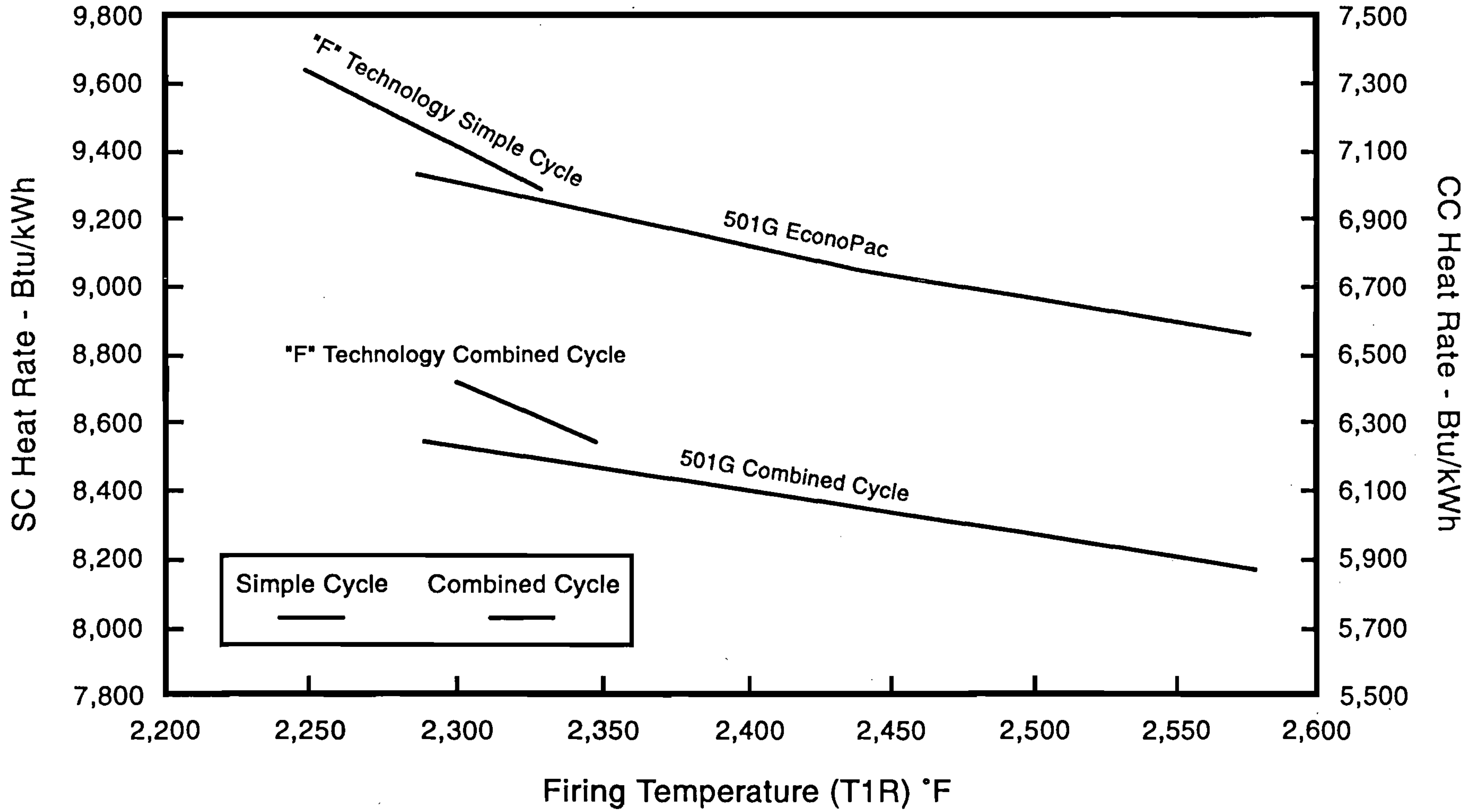
501G Heat Rate vs Firing Temperature



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501G Component Verification Tests

- Combustor (full scale, stability, emissions)
- Transition steam cooling
- Model turbine aerodynamic
- Film cooling of vane and blade (cascade test)
- HTDU (0.6 scale of Row 1 vane and blade)
- Model blade tip cooling
- Scaled compressor
- Full load engine

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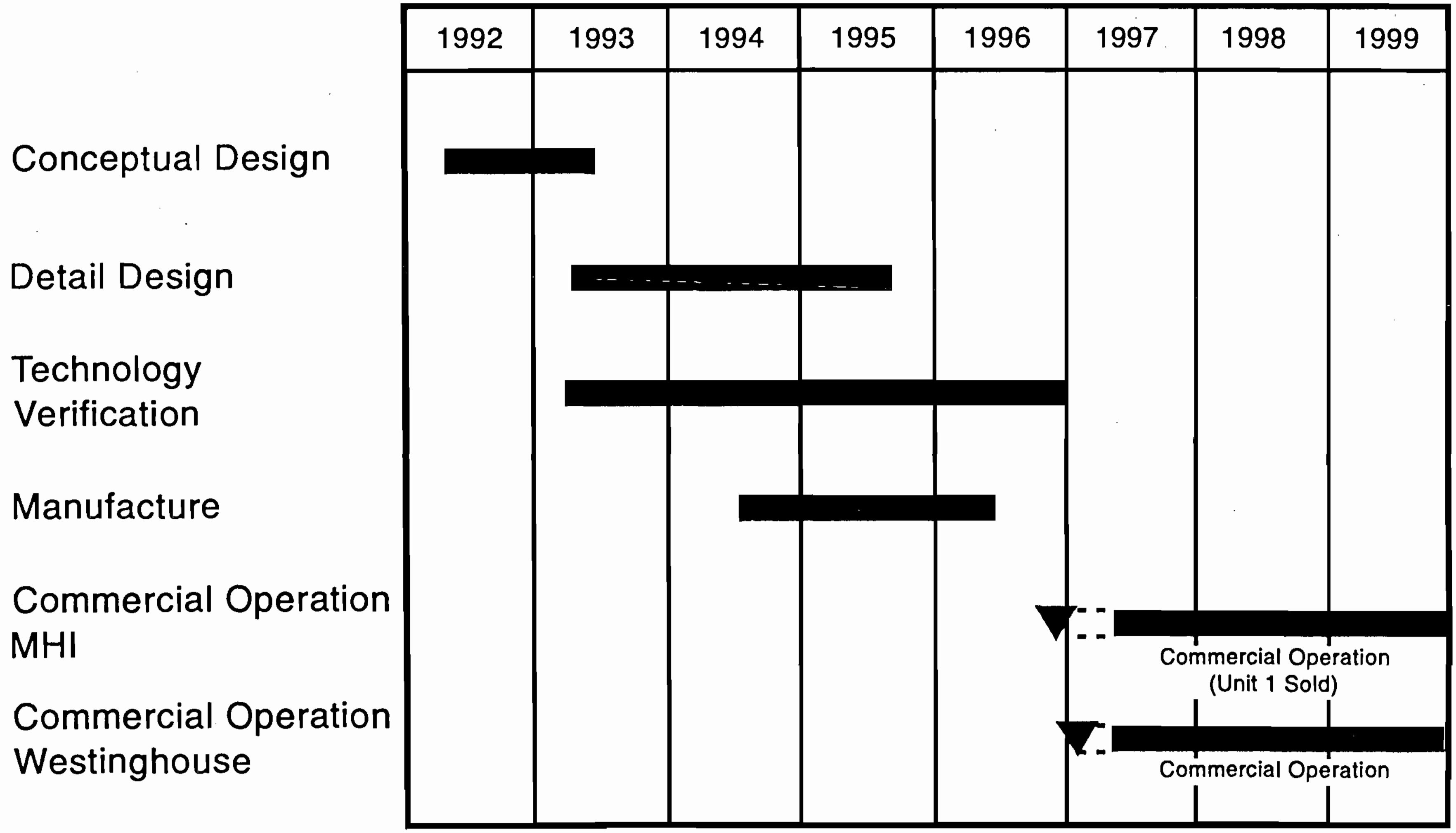
501G Development Schedule



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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

32409.39L

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%

32409.50L

501G: The Economic Answer

- Highest Efficiency
- Largest Power Blocks
- Lowest Life Cycle Costs
- Lowest Cost of Electricity

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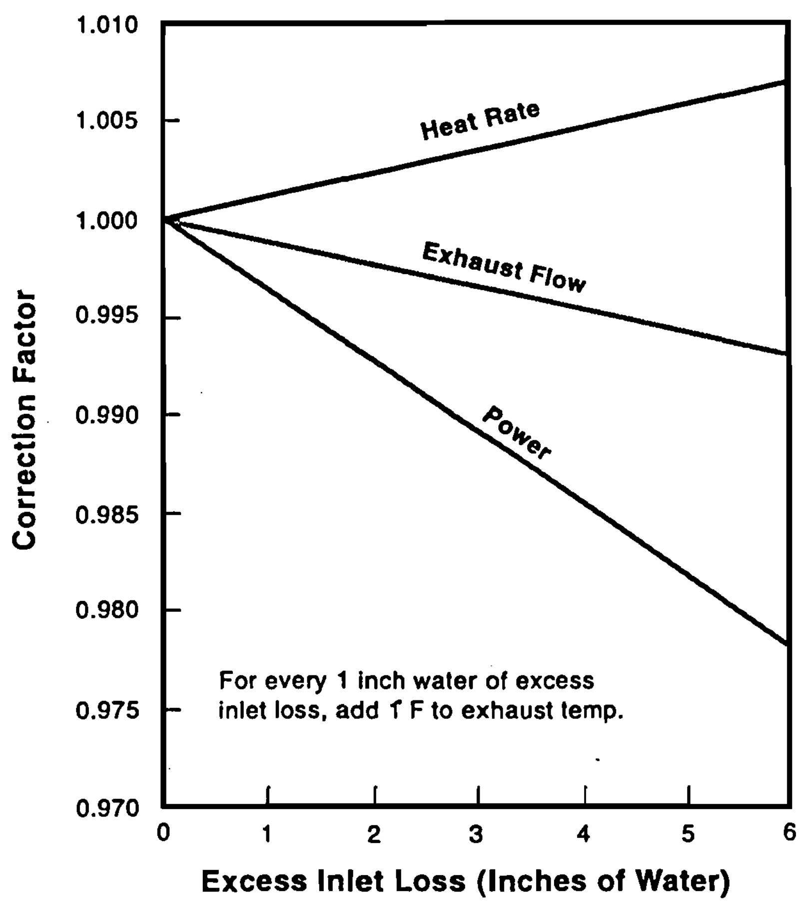
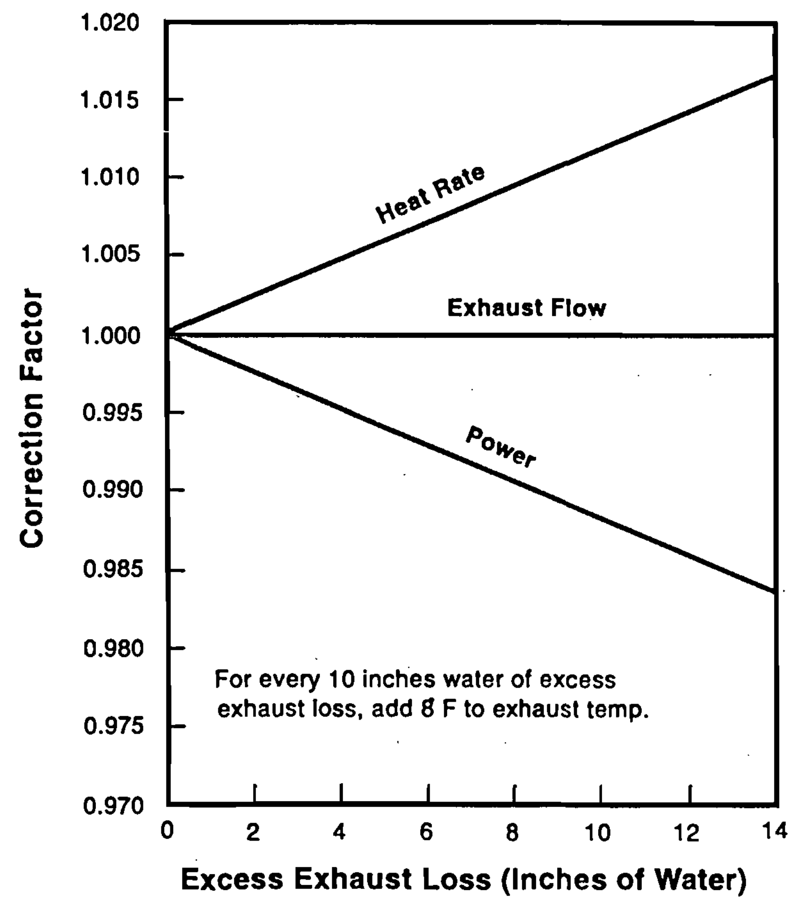
501G Performance Correction Curves





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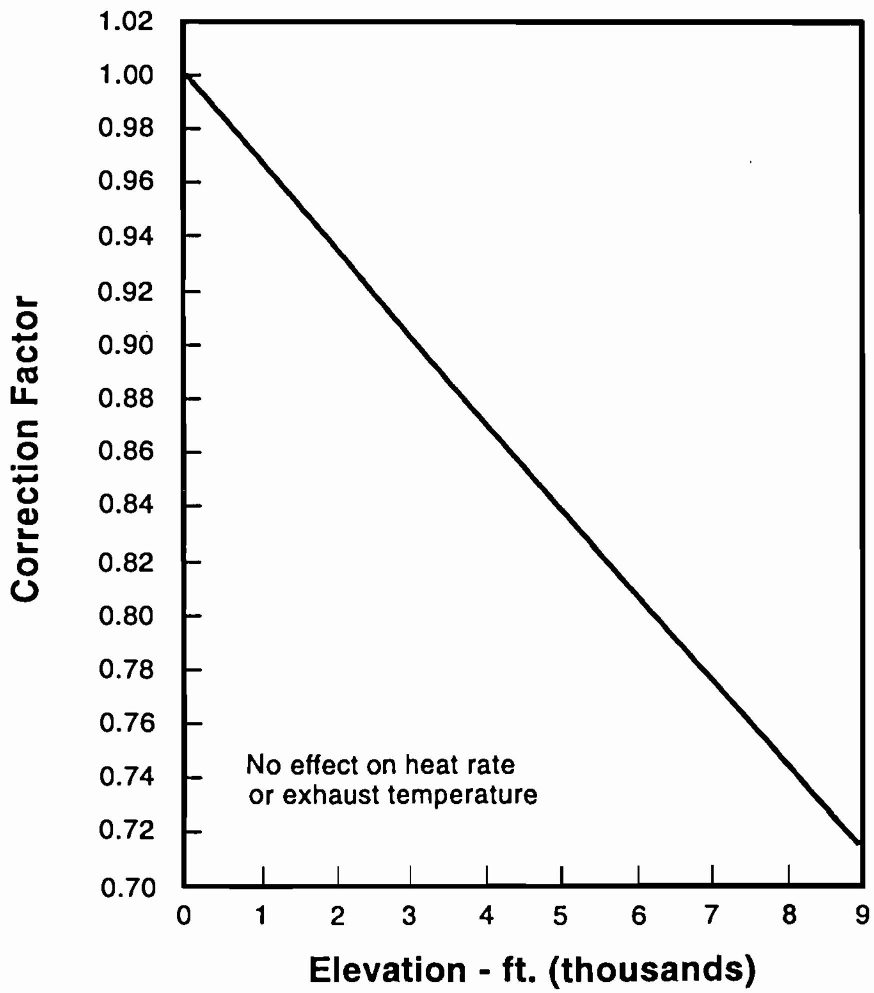
501G EconoPac System Performance



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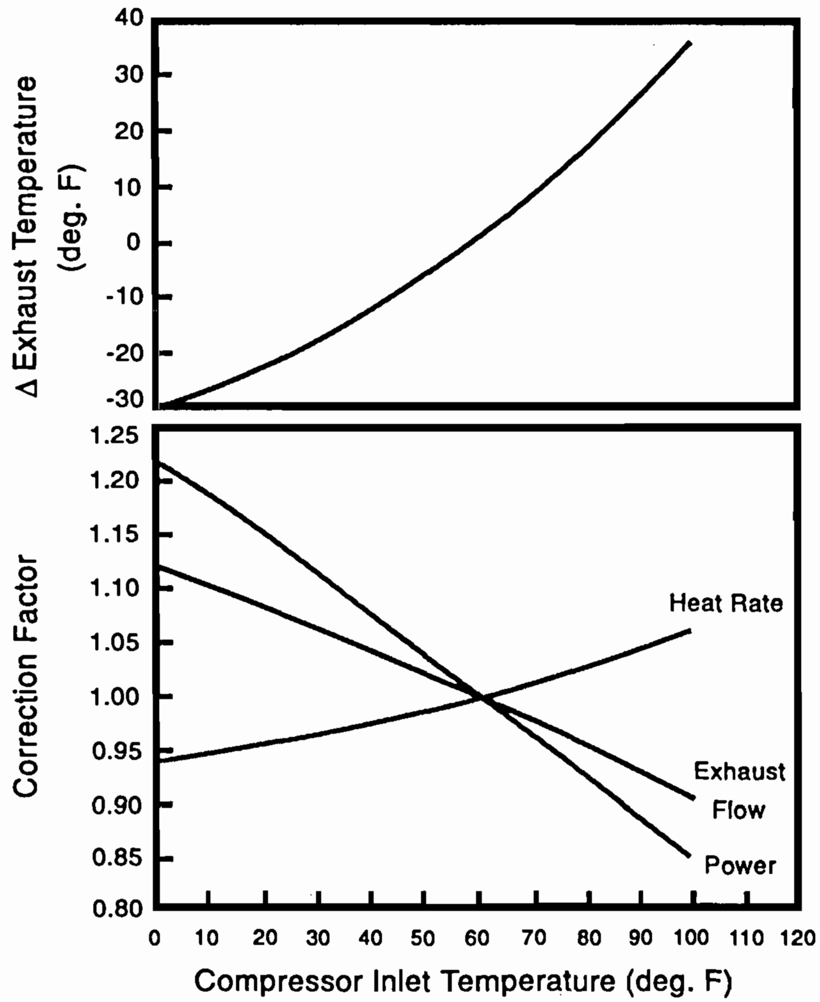
501G EconoPac System Performance



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RICHARD J. ANTOS

COMBUSTION TURBINE ENGINEERING
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Technical Paper TP-96003

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Westinghouse Combustion Development 1996 Technology Update

Richard J. Antos
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Power Generation Business Unit
Orlando, Florida

Abstract

Westinghouse has aggressively incorporated advanced technologies into the Combustion Turbine family of engines. One area of intense development has been in combustion with a focus on reducing emission levels at increasing firing temperatures while maintaining world class operating reliability and availability.

Proactive combustion development programs have resulted in multiple options for achieving dramatic reductions in emissions with Ultra Low NOx combustion systems. This paper presents a description of the program organization, advanced technologies, and results of development efforts to date.

Background

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

Combustor Design Process

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

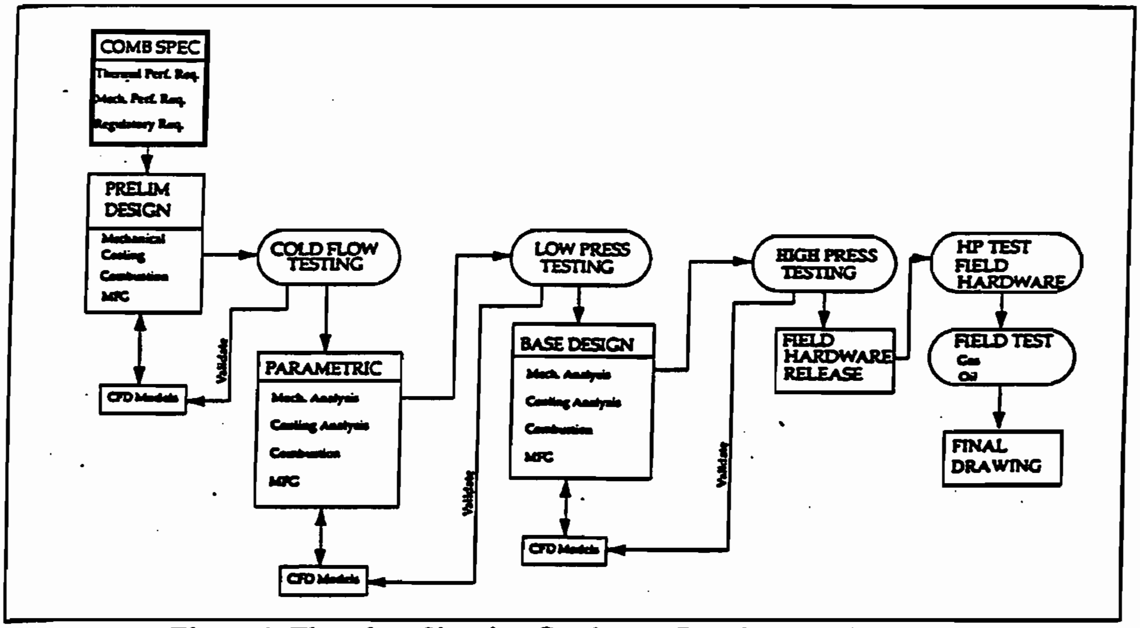

Figure 1 Flowchart Showing Combustor Development Process

CFD Analysis

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

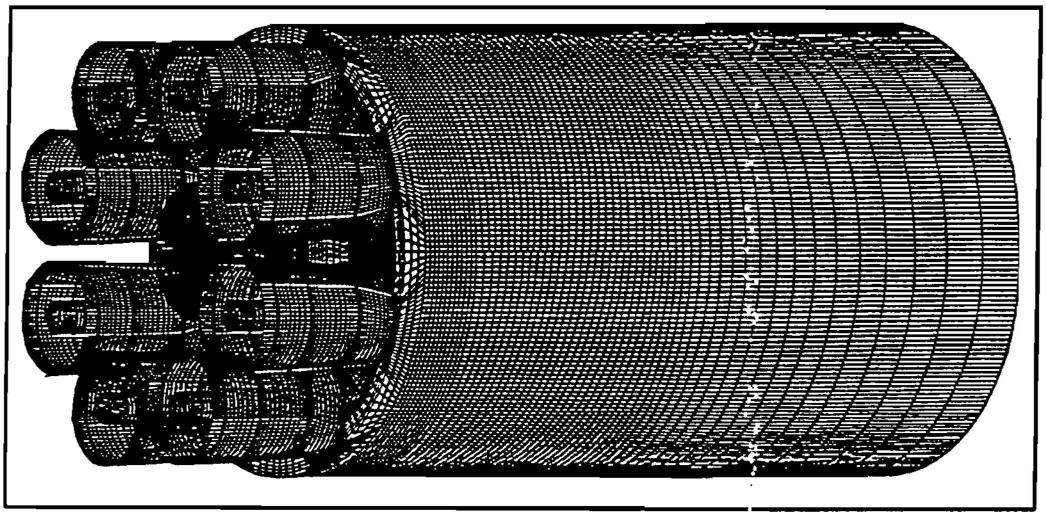

Figure 2. CFD Model

Test Facilities

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

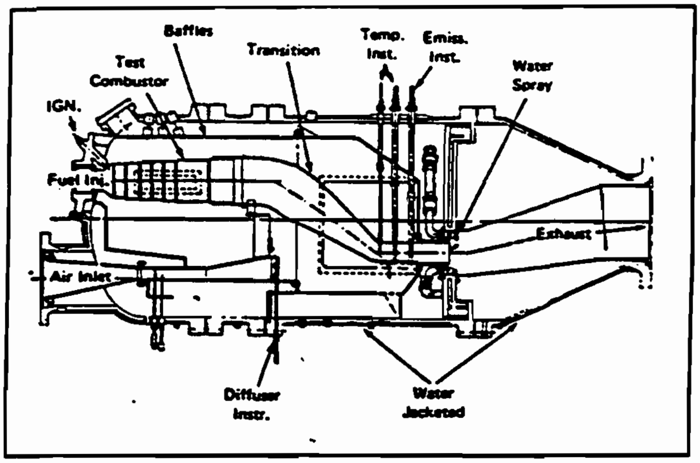

Figure 3

Dry Low NOx Design Philosophy

NOx emissions are governed by two primary mechanisms in combustion turbines, the conversion of atmospheric nitrogen at high temperatures (thermal and prompt NOx) and by the conversion of nitrogen in the fuel (called fuel bound nitrogen,). Fuel bound nitrogen is typically limited to heavy fuel oils or to coal derived gas fuels. Although this paper will focus on natural gas oriented combustors, Westinghouse is also a leader in developing combustors for fuel bound nitrogen laden gases. The Multi Annular Swirl Burner combustor utilizes a rich-quench-lean concept that greatly minimizes the fuel

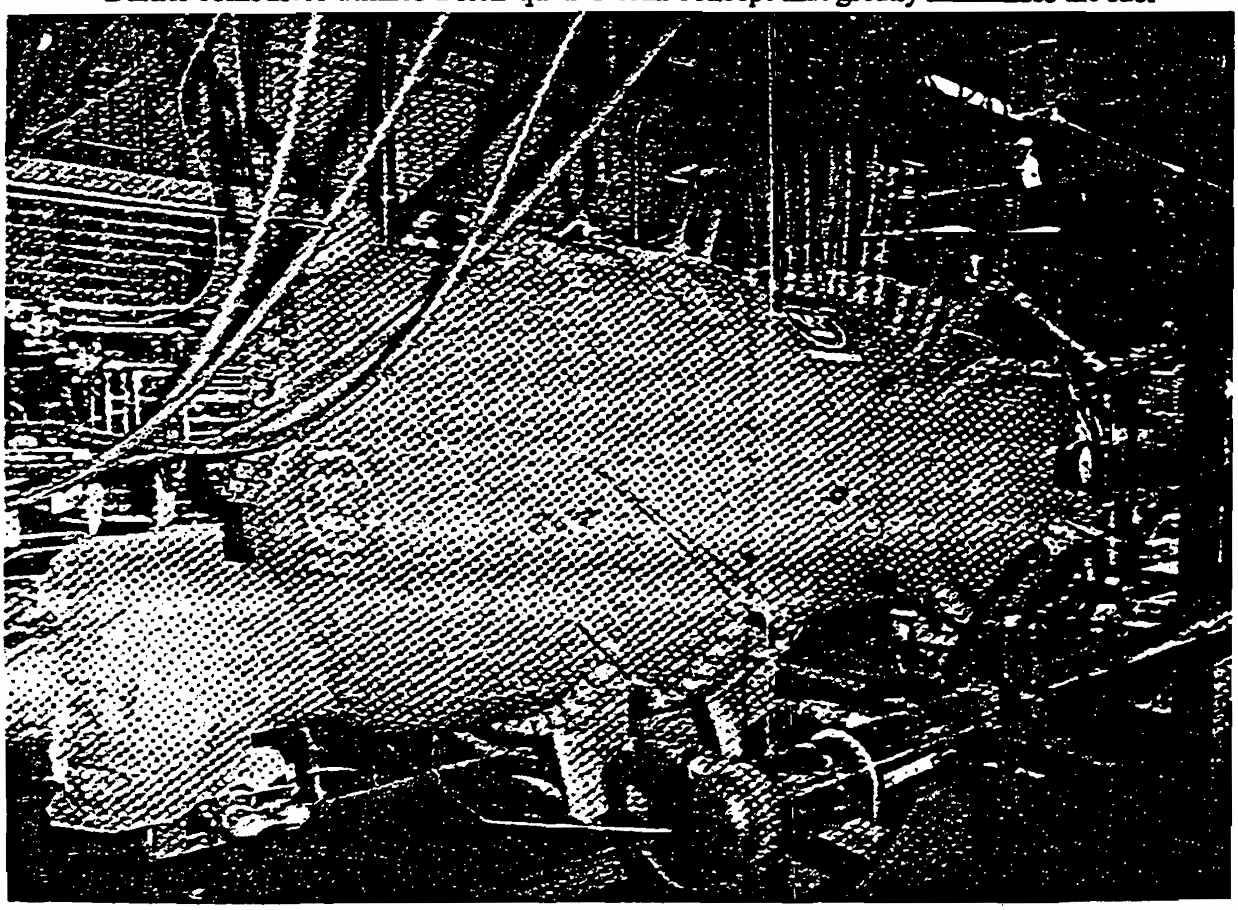

Figure 4 High Pressure Test Rig

bound nitrogen transformation to NOx (Ref. 6). For natural gas fuel the overriding factor in preventing NOx formation is the flame temperature. Flame temperatures in conventional diffusion flames approach 3500F, and in a typical engine would produce about 200ppm of NOx. Dry Low NOx combustors reduce the flame temperature through the partial premixing of fuel and air before ignition (Ref. 7). Figure 5 demonstrates that NOx production is directly related to flame temperature and which in turn is related to the local fuel to air ratio. Premixed combustors operate in a lean fuel/air condition resulting in a lower flame temperature and hence lower NOx. The current DLN system in service is the second generation system that utilizes lean premixed fuel mixing zones surrounding a central pilot. The central pilot provides a stability to the basic system. Third generation ULN systems that utilize fully premixed (no pilot) have been developed and are entering service.

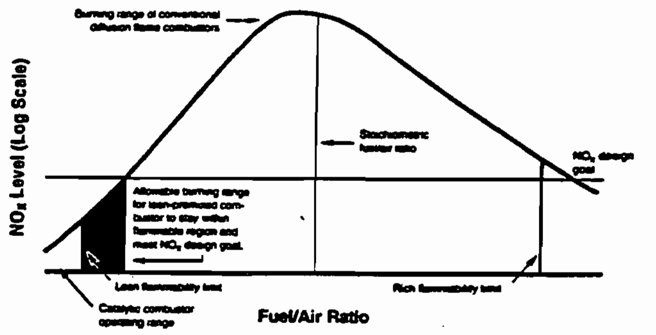

Figure 5 NO_X Formation vs. Fuel Air Ratio

Dry Low NOx Combustion Systems

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

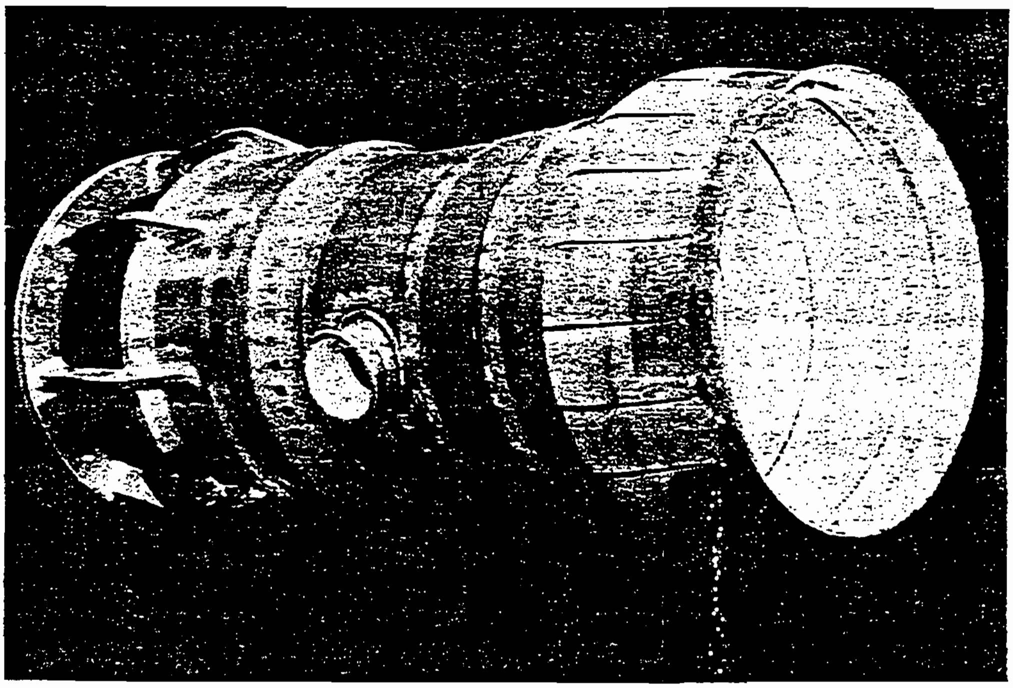

Figure 6

design includes the capability of performing on gas or liquid fuel including startup on either fuel as well as fuel transfers in either direction. The Dry Low NOx design is utilized in engine applications where as low as 15ppm NOx on gas is required.

Current Westinghouse 60 Hz engines include:

Engine	Power (MW)	Number of Combustors	Reference Firing Temperature (F)
251B12	48	8	2100
501D5	107	14	2070
501D5A	120	14	2150
501FA	160	16	2330
501G	230	16	2583

Continuing the evolutionary design approach (Ref. 9), all current engines utilize can-annular designs that facilitate use of common designs for different engines. Figure 7 shows essentially the same Dry Low Combustor in 501D5, 501D5A,701F, and 501F.

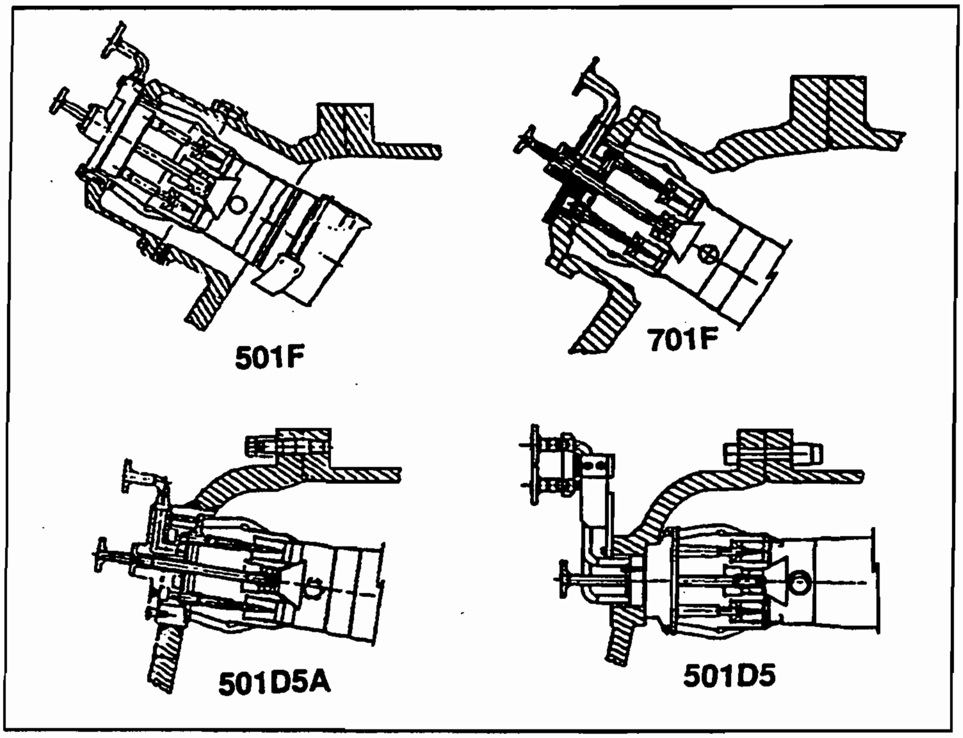

Figure 7

This design philosophy allows the experience base for all Dry and Ultra Low NOx combustors to be additive. The 501G is the newest addition to the Westinghouse 60Hz single shaft heavy duty combustion turbine product line (Ref. 10). This engine offers the option for Ultra Low NOx combustors in the initial production.

Power Augmentation

Power augmentation is defined as adding water or steam to the operating cycle to increase the power output of the engine. With diffusion flame combustors this was achieved by injecting diluent directly into the combustor to also reduce NOx levels. The addition of diluent increases the power output of the engine but generally has a detrimental effect on cycle efficiency. With DLN combustors the operating regime is closer to the lean limit and cannot accommodate large additions of diluent. Thus the augmentation is accomplished by injecting the water or steam into the combustor casing away from the combustor where it still provides the extra power but only a small portion of the diluent finds it way into the flame zone. Augmentation of the power output of an engine utilizing steam augmentation has been in commercial service for over a year. An

8000 hour inspection of this unit revealed that the use of power augmentation has not impacted the excellent operational performance of the combustor. As with non-power augmentation units, the combustors were inspected and did not require any rework prior to reinstallation.

Ultra Low NOx Program

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

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

Fully Premixed Designs

Piloted Ring

The Piloted Ring Combustor is shown schematically in Figure 8. The combustor consists

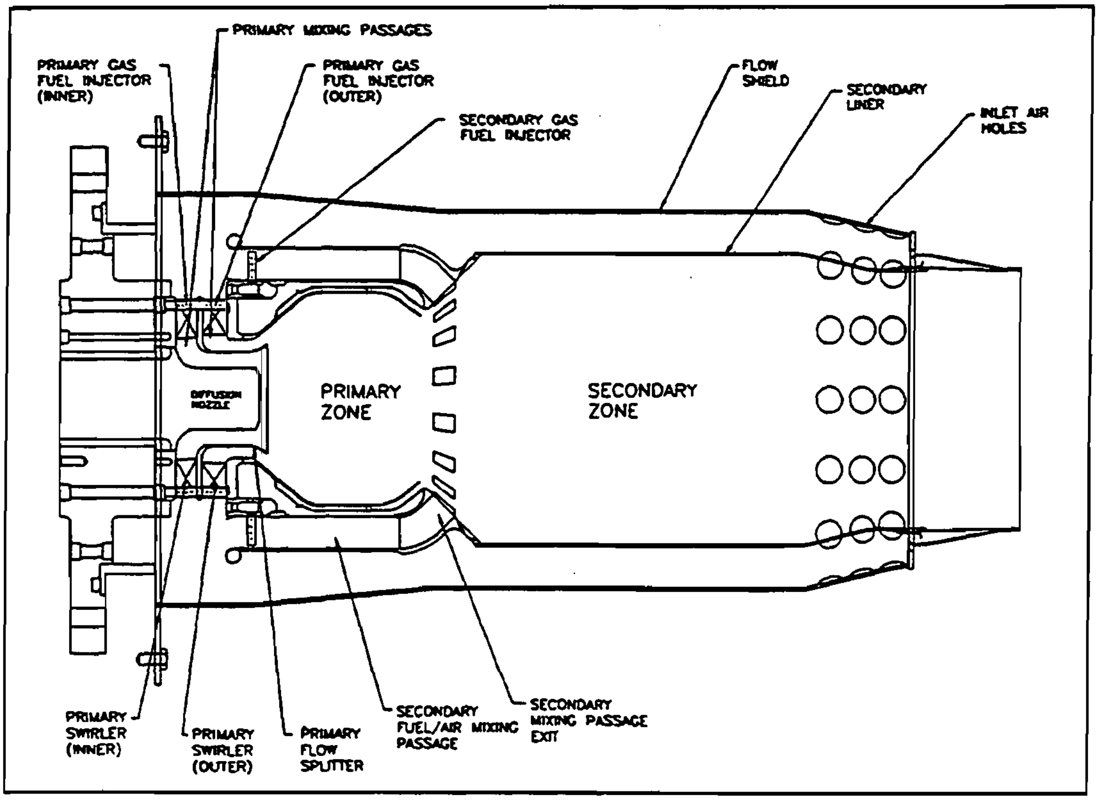

Figure 8 A Westinghouse Ultra Low NO_X Combustor

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

This design has gone through an exhaustive development process including fully integrated cold flow air rig modeling, computational fluid dynamics (CFD), fired atmospheric, mid-pressure, and full pressure rig tests (Ref. 11). The Westinghouse piloted ring design is being released for 1996 installation. This design has a heritage as the RB211 DLE combustor (Ref. 12).

This Westinghouse Piloted Ring combustor demonstrates single digit NOx levels over a wide range of operating temperatures and is focused on Ultra Low Emission high temperature units.

MultiSwirl Combustor

The MultiSwirl combustor utilizes annular, parallel stages to feed a well-premixed fuel and air mixture to a multitude of individual swirlers for final mixing and flame holding. A center pilot is used for starting and low load stabilization. Figure 9 schematically shows the combustor configuration. This combustor has demonstrated excellent stability and emissions over a very wide range of conditions.

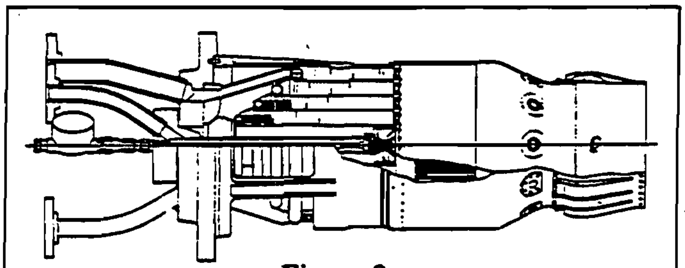

Figure 9

This combustor, shown in Figure 10 installed in our high pressure rig, has passed the pre-operation testing. Installation in a 251B10 unit will occur late in 1995 with commercial operation scheduled for January 1996. The startup process is very similar to the Dry Low NOx design and is shown in figure 11. This design operates below the NOx production flame temperature and thus produces very low emission levels at elevated temperatures. The multitude of flames also provides a very high combustion efficiency resulting in extremely low secondary emissions.

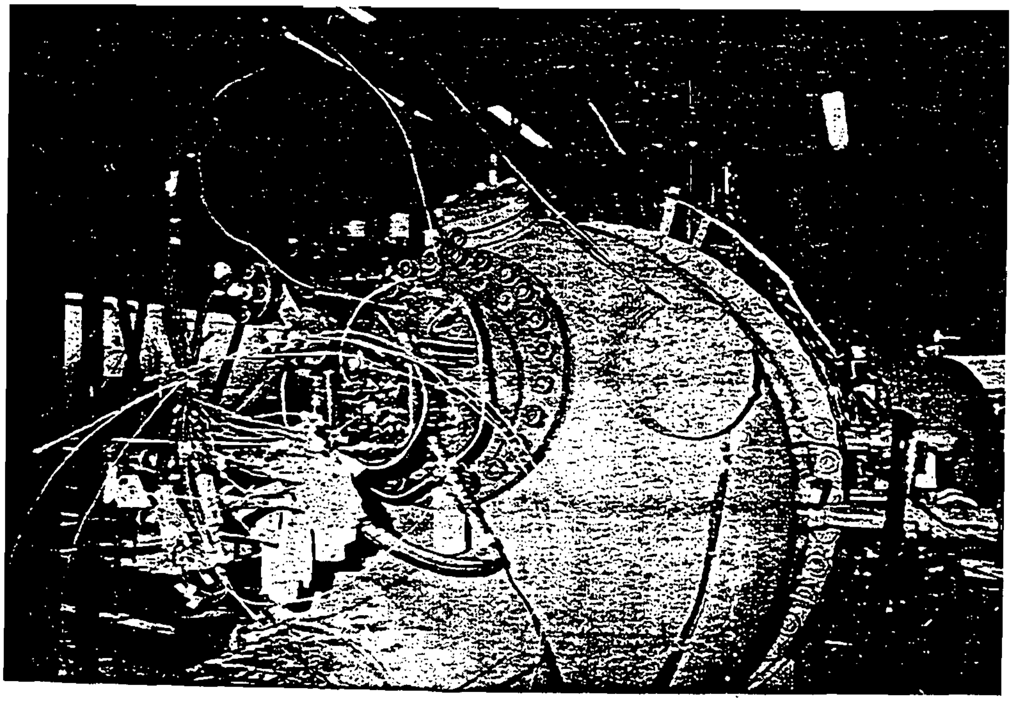

Figure 10

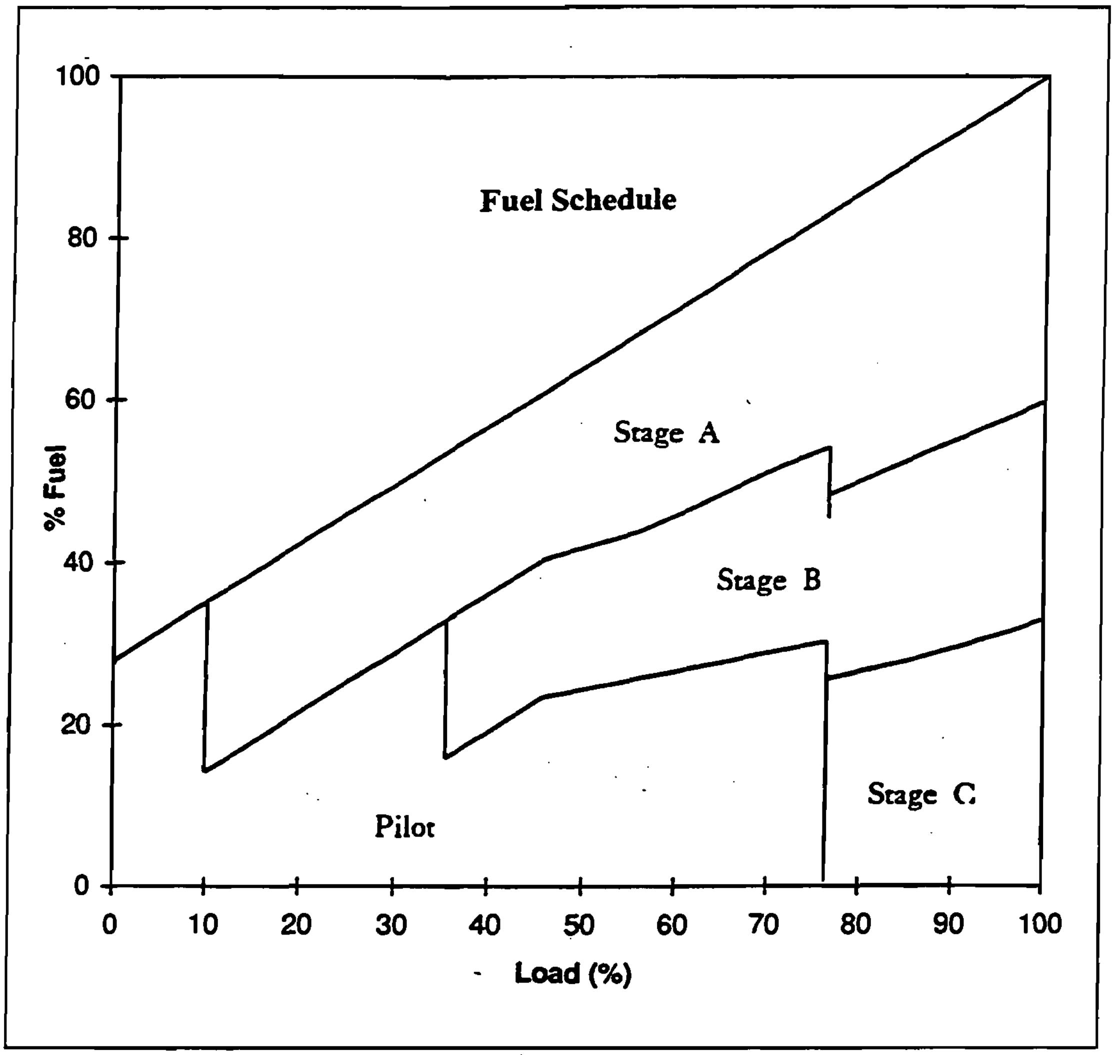

Figure 11

Environmentally Benign

The reduction of emissions in combustion turbines has been dramatic. In the period of about five years the acceptable rate of dry emissions has been reduced from 75ppm to common levels of 25ppm and less than 10ppm in certain site locations. The technologies that have driven this process have required a completely new approach to combustion design. Whereas traditional diffusion flame combustors were designed around an optimum stability point, low emission designs must operate near the lean limit. Advances in combustion technology and control system designs have made these dramatic improvements possible.

The next technology step is aimed at achieving environmentally benign designs. The goal of the Environmentally Benign program is to result in negligible impacts on local contaminant levels. Presently there are some sites where the volatile organic compound emissions exiting the turbine appear lower than the surrounding environment. To achieve this next profound step in NOx reduction requires that new technologies be incorporated. In our development activities, Westinghouse is focusing on several techniques that should increase the stability range. Included in these programs are projects such as active control of pressure oscillations, catalytic combustion, and optical mixing and flame characterization. These techniques, while still in the development stage, offer a great potential to extend the operating range of current designs. Our short term goals are to prove these concepts by adapting the techniques to our current designs with a longer term intent towards full optimization of these technologies.

Fuel Options

Westinghouse Combustion Turbines perform on a variety of fuels ranging from heavy to light liquids and gases. Fuel flexibility is a key attribute of combustion turbines and Westinghouse experience is both broad and deep. Engines in service include those running on crude oils, coal gas, butane, propane, naphtha, blast furnace gas, process gases laden with hydrogen, as well as the more conventional natural gas and Number 2 distillate fuel. The combustion technology involved in burning such as wide range of fuels is continuing to advance as new higher performance engines are introduced, and dry low NOx combustion matures into Ultra Low capabilities.

Summary

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

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

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A COMBINED CYCLE DESIGNED TO ACHIEVE GREATER THAN 60 PERCENT EFFICIENCY

M. S. BRIESCH, Plant Thermal Systems; R. L. BANNISTER, Emerging Technologies; I. S. DIAKUNCHAK, Combustion Turbine Engineering; D. J. HUBER, Plant Thermal Systems

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ABSTRACT

In cooperation with the U.S. Department of Energy's Morgantown Energy Technology Center, Westinghouse is working on Phase 2 of an 8-year Advanced Turbine Systems Program to develop the technologies required to provide a significant increase in natural gas-fired combined cycle power generation plant efficiency. In this paper, the technologies required to yield an energy conversion efficiency greater than the Advanced Turbine Systems Program target value of 60 percent are discussed. The goal of 60 percent efficiency is achievable through an improvement in operating process parameters for both the combustion turbine and steam turbine, raising the rotor inlet temperature to 2600°F (1427°C), incorporation of advanced cooling techniques in the combustion turbine expander, and utilization of other cycle enhancements obtainable through greater integration between the combustion turbine and steam turbine.

INTRODUCTION

The purpose of the Department of Energy's Advanced Turbine Systems (ATS) contract is to investigate technologies and innovative concepts applicable to natural gas-fired combined cycle power generation systems which will allow thermal efficiencies greater than 60 percent,1* while providing electricity at significantly lower cost than current combined cycle power plants and operating with much reduced environmental impact. Additionally, reliability-availability-maintainability (RAM) will be competitive or superior to current power generation systems. The ATS cycle fired with natural gas is to be commercially available by the year 2000. The final ATS design must also be able to be adapted to operate on coal-derived or biomass fuels for the post-2005 power generation market.

Westinghouse has developed a product line that mirrors the general gas turbine inlet temperature trend shown in Figure 1. To make gas turbines more competitive than steam turbine plants, it has been necessary to develop efficient cycles. Over the years, Westinghouse has performed many engineering studies to determine optimum cycles to minimize the cost of electricity. Some of the more promising cycles (intercooled, multiple shafts, reheat, steam injected, and water injected at various locations) have been studied in detail (Scalzo et al., 1994). In the final analysis, the simple cycle gas turbine combined with a steam bottoming cycle (a synergistic combination of the Brayton and Rankine cycles) was developed to increase overall cycle efficiency. Stephens (1952) and Baldwin et al. (1965), are two references which summarize earlier Westinghouse work on optimizing plant cycle efficiency.

Current large natural gas-fired combined cycle power generation systems are capable of net efficiency levels in the range of 54 percent. Within the ATS program, Westinghouse has been given the opportunity to re-evaluate cycle efficiencies using older, established concepts, such as intercooling and recuperation, and newer concepts, such as thermochemical recuperation (Little, Bannister, and Wiant, 1993). In addition, efficiency enhancements within the ATS selected cycle are to be evaluated to determine the best approaches to raising overall thermal plant efficiencies to greater than 60 percent while adhering to the other ATS program goals. The concepts considered in the Westinghouse analyses are required to be capable of demonstration within a three to four year time frame. From a baseline cycle definition, this paper reports on how different concepts will affect the overall plant thermal efficiency. Results given in the paper show that a plant efficiency of greater than 60 percent is achievable.

BASELINE CYCLE

In order to evaluate different technologies and concepts applic-

* All plant efficiency values in this paper are based on lower heating valve (LHV).

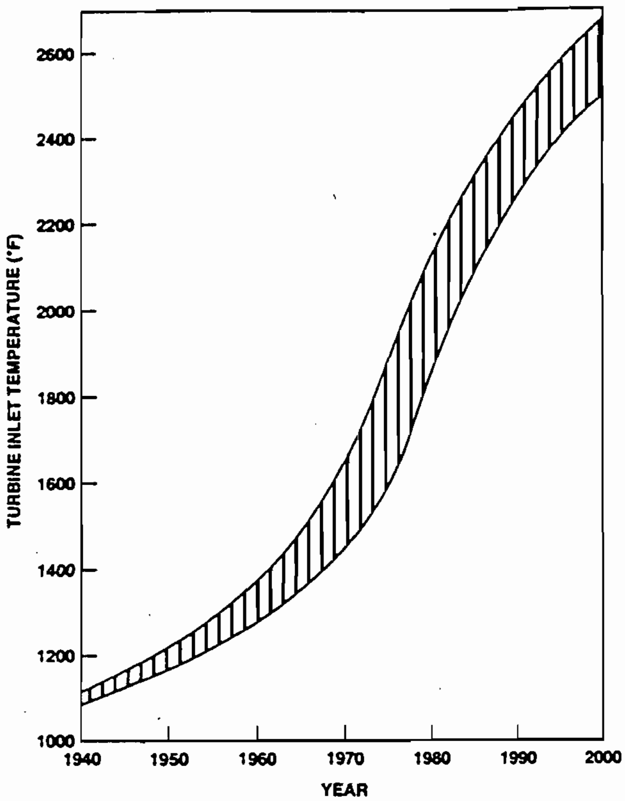

FIGURE 1. GAS TURBINE INLET TEMPERATURE TREND

able to combined cycle power generation systems, a baseline combined cycle configuration first had to be developed to provide a basis for comparison of all the cycle concepts and technologies to be considered. For this purpose, a conventionally configured combustion turbine coupled with a three-pressure level reheat steam cycle (Figure 2) was modeled to provide a baseline cycle. The combustion turbine rotor inlet temperature (RIT) was set at 2600°F (1427°C) to approximate near-term temperature capabilities (Bannister et al., 1994). Compressor pressure ratio was set at 18. High pressure steam conditions entering the steam turbine were specified at 1450 psi (10.2 MPa) and 1000F (538°C) and the hot reheat steam temperature was also set at 1000F (538°C). Note that this configuration utilizes turbine rotor cooling air heat to produce additional low pressure steam in the steam cycle via a heat exchanger located in the heat recovery steam generator (HRSG). Also, the natural gas fuel is preheated by feed water recirculation flow.

COMPONENT IMPROVEMENTS

Incorporation of several component improvements, available through recent technological developments and advanced design techniques, into the power generation system of Figure 2 results in significant efficiency gains.

The application of advanced compressor analysis and design tools results in increased efficiency compressors. Additionally, the application of brush seals in the compressor, as well as in the combustion turbine expander and the steam turbine, results in further plant efficiency improvements. At the compressor inlet, an advanced inlet design improves efficiency via reduced pressure loss.

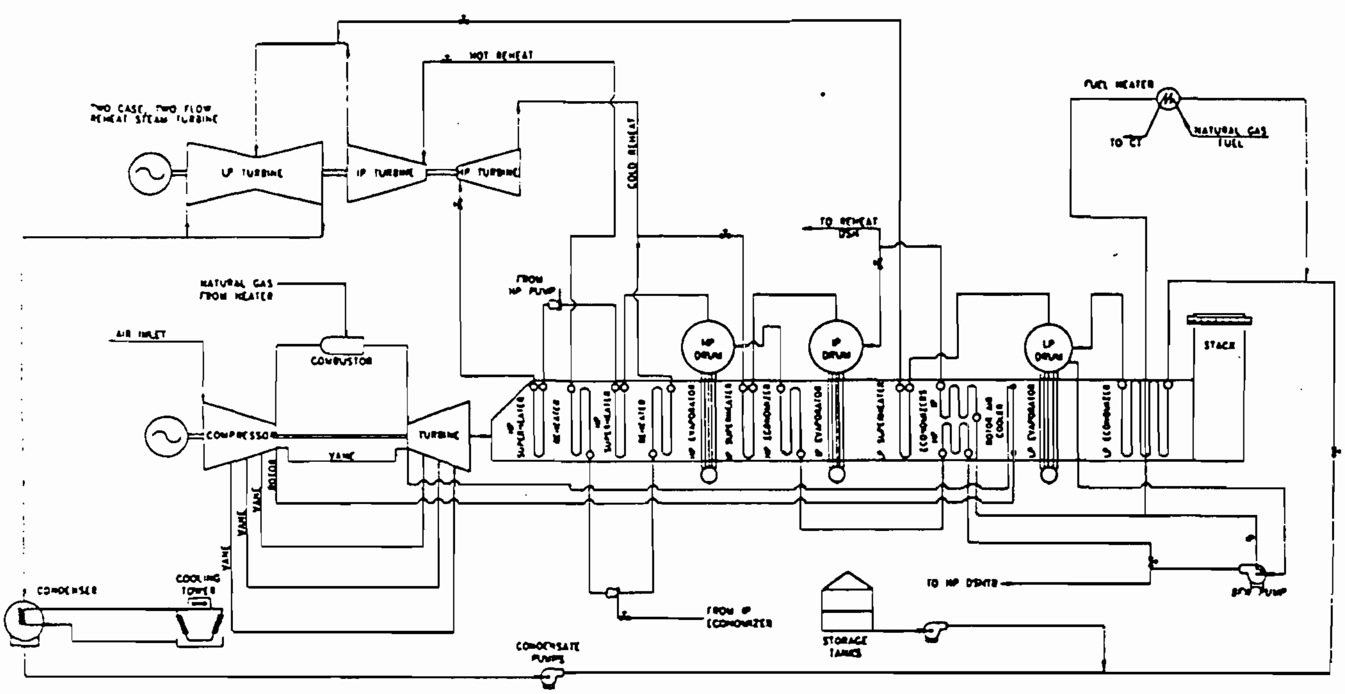

FIGURE 2. BASELINE COMBINED CYCLE

Westinghouse is currently engaged in full-scale rig tests of several diffuser / combustor configurations. These tests will allow the design of diffusers and combustors with reduced pressure loss, which will improve plant efficiency.

Several advanced turbine technologies may be applied to the combustion turbine expander. These include the application of single crystal and ceramic components to increase material operating temperatures and reduce turbine cooling requirements, active blade tip clearance control to minimize tip leakages and improve turbine efficiency, and the use of a three-dimensional (3-D) airfoil design philosophy. By utilizing 3-D analytical design tools, airfoils can be designed which are more efficient than those designed with 2-D design tools because they can accommodate more effectively the complex flows inside a turbomachine. The use of a 3-D airfoil design philosophy may also be applied to the steam turbine to enhance its efficiency.

There are two generators in the baseline configuration. One of these is the combustion turbine generator, while the other is the steam turbine generator. Current generator designs are capable of higher efficiency than those chosen for the baseline cycle. While the combustion turbine generator of the baseline configuration is of sufficient size to cost effectively apply this technology, the steam turbine generator is not. By utilizing a single shaft arrangement, however, the smaller steam turbine generator is eliminated and the remaining single generator may be designed at the higher efficiency.

When the component improvements listed above are all incorporated into the baseline cycle, the net plant thermal efficiency is increased by approximately 2 percentage points.

STEAM CYCLE ENHANCEMENTS

The basic reason for raising the steam pressure and temperature of the Rankine cycle is to improve the potential thermal efficiency (previous Westinghouse studies to optimize steam cycle configurations for subcritical and supercritical applications are summarized by Ernette and Silvestri, 1990 and Silvestri et al., 1992). The first cycle variations investigated within this study were modifications to the baseline cycle in which the steam cycle was enhanced. The results of these studies indicated that increasing either high pressure steam superheat temperature or reheat steam temperature by 50°F (28°C) results in an improvement in combined cycle thermal efficiency of 0.1 percentage point. Increasing high pressure steam pressure from 1450 psi (10.2 MPa) to 1800 psi (12.6 MPa) results in an increase in net plant thermal efficiency of 0.1 percentage point. A further increase in pressure to 2400 psi (16.8 MPa) yields only an additional 0.05 percentage point in thermal efficiency, while adding to the cost of the high pressure steam system. Also, since the steam turbine size is set by the exhaust energy of the combustion turbine, increasing steam pressure reduces the blade heights in the high pressure steam turbine. For 2400 psi (16.8 MPa) high pressure steam, the resulting blade heights are much smaller and less efficient than for the 1800 psi (12.6 MPa) steam. Therefore, the optimum steam cycle was determined to be at 1800 psi (12.6 MPa) with 1100°F (593°C) high pressure superheat steam and 1100°F (593°C) reheat steam (both 100°F (56°C) over the baseline temperature). This results in a 0.5 percentage point increase in net plant thermal efficiency and also in a slight increase in output due to the increased efficiency of the steam cycle. The steam temperatures were limited to 1100°F (593°C) for this study. The steam temperature of 1100°F (593°C) plus a reasonable steam superheater approach T determined the gas turbine exhaust temperature and this set the baseline cycle pressure ratio.

ROTOR AIR COOLER HEAT UTILIZATION

The Westinghouse 501F combustion turbine combined cycle provides two options for rotor air cooler heat utilization. The first option is an air-to-air cooler to cool the rotor cooling air after it exits the compressor and prior to its introduction into the rotor. The rotor air heat is rejected to the atmosphere via an air-to-air cooler. The other option is to cool the rotor air via an air-to-exhaust gas heat exchanger located in the heat recovery steam generator upstream of the low pressure evaporator, as was done in the baseline cycle. With this configuration, the rotor air cooler heat is recovered by the steam cycle, which produces low pressure steam with the heat. This results in higher plant efficiency than that of the air-to-air cooler method since the rotor air cooler heat is recovered by the low pressure steam system.

Another concept involves removing the HRSG rotor air cooler used in the baseline configuration and installing a rotor air cooler which exchanges heat with the incoming natural gas fuel (after the fuel has been preheated by feed water recirculation flow). This returns the rotor air heat back to the combustion turbine, which then requires less fuel to achieve the desired rotor inlet temperature. Therefore, the rotor air heat is recovered at the combustion turbine efficiency (typically about 40 percent), which is much higher than the low pressure steam system efficiency. This is, therefore, a much more effective recovery of the heat than is obtained via low pressure steam production, and results in an increase in net plant thermal efficiency of 0.4 percentage point over the baseline configuration.

CLOSED-LOOP STEAM COOLING

Most current technology gas turbine engines utilize air to cool the turbine vanes and rotors. This allows the turbine inlet temperature to be increased beyond the temperature at which the turbine material can be used without cooling, thus increasing the cycle efficiency and power output. However, the cooling air itself is a detriment to cycle efficiency in four ways. First, it is ejected from the turbine airfoils causing a disruption in the surrounding flow field. This increases the airfoils' irreversible pressure losses and results in a reduction in turbine efficiency. Secondly, since the cooling air is ejected from the airfoil into the gas path, the resulting mixing of the cooling air into the gas path results in irreversible pressure losses due to the non-ideal mixing of the streams, which have very different velocity vectors. The third loss mechanism is caused by the reduction in gas path temperature that accompanies the mixing of the cooling air into the gas path. This reduction in temperature reduces the work output of the turbine and, therefore, compromises cycle efficiency. Finally, the turbine cooling air must be pumped to pressures significantly higher than that of the gas path pressure at the location it is injected. This is done to assure that the cooling flow rate will be sufficient during certain operating conditions where the ratio of coolant pressure to gas path pressure drops below its design level. While some of this pressure is recovered by the turbine, there are internal losses as the cooling air passes from the compressor to the turbine gas path. The additional pumping work required to raise the cooling air to the required pressure is the associated loss.

The effect of cooling air on cycle efficiency is shown in Figure 3. This figure shows the potential increase in combined cycle thermal efficiency for fractional reductions in cooling or leakage flows. In this figure, the lines labeled 'Fixed P/P' show the effect for fixed compressor pressure ratio (i.e., the turbine expander is increased in size to handle the additional flow resulting from the reduction in cooling or leakage) and the lines labeled 'Fixed Expander' show the effect for fixed expander size (the compressor pressure ratio is allowed to rise so that the additional flow caused by the reduction in cooling or leakage can be accommodated by a turbine of the original size). Note that, although turbine leakage generally carries a larger efficiency penalty than turbine cooling per given amount of flow, the fact that the amount of leakage flow is far less than the amount of cooling flow results in far less efficiency benefit from reducing turbine leakage flows by a given fractional amount compared to reducing turbine cooling flows by the same fraction of their baseline value.

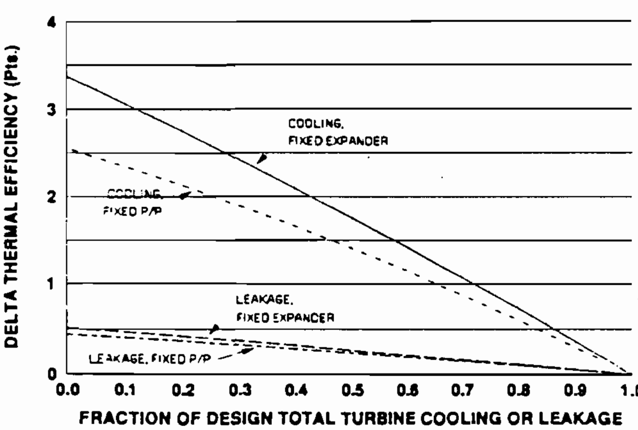

FIGURE 3. TURBINE COOLING AND LEAKAGE, EFFECT ON COMBINED CYCLE THERMAL EFFICIENCY

By using closed-loop steam cooling, the loss mechanisms described above can be largely eliminated, while still maintaining turbine material temperatures at an acceptable level. In combined cycles, the steam used for cooling the combustion turbine hot parts will be taken from the steam bottoming cycle. This steam is then returned to the bottoming cycle after it has absorbed heat in the closed-loop steam cooling system. For an advanced bottoming steam cycle, closed-loop steam cooling would route cold reheat steam from the exit of the high pressure steam turbine to the combustion turbine vane casing and rotor. The steam is passed through passageways within the vane and rotor assemblies and through the vanes and rotors themselves, then collected and sent back to the steam cycle intermediate pressure steam turbine as hot reheat steam. This approach to turbine cooling relies solely on convective heat transfer. Since no steam or cooling fluid is ejected from the airfoils, aside from a small amount of steam leakage through the rotor seals, there is very little influence of the cooling steam on the airfoil flow fields, and hence minimal mixing losses. Also, the reduction in gas path temperature is minimized, since the convective heat flux across the airfoils is relatively small. Typically, first vane cooling air mixing reduces the gas path temperature approximately 100°F to 150°F (56°C to 83°C). For closed-loop steam cooling however, the reduction in gas path temperature is only about 10°F to 15°F (6°C to 8°C), or one tenth of the reduction of conventional cooling techniques. Application of closed-loop steam cooling to the baseline configuration yields a 2 percentage point increase in combined cycle efficiency.

INCREASED TURBINE INLET TEMPERATURE

Since thermal efficiency increases with increasing turbine inlet temperature, the potential benefits of increased turbine inlet temperature was investigated. The turbine inlet temperature for the baseline cycle was increased 300°F (167°C) to 2900°F (1593°C). This resulted in a cycle output increase of 10 percent, and combined cycle thermal efficiency increase of slightly more than 1 percentage point. The reason that the performance increase was relatively small for such a large increase in turbine rotor inlet temperature is that, since the (air) cooling technology remained constant as the temperature was increased, large amounts of additional turbine cooling air were required to maintain turbine material operating temperatures at an acceptable level. This increase in cooling flow decreased cycle efficiency by the three mechanisms described earlier, and this significantly offset the benefit of increasing the turbine rotor inlet temperature. Therefore, since efficiency and output would have been increased much more if turbine cooling was held at the same level as in the baseline cycle, increased turbine operating temperature must be accompanied by corresponding advancements in turbine cooling. However, even if cooling technology advancements were available to allow operation at much higher rotor inlet temperatures, the formation of NOx at these higher temperatures would result in unacceptable emissions characteristics.

INCREASED COMPRESSOR PRESSURE RATIO

Commercial aircraft gas turbine engines are designed with high overall pressure ratio. This is done to maximize the simple cycle efficiency. For the ideal Brayton gas turbine cycle, the cycle efficiency is a function solely of the cycle pressure ratio and increases with cycle pressure ratio (the ratio of specific heats of the working fluid also effects the cycle efficiency, but for air-breathing cycles there is little that can be done to change this property). In fact, for this ideal cycle, the maximum efficiency occurs at the point where the compressor exit temperature is very close to the combustor exit temperature. Of course, the cycle output for this case is very close to zero.

In real cycles, the effect of non-ideal components causes the peak efficiency pressure ratio to decrease significantly from that of the Brayton cycle. Figure 4 shows the effect of compressor pressure ratio on simple cycle performance for a family of engines based on the combustion turbine of the baseline configuration. Also included in Figure 4 are the corresponding steam cycle and combined cycle efficiencies. Note that the simple cycle efficiency curve is relatively flat above a pressure ratio of approximately 40. This indicates that it is nearing the peak simple cycle efficiency. The steam cycle efficiency is seen to decrease with increasing combustion turbine pressure ratio. This is due to the reduction in combustion turbine exhaust temperature, which in turn reduces the maximum steam temperature and pressure and the steam's availability, and results in lower steam cycle efficiency. The effect of all of this on combined cycle efficiency is that it peaks around a pressure ratio of about 20, but remains approximately constant for a relatively large increase in compressor pressure ratio.

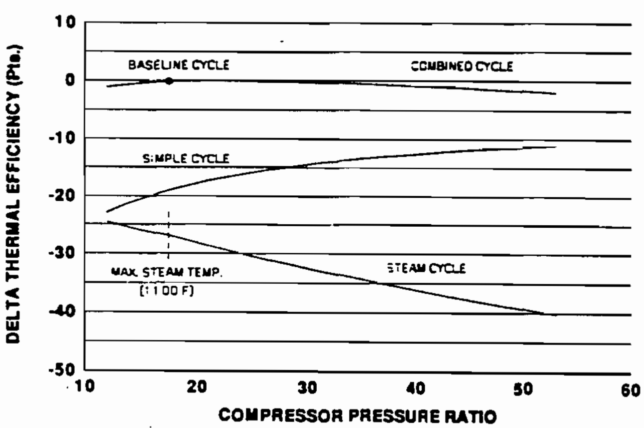

FIGURE 4. COMPRESSOR PRESSURE RATIO, EFFECT ON THERMAL EFFICIENCIES

Reducing the compressor pressure ratio below the baseline value of 18 results in a significant decrease in combined cycle efficiency. This is due to the fact that, since the maximum steam temperature considered for this study was 1100°F (593°C), any decrease in pressure ratio below the baseline value of 18, where the maximum steam temperatures are reached, will increase the turbine exhaust temperature while maintaining the steam temperatures at 1100°F (593°C). This results in a much smaller increase in steam cycle efficiency than that obtainable by allowing the steam temperatures to rise with the turbine exhaust temperature. Figure 4 shows the significant reduction in the slope of the steam cycle efficiency line at this point, which causes the combined cycle efficiency decrease.

The maximum specific work output of the Brayton cycle occurs at a significantly lower value of pressure ratio than that for the peak efficiency. Figure 5, which includes intercooled cycle characteristics to be discussed later, shows the specific output of the cycles in Figure 4 (solid lines). The simple cycle peak specific output occurs at a pressure ratio of approximately 18. Also, note that the steam cycle specific output is reduced as pressure ratio is increased, since there is less exhaust energy available to the steam cycle. The combined cycle specific output, which is merely the sum of the simple cycle and steam cycle specific outputs, decreases for increasing pressure ratio across the entire range shown.

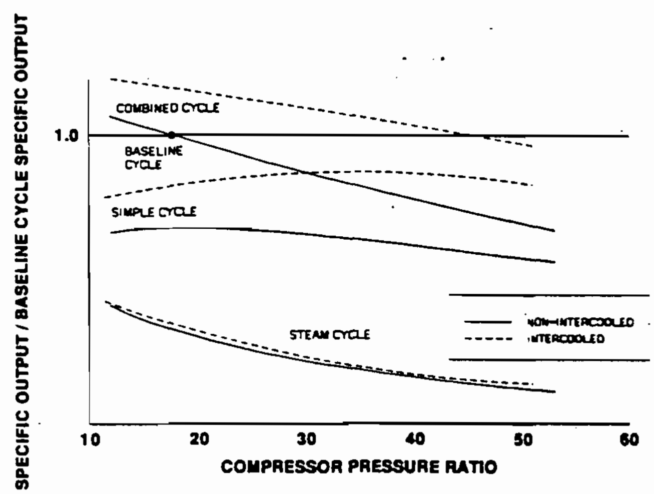

FIGURE 5. COMPRESSOR INTERCOOLING, EFFECT ON SPECIFIC OUTPUT

It, therefore, is optimum to select the lowest pressure ratio at which the peak combined cycle efficiency level is obtained. In this way both efficiency and output are maximized, and the cost of electricity is minimized (the baseline cycle is designed in this fashion).

COMPRESSOR INTERCOOLING

The most typical arrangement for compressor intercooling involves removing the compressor air flow halfway through the compressor temperature rise, sending it through an air-to-water heat exchanger, and returning it to the compressor for further compression to combustor inlet pressure. The heat removed from the compressor air flow by the intercooler is rejected to the atmosphere, because, at the pressure ratios considered in this study, the heat is of too low quality to be of use to the cycle.

Another intercooling concept is to spray water droplets into the compressor. As the air is compressed and increases in temperature, the water evaporates and absorbs heat. This results in a continuous cooling of the compressor. Note that for this concept the heat absorbed by the water is also rejected to the atmosphere, since this water is never condensed by the cycle but instead exhausted with the stack gases as low pressure steam.

Compressor intercooling reduces the compressor work, because it compresses the gas at a lower average temperature. Since the combustion and steam turbines produce approximately the same output as in the non-intercooled case, the overall cycle output is increased. However, since the compressor exit temperature is lowered, the amount of fuel that must be added to reach a given turbine inlet temperature is greater than that for the non-intercooled case. The ratio of the amount of compressor work saved to the amount of extra fuel energy added is about equal to the simple cycle efficiency. It can therefore be said that intercooling adds output at approximately the simple cycle efficiency. Since combined cycle efficiencies are significantly greater than simple cycle efficiencies it would be expected that the additional output at simple cycle efficiency would reduce the combined cycle net plant efficiency for the intercooled case. Figure 6 verifies this expectation and shows that this trend is the same for a wide range of cycle pressure ratios. Note that the simple cycle shows almost no change in efficiency for intercooling, which is expected since output is added at approximately the simple cycle efficiency.

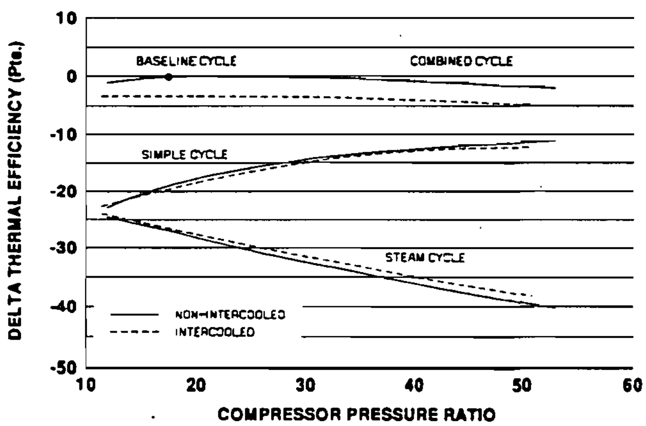

FIGURE 6. COMPRESSOR INTERCOOLING, EFFECT ON THERMAL EFFICIENCIES

Figure 5 shows the effect of intercooling on specific output. Since the compressor work requirement is reduced while the gas and steam turbine work outputs remain approximately the same as in the non-intercooled case, the net power output of both the simple and combined cycles is increased. Also, since the turbine exhaust temperature is increased slightly due to the exhaust gas composition effects, the steam cycle specific output is also increased slightly.

RECUPERATION

In recuperative cycles, turbine exhaust heat is recovered and returned to the combustion turbine combustor, usually via a heat exchange between the turbine exhaust gases and the compressor exit air flow. The discharge from the compressor exit is piped to an exhaust gas-to-air heat exchanger located aft of the combustion turbine. It is then heated by the turbine exhaust and returned to the combustor. Since the resulting combustor air inlet temperature is increased above that of the non-recuperated cycle, less fuel is required to heat the air to a given turbine inlet temperature. Because the turbine work and the compressor work are approximately the same as in the non-recuperated cycle, the decrease in fuel flow results in an increase in thermal efficiency. This is especially true for the simple cycle, since the heat recovered by recuperation is rejected to the atmosphere in the non-recuperative case. For combined cycles the efficiency is also increased, because the combustion turbine recovers the recuperated heat at the simple cycle efficiency, which is larger than the 30 to 35 percent thermal efficiency of the bottoming steam cycle, which recovers this heat in the non-recuperated case.

Installation of a recuperation system on the baseline configuration results in an increase in thermal efficiency of 1 percentage point. The steam cycle in this recuperated cycle has a lower efficiency than the steam cycle in the baseline configuration, because the recuperator exit temperature is significantly lower than the turbine exhaust temperature. However, the effect of reduced steam cycle efficiency is smaller than the effect of recovering the recuperated heat at the combustion turbine efficiency.

The thermal efficiency of the recuperated cycle can be increased further. Since the combustor inlet flow is smaller than the turbine exhaust flow (due to the removal of the turbine cooling air prior to combustion) and has a higher specific heat (due to the combustion products of the fuel), the heat capacity of the turbine exhaust flow is somewhat higher than that for the burner inlet flow. This means that the recuperated cycle described above does not fully utilize the quality of heat available in the turbine exhaust. By placing a steam superheater in parallel with the recuperator, the remainder of the available turbine exhaust heat can be recovered at its maximum quality. The maximum steam temperature can then be raised to that of the baseline cycle (1000°F (538C°), and the cycle efficiency is increased by an additional 0.1 percentage point.

Since recuperative cycles return exhaust energy to the combustion turbine, less energy is available to the steam cycle, and the resulting steam turbine output is lower than that of the baseline configuration. However, the combustion turbine output is approximately the same as in the baseline cycle (minus losses in the recuperation system). This means that recuperative cycles carry a significant output penalty, with this penalty being proportional to the amount of recuperation performed.

INTERCOOLING WITH RECUPERATION

From a simple cycle standpoint, the combination of intercooling with recuperation eliminates the problem of the reduced combustor inlet temperature associated with intercooled cycles. The simple cycle then gets the benefit of the reduced compressor work and, at all but high pressure ratios, actually has a higher burner inlet temperature than the corresponding non-intercooled, non-recuperated cycle. This results in a dramatic increase in the simple cycle efficiency.

However, the bottoming cycle receives even less energy than in the recuperated cycle, since the recuperator removes much more heat from the turbine exhaust than in the recuperated, non-intercooled cycle. The additional heat removed corresponds to the heat rejected to the atmosphere by the intercooler. This means that we have merely displaced the lost energy of the intercooler by taking energy from the bottoming cycle. This is in addition to the energy already removed from the bottoming cycle in the non-intercooled, recuperative cycle. The result is a very low recuperator exit temperature, which in turn translates into a low generated steam pressure (low availability) and a low efficiency steam bottoming cycle. Thus, while simple cycle efficiency can be increased to over 50 percent, the combined cycle efficiency is reduced for the entire useful range of compressor pressure ratios. For conventional air-to-water heat exchanger intercooling of the compressor, the combined cycle efficiency is reduced approximately 1.9 percentage points at the baseline cycle pressure ratio. For continuously cooled compressors utilizing water droplet spraying into the compressor, the combined cycle efficiency is reduced by 0.4 percentage point.

Since the continuously cooled compressor with recuperation is not far below the baseline level of combined cycle thermal efficiency, it is worth investigating further optimization of the steam cycle in this case. As mentioned earlier, steam may be superheated in parallel with the recuperator, yielding more efficient recovery of the heat available to the steam cycle. Utilizing this approach, along with a two-pressure level steam cycle, results in an increase in net plant efficiency of 0.8 percentage point over the baseline efficiency level.

Another approach to optimizing the intercooled recuperative cycle is to place a saturator between the compressor exit and the recuperator entrance, as illustrated in the combined cycle shown in Figure 7. This saturator, also called an aftercooler, evaporates water into the compressor exit flow, resulting in a lower temperature, higher mass flow entering the recuperator. While this may be seen as a way to better balance the heat capacities of the hot and cold streams in the recuperator and thereby increase the amount of heat recuperated by the combustion turbine (in addition to the fact that the air flow is at lower temperature), it is important to realize that all of this additional recuperation is accomplished by the evaporation of water in the saturator. Since this water is never condensed by the cycle but instead is rejected through the stack as low pressure steam, the additional amount of energy recuperated is not recovered anywhere in the cycle. Furthermore, the recuperator exit temperature is reduced even further than in the intercooled recuperative cycle, resulting in an even lower efficiency steam cycle. Finally, note that, since the heat capacity of the cold side recuperator flow now closely matches that of the hot side flow, parallel steam superheat cannot be utilized to increase the steam cycle efficiency. The application of this concept to the baseline cycle results in a decrease in thermal efficiency of 2 percentage points.

REHEAT COMBUSTION TURBINE

Reheat combustion turbines utilize a sequential combustion process in which the air is compressed, combusted, expanded in a turbine to some pressure significantly greater than ambient, combusted again in a second combustor, and finally expanded by a second turbine to near ambient pressure. For a fixed turbine rotor inlet temperature limit, the simple cycle efficiency is increased for a reheat combustion turbine compared to a non-reheat cycle operating at a pressure ratio corresponding to the second combustor's operating pressure. This is because the reheat cycle per-

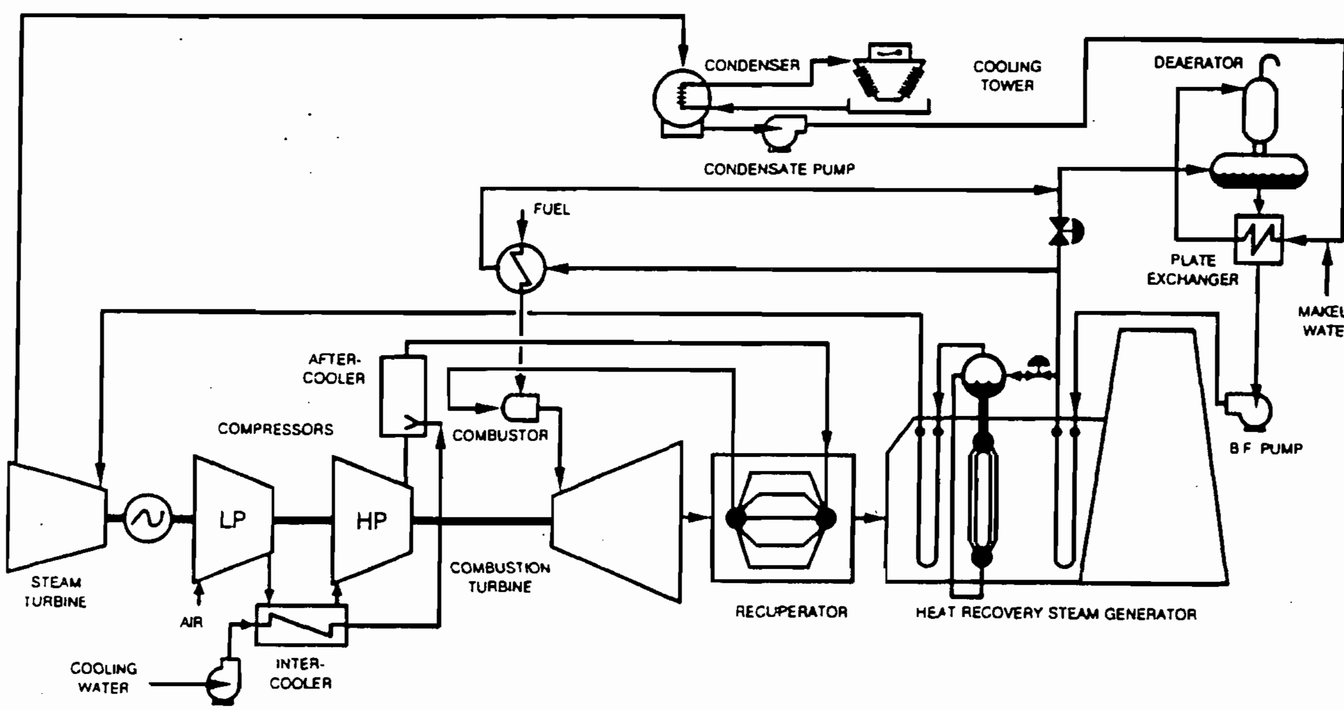

FIGURE 7. INTERCOOLED, AFTERCOOLED (EVAPORATIVE), RECUPERATIVE COMBINED CYCLE

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forms some of its combustion and expansion at a higher pressure ratio, which increases simple cycle efficiency (see section on increased compressor pressure ratio). From a purely thermodynamic standpoint, the average temperature at which heat is added is raised, thus raising the Carnot efficiency of the cycle. For combined cycles the turbine exhaust temperature can be controlled by the selection of second turbine inlet temperature and expansion ratio. This in turn allows control over the efficiency of the steam bottoming cycle.

Another beneficial feature of reheat combustion turbine cycles is that they exhibit higher output for a fixed compressor flow rate and turbine inlet temperature than non-reheat cycles. This is due to the fact that they burn sequentially with an expansion between the combustors. This allows for the addition of more fuel (in the second combustor) without violation of the turbine rotor inlet temperature limit. Also, since this results in a higher fuel-to-air ratio than in non-reheat cycles, they burn closer to stoichiometry and exhaust lower concentrations of excess oxygen.

Applying combustion turbine reheat to the baseline cycle, with the second combustor operating at the exit pressure and temperature equal to those of the baseline cycle, results in nearly identical turbine exhaust temperatures, and therefore the steam cycle of the combustion turbine reheat case is not compromised and is identical to the steam cycle of the baseline cycle. However, the compressor pressure ratio has been increased to 36. This necessitates the addition of 6 compressor stages, and an additional combustor and turbine stage located upstream of the second combustor. The simple cycle efficiency is increased nearly 2 percentage points from the baseline simple cycle level. Since steam cycle efficiency remains at the level of that in the baseline cycle, the combined cycle efficiency is increased 1.3 percentage points.

An investigation was made into the application of intercooling and recuperation to reheat combustion turbine cycles. The results showed the same reduced efficiency as for non-reheat combined cycles.

THERMOCHEMICAL RECUPERATION

In a thermochemical recuperative (TCR) power plant, a portion of the stack exhaust (flue) gas is removed from the stack, compressed, mixed with natural gas fuel, heated with exhaust heat from the combustion turbine, and mixed with the air compressor exhaust as it enters the combustor. As the mixture of natural gas and flue gas is heated by the combustion turbine exhaust, an endothermic reaction occurs between the methane and the carbon dioxide and water in the flue gas. This reaction occurs in the presence of a nickel-based catalyst, and results in the production of hydrogen and carbon monoxide. For complete conversion of the methane, the effective fuel heating value is increased approximately 30 percent. Therefore, the natural gas / flue gas mixture absorbs heat thermally (as it is heated) and chemically (via the endothermic reaction), resulting in a larger potential recuperation of exhaust energy than could be obtained by conventional recuperation, which recovers energy by heat alone. In fact, with full conversion of the natural gas fuel to hydrogen and carbon monoxide, up to twice the energy recuperated by the standard recuperative cycle may be recovered.

The endothermic reaction described above is accelerated for low excess oxygen in the reacting mixture, low pressures, and high mass ratios of recirculated flue gases to methane. Therefore, in order to take full advantage of this concept, the engine is controlled by running the combustor at near stoichiometric fuel-to-air ratios (10 percent excess air at the combustor exit) and using flue gas recirculation to quench the combustion products down to the desired turbine inlet temperature. This maximizes flue gas recirculation and minimizes excess oxygen in the flue gas. For typical cycles utilizing this control philosophy, the resulting recirculation rate of flue gas is over 50 percent of turbine flow. This means that both the air compressor flow rate and stack exhaust flow rate are less than half that of conventional cycles with the same turbine size.

Another advantage of the thermochemical recuperation / flue gas recirculation (TCR/FGR) concept is that, because the fuel has a low adiabatic flame temperature and operates with very low levels of excess oxygen in the exhaust, the resulting emissions of NOx and CO are much lower than those for conventional design power plants.

When applied to the baseline configuration, thermochemical

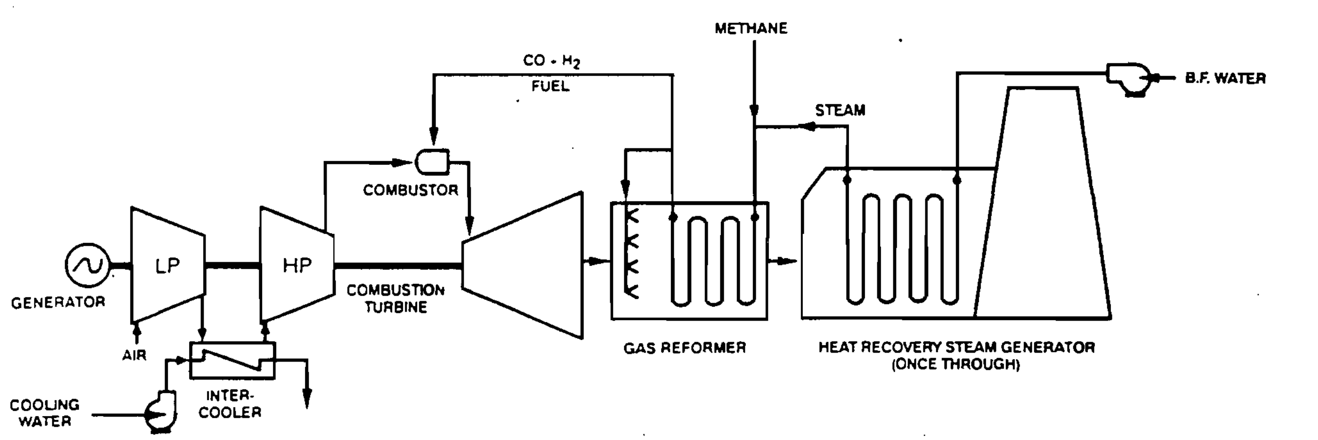

FIGURE 8. THERMOCHEMICAL RECUPERATION CYCLE

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D. J. Huber

recuperation yields a combined cycle thermal efficiency over 2 percentage points greater than that of the baseline cycle for several different TCR/FGR configurations. Additionally, there are many possible cycle configurations, other than those described above, which can utilize thermochemical recuperation. For example, steam reforming may be used instead of flue gas reforming, as illustrated in Figure 8.

STEAM INJECTION

To apply steam injection to the baseline configuration, both the high pressure and low pressure steam systems are eliminated, leaving only the intermediate pressure steam system. The intermediate pressure superheated steam is then routed into the combustion turbine combustor inlet. Therefore, all steam turbines are eliminated, along with the condenser and the cooling tower. This results in a cycle which is significantly less expensive to build than the baseline cycle and it provides a means to reduce NOx emissions via the large amount of steam injection. However, the cost associated with demineralization of the large cycle make up flow must also be considered.

For a given turbine flow area, the compressor flow size must be reduced significantly, due to the addition of a large amount of steam, which now must pass through the turbine in addition to the compressor exit air flow. Since the steam is generated with exhaust heat, which is not used in a simple combustion turbine cycle, this concept provides a significant portion of the combustor inlet gas flow with very little work requirement (a small amount of energy is needed to run the feed water pumps which pump the water to the intermediate steam pressure). Therefore, from a simple cycle standpoint, the work of compression is much reduced due to the fact that some of the combustor inlet gas flow is compressed as a liquid. Also, the turbine output is increased significantly, since the average specific heat of the working fluid is increased considerably by the presence of the steam. The simple cycle efficiency and output are therefore increased by steam injection.

Compared to combined cycles, however, elimination of the high pressure steam system results in generating more intermediate pressure steam, but this steam is at significantly lower availability due to its lower pressure. Also, since the low pressure steam system has been eliminated as well, the exhaust stack gas temperature is much higher, as is the associated heat loss. Finally, since the steam injected into the gas turbine is effectively throttled to its partial pressure upon mixing with the compressor exit air without doing any work, and is only expanded to its partial pressure in the exhaust stack (which is significantly higher than typical low pressure steam turbine exit pressure), the resulting steam expansion ratio is much smaller than that of the conventional steam turbine cycle. These losses result in a reduction in combined cycle efficiency in the range of 5 to 8 percentage points. Net plant output, while much higher than the baseline configuration simple cycle output, is less than the combined cycle output.

CONCLUSIONS

Through component improvements and cycle innovations, the goal of achieving a 60 percent efficiency natural gas-fired power plant for industrial application can be met within an 8-year time frame. The selected cycle and efficiency enhancements will be cost competitive, as a result of not only high thermal efficiency, but also low plant construction and maintenance costs and high plant power output. Additionally, the cycle will demonstrate reduced environmental impact through innovations to reduce emission levels.

This paper has outlined a number of technologies and cycle innovations which will allow Westinghouse to design and build an ATS plant for power generation which meets or exceeds the goals of the DOE-sponsored program. This advanced power plant will demonstrate the continued evolution of Westinghouse large frame gas turbines as depicted in Figure 9. Starting with the 501A engine through the ATS engine, gas turbine output versus combined cycle efficiency is plotted. The data shows the step change that will occur with the successful completion of the ATS Program.

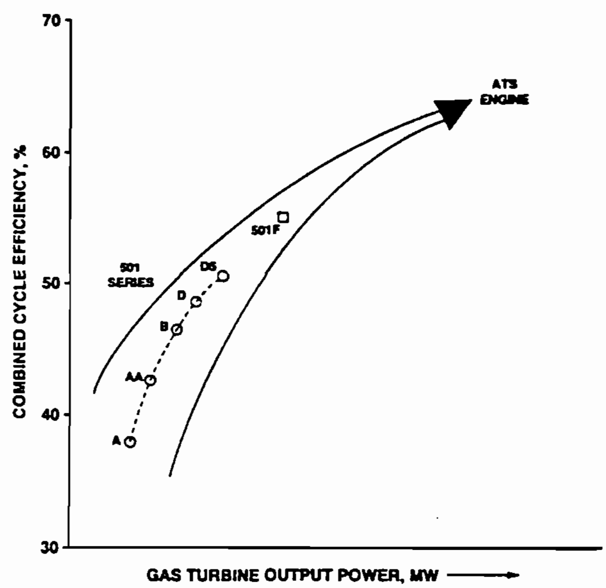

FIGURE 9. EVOLUTION OF LARGE WESTINGHOUSE GAS TURBINES

ACKNOWLEDGMENTS

The innovative cycle and gas turbine component concepts applicable to raising the efficiency of natural gas-fired combined cycles to greater than 60 percent were studied under DOE Contract No. DE-AC21-93MC30247. The program is administered through the Morgantown Energy Technology Center under the guidance of METC's Program Manager, Mr. Donald W. Geiling.

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The authors also acknowledge the technical assistance provided by the Institute of Gas Technology on the thermochemical recuperation / flue gas recirculation and steam reforming concepts evaluated in this study.

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DEVELOPMENT REQUIREMENTS FOR AN ADVANCED GAS TURBINE SYSTEM

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ABSTRACT

In cooperation with U.S. Department of Energy's Morgantown Energy Technology Center, a Westinghouse led team is working on the second part of an 8-year, Advanced Turbine Systems Program to develop the technology required to provide a significant increase in natural gas-fired combined cycle power generation plant efficiency.

This paper reports on the Westinghouse program to develop an innovative natural gas-fired advanced turbine cycle which, in combination with increased firing temperature, use of advanced materials, increased component efficiencies and reduced cooling air usage, has the potential of achieving a lower heating value plant efficiency in excess of 60%.

INTRODUCTION

Today's gas turbine systems feature high fuel-to-electricity efficiencies. Efficiencies, on a lower heating value (LHV) basis, for large natural-gas-fired combined-cycle systems for the utility market have been demonstrated at 54 to 55%. Even though manufacturers will make improvements in the 1990s, efficiency levels will reach a plateau. Cycle innovations, plus gas turbine design changes will achieve LHV efficiencies in the 60% range for natural gas-fired utility machines.

Advanced Turbine Systems (ATS) using natural gas or coal-derived fuels are candidates for the post-2005 power-generation market. An ATS is a highly efficient, environmentally-superior, and cost-competitive gas turbine system for base-load application in the utility, independent power producer, and industrial markets. The final design must be fuel flexible in that it will operate on natural gas, but also be capable of being adapted to operate on coal, coal-derived, or biomass fuels. Reliability-availability-maintainability (RAM) is to be equivalent to current turbine systems and water consumption is to be minimized to levels consistent with cost and efficiency goals.

Westinghouse, a pioneer of gas turbine development, has developed a product line that mirrors the general gas turbine inlet temperature trend shown in Figure 1. Combined cycle efficiency improvements have followed the general advance in gas turbine technology reflected in this inlet temperature trend.

For example, in 1970 a Westinghouse supercharged, evaporative cooled, Model 301 (1450°F [788°C] turbine inlet temperature) gas turbine exhausting into a heavy fired, reheat boiler achieved an annual average efficiency (LHV) of 39.6%. This West Texas Utilities, San Angelo Power Station reportedly held the distinction of achieving the highest operating efficiency in the U.S. for a number of years (Stephens et al., 1990).

Today, with a gas turbine burner outlet temperature (BOT) of about 2460°F (1350°C) [2300°F (1260°C) rotor inlet temperature (RIT)], a Westinghouse 501F based combined cycle is in the range of 54 - 55% (LHV) plant efficiency, ISO with: 1) dry low NOx; 2) three -pressure level, reheat, heat recovery steam generator (HRSG); 3) rotor cooling; and, 4) fuel gas heating.

The bottoming cycle has been fine tuned to convert as much of the turbine's exhaust heat into electricity as possible. Additionally, the gas turbine incorporates all the material, aerodynamic and cooling technology gains of the last 25 years.

As suggested by the Department of Energy (DOE), the target of 60% combined cycle efficiency by the year 2000 is shown to be a challenging target in Figure 2, where cycle efficiency is plotted against the turbine inlet temperature trend of Figure 1.

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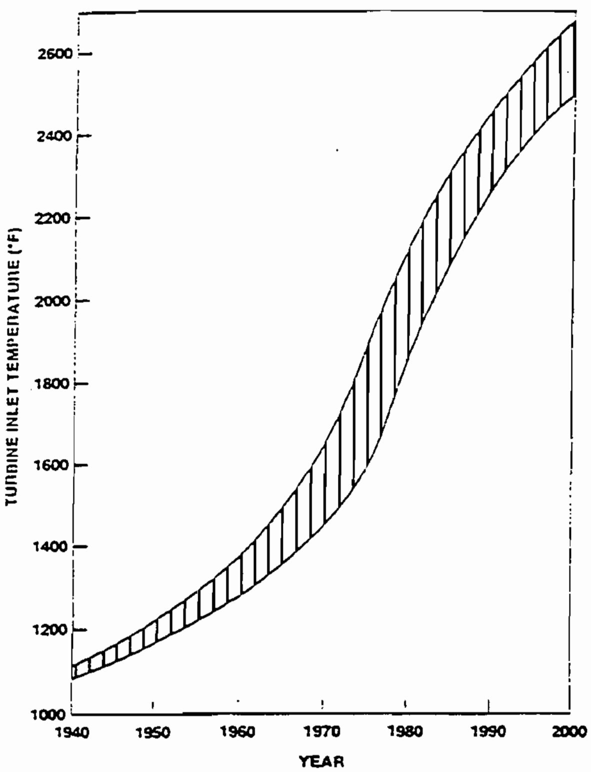


FIGURE 1.
GAS TURBINE INLET TEMPERATURE TREND

PROPOSED REFERENCE SYSTEM

In the first phase of the ATS program, the effect on efficiency of reconfiguring the gas turbine based combined cycle was studied, to see if a step gain in efficiency was possible. As reported in a previous paper (Little, Bannister, Wiant, 1993), it was found that a significant increase in combined cycle efficiency could indeed be expected by reconfiguration into an intercooled, recuperative combined cycle, with closed loop steam cooling as shown in Figure 3. All rotating components will be directly coupled to form a single shaft running at 3600 RPM, and the generator rotor will be double ended so that the steam turbine and gas turbine can drive from opposite ends.

Intercooling could take the form of: 1) surface heat transfer where heat is extracted from air leaving a compressor section and transferred to cooling water; 2) evaporative intercooling where the temperature of air leaving a compressor section is reduced by evaporation of water into the air stream; 3) either one intercooler [low pressure (LP) and high pressure (HP) compressors], or two intercoolers [LP, intermediate pressure (IP), HP compressors]; or, 4) continuous evaporative cooling in all stages of a single compressor.

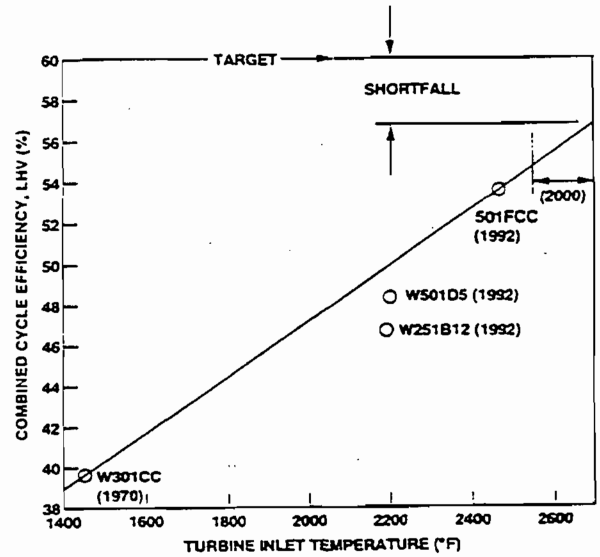


FIGURE 2.
COMBINED CYCLE EFFICIENCY TREND

Recuperation could take the form of: 1) surface heat transfer between turbine exhaust gas and HP compressor delivery air; 2) evaporative recuperation where heat extracted from turbine exhaust would both heat and evaporate water into HP compressor delivery air and; 3) chemical recuperation whereby turbine exhaust energy would be transferred back into the turbine through a reformed natural gas fuel. In most cases, intercooling and recuperation would not displace entirely the bottoming cycle, but would instead reduce its size.

The initial ATS study, although preliminary in nature, showed increases in advanced turbine system efficiencies ranging from 0.5 to 4.0 percentage points depending on the cycle configuration and assumptions made. A change in configuration from the basic single shaft gas turbine to that of the reference system is thus anticipated to provide about 2.0 percentage points increase in system efficiency. Closed loop steam cooling of hot gas path components is anticipated to improve cycle efficiency approximately 1.5 percentage points.

Within the reference system configuration, additional efficiency gains can be made by: 1) high temperature developments in materials, coating systems, and cooling techniques to allow the attainment of a 2600°F (1427°C) rotor inlet temperature; 2) reduction in cooling air requirements; 3) application of advanced aerodynamic design techniques to further enhance component efficiencies; and, 4) reduction in leakages, clearances and parasitic losses.

It is expected that higher firing temperature in combination with cooling air reduction should yield about 2.5 percentage points in efficiency, while advanced aerodynamics, and reduced leakages, clearances, and losses would give a further

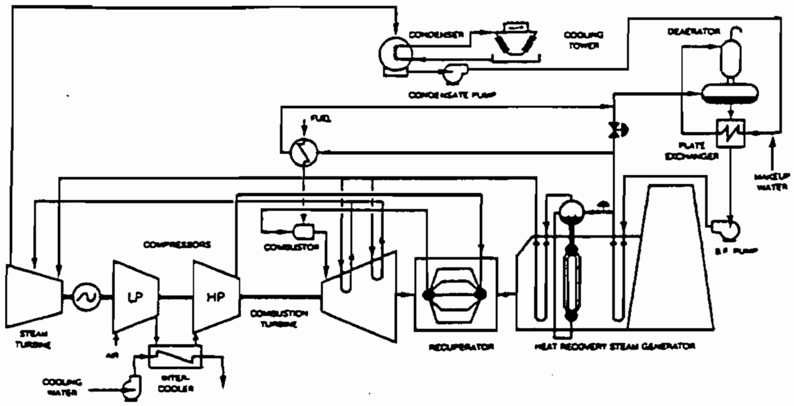


FIGURE 3.
PROPOSED REFERENCE SYSTEM (ICRCC)

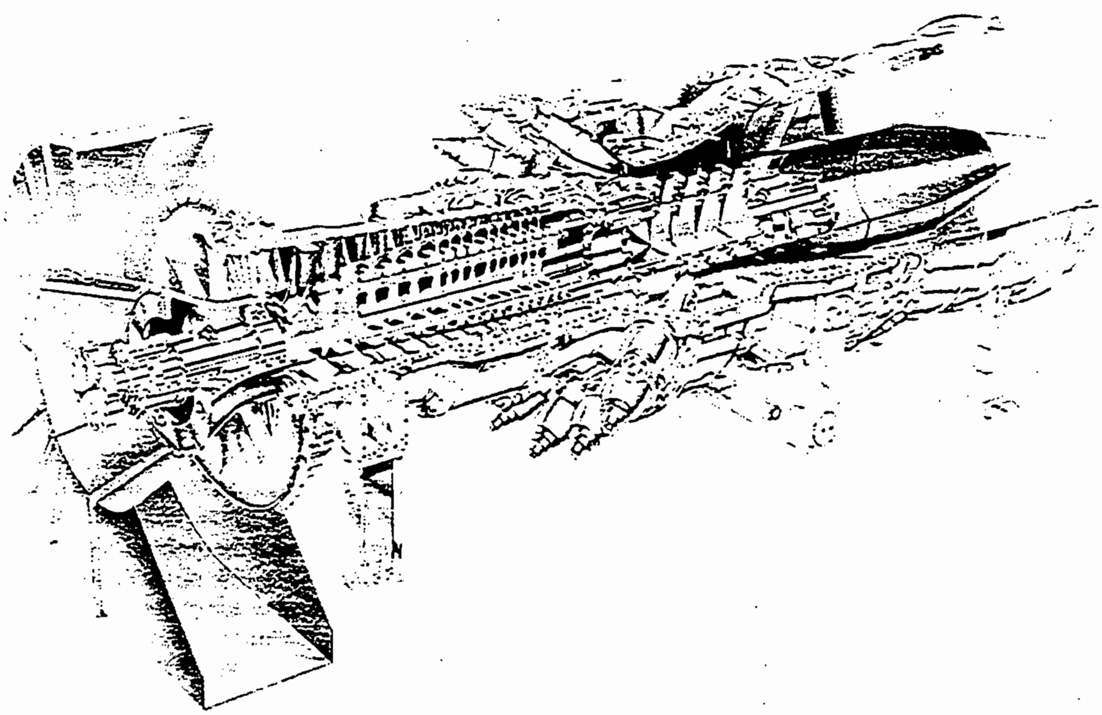


FIGURE 4.
WESTINGHOUSE 501F GAS TURBINE

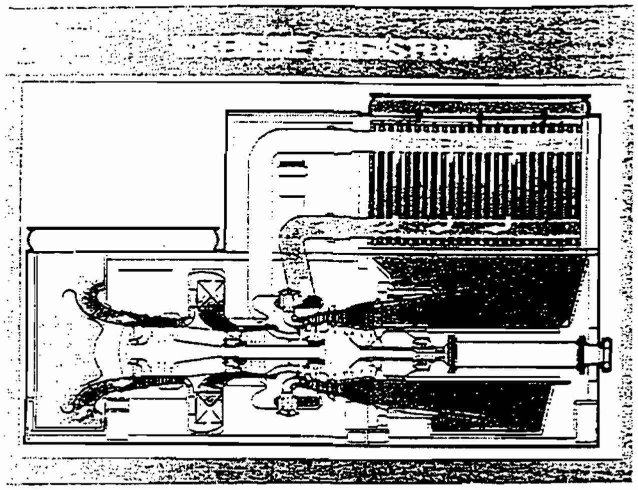


FIGURE 5.
WR21 ENGINE SYSTEM
WITH COMPACT SURFACE INTERCOOLER

1.0 percentage point. Therefore, within the reference system structure, 60% (LHV) target ATS efficiency is obtainable.

CYCLE STUDIES

Intercooling between compressor stages to reduce compression power has long been a feature of centrifugal compressor installations. The radial delivery of compressor air from each impeller lends itself to flow through an external water-to-air cooler before being introduced to the following impeller. Stages in the axial compressor of the industrial gas turbine are extremely close coupled, as shown in the 501F longitudinal (Figure 4), making intercooling impossible without significant configuration changes.

Intercooling between separate axial compressors has been done successfully in the past, where air is ducted from the LP compressor to a large water-spray evaporative cooler, and returned to the HP compressor inlet. More recently the compact water-to-air surface intercooler configuration, shown in Figure 5, is being developed by Westinghouse/Rolls-Royce for the U.S. Navy intercooled, recuperative (ICR) engine program (Crisall and Parker, 1993).

In the ATS program, either of these concepts may be adopted, depending upon the results of detailed thermodynamic cycle analysis comparing evaporative to surface intercooling. Additionally, the number of positions through the compressor where air is intercooled will be studied. It may be that double intercooling could prove most effective.

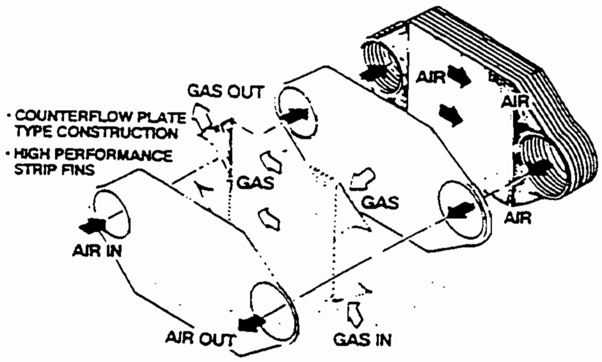


FIGURE 6.
RECUPERATION CORE DESIGN FEATURES

The major problem in the entire intercooling area is the conflicting requirements of the compression and intercooling functions. Velocity through the blading is high, approximately 640 ft/s (195 m/s) between stages, while for cooling (either evaporative or surface) velocity must be very low to reduce pressure loss and maximize residence time. In surface intercooling, a face velocity of approximately 32 ft/s (9.8 m/s) would result in a $\Delta P/P$ for the core elements of about 1%, and a effectiveness of over 90%. Diffusing, turning and reaccelerating air through a 20:1 area ratio will require careful engineering to minimize loss, as pressure loss cuts cycle efficiency and defeats the purpose of intercooling. A trade-off between area ratio, loss and effectiveness will have to be taken.

Evaporative intercooling requires an enormous pressure vessel. It would be a great advantage if evaporation could be done in a shorter length, in fact the ultimate scheme could be to evaporate in the compressor itself.

There is the possibility of introducing a water mist into the air flowing through the compressor. If the droplet size were of the order of 5 microns, collisions with the compressor blades would be minimized; such droplets would follow the flow streamlines. (It should be noted that the LP ends of steam turbine expanders have coped well with water droplet concentrations of up to 14% of the total flow.) A continuous cooling of the compression process by droplet evaporation might then be achieved. A preliminary analysis of such a compression process indicates a 25-30% reduction in the work of compression; a corresponding reduction in the temperature increase over the compressor; and, perhaps surprisingly, a reduction in the water used over a staged inter- and after-cooler process.

Techniques have recently been developed to produce such fine droplets, to maintain a uniformly distributed spray, and to

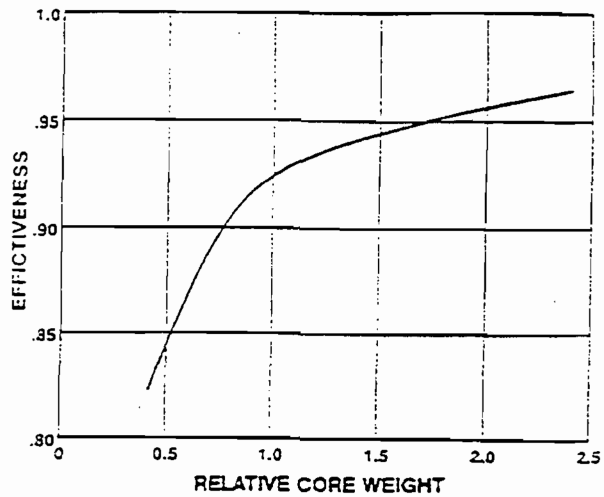


FIGURE 7.
RECUPERATION WEIGHT VS. EFFECTIVENESS

Techniques have recently been developed to produce such fine droplets, to maintain a uniformly distributed spray, and to avoid droplet coalescence. Incorporation of the water distribution system within the thin stationary aerofoils is an obvious means of access into the tightly spaced compressor stages, which will not disrupt the main flow. Spraying of these tiny, 5 micron, droplets into the air stream with minimum momentum mixing penalty would be the objective.

Designing the aerofoil shapes to properly account for the evaporation of the water mist in a finite distance downstream of the introduction points will require careful analysis of the time required for evaporation. Vaporization will be a function of water droplet temperature, injection velocity, air temperature, pressure, velocity and humidity. The modeling and experimental verification of the processes, just described, will be key prerequisites to being able to incorporate a design procedure into existing compressor blading design systems. Continuous evaporation within the compressor appears to be an attractive innovation which could improve the performance and reduce the cost of the ATS.

In the last 30 years, Westinghouse has supplied recuperative gas turbines from 5000 hp (Model 52) to 35,000 hp (Model 352) to the industrial market, thus, although recuperation is an innovation to the 2600°F (1427°C) RIT combined cycle, the surface recuperator itself is tried and proven. AiResearch, a Westinghouse team member, who will size, specify and supply the recuperator for the ATS, has designed and produced recuperators for large industrial gas turbines ranging in power levels from 6,000 to 60,000 hp. Gas turbines with AiResearch recuperators are being used for gas pipeline pumping, electric utility peaking power, and chemical plant power generation.

The standard core shown in Figure 6, utilized by AiResearch for large industrial recuperators, has a stainless-steel, brazed, plate fin construction. It is designed for 5,000 start/stop cycles and 120,000 hours of operation with exhaust gas temperatures up to 1200°F. The design has proven to be completely compliant by extensive laboratory tests and over 1,000,000 hours of field experience.

Higher temperature capabilities, if needed in the ATS engine, will be facilitated by the substitution of a new material which has 1300°F (704°C) temperature capability. Material development work is currently being done at 1500° to 1800°F.

AiResearch has performed a rough sizing for the ATS recuperator, at possible system operating conditions to achieve an effectiveness of 0.942 with a combined pressure drop of no more than 3.45% at an exhaust flow rate of about 1146 lb/s (520 kg/s). The high effectiveness, low pressure drop, and high flow rates dictate the size of the design, as shown in Figure 7. The requirements can be met by a system of counterflow heat exchangers, each handling part of the total flow of air and of gas.

The temperature drops and pressure losses in the piping leading from the combustor shell to, and from, the recuperator must be added to the estimated core performance to assess the full impact on the cycle efficiency. In the case of the Westinghouse Model 352 unit, air leaves the combustor shell, and returns to the unit through pipes located both above, and below, the horizontal split line on the shell (as shown in Figure 8 for the lower half). Within the shell itself, hot and cold air are separated by a flexible dividing wall. Turbine casing structural connectivity was obtained by the use of ribs (struts), each bolted at one end to the compressor cylinder, and at the other end to the turbine cylinder. The horizontally split combustor shell could thus be designed to contain the pressurized gases, yet be flexible.

Additionally the lessons learned in the Model 352 unit that will be factored into the ATS design, include the absolute necessity of sealing all clearances in the dividing wall and in the transition-basket, and transition-row 1 vane interfaces to ensure that compressor delivery air is actually forced to flow to the recuperator. Often in the past, when recuperated engine efficiency targets were not met, the cause was determined to be the bypass of air around the recuperator (in the combustor shell region). Also, the minimization of (using closed loop steam cooling in combination with thermal barrier coatings) and accounting for, heat pickup by compressor delivery air as it flows around the hot transitions while heading to the recuperator, needs to be considered. Every Btu picked up by compressor air reduces the heat that can be transferred from the exhaust, and thus, reduces cycle efficiency.

Initial studies suggested the possibility that evaporative recuperation may improve ATS efficiency, since more exhaust heat could be transferred into the topping Brayton cycle through moisture evaporation. In the current study, if the

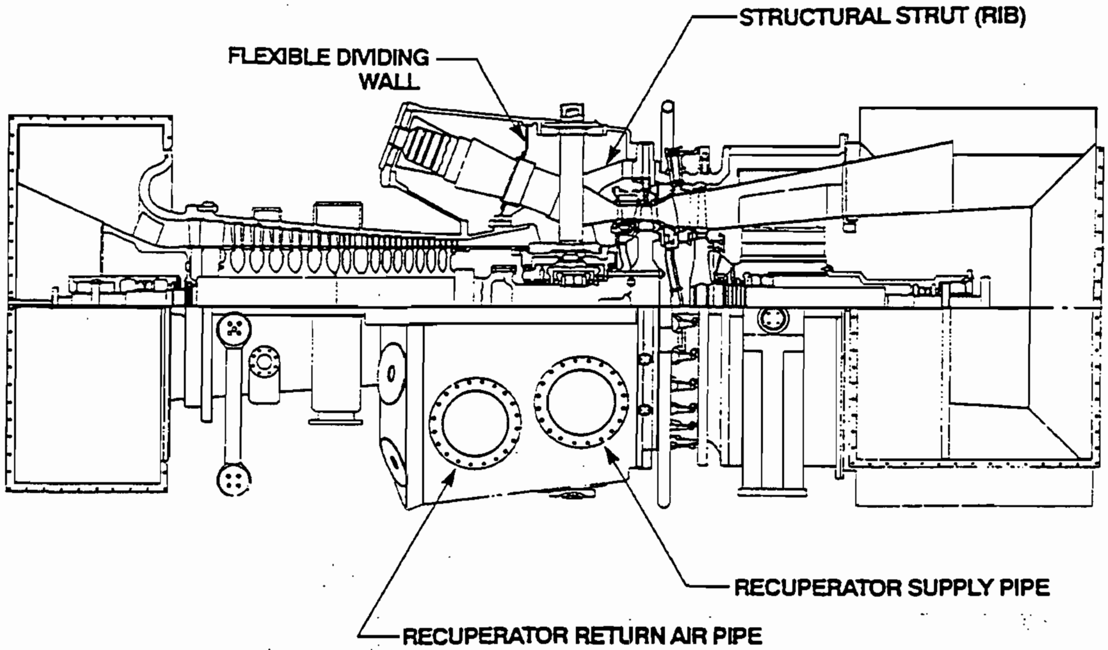


FIGURE 8.
MODEL 352 RECUPERATED GAS TURBINE

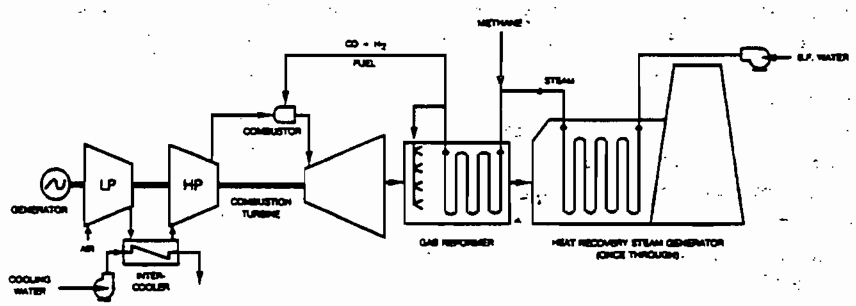


FIGURE 9.
INTERCOOLED, THERMOCHEMICAL RECUPERATIVE CYCLE

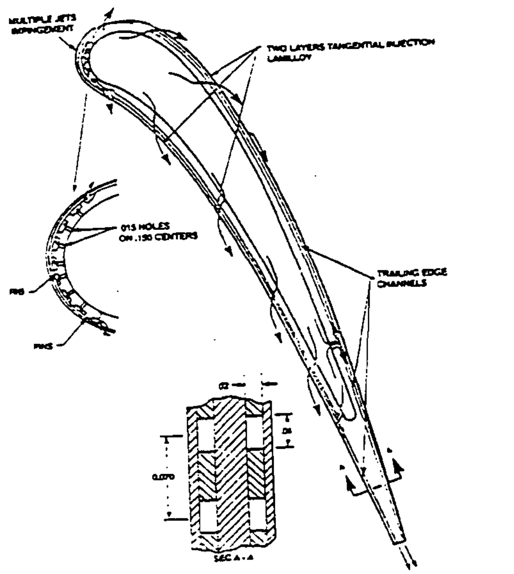


FIGURE 10.
COOLING GEOMETRY,
AIR-COOLED FIRST STAGE VANE

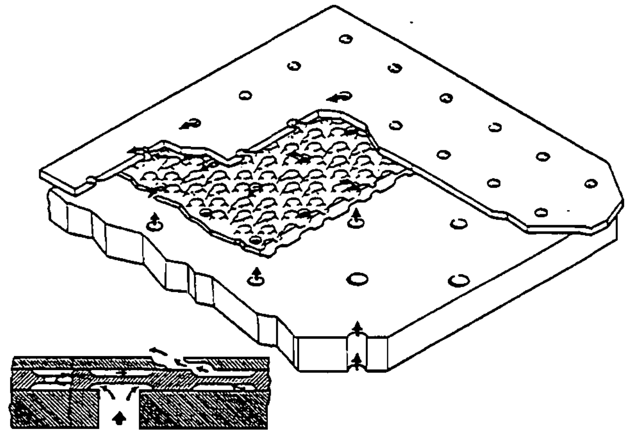
detailed thermodynamic cycle evaluation confirms this idea, then the possibility of water injection in the recuperator cores (either within the air side fin sections, or in the outlet headers) will be investigated.

Thermochemical recuperation of gas turbine exhaust energy, as shown in Figure 9, was also considered. Here only the gas turbine would produce power (no longer a combined cycle) by burning reformed, recuperated fuel. Methane and sufficient steam in the presence of a catalyst, and at appropriate temperature, will reform into a fuel consisting of H_2 and CO. None of the latent heat of vaporization of steam generated in the HRSG is lost to the cycle, and so the potential exists for efficient exhaust energy recuperation.

In current reforming technology, methane conversion efficiency is a function of pressure, temperature and excess steam/ methane ratio. Therefore, the reformed fuel could consist of CO, H_2, and CH_4 in various ratios depending on process variables.

COOLING REQUIREMENTS AND POSSIBLE ALTERNATIVES

Currently the first 3 (of 4) stages in the 501F turbine are cooled. First stage vane cooling is accomplished by a combination of impingement, film and convective cooling. First stage blade cooling incorporates serpentine, ribbed, and pin passages with external film. Both of these highly complex



NUMBER 8
SCHEMATIC OF TYPICAL LAMILLOY GEOMETRY

FIGURE 11.
SCHEMATIC OF TYPICAL LAMILLOY GEOMETRY

cooling schemes may be further refined, but potential cooling air reductions may be small. Alternatively, several approaches which have been investigated in the past may be reconsidered.

One of the most promising of these is shell/spar construction. Shell/spar vanes and blades may be formed by bonding a thin non-porous aerofoil shaped metal sheet (the shell) to an inner hollow cast support member (the spar), or by casting. Cooling air for the assembly is supplied from alternate cavities within the spar (the supply cavities). It flows along chordwise convection cooling channels between the spar and the shell and returns to the remaining spar cavities (the discharge cavities). The heated or spent cooling air is then routed from the discharge cavities to the main gas stream through exit holes in the shrouds or aerofoil.

Westinghouse, together with Allison/General Motors (GM), made an extensive study of air cooling approaches suitable for industrial size gas turbines at the elevated firing temperature of 2650°F (1454°C) and 3000°F (1650°C) under a U.S. Energy Research and Development Administration High Temperature Turbine Technology program. This work identified the feasibility of reaching these temperature levels using an advanced transpiration type air cooled technology.

One candidate for the row 1 vane is shown in Figure 10. This transpiration design consists of two layers of sheet material diffusion bonded to a hollow, cast spar. In the leading edge region, the sheet material is solid to minimize susceptibility to erosion and deposition. It is cooled by a multiple diffusion bonded scheme. In the trailing edge region, the outer layer of the sheet material is solid for aerodynamic and fabrication reasons and is cooled via chordwise channels located in the inner layer of the skin. Over the rest of the airfoil, the skin is tangential injection Lamilloy® which is a porous material that produces quasi-transpiration cooling. A cutaway drawing of a typical Lamilloy geometry is shown in Figure 11 (Lamilloy is a registered trademark of Allison Division/GM.) Preliminary studies have demonstrated the improved heat transfer effectiveness of Lamilloy over conventional multipass cooling.

Spanwise holes which taper from hub to mid height represent an improvement over constant diameter holes used in rotor blade cooling. With this technique, increased cooling in the critical mid height region is obtained by reducing over cooling in the hub region resulting from the lower coolant temperature as the cooling air enters the hub region. Increased hub region flow area obtained by tapering reduces heat transfer in that region, thus reducing temperature rise in the coolant as it flows radially outward.

Another variation in cooling hole geometry is to integrally cast circumferential ribs periodically spaced along the length of each cooling hole which act as flow turbulators to produce turbulent rather than laminar heat transfer for the cooling air. Field tests have been run on a Model 501 engine comparing smooth and turbulated holes. These tests verified that the heat transfer coefficient doubled by the use of the turbulators. A combination of turbulators and tapered holes could provide a very significant improvement in the cooling effectiveness required for the first stage rotating blade and possibly the second stage rotating blade.

Westinghouse policy has been to use high strength ferritic steel for rotating parts such as discs and torque tubes. The advantages of the low alloy, time-proven NiCrMoV turbine disc material over Ni based alternatives are better fracture toughness, lower cost, availability in industrial size forgings, and higher strength at the 750°F (400°C) design temperature. This material can only be used up to approximately 800°F (427°C) for temper embrittlement concerns.

For the ICR cycle, the HP compressor discharge temperature will always be sufficiently low so that it can be used, uncooled, for rotor cooling. The use of compressor discharge or interstage bleed air to cool engine parts reduces engine efficiency by up to 0.5% for each percent of cooling air utilized, depending on the coolant source and flow path entrance conditions. In the 501F engine, some 60% of the cooling air is used for aerofoil cooling. Most of the remainder leaks into the turbine hot gas flow through clearances in the parts which bound the coolant flow path as it proceeds to its destinations throughout the engine. These clearances are required to permit differential expansion of parts during temperature transients in order to avoid low cycle fatigue damage.

Another area that has a large potential for cooling air reduction is the reduction of the combustor outlet hot spot that the turbine blading must account for during design. In the case of the stage 1 vane, some vanes in the row will be directly impacted by the hot spot. This hot spot will be carried downstream, but will be attenuated somewhat by the averaging process due to blade rotation. Even so, the hot spot temperature may also have a special effect on the first rotating blade due to time averaged migration to the pressure side. Once the amount of hot spot reduction is known, the amount of cooling flow reduction can be estimated and the improvement in cycle efficiency predicted. Hot spot reduction will be estimated from ongoing tests of premix lean-burn combustors employing reduced cooling.

CLOSED LOOP STEAM COOLING

Another innovation which will provide increased ATS cycle efficiency at constant RIT, is closed loop steam cooling. Closed loop steam cooling involves directing a portion of the dry steam raised in the HRSG through the walls of hot end components, such as combustor baskets, transitions, and vanes, prior to expanding it through the steam turbine. The steam is superheated as it removes heat radiated and convected from the hot gas path. The idea of using steam to cool a gas turbine was suggested in the 1960s (Arsen'er et al., 1990).

When a comparison is made of the implications of replacing cooling air with bottoming cycle steam, while maintaining constant RIT, it is found that temperatures in the combustion reaction drop significantly because the same quantity of fuel is burned with much more air (original quantity, plus all the air that was used for basket wall, transition wall, and row 1 vane wall cooling). Thus, emissions may drop because the premix lean-burn, dry low NOx combustion will be even more lean provided flame stability is maintained.

The total pressure available at the 1st rotor inlet for expansion through the turbine will be higher, because no momentum mixing loss between cooling air and mainstream gas flow will have occurred. Therefore, extra power will be produced by the gas turbine. Also, the hot spot temperature from each basket will be reduced since much less $\Delta T/T$ was required. This will reduce both row 1 vane and blade cooling requirements. Additional kilowatts will be generated in the steam turbine from the higher temperature (but lower pressure) steam expanding through the steam turbine.

Use of steam cooling in the row 1 vane would raise ATS efficiency 0.8 percentage points. Inclusion of the heat extracted from the baskets and transitions would further raise efficiency. Steam cooling for row 2, 3 and 4 vanes would also produce more power, and would additionally boost ATS efficiency, since exhaust temperature would rise, thus reducing fuel consumption (more heat transferred across recuperator to compressor delivery air), and recuperator exhaust temperature would also rise resulting in the raising of more steam in the HRSG. The net effect could be to raise ATS efficiency another 0.5 percentage point or more.

Closed loop steam cooling is a very attractive means of boosting ATS combined cycle efficiency. The technical challenges, are significant, but are all understood and lend themselves to design and analysis. Factors that must be considered include: 1) control requirements to ensure an uninterrupted supply of steam; 2) steam pressure loss minimization and leakage elimination; 3) heat transfer requirement and steam capacities; 4) steam cooling paths through components and casting limitations; and, 5) maintaining constant thermal stress to assure required low cycle fatigue life.

The possibility of applying closed loop steam cooling to the rotating blades should also be investigated. A conceptual design of steam transfer into, and retrieval from, the shaft, as well as routing through the discs and blades will be investigated. The complexity and development effort will be weighed against the potential gain in cycle efficiency to determine the advisability of pursuing this option.

ADVANCED AERODYNAMIC DESIGN

The 501F compressor was designed between 1986 and 1988 by Westinghouse using 20 years of successful design experience on the 501 frame (501AA to 501D5). The experimental knowledge gained in the 501 compressor was incorporated into a design system using appropriately prescribed aerofoil shapes with their loss and deviation characteristics incorporated into a compressible flow. The key element in the design process was to achieve a compressor design which could be built and applied confidently in the engine without developmental testing. This target was achieved using the base of experience which grew as the 501 evolved from the 501AA to the 501D5. The total experience was developed into compatible parts of a system for design and performance analysis which provided the necessary confidence to develop the new 501F compressor.

The design was successful, and resulted in the high efficiency, low loading, high surge margin, 16-stage compressor. For the compressor(s) of the ATS it is anticipated that this traditional Westinghouse approach will be strengthened.

The 501F turbine aerodynamic design benefited from turbine design experience and the application of advanced three-dimensional design techniques. The resulting high efficiency four-stage turbine configuration contributed greatly to the success of the 501F. Within this basic four-stage turbine philosophy, it is anticipated that further aerodynamic refinement can be incorporated.

REDUCTION IN LEAKAGES, CLEARANCES AND MECHANICAL LOSSES

Additional gains in ATS efficiency can be realized through more efficient utilization of cooling and sealing air, and reduction in mechanical losses. It is intended to incorporate ideas which have in many cases been formulated, but not implemented in the past.

Improvement of component performance is possible by reducing clearances in both the compressor and turbine. The use of knife edge seals on disc seal arms which wear into abradable material such as felt metal or filled, honeycomb surfaces that are mounted on the stationary compressor and turbine seal housings, is a method of minimizing running clearance. The process of rubbing the knife edge into the abradable surface during both steady-state and transient operation will produce a groove in the abradable material and establish both a minimum radial and axial running clearance. The final steady-state clearance will be smaller than when seals are designed not to rub. With the knife edge seal rubbing into the abradable material, the frictional heat generated by rubbing is not large enough to cause structural distortion.

Innovative brush seals which are gradually finding acceptance in gas turbines, will be considered for the ATS engine. These seals restrict the flow of air through a gap between stationary and rotating components by filling the gap with a brush of very fine (0.0025 in.[.0064 cm]) alloy wires. The wires are oriented at 45° to the radial direction so they can bend and accommodate transient reduction of radial clearance. Cost versus benefit from reduced leakage flow is the major tradeoff to be considered.

Further clearance reduction beyond wear-in type seals would be to utilize an active clearance control design that would reduce the running clearance caused by transients. It is well documented that the largest clearance required between rotating and stationary parts occurs during startup of a cold engine. If a method can be developed to minimize or eliminate this added clearance then operation with a running clearance set only by steady-state operation can be achieved. Reduction of the transient clearance is important because, in most cases, especially for the blade tips, the transient clearance requirement is more than double that required for steady-state. The effect of elimination of the transient allowance is to reduce the steady-state leakage area and resulting flow by one half.

Some improvement in overall cycle efficiency is possible with a reduction in mechanical and/or windage losses. The use of a directionally lubricated thrust bearing to replace the more conventional flooded design will reduce the mechanical loss. These bearings are being used commercially and could be used for this application. If a concern exists that a sudden loss in oil supply would cause damage to the bearing and rotor, an oil reservoir could be designed to protect the bearing during an emergency shutdown.

Another area for even greater improvement would be the application of active magnetic thrust and radial bearings in place of the conventional oil lubricated bearings. These type of bearings are currently being used in small gas turbines (≈ 2 MW), and special applications, and are under development for large size applications such as gas turbines. This system would eliminate the need for an oil lubrication system. It would benefit the cycle by reducing mechanical losses for the turbine bearings, oil system pumps, oil cooler fans, etc., and also eliminate the oil cooler, piping, fire protection, controls, etc.

Another area that translates into a mechanical loss is windage created by any rough or protruding surface, such as uncovered coupling bolts, blade root projections, etc. In any design, attention to minimizing areas that create windage must always be considered.

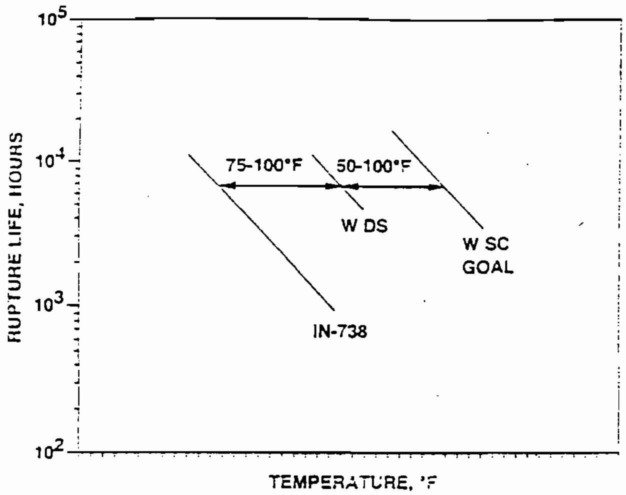


FIGURE 12.
TEMPERATURE ADVANTAGE OF
Ⓦ DS AND Ⓦ SC ALLOYS

HIGH-TEMPERATURE MATERIAL REQUIREMENTS AND NEEDED DEVELOPMENT

Materials play a critical role in the design of engines with higher firing temperatures, since the temperature capability of materials establishes the cooling requirements which in turn affects the engine efficiency. Hot section components for land-based engines typically require materials with superior mechanical properties and good corrosion/oxidation resistance at elevated temperatures. Ni and Co base super alloys with high Cr content are extensively used for this application, the chemistry of these alloys having been adjusted to yield an optimum combination of strength and corrosion/oxidation resistance. At higher firing temperatures, additional protection of hot section superalloy components by coatings has became an absolute necessity. It may not be possible to further adjust the composition of superalloys to obtain higher strength and better hot corrosion and oxidation resistance at elevated temperatures without adversely affecting their stability. The high temperature strength of superalloys arises from a combination of various hardening mechanisms, the most potent being precipitation hardening. The commercial superalloys are solution treated (around 2050° to 2300°F [1121° to 1260°C]) and aged to obtain optimum elevated temperature properties. Thus, the ultimate temperature capability of these materials is limited by the solution treatment temperature. The advent of single crystal casting, which eliminates the need for grain boundary strengthening elements, makes it possible to increase the solution treatment temperature.

The third and fourth generation Ni base single crystal alloys offer a temperature advantage of about 200°F (111°C) compared to conventionally cast IN-738 which is used as a blading material in land based engines. The French have developed a single crystal alloy with 16% Cr which offers a 90° to 100°F (50° to 56°C) temperature advantage at about 22 kpsi (1547 kg/cm^2) stress level when compared to conventionally cast IN-738.

Westinghouse has been developing corrosion resistant directionally solidified (DS) and SC Ni base superalloys for land-based engine applications (Cr levels around 16%). At typical row 1 blade operating stress levels, these new alloys in the DS condition offer a temperature advantage of around 75° to 100°F (42° to 56°C) when compared to equiaxed IN-738, as shown in Figure 12. Westinghouse SC alloys are expected to exhibit 50° to 100°F (28° to 56°C)higher temperature capability than that of the corresponding DS alloys.

Coatings used for land based hot section components fall into the categories of corrosion resistant and thermal barrier. As the name implies, the former is applied for corrosion and/or oxidation protection, while the latter is used to reduce the heat transfer between the gas stream and the substrate of the coated component. It is known that when corrosion resistant MCrAlY coatings are exposed to elevated temperature, they degrade due to inward and outward diffusion of elements present in the coating. The extent of degradation depends both on service temperature and time. Figure 13 shows MCrAlY coating degradation as a function of service exposure at a temperature of around 1700°F (927°C). After 9000 hours of operation, the coating structure reveals denuded zones at the outer surface as well as at the coating - substrate interface. The coating was also locally corroded/oxidized at its outer surface. After 19,000 hours of operation, the coating was almost completely corroded/oxidized, and the substrate was oxidized significantly. These results show that current MCrAlY type coatings do not offer reliable protection at ATS target metal temperatures.

Advanced coatings are needed to realize the full potential of new DS and SC alloys. At present, thermal barrier coatings (TBCs) are being used in service on static components and are being evaluated for application to rotating parts. The TBC is needed to lower the substrate temperature and to improve the reliability of MCrAlY coatings. Though these coatings are being used industry wide, development work is needed to increase their temperature capability for reliable service in ATS engines.

For both corrosion resistant and TBCs, programs to evaluate all available coatings, select candidate coatings, perform screening tests and outline long term development plans will be established.

The target RIT for an ATS engine requires implementation of SC and DS components coupled, with advanced coatings (including TBC) to minimize cooling air/steam usage in the ATS engine. The key is to take advantage of increasing creep

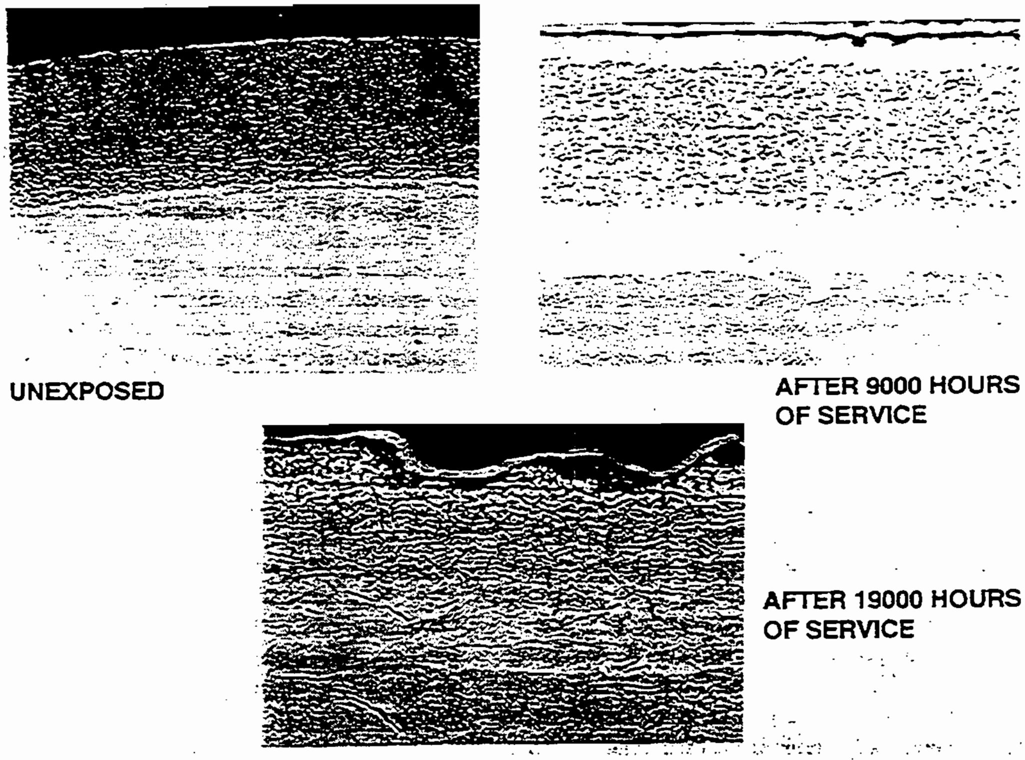


FIGURE 13.
MCrAlY COATING DEGRADATION

strength by letting the blade temperature increase. Corrosion resistant SC materials are expected to exhibit about a 150°F (83°C) temperature advantage compared to current conventionally cast blading materials, while, TBCs typically lower service metal temperature of the coated component by an additional 150°F (83°C).

Ceramics and ceramic composites offer excellent temperature capability and are less significantly affected by the environment (corrosion & oxidation) than superalloys. For continuous advancement in high temperature capability, it will be necessary to consider implementing ceramics, composites, and intermetallics. In these cases, available structural ceramics, and composites will be assessed for their potential application. Ceramics and ceramic composites will be considered for stationary components of the ATS engine.

COMPONENT SPECIFIC MATERIALS

Combustors

Improved metallic materials with TBC or fiber reinforced ceramics will reduce cooling air requirements. Minimization of cooling air flows will reduce NOx emissions.

The use of combustors fabricated from advanced ceramics and fiber reinforced ceramic composites, which provides mechanical integrity, greatly advance the technology. Ceramic composites will allow the use of uncooled or minimally cooled combustors systems. Ceramics will be evaluated as alternatives to conventional metal based combustors for the long-term.

Transitions

Advanced Ni based materials and high temperature coatings coupled with TBC will be considered for the ATS engine. Recently developed oxide dispersion (Y_2O_3) strengthened superalloys offer excellent creep strength, as well as superior oxidation and hot corrosion resistance. These alloys, along with ceramics and ceramic composites, may be evaluated to replace conventional Ni base transitions.

Vanes and Blades

Given the time-frame of the ATS program, intermetallics and composite materials may not be available for the subject application. These materials will be evaluated for future engine applications. Availability of these materials for this application depends on how rapidly the technology advances and how much design data would be generated and available. However, any developmental materials such as intermetallics and metal matrix composites will be evaluated as they become viable within the development time-frame for both vane and blade applications.

Stationary vanes do not have to withstand the rotating stresses that are imposed upon blades, but are subjected to environmental attack and the thermomechanical stresses imposed by thermal cycling. Advanced superalloys that are processed by conventional and improved process methods, including DS and SC casting, are the principal candidates for improved vane materials.

Improved oxidation resistant MCrAlY coatings are candidates for this application. In addition to corrosion resistance, the properties of the coatings need to be evaluated with respect to mechanical stability for candidate vane materials under thermal cycling conditions.

TBCs are expected to help improve the cooling efficiency of vane systems. Key issues regarding the application of TBCs to vanes are the mechanical compatibility of the TBCs with the vane substrate and the interaction of the porous coating with molten corrosive oxides and sulfides. TBCs, primarily those based upon yttria stabilized zirconia, will be evaluated with respect to mechanical and chemical effectiveness for application as improved coatings for vanes.

Intermetallic and composite systems will also be considered for vane applications. These systems are currently limited by the very few intermetallics that display good high temperature ductility and are chemically stable in oxidizing/hot corrosion atmospheres. The most promising systems are those based on NiAl intermetallic. The properties of these systems will be reviewed for prospective vane applications.

Ceramic materials will be assessed for vane applications in the natural gas-fired advanced turbine systems. While ceramics, particularly those based on oxide systems, offer increased temperature capability, the structural integrity of the large sized components that are required in the power generation ATS must be demonstrated. Currently, fiber reinforced ceramic composites for advanced gas filter systems are under development at Westinghouse as part of a DOE sponsored program (Newby and Bannister, 1993).

The most viable candidate materials for improved capability turbine blades are advanced nickel base superalloys that are processed by DS and SC casting methods, in combination with improved oxidation/hot corrosion resistant coatings and thermal barrier coatings.

The study of improved alloy compositions and processes will be based upon current Westinghouse approaches to develop DS and SC alloys for land-based turbine blades. On-going Westinghouse programs have demonstrated that improved high temperature creep and fatigue performance can be delivered by directional solidification of modifications of current turbine alloys. Production of SC alloys has also been demonstrated. The key to utilization of these alloys is to develop coatings that can operate at the high temperature capability of DS and SC materials.

Hot corrosion/oxidation protection of the turbine blades is expected to be provided by advanced coatings based upon existing MCrAlY coatings and oxidation resistant alloy modifications. Candidate coating materials will be assessed based upon their ability to protect against environmental attack and their compatibility with candidate blade alloys. Improved coatings will be evaluated based upon their ability to withstand hot corrosion attack at intermediate temperatures on the cooler portions of the blade, high temperature oxidation attack at the maximum temperatures of the blade, and their impact upon the mechanical performance of the underlaying blade alloy.

The current risks of TBCs are mechanical and corrosion related. The mechanical properties of TBCs must be demonstrated to ensure integrity against spalling under thermal cycling conditions. The corrosion issue is not due to corrosion of the coating itself but derives from the ability of the coating to absorb and retain corrosive molten oxides and sulfides that attack the underlaying metallic blade and coating. Processing of the TBC to avoid this accelerated form of attack will be required to improve the capabilities of TBCs.

Turbine Discs

High strength, low alloy steel discs are used in the turbine section of the 501F with 2300°F (1260°C) RIT. The service temperature of these discs is maintained below 750°F (400°C) through the use of cooling air to minimize in-service temper embrittlement.

COMBUSTION

The extremely low NOx (8 ppmvd @ 15% O_2), CO and UHC emission levels which must be achieved at the higher temperature of the fully developed ATS is a serious challenge. Significant internal R&D is currently being devoted to the achievement of single digit NOx by pursuing the premix, lean-burn strategy.

Alternatively, it has been proposed to investigate catalytic combustion, which in the past did demonstrate single-digit NOx emissions. In the current investigation, a test program is outlined to begin investigating the thermomechanical stability of the catalyst substrate, and the effect on catalyst performance of prolonged exposure to high temperatures. ATS emission control will be discussed in a future paper.

SELECTION OF COAL-FIRED PLANT REFERENCE SYSTEM

Within the natural gas-fired ATS program, a brief effort will be expanded to select a reference coal-fired ATS (Webb, Parsons and Bajura, 1993). Westinghouse will apply its background with advanced coal-fueled power generation (Bannister, Bevc and Newby, 1993) to provide the information needed. The selected coal-fired ATS will be described in sufficient detail to provide information that can be used to identify any conversion issues from natural gas to coal. The natural gas-fired ATS is to be applied to a coal-fueled ATS combined cycle. Modifications to the gas turbine components are to be minimized. Modifications should account for the differences in fuel.

Estimates will result for the reference coal-fired system with respect to thermodynamic cycle efficiency, turbine tolerance factors (e.g., expansion gas particle loading, particle size distributions, and alkali vapor content), turbine maintenance (i.e., blade replacement and cleaning frequency, and environmental emission levels (e.g., particulate, NO_x, CO, SO_2 and CO_2).

MATERIALS FOR COAL-DERIVED FUELS

Conversion of a coal-fired advanced turbine systems operation imposes, more severe environmental constraints on the materials selection for the turbine components. Specifically, sulfur, halides, and low levels of metallic elements, such as vanadium, will be carried by the coal-derived fuel and will present significant corrosion attack to the hot section components of the engine.

Under conditions of increased corrosion in the coal-fired ATS, advanced superalloys will be required to form corrosion resistant chromia scales rather than alumina scales; this capability may significantly impact the availability of higher strength alloys under these conditions.

Ceramic materials are expected to be less significantly affected than metallic materials. In specifically severe cases, it will be necessary to consider ceramics for some selected applications. For these cases available structural ceramics will be assessed for potential applications.

The suitability of coatings will also be significantly affected by the atmosphere. Chemically protective coatings will, in a similar manner to the effect on metals, be required to display corrosion resistance. Coating selection for coal-fired ATS components will be more significantly weighted by the ability of the coating to form corrosion resistant chromia coatings. Coatings will be assessed by evaluating the available coating corrosion data for oxygen/ sulfur atmospheres that are similar to the coal-fired ATS atmosphere.

The conversion to coal as a fuel is also expected to impact the use of TBCs. Although TBCs themselves are expected to be only minimally corroded by the more aggressive nature of this atmosphere, significant effects may be expected on the substrate and bond coat. The acceptability of TBCs will be determined by evaluating the data that define the role of the TBC in accelerating the corrosion of the bond coat and the underlaying substrate. These data will be evaluated with respect to the more corrosion resistant atmosphere.

CONCLUSIONS

The feasibility of achieving a 60% (LHV) efficiency in a natural gas-fired ATS cycle within an 8-year period has been established. Cycle innovations, a 2600°F (1427°C) RIT, reduced cooling air usage, improved component efficiencies and improved material/ coating systems will all be needed to accomplish this goal. The ATS needs to be cost competitive, as well as be fuel flexible to use coal-derived and biomass fuels.

This paper has outlined some of the development work that Westinghouse is pursuing to identify the equipment requirements and technological barrier issues that need to be solved during the component development phase of the ATS program. Critical components will be tested. Subscale assemblies will be evaluated. The laboratory experimental data will lead to the testing of full-scale components and integrated subsystems in the next stage of the ATS program.

ACKNOWLEDGMENT

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..AB-In cooperation with U.S. Department of Energy's Morgantown Energy Technology Center, a Westinghouse led team is working on the second part of an 8-year, Advanced Turbine Systems Program to develop the technology required to provide a significant increase in natural gas-fired combined cycle power generation plant efficiency. This paper reports on the Westinghouse program to develop an innovative natural gas-fired advanced turbine cycle which, in combination with increased firing temperature, use of advanced materials, increased component efficiencies and reduced cooling air usage, has the potential of achieving a lower heating value plant efficiency in excess of 60 percent.

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EVOLUTION OF HEAVY-DUTY POWER GENERATION AND INDUSTRIAL COMBUSTION TURBINES IN THE UNITED STATES

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ABSTRACT

This paper reviews the evolution of heavy-duty power generation and industrial combustion turbines in the United States from a Westinghouse Electric Corporation perspective. Westinghouse combustion turbine genealogy began in March of 1943 when the first wholly American designed and manufactured jet engine went on test in Philadelphia, and continues today in Orlando, Florida with the 160 MW, 501F Advanced Combustion Turbine. In this paper, advances in thermodynamics, materials, cooling, and unit size will be described. Many basic design features such as two-bearing rotor, cold-end drive, can-annular internal combustors, CURVIC[2] clutched turbine discs, and tangential exhaust struts have endured successfully for over 40 years. Progress in turbine technology includes the clean coal technology and advanced turbine systems initiatives of the U.S. Department of Energy.

HISTORICAL PERSPECTIVE

Westinghouse, a major supplier of steam turbines since the beginning of the 20th century (Bannister and Silvestri, 1989), obtained the experience it needed to develop land based power generation combustion turbines through its entry into the jet engine business. In March of 1943, the first wholly American designed and manufactured jet engine went on test at Westinghouse, 15 months after obtaining a contract from the U.S. Navy. The engine (designated WE19A) had a thrust of 1130 lb (513 kg) and weighed 827 lb (375 kg). Without any knowledge of German, British or other United States activity, Westinghouse developed the first American jet engine with an axial compressor, an annular combustor, a turbine and a jet exhaust nozzle. The device resembled the Whittle engine developed in England, but there were major differences, in that an axial flow compressor was used, along with a submerged combustion chamber.

An improved version of the engine, the WE19B, was test flown at Patuxent Flight Test Center in January 1944 as a booster unit on a Chance Vought Corsair. It delivered 1365 lb (620 kg) of thrust, weighed 731 lb (332 kg), and one year later, as the J30, was used to power the Navy's first jet fighter, the McDonnell Douglas FH-1 Phantom. Sixty-one (61) Phantom planes were equipped with the J30 engine.

The J34, a 34-in. diameter engine that delivered 3000 lb (1362 kg) of thrust, was the last production aero engine built by Westinghouse. It was used extensively by the Navy in the McDonnell Banshee. Overall, Westinghouse supplied the engines for 1223 Navy jets before exiting the business in 1960.

Westinghouse's experience with land based gas turbines started in 1945 with the development of a 2000 hp gas turbine generator set (W21) that consisted of a single reduction gear, compressor, 12 combustors and turbine (Putz, 1946). A thermal efficiency of 18% lower heating value (LHV)* was obtained. By 1948, Westinghouse built a 4000 hp gas turbine locomotive with the Baldwin Company that used two of these units. Initial operation was on the Union Railroad burning distillate fuel oil. Later operation was on the Pittsburgh and Lake Erie Railroad using residual oil fuel.

In the late 1940s, the U.S. Navy wanted to develop a back-up for the nuclear submarine power plant. Westinghouse received a contract designated "Wolverine" to develop a gas turbine engine for surface, snorkel, and submerged operations. A gas turbine engine of 7500 shaft horsepower was designed to operate in open, semi-closed, and closed cycle modes. In the semi-closed mode, oxygen was supplied to the cycle from the snorkel. While in the submerged mode (fully closed cycle) oxygen was supplied and CO_2 gas was discharged overboard. Engine testing was done at the U.S. Naval Test Laboratory

[1] Westinghouse Electric Corporation Retiree
[2] Gleason Works

*All efficiency values in this paper will be LHV.

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in Annapolis, MD during the early 1950s. While the power plant met all contract requirements, the success of the nuclear submarine program eliminated the need for "Wolverine."

By 1954, gas turbine power plants were becoming a practical and economic reality for particular applications in the power industry. Westinghouse was offering 3 basic gas turbine designs for power generation which had a rotor inlet temperature of 1350°F (732°C) (Putz, 1954). The units were rated at 3500 kW, 5000 kW (with a regenerator), and 15,000 kW (with a regenerator and intercooler). The latter unit was designed for a full-load simple cycle efficiency of 29% compared to the full-load efficiency of 21% for the 5000 kW unit.

West Texas Utilities helped pioneer combustion turbine baseload generation with a 5000 kW unit that was installed in 1952 (Cox, 1957). In 1954, another 5000 kW combustion turbine was installed. The waste heat from this unit was used for feedwater heating until 1959 when it was incorporated into a fully-fired combined-cycle system. This system generated 39 MW in the steam cycle and 5 MW in the combustion cycle.

The Westinghouse single shaft, two bearing, combustion turbine with a reduction gear was first introduced in 1952 as the W81 at 5.5 MW (Stephens, 1952). In 1967, the W251A introduced major innovations such as minimum peak stress turbine blade roots, and cooled low alloy steel turbine discs. Today there are over 300 gear driven units operating in both simple, combined, and cogeneration cycle modes with the current W251 B12 rated at 48 MW.

The first direct drive combustion turbine (W201) at 20 MW was introduced in 1960. A modified W201 combustion turbine was used in 1960 as part of a blast furnace system at U.S. Steel's Chicago Works. The successful development program included design, development, and manufacture of a special casing configuration to efficiently remove compressor discharge flow and deliver it externally to the engine. (Krapf and Stephens, 1958). Gases from the blast furnace were burned and ducted back to the turbine through a special duct and scroll.

In 1962, Westinghouse designed the first "packaged" combustion turbine power plant, which was delivered to the City of Houma. The "packaged" power plant concept is retained today in the ECONOPAC[3] system. This simple cycle package includes the combustion turbine engine assembly; generator and exciter; starting package; inlet and exhaust systems; and plant auxiliary equipment. It is constructed in modules for easy shipment and installation. The ECONOPAC system is also the base for cogeneration and other heat recovery applications.

In 1967, a supercharged direct drive W301 at 25 MW in a heat recovery application was installed at West Texas Utilities San Angelo's Power station and achieved over 39% in combined cycle efficiency, the highest in the U.S. for a number of years.

The first direct drive W501 combustion turbine went into service in 1968 at the Dow Chemical Company with a rating of 42 MW. Many basic design innovations were introduced on the W501A including unique cooled, filtered rotor cooling systems and tilting pad bearings. By 1974, fifty-seven 501s were operating. The 501 technology has grown steadily over 25 years. The current production engine, W501D5 is now being offered with an ISO rating of over 118 MW and the 501F is at 160 MW. The "F" technology includes increases in airflow and firing temperature, improved component efficiencies, and advances in materials, turbine cooling, and dry low NOx. Currently, there are about 300 direct drive units in operation. A complete listing of all models sold is shown in Table 1 where total service hours is seen to exceed 47 million.

For over 30 years, Westinghouse has had licensee arrangements with several combustion turbine manufacturers, the major ones being Fiat Avio in Italy and Mitsubishi Heavy Industries (MHI) in Japan. These partners have contributed to the development of the combustion turbine with Westinghouse, particularly in the 50 Hz market; i.e., the TG50 of Fiat Avio and the MW 701 of MHI, 50 Hz versions of the Westinghouse W501 Model. During the late 1980s and early 1990s, a tri-lateral alliance was formed between Westinghouse, Fiat Avio and MHI to replace the old licensee/licensor arrangement. The alliance provides for joint development of combustion turbines and sharing of technology. The 501F and the 50 Hz 701F are the first engines developed under this partnership arrangement.

WESTINGHOUSE ENGINE TECHNOLOGY EVOLUTION

Westinghouse model designations initially meant the horsepower output in thousands followed by the number of shafts with letters denoting whether the engine was intercooled, regenerated, reheated, or extracted. Therefore, W201RE would mean 20,000 hp, single shaft, regenerated, with cycle air extraction. Later engine evolution, accelerated by materials and cooling improvements, invalidated such designations.

It should be noted that in this paper, the term "firing temperature" for uncooled engines will be defined as the average temperature leaving the combustors and entering the turbine. This neglects the effect of turbine inlet leakage and first stage vane cooling and will be confined to first and second generation engines. For all engines discussed in the third through fifth generations, rotor inlet temperature (RIT) will be used to define the temperature level. RIT is the mixed out average temperature entering the first rotor blade. The basic reason for the change is to include the effects of cooling air used by the row 1 vane.

Westinghouse combustion turbine evolution will be presented as follows:

First Generation - This period of the mid 1940s was heavily influenced by jet engine and steam turbine philosophies and will be confined to the W21 engine.

Second Generation - This period spanned from the late 1940s to the mid 1960s and generated many major design innovations that have been retained in our present designs.

Third Generation - The "Northeast Blackout" of 1965 initiated this generation that saw an explosion of design effort and introduced air cooling, higher firing temperatures, improved materials, and precision cast components. In addition, innovative concepts such as cooled, filtered rotor cooling air and rotor blade cooling and low alloy turbine discs, were introduced.

Fourth Generation - The fourth generation covered the 1970s and the 1980s, a period that was severely impacted by the "Oil Embargo" and the Fuel Use Act. Essentially the combustion turbine market disappeared until the Fuel Use Act was repealed and the Public

[3] Westinghouse Electric Corporation

TABLE 1. WESTINGHOUSE SUPPLIED COMBUSTION TURBINES

Model	No. of Units	Rating (kW)	Installed Capacity (kW)	Oper. Year	Mech. Drive	60 Hz	50 Hz	Service Hours*
W21	5	1,300	6,500	1949	3	5	0	500,000
W31	6	2,200	13,200	1956	6	0	6	600,000
W41	8	3,100	25,000	1961	4	7	1	800,000
W52	14	3,800	52,400	1956	2	14	0	1,400,000
W62	15	5,500	83,000	1961	13	15	0	1,500,000
W72	17	6,300	107,100	1961	17	1	16	1,700,000
W81	30	5,500	155,400	1952	17	30	0	3,070,345
W82	12	6,000	72,300	1962	12	0	12	1,200,000
W92	29	8,200	231,500	1960	27	29	0	2,900,000
W101	83	7,450	607,600	1961	54	70	13	8,306,630
W121	2	8,950	19,000	1959	1	2	0	200,000
W122	1	10,215	10,200	1967	0	1	0	100,000
W171	39	16,425	509,900	1961	1	28	11	2,184,371
W191	182	17,300	3,044,500	1965	14	127	55	8,596,174
W201	3	18,650	62,600	1960	0	3	0	296,022
251	195	49,100	5,626,700	1967	1	147	48	4,322,303
W301	32	23,850	938,100	1964	0	27	5	1,638,369
W352	7	27,900	190,900	1979	4	7	0	665,227
501	227	159,000	13,929,466	1968	0	227	0	7,192,050
701	8	136,900	1,095,200	1992	0	0	8	0
TOTAL	915		26,780,566		176	740	175	47,171,491

* Service hours are estimated as of 12/31/92

Regulatory Policies Act of 1978 (PURPA) was upheld. The latter part of this generation saw the introduction of increased firing temperatures and improvements in materials, cooling and efficiency. The W501D5, introduced in 1983, became the largest and most efficient 60 Hz single shaft combustion turbine in the world at 100 MW and over 33% efficiency for a simple cycle plant.

Fifth Generation - This generation covers the late 1980s to the present and starts with the 501F advanced combustion turbine with an RIT of 2300F (1260°C). Units in this generation will extend the air flow limits of last row turbine blades, the temperature limits of row 1 turbine vanes, and the flow limits of row 1 compressor blades through the use of advanced materials and cooling.

First Generation

The jet engine designers needed a high pressure, high flow facility, for combustor and turbine aerodynamic development. A lightly loaded 23-stage axial flow compressor was designed to meet the needs of the air supply facility. This test compressor together with a 12 can interconnected combustion system and an 8-stage turbine formed the first industrial combustion engine at 2000 hp. The air flow was 35.5 lb/sec (16.1 kg/sec) at a pressure ratio of 5, a firing temperature of 1250°F (677°C), and a power output of 2070 hp at an efficiency of 18 % (Mochel, 1947). The unit was a single shaft, three bearing design with a design speed of 8750 rpm. The external load was driven from the compressor end of the engine.

After a development period, the engine was first applied (1948) as a twin set in a locomotive built by Baldwin and Westinghouse (Stephens and Young, 1989). The engines burned either diesel fuel or residual oil. The locomotive was used as a demonstrator and ran on several railroads, but was never placed in commercial service. Although the locomotive operated at a cost approximately 5% less than a diesel locomotive, the capital costs were not competitive. The locomotive was subsequently scrapped, but both turbines were sold for further operation. The left hand unit was sold to the city of Larned, Kansas as one of the early decentralized peak shaving plants and the right hand unit became the world's first intercooled steam injected plant driving an air compressor at Hopewell, Virginia. The first base-load service of the engine was as a pipeline gas booster pumper on The Mississippi River Fuel Company System in March 1949. This was a dual fuel application burning either oil or gas with the capability of changing to either fuel at full load, an industry first. This particular engine, the first combustion turbine in the world to achieve 100,000 operating hours, was retired after more than 150,000 hours of operation when the gas line was retired.

W21 combustor baskets were contained in individual pipe-like enclosures connecting compressor discharge to turbine inlet, as shown in Fig. 1, and bore little resemblance to the Westinghouse aviation gas turbine design which was an annular combustor, but it used the wall cooling arrangement (wiggle strips) from the aviation design. The wiggle strip concept of wall cooling was unique; it interposed a corrugated strip of metal between two cylindrical sections of combustor that permitted the injection of cooling air, is structurally superior to a single cylinder because the increased section modulus provides superior buckling characteristics, and proved to be a fundamental cooling feature that is still being used in current Westinghouse turbines. Also, casings were horizontally split (like steam turbines) instead of the axial stacking used by the jets. In addition, late production units introduced the CURVIC coupled rotor structure, as shown in Fig. 2, to align discs and transmit torque.

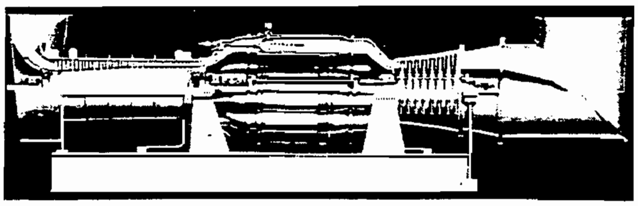


FIG. 1. CROSS SECTION OF W21 COMBUSTION TURBINE

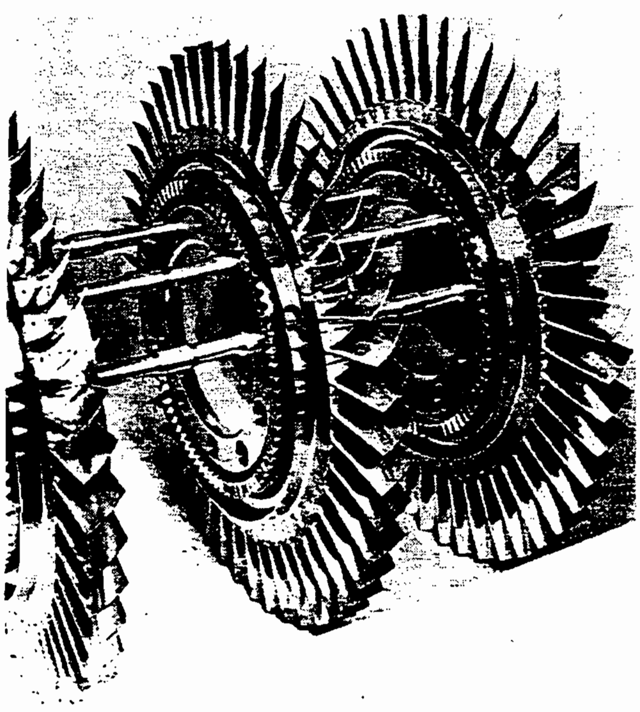


FIG. 2. CURVIC COUPLED TURBINE DISCS

Second Generation

In the late 1940s, Westinghouse formed a design group independent of the aircraft group to develop gas turbines for land based applications. Engineering studies indicated that with the high temperature materials then available a firing temperature of 1350°F (732°C) was feasible for base-load duty (100,000 hr life). In response to a market survey, the first engine developed was a 5000 kW single shaft, simple cycle engine. This engine had a design speed of 5740 rpm, an air flow of about 125 lb/s (57 kg/s) at a pressure ratio of 6.25.
The second generation engine design eliminated the undesirable center bearing and placed the combustion system inside a pressure vessel. Overall, this design had the following improvements:

- Elimination of center bearing removed a fire hazard and simplified shaft alignment.
- Compressor flow from the diffuser provided impingement and convective cooling of the transition duct.
- Flow into this plenum type enclosure attenuated flow disturbances to and from the compressor.
- The annular plenum effect provided damping of combustor pressure fluctuations (This became valuable in later years when limits of combustor stability were approached when using water injection for NOx control).
- Provided for improved cross-flame tube connections.
- Permitted the inclined position for the combustors and transitions, thus, facilitating the center bearing removal by shortening the span length.
- Combustors and cross-flame tubes completely encased in relatively cool compressor discharge air, thereby eliminating a multitude of pressure connections and potential fire hazard.

In addition to the combustion system changes, the 5000 kW (W81) combustion turbine, introduced in 1952, contained the following basic mechanical design features that are illustrated in Fig. 3:

- Individually replaceable turbine and compressor rotor blading without removal of the rotor.
- Inner shrouded diaphragm construction for turbine and compressor stationary blading to permit servicing with rotor in place.
- Support of the exhaust bearing housing with 6 tangential struts that rotate the housing during thermal transients and maintain shaft alignment without the need of cooling.

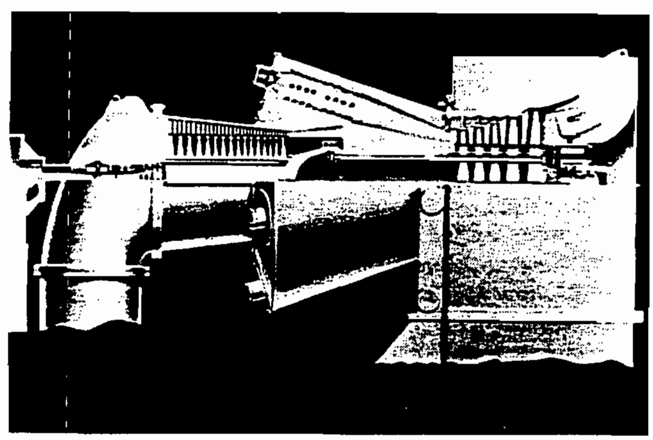


FIG. 3. CROSS SECTION OF W81 COMBUSTION TURBINE

The W81 16-stage compressor design was the result of extensive analytical and laboratory development. While the free-vortex design of the early compressor had the advantage of minimizing the effect of neglecting some terms in the Euler equations, the result was many stages at relatively low blade tip speeds. In addition, theoretical studies indicated that a design of 50% reaction with a flow coefficient of about 0.55 would give a stage of maximum efficiency. By setting up a pre-swirl entering the first rotating blade, the blade relative velocity could be significantly reduced and high reaction obtained. This would allow an increase in blade speed with the consequent reduction in the number of compressor stages required for a given pressure ratio. The vortex pattern selected was a compromise between little change in reaction radially and blade shock losses. This vortex pattern specified the mean stage absolute swirl constant and made the axial velocity relatively constant radially. A positive energy gradient was added from blade hub to tip in the first few stages, the energy addition was kept constant in the middle stages, and the gradient removed in the last stages.

Other design techniques used were to specify flow area blockage factors and to use NACA 65 blade sections on a circular arc mean line for the higher Mach number front stages and NACA (4-digit) sections elsewhere. The resulting design was successful except that the starting surge margin was inadequate; therefore, an interstage bleed was added. The average stage efficiency was about 89%.

The aerodynamic design of the 5-stage turbine was taken mainly from Westinghouse aircraft engine design practice using a free-vortex swirl distribution and constant work radially with a last stage designed for axial velocity outflow. A minimum reaction was maintained at the blade hub sections to prevent suction side separation. All blade sections were designed to provide smooth accelerating flow passages. The average stage efficiency was about 90% and the matching of the compressor and turbine flow characteristics was excellent. The engine produced 5700 kW at the generator terminals at a firing temperature of 1350°F (732°C) and a thermal efficiency of about 21%. The prototype engine, sold to West Texas Utilities, went in commercial service in 1952. This unit was the first utility application of a Westinghouse gas turbine.

Marketing studies indicated there were many differing applications for gas turbines from power generation, transportation, to mechanical drives. Engineering cycle studies were made to determine the best cycle arrangements for the various applications. A summary of those studies at a 1400°F (760°C) firing temperature is shown by Fig. 4. Component efficiencies, pressure losses, and heat exchanger effectiveness for these studies were state-of-the-art.

With the successful completion of the 5000 kW design, a line of mechanical drive engines using the same basic blading as the 5000 kW engine was designed. For pipeline pumping, a unit was designed with regeneration and a free power turbine (Stephens and Bruce, 1955). The regenerative engine produced about 5400 hp at the turbine coupling with an efficiency of approximately 30%. The cycle pressure ratio was 4.2, the compressor speed was 6000 rpm, and the firing temperature was 1350°F (732°C). The regenerative units did not perform in the field as expected, primarily because leakage and pressure loss were greater than expected. This same unit was also modified to be used without regeneration.

To make the engines more competitive with steam plants and other prime movers, it was necessary to use a more efficient cycle. As shown in Fig. 4, a gain of about 12% could be obtained by adding intercooling to the regenerative cycle resulting in 34% efficiency which made it competitive with small steam plants. A 15,000 kW engine was designed as a two shaft, intercooled, and regenerative engine with the load taken from the high pressure shaft. By taking the load from the 3600 rpm high pressure shaft, the low pressure (LP) shaft was made variable speed resulting in little drop off in turbine inlet temperature at part load and, therefore, excellent part load efficiency.

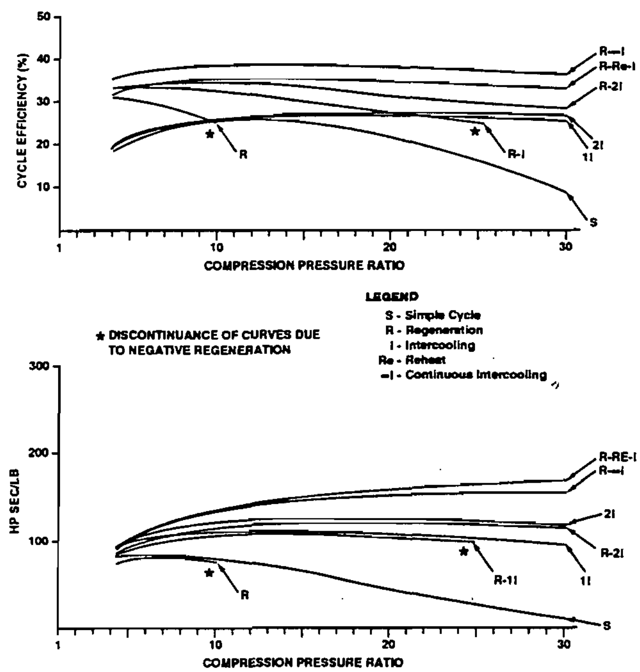


FIG. 4. SUMMARY OF ENGINEERING CYCLE STUDIES AT 1400°F

In 1954, prior to the cancellation of the 15,000 kW project, work was begun on a single shaft simple cycle 3600 rpm gas turbine. This engine was later to become the W201 gas turbine, the first direct drive (no gear) Westinghouse combustion turbine. In the W201, the aerodynamic design of the successful 5000 kW engine compressor was modified slightly by eliminating the energy gradient so that stages could be more easily added or removed from the basic design. In addition, lightly loaded stages for high efficiency were adopted for these engines. Design techniques were also improved by refining empirical factors. As high temperature materials advanced, the allowable turbine inlet temperature was increased, thus improving output and efficiency. By the end of the 1950s, firing temperatures had risen to 1450°F (788°C) at base load. Also, the W31 and the W121 at 3000 hp and 12,000 hp, respectively, both single shaft engines, were designed following the same philosophy developed in the W201.

In the middle 1950s, Westinghouse designed a blast furnace blower to supply 125,000 ft3/min (3540 m3/min) of air at about 2 1/2 atmospheres gauge pressure, and burning blast furnace gas at about 100 Btu/scf (3700 kJ/scm). The blower was a modification of the W201 in which the blast furnace air was extracted from the compressor discharge and the fuel gas supplied to the engine through a shaft driven fuel compressor. The fuel compressor was a modified compressor from the W31 engine. The engine and it's performance are shown in Figs. 5 and 6, respectively. Turbine blading, turbine discs, compressor discs, and recuperator were taken from the 15,000 kW unit. This was a very successful design from an engineering point of view, but the market disappeared when oxygen blown furnaces displaced the old air blown ones.

In the late 1950s, production for the direct drive W201 was initiated. The W201 was the forerunner of the W301 and the W501 line. Also, the W121 was improved to the W171 by eliminating the excess quote margin and increasing firing temperature to 1450F (788°C). In the early 1960s, a zero stage was added to the 14-stage

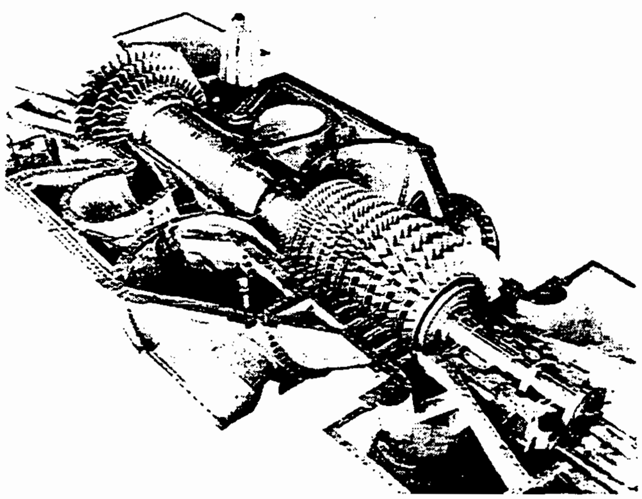


FIG. 5. BLAST FURNACE ENGINE

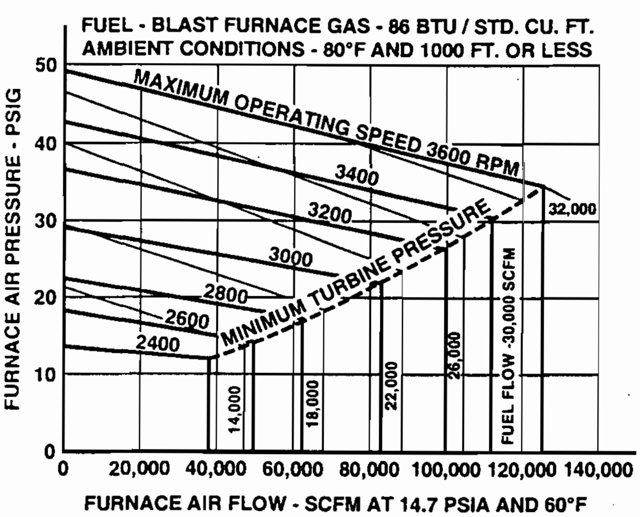


FIG. 6. PERFORMANCE OF BLAST FURNACE ENGINE

W171 compressor to create the W191 and the firing temperature of the W31 was increased to 1450F (788°C) to create the W41.

President Eisenhower's Administration started the "Atoms for Peace Program." An interesting outgrowth of this program was the "Marine Gas Cooled Reactors Program" (designated MGCR) that was expected to power a nuclear powered commercial ship. The power plant was to be a helium cooled reactor as the heat source, coupled with a closed cycled gas turbine. Westinghouse was selected to provide the turbomachinery for the power plant and the design proceeded to development testing and engine design. However, when the reactor development lagged, the program was canceled. The turbomachinery presented no severe aerodynamic problems and was actually much easier to design than air breathing machinery due to the fact that helium is a light monatomic gas and the speed of sound through it is very high. The engine was rated at 20,000 hp, at an expected efficiency of 31%.

Combined gas and steam plants had been developed as early as the locomotive engine, but the 1960s saw the development of the combined cycle. The combined cycle is an ideal thermodynamic solution to the thermal efficiency problem as it combines the best attributes of the Joule-Brayton cycle with that of the Rankine cycle; namely, the addition of heat energy at the high temperature of the gas turbine and the rejection of heat at the low temperature of the steam turbine. In 1967, a Westinghouse supercharged combustion turbine (W301), rated at 25 MW with a firing temperature of 1450F (788°C), was placed in operation at West Texas Utilities San Angelo's Power Station. Hot turbine exhaust gases were used in a heavy fuel, reheat boiler (1500 psi, 1000°F [10.3 MPa, 537°C]) which furnished steam to drive a 85 MW turbine (Cox, Henson, Johnson, 1967). The plant achieved an annual average efficiency of over 39%, the highest in the U.S. for a number of years. In 1990, this plant with over twenty-three years of successful operating experience, continued to demonstrate that good combined cycle efficiency over a broad load range can be obtained with a combustion turbine combined with a heavy fuel, reheat boiler (Stephens et al., 1990).

An interesting feature of this plant was that the forced draft fan of the steam power plant was used to supercharge the gas turbine. Not only did this feature increase the plant capability and efficiency, but the fan was used as a starting device to start the gas turbine by windmilling the compressor up to self-sustaining speed. In addition, the fan could supply the steam boiler while the gas turbine was out of service.

Third Generation

In November 1965, the "Northeast Blackout" ushered in the "Gas Turbine Age" as gas turbine manufacturers were swamped with peaking power plant orders. Development of gas turbines accelerated as technical staffs expanded. Blade and vane cooling, pioneered by the aircraft engine industry, became available to the industrial engine builders. In response to a need for larger, more efficient engines, Westinghouse developed the W251 and the W501 engines.

The 20 MW W251A, introduced in 1967, was a single shaft, two bearing, combustion turbine with reduction gear to accommodate either 60 Hz or 50 Hz for simple or combined cycle applications. Many basic design features proven reliable over many years were retained along with the two bearing, single shaft concept. Most noteworthy of these are the CURVIC coupled turbine discs, tangential exhaust bearing struts, blades and stationary vanes which are field removable with the rotor in place, and a compressor end drive. The evolution of the W251 is shown in Table 2.

The compressor of the W251A was taken from the W191, a rear stage added to allow an increase in engine pressure ratio, and a new 3-stage turbine designed with higher blade speeds to replace the old 5-stage turbine. The first stage turbine vane was cooled with compressor discharge air. The base load RIT was increased to 1575°F (857°C) from 1450°F (788°C) increasing the output power by 16% at constant heat rate. The first engine was placed in commercial peaking service at Detroit Edison in 1967. The W251A introduced the following improvements for the first time in a Westinghouse design:

- New 5-serration, minimum peak stress root design with root extensions to eliminate 3-D stress concentration.
- Precision cast turbine vane segments of cobalt-base material (X45) to eliminate structural weld concerns with the nickel-base welded diaphragm assemblies.
- Single turbine blade ring concept with roll out feature to provide service of turbine stationary parts with the rotor in place.
- Extensive use of turbine cooling including the row 1 vane segment, all three rows of turbine discs, and blade rings together with associated stationary flow path parts.
- Segmented ring segments over the rotor blade tips to allow free thermal expansion.
- Interstage seal housing supported from the vane segments on radially oriented keys to allow independent thermal growth of the seal housing to minimize running seal clearances.
- Use of cooled and filtered compressor discharge air for rotor cooling.
- Use of NiCrMoV turbine disc material.
- Compressor bleed extractions for selected cooling of turbine vanes and disc cavities to provide the lowest cost air for duty required.

The W251AA used the W251A compressor with an added front and aft stage to increase the airflow and pressure ratio while using the same turbine except improved row 1 vane cooling to permit a modest increase in RIT to 1640°F (893°C).

The W501 genealogy begins with the 30 MW W301 which began commercial operation in 1960. Unlike previous smaller, higher speed engines, the W301, like the W201, was directly connected to the generator without a gear.

Table 3 traces the development of the 501 family from the W501A to the current fifth generation 501F model. The W501A was designed to meet a 42 MW need of the Dow Chemical Company by utilizing

TABLE 2. W251 EVOLUTION

Engine	W191	W251A	W251AA	W251B	W251B2	W251B8	W251B10	W251B12
First Startup Date	1961	1967	1969	1971	1973	1978	1983	1990
Power, MW Class	18	20	26	31	34	36	40	48
Rotor Inlet Temp.,F	1450	1575	1640	1806	1806	1911	1985	2100
Air Flow, lb/s	270	270	353	353	353	353	345	372
Pressure Ratio	7	8	10	10	11	11	14	15
No. Comp. Stages	15	16	18	18	18	18	19	19
No. Turb. Stages	5	3	3	3	3	3	3	3
No. Cooled Rows	0	1	1	3	3	3	4	4
Exhaust Temp., F	777	850	850	930	898	962	941	990
Heat Rate, Btu/kWh; (ISO Gas)								
Simple Cycle	13,430	13,775	13,130	12,540	12,265	11,980	10,980	10,600
Combined Cycle	9,600	9,840	9,040	8,600	8,400	7,900	7,400	7,100

the proven, high performance, 15-stage W301 compressor, with an added front and aft stage to increase the air flow and pressure ratio, and a newly designed four-stage turbine to replace the old five-stage turbine. Dow required a cold end drive because their system design was a single train of combustion turbine, steam turbine, and generator with the steam turbine providing combustion turbine starting. Also, the hot end drive was undesirable because a flexible coupling was required. They also preferred two bearings which provided an excellent match with Westinghouse turbine design philosophy. In addition, the W501A introduced the following improvements:

- Variable inlet guide vane to provide exhaust temperature control on heat recovery applications and to improve starting characteristics.
- Individual blade rings with a roll-out feature to provide independent field service of each stator and seal system with rotor in place.
- Unique cooled, filtered rotor cooling concept utilizing "air separator" rotor component to confine rotor cooling air.
- Unique fore and aft blade seal plates to prevent cooling air leakage and service of blades with rotor in place.
- Four-pad, tilting pad bearings to eliminate any possibility of bearing instability from "oil whip" phenomenon.
- Compressor rotor utilizing a hollow shaft with shrunk on discs to reduce stresses and improve rotor dynamics.

The 60 MW W501AA in 1971 used a newly designed, higher flow, higher pressure ratio compressor with the W501A turbine at essentially the same RIT. Another major design change was a reduction in combustor shell diameter in order to facilitate shipping the engine fully assembled, a feature which has been retained on subsequent models. The combustor was set parallel to engine axis, resulting in an s-shaped transition duct. A secondary benefit of this system was a reduction in pattern factor or peak temperature due to increased mixing.

A significant improvement in engine performance was due to the new axial exhaust system. The axial exhaust system allowed waste heat recovery systems to be located directly downstream of the turbine exhaust, avoided high duct losses, and accommodated a longer and more efficient turbine diffuser.

Many engineering studies were made to determine the optimum cycle to minimize the cost of electricity. Some of the more promising ones (intercooled, multiple shafts, reheat, steam injected, water injected at various locations) were studied in great detail. In the final analysis, the simple cycle gas turbine combined with a steam bottoming cycle was the most widely accepted in the market. The missing link was higher firing temperatures. Fig. 7 is a summary of some of those studies. (The question of more efficient cycles is currently being re-visited in the advanced turbine systems program discussed later in the paper.)

As shown by Fig. 7, the combined cycle is superior to the regenerated cycle by a significant amount. The pressure ratio of the gas turbine that yields maximum specific power (power output per

TABLE 3. W501 EVOLUTION

Engine	W501A	W501AA	W501B	W501D	W501D5	W501D5	501F
First Startup Date	1968	1971	1973	1975	1981	1995	1993
Power, MW Class	42	60	80	95	107	118	160
Rotor Inlet Temp.,F	1615	1630	1819	2005	2070	2150	2300
Air Flow, lb/s	548	744	746	781	781	830	960
Pressure Ratio	7.5	10.5	11.2	12.6	14	14.8	14.6
No. Comp. Stages	17	17	17	19	19	19	16
No. Turb. Stages	4	4	4	4	4	4	4
No. Cooled Rows	1	1	3	4	4	5	6
Exhaust Temp., F	885	798	907	982	987	1006	1083
Heat Rate, Btu/kWh; (ISO Gas)							
Simple Cycle	12,600	11,600	11,180	10,925	10,270	10,040	9,590
Combined Cycle	9,000	7,990	7,350	7,025	6,950	6,900	6,600

pound of air flow) also gives optimum combined cycle efficiency. This is a most interesting conclusion and shows that for simple cycle gas turbine engine applications, a high pressure ratio engine is the economic choice, such as for aircraft propulsion. For the same firing temperature levels, the lower pressure ratio gas turbine engine is superior for combined cycle applications. Since the 1970s Westinghouse engines have been designed to be optimum for combined cycle applications and these engines are also excellent for peaking applications, where first cost dominates, since they yield the maximum power for a given amount of hardware. The figure also indicates the dominant role of turbine inlet temperature on both power output and combined cycle efficiency.

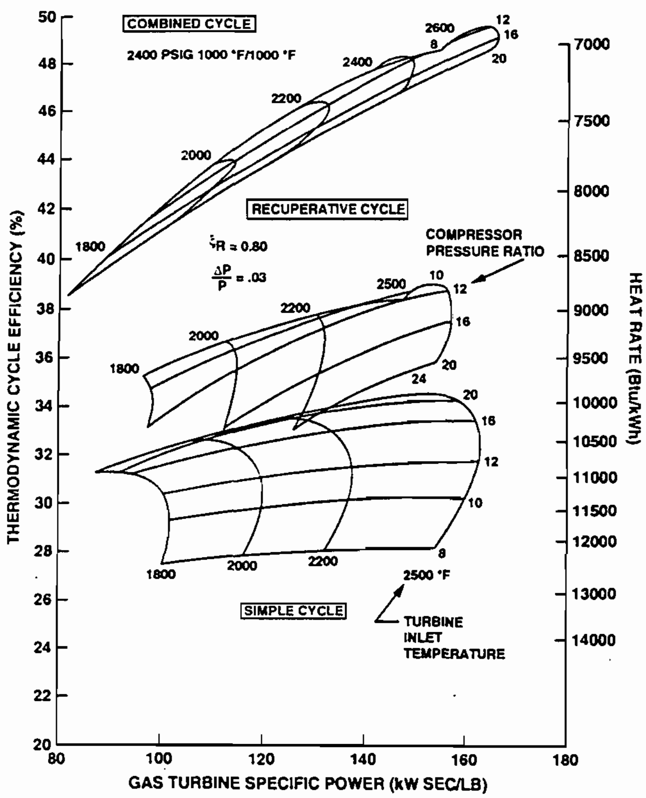


FIG. 7. SUMMARY OF COMBINED CYCLE STUDIES

Fourth Generation

In this era, the W251B used the same compressor as the W251AA, but with RIT increased to 1806°F (986°C). In addition to further improvement in row 1 vane cooling, the row 1 blade and row 2 vane segment were cooled for the first time in a Westinghouse design. At this point material changes were made such as the row 1 blade made as a casting for the first time with cooling passages integrally cast.

The W251B2 represented additional design improvements in the turbine that produced increased performance, while using the same W251AA compressor with no increase in RIT. The continuation of growth represented in this model consisted of adding a single vane with further improvements in cooling, restaggering of the turbine blade path for an increase in pressure ratio, improvements in cooling flow management and an improvement in row 2 vane cooling. The single vane was designed to permit service without removing the casing cover, an industry first.

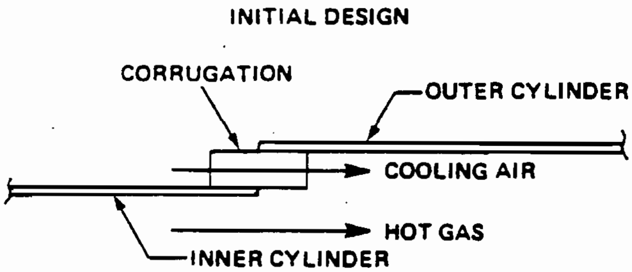
The W251B8 used the W251AA compressor with performance improvement from an increase in RIT to 1911°F (1044°C) brought about by a redesigned combustion system for improved temperature profile into the turbine, and additional improvements in row 1 vane cooling. Also, the compressor used coated diaphragms for improved performance as well as to retard degradation from ingested contaminants, and rows 1 and 2 turbine vanes and blades were coated for corrosion protection.

The 80 MW W501B, in 1973, was a planned growth step of the W501 model with the principal change being an increase in RIT to 1819°F (993°C). In addition to increased row 1 vane cooling, cooling was added to the row 1 blade and row 2 vane and material was changed, as required, on other rows to compensate for higher gas temperatures. Provision was added for removal of combustors and transition pieces without a cover lift.

The 95 MW W501D was a continuation of the planned growth program for the W501 frame. A further increase in RIT to 2005°F (1096°C) was made possible by advances in turbine cooling technology. Two stages were added to the aft end of the W501B compressor for higher pressure ratio in order to optimize efficiency in combined cycle operations. Cooling was added to the row 2 turbine blade along with increased cooling in upstream stages and material changes as required.

The W501D5 achieved additional performance gains from improvements in component efficiencies, conservation of cooling air energy, and a modest increase in RIT. Compressor performance was improved by increasing the number of diaphragm seal points from two to four, by use of coated diaphragms with improved surface finish, and by restaggering airfoils to improve work distribution. Turbine performance was improved by reducing exit velocity and swirl, by reducing incidence losses, and by better stage work distribution. Stator cooling air was extracted from three compressor bleed points in order to use air at the lowest suitable pressure available. Improvement in detail design reduced internal cooling flow leakage by 12% compared to the earlier W501D. In addition, cooling of the first two vanes and blades. was improved. Other features provided improved reliability and availability by virtue of improvement in parts' life and easier maintenance and inspection such as a single row 1 vane. In the compressor, the aerofoil-shroud joint was redesigned for increased strength in key diaphragm stages. The combustor cooling technique using the standard "wiggle strip" corrugation was improved by the extended lip, as shown in Fig. 8. This extension improved the tenacity of the convective heat transfer coefficient and reduced downstream temperatures by 200°F (111°C) (Scalzo et al., 1983).

The last engine models of this generation were the W251B 9/10 and the W501D5. Both engines used the same basic compressor, the W251 compressor being a 2/3 scale of the W501. In combined cycle applications the engine's potential efficiency approaches 50%. The power capability of these engines are more than 2 1/2 times their



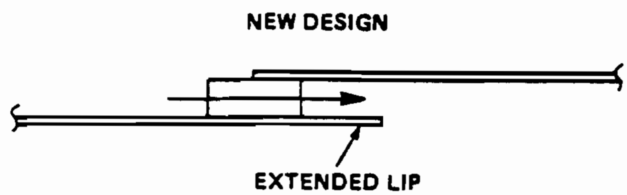


FIG. 8. EXTENDED LIP IMPROVED COMBUSTOR COOLING

third generation antecedents and the efficiency was increased by about 1/3.

The last model engines of this generation utilized streamline curvature calculation methods to solve the Euler equations, with energy loss models developed from a very large experimental data base. The result was compressors with average stage efficiencies approaching 93% and cooled turbines with excellent characteristics.

The power rating of a gas turbine engine is limited by the amount of flow that can be passed by the last stage blade row of the turbine component. Stress capability of the last row turbine blade material at operating temperature and aeroelastic blade limits determines the flow area of the last stage, while leaving axial velocity and density of the exhaust gases, in addition to flow area, determines engine flow. The next generation of engines, the F series and beyond, will be flow limited designs.

Fifth Generation

The fifth generation of Westinghouse gas turbine engines brings us to the present. These engines are designed with the aid of complete 3-D computer codes some of which solve the Navier-Stokes equations. The 501F at 160 MW and 2300°F (1260°C) firing level approaches 55% thermal efficiency in combined cycle applications.

The 501F, shown in Fig. 9, is a 3600 rpm heavy-duty combustion turbine designed to serve the 60-Hz power generation needs for utility and industrial service in the 1990s. It was jointly developed by Westinghouse and Mitsubishi Heavy Industries, Ltd. (Scalzo et al., 1989). Designed for both simple and combined cycle applications, it will operate on all conventional combustion turbine fuels as well as with coal-derived low-Btu gas produced in an integrated gasification combined cycle (IGCC) power plant.

The 501F rotor is of bolted construction supported by two, two-element tilting-pad bearings for load carrying and an upper half fixed bearing. This provides inherent stability of the tilting pad with the

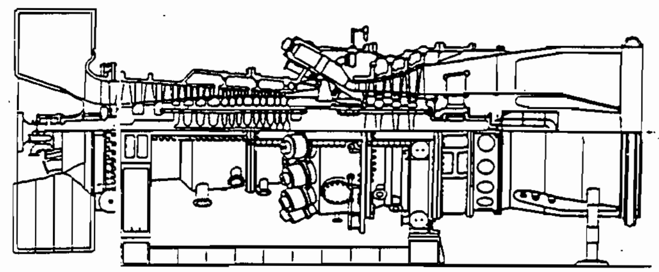


FIG. 9. GENERAL CONFIGURATION OF 501F COMBUSTION TURBINE

reliability of the plain bearing, thus eliminating the top pad fluttering problem that has led to local babbitt fatigue distress. The thrust bearing is a double-acting Kingsbury thrust bearing that uses leading edge groove (LEG) lubrication system.

The compressor rotor is comprised of a number of elements, spigotted and bolted together by 12 through bolts. The turbine rotor section is made up of disks bolted together by 12 through bolts and using CURVIC clutches. This turbine rotor design has amassed over 40 million hours of reliable service in all sizes of combustion turbines. The compressor is a 16-stage axial flow design of 14 pressure ratio that is based on the highly successful W501D5 compressor. A four-stage turbine was selected to maintain moderate aerodynamic loadings even at the increased firing temperature.

Blade rings have been added in the compressor for stages 7 through 16. Similar to those used in the turbine, they have a high thermal response independent of the outer casing, can be aligned concentric to the rotor to prevent blade rubs and minimize clearance, and therefore maximize performance as well as enhance maintainability of stationary parts.

Flow and pressure coefficients of the 501F compressor have been kept similar to the D5 compressor by increasing the mean diameter of the stages to accommodate the 20% increase in flow. In addition, the rear stages of the new compressor have larger diameters to help balance spindle thrust. Interstage bleeds are used for starting and for supplying cooling air to the turbine stationary blading and interstage cooling system. Rotor blades are double circular arc designs in the first four stages. The stators and all other rotor blades are conventional W65 airfoil sections.

The design of the 501F turbine has maintained moderate aerodynamic loadings in spite of the increased inlet temperature by choosing a four-stage turbine with higher peripheral speed compared to the W501D5. The 1st and 2nd stage blades are the free-standing type, while the 3rd and 4th stages utilize integral "Z" tip shrouds. The use of a shrouded system is a departure from past design practice on the 501 series, but has been in use on the W352.

The 1st turbine stationary row consists of precision-cast, single-vane segments. There are precision-cast, two-vane segments in the second turbine station row while the 3rd and 4th turbine stationary rows are precision-cast vane segments three-vane and four-vane segments, respectively.

Cooling circuits for the turbine section, displayed in Fig. 10, are similar to those used on the W501D5. Rotor cooling air is provided by compressor discharge air extracted from the combustor shell. This air is externally cooled and filtered before returning to the torque

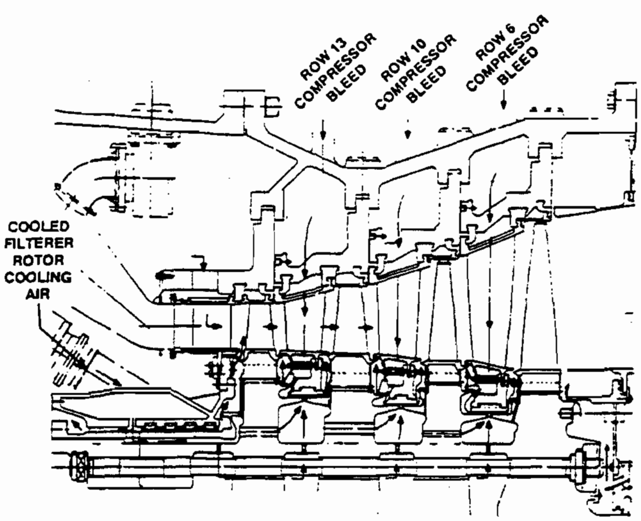


FIG. 10. COOLING CIRCUITS FOR THE 501F COMBUSTION TURBINE

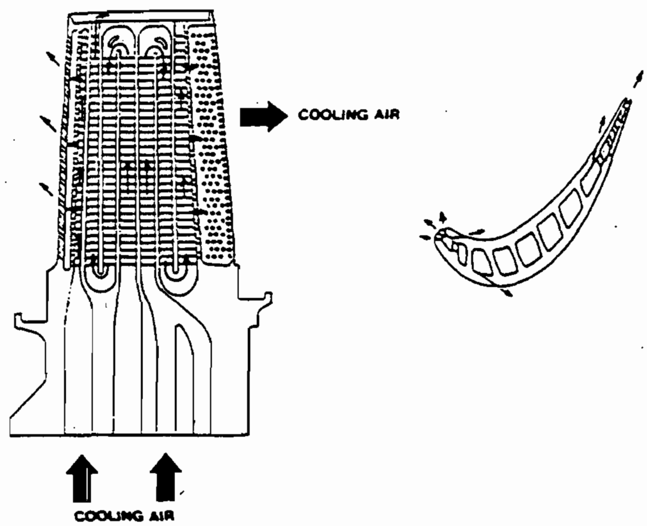


FIG. 12. COOLING CIRCUITRY OF 1ST STAGE BLADE USED IN 501F

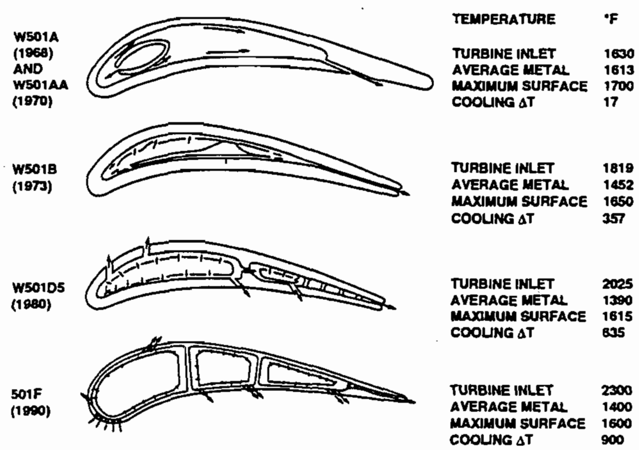


FIG. 11. EVOLUTION OF COOLING TECHNOLOGY

tube casing for seal air supply and for cooling of the turbine disks as well as the first, second, and third-stage turbine rotor blades. The row 1 vane cooling design is shown in Fig. 11. This highly effective configuration, which evolved directly from the W501D5 design utilizes state-of-the-art concepts with three impingements inserts in combination with an array of film cooling exits and a trailing edge pin fin system. The first stage blade is cooled by a combination of film cooling and convection techniques via multipass, turbulated, serpentine passages, with pin fin cooling in the trailing edge exit slots. The cooling circuitry is shown in Fig. 12.

The fifth generation also produced improvements in the W251B10 and the W501D5 models. Introduced in 1990, the W251B12 improvements included modest increases in airflow, pressure ratio, and firing temperature. To accommodate these changes, double circular arc compressor blade profiles were used for the first two blade rows, compressor stages were restaggered, and cooling was improved for the first turbine vane and first rotor blade. Current rating is 48 MW at a simple cycle efficiency of 32% (Diakunchak, 1989). The improved W501D5, to be introduced in 1995, also will include modest increases in airflow, pressure ratio, and firing temperature. Compressor changes were scaled from the W251B12 and cooling was improved for the first three vanes and the first two rotor blades. In addition, the increase in airflow required that the row 4 blade be changed to a "Z" tip shroud similar to the 501F design. Rating of the improved W501D5 will be 118 MW at a simple cycle efficiency of 34%.

COOLING EVOLUTION

The evolution of the W501 and the W251 was highly dependent upon improvements in cooling technology as shown in Fig. 13. Without cooling, the maximum RIT would be under 1800F (982C). Fig. 11 depicts this evolution for row 1 vane, from the early W501A in 1968 to the latest highly sophisticated cooled design used in the current 501F. Similarly, rotor blade cooling has evolved from spanwise holes of the 501B to a sophisticated multi-pass, turbulated, pin-fin, film cooled design of the 501F. These advances in cooling technology were beyond the published state-of-the-art, hence, a comprehensive development program was required to verify the latest blade and vane cooling designs and to provide a broad base for future designs.

For example, parametric design information on various vane internal cooling features was generated in atmospheric pressure rigs, with the geometry scaled up to effect Reynolds number simulation. (Scalzo, Holden and Howard, 1981). Tests were run over a wide range of test parameters using basic test rigs such as the leading edge rig shown in Fig. 14. The insert nose in the leading edge heat transfer rig can be replaced so as to vary target distance, radius, and hole array. Actual leading edge cooling geometries have been tested as well as a range of geometries for the generation of parametric design information. In addition to atmospheric model tests, design verification tests were run on production vane segments at full operating temperature and

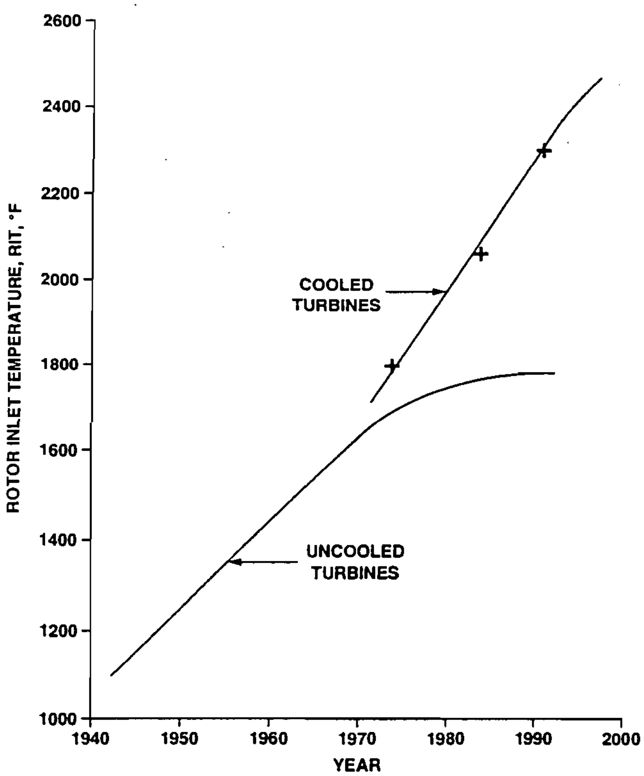


FIG. 13. FIRING TEMPERATURE TREND

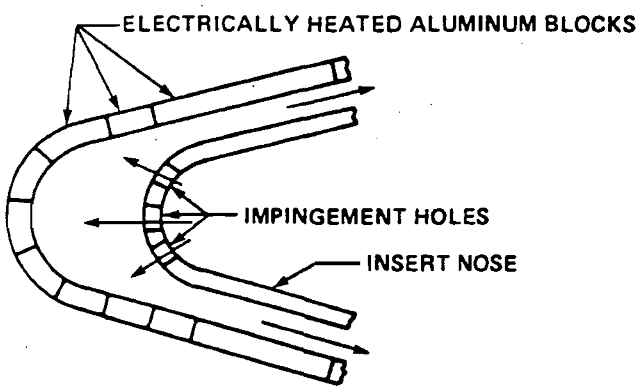


FIG. 14. INSERT NOSE IN THE LEADING EDGE HEAT TRANSFER RIG

pressure in a full-scale vane cooling rig.

Final verification of blade and vane temperatures were obtained from a fully instrumented full-load engine tests utilizing over 1400 pressure and temperature sensors. Comparisons were made to rig data to update the technology data base. Rotating blades and discs were monitored via telemetry (Scalzo, Allen and Antos, 1986; Gabriel and Donato, 1986).

MATERIAL EVOLUTION

In the early years (1950s to 1960s) materials were selected from available in-house steam turbine and jet engine experiences. However, since aero engines enjoy a pristine environment, many of these materials were not the best choice for the more corrosive fuels and operating environments of the land based gas turbine. Also, inspection intervals for aero components are more frequent as dictated by governmental regulations, while intervals in combustion turbines are being driven up to 24,000 hours by commercial considerations. For these and other reasons, material selection criteria, problems encountered, and developed solutions, would fill several volumes and are beyond the scope of this paper; however, a few pertinent comments will be made.

Compressor Area

Steam turbine and aero engine experience at the time of the initiation of the Westinghouse combustion turbine (1948 with the W21) dictated using a 12% chrome material for rotating and stationary blading because of its high strength, good corrosion resistance, and superior damping characteristics. This rationale is still valid today with standard strength 12% chrome material the choice for all compressor rotating blades and diaphragms with the exception of first two rotating blades in the 501F which use 17-4 PH, a 17% precipitation hardened stainless steel. Sermetel 5380DP[4] coating is currently used in the compressor to retard corrosion. To inhibit fretting, CuNiIn coating is used on blade roots. Compressor rotor materials have essentially retained the low-alloy steel materials based on steam turbine experience.

Combustor Area

The 25-20 series and 18-8 series stainless steel materials were used in early engines, however, Hastelloy X[5], a high temperature nickel-base alloy, became the standard for combustor baskets and transition ducts in the late 1960s. This material has been highly successful when kept below 1550°F (843°C) metal temperatures. For turbines with the increased firing temperatures used in the 1980s and later, the transition duct material was changed to IN617[6]; however, the standard combustor basket material is still Hastelloy X. IN617 provided a more stable higher strength material that required no pre or post heat treatment as was required by some sheet alloy candidates.

Turbine Stationary

Early designs utilized welded structures in AISI 310, a 25-20 austenitic stainless steel that had excellent resistance both to corrosion and to oxidation at elevated temperatures, but had limited strength capabilities.

A change to the higher strength, nickel-base, IN713 used successfully by aero engines, met with unsatisfactory results because

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[4] Sermetech International Incorporated
[5] Hayes International
[6] International Nickel Company

of a lack of oxidation/corrosion resistance. A change to another precision cast nickel-base alloy, U500[7], resolved the corrosion concern, but the integrity of the welded structure was limited.

In 1967, Westinghouse introduced precision cast, colbalt-base, X45 turbine vane segments. This material was a modification of Haynes *Stellite* 31 used for years in aero engine turbine blades. It was the standard for precision cast turbine vane segments up to 1975, when the W501D was introduced with Westinghouse's ECY768 material in row 1. ECY768, is a cobalt-base alloy with higher creep strength and oxidation/corrosion resistance than standard X45 material. This improved cobalt-base alloy has become the standard for all row 1 vane segments and some selected row 2 and row 3 vane segments. Beginning in about 1975, diffusion and overlay coatings have been used selectively to enhance oxidation/corrosion resistance, as dictated by application.

Turbine Rotating

Various forged nickel-base alloys, and even 12% chrome materials, were used for early combustion turbine blades. Today nickel-base alloy Inconel X-750 remains the choice for many last row blades. Increases in firing temperatures necessitated changing to the higher strength Udimet nickel-base alloys in the mid 1970s. U520 forgings and cast U500 become the standard materials for front turbine stages. (All turbine blades are free-standing except for rows 3 and 4 of the 501F and row 4 of the improved W501D5.)

The 1980s and 1990s saw a move from forgings to higher strength cast IN738 material for front end blading because the complex cooling configurations could not be produced in machined, forged blades. As with the turbine stationary, diffusion and overlay coatings have been used for rotor blades. Future advanced engines will see a move to directionally solidified (DS) and to single crystal (SC) blading together with advanced coatings.

Turbine Discs

Early combustion turbine discs used a variety of materials including AISI 422, 19-9, and Discalloy 24 (Westinghouse-developed, austenitic alloy similar to A286). Selected cooling of the disc rims was required to prevent creep and notch sensitivity type concerns. To avoid these concerns, Westinghouse developed, in the mid 1960s, a unique cooling system for turbine rotors. High temperature, high pressure compressor discharge air is taken outside the engine where it is cooled and filtered before returning to the turbine rotor. This cooled, filtered air provides the rotor with a blanket of protection from hot blade path gases and supplies filtered cooling air to all disc rims as well as cooled airfoils. Filtration eliminates excessive contaminants that could block critical, intricate cooling passages of today's advanced combustion turbines. A reliable steam turbine material, NiCrMoV, was selected because of its high strength and outstanding fracture toughness. When cooled below 750°F (400°C), this material has infinite life because it is below the creep and aging thresholds. Also, its outstanding fracture toughness accommodated standard ultrasonic qualification and, therefore, did not require overspeed spin pits to qualify the forging as is the case for some materials. Since the mid 1960s, NiCrMoV discs integrated into the Westinghouse filtered, cooled air cooling system have generated over 20 million hours of problem free operation.

MECHANICAL EVOLUTION

The evolutionary Westinghouse design philosophy has resulted in operational reliabilities of over 99% and unit availabilities of over 95%. Many of the basic design features have stood the test of over four decades of design evolution. These design innovations were identified in previous sections of the paper; for example, cooled, filtered turbine cooling air with NiCrMoV turbine discs. However, several will be expanded in this section; i.e., single row 1 vane, integral compressor vanes, and minimum peak stress turbine blade roots.

Single Row 1 Vanes

In the early 1970s, the row 1 vane segment of the W251B2 was introduced as a single vane that could be serviced along with baskets and transitions through the combustor basket openings with the casing cover and enclosure roof in place. Other advantages of this design were structural thermal stress at 25 to 50% of a three-vane structure and improved casting quality. (Hultgren, 1981 and Scalzo et al., 1988). Entering a log/log plot displaying the low cycle fatigue (LCF) of a nickel base alloy or cobalt base alloy, LCF is increased by over a factor of 10 when stress is reduced 50%. In addition, a single vane facilitates higher quality castings compared to multi-vane castings. For advanced turbines, the inner shroud is supported from the inner casing to limit axial and circumferential displacements, thus, controlling flow angles.

Compressor Integral Vane

Selected diaphragm rows on current product models incorporate an integral airfoil/shroud design with four point seals on a removable seal carrier as shown in Fig. 15. Critical structural weld joints are eliminated by use of the integral structure. Also, the airfoil thickness/chord ratio is tapered to produce an optimized aero/mechan-

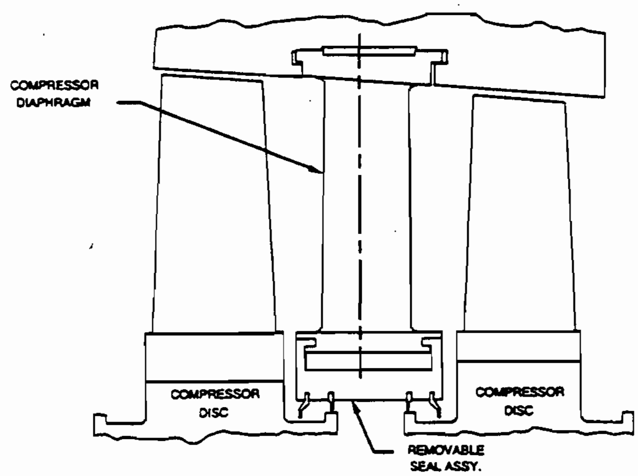

FIG. 15. INTEGRAL DIAPHRAGM DESIGN

[7] Special Metals Company

ical design; i.e., high at the tip required mechanically and acceptable aerodynamically, and low at the hub, required aerodynamically and acceptable mechanically. Endurance strength of the structure is equal to base-metal properties as shown in Fig. 16. This design also provides for service of compressor diaphragms with rotor in place, as in past designs.

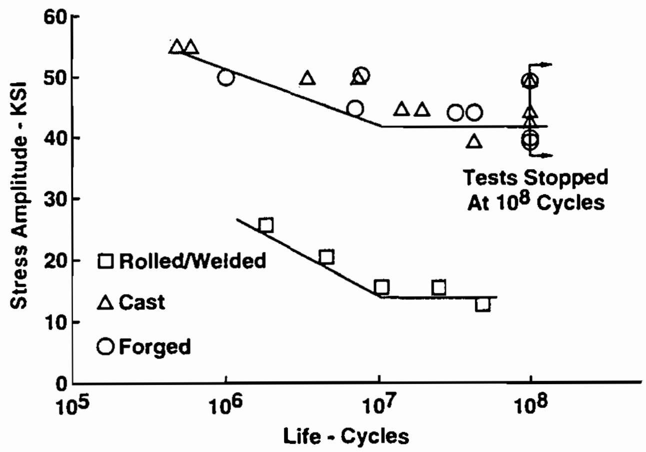

FIG. 16. ENDURANCE STRENGTH OF DIAPHRAGM DESIGNS

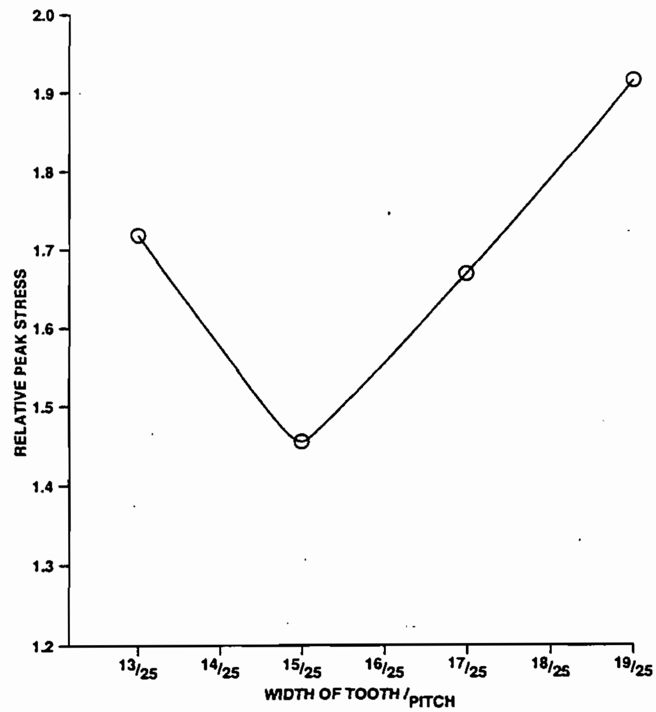

FIG. 17. STRESS VERSUS WIDTH OF TOOTH/PITCH

Turbine Blade Roots

In 1963, one of the top priority design goals was to develop an improved turbine blade root more suitable for higher firing temperatures and increased dynamic loadings expected in the third generation designs. Earlier designs were simply scaled from existing steam turbine and aero technology sources. There was also a desire to incorporate the new root design using NiCrMoV material as described in the preceeding materials section. Three basic objectives were identified; i.e., provide a thermal barrier, eliminate 3-D stress concentration, and minimize peak stresses. Using an extended root or extension isolates the root from flow path temperatures, thus providing a thermal conductive barrier. Also, it eliminates 3-D stress concentration resulting from the transfer of bending or dynamic moments from an airfoil shape to the root neck (Scalzo, 1992).

Minimizing peak stresses required the knowledge of 2-D stress distribution in irregular shapes. Since there were no finite element analysis programs available in the early 1960s, a general method for the determination of 2-D stress distribution in irregular shapes subjected to body and surface forces was developed using the finite difference method to represent the governing fourth order partial differential equation together with suitable boundary conditions. A mainframe computer was used to solve the multitude of equations using the over relaxation technique (Scalzo, 1963). Parametric analyses similar to Fig. 17, developed to determine the optimum tooth shape for minimum peak stress, resulted in Fig. 18. This was used to establish the root configuration for the W251A combustion turbine shipped in 1967, and has been used successfully for every Westinghouse combustion turbine since that time.

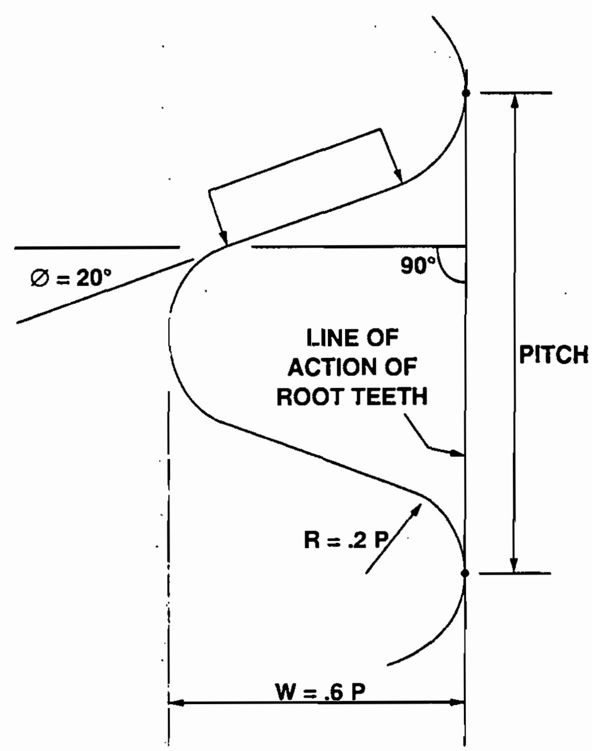

FIG. 18. ROOT TOOTH PROPORTIONS FOR MINIMUM PEAK STRESS UNDER DIRECT LOAD

COMBUSTION DESIGN EVOLUTION

Overall Geometry

In selecting the can-annular design, the W21 designers drew on the early experimental combustor can experience of the jet engine group even though the jets eventually selected an annular combustor. Sets of holes placed at the upstream end provided primary air sufficient for stoichiometric burning and another set of holes placed some distance downstream provided dilution air, bringing the stream temperature down to the required burner outlet temperature (BOT). (Note that BOT is the same value as the "firing temperature" used in the first and second generation.)

All engines have used can-annular combustors except for a silo type combustor installed in the blast furnace unit. The rationale that supports the can-annular design is still valid after 45 years. Advantages of this concept are:

- Shipped fully assembled with engine, thus reducing field cost.
- Facilitated full-scale laboratory testing.
- Can be developed to provide a preferential radial temperature profile, thus satisfying rotating blade requirements.
- Provides a lower "hot spot" by control of circumferential temperature gradients to improve turbine vane life.
- Generates a discrete harmonic content, thus minimizing blade vibratory design requirements.

Fuel Injection

The basic concept of fuel injection and ignition has been maintained from the W21 up to present engines, with the exception of the new advanced low NOx designs. Key elements are a pressure atomizing liquid fuel nozzle with a concentric atomizing air-assist used for starting. Gas fuel is injected via a concentric set of orifices. To prevent undesirable combustor noise, the orientation of fuel injection vectors must be compatible with the essential recirculation stabilization pattern required to anchor the flame front (Scalzo et. al., 1990). In models built after the mid 1970s, mechanical flow dividers were used to meter liquid fuel equally to each combustor. When required for emissions control, water is injected through the air atomizing ports of the liquid nozzle or pre-mixed, steam is injected either pre-mixed with gaseous fuel or via a separate set of orifices.

Ignition

The ignition scheme used on the earliest combustor designs was a spring loaded spark plug in each can which retracted as combustor pressure built-up to operating conditions; and cross-flame tubes provided ignition between cans. This belt and suspenders approach was used because, with the large distance between adjacent cans, cross-firing was not reliable. In later engines, with combustors being nested closer together (W251A model and later), cross firing was more effective and spark ignition was provided for only two cans (for redundancy) and cross-firing lit the others. In early designs the cross-firing occurred through tubes attached to each combustor at the combustor flame zone, with one tube fitting inside the other in a sliding fit. In more recent models this arrangement has been replaced by hard-connected flexible tubing. The retractable spark plug approach remained basically the same with improvements made to the spark plug, the retracting piston, and the electrical power to the plug.

In the earlier engines, flame-on indication was provided by thermocouples protruding into each transition section, which recorded BOT as well as other control input functions. When the BOT increased to that required for the W251AA engine and succeeding models, this arrangement had to be abandoned due to the impact of the higher temperature environment on sensor life. The flame-on detection is now by an optical sensor which views the combustor flame zone through a port. Other control supervisory functions are taken up by thermocouples placed in the blade path downstream of the last turbine blade row. These exhaust blade path thermocouples also monitor each combustor to protect rotating blades against harmful harmonies (Scalzo, 1992).

Special Fuels

Gas turbines have the capability to burn a wide variety of fuels. Combustor and fuel injector design modifications have been able to accommodate fuels which have included: natural gas, blast furnace gas, coal gas, distillate fuel, residual fuel, crude oil, methanol, propane, coal derived liquids, and shale oil (Pillsbury et al., 1974, 1978 and 1979; Seglem and DeCorso, 1980). Burning fuels which have potentially corrosive elements requires that fuel contaminant specifications be set (Wenglarz and Menguturk, 1981). The Westinghouse Research Laboratory was equipped with corrosion evaluation test rigs where actual fuels were burned making accurate determinations of fuel element corrosion levels on the combustor and other turbine hot parts. This work at the Research Laboratory was key to setting the ASTM D2880 and ASME B-133 fuel contaminant specifications now in use industry wide (DeCorso et al., 1971 and Hussey et al., 1973). Use of these various fuels in the future will now be subject to more stringent emission regulations.

Emissions

The first emission concerns to impact combustor designers began with exhaust visibility (smoke) in 1966. As a result, the W171 and W191 combustors were modified to produce a smokeless design (DeCorso, Hussey and Ambrose, 1967). In the early 1970s, EPA began to develop regulations which dealt with NOx emission levels. In local areas of California more stringent emission regulations were passed. In the Los Angeles Air Pollution Control District (LAAPCD) regulations (rule 67) called for particulate emissions of no more than 10 lb/hr (4.54 kg/hr) regardless of plant size, and a NOx regulation which required 32 ppmv from a W501 engine. Particulate levels were minimized by adhering to established fuel specifications (Carl, Obidinski and Jersey, 1975) and limiting sulfur content in the fuel, since the Los Angeles particulate measurement technique counted sulfur compounds. (Many current regulations require NOx to be 25ppmv or lower, regardless of engine size.)

Working in cooperation with the Westinghouse Research Laboratory, a theoretical understanding of NOx formation was gained and a NOx formation model was developed and verified by laboratory and field testing. This model proved to be invaluable in predicting the effect of combustor operating parameters on NOx formation. It was capable of giving NOx emission effects due to combustor operating parameters; and, it also accurately predicted the effect on NOx emission of various fuels, fuel bound nitrogen, water injection, and steam injection (Hung, 1974 and Vermes, 1974). With the NOx model as a guide, combustion laboratory test time was greatly reduced and valuable insight into potential low NOx approaches was provided.

In order to meet the 32 ppm NOx regulation for W501 turbines, water injection for NOx control was designed, tested and proven in the laboratory, and then in a full-scale field test (Ambrose and Obidinski, 1972), in what is believed to be the first application of water injection for NOx control.. Subsequent design and testing also confirmed the use of steam for NOx control, with steam being less effective, pound for pound, than water.

Dry Low NOx

Dry low NOx development schemes were explored in the three areas; i.e., premixed lean combustion, rich-lean combustion, and catalytic combustion. Small scale Research Laboratory tests had confirmed that very low NOx levels were attainable by premixing the air and fuel. Premixing means in this context that the air and fuel are mixed on a molecular level. A practical scheme to use premixing was devised and given the name of "hybrid combustor" because it utilized the dual approach of a premixed fuel/air stream and a pilot flame zone which burned in the diffusion flame mode. The term "hybrid combustor" is now commonly used in the industry to refer to this type of low NOx combustor. An example of an early design which was tested is shown in Fig. 19 (Mumford, Hung and Singh, 1977). This design was the basis for the lean, pre-mix combustor design used in the MW701D combustion turbine (Aoyama and Mandai, 1984). Advanced versions of this design are now operating in the 701F (50Hz scale of the 501F) engines in Japan with NOx emissions less than 25 ppmv. This design is currently being developed further to produce less than 15 ppmv by the late 1990s.

Another approach to NOx reduction utilized the rich-lean burn principle, which did not require premixing and was effective for cases where the fuel contained fuel bound nitrogen (FBN). The premixing or water/steam injection approach is defeated by the presence of significant amounts of FBN. In rich-lean burning, the burning is

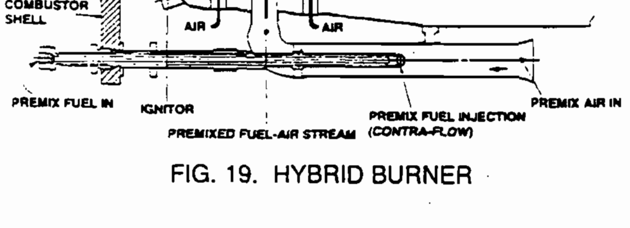

FIG. 19. HYBRID BURNER

staged to occur in a fuel-rich zone where the oxygen deficiency prevents NOx formation; in a second lean zone which follows the rich zone, burning of the products from the rich zone are completed at a temperature low enough to prevent NOx formation. The multi-annular swirl burner (MASB) was developed which had the capability of operating as a rich-lean burner, as well as in the lean burn mode. This combustor was successfully operated at the Waltz Mill, PA coal gas test site (Lew, DeCorso et al., 1981) and is now under development as a topping combustor for an advanced PFB cycle program (Garland and Pillsbury, 1992).

The prospects of ultra low NOx using catalytic combustion was first evaluated in 1971. Tests run at the Research Center confirmed that virtually zero emissions could be attained and that very uniform temperature patterns were possible (DeCorso, Mumford et al., 1977). A very active program included testing of catalytic combustors at full-scale conditions (Hung, Dickson and DeCorso, 1978; Scheihing et al., 1982). Although NOx was in single digits, the mechanical integrity of the substrate was very unsatisfactory. After the oil embargo sharply curtailed market activity, development effort in low emissions tapered off through the early 1980s; however, activity has surged again in the 1990s with advanced designed catalytic systems currently under review.

CLEAN COAL TECHNOLOGY

Combustor design and testing first took place in the mid 1970s under U.S. Government sponsorship for a projected coal gas plant for Public Service of Indiana. Full-scale test facilities were built in which combustors modified for coal gas use were tested with actual coal gas compositions encompassing air blow gasifier and oxygen blown gasifier gas (Pillsbury, 1974). This development supported the joint Westinghouse/Dow Chemical Co. program to burn medium Btu (239 Btu/scf [8890 kJ/scm]) coal gas; first, in a W191 trial engine; and, later in W501D5 turbines at the Dow Chemical Co. IGCC plant in Plaquemine, LA (Hendry and Pillsbury, 1987). These two 104 MW units are operating in a Dow Chemical developed oxygen-blown integrated gasification combined cycle (IGCC) that includes a cold gas cleanup system (Morrison and Pillsbury, 1989). To date, these combustion turbines have operated with average availabilities in excess of 95% (Geoffroy and Amos, 1991).

Most commercial size gasification projects have used high purity oxygen rather than air as the oxidant for the gasifiers. Recent IGCC evaluations have looked at using the combustion turbine air compressor to supply air for the air separation unit. Typically, this air stream is sent to a high pressure air separator unit which produces oxygen for gasification and high pressure nitrogen for combustion turbine NOx control. The diluent nitrogen lowers the flame temperature and, therefore, lowers the NOx.

Other concepts being developed at Westinghouse include incorporating combustion turbines in a coal-fueled combined cycle for second generation pressurized fluidized bed (PFB), and direct coal-fired (DCF) combined cycle configurations. IGCC, PFB and DCF concepts require a fuel gas cleanup system to remove particulates, sulfur, and alkali (Newby and Bannister, 1993). Low NOx levels are obtained through use of advanced combustion processes (Scalzo et al., 1991).

Pressurized Fluidized Bed

Under a DOE-sponsored program, Westinghouse is developing a MASB topping combustor which will be used in the second generation PFB topping combustor (Domeracki, Dowdy and Bachovchin, 1994). The entire combustion air quantity is introduced into the combustor through axial flow, concentric vane rows. The MASB utilizes vitiated air at 1600°F (871°C) for cooling. Thermal NOx levels of less than 10 ppm have been measured for a burner outlet temperature of 2300°F (1260°C).

In addition to the topping combustor, Westinghouse is developing and supplying integrated gas turbine systems that will interface with PFB plants and incorporate the functions of hot gas filtration, alkali vapor removal, hot gas piping and control, and turbine compression and expansion (Newby et al., 1994).

Direct Coal

In a direct coal-fueled concept, ash and sulfur are to be removed from the coal during the combustion process. Air from the combustion turbine driven compressor flows into the pressurized slagging combustor and into a topping combustor. About one-third of the air is directed to the slagging combustor for utilization in the substoichiometric combustion of the coal fuel. Two-thirds of the compressor discharge air goes directly to the topping combustor where the low Btu fuel gas is fired under lean-burn conditions. One advantage of this split is that the majority of the primary combustion process only has to handle one-third of the total air flow required by the combustion turbine. The slagging combustor operates at temperatures high enough to melt or vaporize the inert ash constituents in the coal. Westinghouse has worked with Textron Defense Systems under a DOE contract to demonstrate the feasibility of this concept (Bannister, Newby and Diehl, 1992). Test results confirmed 99% carbon conversion with NOx levels under 50 ppmw. The next step in the development of this process is to integrate various hardware components into an operating cycle in a pilot plant.

CURRENT AND FUTURE TRENDS

In cooperation with U.S. Department of Energy's Morgantown Energy Technology Center, a Westinghouse led team is working on the second part of an 8-year, Advanced Turbine Systems (ATS) Program to develop the technology required to provide a significant increase in natural gas-fired combined cycle power generation plant efficiency (Bannister et al., 1994).

Efficiencies for large natural-gas-fired combined-cycle systems for the utility market have been demonstrated at 54 to 55%. Even though manufacturers will make improvements in the 1990s, pursuing the historic trend, shown in Tables 2 and 3, efficiency levels will reach a plateau for simple and combined cycle plants. Cycle innovations, a 2600°F (1427°C) combustion turbine RIT, reduced cooling air usage, steam cooling, improved component efficiencies, together with improved material/coating systems can achieve combined cycle efficiencies in the 60% range for natural gas-fired utility machines.

ATS using natural gas is to be commercially available by the year 2000. Coal-derived fuel concepts are candidates for the post-2005 power-generation market. The final design will be fuel flexible in that it will operate on natural gas, but also be capable of being adapted to operate on coal, coal-derived, or biomass fuels.

SUMMARY AND CONCLUSION

The Westinghouse evolutionary combustion turbine design philosophy has always maintained reliability and maintainability as major considerations. Many basic design innovations have been retained after over four decades of evolution, thereby attesting to the soundness of their selection. Future advancements in firing temperature, materials, cooling, and cycles must also satisfy reliability/maintainability requirements.

Westinghouse has actively worked with industry and the government for over three decades in developing the use of coal as a clean fuel for power generation. The company is currently actively supporting clean coal technology programs in advanced IGCC, first generation PFB, and second generation PFB plants.

ACKNOWLEDGEMENTS

The authors acknowledge the hundreds of customers who through their never ending demand for better products have fostered many of the improvements presented in this paper. The authors are also indebted to hundreds of Westinghouse steam and combustion turbine engineers who have also contributed to the development of combustion turbine technology.

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..AB-This paper reviews the evolution of heavy-duty power generation and industrial combustion turbines in the United States from a Westinghouse Electric Corporation perspective. Westinghouse combustion turbine genealogy began in March of 1943 when the first wholly American designed and manufactured jet engine went on test in Philadelphia, and continues today in Orlando, Florida with the 160 Megawatts, 501F Advanced Combustion Turbine. In this paper, advances in thermodynamics, materials, cooling, and unit size will be described. Many basic design features such as two-bearing rotor, cold-end drive, can-annular internal combustors, CURVIC[2] clutched turbine discs, and tangential exhaust struts have endured successfully for over 40 years. Progress in turbine technology includes the clean coal technology and advanced turbine systems initiatives of the U.S. Department of Energy.

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NEW 200 MW CLASS 501G COMBUSTION TURBINE

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POWER GENERATION DEPARTMENT
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NEW 200 MW CLASS
501G COMBUSTION TURBINE

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Orlando, Florida

ABSTRACT

The 501G 60-Hz Combustion Turbine has been developed jointly by Westinghouse Electric Corporation, Mitsubishi Heavy Industries, Ltd., and FiatAvio. It continues a long line of large heavy-duty single-shaft combustion turbines by combining the proven efficient and reliable concepts of the 501F with the latest advances in aero technology via the Westinghouse Alliance with Rolls-Royce. The output of the 501G is over 230 MW with a combined cycle net efficiency of 58%. This makes the 501G the largest 60-Hz combustion turbine in the world and also the most efficient.

INTRODUCTION

The 501G is a 3600 rpm heavy-duty combustion turbine designed to serve the 60-Hz power generation needs for utility and industrial service. The 501G combines the efficient, reliable design concepts of the 501F with the latest low NO_X combustion technology and the state-of-the-art cooling utilized in advanced, high-temperature aero engines (Reference 1). The result is an advanced design, high-temperature, efficient, low NO_X, more powerful combustion turbine based on time proven reliable design concepts that will satisfy the large combustion turbine power generation needs for the next decade (see Table 1). Designed for both simple and combined cycle applications, it will operate on all conventional combustion turbine fuels as well as with coal-derived low-BTU gas produced in an integrated gasification combined cycle power plant.Two units are being manufactured with both to begin operation in 1997. It will have an initial ISO rating of 230 MW at a turbine inlet temperature of 1500°C SYMBOL 176 \f "Symbol"C on natural gas fuel. In combined cycle applications, the net thermal efficiency of the plant is 58% (LHV) in power blocks of 340 MW nominal power rating.

This paper describes the features of this latest in a long line of heavy-duty combustion turbines of the 501 model series. Aerodynamic, cooling, and mechanical design improvements are discussed along with the evolutionary changes based on time proven design concepts. Technological advances as well as planned verification test programs are discussed including cascade, model turbine aerodynamic tests, combustor tests, rotating blade vibration tests, and shop test at load.

TABLE 1. 501 EVOLUTION

Engine	501A	501B	501D	501D5	501DA	501FA	501G
Commercial Operation	1968	1973	1976	1982	1994	1992	1997
Power, MW	45	80	95	107	120	160	230
Rotor Inlet Temp., °F	1615	1819	2005	2070	2150	2330	2583
Air Flow, Lb/Sec	548	746	781	790	832	961	1170
Pressure Ratio	7.5:1	11.2:1	12.8:1	14:1	15:1	15:1	19.2:1
No. Comp. Stages	17	17	19	19	19	16	17
No. Turbine Stages	4	4	4	4	4	4	4
No. Cooled Rows	1	3	4	4	4	6	6
Exhaust Temp., °F	885	907	956	981	1004	1083	1100
Heat Rate (Btu/kWh)							
LHV - ISO Gas							
Simple	12,600	11,600	10,925	10,040	9,900	9,810	8,860
Combined	9,000	7,350	7,280	7,055	7,024	6,429	5,883

General Description

Figure 1 illustrates the general configuration of the 501G. Several basic design concepts are evident; such as the two bearing single shaft construction, cold end drive, and axial exhaust. These fundamental time proven concepts used by Westinghouse for over 25 years have now become industry standards.

As in all past 501/701 designs, the single rotor is made up of the compressor and turbine components supported by two tilting pad bearings. For comparison with 501F, see Table 2. The 501G rotor is of bolted construction supported by two 18-inch-diameter, two-element tilting-pad bearings and an upper half fixed bearing. The thrust bearing is a double-acting bearing.

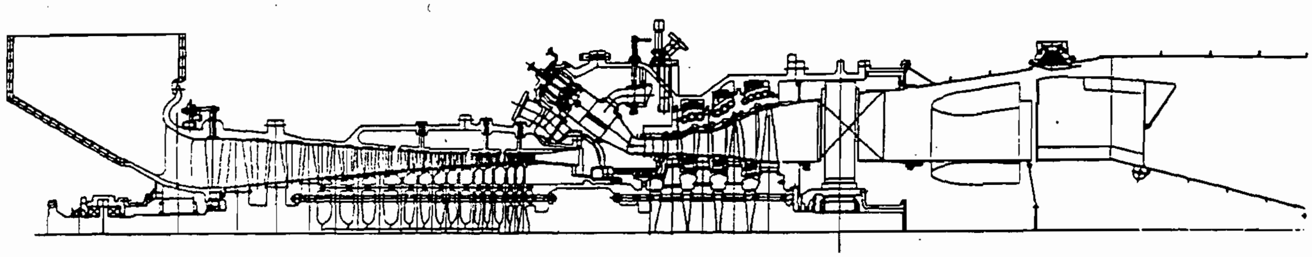


FIGURE 1. 501G

TABLE 2. 501G vs 501F ROTOR DESIGN

	501F	501G
Rotor Span	294.0"	311.6"
Journal Bearings	17.0"	18.0"
	2 Tilting Pads	
Thrust Bearings	22.5"	25.0"
Rotor Weights (Tons)		
Compressor	25.5	37.9
Turbine	21.0	26.9

The compressor rotor is comprised of a number of elements, spigotted and bolted together by 12 through bolts. Alignment and torque transmission is assured by the use of radial pins between the discs. The turbine rotor section is made up of disks bolted together by 12 through bolts and using CURVIC clutches, which consist of toothed connection arms that extend from adjacent disks and interlock providing precise alignment and torque carrying features. This turbine rotor design has amassed over 10 million hours of reliable service in all sizes of combustion turbines.

The air inlet system, which contains a silencer, delivers air to the compressor via a plenum-bell mouth and houses the inlet, main journal, and thrust bearings. The compressor is a 17-stage axial flow design of 19.2:1 pressure ratio that is based on the highly successful 501F. A four-stage turbine was selected to maintain moderate aerodynamic loadings even at the increased firing temperature.

The combustion system consists of 16 can-annular combustors. This low NO_X hybrid design is an improvement on the current highly successful design that has been in commercial operation for over three years in the 701F and 501D5. The presence or absence of flame and the uniformity of distribution of fuel flow between combustors are monitored by thermocouples located downstream of the last stage turbine blades. These can also detect combustor malfunctions when at load while U/V detectors are used to sense ignition during the early starting phase.

All engine casings are split horizontally to facilitate maintenance with the rotor in place. Inlet and compressor casings are of nodular cast iron and cast steel, respectively, while combustor, turbine, and exhaust casings are alloy steel. The inlet bearing housing is supported by eight radial struts, and the aft end bearing housing is supported by tangential struts. Airfoil-shaped covers protect the tangential struts from the blade path gases and support the inner and outer diffuser walls.

Tangential struts respond slowly during transients and maintain alignment of the bearing housing by rotating it as required to accommodate thermal expansion. Individual inner casings (blade rings) are used for each turbine stationary stage and can be readily removed and replaced or serviced with the rotor in place. Similar blade rings are used in the compressor. Another feature of these blade rings is that they have a relatively higher thermal response independent of the outer casing and can be aligned concentric to the rotor to prevent blade rubs, minimize clearance, and maximize performance.

Cooling circuits for the turbine section displayed in Figure 2 are similar to those used on the 501F. They consist of a rotor cooling circuit and four stationary cooling circuits. Rotor cooling air is provided by compressor discharge air extracted from the combustor shell. This air is externally cooled and filtered before returning to the torque tube casing for seal air supply and for cooling of the turbine disks as well as the first, second, and third-stage turbine rotor blades. This filtered air eliminates excessive contaminants that could block critical intricate cooling passages of the rotor blades.

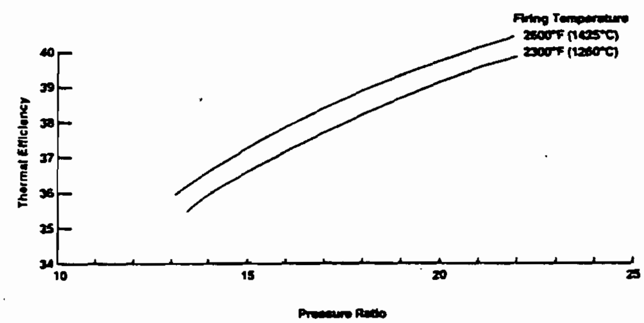


FIGURE 2. SIMPLE CYCLE - THERMAL EFFICIENCY VERSUS PRESSURE RATIO

Direct compressor discharge air is used to cool the row 1 vane while compressor bleed air is used to provide cooling air to turbine blade ring cavities at stages 2, 3, and 4, respectively. The compressor bleed air also cools the stage 2 and 3 vane segments and provides cooling and purging air for the turbine interstage disk cavities preventing the ingestion of hot blade path gases.

The stationary vanes and rotating blades for the first two turbine stages are coated with thermal barrier coatings. Compressor diaphragms are coated to improve aerodynamic performance and corrosion protection. For some environments, compressor rotor blades may be coated for corrosion protection.

CYCLE PARAMETER SELECTIONS

The 501G engine, like all recently designed combustion turbines of the authors' company, is designed for both simple and combined cycle service. The operating firing temperature level is selected to be commensurate with state-of-the-art materials and the latest aero-type cooling schemes. The value selected is 1425 SYMBOL 176 \f "Symbol"C at rotor inlet temperature.

After the turbine inlet temperature has been selected, the cycle pressure ratio can be chosen to maximize simple cycle power output and combined cycle efficiency. Figures 3 and 4, which are plots of simple and combined cycle efficiencies are used to select a pressure ratio of 19.2:1. This results in a cycle that has near maximum simple cycle output with a potential combined cycle efficiency of 58%.

The cycle air flow was set by the turbine exit annular flow area. It can be shown that the last stage blade stress level is directly proportional to the exit annular area. Since the long highly twisted last stage blade is uncooled, the blade material capability and last stage gas temperature then determine the flow capacity of the engine. A flow of 1200 lb/sec was selected, which results in a conservatively stressed blade and high power output.

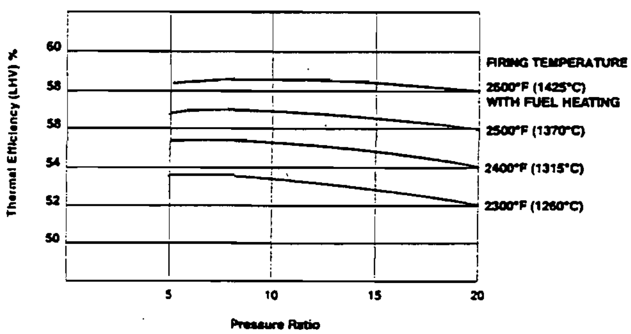


FIGURE 3. COMBINED CYCLE EFFICIENCY

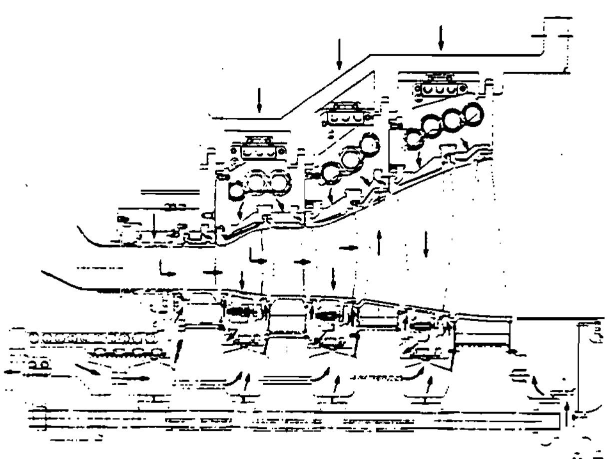


FIGURE 4.

COMPRESSOR DESIGN

The compressor is a highly efficient, 17-stage axial flow compressor patterned after the proven compressor of the W501F. Flow and pressure coefficients of the 501G compressor have been kept similar to the F compressor by increasing the mean diameter of the stages to accommodate the 25% increase in flow. In addition, the rear stages of the new compressor have larger diameters to help balance spindle thrust. Interstage bleeds for starting and cooling flows are in the sixth and eleventh stages, with the fourteenth stage used only for supplying cooling air to the second-stage turbine stationary blading and interstage cooling system. The compressor is also equipped with variable inlet guide vanes, which improve the compressor low-speed surge characteristic and are used in combined cycle applications for improved part-load performance.

Rotor blades are multiple circular arc designs and controlled diffusion airfoils.

Stationary blading is fabricated into two 180 SYMBOL 176 \f "Symbol" diaphragms per stage for easy removal and will maintain the highly efficient inner shroud sealing system currently used on the 501F. These seals will be supported by machined lips on the inner shroud and can be removed to facilitate inspection and maintenance of shrouds and seals. Stationary blading and shrouds are standard strength AISI 403 throughout. Abradable seals will be used to improve sealing.

TURBINE DESIGN

The design of the 501G has maintained moderate aerodynamic loadings by using a four-stage turbine with higher peripheral speed compared to the 501F. Furthermore, improvements in aerodynamic airfoil shapes have been made possible by utilization of a fully three-dimensional viscous analysis code. This sophisticated airfoil design approach was employed to assure that the turbine has the highest practical aerodynamic efficiency and the lowest cooling flow usage. The number of airfoils have been reduced relative to the 501F by approximately 15%. The first two turbine blades are unshrouded. The second and third blades are shrouded as on the 501F.

The first turbine stationary row consists of 32 precision-cast, single-vane segments of IN939 alloy. As in past designs, the row 1 vanes are removable, without any cover lift, through access manways. Inner shrouds are supported from the torque tube casing to limit flexural stresses and distortion, thus maintaining control of critical row 1 vane angles. This is the same method that was used successfully on the 501F. There are 36 precision-cast, single vane segments of IN939 material in the second turbine stationary row. The third and fourth turbine stationary rows are precision-cast vane segments with 14 three-vane and 14 four-vane segments, respectively.

Each row of vane segments is supported in a separate inner casing (blade ring) that is keyed and supported to permit radial and axial thermal response independent of possible external cylinder distortions. Blade ring distortion in the 501G turbine is further minimized by use of segmented isolation rings that support the vane segments and also ring segments over the rotor blades to form a thermal barrier between the flow path and the blade ring. As in all past designs, the interstage seal housings are uniquely supported from the inner shrouds of rows 2, 3, and 4 vane segments by radial keys that permit the thermal response of the seal housings to be independent of the more rapid thermal response of the vane segments

COOLING OF VANES, BLADES, AND DISCS

The cooling system shown in Figure 4 maintains the NiCrMoV turbine disks below 400°C (752°F), which keeps the disk below the creep range and assures long life. Fleet leaders with this disk design are the W501A turbines with up to 150,000 operating hours.

Blade and vane cooling flows have been kept to a minimum while maintaining similar metal surface temperatures as used in the 501F (Figure 5). By using thermal barrier coatings and proven aero engine cooling schemes such as serpentine cooling passages, shower head film cooling, and shroud film cooling along with improved materials, the creep and thermal fatigue margins have been maintained or improved over the 501F (see Figure 6).

The row 1 vane cooling is provided by impingement convection and film cooling. The film cooling holes are fan shaped and the airfoil and shrouds will be coated with a ceramic thermal barrier coating.

The row 1 vane cooling design is shown in Figure 7. This highly effective configuration utilizes state-of-the-art concepts with three impingements inserts in combination with an array of film cooling holes and a trailing edge pin fin system. Film cooling is used at the leading edge as well as at selected pressure and suction side locations. This limits vane wall thermal gradients and external surface temperatures, while providing an efficient re-entry for spent cooling air. Pin fins are employed to increase turbulence and surface area, thereby optimizing the overall edge pin fin exit system.

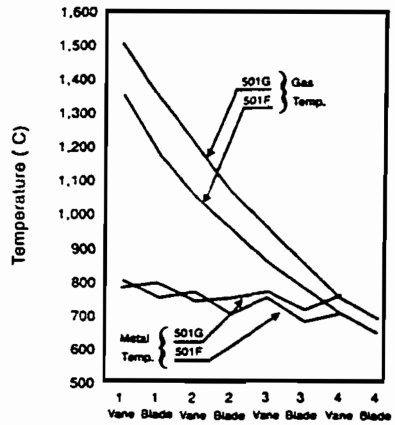


FIGURE 5. 501F AND 501G METAL TEMPERATURE COMPARISON

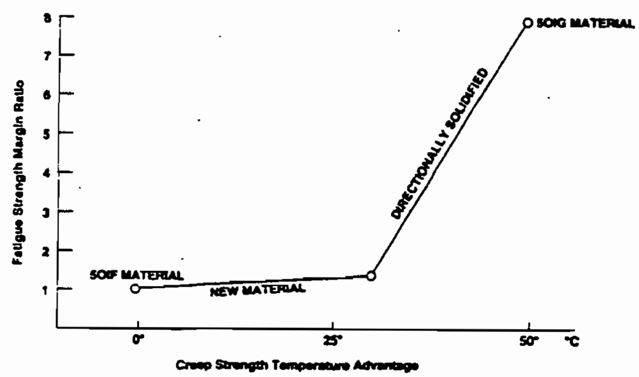
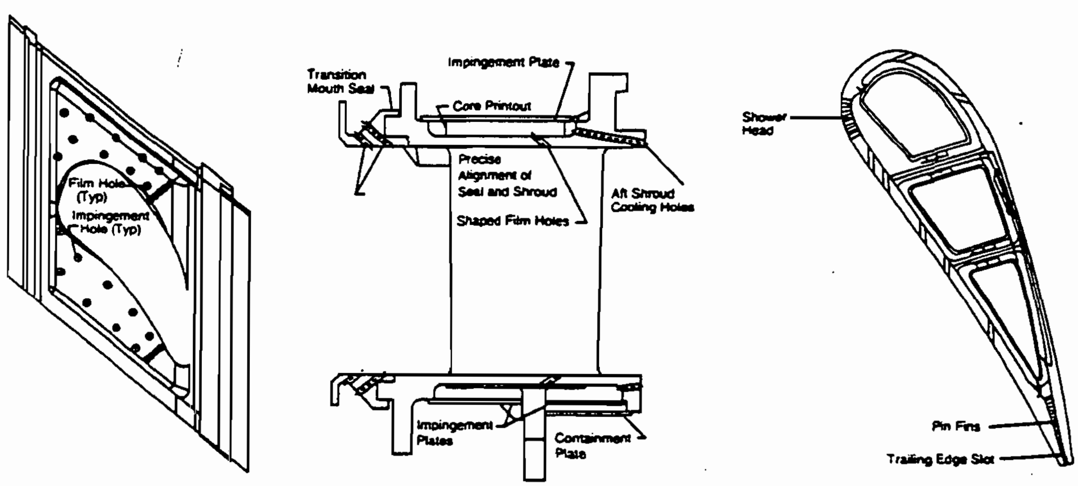


FIGURE 6. DIRECTIONALLY SOLIDIED ADVANCED MATERIALS CREEP AND FATIGUE STRENGTH IMPROVEMENT



Outer Shroud Impingement and Film Holes

Shroud Cooling

Vane Cooling

FIGURE 7. 501G ROW 1 VANE - COOLING

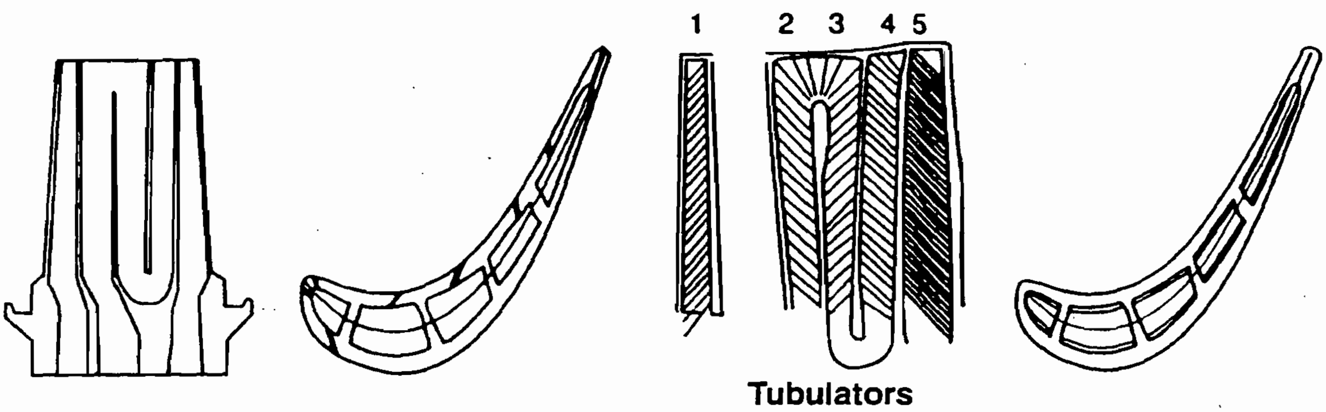


FIGURE 8. 501G ROW 1 BLADE - COOLING

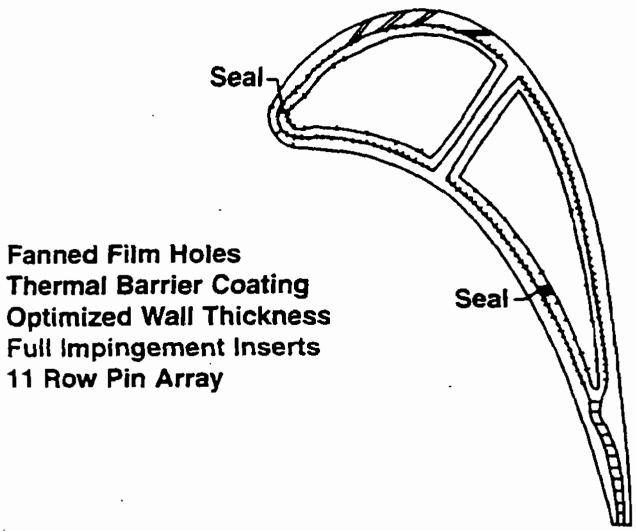


FIGURE 9. 501G ROW 2 VANE - COOLING MID HEIGHT

Particular attention is paid to the inner and outer shrouds because of the flat temperature profile from the dry low NO_x combustor. Cooling of the shrouds will be provided by impingement plates and film cooling as well as convection cooling via drilled holes.

The row 1 blade cooling consists of convectional serpentine cooling with angled turbulators. The film cooling utilizes fan shaped cooling holes for more effective cooling. The blade also features extensive film cooling at the tip to reduce the metal temperature of the squealer tip and platform cooling holes to positively cool the inner platforms. The airfoil will be coated with a vapor deposition thermal barrier coating (Figure 8).

The row 2 vane is cooled by a combination of impingement cooling via the inserts and film cooling using fan shaped cooling holes. The vane will be manufactured as a single vane to reduce thermal stress and to allow the vane to be coated with thermal barrier ceramic coating. As with the row 1 vane, intensive cooling schemes are applied to the inner and outer shrouds using impingement and convection cooling (Figure 9).

The row 2 blade is cooled by convection with no film cooling. The airfoil will be coated with a vapor deposition T.B.C. (Figure 10).

The row 3 blade cooling is unique in that it positively cools the blade tip shroud. Because of the flat profile from the combustor and because of tip leakage from the rows 1 and 2 turbine blades, it was decided to allow for positive cooling of the tip shroud. Analysis has shown that this scheme will have ample margin for cooling the shroud (Figure 11).

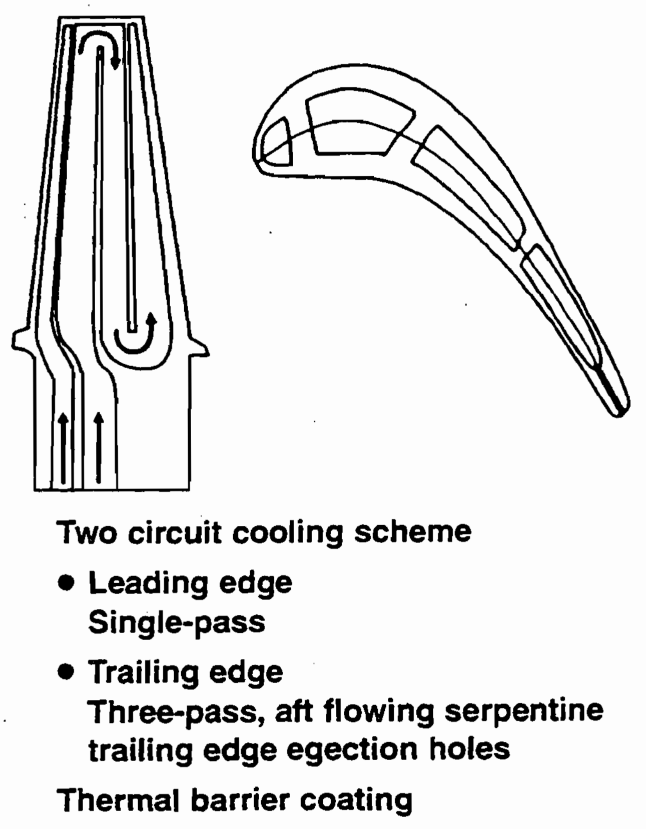


FIGURE 10. 501G ROW 2 BLADE - COOLING

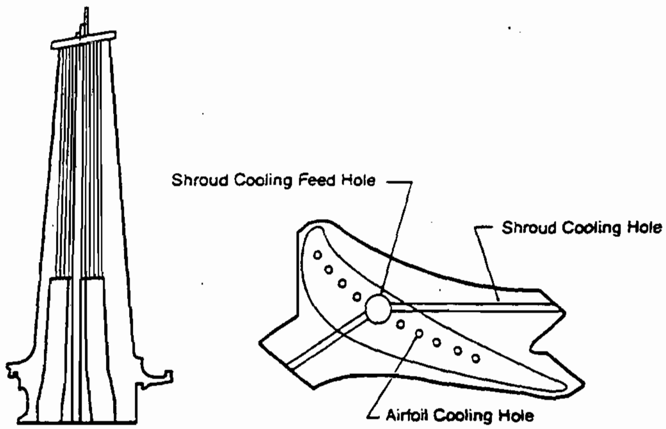


FIGURE 11. 501G ROW 3 BLADE - COOLING

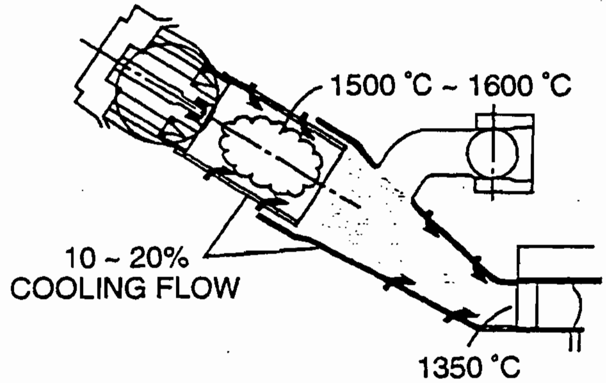


FIGURE 12. 501F COMBUSTION SYSTEM

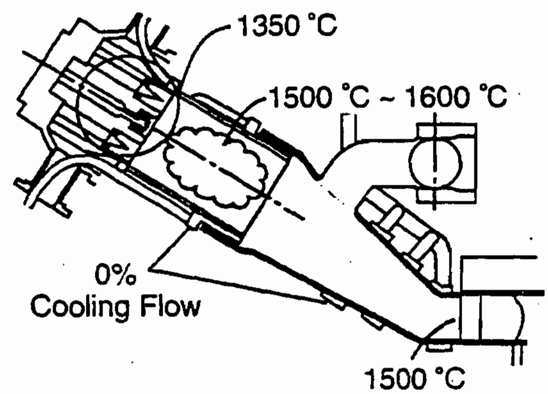


FIGURE 13. 501G COMBUSTION SYSTEM

Compressor bleed air from the 11th stage is used to supply cooling air to the third-stage blade ring cavity. Cooling air is directed to the inlet cavity of a five-cavity multipass convective cooled vane airfoil. Leading edge cavity flow also supplies the interstage seal and cooling system while the fifth pass cavity exits at pressure side "holes" on the vane surface near the trailing edge. The fourth-stage vane is uncooled but does transport sixth-stage compressor bleed air for the fourth-row interstage seal and cooling system.

The rotating blades are precision cast of CM247 for all four rows. All rows utilize long blade root extensions or transitions in order to minimize the three-dimensional stress concentration factor that results when load is transferred between cross sections of different size and shape. The blade roots are the same geometric multiple serration type used on past designs with four serrations used on the first three rows and five serrations used on the rear stage.

501G COMBUSTOR

The combustor is based on the successful dry low NO_X combustor developed for the 501F. This combustor is presently operating at a 25 ppm NO_X level at 1260°C (2300°F) R.I.T. temperature. The 501G combustor will make use of steam cooling to allow for the same NO_X reduction at the higher firing temperature. By eliminating the transition cooling air, virtually all the combustion air is introduced into the primary zone of the combustor so maintaining the flame temperature at nearly the same level as that of the 501F turbine. Therefore, NO_X levels are similar to the 501F level (see Figure (12) and Figure (13). Fuel heating will be used to improve the efficiency of the cycle with the heat coming from the rotor cooling air heat exchanger. The same combustor is designed to burn liquid fuel using water or steam injection to control NO_X levels. Initial emission targets are given in Table 2.

VERIFICATION TESTING

All new advanced technology parts applied in the 501G engine are qualified for engine use by verification tests, including: (a) rotating blade vibration, (b) turbine aerodynamic, (c) combustion tests, and (d) hot turbine cascade testing. Overall engine performance and durability will be verified by engine shop tests.

AERODYNAMICS

The total compressor was tested as a scaled model in a small combustion turbine in 1994. This followed extensive single and dual stage rig testing in 1993.

The turbine design tools have been verified in extensive model and rig tests, and in particular a scale model of the 501G turbine row one vane and blade was tested in 1994 and fully verified the expected aerodynamic performance.

COMBUSTION

The development of the low NO_X combustor is being carried out using full scale pressure and temperature rigs. The initial specification is for a 25 ppm NO_X combustor, with gradual movements to lower levels (see Table 3). The combustor is a dual fuel combustor and will use water or steam to control NO_X when burning liquid fuel.

TABLE 3. 501G INITIAL EMISSIONS TARGETS

	Natural Gas	Oil
• NOx	< 25 ppm	< 42 ppm
• CO	< 10 ppm	< 25 ppm
• UHC	< 10 ppm	< 15 ppm

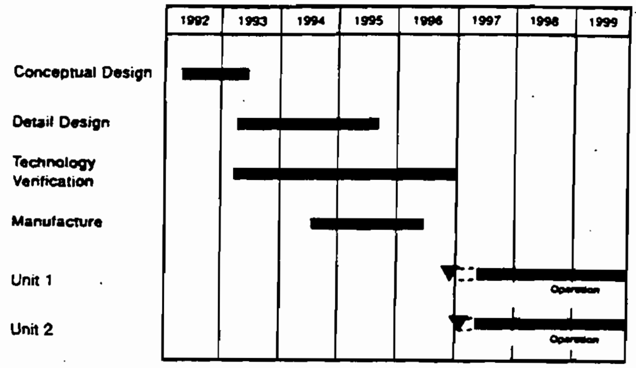


FIGURE 14. 501G DEVELOPMENT SCHEDULE

COOLING

Because of the elevated firing temperatures, it is planned to carry out a cascade test of the row one blade and vane in a full firing temperature rig facility in 1995. This test will verify operating temperatures, especially for the difficult endwall regions, before the engine is introduced into commercial operation.

In addition, cascade testing of model vanes and model tests of blades will be conducted to verify pressure loss in turbine passages and film cooling of shrouds.

SHOP AND FIELD TESTING

Two prototype units will be tested, these will be fully instrumentated engines which will be tested to full power conditions before entering commercial service in 1997 (see Figure 14).

The prototype test is the important final stage for the confirmation of the following:

1. Compressor inlet airflow over entire IGV range
2. Compressor surge margin
3. Engine starting and acceleration characteristics
4. Mechanical integrity of the engine from starting to overspeed including rotor vibration characteristics.
5. Mechanical and thermal performance of the engine over its entire operating range.
6. Reliability of the engine by measurement of gas and metal temperatures, pressure, vibratory stresses, etc.
7. Emission characteristics of the engine and the effects of injection upon emissions and thermal performance.

To provide this data, the engine will be extensively instrumented to measure thermodynamic values, metal temperatures, static and vibratory strains, vibration characteristics, displacements, and other parameters. Dynamic strain gauges will be installed on the turbine blades to verify dynamic responses. The signals from the rotating sensors will be transmitted by a telemetry system. Clearance measurement systems using proximity probes allow stator-to-rotor radial displacement measurements during transients. Data acquisition equipment will be installed to record the special engineering test data. This equipment includes tape recorders, spectrum analyzers, plotters, and chart recorders.

LIFE CYCLE COSTS

Combustion turbines are designed for long life. However, the hot parts especially the cooled turbine components and the combustion equipment, have a finite life because of thermal fatigue cracks, corrosion, oxidation, creep, and other phenomena. In order to reduce the cost of these parts to the customer, the 501G has been designed with the objective of reducing the number of hot parts. The most expensive and most often replaced aerofoils are the row one and row two vanes and blades. Compared to the 501F, these numbers have been reduced by 20%.

Maintenance intervals, despite the higher firing temperatures, have been maintained at the current generation level (see Table 4). This is possible by keeping the same surface metal temperatures as exists in the 501F, and by improving the creep and thermal fatigue resistance by utilizing directionally solidified superalloys.

TABLE 4. 501G INSPECTION INTERVALS

Inspection Type	Hours	Starts
Combustor	8,000	400
Turbine	24,000	1,200
Major	48,000	2,400

Gas Fuel

CONCLUSION

The major market drivers for combustion turbines are capital cost, operating cost, emissions, and fuel availability. To make a step change in the technology of the combined cycle projects, a new advanced design combustion turbine is introduced that is more efficient and cost effective than competitive machines currently available or projected. The 501G engine utilizing advanced aeroengine design and tools, elevated firing temperatures, and proven technology, results in a design that maximizes the output for minimum cost per KW at maximum operating efficiency. By the novel use of steam cooling, the flame temperature is kept at the same level as the 501F; thereby, the new engine will have low levels of NO_X despite the elevated rotor inlet temperature.

The resulting power plant efficiency will improve from today's best of 54% to 58% an improvement of 7.4%. At the same time the size of the engine, compared to the 501F, will be only slightly increased. The 501G engine will produce approximately twice the output of a 501D machine and is 70 MW larger than any other currently available 60 Hz combustion turbine on the market. The high power output will further enhance the maintenance and balance of plant cost advantage of the 501G engine when compared to a plant of similar output but requiring more combustion turbines.

REFERENCES:

1. A. J. Scalzo and Others, "A New 150 MW High Efficiency Heavy Duty Combustion Turbine", ASME 88-GT-162

PSD-FL-245

LAKELAND ELECTRIC

Farzie Shelton, chE; REM

Manager of Environmental Affairs – Energy Supply

October 23, 2000

RECEIVED

OCT 26 2000

BUREAU OF AIR REGULATION

Greg Worley, Chief
Pre-Construction/HAP Section
United States Environmental Protection Agency
Region 4
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303-8909

Re: Air Construction Permit, DEP File No. 1050004-004-AC (PSD-FL-245)
250 Megawatt Combustion Turbine - McIntosh Power Plant Unit No. 5

Dear Mr. Worley:

As you are aware, Unit No. 5 is the first generation of Westinghouse 501G series Combustion Turbine that commenced initial operation on April 14, 1999. In accordance with the 40 CFR 60.8(a) as referenced in Specific Condition 29 of our permit, demonstration of compliance with the New Source Performance Standards (NSPS) and emission limits while burning Natural gas was conducted on March 2, 2000. However, this demonstration did not include tests while burning fuel oil as the unit had not commenced oil burning at that time.

On July 24, 2000 Siemens Westinghouse Power Corporation (SWPC), the manufacturer and supplier of the gas turbine 501G series, commenced firing fuel oil in this unit with the intention of demonstrating NSPS compliance tests after the initial shake down of equipment and tuning of the control system. Hence, on August 31, 2000 SWPC was able to synchronize the unit. However, due to multitude of problems (please see attached letter from SWPC addressed to Mr. Al Dodd) the operation of Unit No. 5 had to be stopped and presently the unit is none operational while SWPC is trying to remedy the problems.

As you will note from the attached document this unit operated a mere 13 hours at below 25% load (unit rated at 250 MW) utilizing 11000 MMBTU of fuel oil. Therefore, with the present circumstances SWPC does not believe they will be able to meet the requirement of our construction permit as specified in condition 29 as modified on December 9, 2000 which reads:

> *Compliance with allowable emission limiting standards shall be determined for applicable New Source Performance Standards in accordance with the most recent approved EPA schedule. Initial compliance with all other applicable emission limiting standards shall be determined concurrently with the*

> *demonstration of compliance with New Source Performance Standards with the excerption that compliance with emissions limits applicable to fuel oil firing shall be determined not later than 90 days after the first oil firing that occurs after December 8, 1999. ...*

Therefore, we are writing to request a 90-day window from the time Unit No. 5 is operational again and burning fuel oil to perform NSPS compliance testing while utilizing fuel oil. Your cooperation in this matter is greatly appreciated. As always, we look forward to working with you and your staff in finding a suitable solution to our request. If you should have questions, please do not hesitate to contact me.

Sincerely,

Farzie Shelton

Cc: Mr. C.H. Fancy, P.E. - DEP
Mr. Hamilton Oven P.E. - DEP
Mr. Al Linero P.E. - DEP
Mr. David McNeal – EPA

Attachment

SIEMENS
Westinghouse

October 19, 2000

W-COL-0371
File: 055.2

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

Subject: **City of Lakeland - McIntosh Unit #5 Project**
Fuel Oil Emissions Compliance Request for Extension

Dear Al:

Introduction

This letter is being sent to provide the City of Lakeland an update on the Liquid Fuel Commissioning Activities associated with the W501G Simple Cycle McIntosh 5 unit located at Lakeland, Fl. As you know, this is the first W501G advanced turbine of its kind to be commissioned on oil fuel.

Siemens Westinghouse Power Corporation (SWPC) has been working diligently to commission the McIntosh 5 unit on oil fuel and conduct the compliance test within the 90-day period specified in the permit. Although it is very early in the fuel oil commissioning program, SWPC does not anticipate meeting this schedule requirement due to unanticipated mechanical issues that have occurred with the unit that still need to be resolved.

Initial Plan and Current Status:

The initial oil fuel plan was to complete the oil fuel commissioning process in nominally two weeks of operation with the following major milestones:

- Achieve Ignition and Synchronize
- Demonstrate reliable oil Operation Throughout the Load Range
- Tune for emissions and dynamics
- Successful completion of performance and Compliance Testing

To date, the W501 G has been able to demonstrate reliable ignition on oil and reliable operation up to 25% load. Operation above 25% load has been prevented due to difficulties with fueling the "B" Stage valve. Since the "B" stage valving issues arose, other mechanical issues, outlined below, have prevented further operation. The unit has now operated on fuel oil for nominally 13 hours (see attachment).

Mechanical Issues:

The oil fuel commissioning process has identified several mechanical issues that have impeded completion of our plan. These issues, as addressed below, have required redesigns, corrective actions and field-testing. The cumulative result of these issues has severely limited the availability of the unit for the purpose of fuel oil testing. These issues require resolution prior to proceeding with additional oil fuel commissioning.

1. Ignition - Problems with ignition were the first to develop. Initial challenges included changing the ignition system to a higher energy spark source, changes to the design of the igniters and eliminating high temperature ignition lead failures. These actions, combined with extensive ignition mapping efforts, have now resulted in reliable operation up to 25 % load, where the final ("B") Stage fuel valve must be initiated. This is the challenge we are currently solving.

2. Fuel Stages – There are three stages of fuel oil injection required to progress through the unit operating range. The stages are defined as "pilot", "A" and "B". Ignition and operations at low loads has been proven and are accomplished while using the "pilot" and "A" stage. The higher load level operations that require the "B" stage have yet to be completed. The "B" stage valve and control logic is being changed to improve operation to permit successful. Initiation of combustion in the "B" stage.

3. Miscellaneous Mechanical Components – Various other oil fuel system components have required repair\replacement. An example is the multi-function valve station that is used to switch between fuel oil injection and purge operations. This component required refurbishment at the supplier's facility. The unit was unavailable for oil fuel operation for the duration of the repair.

4. Generator - The final major impediment to the oil fuel commissioning is unrelated to the oil fuel system. During commissioning activities, a problem with the generator was discovered, specifically, high vibration. The vibration characteristics of the generator rotor have prevented continuous operation in high load ranges ("B" stage required), which would prevent necessary tuning activities required prior to performing the state required performance test. A generator repair outage has been scheduled to coincide with the availability of the necessary repair components.

Regulatory Relief Request:

SWPC proposes that the City of Lakeland request from the FDEP and EPA an additional 90 days from the date the unit is again synchronized operating on fuel oil to perform the emissions compliance test. Although significant progress has been made in commissioning the fuel oil system in ignition and low load operation, important hurdles still remain in commissioning and tuning the system in preparation for the emissions compliance test. Mechanical issues have limited fuel oil operation to nominally 13 hours, and more operating time is required. While the 90-day clock has been started, due to these mechanical issues, SWPC has not been able to realize the full benefit of

SIEMENS
Westinghouse

Mr. Al Dodd
10/19/00

this time to complete commissioning activities. SWPC will support the City with technical support in this effort, as required.

Please call me with any questions regarding this and the upcoming commissioning activities.

Regards,

Andy Mould

Andy Mould
Project Manager

AM/ls

Attachment

cc:	Tim Bachand	COL
	Roger Greenwood	SWPC
	Gerry Myers	SWPC
	Pete DeRosa	SWPC
	Ramesh Kagolanu	SWPC
	Jason Kraus	SWPC

SIEMENS Westinghouse

Lakeland 501G Fuel Oil Statistics

Build 8 Fuel Oil Statistics

- **Total Start Attempts - 73**
- **Successful Starts - 29**
- **Total Fired Hours - 12.51**
- **Days of Oil Operation - 16**
- **First Fire Date - 7/24/00**
- **First Sync Date - 8/31/00**
- **Last Fire Date - 9/12/00**
- **mmBTU's Burned (HHV) ~ 11000**

Lakeland 501G Daily Statistics Summary - Oil

Build	Date	Start Attempts (Oil)	Successful Starts (Oil)	Fired Hours	Hours Above 70% Load
Build 8	7/24/00	6	0	0	0
	7/25/00	3	0	0	0
	8/5/00	3	0	0	0
	8/6/00	4	0	0	0
	8/13/00	9	0	0	0
	8/15/00	3	0	0	0
	8/17/00	3	2	0.13	0
	8/18/00	3	1	0.08	0
	8/19/00	4	2	0.17	0
	8/20/00	8	3	0.5	0
	8/25/00	6	0	0	0
	8/26/00	4	4	0.9	0
	8/27/00	6	6	1.02	0
	8/31/00	3	3	2.95	0
	9/1/00	5	5	2.13	0
	9/12/00	3	3	4.63	0
Totals		73	29	12.51	0

LAKELAND ELECTRIC

Farzie Shelton, chE; REM

Environmental Affairs Manager of Licensing & Permitting

February 22, 1999

RECEIVED

FEB 23 1999

BUREAU OF
AIR REGULATION

Mr. Greg Worley
Chief
Pre-Construction/HAP Section
United States Environmental Protection Agency
Region 4
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303-8909

Re: Air Construction Permit, DEP File No. 1050004-004-AC (PSD-FL-245)
250 Megawatt Combustion Turbine - McIntosh Power Plant Unit No. 5

Dear Mr. Worley:

As you are aware, Unit No. 5 is the first generation of Westinghouse 501G series Combustion Turbine and due to its large size has not been factory tested prior to its installation on site of McIntosh Power Plant. Hence, special test program has been developed to validate the unit's design in the field. The overall test program includes mapping and tuning of fuel combustors design, followed by the disassembly of the engine to remove the test instruments and inspection of the engine hardware. Finally the engine is reassembled in preparation of compliance testing and commercial operation.

The test period is planned to cover a period of approximately thirteen weeks from an expected first fire date. The test program planned for this unit is critical for the evaluation of the integrity and long-term operability of the unit. The test program includes various phases beginning with the loading of the combustion turbine to full operating conditions in programmed steps with as few operating hours and starts as possible. Operating the combustion turbine at maximum load and temperatures early in the program is critical due to the limited life of the instrumentation that is used to collect the data. For the proper evaluation of the integrity of the unit, the data must be based on operation of the engine under the most extreme conditions. The primary focus of this testing period is the critical temperature data. However, vibration frequencies, blade clearances, stress and strain, thermal and aerodynamic data are also recorded. The combustion system will be tuned for maximum stability for this testing period. The 501G engine will be instrumented with over 2000 data points for the validation testing effort. This testing program is governed by a strategy to obtain the highest priority or most critical data early in the test plan when the highest percentage of the test instrumentation is full functional. The test period will include extensive validation testing on the engine, its auxiliaries, single and dual fuel combustors, a combustor changeout, an engine outage to disassemble and reassemble the engine, as well as the normal production unit commissioning activities.

February 22, 1999

Mr. Greg Worley
Chief
Pre-Construction/HAP Section
United States Environmental Protection Agency
Region 4

We are cognizance of the 40 CFR 60.8(a) requirements, demonstration of compliance with the New Source Performance Standards (NSPS) as referenced in specific condition 29 of our permit. However, based on the above test program and due to an extenuating circumstances beyond our control, we are writing to request an extension of time beyond the 60 days allowed after achieving the maximum production rate to demonstrate compliance. In a telephone discussion with Mr. David McNeal he stated that the Agency will consider an extension of time, a 30 day time window from the last reassembley of the unit but no later than 180 days of initial operation of the unit, to perform the NSPS compliance test. Therefore, we are writing to request this extension.

We appreciate the Agency's consideration to our request and wait to hear from you soon. However, if you should have any questions, please do not hesitate to contact me.

Sincerely

Farzie Shelton

Cc: Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Mr. Hamilton Oven P.E.
Administrator
Siting Coordination Office
Florida Department of Environmental Protection
2600 Blair Stone Rd
MS-48
Tallahassee, Fl 32399-2400

cc: J. Heron, BAR

LAKELAND ELECTRIC

Farzie Shelton, chE; REM
Environmental Affairs Manager of Licensing & Permitting

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 14, 2000

RECEIVED
JAN 21 2000
BUREAU OF AIR REGULATION

Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Re: Air Construction Permit No. 1050004-006-AC (PSD-FL-245 –A) Lakeland Electric Unit No. 5

Dear Mr. Fancy:

In compliance with the above referenced permit (Section III. Emission Unit Specific Condition 29) and 40CFR 60.7 and 60.8, we are writing to notify the Department of our intention to perform the initial stack testing commencing on January 14, 2000. Accordingly, we intend to demonstrate compliance with the NSPS and BACT Standards while burning Natural Gas. However, at this time we do not intend to demonstrate compliance while burning low sulfur fuel oil as, to date, we have not used any fuel oil during start up of this unit. Please note that we restarted this unit on January 7, 2000 following redesign and reassemble of some combustion components. We have informed DEP Southwest District by telephone of this event, however, we will provide a copy of this letter to Mr. Bill Thomas of DEP's Southwest District and Mr. Greg Worley of the Environmental Protection Agency.

If you should have any questions, please do not hesitate to contact me.

Sincerely

Farzie Shelton

Cc: Mr. William C. Thomas P.E.
Administrator
Department of Environmental Protection
3804 Coconut Palm Drive
Tampa Fl 33619

Mr. Greg Worley
Chief
Pre-Construction/HAP Section
United States Environmental Protection Agency
Region 4
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303-8909

Teresa — F.Y.I. file

City of Lakeland

PSO-FI-245

MEMORANDUM

TO: MAYOR AND CITY COMMISSION

FROM: CITY ATTORNEY'S OFFICE

DATE: September 8, 1998

RE: **Task Authorization with Black and Veatch**

Attached hereto is a proposed Task Authorization 98-07 with Black and Veatch Engineers to provide support during the need certification process required by the Power Plant Siting Act for the combined cycle conversion of McIntosh Unit #5.

The Public Service Commission conducts an involved review and public hearing process to determine a need for most types of additional generation. This involves multiple filings and testimony by experts as to the available generation within the state and how the proposed unit will effect the overall state system. Black and Veatch is experienced in this process and the staff recommends hiring them as a consultant. The not-to-exceed fee is $334,510.

This Task Authorization is pursuant to our existing continuing contract with Black and Veatch and it is recommended that the appropriate City officials have authorization for its execution.

TJM/cs

attachment

LAKELAND
ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

Farzie Shelton, chE; REM

Manager of Environmental Licensing & Permitting

al

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

RECEIVED
JUL 16 1998
BUREAU OF
AIR REGULATION

July 13, 1998

Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Re: Air Construction Permit No. PSD-FL-245 - Lakeland Electric & Water Unit No. 5 Construction Commencement Notification

In compliance with the 40 CFR Part 60 § 60.7 we are writing to notify you of our intention to commence construction of the above referenced unit on Monday July 13, 1998. We would be forwarding a copy of this communication to Mr. Hamilton S. Oven (Administrator, Siting Coordination Office), and Mr. William C. Thomas (Administrator Division of Air - Southwest District).

If you should have any questions, please do not hesitate to contact me at (941) 499-6603; by Fax at (941) 603-6335; or by E-Mail at fshel@city.lakeland.net.

Sincerely

Farzie Shelton

cc: Teresa Heron, BAR

cc: Mr. Hamilton Oven P.E.
Administrator
Siting Coordination Office
Florida Department of Environmental Protection
2600 Blair Stone Rd
MS-48
Tallahassee Fl 32399-2400

Mr. William C. Thomas P.E.
Administrator
Department of Environmental Protection
3804 Coconut Palm Drive
Tampa Fl 33619

NATIONAL PARK SERVICE
AIR RESOURCES DIVISION

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

FACSIMILE COVER SHEET

Date: April 21, 1998

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

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

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

Subject: *Lakeland McIntosh*

Al,

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

Don

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

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

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

Lakeland McIntosh

Plant Data

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

3

Lakeland McIntosh

Given/Assumptions

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

4

Lakeland McIntosh

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

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

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

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

Lakeland McIntosh

Cost Effectiveness

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

Lakeland McIntosh

Given/Assumptions

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

Lakeland McIntosh

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

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

9

Lakeland McIntosh

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

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

Lakeland McIntosh

Cost Effectiveness

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

LAKELAND ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

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

ph: (941) 499-6600
FAX: (941) 603-6335

TELECOPY REQUEST/COVER PAGE

Please deliver the following page(s) to:

AL LINERO **at** DEP

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

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

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

Number of Pages (Including Cover Page): 13

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

Al:

Please Call me.

Thanks
Farzie

PERMITTEE:

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

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

Authorized Representative:
Ronald W. Tomlin
Assistant Managing Director

PROJECT AND LOCATION:

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

STATEMENT OF BASIS:

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

Attached appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources Management

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

SECTION I. FACILITY INFORMATION

SUBSECTION A. FACILITY DESCRIPTION

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

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

SUBSECTION B. EMISSION UNITS

This permit addresses the following emission units:

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

SUBSECTION C. REGULATORY CLASSIFICATION

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

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

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

SUBSECTION D. PERMIT SCHEDULE

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

SECTION I. FACILITY INFORMATION

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

SUBSECTION E. RELEVANT DOCUMENTS:

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

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

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

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR) ~~and the Power Plant Siting office~~, Florida Department of Environmental Protection (FDEP) at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District office (DEPSW), 3804 Coconut Palm Drive, Tampa, Florida 33619 and phone number 813/744-6100.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a conversion to combined cycle operation. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

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

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

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

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

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

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

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

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

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

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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

SUBSECTION A. APPLICABLE STANDARDS AND REGULATIONS:

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

2. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

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

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

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

SUBSECTION B. GENERAL OPERATION REQUIREMENTS

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

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

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

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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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

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

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

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

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

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

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

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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

SUBSECTION C. EMISSION LIMITS AND STANDARDS

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

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

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

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

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

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

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

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

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

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

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

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

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

SUBSECTION D. EXCESS EMISSIONS

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

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

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

SUBSECTION E. COMPLIANCE DETERMINATION

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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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

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

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

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

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

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

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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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

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

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

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

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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

34.

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

April 15, 1998

PSD-FL-245

RECEIVED
APR 20 1998
BUREAU OF
AIR REGULATION

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

Dear Mr. Fancy:

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

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

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

Sincerely yours,

H Dale Hall

For/ Sam D. Hamilton
Regional Director

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

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

by

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

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

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

Best Available Control Technology (BACT) Analysis

Background

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

NO_x Controls

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

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

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

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

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

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

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

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

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

Labor costs are still overestimated.

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

Electrical costs are not documented and appear to be overestimated.

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

The "Fuel Escalation" cost is not justified.

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

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

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

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

Conclusions and Recommendations

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

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

Visibility Analysis

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

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

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

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

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

Lakeland McIntosh

Plant Data

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

Lakeland McIntosh

Given/Assumptions

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

Lakeland McIntosh

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

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

Requires recalculation based on revised Engelhard proposal. Advised NPS.

Lakeland McIntosh

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

Cost Item	Factor			Cost
Direct Annual Costs, DC				1 CT
Operating labor				
Operator	0.5 hr/shift			$6,570
Supervisor	15% of operator			$986
PSM/RMP Update				$5,000
Operating materials				
Reagent	286 lb/hr *	7008 hr/yr/2000lb/T*	300 $/T =	$301,106
Maintenance				
Labor	0.5 hr/shift			$6,570
Material	100% of maintenance labor			$6,570
Catalyst replacement				$983,333
Electricity	286 lb/hr *	518.1 Btu/lb*	0.000293 kW*hr/Btu*	
	0.05 $/kWh*	7008 hr/yr*	0.90 ef. =	$13,713
Total DC				$1,260,135
Energy Costs				
Heat rate penalty	250 MW *	7,008 hr/yr *		
	1000 kW/MW *	0.005 loss *	0.05 $/kWh =	$438,000
Indirect Annual Costs, IC				
Overhead	60% of maintenance costs			$193,081
Administrative charges	2% of Total Capital Investment			$132,296
Property tax	1% of Total Capital Investment			$0
Insurance	1% of Total Capital Investment			$66,148
Capital recovery	0.1098 * [Total Capital Investment-1.08(Cat Cost)]			$615,599
Total IC				$1,007,125
Total Annual Cost	DC + IC			$2,267,259

Requires recalculation. Advised NPS
aafrin

*

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

Lakeland McIntosh

Cost Effectiveness

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

Requires recalculation
They will send update.

Lakeland McIntosh

Environmental Impacts of SCR at	70% removal
NOx removed	596 TPY
Ammonia released	104 TPY @ 10 ppmv

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

Gas Turbine Limits from RBLC

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

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
		Dry Lox-NOx Comb.		SCR	
		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Gordonsville Energy	Sep-92			9.0	
Pansy/Holtsville	Sep-92	9.0			
Saranac Energy	Jul-92			9.0	
Selkirk Cogen	Jun-92			9.0	
Narragansett Elec.	Apr-92			9.0	
Bermuda Hundred	Mar-92			9.0	15.0
Kalamazoo Power	Dec-91	15.0			
So. Cal. Gas	Oct-91			8.0	
Sumas Energy	Jun-91			8.0	
Granite Rd. Ltd.	May-91			3.5	
Lakewood Cogen	Apr-91			9.0	
Cimaron Chemical	Mar-91			9.0	
Seminole Fertilizer	Mar-91			9.0	
Sumas Energy	Dec-90			9.0	
Newark Bay Cogen	Nov-90			8.3	
Las Vegas Cogen	Oct-90			10.0	
Doswell Ltd.	May-90			9.0	
Pedricktown Cogen	Feb-90			9.0	
Arrowhead Cogen	Dec-89			9.0	
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Kingsburg Energy Sys.	Sep-89			6.0	
Unocal	Jul-89			9.0	
Pawtucket Power	Jan-89			9.0	
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Permits Pending or Not Yet in RBLC

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Tiverton, RI				3.5	
ARCO Watson Project				5.0	
Bridgeport Energy Project				6.0	

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

April 3, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

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

Dear Mr. Tomlin:

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

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

Sincerely,

A. A. Linero 4/3

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

AAL/ch/t

Enclosure

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

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

FACSIMILE COVER SHEET

Date: April 2, 1998

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

To: Cleve Holladay

From: Ellen Porter

Subject: Technical Review Document of Lakeland McIntosh Additional Information

Number of Pages: 9
(Including this cover sheet)

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

Florida Department of Environmental Protection

Memorandum

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
MR. RONALD TOMLIN
LAKELAND ELECTRIC + WATER
501. E. LEMON ST
LAKELAND, FL 33801-5079

4a. Article Number
P 265 659 327

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

7. Date of Delivery
4-6-98

5. Received By: *(Print Name)*

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

6. Signature: *(Addressee or Agent)*
X Bonnie Bu[illegible]

PS Form **3811**, December 1994

Domestic Return Receipt

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US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
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Street & Number LAKELAND ELECTRIC	
Post Office, State, & ZIP Code +WATER	
Postage LAKELAND	$ FL
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$ 4-3-98
Postmark or Date 10 5004-004-AC PSD-FL-245	

PS Form **3800**, April 1995

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

by

Air Quality Branch, Fish and Wildlife Service – Denver

April 2, 1998

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

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

Best Available Control Technology (BACT) Analysis

Background

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

NO_x Controls

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

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

- Experience has shown that other vendors may provide lower SCR quotes.
- If the Engelhard estimate covered both NO_x and CO, either the NO_x portion of the cost should be split out or a combined cost effectiveness calculated.
- In the DLN-SCR scenario, is the smaller catalyst and ammonia usage resulting from DLN considered?
- Because Instrumentation is included in the Engelhard proposal, the addition of $94,000 for this expense appears to be double-counting.
- There is no justification for $20,000 for Site Preparation and Building expenses.
- The Capital Recovery Factors are too high. Although Lakeland cites the OAQPS Control Cost Manual and city practices as justification for using 10% interest, the current version of the Manual recommends 7%.
- Despite Lakeland's argument that addition of SCR to a simple cycle combustion turbine is a unique application, there is now so much experience with SCR on power generation turbines that the high Indirect Contingency cost and addition of Contingency costs to Direct Annual Costs and Energy Costs is no longer justified.
- Labor costs are still overestimated.
- Ammonia costs and catalyst replacement costs are underestimated, although the latter may be partially addressed by the inclusion of an "Inventory Cost" and a "Catalyst Disposal Cost." Lakeland should check to determine if the catalyst vendor offers free catalyst disposal as part of its replacement service. If additional catalyst is used, either the removal efficiency or catalyst life should be adjusted upward. Lakeland appears to be assuming that all of the catalyst will be replaced every year.
- Electrical costs are not documented and appear to be overestimated.
- If catalyst replacement is scheduled for some of the 1752 hours that the system will normally be down, there is no need to include a "MW Loss Penalty."
- The "Fuel Escalation" cost is not justified.

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

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

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

Conclusions and Recommendations

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

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

Visibility Analysis

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

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

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

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

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

Lakeland McIntosh

Given/Assumptions

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

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm			
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		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
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SW PSCo	Nov-96	15.0			
Blue Mtn. Pwr.	Jul-96			4.0	
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U.S.FISH&WILDLIFE SERVICE
AIR QUALITY BRANCH
P.O. BOX 25287, Denver, CO 80225-0287

FACSIMILE COVER SHEET

Date: April 2, 1998

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

To: Cleve Holladay

From: Ellen Porter

Subject: Technical Review Document of Lakeland McIntosh Additional Information

Number of Pages: 9
(Including this cover sheet)

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

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

by

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

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- If catalyst replacement is scheduled for some of the 1752 hours that the system will normally be down, there is no need to include a "MW Loss Penalty."
- The "Fuel Escalation" cost is not justified.

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

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

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

Conclusions and Recommendations

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

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

Visibility Analysis

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

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

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

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

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

Lakeland McIntosh

Plant Data

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

Lakeland McIntosh

Given/Assumptions

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

Lakeland McIntosh

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

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

Lakeland McIntosh

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

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

Lakeland McIntosh

Cost Effectiveness

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

Lakeland McIntosh

Environmental Impacts of SCR at 70% removal

NOx removed	596 TPY
Ammonia released	104 TPY @ 10 ppmv

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

Gas Turbine Limits from RBLC

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

Gas Turbine Limits from RBLC

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

Permits Pending or Not Yet in RBLC

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

U.S.FISH&WILDLIFE SERVICE
AIR QUALITY BRANCH

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

FACSIMILE COVER SHEET

Date: April 2, 1998

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

To: Ken Kosky / Cleve Holladay

From: Ellen Porter

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

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

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

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

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

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

Number of Pages: 2

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Number of Pages:2

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

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

Farzie Shelton, chE; REM

Manager of Environmental Licensing & Permitting

March 31, 1998

RECEIVED
APR 01 1998
BUREAU OF
AIR REGULATION

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

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

Dear Al:

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

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

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

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

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

Sincerely,

Farzie Shelton

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

Enc.

Cc: File
EPA
SWD
NPS
POLK Co.

Westinghouse Electric Corporation

Power Generation Business Unit

Generations Systems Divisions

The Quadrangle
4400 Alafaya Trail
Orlando Florida 32826-2399

COL W-COL-0020
File: 042.3

March 30, 1998

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

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

Dear Al:

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

Please advise if you require any additional assistance.

Regards,

Andy Mould
Project Manager, City of Lakeland

attachment

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

Westinghouse Combustion Technology Update

501G and Westinghouse Family of Combustion Turbines

Abstract

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

Background

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

Combustor Design Process

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

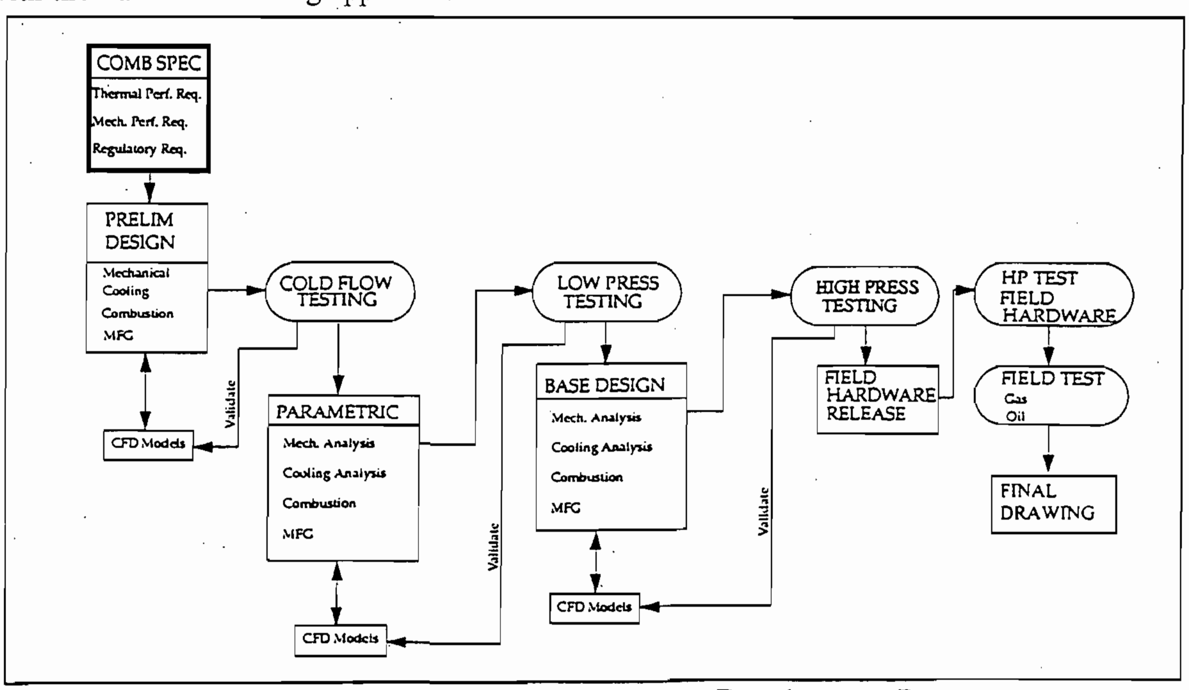

Figure 1 Flowchart Showing Combustor Development Process

CFD Analysis

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

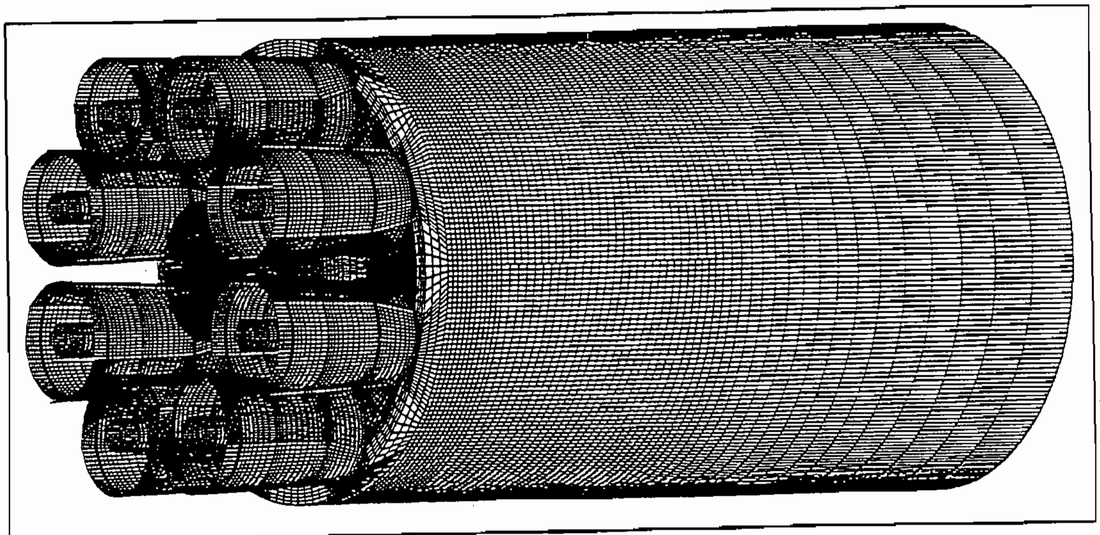

Figure 2. CFD Model

Test Facilities

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

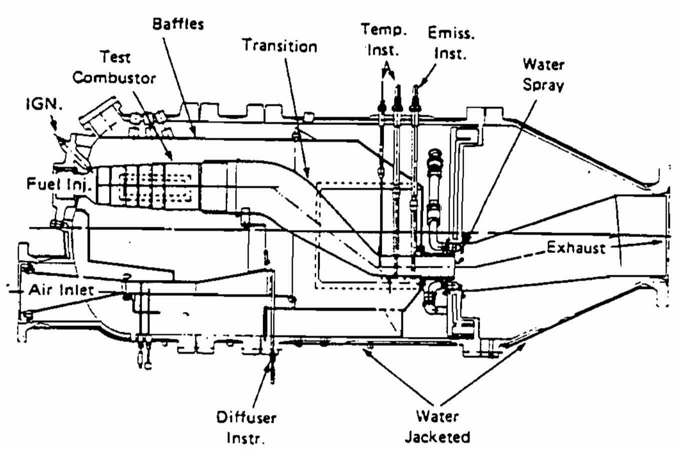

Figure 3. Full Pressure Test Rig

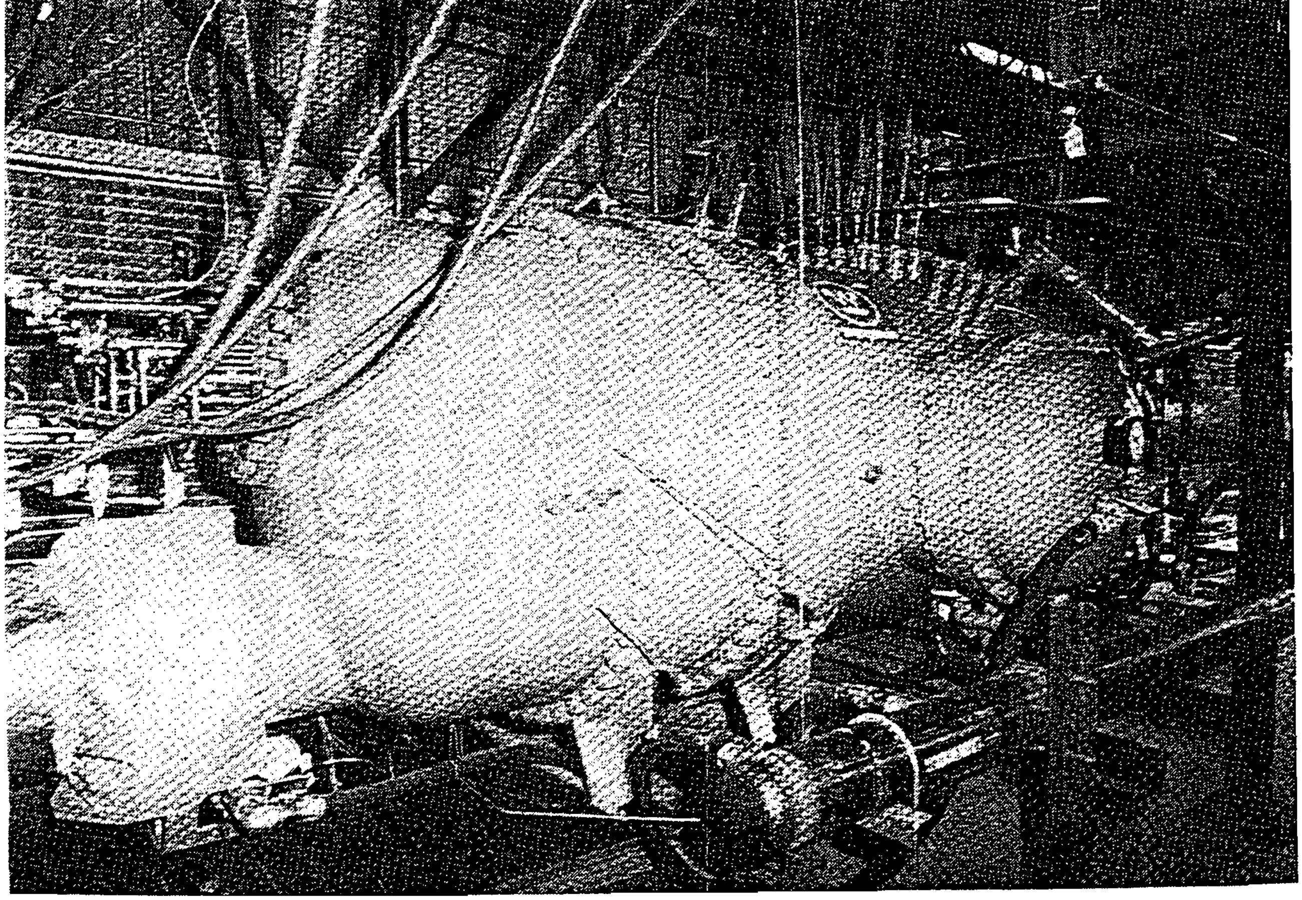

Figure 4 High Pressure Test Rig

Dry Low NOx Design Philosophy

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

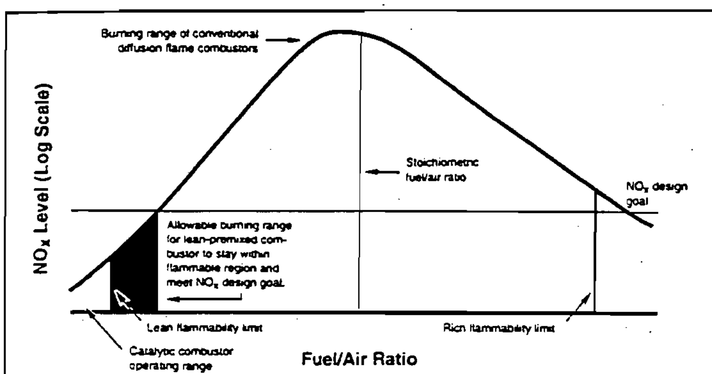

Figure 5 NO_X Formation vs. Fuel Air Ratio

Dry Low NOx Combustion Systems

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

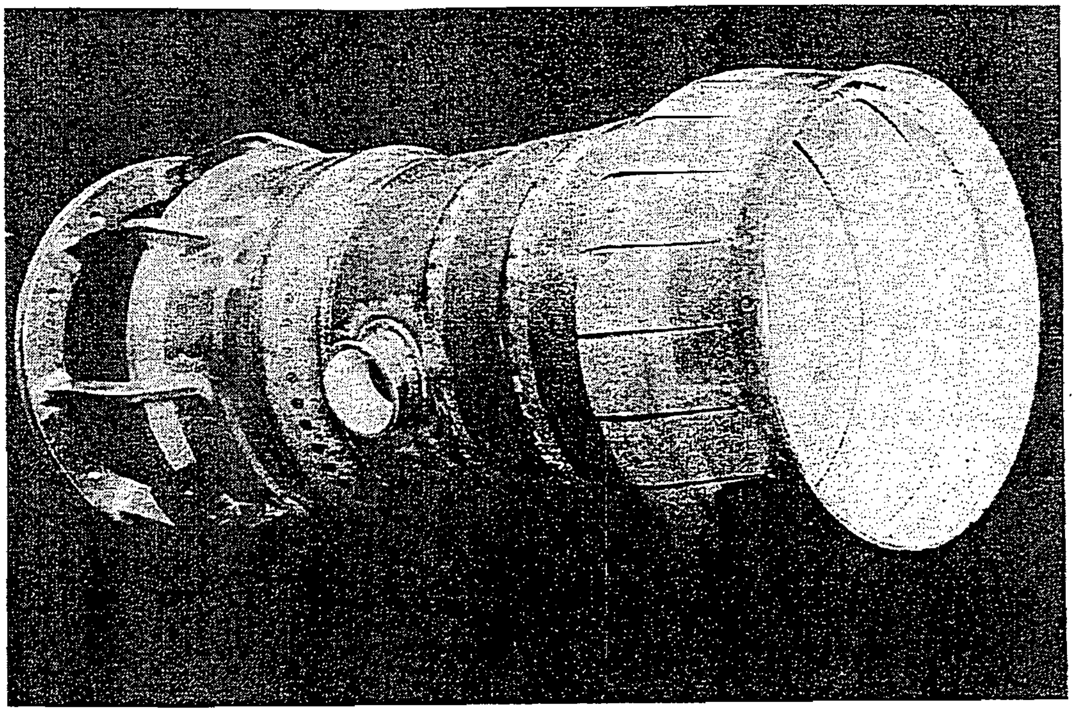

Figure 6

Table 1: Current Westinghouse 60 Hz engines

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

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

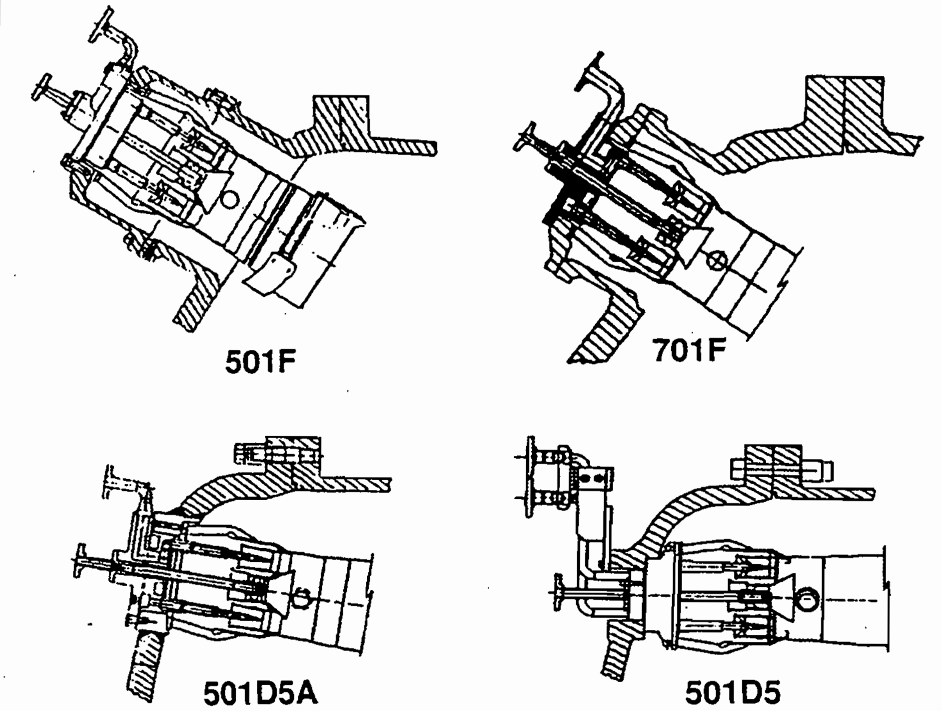

Figure 7. Dry Low NOx Engine Installations

Ultra Low NOx Program

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

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

Fully Premixed Design - Piloted Ring Combustor

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

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

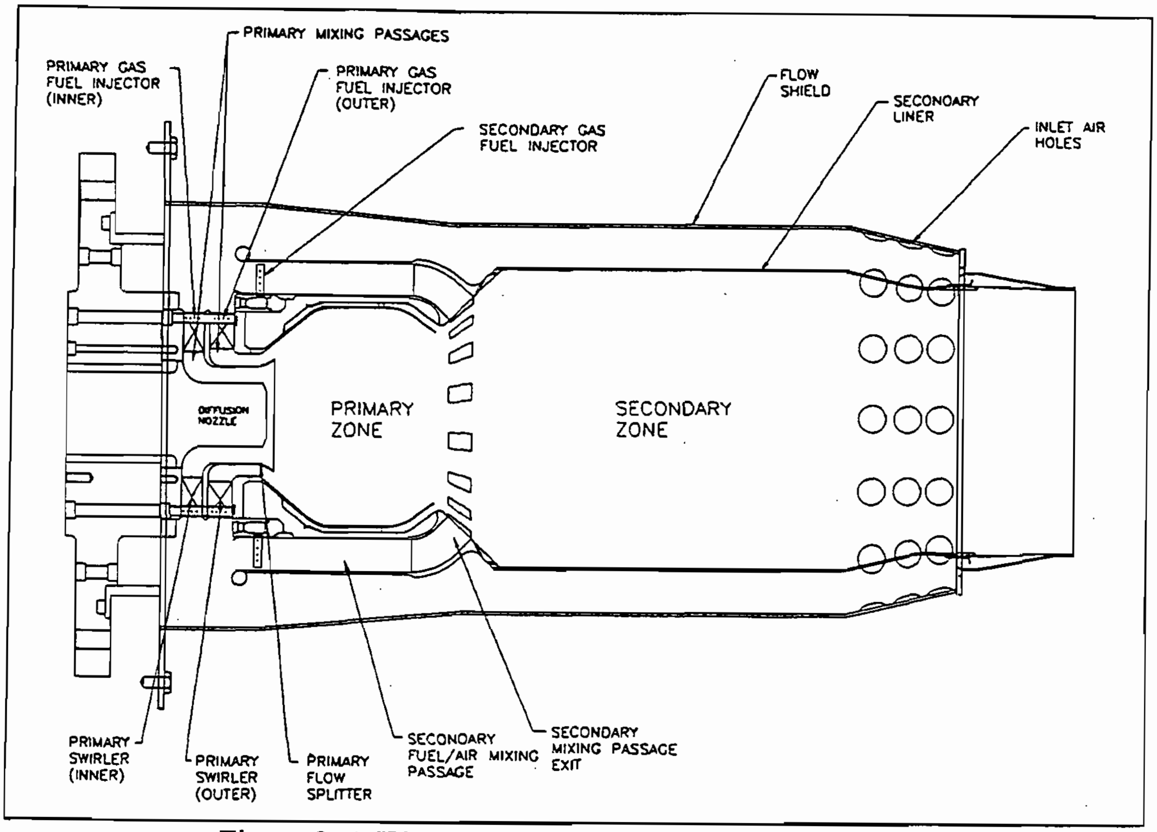

Figure 8 A Westinghouse Ultra Low NO_X Combustor

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

501G Combustion Systems - Development Status and Schedule

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

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

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

Summary

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

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION II
JACOB K. JAVITS FEDERAL BUILDING
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DEC 5 1996

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

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

Dear Mr. Brito:

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

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

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

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

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

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

Sincerely,

William [signature]
Jeanne M. Fox
Regional Administrator

Attachment

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

Norma Burgos, Chair
Puerto Rico Planning Board

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

Paul A. Eisen, Director
Environmental Sciences
SBE Environmental Company

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

ATTACHMENT I

PREPA Cambalache Combustion Turbine Project
Project Description

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

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

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

ATTACHMENT I

PREPA Cambalache Combustion Turbine Projec:
Project Description

<u>PREPA Cambalache Combustion Turbine Control Equipment;</u> The proposed facility will employ Best Available Control Technology to control the pollutants described above.

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

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

I. Permit Expiration

1. This PSD Permit shall become invalid if construction:

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

II. Notification of Commencement of Construction and Startup

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

III. Plant Operations

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

IV. Right to Entry

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

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

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

V. Transfer of Ownership

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

VI. Severability

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

VII. Operating Requirements

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

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

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

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

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

VII. Operating Requirements (cont'd)

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

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

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

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

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

1. Oxides of Nitrogen (NO_x)

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

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

2. Sulfur Dioxide (SO_2)

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

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

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

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

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

4. **Carbon Monoxide (CO)**

   a. The CO emissions shall not exceed:

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

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

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

5. **Particulate Matter (PM)**

   a. The PM emissions shall not exceed:

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

IX. Pollution Control Equipment

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

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

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

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

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

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

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

X. Fuel Sampling Requirements

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

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XI. Continuous Emission Monitoring (CEM) Requirements

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

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

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

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

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

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

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

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

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

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

XII. Performance Testing Requirements For Each Combustion Turbine

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

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

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

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

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

XIII. Recordkeeping Requirements

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

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

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

   c. the sulfur content of all fuel oil burned;

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

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

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

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XIV. REPORTING REQUIREMENTS

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

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

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

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

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XIV. REPORTING REQUIREMENTS (cont'd)

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

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

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

XV. OTHER REQUIREMENTS

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

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

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

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XV. OTHER REQUIREMENTS (cont'd)

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

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

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

ENGELHARD

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

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

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

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

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

WARRANTY AND GUARANTEE:

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

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

Typical, useful catalyst life is 5 - 7 years.

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

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

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

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

ENGELHARD

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

Performance Data

GIVEN / CALC. DATA				GIVEN / CALC. DATA	
LOAD	BASE	BASE	BASE	LOAD	BASE
AMBIENT	90	59	30	AMBIENT	30
FUEL	NG	NG	NG	FUEL	OIL
TURBINE EXHAUST FLOW, lb/hr	4,224,240	4,581,360	4,790,880	TURBINE EXHAUST FLOW, lb/hr	4,901,040
TURBINE EXHAUST TEMPERATURE, °F	1147	1114	1099	TURBINE EXHAUST TEMPERATURE, °F	1056
TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	69.07	71.36	72.21	TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	71.25
O_2	10.66	11.23	11.40	O_2	11.30
CO_2	4.03	4.06	4.09	CO_2	5.51
H_2O	15.35	12.44	11.38	H_2O	11.03
Ar	0.87	0.90	0.91	Ar	0.89
GIVEN: TURBINE NOx, ppmvd @ 15%O_2	25	25	25	GIVEN: TURBINE NOx, ppmvd @ 15%O_2	42
GIVEN: TURBINE NOx, lb/hr	220	237	249	GIVEN: TURBINE NOx, lb/hr	433
CALCULATED FLUE GAS MOL. WT.	27.65	27.97	28.09	CALCULATED FLUE GAS MOL. WT.	28.35
GAS TEMP. @ SCR CATALYST, °F (+/-20)	1018	1014	994	GAS TEMP. @ SCR CATALYST, °F (+/-20)	959
DESIGN REQUIREMENTS				DESIGN REQUIREMENTS	
NOx OUT, ppmvd@15%O_2	9	9	9	NOx OUT, ppmvd@15%O_2	ADVISE
NH_3 SLIP, ppmvd@15%O_2	10	10	10	NH_3 SLIP, ppmvd@15%O_2	10
SCR PRESSURE DROP, Nom. 4.0 "WG - Max.				SCR PRESSURE DROP, Nom. 4.0 "WG - Max..	
GUARANTEED PERFORMANCE DATA				EXPECTED PERFORMANCE DATA	
NOx CONVERSION, % - Min.	64.0%	64.0%	64.0%	NOx CONVERSION, % - Min.	69.0%
Nox OUT, ppmvd@15%O_2 - Max.	9	9	9	NOx OUT, ppmvd@15%O_2 - Max.	13
NOx OUT, lb/hr - Max.	79.1	85.4	89.5	NOx OUT, lb/hr - Max.	134.3
EXPECTED AQ. NH_3 (28% SOL.) FLOW, lb/hr	287	310	325	EXPECTED AQ. NH_3 (28% SOL.) FLOW, lb/hr	506
NH_3 SLIP, ppmvd@15%O_2 - Max.	10	10	10	NH_3 SLIP, ppmvd@15%O_2 - Max.	10
SCR PRESSURE DROP, "WG - Max.	3.5	3.5	3.5	SCR PRESSURE DROP, "WG - Max.	3.5

ENGELHARD

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

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

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

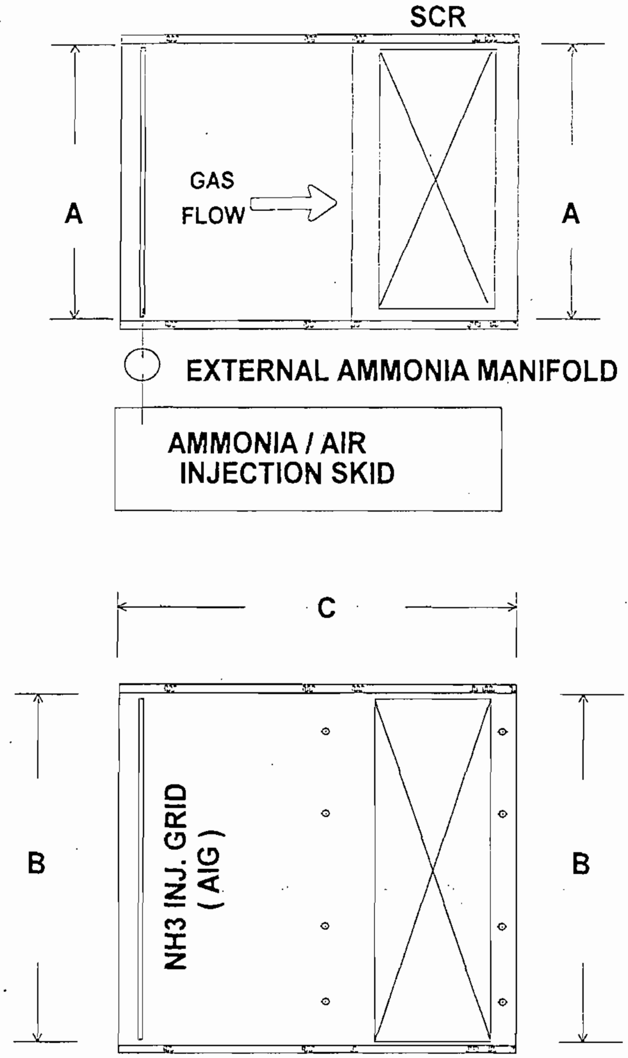
Excluded from Scope of Supply:

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

Dimensions: Estimated

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

Note: Cross section - dimensions can vary due to site



ENGELHARD

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

April 10, 1998

Florida DEP

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

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

Dear Mr. Linero,

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

This Proposal includes:

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

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Sales Engineer

cc: Lorraine Pierson - Proposal Administrator

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

March 9, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

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

Dear Mr. Tomlin:

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

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

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

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

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

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

Sincerely,

AA Linero 3/9

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

AAL/aal

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

Memorandum

Florida Department of
Environmental Protection

Is your **RETURN ADDRESS** completed on the reverse side?

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

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

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

Consult postmaster for fee.

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

4a. Article Number
P 265 659 304

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

7. Date of Delivery 3-12-98

5. Received By: *(Print Name)*

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

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

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 304

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Ronald Jordin	
Street & Number Lakeland Electric	
Post Office, State, & ZIP Code & Water	
Postage Lakeland, Fl	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 3-10-98	

1050004-004-AC
PSD-FL-245

PS Form **3800**, April 1995

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

al

MAR 0 6 1998

RECEIVED

MAR 1 1 1998

BUREAU OF
AIR REGULATION

4APT-ARB

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

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

Dear Mr. Fancy:

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

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

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

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

Sincerely yours,

Douglas Neeley

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

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

Westinghouse Electric Corporation

Power Generation Business Unit

Generations Systems Divisions

The Quadrangle
4400 Alafaya Trail
Orlando Florida 32826-2399

COL W-COL-0018
File: 042.3

March 26, 1998

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

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

Dear Al:

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

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

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

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

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

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

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

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

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

Regards,

Andy Mould

Andy Mould
Project Manager, City of Lakeland

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

Westinghouse
Electric Corporation

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

March 25, 1998

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

Subject: **Ultra Low NOx Combustion Technology**

Dear Farzie:

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

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

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

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

Very truly yours,

J. L. Gibson
Regional Marketing Manager

cc: Mr Al Dodd, Project Manager, McIntosh 5

LAKELAND
ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

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

March 11, 1998

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

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

Dear Al:

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

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

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

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

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

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

Sincerely,

Farzie Shelton, Manager
Environmental Licensing and Permitting

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

cc: EPA
NPS

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

General Requirements

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

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

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

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

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

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

Performance Testing

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

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

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

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

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

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

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

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

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

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

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

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

Performance Testing

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

    a. Method 1 for sample point location.

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

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

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

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

    f. Method 10 for concentration of carbon monoxide.

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

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

    i. Method 20 for the concentration of nitrogen oxides.

    j. Method 0011 for the concentration of formaldehyde.

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

Allowable Emissions

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

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

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

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

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

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

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

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

    e. exhibit greater than 20 percent opacity.

Allowable Emissions

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

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

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

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

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

    e. exhibit greater than 10 percent opacity.

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

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

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

Allowable Emissions

18. (cont.)

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

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

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

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

Monitoring Requirements

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

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

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

Monitoring Requirements

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

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

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

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

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

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

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

STATE OF GEORGIA
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ENVIRONMENTAL PROTECTION DIVISION

Notification, Reporting and Recordkeeping

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

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

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

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

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

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

Fugitive Emissions

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

Modifications

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

Special Conditions

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

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

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

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

AIR QUALITY PERMIT

Permit No.
4911-072-12256

Effective Date

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

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

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

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

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

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

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

Director
Environmental Protection Division

LAKELAND ELECTRIC & WATER
Excellence Is Our Goal, Service Is Our Job
(813) 499-6603
Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

March 4, 1998

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

RECEIVED
MAR 05 1998
BUREAU OF
AIR REGULATION

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

Dear Al:

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

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

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

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

March 4, 1998

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

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

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

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

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

March 4, 1998

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

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

As always, your cooperation and assistance is most appreciated.

Sincerely,

Farzie Shelton
Manager of Environmental Permitting/Compliance
Production Division

Enc.

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

Owner/Authorized Representative or Responsible Official

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

   Ronald W. Tomlin, Assistant Managing Director

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

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

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

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

4. Owner/Authorized Representative or Responsible Official Statement:

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

Ronald W. Tomlin 3-4-98

Signature Date

* Attach letter of authorization if not currently on file.

4. Professional Engineer's Statement:

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

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

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

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

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

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

Kennard F. Kosky | 2 March 1998

Signature | Date

(seal)

* Attach any exception to certification statement.

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

Information Addressing the January 5, 1997 FDEP

Lakeland 250 MW Combustion Turbine Project (Westinghouse 501G

Pollutant Emissions

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

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

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

Power Augmentation:

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

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

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

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

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

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

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

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

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

Best Available Control Technology:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Source: Westinghouse, 1997; EPA, 1996

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

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

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

Sources: Westinghouse, 1997; EPA, 1996

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

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

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

Sources: Westinghouse, 1997; a-EPA, 1996

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

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

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

Sources: Westinghouse, 1997; a-EPA, 1996

Fuel Analysis

No. 2 Fuel Oil

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

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

[1] Data taken from the fuel procurement specification

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Note: ISO Conditions used for comparison.

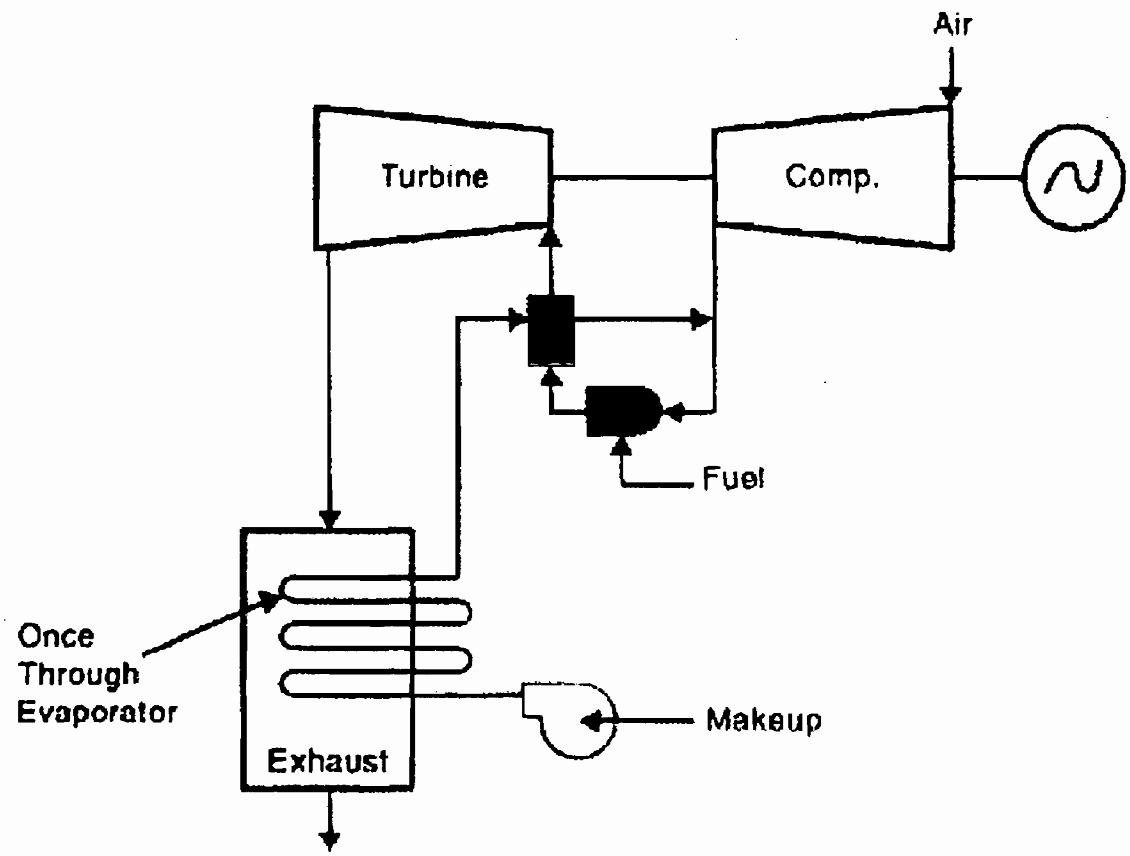
Table B-9. Cost Comparison of Lakeland 501G with 2 Frame F Combustion Turbines

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

Note: ISO Conditions used for comparison.

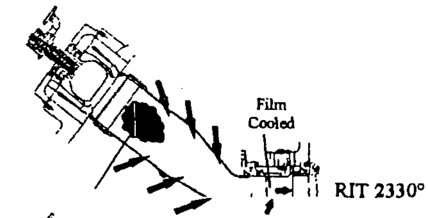
STEAM COOLING DIAGRAMS

501G S.C.
Transition Steam Cooling - Open



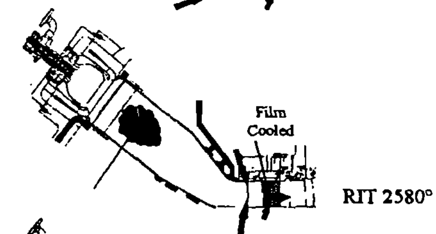
F Technology

BOT 2700°F - 2850°F



G Technology

BOT 2700°F - 2850°F



ATS Technology

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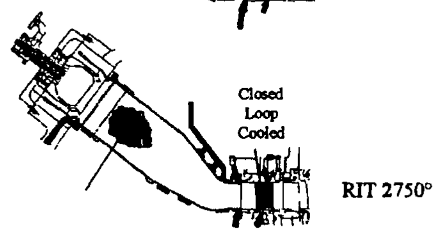
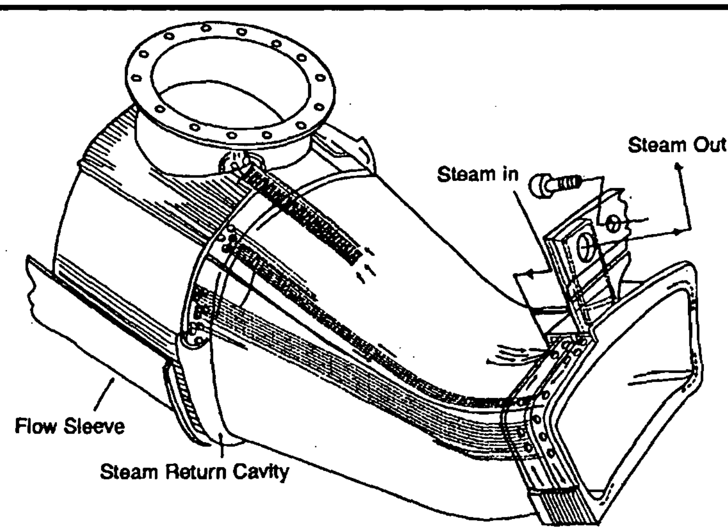


Transition - Steam Cooling



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

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

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

Technical Implications--The exhaust temperature of the advanced 501G is at temperatures exceed that required to install a high temperature. While much smaller conventional and aero-derivative turbines have exhaust temperatures that could accommodate the installation of high temperature catalyst modules (i.e., maximum temperatures of 1,100^{0} F), this in not the case with the 501G or even "F" Class turbines. The potential feasibility of installing a "hot" SCR with the proposed Lakeland 501G project, only comes with the installation of the once through steam generator (OTSG). As discussed in previous responses the OTSG is needed to supply cooling steam required for the 501G. If the project is converted to combined cycle a heat recovery steam generator (HRSG) would be installed to produce steam for a steam electric generator. The HRSG could provide the steam for cooling more efficiently, therefore the OTSG would no longer be needed. Because of the various steam production requirements needed for steam electric turbine and optimizing steam production quality, it is not feasible to place a HRSG after the OTSG.

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

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

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

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

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

Best Available Control Technology (BACT)

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

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

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

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

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

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

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

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

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

Air Quality Related Values (AQRV) Analysis

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

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

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

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

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

It must be noted that these results are conservative since:

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

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

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

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

Information Addressing the February 10, 1998 Letter from EPA
Lakeland 250 MW Simple Cycle Combustion Turbine Project (Westinghouse 501G)

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

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

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

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

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

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

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

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

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 5, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

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

Dear Mr. Tomlin:

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

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

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

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

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

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

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

Sincerely,

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

AAL/th

Attachment

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

ADDITIONAL COMMENTS - LAKELAND 250 MW COMBUSTION TURBINE PROJECT

POLLUTANT EMISSIONS

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

POWER AUGMENTATION

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

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Fille
AC
T3R55A

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

RECEIVED

FEB 23 1998

BUREAU OF
AIR REGULATION

4APT-ARB

FEB 10 1998

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

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

Dear Mr. Fancy:

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely yours,

for

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

cc: NPS
SWD
polk Co
J. Shelton, CofL
K. Kosky, Golder Assoc.

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 12, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

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

Dear Mr. Tomlin:

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

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

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

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

Sincerely,

A A Linero 1/12

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

AAL/aal

Attachment

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

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

January 15, 1998

RECEIVED
JAN 20 1998
BUREAU OF
AIR REGULATION

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

Dear Mr. Fancy:

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

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

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

cc:
EPA
SWD
POLK CO
J. Shelton, C of L
K. Kosky, Golder

Sincerely yours,

H Dale Hall
for Sam D. Hamilton
Regional Director

cc: T. Heron, BAR

Enclosures

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

by

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

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

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

<u>**Best Available Control Technology (BACT) Analysis**</u>

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

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

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

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

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

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

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

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

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

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

Gas Turbine Limits from RBLC

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

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

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

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

Sources less than 50 km from a Class I area:

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

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

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

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

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

4APT-ARB

FEB 10 1998

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

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

Dear Mr. Fancy:

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely yours,

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

Westinghouse
Electric Corporation

Generation Systems Division

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

COL W/COL-006
File: 016.1

January 21, 1998

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

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

Dear Farzie:

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

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

Regards,

Robert O'Bay — for Andy Mould

Andy Mould
Manager, City of Lakeland

enclosure

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

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

January 15, 1998

RECEIVED

JAN 20 1998

BUREAU OF
AIR REGULATION

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

Dear Mr. Fancy:

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cc:
EPA
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J. Shelton, C of L
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Sincerely yours,

H Dale Hall

for Sam D. Hamilton
Regional Director

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

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by

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

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

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

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

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

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

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

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

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

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

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

January 12, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

Attached are the comments we received by Fax from the Air Quality Branch of the Fish and Wildlife Service. We will send you a copy of the signed version when we receive it. Please note their comments regarding the proposed Best Available Control Technology (BACT) nitrogen oxides (NO_X)emission limit of 25 ppm. They also have requested some additional modeling which would might not be necessary if the emissions were lower.

We have reviewed the BACT information in the application in more detail. It appears that it would not be necessary to write off high temperature SCR (installed at start-up) if and when a heat recovery steam generator (HRSG) were installed in the future. Therefore additional costs of future Dry Low-NO_X (DLN) technology and/or low temperature SCR do not need to be summed into the long term cost of pollution control by hot SCR.

High temperature SCR could be installed by start-up. Westinghouse would not then need to attempt to refine its DLN technology (for this project) to achieve lower NO_X emissions at higher temperature and pressure ratios under such challenges as pressure pulsation and lower flame stability. Low temperature SCR might not need to be installed later. In fact, HRSG operation would likely be simplified by one-piece construction instead of having separate components with a low temperature SCR module in-between. This approach would allow the City to proceed with the planned staged project, satisfy BACT requirements for NO_X, and defer the decision on installation of a HRSG until a future date consistent with the PSD application.

We are still awaiting comments from EPA If you have any questions regarding this matter, please contact Teresa Heron (review engineer) or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A A Linero 1/12

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/aal

Attachment

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
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3. Article Addressed to:
Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water
501 E. Lemon St.
Lakeland, Fl
33801-5079

4a. Article Number
P 265 659 279

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Diane Mullis

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PS Form **3811,** December 1994

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TOTAL Postage & Fees	$
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PS Form **3800**, April 1995

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration Application for the City of Lakeland's proposed 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. The technical review comments from our Air Quality Branch are enclosed. Specifically, we recommend that your department require Lakeland to meet lower limits on nitrogen oxides emissions than those proposed. At the proposed limits, Lakeland has predicted that significant visibility degradation will occur in Chassahowitzka. In addition, lower limits would more accurately reflect best available control technology.

In addition, we are enclosing the "Interim Visibility Modeling Guidance for Sources Locating or Expanding Near Chassahowitzka Wilderness, Florida." As you know, we have enclosed this document with other recent comment letters to your department and we ask you to provide this document to future PSD applicants. Our Air Quality Branch is compiling a more detailed and comprehensive document addressing visibility analyses that will be available in early 1998.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ellen Porter of our Air Quality Branch in Denver at (303) 969-2617.

Sincerely,

Sam D. Hamilton
Regional Director

Enclosures

cc: Doug Neeley, Chief
Air and Radiation Branch
U.S. EPA, Region IV
100 Alabama St., SW
Atlanta, Georgia 30303

bcc: FWS-REG. 4: AQC
CHAS: Refuge Manager
AQD-DEN: Ellen Porter
National Park Service - AIR
P.O. Box 25287
Denver, CO 80225

Technical Review of Prevention of Significant Deterioration Permit Application
For a 250-Megawatt Simple Cycle Combustion Turbine at
McIntosh Power Plant
Polk County, Florida

by

Air Quality Branch, Fish and Wildlife Service – Denver
January 6, 1998

The City of Lakeland (Lakeland) is proposing to construct a 250-megawatt simple cycle combustion turbine at the McIntosh Power Plant in Polk County, Florida. The power plant is located 90 km southeast of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. Lakeland proposes to use natural gas as the primary fuel and low-sulfur (0.05 %) fuel oil as backup fuel for the turbine. Therefore, sulfur dioxide emissions will be minimized and less than significant for Prevention of Significant Deterioration (PSD) Review. However, the project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), particulate matter (PM-10), volatile organic compounds (VOC), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	863
PM-10	41
VOC	94
CO	1264

<u>Best Available Control Technology (BACT) Analysis</u>

Lakeland has proposed a simple cycle turbine system to generate electricity, rather than a more efficient combined cycle system with a heat recovery steam generator. In addition to being a less efficient system, emissions from the simple cycle system are inherently more difficult and expensive to control. We recommend that FDEP set emissions limits that reflect the end product, not the generation method (This is essentially the approach proposed by EPA in its New Source Performance Standards for boiler NO_X emissions.) Specifically, NO_x emissions should be limited to 5.0 parts per million by volume on a dry basis (ppmvd) during gas firing, and 20 ppmvd for oil firing, limits that could be achieved with selective catalytic reduction (a control technology that would be feasible with a combined cycle unit). These limits would result in a NO_x emission reduction of about 680 TPY. A second alternative would be to limit NO_x emissions to 9.0 ppmvd (while gas firing), which reflects the optimal use of the dry low-NO_x combustors proposed and would result in a NO_x emission reduction of about 545 TPY. Our comments on Lakeland's BACT analysis follow.

Lakeland has proposed the use of advanced dry low-NO_x combustors to meet NO_x limits of 25 ppmvd corrected to 15% oxygen (O_2) while burning natural gas. Water injection would be used to meet NO_X limits of 42 ppmvd while burning fuel oil. A review of the EPA

RACT/BACT/LAER clearinghouse data submitted by the applicant found at least 18 examples (see enclosed table) of gas turbines using dry low-NO_x combustors permitted with NO_x limits in the 9-15 ppmvd range. In addition, the applicant states, "NO_x emissions ranging from 25 to 9 ppmvd (corrected to 15% O_2) has been offered by manufacturers for advanced combustion turbines." Therefore, this technology is capable of achieving emission limits well below the 25 ppmvd proposed by the applicant.

Even greater NO_X removal efficiency could be achieved by the use of selective catalytic reduction (SCR). SCR is capable of 70% NO_x removal efficiency. The attached table (showing NO_X limits from 43 gas turbines) demonstrates that SCR can achieve emission limits of 2.5-17.0 ppmvd. However, Lakeland has rejected the use of SCR on the grounds of economic unfeasibility. The high costs of SCR ($5,236 - $6,156/ton NO_x removed) are in part due to the high (1000–1100 °F) exhaust temperature of this simple cycle gas turbine which would require the use of high temperature catalyst materials and shorten equipment life. By contrast, a combined cycle system would use the waste heat from the turbine and its exhaust temperature would be lowered into the range at which less expensive SCR systems can function.

The high costs calculated are also due to calculation errors on the part of the applicant. For example:

- Contingency costs are overestimated at 10% of Total Direct Capital Cost instead of 3% of the Purchased Equipment Cost.
- Operating and maintenance labor costs exceed the costs estimated by EPA (EPA Control Cost Manual).
- Ammonia costs appear too high and should be documented.
- The Capital Recovery Factors are too high because they are based on a 10% interest rate instead of the 7% rate recommended by EPA.
- Contingency costs have arbitrarily been added to Direct Annual Costs and Energy Costs without any justification.
- The "Heat Rate Penalty" should be explained and justified.
- The inclusion of both an "Inventory Cost" and "Annualized Total Direct Recurring" capital cost appears to be "double-counting" the cost of replacing the catalyst.

Lakeland has also presented SCR economic costs associated with a possible conversion to a combined cycle system in five years. These associated costs should not be considered without a commitment from Lakeland regarding the future conversion.

Air Quality Related Values (AQRV) Analysis

The current information provided by the applicant suggests that, at the proposed NO_X emissions rates, visibility will be unacceptably degraded at Chassahowitzka. Lakeland's regional haze analysis predicted that the project's emissions would cause a change of 0.97 deciview at Chassahowitzka. This is significantly higher than the 0.5 deciview screening value for a single source (see attached *Interim Visibility Modeling Guidance for Sources Locating or Expanding Near Chassahowitzka Wilderness, Florida*). In addition, the 0.97 deciview value is underestimated because Lakeland did not include potential impacts from their PM-10 emissions in the analysis.

The predicted visibility degradation from Lakeland's new turbine is likely to constitute an adverse impact to visibility at Chassahowitzka, as defined by the federal visibility protection regulations (40 CFR 51.300, *et seq.*, 52.27). Therefore, we recommend that FDEP require Lakeland to meet lower NO_x emissions limits to ensure that this project's contribution to regional haze is less than 0.5 deciview. Lakeland should perform a new regional haze analysis (including PM-10 emissions and lower NO_x emissions rates) to demonstrate that the project's impacts are less than 0.5 deciview. Lakeland should perform this analysis according to guidance provided by our office and the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 1 Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility*, EPA-454/R-93-015, April 1993. If Lakeland is unwilling to accept lower NO_x limits, we recommend that FDEP deny the permit on the basis of potential adverse impacts to the Class I area.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

BEST AVAILABLE COPY

Gas Turbine Limits from RBLC

		NOx Emission Limits < 25 ppm			
	Permit	Dry Lox-NOx Comb.		SCR	
	Issue	Gas	Oil	Gas	Oil
Facility Name	Date	(ppm)	(ppm)	(ppm)	(ppm)
Formosa Plastics	Mar-97	9.0			
SW PSCo	Nov-96	15.0			
Blue Mtn. Pwr.	Jul-96			4.0	
Mid-Ga. Cogen	Apr-96			9.0	20.0
Seminole Hardee Unit 3	Jan-96	15.0			
Brooklyn Navy Yard Cogen	Jun-95			3.5	10.0
Panda-Kathleen	Jun-95	15.0			
Pilgrim Energy Center	Apr-95			4.5	
Gainesville Regional Utilities	Apr-95	15.0			
Formosa Plastics	Mar-95	9.0			
Lap-Cottage Grove	Mar-95			4.5	
Portland General Elec.	May-94			4.5	
Hermiston Generating	Apr-94			4.5	
Florida Power	Feb-94	12.0			
Orange Cogen	Dec-93	15.0			
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Phoenix Power Part.	May-93	22.0			
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Kissimmee Utility Authority	Apr-93	15.0			
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Sithe/Independence	Nov-92			4.5	
Kamine/Besicorp	Nov-92	9.0		9.0	
Kamine/Besicorp	Nov-92	9.0		9.0	
Grays Ferry	Nov-92	9.0			
Goal Line	Nov-92			5.0	
Bear Island Paper	Oct-92			9.0	15.0

Gas Turbine Limits from RBLC

Facility Name	Permit Issue Date	NOx Emission Limits < 25 ppm: Dry Lox-NOx Comb. Gas (ppm)	Dry Lox-NOx Comb. Oil (ppm)	SCR Gas (ppm)	SCR Oil (ppm)
Gordonsville Energy	Sep-92			9.0	
Pansy/Holtsville	Sep-92	9.0			
Saranac Energy	Jul-92			9.0	
Selkirk Cogen	Jun-92			9.0	
Narragansett Elec.	Apr-92			9.0	
Bermuda Hundred	Mar-92			9.0	15.0
Kalamazoo Power	Dec-91	15.0			
So. Cal. Gas	Oct-91			8.0	
Sumas Energy	Jun-91			8.0	
Granite Rd. Ltd.	May-91			3.5	
Lakewood Cogen	Apr-91			9.0	
Cimaron Chemical	Mar-91			9.0	
Seminole Fertilizer	Mar-91			9.0	
Sumas Energy	Dec-90			9.0	
Newark Bay Cogen	Nov-90			8.3	
Las Vegas Cogen	Oct-90			10.0	
Doswell Ltd.	May-90			9.0	
Pedricktown Cogen	Feb-90			9.0	
Arrowhead Cogen	Dec-89			9.0	
Richmond Power Enterprise	Dec-89			8.2	
Kingsburg Energy Sys.	Sep-89			6.0	
Unocal	Jul-89			9.0	
Pawtucket Power	Jan-89			9.0	
Ocean State Power	Dec-88			9.0	
Baf Energy	Jul-87			9.0	
Cogen Technologies	Jun-87			9.6	
Western Power Sys.	Mar-86			9.0	
Union Oil	Mar-86			2.5	
Ols Energy	Jan-86			9.0	
American Cogen Tech.	Sep-85			17.0	
Sunlaw	Jun-85			9.0	
Willamette Ind.	Apr-85			15.0	

Interim Visibility Modeling Guidance
For Sources Locating or Expanding Near
Chassahowitzka Wilderness, Florida
December 1997

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***Sources less than 50 km from a Class I area*:**

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Sources greater than or equal to 50 km from a Class I area:

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Contact: Bud Rolofson, FWS Air Quality Branch (303) 969-2804

Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

January 5, 1998

Ms. Farzie Shelton
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

Re: McIntosh Unit No. 5

Dear Ms Shelton:

I have reviewed a copy of the Air Construction Permit Application submitted to the Bureau of Air Regulation on December 5, 1997. Based on the description of the project in your transmittal letter and on page 2-1 of the Air Permit Application and PSD Analysis, the Department has determined that this unit will result in an increase in steam-electric generating capacity at a certified power plant site. Because of the increase in steam generating capacity, your utilitiy is required to file an application pursuant to the Florida Electrical Power Plant Siting Act, sections 403.501-519, F.S. The initial $7,500 application fee will be applied against the required $75,000 power plant siting application fee.

Even if there were to be no increase in steam electric generating capacity for this unit, it would still be governed by the PPSA. The addition of Unit 5 at the certified McIntosh site requires that the conditions of certification for Unit 3 be modified. I suggest you review General Condition 1.

If there are any questions concerning this matter, I may be reached at (850) 487-0472.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

cc: Clair Fancy, P.E., BAR ✓
Tom Ballinger, PSC
Scott Goorland, OGC
cc: T. Heron, BAR

RECEIVED
JAN 06 1998
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AIR REGULATION

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

January 5, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

The Department has conducted a completeness review of the City of Lakeland's application received on December 8, 1997 for installation of a 250 megawatt Westinghouse 501G simple cycle combustion turbine and once-through steam generator to be referred to as Unit No. 5 at the C. D. McIntosh Power Plant. Please provide responses to our comments given below and our questions in the attachment.

Unit 5 will be located at a facility on a site which constitute an electrical power plant and site as defined in the Florida Electrical Power Plant Siting Act. We have forwarded a copy of your application to the Department's Office of Siting Coordination to determine whether or not construction of Unit 5 constitutes a new project or modification with respect to the Act. Please contact Mr. Buck Oven, P.E., at 850/487-0472 regarding the status of that review.

The Department is in the process of modifying the certification for the FPC Hines facility for a 243 MW project consisting of a 165 MW Westinghouse 501 FC combustion turbine and a 78 MW heat recovery steam generator. That project is characterized by a net heat rate of approximately 7000 Btu/kWh and emissions of 12 ppm of nitrogen oxides (NO_X) and 25 ppm of carbon monoxide (CO) while firing gas. The City of Tallahassee is also in the process of obtaining certification for a project with similar power, heat rate, and emissions characteristics to the FPC Hines project. The planned project at C. D. McIntosh exhibits a net heat rate of 8,725 Btu/kWh and emissions of 25 ppm of NO_X and 50 ppm of CO. Therefore, the limits requested by the City of Lakeland appear to be high without sufficient compensating energy, environmental, or economic benefits.

If the City were to include a heat recovery steam generator now, to yield closer to 350 MW, the project characteristics would be on the order of 6000 Btu/kWh and emissions of approximately 10 ppm of NO_X by low temperature selective catalytic reduction (SCR) and 10 ppm CO. This option would yield lower emissions with substantial energy benefits.

The cost calculations indicating that lower NO_X emissions are not economically feasible, and the higher CO emissions from power augmentation, are consequences of the City's plan or need to stage the project. It would be difficult for the Department to conclude that BACT should be less stringent as a result of project staging or uncertain ultimate development plans.

At this time, there is no reasonable assurance that Westinghouse will guarantee emissions less than 25 ppm through Dry-Low NO_X (DLN) combustion. If Westinghouse could guarantee a lower emission rate, it should be achieved at or very soon after start-up. The longer periods of time given to applicants in the early 90's were for the purpose of allowing development of the DLN technology. We do not consider the technology to be experimental anymore. For example, no additional time was provided to FPC or the City of Tallahassee to achieve the 12 ppm NO_X emission rate in their PSD permits.

We expect to receive comments from the Department of Interior and EPA Region IV and will forward them to you as soon as they are received. If you have any questions regarding this matter, please contact Teresa Heron (review engineer) or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A A Linero 1/5

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/th

Attachment

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

ADDITIONAL COMMENTS - LAKELAND 250 MW COMBUSTION TURBINE PROJECT

POLLUTANT EMISSIONS

1. Show basis of calculations and equivalence in lb/MMBtu emission rate for each one of the pollutants considered in this project.

2. Is it Lakeland's intention to operate Unit 5 under the two options presented in Table 2-5?

3. Please explain the apparent inconsistency between the 0.05 percent (%) maximum sulfur content of the No. 2 fuel oil shown on page 25 and the typical value of 0.5 % sulfur shown on the unnumbered "Fuel Analysis" page following Table A-18 in Appendix A.

POWER AUGMENTATION

4. How much more power output is due to operation in the power augmentation mode and will operation be continuous in that mode?

5. Expand on the details of the Westinghouse DLN burner technology (combustor silo vs. can-annular combustor). What is the firing temperature of this unit?

6. What is the heat input of the once-through steam generator? Describe the primary function of the once-through steam generator? Will this unit be part of the system after the possible installation of the heat recovery steam generator?

7. Submit corresponding data to scenarios presented (Section and Appendix A of the Application) excluding the power augmentation mode.

8. Power augmentation will allow the firing of additional natural gas while injecting steam into the turbine, to produce more megawatts. What is the NO_X emissions increase (ppmvd) during the power augmentation mode? Would power augmentation be the preferred mode of operation . Will power augmentation be during the peak-demand period.

9. Provide a more specific description of the conditions under which operation in the PA mode would be required.

10. Why can't the extra power capacity from the power augmentation be generated under the base load capacity of the CT?

11. Does Lakeland plan to operate in the power augmentation mode as standard operating procedure? Under what circumstances will the power augmentation mode operate (i.e. base load, peaking, etc.)?

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

12. Section B.2., BACT review, indicates that "the available information suggests that SCR with DLN combustor technology or with wet injection is also technically feasible." Was this design evaluated in the BACT analysis?

13. On page B-4 and B-5 it is stated that Westinghouse and GE have offered DLN combustors on advanced heavy-duty industrial machines. Were other manufacturers considered for this project? If so, what was the NO_X pppmv at 15% O_2 and the earliest delivery dates?

14. Are other vendors willing to provide a NO_X emissions limit guarantee less than 15 ppmvd at 15%? What is the cost of converting a CT from a dry low combustor which can initially limit NO_X emissions to 15 ppmvd at 15% O_2 to a combustor which is capable of achieving a 9 ppmvd at 15% during a maintenance period (for example by 2005)?

15. There is a discrepancy between the operating capacity listed on page 4-3, last paragraph, and Table 4-1(80 percent operating capacity vs 100 percent operating capacity). Which one is correct?

16. What type of catalyst was evaluated? Please refer to Section 4.3.1.1.3 and Pages B-5 and 45. Was the ceramic catalyst explored? This system does not promote the conversion of SO_2 to SO_3 and has virtually no catalysis poisoning, plugging or masking problems. The ammonia slip is also limited. In addition the catalyst is not considered a hazardous waste.

17. What will be the actual NO concentrations at the inlet to the SCR system?

18. Evaluate and compare the economic alternatives and the environmental benefits associated with the consumption of No. 2 fuel oil (0.05%) when calculating secondary emissions (Table 4-3, note 3). Show basis of calculations..

19. What other mechanism was considered (i.e. dilution air) to reduce the exhaust temperature to the optimum range of 600-750 degree Fahrenheit. What is the cost associated with use of this technology.

20. Was the economic analysis based on Engelhard quotations only?

21. Submit vendor-supplied design parameters (space velocity, ammonia-to-NO_X mole ratio, pressure drop, catalyst life). How many vendors supplied information.

22. On page 4-5, what is the basis for the values given in the last paragraph when analyzing SCR and combined cycle operation. Is the incremental cost effectiveness of $3,921/ton NOx removed based on combined cycle for the life of the project?

23. What is the possibility of developing more efficient combustors to reduce the emissions to 15 ppmvd by start-up. Application should address the possibility of using "improved combustors" which are capable of limiting NO_X emission to no greater than 15 ppmvd at 15 O_2.

24. Please provide more detailed information for equipment details specifications.

25. Please provide economic of using SCR for oil firing. Molecular sieve catalysts have been proven on oil operations.

26. Provide basis for using capable recovery factor with 12 percent over 20 years for annualized capital cost on Page 23. On Page B-23 Supplemental Calculations Related to SCR and Options: What is the basis of the average 20 years NOx emissions of 429 TPY. Please explain.

27. Page 49, paragraph 1 states that "While the increased firing temperature increases the thermal NO_X generated, this NO increase is controlled through combustion design" How much additional thermal NOx is due to higher temperature?

28. On page 4-4, the estimated cost of SCR is reported to be about $ 6,516 per ton of NOx removed and it exceeds $ 8,000 per ton of pollutant removed when the net emissions of all pollutants (exclusive of CO_2) are considered. Provide us with the names and addresses of all manufacturers that were contacted along with their estimates while developing capital and annualized cost estimates for this project.

29. It appears the cost effectiveness ($/ton removed) presented on using SCR technology is within a reasonable cost range when compared to similar projects. If you don't agree, please expand the BACT analysis for NO_X and CO to demonstrate the contrary. Include a table summarizing the emission reductions, economics, energy and environmental impacts of the control technology chosen (including the BACT limit determined) vs. the SCR technology rejected for different projects in Florida for the last 8 years.

30. What is the cost effectiveness ($/ton NO_X removed) of the proposed water injection technology?

Memorandum

Florida Department of
Environmental Protection

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ronald W. Tomlin, AND
Lakeland Electric & Water
501 E. Lemon St.
Lakeland, Fl
33801-5079

4a. Article Number
P 265 659 276

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
1-7-98

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Bernie Brew

PS Form **3811**, December 1994

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Thank you for using Return Receipt Service.

P 265 659 276

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Ronald Tomlin	
Street & Number Lakeland Electric	
Post Office, State, & ZIP Code & Water	
Postage Lakeland, Fl	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 1-5-97 1050004-004-AC PSD-Fl-245	

PS Form **3800**, April 1995

Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

April 22, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric and Water Utilities Department
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
250 Megawatt Combustion Turbine

Dear Mr. Tomlin:

Enclosed is one copy of the Draft Air Construction Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the referenced project at the C. D. McIntosh, Jr Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. The Department's Intent to Issue Air Construction Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" must be published within 30 (thirty) days of receipt of this letter. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit modification.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please call Ms. Teresa Heron at 850/921-9529 or Mr. Linero at 850/921-9523.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/aal

Enclosures

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
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- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water U.D.
501 E. Lemon St.
Lakeland, Fl 33801-5079

4a. Article Number
P 265 659 339

4b. Service Type
- ☐ Registered
- ☒ Certified
- ☐ Express Mail
- ☐ Insured
- ☐ Return Receipt for Merchandise
- ☐ COD

7. Date of Delivery

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Bonnie Pitts

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 339

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Ronald Tomlin	
Street & Number Lakeland Electric	
Post Office, State, & ZIP Code & Water	
Postage Lakeland, Fl	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 4-24-98 105C004-002-AC	

PS Form **3800**, April 1995

In the Matter of an
Application for Permit by:

Mr. Ronald W. Tomlin, Assistant Managing Director
City of Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

DEP File No. 1050004-004AC
DRAFT Permit No.: PSD-FL-245
C.D. McIntosh, Jr. Power Plant, Unit No. 5
Polk County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of DRAFT Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, City of Lakeland Electric & Water Utilities, applied on December 8,1997 to the Department for an air construction permit to construct a 250 megawatt combustion turbine with a once-through heat generator and a 1.05 million gallon fuel oil storage tank at the C.D. McIntosh, Jr. Power Plant, located at 3030 East Lake Parker Drive, Lakeland, Polk County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit under the provisions for the Prevention of Significant Deterioration (PSD)of Air Quality is required for the proposed work.

The Department intends to issue this Air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue AIR CONSTRUCTION PERMIT". The notice shall be published one time only within 30 (thirty) days in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 904/488-1344; Fax 904/ 922-6979) within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-103.150 (6), F.A.C.

The Department will issue the FINAL Permit, in accordance with the conditions of the enclosed DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT." Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the Department shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 4-24-98 to the person(s) listed:

Mr. Ronald W. Tomlin, City of Lakeland *
Ms. Farzie Shelton, City of Lakeland
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Bill Thomas, SWD
Mr. Buck Oven, DEP
Mr. Ken Kosky, P.E., Golder Associates
Mr. Joe King, Polk County

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

4-24-98
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050004-002AC (PSD-FL-245)

City of Lakeland Electric and Water Utilities Department
C.D. McIntosh, Jr. Power Plant - Unit No. 5
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to The City of Lakeland Electric & Water Utilities Department. The permit is to construct a 250 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine with a once-through steam generator, a 1.05 million gallon fuel oil storage tank, and a new 85-foot stack at the C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), volatile organic compounds (VOC) and carbon monoxide (CO) pursuant to Rules 62-212.400 and 410, F.A.C. and 40 CFR 52.21. The applicant's name and address are The City of Lakeland Electric and Water Utilities Department, 501 East Lemon Street, Lakeland, Florida 33801-5079.

The new unit is a Westinghouse 501 G, 250 MW turbine which will operate in simple cycle mode as a continuous duty unit. It will be the largest and most efficient simple cycle gas turbine installed in the United States to-date. The unit will operate primarily on natural gas and will be permitted to operate 7008 hours per year of which no more than 250 will be on 0.05 percent sulfur distillate fuel oil.

During the first three years of operation, NO_X emissions will be controlled by "Advanced Dry Low NO_X" technology combustors capable of achieving emissions of 25 parts per million by volume at 15 percent oxygen (ppm @15 % O_2). "Ultra Low NO_X" technology consisting of Piloted Ring Combustors is under development to achieve a limit of 9 ppm @15% O_2 (12 ppm averaged over 30 days) three years after start-up. Emissions of NO_X will be controlled under the minimal back-up fuel oil operation by water injection. SO_2 and PM/PM_{10} will be limited by use of clean fuels. Emissions of VOC will be controlled by good combustion practices. Emissions of CO will be similarly controlled unless the City chooses to install an oxidation catalyst.

The maximum potential annual emissions in tons per year based on the original application are summarized below. NO_X emissions will be reduced by over half after installation of the Ultra Low NO_X combustors. CO emissions will also be substantially lower as a result of the Department's BACT determination.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	41	25/15
SO_2	38	40
NO_X	863	40
VOC	93	40
CO	1264	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the Department shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

The Department will issue FINAL Permit with the conditions of the DRAFT Permit unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth below. Mediation is not available for the proposed action.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9370, fax: 904/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the Department's action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of
Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: (850)488-1344
Fax: (850)922-6979

Florida Department of
Environmental Protection
Southwest District Office
3804 Coconut Drive
Tampa, Florida 33619-8218
Telephone: (813)744-6100
Fax: (813)744-6084

City of Lakeland
Electric and Water Utilities
Attention: Ms. Farzie Shelton
501 East Lemon Street
Lakeland, Florida 33801-5079
Telephone: (941)499-6603
Fax: (941)603-6335

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 904/488-1344, for additional information.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

City of Lakeland Electric and Water Utilities

C. D. McIntosh, Jr. Power Plant Unit 5

250 Megawatt Combustion Turbine and
Once Through Heat Generator

Lakeland, Polk County

DEP File No. 1050004-004-AC
PSD-FL-245

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

April 22, 1998

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

City of Lakeland Electric and Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Authorized Representative: Mr. Ronald W. Tomlin, Assistant Managing Director

1.2 Reviewing and Process Schedule

12-08-97: Date of Receipt of Application
01-05-98: DEP Incompleteness Letter
03-05-98: Received Lakeland Response to Incompleteness Letter
04-01-98 Received Combustor Development Schedules from Lakeland and Westinghouse
04-22-98: Intent Issued

2. FACILITY INFORMATION

2.1 Facility Location

The C. D. McIntosh, Jr. Power Plant is located at 3030 East Lake Parker Drive in Lakeland, Polk County. This site is approximately 90 kilometers from the Chassahowitzka National Wilderness Area, a Class I PSD Area. The UTM coordinates of this facility are Zone 17; 409.0 km E; 3106.2 km N.

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3 Facility Category

This facility generates electric power from: two 3.5 megawatt (MW) diesel powered electric generators, one 20 MW gas and distillate-fired combustion turbine; one 90 MW gas and fuel oil-fired steam generator; one 115 MW gas and fuel oil-fired steam generator; and one 364 MW multiple (primarily coal) fuel-fired steam generator. The large 364 MW unit is serviced by a limestone sulfur dioxide scrubber.

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY.

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications at the facility resulting in emissions increases greater than 40 TPY of NO_X or SO_2, 25/15 TPY of PM/PM10, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.410, F.A.C.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	250 Megawatt Combustion Turbine and Once Through Steam Generator
002	Fuel Storage	1.05 Million Gallon Fuel Oil Storage Tank

The City of Lakeland (City) proposes to install a nominal 230 megawatt (MW) (net) new continuous duty, simple cycle, combustion turbine (Unit 5) at the existing C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive in Lakeland, Polk County. The project includes a Westinghouse 501 G combustion turbine operating primarily on natural gas, a once-through steam generator (OTSG), and a fuel oil storage tank. There are no plans to convert the unit to combined cycle operation. However the City wishes to maintain flexibility to make such a conversion in the future. This would involve additional heat recovery components and possible inclusion of a steam cycle.

An external perspective open view of the "501 G" is shown in Figure 1. The key components are identified in Figure 2. The unit will be delivered with 16 can-annular design, Advanced Dry Low NO_X combustors. These will be replaced with the more advanced piloted ring combustors designated as Ultra Dry Low NO_X burners. The unit incorporates steam cooling of key components, such as the transition pieces and turbine blade with subsequent steam injection for power augmentation. With power augmentation, the unit will produce approximately 250 MW of electrical power.

The main fuel will be natural gas and the unit will operate up to 7008 hours per year, of which no more than 250 hours represent fuel oil operation and 1000 represent "low load" operation. Emission increases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), particulate matter (PM/PM_{10}), volatile organic compounds (VOC) and nitrogen oxides (NO_X). Emission increases of SO_2, and H_2SO_4 will be less than their respective significant emission levels per Table 62-212.400-2, F.A.C. and do not require PSD or non-attainment new source review. PSD review is required for CO, PM/PM_{10}, NO_X, and VOC since emissions, per the application, will increase by more than their respective significant emissions levels.

4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 17-stage compressor of the 501 G where it is compressed by a pressure ratio of 19.2 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 16 separate can-annular combustors instead of a single combustion chamber.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 501 G operate at lower flame temperatures which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures up to 2700 °F. Steam cooling of key components of the 501 G minimizes the need for less efficient air cooling. The 501 G operates at the higher turbine inlet temperatures. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

There are four basic operating cycles for gas turbines. These are simple cycle, regenerative, and combined cycles. In the Lakeland project, the 501 G will operate in simple cycle mode and as a continuous duty unit (versus an intermittent duty peaking unit). Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically 30 to 35 percent, although the 501 G being introduced into the market, claims an efficiency of 38.5 percent. In addition to shaft energy output, 1 to 2 percent of fuel input energy can be attributed to mechanical losses. The balance is exhausted from the turbine in the form of heat.

Simple cycle operation offers the lowest installed capital cost. Although the 501 G has a remarkable simple cycle efficiency, this mode represents the least efficient use of fuel and therefore the highest operating cost. Because of the presence of the OTSG for more efficient steam cooling of key components and power augmentation, the cycle is somewhat like a regenerative cycle, wherein a heat exchanger (called a regenerator or recuperator) is used to preheat combustion air.

In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In this case, most of the steam is fed to a separate steam turbine which also drives an electrical generator. Typical combined cycle efficiencies are up to 55 percent. The 501 G can achieve up to 58 percent efficiency in combined cycle operation, especially if the gas turbine and the HRSG/steam generator power a common shaft connected to a single electric generator.

Additional process information related to the can-annular combustor design, and control measures to minimize NO_X formation are given in the draft BACT determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Polk County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, CO, VOC and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, VOC, CO, and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth. This project will also be reviewed for a minor modification of the existing Site Certification under the Power Plant Siting Act. A further, full review as a modification of the Site Certification will be conducted if and when the City requests authority to operate the unit in combined cycle mode and generate additional electricity from steam.

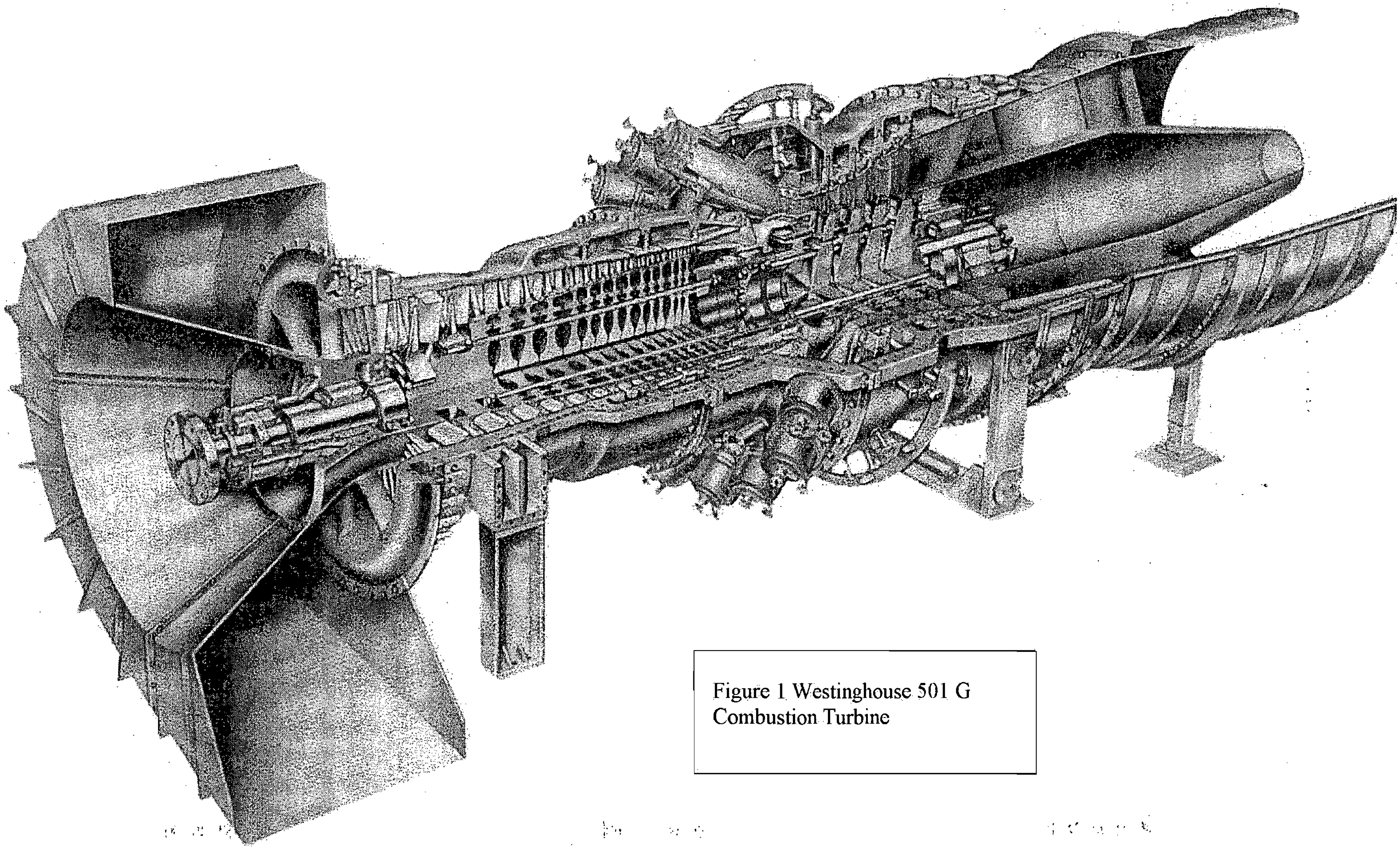

Figure 1 Westinghouse 501 G
Combustion Turbine

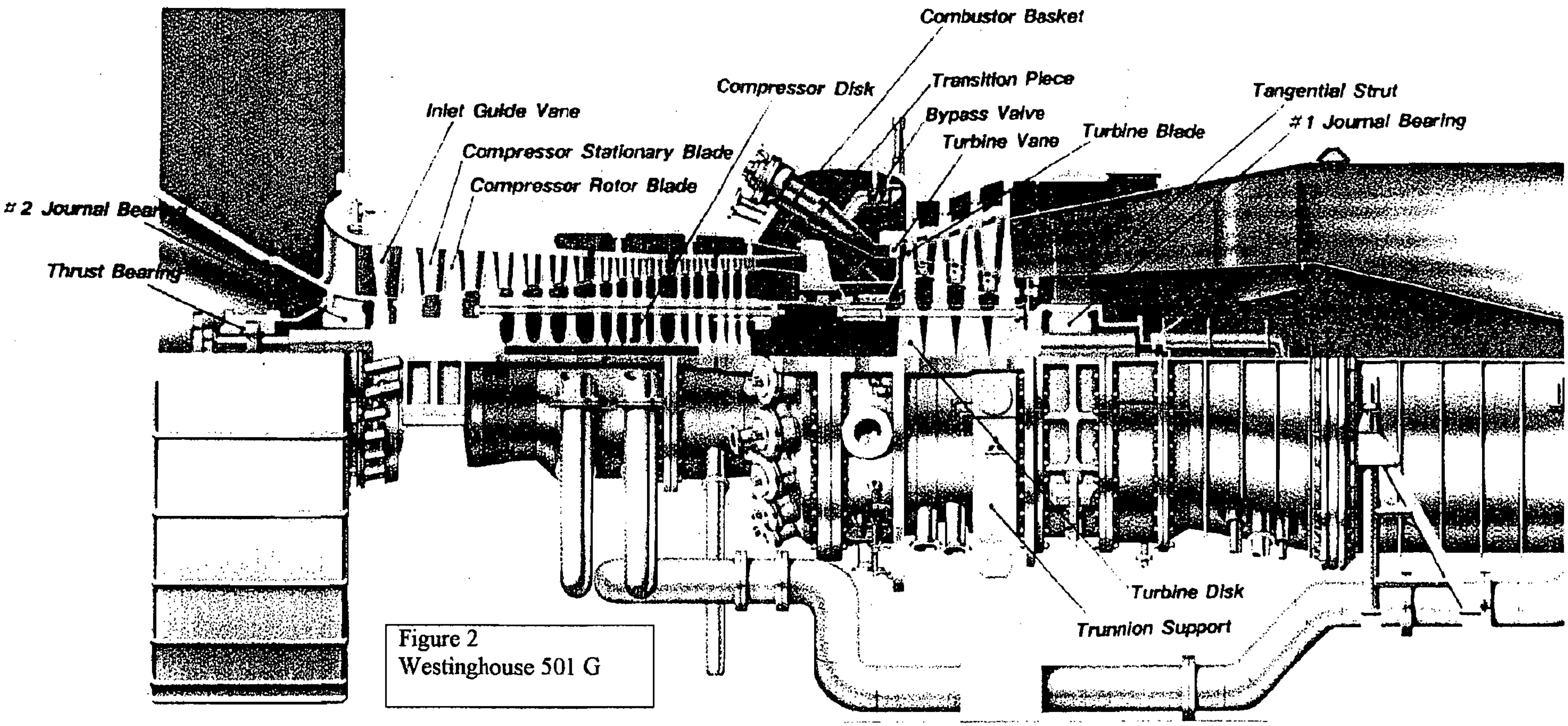

Figure 2
Westinghouse 501 G

The emission units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 60	NSPS Subparts GG and Kb
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)
40 CFR 52	Prevention of Significant Deterioration of Air Quality (applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed Unit 5 will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, sulfuric acid mist, and negligible quantities of fluorides, beryllium, mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for this Unit 5 are summarized in the Draft BACT document and Specific Condition Nos. 20-25 of Draft Permit PSD-FL-245.

6.2 Emission Summary

Table 1 PSD Applicability Summary

POLLUTANTS	POTENTIAL EMISSIONS TON/YR	PSD SIGNIFICANT EMISSION RATE TON/YR	PSD REVIEW REQUIRED [c]
PM	41.3 [a,b]	25	Yes
PM10	41.3 [a, b]	15	Yes
SO_2	38.4 [b]	40	No
NO_X	863 [a]	40	Yes
CO	1264.4 [a]	100	Yes
Ozone(VOC)	93.7 [a]	40	Yes
Sulfuric Acid Mist	5.9 [b]	7	No
Total Reduced Sulfur	NEG [d]	10	No
Hydrogen Sulfide	NEG [d]	10	No
Vinyl Chloride	NEG [d]	1	No
Total Fluorides	0.01 [b]	3	No
Mercury	0.0003 [b]	0.1	No
Beryllium	0.00005 [b]	0.0004	No
Lead	less than 0.1 [b]	0.6	No

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.

c If the netting procedure in 62-212.400(2)(d) F.A.C. results in a net emissions increase which exceeds the levels in Table 212.400-2, PSD requirements apply for the pollutants indicated.

d NEG = negligible emissions

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of clean natural gas and limited use of low sulfur (0.05 percent) distillate fuel oil. The combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The initial Advanced Dry Low NO_X combustors will be replaced after three years by Ultra Low NO_X technology consisting of Piloted Ring Combustors. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of four pollutants at levels in excess of PSD significant amounts: PM_{10}, CO, NO_X, and VOC. PM_{10} and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO and VOC are criteria pollutants and have only AAQS and significant impact levels defined for them. Since the project's VOC emissions increase is less than 100 tons per year no air quality analysis is required for VOC.

The applicant's initial PM_{10}, CO and NO_X air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for PM_{10}, CO and NO_X;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.4.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model 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, Florida (surface data) and Ruskin, Florida (upper air data). The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

For determining the project's significant impact area in the vicinity of the facility and if there are significant impacts from the project on any PSD Class I area, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.4.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions. If this modeling shows significant impacts, further modeling is required to determine the project's impacts on the existing air quality and any applicable AAQS and PSD increments. Receptors were placed within 12 km of the facility, which is located in a PSD Class II area, and the Chassahowitzka National Wilderness Area (CNWA) which is a PSD Class I area located approximately 91 km to the northwest of the project at its closest point. The receptor grid for predicting maximum concentrations in the vicinity of the project was a polar receptor grid comprised of 648 receptors. This grid included receptors located on 18 radials extending out from the proposed gas turbine stack location. Along each radial, 36 receptors were located at 10° intervals and 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 stack location. For predicting impacts at the CNWA, 13 discrete receptors along the border of the PSD Class I area were used. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility or in the CNWA. The tables below show the results of this modeling.

Maximum Project Air Quality Impacts for Comparison to the PSD Class II Significant Impact Levels in the Vicinity of the Facility

Pollutant	Averaging Time	Max Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	Significant Impact?
PM_{10}	Annual	0.03	1	NO
	24-hour	0.4	5	NO
CO	8-hour	9	500	NO
	1-hour	39	2000	NO
NO_2	Annual	0.1	1	NO

Maximum Project Air Quality Impacts for Comparison to the PSD Class I Significant Impact Levels (CNWA)				
Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m3)	Proposed EPA Significant Impact Level (ug/m3)	Significant Impact?
PM_{10}	Annual	0.007	0.2	NO
	24-hour	0.13	0.3	NO
NO_2	Annual	0.02	0.1	NO

The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.4.4 Impacts Analysis

Impact Analysis Impacts On Soils, Vegetation, And Wildlife

The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, and VOC as a result of the proposed project, including background concentrations and all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected.

Impact On Visibility

A regional haze analysis was done which shows that the proposed project will not result in adverse impacts on visibility in the PSD Class I area.

Growth-Related Air Quality Impacts

The proposed project is being constructed to meet current electric demands. Additional growth 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. Therefore, no additional growth impacts are expected as a result of the proposed project.

Air Toxics Air Quality Impacts

The maximum predicted impacts of regulated and non-regulated toxic air pollutants that are proposed to be emitted by the project are all less than the Department's draft Ambient Reference Concentrations (ARC).

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations, provided the Department's BACT determination is implemented.

A. A. Linero, P.E.
Teresa Heron, Review Engineer
Cleve Holladay, Meteorologist

PERMITTEE:

City of Lakeland
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Fl 33801-5079

File No.	1050004-004-AC
FID No.	1050004-004
SIC No.	4911
Permit No.	PSD-FL-245
Expires:	December 31, 1999

Authorized Representative:
Ronald W. Tomlin
Assistant Managing Director

PROJECT AND LOCATION:

Permit for the construction of 250 megawatt (MW) simple cycle, gas-fired, stationary combustion turbine (CT), a once-through steam generator, and a 1.05 million gallon storage tank for back-up distillate fuel oil. Conditions are included for possible future conversion to a 350 megawatt combined cycle installation including a heat recovery steam generator provided there are no increases in emissions associated with the conversion. The turbine is designated as Unit No. 5 and will be located at the C.D. McIntosh, Jr., Power Plant, 3030 East Lake Parker Drive, Lakeland, Polk County. UTM coordinates are: Zone 17; 409.0 km E; 3106.2 km N.

STATEMENT OF BASIS:

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

SUBSECTION A. FACILITY DESCRIPTION

The existing facility includes: two small diesel powered electric generators; one small gas and distillate-fired combustion turbine; one 90 MW gas and fuel oil-fired steam generator; one 115 MW gas and fuel oil-fired steam generator; and one 364 MW multiple (primarily coal) fuel-fired steam. This permit is for the installation of: a 250 MW simple cycle, gas-fired, stationary combustion turbine; a once-through steam generator; a 1.05 million gallon storage tank for back-up (0.05 percent sulfur) distillate fuel oil; and an 85-foot stack. It is possible that in the future the turbine will be converted by the addition of a heat recovery steam generator and a new stack to a 350 MW combined cycle operation without increases in emissions.

Emissions from Unit 5 will be initially controlled by Advanced Dry Low NO_X combustors, steam injection when firing fuel oil, use of inherently clean fuels, and good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions reduced by more sophisticated Ultra Low NO_X burners. Otherwise emissions will be reduced by the addition of a selective catalytic reduction (SCR) system.

SUBSECTION B. EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	250 Megawatt Combustion Turbine and Once Through Steam Generator
002	Fuel Storage	1.05 Million Gallon Fuel Oil Storage Tank

SUBSECTION C. REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications (such as the construction of Unit 5) at the facility resulting in emissions increases greater than 40 TPY of NO_X or SO_2, 25/15 TPY of PM/PM_{10}, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.410, F.A.C.

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

SECTION I. FACILITY INFORMATION

SUBSECTION D. PERMIT SCHEDULE

- 04/xx/98 Notice of Intent published in the Lakeland ________
- 04/23/98 Distributed Intent to Issue Permit
- 12/08/97 Received Application

SUBSECTION E. RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on December 8, 1997
- Department letters dated January 5, January 12, and March 9, 1998
- Comments and letters from the National Park Service dated January 6, January 12, April 2 and April 15, 1998.
- EPA letters dated February 10 and March 6, 1998
- City of Lakeland letters dated March 4, March 11, and March 31, 1998
- Letters from Westinghouse dated March 25, March 30, and March 31, 1998
- Department's Intent to Issue and Public Notice Package dated April 22, 1998
- Department's Final Determination and Best Available Control Technology Determination dated May xx, 1998

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District office (DEPSW), 3804 Coconut Palm Drive, Tampa, Florida 33619 and phone number 813/744-6100.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a conversion to combined cycle operation. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

This reassessment will be conducted for this project only if the conversion to combined cycle operation is accompanied by any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, or similar changes. [40 CFR 52.21(j)(4)]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Southwest District office (DEPSW). [Chapter 62-213, F.A.C.]
9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District office by March 1st of each year.
11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).
13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (7) (c) (1997 version), shall be submitted to the DEP's Southwest District office.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements
4. Emission Unit 001, Power Generation, consisting of a 250 megawatt combustion turbine with a once-through steam generator shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).
5. Emission Unit 002, Fuel Storage, consisting of a 1.05 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of performance for Storage Tanks, adopted by reference in Rule 62-204.800, F.A.C.
6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District office.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur No. 2 distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,174 million Btu per hour (mmBtu/hr) when firing natural gas, nor 2,236 mmBtu/hr when firing No. 2 fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Permitting Authority as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

Hours of Operation

13. Hours of operation for the stationary gas turbine and once through steam generator shall not exceed 7008 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

14. Hours of operation for the stationary gas turbine and once through steam generator shall not exceed 250 hours per year while firing distillate fuel oil. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Control Technology

15. Westinghouse Second Generation Advanced Dry Low NO_X (DLN) combustors (or equivalent) shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]

16. The initial combustors shall be replaced with Westinghouse Ultra Low NO_X (ULN) Piloted Ring Combustors within 36 months after start-up to accomplish further NO_X control unless a high temperature selective catalytic reduction (Hot SCR) system or a low temperature SCR system is installed within 36 months. [Design, Rules 62-4.070 and 62-212.410, F.A.C.]

17. The permittee shall design the stationary gas turbine, ducting, possible future heat recovery steam generator, and stack(s) to accommodate installation of SCR equipment or oxidation catalyst in the event that the ULN technology fails to achieve the NO_X or carbon monoxide (CO) limits given in Specific Condition No. 21 and 22 within 36 months after start-up. [Rule 62-4.070, F.A.C.]

18. A water injection system shall be installed for use when firing No. 2 fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.410, F.A.C.]

19. The Advanced DLN and ULN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the Advanced DLN or ULN systems in the diffusion firing mode shall be minimized when firing natural gas. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. The following emission limits based shall apply upon completion of the initial performance tests: Best Available Control Technology (BACT). Following is a summary of the BACT determination by DEP. Values for NO_X are corrected to 15% O_2. [Rule 62-212.410, F.A.C.]

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Simple Cycle	25 - NG 42 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Adv. DLN on gas, WI on oil. Applies first 36 months after startup. Clean fuels, good combustion
Simple Cycle	9 - NG 12 - (30 day) 42 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after 36 months operation. Clean fuels, good combustion
Simple Cycle	9 - NG 15 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies after 36 months if 9 ppm NOX not achievable by ULN. Clean fuels, good combustion.
Combined Cycle	7.5 - NG 15 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR if converted to combined cycle, unless 9 ppm is attained by ULN or Hot SCR as described above. Clean fuels, good combustion

21. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- During the first 36 months after start-up (commercial operation), the concentration of NO_X in the exhaust gas shall not exceed 25 ppmvd at 15% O_2 when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 24-hr average except during periods of startup, shutdown, malfunction or fuel switching, as measured by the continuous emission monitoring system (CEMS). NOx emissions calculated as NO_2 (at ISO conditions) shall not exceed 237 lb/hr (gas) and 413 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- Beginning 36 months after start-up, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during an annual compliance test not to exceed 9 ppmvd at 15% O_2 when firing natural gas. NO_X emissions shall not exceed 12 ppmvd at 15% O_2 when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 85 lb/hr (gas) and 413 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If Hot SCR is installed, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O_2 when firing natural gas. NO_X emissions shall not exceed 9 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 85 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If conventional SCR is installed in conjunction with conversion to combined cycle operation, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O_2 when firing natural gas. If conventional SCR catalyst is installed, NO_X emissions shall not exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. NOx emissions calculated as NO2 (at ISO conditions) shall not exceed 71.1 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

22. Carbon Monoxide (CO) emissions: The concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Reference Method 10 test. CO emissions (at ISO conditions) shall not exceed 106 lb/hr (gas) and 386 lb/hr (oil). [Rule 62-212.400, F.A.C.]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions (at ISO conditions) shall not exceed 7.2 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent sulfur distillate fuel oil No. 2 as measured by applicable compliance methods described below. Emissions of SO_2 shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review]

24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 fuel oil.

25. Volatile Organic Compounds (VOCs) Emissions: The concentration of VOCs in the exhaust gas when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as asured by EPA Methods 18, and/or 25 A. VOCs emissions (at ISO conditions) shall not exceed 10 lb/hr (gas) and 25 lb/hr (oil). -[Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

27. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C.

28. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

29. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-297, F.A.C.

30. Initial (I) performance tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of Ultra Low NOX burners, Hot SCR, or conventional SCR.

Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on Unit 5 as indicated. The following reference methods shall be used.. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I,A) short-term NO_X BACT limits (Method 7E or RATA test data may be used to demonstrate compliance for annual test requirement)
- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

31. Continuous compliance with the NO_X emission limits: Except as noted in Specific Condition No. 21, continuous compliance with the NO_X emission limits shall be demonstrated with the CEMS system based on a 30 day rolling average. Based on CEMS data, a separate compliance test is conducted at the end of each operating day and a new 30 day average emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. [Rule 62-4.070, F.A.C., 40CFR75]

32. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and the use of no more than 250 hours per year of maximum 0.05 percent sulfur (by weight) distillate No. 2 fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

33. Compliance with CO emission limit: An initial test for CO, concurrent with the initial NO_X test, is required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing may be conducted concurrent with the annual RATA testing required pursuant to 40 CFR 75 (required for gas only).

34. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, CO emission limit will be employed as surrogate.

35. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. nce the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-297 F.A.C.

36. Test Notification: The DEP's Southwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

37. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

38. Test Results: Compliance test results shall be submitted to the DEP's Southwest District office no later than 45 days after completion of the last test run.

NOTIFICATION, REPORTING, AND RECORDKEEPING

39. Records: All measurements, records, and other data required to be maintained by the City of Lakeland Department of Electric & Water Utilities shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

40. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed with the DEP SW District Office as soon as practical, but no later than 45 days after the last sampling run is completed. [Rule 62-297.310(8), F.A.C.]. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 5. Periods when NOX emissions (ppmvd @ 15% oxygen) are above the BACT standards listed in Subsection C. Specific Condition C.1. shall be reported to the DEP Southwest District Office pursuant to Rule 62-4.160(8), F.A.C. Periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the BACT standards following the format of 40 CFR 60.7 (1997 version).

42. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NOX on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NOX standard established in 40 CFR 60.332.

43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, and 40 CFR 60.75 including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5). Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Southwest District Office (DEPSWD) for review at least 90 days prior to installation.

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at the C.D. McIntosh , Jr. Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- Monitoring of natural gas nitrogen content shall not be required.
- Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods in Specific Condition No. 32 for the measurement of sulfur in gaseous fuels, or an approved alternative method. Once Unit 5 becomes operational, monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur

content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.

- Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify DEP of such excess emissions and the customized fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.
- The City shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.
- Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.
- The City may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission) provided the test methods listed in Specific Condition E.4 are used.

46. <u>Determination of Process Variables</u>:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

C. D. McIntosh, Jr. Power Plant
City of Lakeland Electric & Water Utilities
PSD-FL-245 and 11050004-004AC
Lakeland, Polk County, Florida

BACKGROUND

The applicant, The City of Lakeland (City), proposes to install a nominal 250 megawatt (MW) (net) new simple cycle combustion turbine at the existing C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive in Lakeland, Polk County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400 and 410, F.A.C.

The unit to be installed is a 230 MW Westinghouse 501 G combustion turbine and includes a once through steam generator (OTSG) which provides steam for steam cooling of critical components and injection for further cooling and power augmentation to 250 MW. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination issued with the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on December 8, 1997 and included a proposed BACT determination prepared by the applicant's consultant, Golder Associates Inc.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E., and Teresa Heron, Review Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil Use (250 hr/yr) Combustion Controls	9.1 lb/hr (Gas) 140 lb/hr, 0.05% sulfur (Oil)
Volatile Organic Compounds	As Above	4 ppm (Gas) 10 ppm (Oil)
Visibility	As Above	20 percent
Carbon Monoxide	As Above	50 ppm (Gas, baseload) 90 ppm (Oil, baseload)
Nitrogen Oxides	Advanced Dry Low NO_X Burners (Gas) Water Injection (Oil)	25 ppm @ 15% O_2 (Gas, baseload) 42 ppm @ 15% O_2 (Oil, baseload)

The plant, with the proposed controls and limits, will emit approximately 852-863 tons per year (TPY) of NO_X, 761-1,264 TPY of CO, 37-94 TPY of VOC, and 41 TPY of PM/PM_{10}. The basis is 7,008 hours of operation including 250 hours of oil firing and 1050 hours at 50% load.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (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. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppm NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppm SO_2 @ 15% O_2.(or <0.8% sulfur in fuel). The BACT proposed by the City is consistent with the NSPS which allows NO_X emissions over 110 ppm for the higher efficiency unit purchased by the City of Lakeland. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

Most recent stationary gas turbine BACT determinations made to-date by EPA and the states, including the State of Florida, have been much more stringent than the requirements of the NSPS. The following table is a sample of information on recent BACT and a few Lowest Achievable Emission Rate (LAER) determinations made by EPA and the States for stationary gas turbine projects as large or larger than the one under review. LAER is required in areas where the ambient air (unlike that Florida) does not attain the National Ambient Air Quality Standards (NAAQS).

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output and Duty	NOx Limit ppm @ 15% O_2 and Fuel	Technology	Comments
Cataula, GA	1200 MW SC PKR	25 - NG 42 - No. 2 FO	DLN WI	4x300 MW **WH 501G** CTs CTs rated 230 MW @ ISO, NG
CCC, VA	398 MW **SC** PKR	42/65 - No. 2 FO	WI	3x132.5 MW CTs 2000 (500 @ Peak) hr/yr/CT
PREPA, PR	248 MW SC **CON**	10 - No. 2 FO	WI & Hot SCR	3x83 MW CTs
Tiger Bay, **FL**	270 MW CC **CON**	15/10 - NG 42 - No. 2 FO	DLN &/or SCR WI	184 MW GE MS7001FA CT DLN/15 ppm or SCR/10 ppm
Hines Polk, **FL**	485 MW CC **CON**	12 - NG 42 - No. 2 FO	DLN WI	2x165 MW WH 501FC CTs Canceled GE CTs
Tallahassee, **FL**	260 MW CC **CON**	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS 7231FA CT DLN Guarantee is 9 ppm
Eco-Electrica, PR	461 MW CC **CON**	7 - NG 9 - LPG, No. 2 FO	DLN & SCR	2x160 MW WH 501F CTs
Sithe/IPP, NY	1012 MW CC **CON**	4.5 - NG	DLN & SCR	4 x160 MW GE 7FA CTs
Hermiston, OR	474 MW CC CON	4.5 - NG	SCR	2x160 MW GE 7FA CTs
Brooklyn, NY	240 MW CC **CON**	3.5 - NG (LAER) 10 - No. 2 FO	SCR	2x106 MW Siemens V84.2 CTs
Berkshire, MA	272 MW CC **CON**	3.5 - NG (LAER) 9.0 - No. 2 FO	DLN & SCR WI & SCR	178 MW ABB GT24 CT

SC = Simple Cycle
CC = Combined Cycle
NG = Natural Gas
CT = Combustion Turbine
CON = Continuous
PKR = Peaking Unit
FO = Fuel Oil
ISO = 59°F
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
LPG = Liquefied Propane Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari
ppm = parts per million

Factors in Common with City of Lakeland Project are bolded. All determinations are BACT unless denoted as LAER.

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf)	Technology and Comments
Cataula, GA	25 - NG @15% O_2 75 - FO@ 15% O_2	0.01 lb/mmBtu	0.005 - NG 0.03 - FO	Clean Fuels Good Combustion
CCC, VA	Not PSD	Not PSD	0.0216 - FO	Clean Fuels Good Combustion
PREPA, PR	9 - FO @15% O_2	11 - FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion
Tiger Bay, FL	0.045 lb/mmBtu-NG 0.053 lb/mmBtu-FO		0.053 - NG 0.009 - FO	Clean Fuels Good Combustion
Hines Polk, FL	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG			Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Brooklyn, NY	4 - NG (Avoid LAER) 5 - FO (Avoid LAER)	3.5 - NG 10 - FO		Clean Fuels CO Catalyst
Berkshire, MA	4 - NG (LAER) 5 - FO (LAER)	4 - NG 16 - FO	0.0105 - NG 0.0468 - FO	Clean Fuels CO Catalyst

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from the National Park Service dated January 6 and 12, April 2 and 15, 1998
- Letters from EPA Region IV dated February 10 and March 6, 1998
- Decisions by the Environmental Appeals Board
- Papers and letters written by Westinghouse on the development of the 501 G combustion turbine and nitrogen oxides control technologies
- DOE website information on Advanced Turbine Systems Project
- Mitsubishi website
- City of Lakeland Website, City Commission Meeting Minutes
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in lean, near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not important for the Lakeland project because natural gas will be the primary fuel and low sulfur fuel oil will be used only for 250 hours per year.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppm @15% O_2). For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppm @15% O_2.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are about 25 ppm when firing gas and 42 ppm when firing fuel oil in large combustion turbines. These values often form the basis for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion, cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

Combustors used in Westinghouse products are shown in Figure 2. These operate according to the same principles as described above. However they have different characteristics and do not reach the so-called fully pre-mixed operation until the load is over 50 percent.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, results in a lower achievable thermal efficiency for the unit.

By using steam in a closed loop system, the fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor the nozzle and does not enter the exhaust stream. Instead it is normally sent back to the steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher thermal efficiency is achieved.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 3 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppm (and even lower) from gas turbines smaller than about 200 MW (simple cycle). Initial guarantees of 25 ppm by combustion controls are proposed for turbines larger than larger than 200 MW. The guaranteed values are expected to be reduced for the reasons given above. As in the case of wet injection, higher CO and hydrocarbon emissions can occur as a result of employing combustion controls to minimize NO_X.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technique that is placed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas. As of early 1992, over 100 gas turbine installations already used SCR in the United States. No combustion turbines in Florida employ SCR. Virtually all SCR units are used in combination with wet injection or combustion controls.

Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalyst used in combined cycle, low temperature applications (conventional SCR), is usually vanadium or titanium oxide and accounts for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas.

In a manner analogous to balancing control of NO_X from the combustor with emissions of CO and hydrocarbon, similar balancing is required when controlling NO_X by SCR. Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur bearing fuels are used). Permit limits as low as 3.5 ppm NO_X have been specified for certain conventional SCR applications in ozone non-attainment areas.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

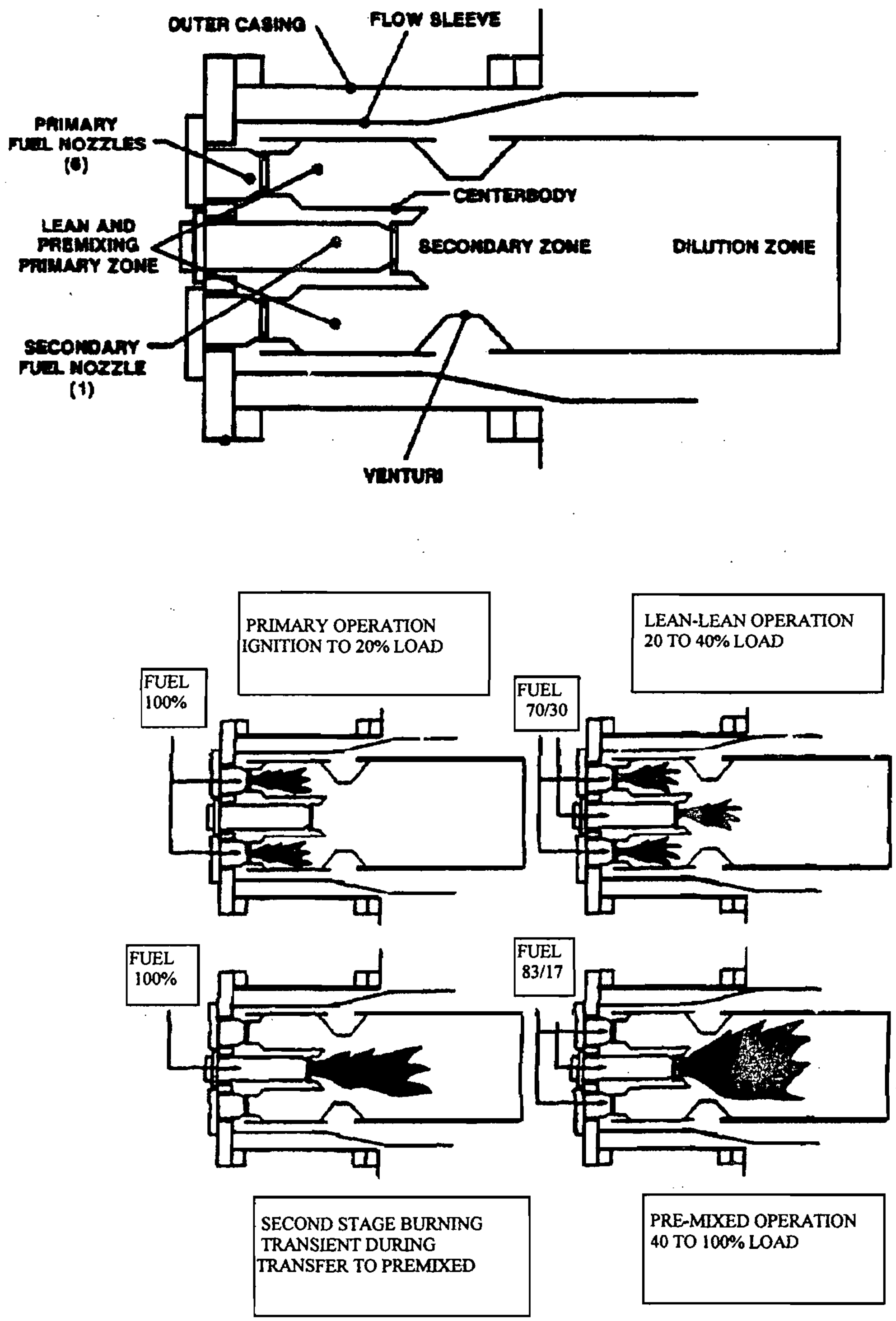

Figure 1 - Cross Sections of a Lean Premixed Can-annular Combustor

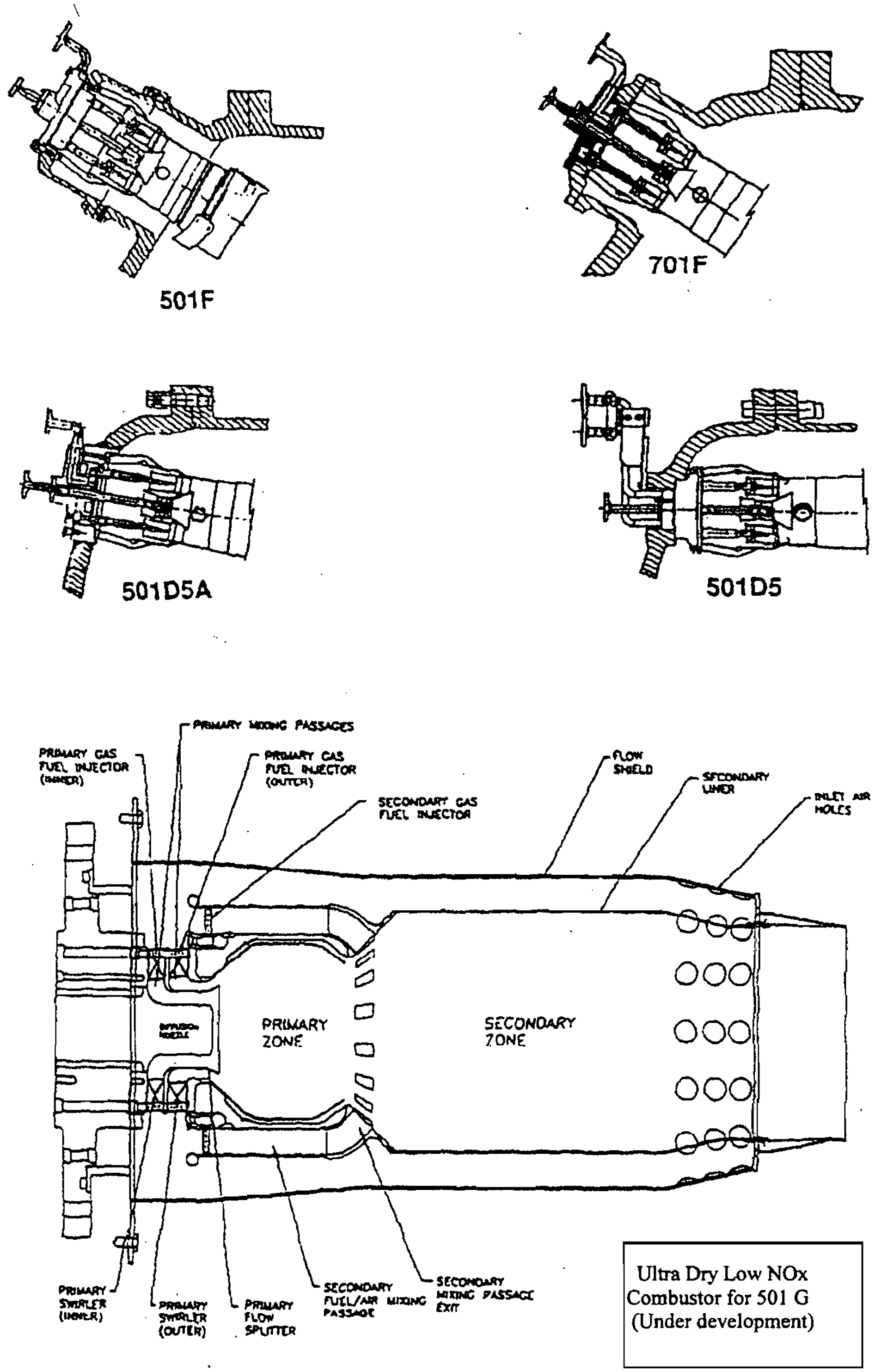

Figure 2 - Westinghouse Dry Low NOx Combustors

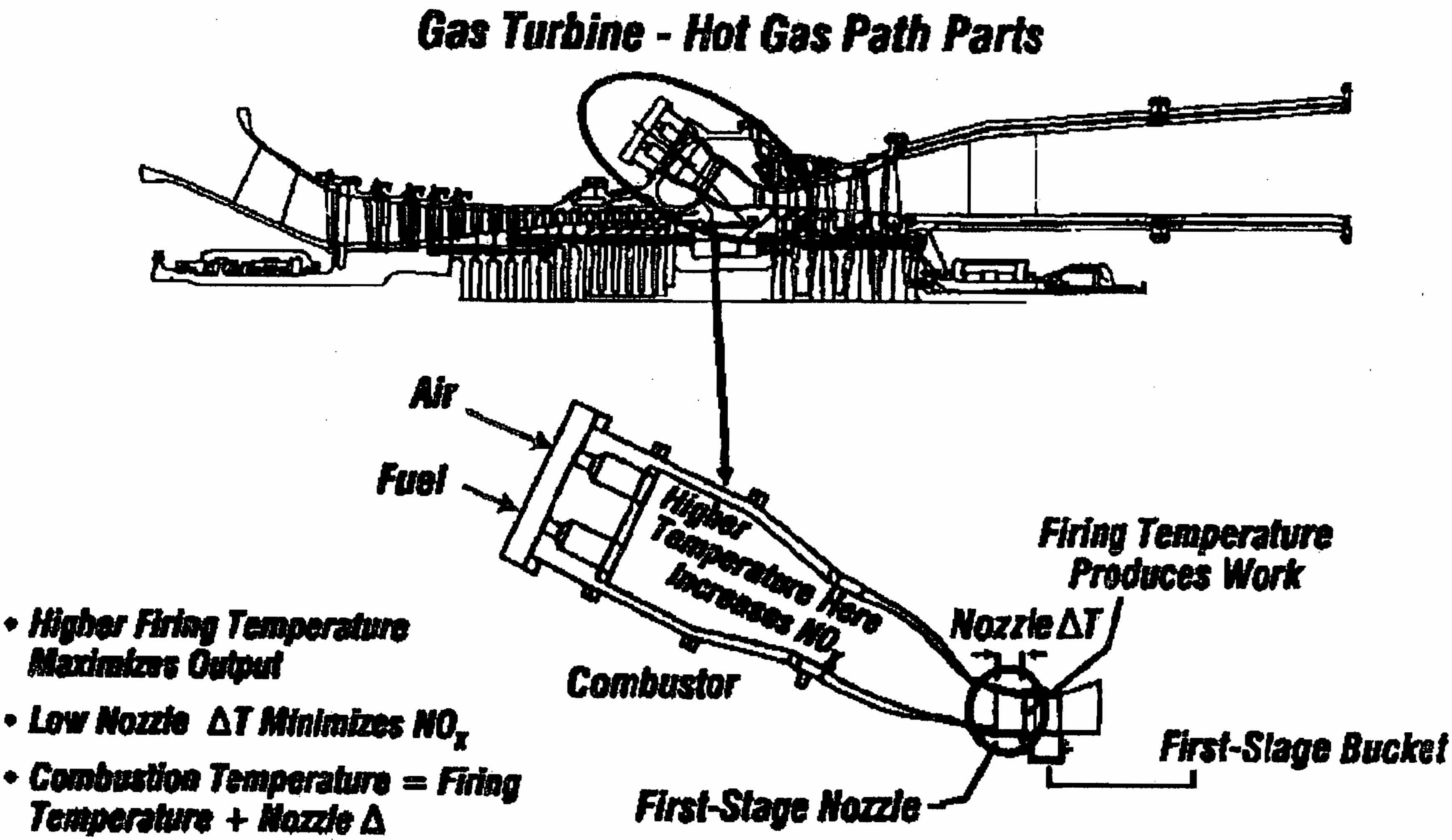

Figure 3. Relationship — combustion temperature to firing temperature

Natural gas and 0.05 percent sulfur No 2. fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for only 250 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. The City indicated that the PM_{10} emissions will not exceed 0.01 gr/scf when firing natural gas and pointed out that such a value is equal to a typical specification for baghouse design. Annual emissions of PM_{10} are expected to be approximately 30 tons for natural gas and less than 15 tons for fuel oil.

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

Most installation using catalytic oxidation are located in the Northeast. Besides the Berkshire and Brooklyn installation listed above, CO oxidation catalyst has been installed at the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the values of 50 and 90 ppm for gas and oil respectively at baseload proposed in the City's application appear high.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The limits proposed for this project are 4 and 10 ppm for gas and oil firing respectively.

BACKGROUND ON SELECTED GAS TURBINE

The City has already committed to the purchase of a 230 MW Westinghouse 501 G simple cycle gas turbine.[1] The unit was already under construction by Westinghouse and awaiting sale. The contract for the unit includes NO_X emission guarantees of 25 ppm on gas and 42 ppm on fuel oil.

The choice satisfies the City's immediate power needs and reserve capacity. If it is ultimately converted to combined cycle operation, the power generating capacity will be about 350 MW.[2] In the meantime the City is considering a Department of Energy (DOE) Pressurized Circulating Fluidized Bed Project while "re-evaluating the (electric utility) regulatory climate."[1, 3]

The 501 G was jointly developed and is manufactured by both Westinghouse and Mitsubishi Heavy Industries (MHI). The first 501 G started operation in April of 1997 in Japan at the MHI Takasago Machinery Works 330 MW Demonstrator Combined Cycle Plant. The unit has the "highest firing temperature (1500 °C, 2732 °F) ever recorded, and a combined cycle efficiency of over 58 percent."[4] The efficiency is also the highest ever demonstrated for combined cycle turbine. NO_X emissions are reportedly controlled a selective catalytic reduction (SCR) system located within the heat recovery steam generator (HRSG).

The first commercial operation (i.e. not within MHI subsidiaries) of a "1500 °C" combined cycle unit will begin trial operation at the Tohoku Electric Higashui Niigata Power Plant in October, 1998.[5] The specific unit will be the "701 G," which is a larger, 50 Hertz version of the 501 G. Commercial operation will begin in July, 1999 or soon after the time that Westinghouse and the City plan to start up the first commercial 501 G in the United States.

Westinghouse, MHI and General Electric continue to work on even larger and more efficient turbines. Westinghouse has already tested the compressor for its planned "H" Class turbine capable of achieving 60 percent efficiency while operating in combined cycle mode.[6] General Electric does not have an entry in the "G" class. However it is conducting trials in Greenville, South Carolina on the MS9001H, which is its 50 Hertz entry into the H Class. GE expects a combined cycle efficiency of 60 percent and generation of over 400 MW. GE plans to make its similar 60 Hertz MS7001H version available in 2001 or 2002.[7]

Westinghouse and General Electric are counting on further advancement and refinement of DLN technology to provide sufficient NO_X control for their turbines. In the case of the 501 G, steam cooling of the transition piece allows the unit the maintain the same NO_X formation potential as the 501 F while achieving a higher turbine inlet (firing) temperature. Examples of Westinghouse combustors are shown in Figure 2. These include their second generation of Dry Low NO_X combustors (Advanced DLN) and their fully pre-mixed Piloted Ring Combustor (Ultra LN).[8] Where required by BACT or LAER determinations of certain states, both companies incorporate SCR in combined cycle projects.[9,10]

The approach of progressively refining such technology is a proven one, even on some relatively large units. Basically this was the strategy adopted in Florida throughout the 1990's. Recently GE Frame 7 FA units (160 MW gas turbines with firing temperatures of 2400) met performance guarantees of 9 ppm with "DLN-2.6" burners at Fort St. Vrain, CO and Clark County, WA.[11] Westinghouse will conduct two phases of testing in 1998 to refine the Ultra Low NO_X technology for its "F" Class to meet a NO_X level of 9-12 ppm by about early to mid-2000.[12] The Department is working with Westinghouse and utilities to try to accelerate the testing program to achieve these values sooner so that the developments can be incorporated as applicable to the 501 G.

Both Westinghouse and General Electric are partners with the Department of Energy (DOE) in the Advanced Turbine Systems (ATS) Program.[13] The Mission/Vision Statement of ATS is to "develop base-load advanced turbine systems for commercial offering in the year 2000." Among the goals of the Program are 60 percent combined cycle efficiency while achieving NO_X emissions of 9 ppm or less.[14] The cost of producing the prototypes is estimated at $435,000,000 and $300,000,000 for the GE and Westinghouse projects respectively.[15] The goals of the ATS are reflected in the "H" Class units described above.

In simple cycle, continuous duty mode, the Westinghouse 501 G achieves an admirable efficiency of approximately 38 percent.[16] However this efficiency is much lower than what can be realized with the same unit (58 percent) when operating in combined cycle.[17] For that reason the Department believes it is or will become economically feasible for the City to convert the unit to combined cycle mode after the status of the Lakeland/DOE project and the electrical regulatory climate become clearer.

The 25 ppm initial NO_X guarantee on natural gas appears high when compared with BACT determinations for continuous-duty or combined cycle units, such as those previously listed. It is also higher than the stated goal of the ATS Program. The simple cycle mode with the flexibility of switching (or not switching) to combined cycle operation, presents constraints in evaluating the feasibility and costs of various emission reduction options otherwise available. For this reason, the Department does not constrain itself to any presumed historical cost-effectiveness criteria or cost estimating procedures such as might apply to a project with a clearly defined staging schedule and final configuration. At the same time, however, the Department has a full appreciation of the goals of the ATS Program and does not want to arbitrarily impede progress toward its goals.

Westinghouse provided a technology update of the Westinghouse family of combustion turbines. It includes a schedule for the 501 G to reach low NO_X levels of 9-12 by Ultra Low NO_X. The structure of the schedule is similar to that described for their 501 F class unit. According to Westinghouse, the experience gained from the 501 F will be employed in development of Ultra LN for the 501 G. Basic design and laboratory testing Ultra LN combustors for the 501 G is already underway. Initial field verification will be conducted beginning in mid-1999. Design modification and retesting will occur from mid-1999 through mid 2000. Additional design changes/tests will be carried out from mid-2000. Full commercial application will be implemented from 2001 through 2004.[8]

Westinghouse provided the City with a more specific schedule for the 501 G to be installed at Lakeland.[18] Westinghouse "fully anticipates having a combustion system available that meets the 9-12 NO_X requirement for the McIntosh No. 5 Unit within the next four years." That will occur in early 2002 and is within the general schedule given above. According to the same document, "since McIntosh Unit No. 5 is the demonstration project for the 501 G, there is a high probability that some field verification testing will be performed on the unit."

The proximity of Westinghouse technical staff in Orlando to the project site in Lakeland should enhance the probability of meeting Westinghouse's goal at an early date.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Lakeland project. Values for NO_X are corrected to 15% O_2.

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
250 MW SC CON	25 - NG 42 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	Adv. DLN on gas, WI on oil. Applies first 36 months after startup. Clean fuels, good combustion
250 MW SC CON	9 - NG 12 - (30 day) 42 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after 36 months operation. Clean fuels, good combustion
250 MW SC CON	9 - NG 15 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies after 36 months if 9 ppm NO_X not achievable by ULN. Clean fuels, good combustion.
350 MW CC CON	7.5 - NG 15 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR if converted to combined cycle, unless 9 ppm is attained by ULN or Hot SCR as described above. Clean fuels, good combustion

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The initial 25 and 42 ppm NO_X limits are guaranteed by Westinghouse and the Department has reasonable assurance that these can be met.
- There is a clear plan for achieving emissions of 9-12 ppm at the Lakeland location within 4 years of April, 1998. This will occur in early 2002 - about 3 years after an early-1999 startup.
- The unit will be operated in simple cycle mode while maintaining the flexibility to expand at a future date to combined cycle operation through the addition of a 100 MW heat recovery steam generator. Therefore control options which are feasible for combined cycle units are not immediately applicable at commencement of operation. At project inception, this rules out Low Temperature (conventional) SCR which achieves a 4.5 ppm NO_X BACT limit at the Hermiston and Sithe/IPP projects above.
- The turbine has a very high exhaust temperature of about 1100 °F.[16] This is at the higher limit of the present operational temperature of Hot SCR zeolite catalyst.[19] Therefore the catalyst would have to placed *after* the OTSG. The PREPA simple cycle turbines have exhaust temperatures ranging from 824 to 1024 °F and the Hot SCR catalyst (which must achieve 10 ppm NO_X) is located *between* the turbine and the OTSG.[20]
- Hot SCR is technically feasible for gas.[21] The same evaluation states that the technology has not been demonstrated for oil. However the PREPA units have since been installed.[22] These operate solely on 0.15 percent sulfur fuel oil.[23] The Lakeland unit is proposed to operate only 250 hours per year on fuel oil of 0.05 percent sulfur.

- The levelized costs of NO_X removal by Hot SCR were estimated by the City as $5,236 per ton of NO_X removed. Other Hot and conventional SCR cost estimates submitted by the applicant are not considered in this evaluation because they are based on many conditional assumptions regarding possible ultimate project phasing scenarios which are not typically encountered when applying the methodology used by the applicant. Also the cost estimates do not consider a continuation of the actual downward trend in catalyst prices, progressively improving performance, and typically longer-than-expected life.

- The levelized costs derived in the application for Hot SCR at Lakeland are based on a quote from Engelhard. The vendor based the proposal on design operation on fuel oil with guaranteed NO_X reduction of 70 percent to 12.6 ppm @15% O_2.[24]

- In order to avoid allowing control on fuel oil to become the main design consideration, the Department obtained a budgetary estimate from Engelhard to guarantee reduction of NO_X emissions while operating on gas by 64 percent (from 25 to 9 ppm).[25] The replacement cost of the Hot SCR catalyst designed for gas is $1,600,000 versus the $2,800,000 estimated for the Lakeland project designed for oil. During the very few hours of operation on oil, estimated NO_X emissions from the 501 G controlled by Hot SCR will be approximately 13 ppm @15% O_2.

- The cost effectiveness for NO_X removal given for the PREPA simple cycle project is $2,200 per ton. The main reason for the relatively low levelized cost is that total costs are applied over a reduction of 40 ppm whereas the reduction in the Lakeland case is over a smaller reduction. The cost per ton of NO_X removed by Hot SCR at the PREPA project can be rescaled for the Lakeland project. This would involve a significant increase due lower removal. However there would be decreases due to the natural gas design, application on one large unit versus three smaller ones, and lower ammonia requirements. The resulting costs would be less than $4,000 per ton.

- A cost estimate for Hot SCR was given by U.S. Generating in the BACT application for the planned Cataula peaking project where identical 501 G units have been permitted but not installed. In fact, U.S. Generating, Cataula is the alternative commercial demonstration site for the specific unit that Lakeland has contracted to purchase. According to U.S. Generating, "because the turbines will operate intermittently throughout the year, the cost of add-on SCR technology per ton of NO_X removed are very high and are outside of acceptable costs. Total annual removal cost of SCR technology was estimated to be $4,114 per ton of NO_X removed." This means that continuous duty operation should yield levelized costs less than $4,000 per ton for a 501 G unit.

- The Department does not necessarily accept the comments about what is considered unacceptable costs by U.S. Generating for the Cataula 501 G project. However, the Department is aware that U.S. Generating has a great deal of experience in implementing SCR NO_X technology. Projects include the first coal-fired plants in the country with SCR and the only one in Florida. Also U.S. Generating built many of the low emitting combined cycle plants. The Department, therefore, has some confidence in the $4,114 per ton estimate for intermittent (essentially peaking) operation of a 501 G.

- Using much of the basic capital cost information developed by Lakeland, The National Park Service estimated the cost of NO_X removal by Hot SCR at $3,802 per ton (excluding the energy penalty) for the continuous duty 501 G. A further refinement of the Park Service estimate by including the energy penalty, using the revised catalyst cost data, and assuming a five year estimated life for the catalyst would yield a cost-effectiveness closer to $3,500 per ton of NO_X removed.

- The Department concludes that Hot SCR is both technically and economically feasible now. The probability of success using this technology is at least as high as it is using the Ultra LN technology under development.

- According to Westinghouse, a heat exchange surface is required between the turbine and Hot SCR catalyst to insure an operational temperature less than 1100 °F is maintained. If a future HRSG is installed, Westinghouse indicates that the OTSG (which provides the steam for cooling and power augmentation) will be removed. This would expose the Hot SCR system (if installed) to unacceptable temperatures. Westinghouse does not believe relocation of catalyst to the HRSG is feasible and thus the Hot SCR system would be written off and possibly replaced by a conventional SCR system in the HRSG.

- The Department notes that a future conversion to combined cycle operation has not actually been proposed and details of possible configurations are not available to the Department for evaluation. Therefore the Department does not concur that Hot SCR is not feasible based on conceivable future development scenarios.

- According to Westinghouse, the ultimate design of their ATS-based gas turbine has options for "recuperative cycles" working within combined cycles. These cycles ultimately lower the gas temperature entering the steam cycle and appear to provide heat exchange surface to cool the gases and protect the Hot SCR system before the HRSG.

- There are various kinds of recuperative cycles - some of which make the combined cycle less efficient and others that which make it more efficient. According to a paper heralding the arrival of the 501 G, the author writes that "what is more significant is that the 501 G has been designed to incorporate the technology advances planned in the ATS program, such as intercooling and reheat, humidification and *chemical recuperation*, as and when they are good and ready."[2]

- The Department is not aware of actual plans to incorporate recuperation cycles in Westinghouse 501 products, the likely combined cycle efficiency benefits (or penalties), or their applicability to the Lakeland project by the time of conversion to combined cycle operation. The point is that ultimate wasting of Hot SCR equipment installed at startup, is not a foregone conclusion considering that many developments can occur within the time horizon of possible future project expansion scenarios.

- It is possible, and even likely, that Hot SCR catalysts will be improved (similar to refinement of Ultra LN) and can be used to replace the initial catalyst as it degrades. By the time the OTSG is removed for combined cycle conversion (e.g. 5 years), replacement catalyst might be able to withstand the higher temperature regime.

- Hot SCR has environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. All factors being equal, Ultra LN is a better control strategy than Hot SCR. A three year period to refine this technology to achieve similar emissions as Hot SCR is reasonable and not unprecedented.

- The Department does not conclude at this time that achieving 9-12 ppm of NO_X in three years by Ultra LN is an overall better strategy than immediately achieving 4.5 - 7.5 ppm by conventional SCR in a combined cycle unit. However, if the 9-12 ppm value can be achieved by ULN within the three years, subsequent installation of conventional SCR during a conversion to combined cycle will probably not be cost-effective.

- Three years is equal to the longest period of time provided to any previous applicant to achieve Department BACT limits by DLN technologies. With the accumulated knowledge and experience from DLN technologies for smaller units, it should be possible to achieve the Department's BACT limit for this project within three years after startup.

- The approach promotes further progress of the DOE ATS Program and falls within the realm of BACT determinations made by the Department in recent years.

- The Hot SCR scenario has, nevertheless, been included in the Department's determination for implementation in case that the Ultra LN strategy fails to reach the objectives within a reasonable period of time. If the City converts the unit to combined cycle mode in the near future, conventional SCR (with the catalyst in a low temperature regime within a HRSG) becomes immediately feasible, particularly if progress is slow on Ultra LN. Conventional SCR now rather than Ultra LN in three years, would be BACT at this time if the City planned to operate the unit in combined cycle mode at startup.

- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of clean, low ash, low sulfur fuels; and operation of the unit in accordance with the manufacturer-provided manuals.

- PM_{10} emissions will be very low and difficult to measure at the high temperature exiting the stack in simple cycle operation. Additionally, the higher emission mode will involve fuel oil firing which will occur only 250 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Tallahassee, Florida and the Berkshire, Massachusetts projects in the above table.

- CO emission estimates from the City's project are higher than for any pollutant. However the impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, or PM_{10}.

- The City evaluated the use of an oxidation catalyst designed for 90 percent reduction and having a two year catalyst life. The oxidation catalyst control system was estimated by the City to increase the total capital cost of the project by "about $2,000,000, with an annualized cost of $980,000 per year." The City estimated levelized costs for CO catalyst control at about $800 per ton to control CO emission to 10 ppm.

- The estimate of about $800 per ton for the Lakeland 501 G operating as a continuous duty unit is comparable to the $1,305 value calculated for identical 501 G units operating in intermittent (essentially peaking) mode at the Cataula, Georgia project. Cataula is a U.S. Generating project. This company operates three of the previously-mentioned facilities where CO catalyst is used. Catalytic CO control appears to be cost-effective for the Lakeland unit..
- In the 501 G Application Overview prepared by Westinghouse and included in the City's application for permit, the combustors have "initial emission levels less than the following:"[16]

Pollutant (ppm)	**Natural Gas (no injection)**	**Distillate Oil (water injection)**
Nitrogen Oxides	25	42
Carbon Monoxide	10	90
Unburned Hydrocarbons	5	20

- In an article included in the permit application, the author states "NO_X levels of less than 25 ppm on natural gas, less than 42 ppm on oil, while maintaining CO at less than 10 ppm will be specified for introductory machines."[2] The simultaneous initial CO and NO_X objectives are consistent with measured results for GE tests involving similar levels of DLN technology.[26]
- Westinghouse tables of "expected performance" in the permit application for the specific unit, however, estimate CO emissions while burning natural gas as 50, 100, and 350 ppm when operating at baseload, 75% load, and 50% load respectively. While operating on oil the estimated values are 90, 125, and 350 ppm at baseload, 75%, and 50% respectively.
- The permit application states that the high emission limits are "a result of uncertainty associated with maintaining low NO_X emissions while keeping emissions of CO as low as possible over the load range of the machine." It also mentions that the Westinghouse Application Overview estimate is 10 ppm for CO and accordingly calculates a much higher alternative cost per ton of removal based on the lower expected starting point prior for catalytic oxidation.
- The Department will set CO limits achievable by good combustion equal to those set for the City of Tallahassee project of 25 ppm on gas and 90 ppm on oil. For reference, the FPC Hines 501 F project is limited to 25 ppm on natural gas and 30 ppm on oil. The Hines project will incorporate the same ULN technology that the City of Lakeland plans to use on the 501 G.
- At the relatively high initial NO_X emission rate of 25 ppm, there should not be technical difficulties in achieving 25 ppm of CO with Advanced Dry Low NO_X technology. These values remain as appropriate objectives to meet with the Ultra Low NO_X technology under development. The oil case is relatively insignificant because of the limited firing time.
- It is up to the City to evaluate whether to meet the CO limits by combustion optimization or alternative lower limits achievable by catalytic oxidation. A plan describing how the limits will be met should be submitted prior to issuance of the final permit.
- VOC emission limits proposed by the City are at the lower end of values determined as BACT. Good Combustion is sufficient to achieve these low levels.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

COMPLIANCE PROCEDURES

Pollutant	Compliance Procedure
Visible Emissions	Method 9 (initial tests only)
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (30 day rolling averages)	Calculate Daily from NO_X CEMS and O_2 or CO_2 diluent monitor
NO_X (short-term)	Method 20 (Initial tests only for Subpart GG and short-term BACT)

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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Recommended By:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

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APPENDIX GC
GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

FROM: A. A. Linero *A A Linero 4/22*

DATE: April 22, 1998

SUBJECT: City of Lakeland McIntosh Unit No. 5
250 MW Gas Turbine (PSD-FL-245)

Attached is the draft final permit package for construction of a 250 MW Westinghouse 501 G simple cycle gas-fired combustion turbine at the City of Lakeland's McIntosh Power Plant. The project includes a once-through steam generator to provide steam for cooling key turbine components and for power augmentation to reach the 250 MW level. A 1.05 million gallon storage tank will be constructed for the back-up distillate fuel that will be used for no more than 250 hours per year.

The unit is the largest and most efficient turbine sold commercially for 60 Hertz utilities. It operates at a relatively high flame temperature and a very high turbine inlet temperature. Initially the unit will be delivered with the Westinghouse Advanced Dry Low NO_X combustors guaranteed to achieve NO_X limits of 25 ppm on natural gas. Westinghouse has provided an aggressive schedule to design, test, and implement the Piloted Ring Combustor Ultra Low NO_X (ULN) technology so that emission limits from 9-12 ppm can be met four years from <u>now</u> at the Lakeland site. This is somewhat less than three years from start-up. The location of the Westinghouse combustion experts in Orlando and the installation and refinement of virtually identical ULN technology on the new Westinghouse 501 FC's at the FPC Hines Power Plant this year will maximize the chances of success at Lakeland.

If the technology fails to achieve the requirements, the City must install Hot SCR to meet a 9 ppm limit. If the unit is converted to combined cycle operation and achievement of 9 ppm by ULN or Hot SCR is not in-sight, conventional SCR to meet a 6 ppm value will be required. If the unit achieves the 9 ppm value as scheduled, they do not have to take a lower limit if and when they convert to combined cycle operation.

Although the applicant rejects Hot SCR as not cost effective, we consider it to be cost-effective. We estimate the costs at about $3,500 per ton of NO_X removed. However we consider ULN to be superior because it is simpler, less expensive, avoids handling of additional materials such as ammonia and catalyst, and will achieve comparable emission reductions within a reasonable period of time. The claimed limitations on Hot SCR can be overcome if the City must resort to it in three years. I have just as much assurance that the catalyst manufacturers will within three years respond with a less expensive system capable of operating within the City's constraints as I have that the ULN system will be available within three years.

The City wanted some rather high CO limits (50 and 90 ppm for gas and oil). At these levels CO catalyst becomes cost-effective per the City's own calculations. We are issuing the permit with lower values believing the claim in the application that emissions will actually be lower. At the lower levels the CO catalyst will probably not cost-effective. I expect some discussions with them during the comment period.

I recommend your approval of the attached Intent to Issue.

AAL/aal

Attachments

Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

P.E. Certification Statement

Permittee:

DEP File No. 1050004-004-AC (PSD-FL-245)

City of Lakeland
Electric and Water Utilities Department
Lakeland, Polk County

Project type:

Project to construct a 230 megawatt Westinghouse 501 G gas-fired, simple cycle, continuous duty combustion turbine with a once-through steam generator providing cooling and power augmentation to 250 MW at 59 degrees Fahrenheit. Project includes an 85-foot stack and a 1.05 million gallon storage tank for back-up distillate fuel oil having a sulfur content of 0.05 percent. Initial nitrogen oxides (NO_X) limits are 25 ppm for gas firing achievable by Advanced Dry Low NO_X and 42 ppm for oil firing by water injection. Best Available Control Technology (BACT) is the installation of Ultra Low NO_X piloted ring combustors or high temperature selective catalytic reduction (SCR) within 36 months of start-up to meet a NO_X emission limit of 9 ppm @15% O_2. Failure to achieve the limit within 36 months may result in a stricter limit if and when the turbine is converted to combined cycle operation. In such a case the NO_X limit will be 7.5 ppm by conventional SCR.

Other pollutants, including PM/PM_{10}, VOC, and SO_2 will be controlled by good combustion and use of clean fuels. Similar controls are required for CO, unless the City chooses to meet the required reduction by employment of an oxidation catalyst.

I HEREBY CERTIFY *that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

A A. Linero, P.E. — 4/22/98
Date

A A. Linero, P.E.
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

A. LINERO
CERTIFICATE
NO 26032
aal 4/22
STATE OF
FLORIDA
REGISTERED ENGINEER

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW
ATLANTA, GEORGIA 30303-8909

MAY 21 1998

4APT-ARB

RECEIVED
JUN 01 1998
BUREAU OF AIR REGULATION

Mr. Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

SUBJ: PSD Permit for City of Lakeland, McIntosh Power Plant, Lakeland, Florida (PSD-FL-245)

Dear Mr. Fancy:

Thank you for your April 22, 1998, letter submitting a preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility. The permit is for the construction of a 250 MW continuous duty, simple cycle combustion turbine (CT) at the existing McIntosh Power Plant. A 230 MW Westinghouse Model 501G advanced CT with dry low-NO_x (DLN) burners is proposed. The CT will include a once-through steam generator (OTSG) which will use the waste heat to produce steam for cooling of critical components and for power augmentation. Electric power production will be increased from about 230 MW to about 250 MW by using power augmentation. The primary fuel for the CT will be natural gas, and distillate fuel oil (maximum sulfur content of 0.05 percent) will be used as a backup fuel. The CT and OTSG will operate no longer than 7,008 hours per year and will operate no more than 250 hours per year while firing distillate fuel oil.

Although there are no plans to convert the unit to a combined cycle system, flexibility is provided in the draft permit to allow such a conversion in the future. Conditions are provided in the draft permit for possible future conversion to a 350 MW combined cycle installation, provided there are no increases in emissions associated with the conversion. Section II, Condition 7 of the draft permit indicates that in the event of a conversion to a combined cycle operation, the best available control technology (BACT) will be reviewed and modified as appropriate, in accordance with 40 CFR 52.21(j). Condition 7 also indicates that this reassessment will be conducted only if the conversion to a combined cycle operation is accompanied by any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, or similar changes, in accordance with 40 CFR 52.21(j)(4).

Emission estimates for the project indicate that significance thresholds for the following pollutants will be exceeded, requiring

PSD review: CO, NO_x, VOC, PM, and PM_{10}. As indicated in the preliminary determination and draft permit, the proposed BACT for NO_x emissions from the CT while firing natural gas consists of the use of advanced DLN combustion during the first 36 months of operation to achieve an emission limit of 25 ppm (based on manufacturer guarantee). Within 36 months after startup, the initial combustors must be replaced with Westinghouse ultra low-NO_x (ULN) combustors, which are currently under development, to accomplish further NO_x control to a level of 9 ppm. If 9 ppm is not achievable with ULN technology, a high temperature selective catalytic reduction (SCR) system must be installed within 36 months after initial start-up to achieve a NO_x emission rate of 9 ppm. If the facility is converted to a combined cycle system and an emission rate of 9 ppm is not achievable with either ULN combustion or high temperature SCR, a low temperature SCR system will be required to achieve an emission rate of 7.5 ppm (70 percent reduction from 25 ppm). When firing distillate fuel oil, a NO_x emission rate of 42 ppm must be achieved with the use of water injection, unless a high temperature SCR or low temperature SCR system is later installed. If a high temperature or a low temperature SCR system is installed, a NO_x emission rate of 15 ppm must be achieved when firing fuel oil. CO and VOC emissions will be controlled by the use of good combustion practices. The CO emission limit is 25 ppm when firing natural gas and 90 ppm when firing fuel oil. If the 25 ppm CO limit is not met by combustion optimization, an alternate limit of 10 ppm must be met by catalytic oxidation. Prior to issuance of the final permit, the City will submit a plan describing how the CO limits will be met. The VOC emission limit is 4 ppm when firing natural gas and 10 ppm when firing fuel oil.

As indicated in the draft permit, the regulations at 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines will be applicable to the new combustion turbine, and 40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels will apply to the new 1.05 million gallon fuel oil storage tank.

We have received a copy of the May 6, 1998, letter from the City of Lakeland which requests modifications to the draft permit. Based on our review of the preliminary determination/draft permit and the letter from the City of Lakeland, we have the following comments.

1. In the City of Lakeland's May 6, 1998, letter, they have requested a BACT NO_x emission limit of 12 ppm (while firing natural gas) if ULN combustion technology is installed within 36 months of the initial performance test, or an emission limit of 9 ppm if a high temperature SCR system is installed within 36 months of the initial performance test. With the use of ULN combustion, the City has requested that the State remove from the permit the 9 ppm limit (with compliance determined annually at baseload by an EPA Reference Method test). The PSD regulations define BACT as an "emission

limitation." As indicated in the State's preliminary determination, the present BACT for simple cycle operation of the proposed CT is the use of high temperature SCR, which is both technically and economically feasible, to achieve an emission rate of 9 ppm. If the facility is operated as a simple cycle system and it is determined that the BACT emission limit of 9 ppm is not achievable with the use of ULN combustion, an emission rate of 9 ppm will need to be achieved with the use of a high temperature SCR system. We do not object to allowing a period of time to complete the development of a new combustion technology to achieve the same emission rate. However, the permit should not provide any flexibility in meeting an emission limit of 9 ppm. Also, the permit should require compliance with the emission limit of 9 ppm <u>within 36 months after startup</u>, as indicated in the draft permit, instead of <u>within 36 months of the initial performance test</u>, as requested by the City. The period of time provided in the draft permit for refining the ULN technology should be adequate, without allowing up to an additional 6 months.

2. As indicated in the draft permit (Section III. 21.), if ULN combustion is used, a NO_x emission rate of no greater than 9 ppmvd (at 15 percent O_2) must be demonstrated at baseload during an annual compliance test. The same permit condition also requires that NO_x emissions shall not exceed 12 ppmvd on a 30-day rolling average, as measured by continuous emission monitor (CEM) data. Since the BACT emission limit has been defined as 9 ppmvd, a higher emission limit should not be provided on a 30-day rolling average basis. Although CTs at other facilities have been permitted with a higher emission limit under peak load conditions, we do not consider the 12 ppmvd 30-day rolling average limit to be appropriate since it would allow frequent violation of the 9 ppm BACT limit. Also, since compliance with BACT NO_x emission limits in other States are typically demonstrated on a shorter term (e.g., a rolling one hour or three hour average) with the use of CEM data, we recommend the use of a similar averaging period at the McIntosh Power Plant for monitoring of NO_x emissions <u>with the use of either combustion controls or an SCR system</u>. The use of a shorter averaging period will more accurately demonstrate continuous compliance with the BACT emission limit. [Also, when a longer averaging time is provided in a permit, it is typically associated with an emission limit which is <u>lower</u> than the short term limit. However, the draft permit for the City of Lakeland provides a short term limit of 9 ppm in combination with a less stringent 30-day rolling average limit of 12 ppm.]

3. The City of Lakeland has also requested that the State modify the draft permit by replacing all short term "lb/hr" BACT emission limits with "ton/year" emission limits. To ensure that the PSD permit is practically enforceable, short term BACT emission limits need to be provided in the PSD permit, as opposed to "ton/year" limits.

4. The proposed combined cycle NO_x emission limit of 7.5 ppm with the use of low temperature SCR is based on a reduction of 70 percent from the rate of 25 ppm achieved at start-up with the use of DLN technology. The draft permit seems to indicate that ULN combustion would not be used unless it would achieve an emission rate of 9 ppm. However, if ULN combustors are installed to achieve a higher emission rate and the facility is converted to a combined cycle system, the final emission limit associated with the use of low temperature SCR should be based on the performance capability of the SCR system. A PSD application for another CT combined cycle project in Region 4 has recently been submitted which proposes an emission limit of 3.5 ppm with the use of SCR (based on a removal efficiency of 70 percent). If low temperature SCR is used in combination with ULN combustion, we recommend that the State define the actual emission limit at the time of conversion to combined cycle operation. The limit should be based on the actual efficiency of the SCR system with an emission limit of 7.5 ppm or less.

5. The City of Lakeland has requested modifications to replace the limit on hours of operation of 7,008 hours per year (Section III. 13. of the draft permit) with a limit on fuel usage. A limit of "15.235 x 10^{12} Btu(LHV) per year while firing natural gas and emission rate of 25 ppmvd corrected at 15% O_2 on 30-day rolling average," which is based on 7,008 hours/year, is requested. In the same permit condition, another fuel usage limit is requested of "19.044 x 10^{12} Btu(LHV) per year while firing natural gas and emission rate of 12 ppmvd or less corrected at 15% O_2 on 30-day rolling average." Since the City of Lakeland has based the PSD permit application (which includes an ambient air impact analysis) on operation of the CT for a maximum of 7,008 hours/year, the permit needs to be based on this restriction, and the request for unrestricted hours of operation needs to be denied. The environmental benefits gained by achieving the more stringent final BACT emission limit for NO_x within 36 months should not be offset by a 25 percent increase in operating hours of the CT (with an associated increase in emissions of all pollutants).

6. The City of Lakeland has requested a modification in the draft permit language regarding excess emissions (Section III. 26.) by deleting the restriction on excess emissions to no more than four hours in any 24 hour period for cold startup or two hours in any 24 hour period for other reasons unless specifically authorized by the State for longer duration. The City is correct in that the New Source Performance Standards (NSPS) regulations do not place limits on the duration of excess emissions resulting from startup, shutdown, malfunction, or fuel switching. However, since the excess emissions language in the draft permit is based on the State Implementation Plan and previous PSD permits issued by the

State of Florida have included similar language, we believe that it should remain in the permit.

7. The City of Lakeland has requested a modification in the draft permit (Section III. 31.) to indicate that - "an operating day shall consist of at least 18 hours of operation." The City indicates that the suggested modification would be similar to the definition of "operating day" in the NSPS regulations. However, NSPS Subpart GG, which is applicable to the CT, does not define "operating day." We recommend that the State deny the City's request. The City has also requested a modification in condition 41 to indicate that - "periods of startup, shutdown, malfunction, and fuel switching shall be excluded from the 30-day averages but monitored, recorded, and reported as excess emissions when the emission levels cause the 30-day average to exceed BACT standards..." This language should only be allowed if consistent with State regulations. As discussed in comment no. 2 above, we have concerns regarding the use of the 30-day rolling average emission limits provided in the draft permit.

8. The City has requested a modification in condition no. 42 (Section III) of the permit by deleting the statement - "Upon request from the DEP, the CEMS emission rates for NO_x on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332." Although it would not be necessary to convert results to ISO standard day conditions on a continuous basis, records of the data needed to make the conversion need to be maintained so that NO_x results could be calculated on an ISO standard day condition basis anytime at the request of EPA or the State. Since the BACT NO_x limits are more stringent than those in Subpart GG, compliance with Subpart GG for the CT would be a concern only in cases when the CT is in violation of the BACT NO_x limits. Therefore, when the CEM data indicates an exceedance of the BACT NO_x limits, a conversion of NO_x results to ISO standard day conditions should be conducted to assure compliance with the NO_x limit in Subpart GG.

Thank you for the opportunity to review and comment on the draft permit and supporting information. If you have any questions, please contact Keith Goff of my staff at (404)562-9137.

Sincerely yours,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides, and Toxics
Management Division

cc: T. Heron, BAR
B. Oven, PPS
K. Kosky, G.A.
SWD
Polk Co.
F. Shelton, C&L

LAKELAND ELECTRIC & WATER
Excellence Is Our Goal, Service Is Our Job

Farzie Shelton, chE; REM
Manager of Environmental Licensing & Permitting

RECEIVED
MAY 11 1998
BUREAU OF
AIR REGULATION

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

May 6, 1998

Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

**Re: Draft Air Construction Permit, DEP File No. 1050004-004-AC (PSD-FL-245)
250 Megawatt Combustion Turbine - McIntosh Power Plant Unit No. 5**

We are in receipt of your letter dated April 22, 1998 and attached Draft Air Construction Permit , Technical Evaluation and Preliminary Determination, and Draft BACT Determination, and Public Notice of Intent to Issue Air Construction Permit for the above referenced unit.

We would like to thank you and your staff in particular Mr. Al Linero who has diligently worked with us to prepare this draft permit in a timely manner fully cognizant of our tight time schedule.

Accordingly, we have reviewed this draft permit and have prepared our comments for your consideration. Therefore, enclosed please find this draft permit containing our comments depicted by strikethrough for language we request deletion, bold underlined and in blue color for our suggested addition, italic and in red color offering our explanation and rationale. Additionally, we are enclosing a diskette containing this document, in Word 6.0 for Windows, for your convenience.

Once again we very much appreciate your cooperation in this matter. If you should have any questions, please do not hesitate to contact me at (941) 499-6603; by Fax at (941) 603-6335; or by E-Mail at fshel@city.lakeland.net.

Sincerely

Farzie Shelton

cc: EPA
NPS
SWD
Polk Co.
File

Enclosure

cc: Mr. A.A. Linero P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
111 S. Magnolia
Suite 4
Tallahassee, Fl 32301

Mr. Hamilton Oven P.E.
Siting Coordinator
Florida Department of Environmental Protection
2600 Blair Stone Rd
MS-48
Tallahassee Fl 32399-2400

Mr. Ken Kosky P.E.
Golder Associates
6241 NW 23rd Street, Suit 500
Gainseville, Florida 32653-1500

PERMITTEE:

City of Lakeland
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Fl 33801-5079

File No.	1050004-004-AC
FID No.	1050004-004
SIC No.	4911
Permit No.	PSD-FL-245
Expires:	~~December 31, 1999~~

December 31, 2003

The suggested date is consistent with the permit requirement to achieve lower NO_X limits within 36 months of the initial performance test and would accommodate construction and operation of simple cycle configuration. Establishing a future date is consistent with many of the previous FDEP permits for future compliance. (e.g., Tiger Bay Cogeneration Facility, Orange Cogeneration Facility, and Mulberry Cogeneration Facility).

Authorized Representative:
Ronald W. Tomlin
Assistant Managing Director

PROJECT AND LOCATION:

Permit for the construction of 250 megawatt (MW) simple cycle, gas-fired, stationary combustion turbine (CT), a once-through steam generator, and a 1.05 million gallon storage tank for back-up distillate fuel oil. Conditions are included for possible future conversion to a 350 megawatt combined cycle installation including a heat recovery steam generator provided there are no increases in emissions associated with the conversion. The turbine is designated as Unit No. 5 and will be located at the C.D. McIntosh, Jr., Power Plant, 3030 East Lake Parker Drive, Lakeland, Polk County. UTM coordinates are: Zone 17; 409.0 km E; 3106.2 km N.

STATEMENT OF BASIS:

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

SECTION I. FACILITY INFORMATION

Attached appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

SUBSECTION A. FACILITY DESCRIPTION

The existing facility includes: two small diesel powered electric generators; one small gas and distillate-fired combustion turbine; one 90 MW gas and fuel oil-fired steam generator; one 115 MW gas and fuel oil-fired steam generator; and one 364 MW multiple (primarily coal) fuel-fired steam **generator**. This permit is for the installation of: a 250 MW simple cycle, gas-fired, stationary combustion turbine; a once-through steam generator; a 1.05 million gallon storage tank for back-up (0.05 percent sulfur) distillate fuel oil; and an 85-foot stack. It is possible that in the future the turbine will be converted by the addition of a heat recovery steam generator and a new stack to a 350 MW combined cycle operation without increases in emissions.

Emissions from Unit 5 will be initially controlled by Advanced Dry Low NO_X combustors, ~~steam~~ **wet** injection when firing fuel oil, use of inherently clean fuels, and good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions reduced by more sophisticated Ultra Low NO_X burners. Otherwise emissions will be reduced by the addition of a selective catalytic reduction (SCR) system.

SUBSECTION B. EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
~~001~~ **007**	Power Generation	250 Megawatt Combustion Turbine and Once Through Steam Generator
~~002~~ **008**	Fuel Storage	1.05 Million Gallon Fuel Oil Storage Tank

The emission unit numbers are based on the Title V designations for other units at the site.

SUBSECTION C. REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications (such as the construction of Unit 5) at the facility resulting in emissions increases greater than 40 TPY of NO_X or SO_2, 25/15 TPY of PM/PM_{10}, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.410, F.A.C.

SECTION I. FACILITY INFORMATION

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

SUBSECTION D. PERMIT SCHEDULE

- 04/xx/98 Notice of Intent published in the Lakeland ________
- 04/23/98 Distributed Intent to Issue Permit
- 12/08/97 Received Application

SUBSECTION E. RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on December 8, 1997
- Department letters dated January 5, January 12, and March 9, 1998
- Comments and letters from the National Park Service dated January 6, January 12, April 2 and April 15, 1998.
- EPA letters dated February 10 and March 6, 1998
- City of Lakeland letters dated March 4, March 11, and March 31, 1998
- Letters from Westinghouse dated March 25, March 30, and March 31, 1998
- Department's Intent to Issue and Public Notice Package dated April 22, 1998
- Department's Final Determination and Best Available Control Technology Determination dated May xx, 1998

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District office (DEPSW), 3804 Coconut Palm Drive, Tampa, Florida 33619 and phone number 813/744-6100.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a conversion to combined cycle operation. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

This reassessment will be conducted for this project only if the conversion to combined cycle operation is accompanied by any increases in heat input limits, ~~hours of operation~~, oil firing, low or baseload operation, short-term or annual emission limits, or **annual fuel heat input limits** ~~similar changes~~. [40 CFR 52.21(j)(4)] *See Conditions 13 and 14 for explanation.*

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Southwest District office (DEPSW). [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District office by March 1st of each year.

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (7) (c) (1997 version), shall be submitted to the DEP's Southwest District office.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. Emission Unit ~~001~~ **007**, Power Generation, consisting of a 250 megawatt combustion turbine with a once-through steam generator shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. Emission Unit ~~002~~ **008**, Fuel Storage, consisting of a 1.05 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of performance for Storage Tanks, adopted by reference in Rule 62-204.800, F.A.C.

6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District office.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur ~~No. 2~~ distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] ***This sugested change would allow the use of No. 2 and better grades of fuel (e.g., Jet-A)***.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,174 million Btu per hour (mmBtu/hr) when firing natural gas, nor 2,236 mmBtu/hr when firing ~~No. 2~~ **distillate** fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Permitting Authority as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

~~Hours of Operation~~ **Production Limits**

13. ~~Hours of operation~~ **Fuel usage** for the stationary gas turbine ~~and once through steam generator~~ shall not exceed ~~7008 hours~~ **15.235 x 10^{12} Btu (LHV)** per year **while firing natural gas and emission rate of 25 ppmvd corrected at 15% O_2 on 30-day rolling average. Fuel usage for the stationary gas turbine should not exceed 19.044 x 10^{12} Btu (LHV) per year while firing natural gas and emission rate of 12 ppmvd or less corrected at 15% O_2 on 30-day rolling average**. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] ***The City requested 7,008 hours of operation at a heat input of 2,174 mmBtu/hr (see Page 20). The amount of natural gas could be included as an alternative as listed on Page 26 of the application [i.e., 16,037 million cubic feet per year at 950 Btu (LHV)/cf]. The***

potential emissions calculation and basis of the BACT evaluation used this fuel usage. This limit in production would be federally enforceable and easily monitored. The heat input or fuel usage is monitored with the digital control system and is the basis of the fuel cost (a important plant parameter). Typically there are several back-ups for fuel usage. For emission limits of 12 ppmvd or less corrected at 15% O_2 on 30-day rolling average there shall not be any operational restrictions as per The City of Tallahassee.

14. Hours of operation for the stationary gas turbine ~~and once through steam generator~~ shall not exceed ~~250 hours~~ **559.0 x 10^9 Btu (LHV)** per year while firing distillate fuel oil. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] *The City requested 250 hours of operation at a heat input of 2,236 mmBtu/hr (see Page 20). The amount of distillate oil could be included as an alternative as listed on Page 26 of the application [i.e., 42.558 million gallons per year at 18,500 Btu (LHV)/gal]. The potential emissions calculation and basis of the BACT evaluation used this fuel usage . This limit in production would be federally enforceable and easily monitored. The heat input or fuel amount can be monitored with the digital control sysyem and is the basis of the fuel cost (a important plant parameter). Typically there are several back-ups for fuel usage.*

Control Technology

15. Westinghouse Second Generation Advanced Dry Low NO_X (DLN) combustors (or equivalent) shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]

16. The initial combustors shall be replaced with Westinghouse Ultra Low NO_X (ULN) ~~Piloted Ring Combustors~~ **or equivalent** within 36 months after ~~start-up~~ **the Initial Performence Test (IPT) required by Condition 29** to accomplish further NO_X control unless a high temperature selective catalytic reduction (Hot SCR) system or a low temperature SCR system is installed within 36 months. [Design, Rules 62-4.070 and 62-212.410, F.A.C.] *This condition as well as Condition 20 and 21 require meeting lower NOx emissions within 36 months of start-up. The 36 months from startup is not sufficient to accomodate since any installation or adjustments of both the DLN and ULN must be within the period. In addition, since a lower limit must be demonstrated at a future date, it must accomodate testing for the lower limit. By designating the IPT, Westinghouse and the City could accomodate the installation of the alternative controls as well as the testing.. The IPT would also provide both the City and the Department with specific date as to the future compliance date.*

17. The permittee shall design the stationary gas turbine, ducting, possible future heat recovery steam generator, and stack(s) to accommodate installation of SCR equipment or oxidation catalyst in the event that the ULN technology fails to achieve the NO_X ~~or carbon monoxide (CO)~~ limits given in Specific Condition No. 21 ~~and 22~~ within 36 months after ~~start-up~~ **IPT**. [Rule 62-4.070, F.A.C.]*The Department has already established CO emission limits for which compliance must be demonstrated annually. It is unnecessary to include a requirement for CO in this condition.*

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

18. A water injection system shall be installed for use when firing ~~No. 2~~ fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.410, F.A.C.]

~~19. The Advanced DLN and ULN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the Advanced DLN or ULN systems in the diffusion firing mode shall be minimized when firing natural gas. [Rule 62-4.070, and 62-210.650 F.A.C.]~~ *This condition is not necessary. It is the City's understanding that DLN and ULN operating parameters are established by Westinghouse and the ability of "tuning" the combustors in the traditional sense is not applicable. Also the DCS that controls the turbine operation will automatically control the gas regulation for the pre-mix and diffusion modes. The City will not have the ability to control these parameters. Moreover, the requirement to meet specific emission limits will dictate in part how the turbine is operated.*

EMISSION LIMITS AND STANDARDS

20. The following emission limits ~~based~~ shall apply upon completion of the initial performance tests: Best Available Control Technology (BACT). Following is a summary of the BACT determination by DEP. Values for NO_X **and CO** are **ppmvd** corrected to 15% O_2. [Rule 62-212.410, F.A.C.]

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Simple Cycle	25 - NG **(30-day)** 42 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10 **- NG** **20 - FO**	Adv. DLN on gas, WI on oil. Applies first 36 months after ~~startup~~ **IPT**. Clean fuels, good combustion
SC or CC	~~9 - NG~~ 12 **- NG** (30 day) 42 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10 **- NG** **20 - FO**	ULN on gas, WI on oil. Applies after 36 months ~~operation~~ **IPT**. Clean fuels, good combustion
Simple Cycle	9 - NG 15 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10 **- NG** **20 - FO**	Hot SCR. Applies after 36 months **from IPT** if 9 ppm NOX not achievable by ULN. Clean fuels, good combustion.
Combined Cycle	7.5 - NG 15 - FO	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10 **- NG** **20 - FO**	Conventional SCR if converted to combined cycle, unless 9 ppm is attained by ULN or Hot SCR as described above. Clean fuels, good combustion

The dates have included IPT as the basis; see Condition 16. Compliance with a limit of 9 ppm for a short-term period is not consistent with the Department's recent decisions for the City of Tallahassee. Moreover, the BACT evaluation and impact analyses for NOx use even longer averaging times (i.e., annual) than the 30-day rolling average and therefore providing the basis that the 30-day average is more stringent than the air quality impact of BACT evaluations. In addition, the 30-day average is a rolling average for which compliance is evaluated each day. The use of ULN should also list combined cycle (CC) as being appropriate.

21. Nitrogen Oxides (NO_X) Emissions:

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

- During the first 36 months after ~~start-up (commercial operation)~~ **IPT**, the concentration of NO_X in the exhaust gas shall not exceed 25 ppmvd at 15% O_2 when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a ~~24-hr~~ **30-day rolling** average except during periods of startup, shutdown, malfunction or fuel switching, as measured by the continuous emission monitoring system (CEMS). NOx emissions calculated as NO_2 (~~at ISO conditions~~) **from the CEM system** shall not exceed **863 tons/year** ~~237 lb/hr (gas) and 413 lb/hr (oil) to be demonstrated by stack test~~. [Rule 62-212.400, F.A.C.]*The basis of the impact evaluation for NOx is the annual emissions which were demonstrated to achieve the national ambient air quality standards (NAAQS). The 30-day rolling average and tons/year limits are consistent with the City of Tallahassee PSD determination recently made by the Department (PSD -FL-239/PA97-36 and the PPSA). The 863 tons/year is contained in the application (page 2-9).*

- Beginning 36 months after ~~start-up~~ **IPT**, ~~achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during an annual compliance test not to exceed 9 ppmvd at 15% O_2 when firing natural gas.~~ NO_X emissions shall not exceed 12 ppmvd at 15% O_2 when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. NO_X emissions calculated as NO_2 ~~(at ISO conditions)~~ **from the CEM system** shall not exceed **535.7 tons/year** ~~85 lb/hr (gas) and 413 lb/hr (oil) to be demonstrated by stack test~~. [Rule 62-212.400, F.A.C.] *The 436 tons/year is based on 12 ppmvd at 15% oxygen for gas firing and the 42 ppmvd at 15% oxygen for oil firing.*

- If Hot SCR is installed, ~~achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O_2 when firing natural gas~~. NO_X emissions shall not exceed 9 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. NO_X emissions calculated as NO_2 ~~(at ISO conditions)~~ **from the CEM system** shall not exceed **414.7 tons/year** ~~85 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test~~. [Rule 62-212.400, F.A.C.] *Again, the tons/year is consistent with the City of Tallahassee determination.*

- If conventional SCR is installed in conjunction with conversion to combined cycle operation, ~~achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O_2 when firing natural gas. If conventional SCR catalyst is installed~~, NO_X emissions shall not exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 30-day rolling average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the

CEMS. NOx emissions calculated as NO_2 ~~(at ISO conditions)~~ **from the CEM system** shall not exceed **300.8 tons/year** ~~71.1 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test~~. [Rule 62-212.400, F.A.C.]

22. Carbon Monoxide (CO) emissions: The concentration of CO in the exhaust gas**, at baseload,** when firing natural gas shall not exceed 25 ppmvd ~~when firing natural gas~~ and 90 ppmvd when firing fuel oil as measured by EPA Reference Method 10 test **and corrected to 15% O_2**. ~~CO emissions (at ISO conditions) shall not exceed 106 lb/hr (gas) and 386 lb/hr (oil).~~ [Rule 62-212.400, F.A.C.] *The provision for correcting to 15% O_2 would provide some margin for increased efficiency of the turbine. The more efficient turbines have lower O_2 with less emissions per MW generated (as described in the application and subsequent information transmitted to the Department). The use of the oxygen correction would be equivalent of adjusting the "G" turbine performance to the "F"class turbine. The CO emission limits contained herein are the same as those for approved by the Department for the City of Tallahassee's "F" class turbines; the oxygen correction would therefore provide additional margin due to the increased efficiency of the "G" turbine technology. There is no appropriate reason for adding lb/hr or tons/year limits for CO. The environmental impacts are extremely low even with much higher emissions. Also, the recent City of Tallahassee PSD approval did not contain lb/hr of ton/year limits for CO.*

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions ~~(at ISO conditions)~~ shall **be limited** ~~not exceed 7.2 pounds per hour when~~ **by** firing pipeline natural gas and ~~127 pounds per hour when~~ firing maximum 0.05 percent sulfur distillate fuel oil ~~No. 2 as measured by applicable compliance methods described below~~. Emissions of SO_2 shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review] *With the use of clean fuels and not having a BACT determination, it is unnecessary to establish lb/hr limits. Moreover, the modeling demonstrate that compliance with NAAQS is readily achieved. The suggesed change is consistent with the City of Tallahassee approval.*

24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or **20 percent opacity when firing** ~~No. 2~~ **distillate** fuel oil. *The Westinghouse guarentees provide for 10 percent or less opacity for gas and 20 percent or less opacity for oil. These levels are consitent with other permits using such fuels (e.g., Hardee Unit 3 using Westinghouse 501F turbines). Moreover, the use of oil is limited to only 250 hours/year which is very infrequent.*

25. Volatile Organic Compounds (VOCs) Emissions: The concentration of VOCs in the exhaust gas when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as asured by EPA Methods 18, and/or 25 A. ~~VOCs emissions (at ISO conditions) shall not exceed 10 lb/hr (gas) and 25 lb/hr (oil)~~. -[Rule 62-212.400, F.A.C.] *Since there is no PSD applicablility at these emission limits (i.e., emissions are 37 tons/year; see page 2-9 in application), there should be no lb/hr or tons/year emission limits for VOC. There is no NAAQS and the ppmvd levels provide sufficient basis.*

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. ~~Excess emissions occurrences shall in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration~~. *In accordance with the NSPS, excess emission resulting from startup, shutdown, malfunction or fuel switching is not limited to any specific period or duration. This is also consistent with the EPA's comments (and FDEP agreement) on proposed Title V permits for the FPL's facilities.*

27. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C.

28. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

29. Compliance with the allowable emission limiting standards shall be determined **by an Initial Performance Test (IPT) to be conducted** within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-297, F.A.C. *The IPT added for clarification.*

30. ~~Initial (I) performance tests~~ **IPT** shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. These initial (I) tests shall also be conducted after **installation or modification of equipment used to achieve the emission limits specified in Conditions 20 and 21. The IPT shall be conducted within the time periods specified in Condition 29.** ~~any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of Ultra Low NOX burners, Hot SCR, or conventional SCR~~. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on Unit 5 as indicated. The following reference methods shall be used.. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. *The condition should be constructed around the time periods in Conditions 20 and 21 and allow a similar period for*

performing initial performance tests. The term "shake down" has no regulatory meaning and 100 days seems arbitary.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG. ~~and (I,A)~~ **The** short-term NO_X BACT limits **(A).** (Method 7E or RATA test data may be used to demonstrate compliance for annual test requirement)
- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

31. Continuous compliance with the NO_X emission limits: ~~Except as noted in Specific Condition No. 21, continuous c~~ Compliance with the NO_X emission limits shall be demonstrated with the CEMS system based on a 30 day rolling average. ~~Based on~~ **Using** CEMS data, a separate compliance ~~test~~ **determination** is ~~conducted~~ **made** at the end of each operating day ~~and a new~~ **based on the** 30 day **rolling** average, emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. **An operating day shall consist of at least 18 hours of operation. Periods of allowable excess emissions as provided for in Conditions 26, 27 and 28 shall be excluded from the 30 day average.** [Rule 62-4.070, F.A.C., 40CFR75] *The suggested wording clarifies the intent of the condition. It also provides a definition of operating day similar to the NSPS.*

32. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and the use of ~~no more than 250 hours per year of maximum~~ 0.05 percent sulfur (by weight) distillate ~~No. 2~~ fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

33. Compliance with CO emission limit: An ~~initial test~~ **IPT** for CO, **shall be conducted** concurrent**ly** with the ~~initial~~ **IPT for** NO_X ~~test~~, ~~is~~ **as** required. The ~~initial~~ **IPT for** NO_X and CO ~~test results~~ shall be the average of three valid one-hour runs. Annual compliance testing may be

conducted concurrent with the annual RATA testing required pursuant to 40 CFR 75 (required for gas only). *The suggested wording is provided for clarification.*

34. Compliance with the VOC emission limit: An ~~initial test~~ **IPT** is required to demonstrate compliance with the ~~BACT~~ VOC emission limit. Thereafter, CO emission limit will be employed as surrogate. *The VOC emission limits established by the Department would result in emissions below the PSD significant emission rates and therefore BACT is not applicble. This should also be addressed in the BACT determination.*

35. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. **Si**nce the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-297 F.A.C.

36. Test Notification: The DEP's Southwest District office shall be notified, in writing, at least 30 days prior to the ~~initial performance tests~~ **IPT** and at least 15 days before annual compliance test(s).

37. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

38. Test Results: Compliance test results shall be submitted to the DEP's Southwest District office no later than 45 days after completion of the last test run.

NOTIFICATION, REPORTING, AND RECORDKEEPING

39. Records: All measurements, records, and other data required to be maintained by the City of Lakeland Department of Electric & Water Utilities shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

40. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed with the DEP SW District Office as soon as practical, but no later than 45 days after the last sampling run is completed. [Rule 62-297.310(8), F.A.C.]. The test report shall provide sufficient detail on the tested emission unit and the procedures used to

allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 5. Periods when NOX emissions (ppmvd @ 15% oxygen **30 day rolling average**) are above the BACT standards listed in Subsection C. Specific Condition C.1. shall be reported to the DEP Southwest District Office pursuant to Rule 62-4.160(8), F.A.C. Periods of startup, shutdown, malfunction, and fuel switching shall be **excluded from the 30 day averages but** monitored, recorded, and reported as excess emissions when emission levels **cause the 30 day average to** exceed the BACT standards following the format of 40 CFR 60.7 (1997 version). *The suggested wording corresponds to the 30 day rolling average limits requested.*

42. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. ~~Upon request from DEP, the CEMS emission rates for NOX on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NOX standard established in 40 CFR 60.332.~~ *The NSPS NOx emission limits are at least 4 times higher than the BACT emission limits. The potential for requiring some correction to ISO conditions is unnecessary and if required would add unnecessary costs and reporting complications.*

43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, and 40 CFR 60.75 including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) **or 40 CFR Part 75**. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Southwest District Office (DEPSWD) for review at least 90 days prior to installation. *Clarification added to allow Part 75 as a basis for equipment and performance specificaions.*

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for ~~No. 2~~ **distillate** fuel oil shall be followed: For all bulk shipments of ~~No. 2~~ **distillate** fuel oil received at the C.D. McIntosh , Jr. Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- Monitoring of natural gas nitrogen content shall not be required.
- Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods in Specific Condition No. 32 for the measurement of sulfur in gaseous fuels, or an approved alternative method. Once Unit 5 becomes operational, monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.
- Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify DEP of such excess emissions and the customized fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.
- The City shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.
- Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.
- The City may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission) provided the test methods listed in Specific Condition E.4 are used.

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable **process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C.].** *The original text was cut off and remainder of the rule language was added.*

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079
_____________________________________/

OGC No. 98-_____

DRAFT Permit No.: 1050004-004-AC
(PSD-FL-245)
C.D. McIntosh, Jr. Power Plant
Polk County

REQUEST FOR EXTENSION OF TIME

By and through undersigned counsel, Lakeland Electric & Water Utilities (Lakeland) hereby requests, pursuant to Florida Administrative Code Rules 28-106.111(3) and 62-103.050(1), an extension of time, to and including June 1, 1998, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, Lakeland states the following:

1. On or about April 22, 1998, Lakeland received from the Department of Environmental Protection (Department) an "Intent to Issue Air Constriction Permit" (Permit No. 1050004-004-AC) (PSD-FL-245) for the C.D. McIntosh, Jr. Power Plant located in Polk County, Florida. Along with the Intent to Issue, Lakeland received a Draft Air Construction Permit and "Public Notice of Intent to Issue Air Construction Permit."

2. Based on Lakeland's review, the Draft Permit and associated documents contain several provisions that warrant clarification or correction.

3. This request is filed simply as a protective measure to avoid waiver of Lakeland's right to challenge certain conditions contained in the Draft Air Construction Permit. Grant of

this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to file a petition and proceed to a formal administrative hearing or formal mediation.

4. A.A. Linero with the Bureau of Air Regulation has agreed to an extension until June 1, 1998, on behalf of the Department. Counsel for Lakeland has attempted without success to contact W. Douglas Beason with the Office of General Counsel regarding this request.

WHEREFORE, Lakeland respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Draft Air Construction Permit for Permit No. 1050004-004-AC (PSD-FL-245) be formally extended to and including June 1, 1998.

Respectfully submitted this 1st day of May, 1998.

HOPPING GREEN SAMS & SMITH, P.A.

Robert A. Manning

Robert A. Manning
Fla. Bar. No. 0035173
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500

Attorney for LAKELAND ELECTRIC & WATER UTILITIES

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 1st day of May, 1998:

Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

W. Douglas Beason
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

A.A. Linero, P.E.
Administrator
New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Robert A. Manning

109297.1

FACSIMILE · TELEX · TELEGRAM (1/2)

逓過番号(No.)		
受付時刻(Receipt Time)	至 急・親 展・秘親展・人事親展 (Urgent · Confidential) LT	発信記号·番号(Sender No.) 98G-0543 号 1998 年 Apl. 月 29 日
あて先(To) (写) Mr. Al Linero P. E. Department of Environment Protection, State of Florida 1-850-922-6979	K.HASEGAWA MHI TAKASAGO	MHI Takasago Gas Turbine Engineering Section
関連文書(Ref.No.) 年 月 日付 号	発信側査印	K.Abe
件名(Subject) 501G GT Gas Turbine 501G Question		[伺出・通知・報告・連絡 依頼・照会・回答]

Dear Mr. Al Linero P. E.

Regarding to the above subject, we answer as following sheet.

Please see attached sheet.

Best regards.

Katsuhiko Abe

K. Abe

Engineer

Tel. (0794)45-6691 Fax. (0794)45-6936 JPN

写) ガ技. タ技部. ガ設

2/2

Sub.: Question for 501G Gas Turbine
To: Mr. Al Linero P.E.
Department of Environment Protection,
State of Florida

Dear Mr. Linero

Thank you very much for your attention to our 501G Gas Turbine.
As regarding your question, we would like to make comments below.
What we have to state at first is, unfortunately, that 501G of MHI and 501G of Westinghouse are not identical. MHI and Westinghouse started the development of this Gas Turbine in common, and did conceptional & basic design together, but circumstances forced us to design in detail separately. Therefore, there are many differences between MHI's 501G and Wesginthouse's 501G even though they are similar in appearance.
As for combustor, we hear they are developing new one that is different type from our multi nozzle type DLN (Dry Low NOx) combustor which has many experiences. As you know, purchasing Westinghouse by Siemens has announced the other day. MHI and Westinghouse have little interchange in technical matter from a few years ago. Our proto type 501G in Takasago achieved planned NOx value and CO Emissions using our multi nozzle type DLN combustor. We installed a catalyst only for NOx reduction (not for CO reduction) However, we would like to refrain from stating definite value, because we don't know what kind of combustor is applied for Westinghouse 501G.
So we are very sorry that we are not able to reply to your question. We would like to help you in many ways when 501G of MHI will be installed in Florida.

Yours Faithfully,

E. Akita

Eiji Akita
Manager, G/T Designing Section,
Turbine Engineering Department,
Takasago Machinery Works,
Mitsubishi Heavy Industries, Ltd.

LAKELAND ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

Farzie Shelton, chE; REM

Manager of Environmental Licensing & Permitting

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

April 29, 1998

Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Re: Draft Air Construction Permit, DEP File No. 1050004-004-AC (PSD-FL-245)
250 Megawatt Combustion Turbine - McIntosh Power Plant Unit No. 5

We are in receipt of your letter dated April 22, 1998 and attached Draft Air Construction Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, and Public Notice of Intent to Issue Air Construction Permit.

Pursuant to Section 403.815, Florida Statutes and DEP Rule 62-103.150, F.A.C., on April 23, 1998 we published the "Notice of Intent to Issue Air Construction Permit " in the Lakeland Ledger. Therefore, enclosed please find Affidavit of Publication confirming publication of the Department's notice.

If you should have any questions, please do not hesitate to contact me at (941) 499-6603; by Fax at (941) 603-6335; or by E-Mail at fshel@city.lakeland.net.

Sincerely

Shelton

Farzie Shelton

Enclosure

cc: T. Heron, BAR
Polk Co.
SWD
K. Kosky, Golder Assoc.
NPS
EPA

AFFIDAVIT OF PUBLICATION

THE LEDGER

Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared Nelson Kirkland, who on oath says that he is Classified Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

Public Notice Of Intent

in the matter of

DEP File No. 1050004-002AC (PSD-FL-245)

in the ....

Court, was published in said newspaper in the issues of

April 23;

1998

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed [signature]
Nelson Kirkland
Classified Advertising Manager
By Nelson Kirkland who is personally known to me

Sworn to and subscribed before me this 27TH

day of APRIL A.D. 19 98

(Seal) [signature]
Notary Public

DONALD RAY JENKINS
MY COMMISSION # CC 586345
EXPIRES: September 18, 2000
Bonded Thru Notary Public Underwriters

My Commission Expires ....

Order#693059
S Jones B447

Attach Notice Here

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050004-002AC (PSD-FL-245)

City of Lakeland Electric and Water Utilines Department
C.D. McIntosh, Jr. Power Plant - Unit No. 5.
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to The City of Lakeland Electric & Water Utilities Department. The permit is to construct a 250 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine with a once-through steam generator, a 1.05 million gallon fuel oil storage tank, and a new 85-foot stack at the C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), volatile organic compounds (VOC) and carbon monoxide (CO) pursuant to Rules 62-212.400 and 410, F.A.C. and 40 CFR 52.21. The applicant's name and address are The City of Lakeland Electric and Water Utilities Department, 501 East Lemon Street, Lakeland, Florida 33801-5079.

The new unit is a Westinghouse 501 G, 250 MW turbine which will operate in simple cycle mode as a continuous duty unit. It will be the largest and most efficient simple cycle gas turbine installed in the United States to-date. The unit will operate primarily on natural gas and will be permitted to operate 7008 hours per year of which no more than 250 will be on 0.05 percent sulfur distillate fuel oil.

During the first three years of operation, NO_x emissions will be controlled by "Advanced Dry Low NO_x" technology combustors capable of achieving emissions of 25 parts per million by volume at 15 percent oxygen (ppm @15% O_2). "Ultra Low NO_x" technology consisting of Piloted Ring Combustors is under development to achieve a limit of 9 ppm @15% O_2 (12 ppm averaged over 30 days) three years after start-up. Emissions of NO_x will be controlled under the minimal back-up fuel oil operation by water injection. SO_2 and PM/PM_{10} will be limited by use of clean fuels. Emissions of VOC will be controlled by good combustion practices. Emissions of CO will be similarly controlled unless the City chooses to install an oxidation catalyst.

The maximum potential annual emissions in tons per year based on the original application are summarized below. NO_x emissions will be reduced by over half after installation of the Ultra Low NO_x combustors. CO emissions will also be substantially lower as a result of the Department's BACT determination.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM10	41	25/15
SO_2	38	40
NO_x	863	40
VOC	93	40
CO	1264	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed *DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of* this Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the Department shall issue a *Revised DRAFT Permit and require, if applicable, another Public Notice.*

The Department will issue FINAL Permit with the conditions of the DRAFT Permit unless a timely petition **for an administrative hearing is filed pursuant to Sections** 120.569 and 120.57, F.S. The procedures for **petitioning for a hearing are set forth below. Mediation is not available** for the proposed action.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9370, fax: 904/487-4938. Petitions must be filed within fourteen *days of publication of the public notice or within fourteen days of receipt of this notice of intent,* whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the Department's action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that *the Department's final action may be different from the position taken by it in this* notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection	Florida Department of Environmental Protection	City of Lakeland Electric and Water Utilities
Bureau of Air Regulation	Southwest District Office	Attention: Ms. Farzie Shelton
111 S. Magnolia Drive, Suite 4	3804 Coconut Drive	501 East Lemon Street
Tallahassee, Florida 32301	Tampa, Florida 33619-8218	Lakeland, Florida 33801-5079
Telephone: (850) 488-1344	Telephone: (813) 744-6100	Telephone: (941) 499-6603
Fax: (850) 922-6979	Fax: (813) 744-6084	Fax: (941) 603-6335

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 904/488-1344, for additional information.

B-447 - 4-23; 1998

STATE OF FLORIDA
DEPARTMENT OF COMMUNITY AFFAIRS
"Helping Floridians create safe, vibrant, sustainable communities"

LAWTON CHILES
Governor

JAMES F. MURLEY
Secretary

29 April 1998

Hamilton S. Oven, Jr.
Siting Coordination Office - Mailstop 48
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Oven:

On 16 March 1998 the Department received a copy of a request to modify conditions of certification for the Lakeland Utilities McIntosh power plant site. Pursuant to section 403.516, Florida Statutes, the Department and other agencies that participated in the original certification of the McIntosh site may comment on or object to the proposed modification.

Lakeland proposes to add a 250-megawatt combustion turbine (called McIntosh Unit 5) at its McIntosh site. Materials supplied with the modification request describe the characteristics of the combustion turbine and its probable environmental effects. It appears from a review of this material that the turbine will have minimal environmental impacts, except for its air emissions.

Unit 5's expected emissions of nitrogen oxides (NOx) and carbon monoxide (CO) when burning natural gas, the designated primary fuel, are of concern to the Department. The Department's position on air emissions is guided by the Florida State Comprehensive Plan policies on air quality. The most relevant are Air Quality policies nos. 1, 2, and 3:

> Air Quality Policy 1. Improve air quality and maintain the improved level to safeguard human health and prevent damage to the natural environment.
>
> Air Quality Policy 2. Ensure that developments and transportation systems are consistent with the maintenance of optimum air quality.
>
> Air Quality Policy 3. Reduce sulfur dioxide and nitrogen oxide emissions and mitigate their effects on the natural and human environment.

Lakeland proposes that Best Available Control Technology (BACT) emission rates for NOx be set at 25 parts per million (ppm) and that the CO emissions rate be set at 50 parts per million. Lakeland proposes to reduce Unit 5's NOx emissions to 12 ppm after 5 years of operation.

2555 SHUMARD OAK BOULEVARD • TALLAHASSEE, FLORIDA 32399-2100
Phone: 850.488.8466/Suncom 278.8466 FAX: 850.921.0781/Suncom 291.0781
Internet address: http://www.state.fl.us/comaff/dca.html

FLORIDA KEYS
Area of Critical State Concern Field Office
2796 Overseas Highway, Suite 212
Marathon, Florida 33050-2227

GREEN SWAMP
Area of Critical State Concern Field Office
155 East Summerlin
Bartow, Florida 33830-4641

SOUTH FLORIDA RECOVERY OFFICE
P.O. Box 4022
8600 N.W. 36th Street
Miami, Florida 33159-4022

Recent power plant certifications in which the Department has participated have resulted in lower emission levels being set for NOx and CO. BACT emission rates for the City of Tallahassee's Purdom Unit 8 were set at 12 ppm for NOx and 25 ppm for CO, both on natural gas. During the recent certification proceeding for Florida Power Corporation's Tiger Bay power plant, the BACT emission rate for NOx was also set at 25 ppm on natural gas, but it is to be reduced to 15 ppm or lower by 31 December 1998.

Department staff discussed the issue of the combustion turbine's air emissions with the Air Regulation office of the Florida Department of Environmental Protection (FDEP), which has also reviewed the modification request. The Department of Environmental Protection's preliminary BACT determination would modify Lakeland's requested BACT determination as follows: BACT limits for NOx are set at 25 ppm on natural gas, to be lowered to 9 ppm within 36 months after start-up, and BACT limits for CO are set at 25 ppm on natural gas using combustion optimization or 10 ppm using an oxidation catalyst. These lower limits are more consistent with the State Comprehensive Plan Air Quality policies. The Department recommends that they be adopted for Unit 5.

An additional concern with the project is its energy efficiency (electrical power output per unit of energy consumed). The State Comprehensive Plan contains a policy that bears on this point:

> Energy Policy 6. Increase the efficient use of energy in design and operation of buildings, public utility systems, and other infrastructure and related equipment.

Lakeland has chosen a simple-cycle combustion turbine for its Unit 5 power plant. A combustion turbine operating in combined-cycle mode (with a heat recovery steam generator and separate steam turbine) is one of the most efficient power-generating technologies currently available; however, a simple-cycle combustion turbine, such as the proposed Unit 5, is significantly less efficient. In this era of elevated concern about global warming, it would seem advisable that utilities, when constructing new power plants, should select the most efficient energy-generating technologies available—those that produce relatively low emissions of "greenhouse gases" per unit of power generated—unless there are overriding concerns. For Lakeland, it appears that the overriding concern is cost: the simple-cycle unit is cheaper to construct than the combined-cycle unit. Lakeland has stated that Unit 5 might be switched to a combined-cycle configuration later, when the system needs additional power. There is no state requirement for power plant efficiency applicable to a site modification request; however, the Department encourages the City of Lakeland to convert Unit 5 to a combined-cycle configuration as soon as is feasible.

The Department wishes to raise one additional issue related to this modification request. As noted in Lakeland's modification request, combustion turbines in simple-cycle mode are not required to be certified under the Florida Electrical Power Plant Siting Act (sections 403.501–403.518, Florida Statutes). This is true no matter how large the generating capacity of the unit. No need determination by the Public Service Commission is required, nor is there a site review by state, regional, and local agencies. Because combustion turbines have become so much larger than they were when the act was created and because it is conceivable that not having to apply for state certification may have some bearing on whether utilities choose combined-cycle or simple-cycle combustion turbines for their new generating capacity, it may be advisable to revisit this exemption in the act for combustion turbines. We suggest that this be discussed at the next siting quarterly interagency meeting.

If you have any questions concerning this letter, please call Paul Darst at (850) 922-1764.

Sincerely,

James L. Quinn

James L. Quinn, chief
Bureau of State Planning

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

April 27, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

We recently sent you the Public Notice package including the Intent to Issue for the referenced project. We understand the Public Notice was published on April 23. Prior to issuance of the final permit, we will provide you with any comments that we receive from the public as well as from other agencies.

In our review, we determined that some of additional details are needed prior to issuance of a final permit. These are related to the characteristics of the combustors that will be installed. Because the units do not operate in the "Low NO_X (lean pre-mix) range" throughout the entire operating range, we request that the City develop an operational plan to minimize the time the burners function in the "diffusion mode."

Specifically, please provide diagrams similar to the ones attached for the Westinghouse "Advanced Dry Low NO_X Combustors" as well as for the "Ultra Low NO_X (Piloted Ring) Combustors." As can be discerned from the diagrams, the lean pre-mixed (Low NO_X) mode is fully in effect at 40 percent of full capacity for what is believed to be a GE gas turbine. Based on a Westinghouse 501 F project in Florida, we understand that the lean pre-mixed mode may not be effected until the gas turbine reaches 60-70 percent of capacity. For this reason, we would like to see an operational plan for the 501G that encourages operation at 70-100 percent whenever possible (unless the Westinghouse 501G combustors also exhibit full lean pre-mix at low operational levels). Operation at the higher levels will also minimize carbon monoxide emissions.

We advised your consultant, KBN that we planned to make this request. We have not contacted Westinghouse about the matter regarding this project, but have discussed it with them regarding the 501F gas turbine. If you have any questions regarding this matter, please contact me at 850/921-9523 or Teresa Heron at 921-9529.

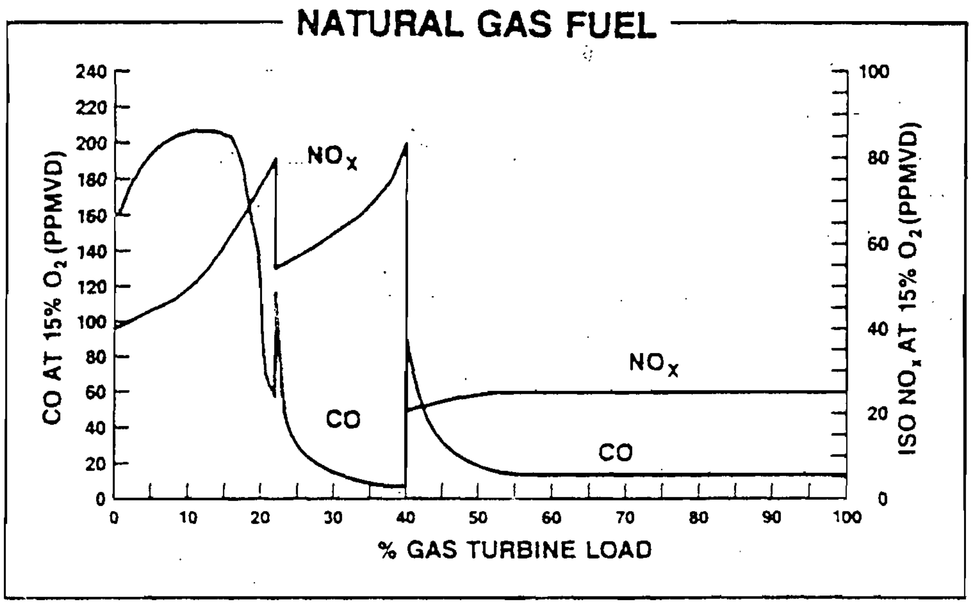
Sincerely,

A.A. Linero 4/27

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/aal

cc: Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates



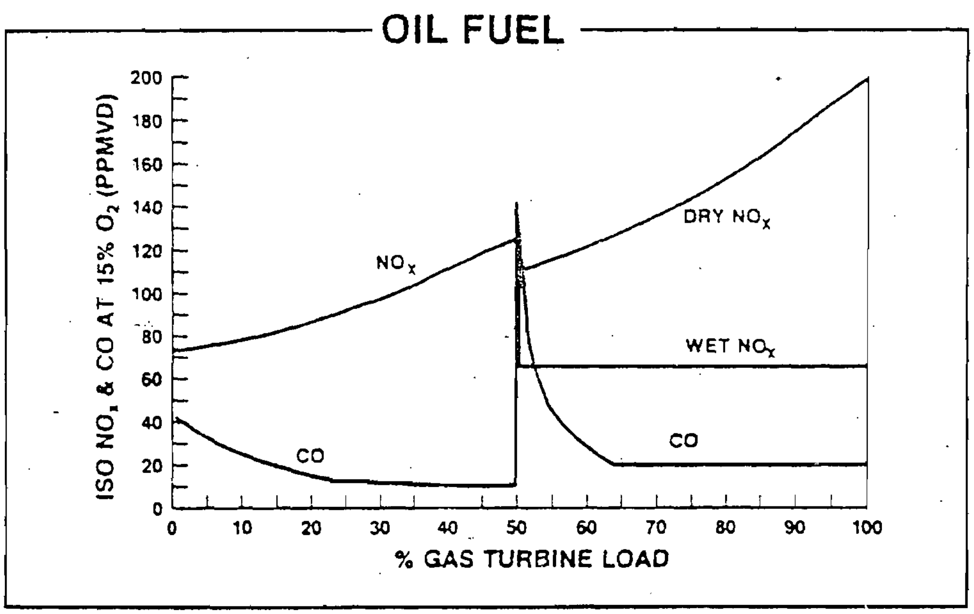


Figure 5-21. "Stepped" NO_x and CO emissions for a low-NO_x can-annular combustor burning natural gas and distillate oil fuels.[47]

Florida Department of
Environmental Protection

Memorandum

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ronald W. Tomlin
Lakeland Electric + Water
501 E. Lemon Street
Lakeland, Fl 33801-5079

4a. Article Number
P 265 659 340

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery APR 30 1998

5. Received By: (*Print Name*)

8. Addressee's Address (*Only if requested and fee is paid*)

6. Signature: (*Addressee or Agent*)
X Bernie Brun

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 340

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail (*See reverse*)

Sent to Ronald Tomlin	
Street & Number Lakeland Electric	
Post Office, State, & ZIP Code + Water	
Postage Lakeland, Fl	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	

PS Form **3800**, April 1995

Golder Associates Inc.

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Golder Associates

April 27, 1998

Ms. Ellen Porter
U.S. Fish & Wildlife Service
Air Quality Branch
P.O. Box 25287
Denver, CO 80225-0287

RE: Lakeland Visibility Analysis
Response to Comments by the U.S. Fish & Wildlife Service

Dear Ms. Porter:

The following responses have been prepared that address your comments on April 2, 1998 concerning the revised regional haze analysis performed by the City of Lakeland for the proposed project's impacts at the Chassahowitzka National Wildlife Refuge (CNWR). On April 16, 1998, I discussed the approach used in the revised analysis with Mr. Bud Rolofson, U.S. Fish & Wildlife Service (FWS).

The revised regional haze analysis followed the Interagency Workgroup on Air Quality Modeling (IWAQM) recommendations and used the ISCST model to estimate sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter concentrations for the project's emissions. These concentrations were estimated for 1987 to 1991, the years of meteorological data used to address the project's compliance with ambient air quality standards (AAQS) and prevention of significant impact (PSD) maximum allowable increments.

From earlier discussions with Mr. Rolofson, a procedure has been developed by the FWS to address the chemical transformation of SO_2 and NO_x to sulfates and nitrates, which are used in the regional haze analysis. For example, the chemical transformation of SO_2 to sulfate is assumed to occur at an hourly rate of 3 percent per hour. The sulfate is then assumed to be transformed to ammonium sulfate ($(NH_4)_2SO_4$), a compound used to assess regional haze. For NO_x conversion, all of the NO_x concentration (100 percent) is assumed to convert to nitrate (NO_3), a very conservative assumption. The NO_3 is then assumed to convert to ammonium nitrate (NH_4NO_3), another compound used to assess regional haze. In the revised regional haze analysis prepared by Golder, a more realistic approach was developed to account for the conversion rate of NO_x to NO_3 (similar to the conversion of SO_2 to sulfate). Based on modeling with the MESOPUFF model using one year of meteorological data (1986), a chemical transformation rate of 31 percent was developed to convert NO_x to NO_3 over a 24-hour averaging period. The transformation rate was based on one year of modeling since the meteorological data needed for running the model for other years (e.g., 1987 to 1991) were not available. As will be shown later in the discussion, the procedure to multiply the NO_2 concentrations predicted with the ISCST model by the 31-percent transformation rate produces higher NO_3 concentrations than NO_3 concentrations produced directly from the MESOPUFF model. As a result, the approach used in the revised regional haze analysis is conservative and does produce higher deciview values than are expected from the project.

Based on comments from the FWS, the regional haze analysis was redone using the MESOPUFF model to predict sulfate, NO_3, and particulate matter concentrations for the project's emissions. Again, these analysis followed the approach recommended by the NPS in the "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report" (April 1993). The MESOPUFF model using one year of meteorological data (1986) predicted the maximum sulfate, NO3, and particulate matter concentrations. A summary of the input parameters, assumptions, and results is presented in Table 1. This deciview value of 0.20 is less than the revised screening deciview value of 0.5 recommended in guidance developed by the FWS in December 1997. This value is lower than the results from the previous regional haze analysis that used the results of the ISCST model and 31-percent NO_x transformation rate.

Please call Mr. Ken Kosky or me at (352) 336-5600 if you have any questions or comments on this analysis.

Sincerely yours,

Robert C. McCann Jr.

Robert C. McCann, Jr.
Manager, Air Resources

RCM/arz

cc: K.F. Kosky, Golder
F. Shelton, City of Lakeland
C. Holladay, Florida DEP
File (2)

Checked w/ Bud Rolofson
This one is ok

Table 1. Estimated Change in Deciview Due to the City of Lakeland-McIntosh Plant, Proposed Westinghouse 501G Combustion Turbine, Fuel-oil Firing at Baseload Conditions and 30 °F Temperature (MESOPUFF Model)

Pollutant	Value	Reference
Maximum Emission Rates (lb/hr)		
SO_2	126.70	(1)
NOx	433.00	(1)
PM10	95.50	(1)
Highest Predicted 24-Hour Concentrations ($\mu g/m^3$)		
SO_4	0.0216	(2)
NO_3	0.0415	(2)
PM10	0.0726	(3)
$(NH_4)_2\ SO_4$	0.0297	(4)
$NH_4\ NO_3$	0.0535	(5)
Average RH (percent)	76	(6)
RH factor, f(RH)	4.0	(7)
Extinction Coefficients (km^{-1})		
Background: (bextb)	0.0602	(8)
Source: (bexts)		
$(NH_4)_2\ SO_4$	0.0004	(9)
$NH_4\ NO_3$	0.0006	(9)
PM10	0.000218	(10)
Total (bexts)	0.0012	
Deciview Change		
total delta dv =	0.200	(11)

(1) Maximum hourly emissions due to CT firing oil at 30° F.
(2) Impacts based on highest 24-hour concentration predicted for 1986 from MESOPUFF. (Note: wet deposition not included in analysis.)
(3) PM concentrations based on highest 24-hour concentration for 1986 from MESOPUFF. (PM impact modeled as sulfate).
(Note: chemical transformation and wet deposition not included in analysis.)
(4) $(NH_4)_2\ SO_4 = SO_4$ times 1.375 from IWAQM Appendix B
(5) $NH_4\ NO_3 = NO_3$ times 1.29 from IWAQM Appendix B
(6) Based on meteorological data collected at the National Weather Service station in Tampa.
(7) From IWAQM Figure B-1. Based on average hourly relative humidity factor for day.
(8) bextb = 3.912 / 65 where background visual range is 65 km.
(9) values= 0.003 * compound concentration* factor (RH) from IWAQM Appendix B
(10) PM10 = 0.003 * compound concentration. factor (RH) set = 1 for fine PM
(11) Delta DV = 10 * ln (1 + bexts/bextb)

7-9-98

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In Re: City of Lakeland	)	
C.D. McIntosh Power Plant	)	
Unit No. 3	)	OGC CASE NO. 98-1994
Modification of Conditions	)	DEP FILE NO. PA74-06F
of Certification	)	
Polk County, Florida	)	
	)	

FINAL ORDER MODIFYING
<u>CONDITIONS OF CERTIFICATION</u>

On December 7, 1978, the Governor and Cabinet, sitting as the Siting Board, issued a final order approving certification for the Lakeland McIntosh Power Plant Unit Number 3. The site certification order approved the construction and operation of a 334 MW (net) coal fired unit and associated facilities in Polk County, Florida. The certification has been previously modified on October 5, 1980, August 10, 1983, August 15, 1988 and February 13, 1996.

On March 16, 1998, Lakeland filed a request with the Florida Department of Environmental Protection ("Department") to amend the conditions of certification pursuant to Section 403.516(1)(b), Florida Statutes. Lakeland requested that the conditions be modified to allow the construction and operation of Unit 5, a 250 megawatt, natural gas fired combustion turbine on the McIntosh Plant site.

Copies of Lakeland's proposed modifications were made available for public review on April 3, 1998, on which date a Notice of Intent to Issue Proposed Modification of Power Plant Certification was also published in the Florida Administrative Weekly. On March 16, 1998, all parties to the original proceeding were served by mail with copies of the intent to modify and supporting documentation. The notice specified that a hearing would be held if a party to the original certification hearing objected within 45 days from receipt of the proposed modifications or if any other person, whose interests would be substantially affected, objected in writing within 30 days after issuance of the public notice. No written objection to the proposed modifications has been received by the Department. Accordingly, in the absence of any timely objection,

IT IS ORDERED:

The proposed changes to the Lakeland McIntosh Power Plant Unit Number 3 as described in its March 13, 1998, request for modification are APPROVED. Pursuant to Section 403.516(1)(b), F.S., the conditions of certification for the Lakeland McIntosh Power Plant Unit Number 3 are **MODIFIED** as follows:

I. Air Unit 3 - No change

II. Air Unit No. 5

A. EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
028	Power Generation	250 Megawatt Combustion Turbine and Once Through Steam Generator
029	Fuel Storage	1.05 Million Gallon Fuel Oil Storage Tank

B. REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY). This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

C. GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, telephone number (850) 488-1344. All

documents related to reports, tests, and notifications should be submitted to the Department's Southwest District office (DEPSW), 3804 Coconut Palm Drive, Tampa, Florida 33619, telephone number (813) 744-6100.

2. General Conditions: The owner and operator is subject to and shall operate under the General Permit Conditions G.1 through G.15 listed in Appendix GC attached to Permit No. PSD-FL-245. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

7. BACT Determination: In accordance with 40 CFR 52.21(j)(4), the Best

Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a conversion to combined cycle operation. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." [40 CFR 52.21(j)(4)] This reassessment will be conducted for this project only if the conversion to combined cycle operation is accompanied by any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, or similar changes. [40 CFR 52.21(j)(4)]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the Department's Bureau of Air Regulation, and a copy to the Department's Southwest District office (DEPSW). [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the Department's Southwest District office by March first of each year.

11. Stack Testing Facilities: Stack sampling facilities shall be installed in

accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7(a)(7)(c) (1997 version), shall be submitted to the Department's Southwest District office.

D. APPLICABLE STANDARDS AND REGULATIONS

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

- 40CFR60.7, Notification and Record keeping
- 40CFR60.8, Performance Tests
- 40CFR60.11, Compliance with Standards and Maintenance Requirements
- 40CFR60.12, Circumvention

- 40CFR60.13, Monitoring Requirements
- 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Unit, Power Generation, consisting of a 250 megawatt combustion turbine with a once-through steam generator shall comply with all applicable provisions of 40 CFR 60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 029, Fuel Storage, consisting of a 1.05 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.

6. All notifications and reports required by the above specific conditions shall be submitted to the Department's Southwest District office.

E. GENERAL OPERATION REQUIREMENTS

1. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur No. 2 distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

2. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,174 million Btu per hour (MMBTU/hr) when firing natural gas, nor 2,236 MMBTU/hr when firing No. 2 fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site

conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

3 . Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering of and/or application of water or chemicals to the affected areas, as necessary.

4. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Department's Southwest District Office as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

5. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

6. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

7. Maximum allowable hours of operation for the stationary gas turbine and once-through steam generator are 8760. Fuel usage as heat input, while burning natural gas in the stationary gas turbine, shall not exceed 15.639×10^{12} BTU (LHV) per year (rolled monthly) until the unit achieves the NO_X emission limits (other than the initial ones) given in Specific Condition 21. Thereafter, only the hourly heat input limits given in Specific Condition 8 apply. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

8. Fuel usage as heat input while burning fuel oil in the stationary gas turbine shall not exceed 559×10^9 BTU (LHV) per year (rolled monthly). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

9. Westinghouse Second Generation Advanced Dry Low NO_X (DLN) combustors (or equivalent) shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]

10. The Dry Low NO_X (DLN) combustors shall be replaced with Westinghouse Ultra Low NO_X (ULN) combustors to accomplish further NO_X control in order to achieve the emission limits specified in Specific Conditions 20 and 21. A high temperature selective catalytic reduction (Hot SCR) system or a low temperature SCR system shall be installed and in operation (together with DLN or ULN combustors) not later than May 1, 2002 if the emission limits specified in Specific Condition Nos. 20 and 21 are not achievable by ULN combustors by this date. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

11. The permittee shall design the stationary gas turbine, ducting, possible future heat recovery steam generator, and stack(s) to accommodate installation of SCR

equipment and/ or oxidation catalyst in the event that the ULN technology fails to achieve the NO_X limit given in Specific Condition Nos. 20 and 21 or if carbon monoxide (CO) limits given in Specific Condition No. 22 are not met. [Rule 62-4.070, F.A.C.]

12. A water injection system shall be installed for use when firing No. 2 fuel oil or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.410, F.A.C.]

13. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and ULN systems prior to their installation. DLN and ULN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the DLN or ULN systems in the diffusion firing mode shall be minimized when firing natural gas. [Rule 62-4.070, and 62-210.650 F.A.C.]

F. EMISSION LIMITS AND STANDARDS

1. The following emission limits shall apply upon completion of the initial performance tests: Best Available Control Technology (BACT). Following is a summary of the BACT determination by DEP. Values for NO_X are corrected to 15% O_2. Values for CO are corrected to 15% O_2 only until May 1, 2002. [Rule 62-212.400, F.A.C.]

Operational Mode	**NO_X (ppm)**	**CO (ppm)**	**VOC (ppm)**	**PM/Visibility (% Opacity)**	**Technology and Comments**
Simple Cycle	25 - NG (basis) 237 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	DLN on gas, WI on oil. Applies until 05/1/2002. Clean fuels, good combustion.

Simple Cycle	9 - NG (basis) 85 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after 05/1/2002 Clean fuels, good combustion.
Simple Cycle	9 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies not later than 05/1/2002 if 9 ppm NO_X not achievable by ULN. Clean fuels, good combustion.
Combined Cycle	7.5 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR unless simple cycle limits are achieved on or before 05/01/2002. Clean fuels, good combustion.

2. Nitrogen Oxides (NO_X) Emissions:

a. When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

b. Until May 1, 2002, the concentration of NO_X in the exhaust gas shall not exceed 237 lb/hr (at ISO conditions) on a 24 hr block average (basis 25 ppm @ 15% O_2, full load) when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3 hr average), as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall exceed neither 25 ppm @15% O_2 nor 237 lb/hr (when firing natural gas) and shall exceed neither 42 ppm @15% O_2 nor 413 lb/hr (when firing oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

c. Not later than May 1, 2002, NO_X concentrations in the exhaust gas shall not exceed 85 lb/hr (at ISO conditions) on a 24 hr block average (basis 9 ppm @ 15% O_2) when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3 hr average as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall exceed neither 9 ppm @15% O_2 nor 85 lb/hr (when firing natural gas) and shall exceed neither 42 ppm @15% O_2 nor 413 lb/hr (when firing oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

d. If Hot SCR is installed, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O_2 when firing natural gas. NO_X emissions shall not exceed 9 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3-hr average as measured by the CEMS. NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 85 lb/hr (when firing gas) and 148 lb/hr (when firing oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

e. If conventional SCR is installed in conjunction with conversion to combined cycle operation, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd @ 15% O_2 when firing fuel oil on the basis of a 3-hr average as measured by the CEMS. If conventional SCR catalyst is installed, NO_X emissions shall not exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3-hr average as measured by the CEMS. NOx emissions calculated as NO_2 (at ISO conditions) shall not exceed 71.1 lb/hr (when firing gas) and 148 lb/hr (when firing oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

3. Carbon Monoxide (CO) emissions: Prior to May 1, 2002,the concentration of CO at 15% O_2 in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Reference Method 10 test. CO emissions (at ISO conditions) shall not exceed 145 lb/hr (when firing gas) and 539 lb/hr (when firing oil). [Rule 62-212.400, F.A.C.] After May 1, 2002, the concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 106 lb/hr (when

firing gas) and 386 lb/hr (when firing oil). [Rule 62-212.400, F.A.C.]

4. Sulfur Dioxide (SO_2) emissions: SO_2 emissions (at ISO conditions) shall not exceed 7.2 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. Emissions of SO_2 shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review]

5. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil.

6. Volatile Organic Compounds (VOCs) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as measured by EPA Methods 18, and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 10 lb/hr (gas) and 25 lb/hr (oil). - [Rule 62-212.400, F.A.C.]

G. EXCESS EMISSIONS

1. Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

2. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C.

3. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify the Department's Southwest District office within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

H. COMPLIANCE DETERMINATION

1. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days after initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C. Emission limits compliance dates shall conform to the timetable specified on Condition No. II.F.1.

2. Initial (I) performance tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of Ultra Low NOX burners, Hot SCR, or conventional SCR. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30), pursuant to Rule 62-297.310(7), F.A.C., on Unit 5 as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from

Stationary Sources" (I, A).

- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).

- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40 CFR 60 Subpart GG and short-term NO_X BACT limits (I,A) (Method 7E or RATA test data may be used to demonstrate compliance for annual test requirement.)

- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

3. Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN or ULN technology) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Condition 28. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rule 62-4.070, F.A.C., 40 CFR 75]

4. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.310, F.A.C., the use of pipeline natural gas and the use of no more than 250 hours per year of maximum 0.05 percent sulfur (by weight)No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2

and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

5. Compliance with CO emission limit: An initial test for CO, concurrent with the initial NO_X test, is required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing may be conducted concurrent with the annual RATA testing required pursuant to 40 CFR 75 (required for gas only).

6. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, CO emission limit will be employed as surrogate.

7. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so

limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-297 F.A.C.

8. Test Notification: The Department's Southwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

9. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310, F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

10. Test Results: Compliance test results shall be submitted to the DEP's Southwest District office no later than 45 days after completion of the last test run.

I. NOTIFICATION, REPORTING, AND RECORD KEEPING

1. Records: All measurements, records, and other data required to be maintained by the City of Lakeland Department of Electric & Water Utilities shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to Department representatives upon request.

2. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed with the Department's Southwest District Office as soon as practical, but no later than 45 days after the last sampling run is completed. [Rule 62-297.310(8), F.A.C.]. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to

determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

J. MONITORING REQUIREMENTS

1. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 5. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards listed in Subsection C. Specific Condition C.1. shall be reported to the Department's Southwest District Office pursuant to Rule 62-4.160(8), F.A.C. Periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the BACT standards following the format of 40 CFR 60.7 (1997 version).

2. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from the Department, the CEMS emission rates for NO_X on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

3. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, and 40 CFR 60.7(a)(5) including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5). Quality assurance procedures must conform to

all applicable sections of 40 CFR 60, Appendix F or 40 CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Southwest District Office (DEPSW) for review at least 90 days prior to installation.

4. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at the C.D. McIntosh, Jr. Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

5. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- Monitoring of natural gas nitrogen content shall not be required.
- Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods in Specific Condition No.32 for the measurement of sulfur in gaseous fuels, or an approved alternative method. Once Unit 5 becomes operational, monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.
- Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City of Lakeland shall notify the Department of such excess emissions and the customized fuel monitoring schedule shall be re-examined. The sulfur content of the natural gas

will be monitored weekly during the interim period while the monitoring schedule is re-examined.

- The City of Lakeland shall notify the Department of any change in natural gas supply for re-examination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being re-examined.

- Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City of Lakeland for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.

- The City of Lakeland may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission) provided the test methods listed in Specific Condition E.4 are used.

6. Determination of Process Variables:

a. The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

b. Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C.].

III. ~~II.~~ WATER DISCHARGES - No change

IV. ~~III.~~ GROUNDWATER

A. and B. - No change

C. Groundwater Use Limitations

1. and 2. - No Change

3. Well Numbers 5 and 8, as identified in the Southwest Florida Water Management District (SWFWMD) Permit 200047.03 (dated August 27, 1996) may be used for raw makeup water for Unit 5.

4. Groundwater used for Unit 5, in simple cycle operation shall not exceed 500 gpm or a peak usage of 720,000 gallons/day (gpd) and an annual usage of 576,000 gpd, respectively.

V. ~~IV.~~ LEACHATE - No change

VI. ~~V.~~ CONTROL MEASURES DURING CONSTRUCTION - No change

VII. ~~VI.~~ SOLID WASTES - No change

VIII. ~~VII.~~ OPERATION SAFEGUARDS - No change

IX. ~~VIII.~~ SOLID WASTE UTILIZATION SYSTEM - No change

X. ~~IX.~~ SCREENING - No change

XI. ~~X.~~ POTABLE WATER SUPPLY SYSTEM - No change

XII. ~~XI.~~ TRANSFORMER AND ELECTRIC SWITCHING GEAR - No change

XIII. ~~XII.~~ TOXIC, DELETERIOUS OF HAZARDOUS MATERIALS -No change

XIV. ~~XIII.~~ TRANSMISSION LINE - No change

XV. ~~XIV.~~ CONSTRUCTION IN WATERS OF THE STATE - No change

XVI. ~~XV.~~ COOLING WATER TREATMENT - No change

XVII. ~~XVI.~~ SANITARY WASTE DISPOSAL - No change

XVIII. SURFACE WATER AND STORMWATER MANAGEMENT FACILITIES

The City of Lakeland shall construct all aspects of the surface water management system in accordance with the construction plans received by the Southwest Florida Water Management District (SWFWMD) on June 23, 1998. This certification for the surface water management systems is valid only for the specific processes and operations applied for and indicated in the approved drawing or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or Conditions of Certification may constitute grounds for modification, revocation or enforcement action.

A. General

1. City of Lakeland Confirmation.

The operational phases of the surface water management systems authorized under this certification shall not become effective until the City of Lakeland confirms in writing, upon completion of each phase, that these facilities have been constructed consistent with the conditions of certification. Such confirmation shall include a certification by an engineer (practicing in the State of Florida, having the appropriate experience in surface water management design and construction, and in compliance with Chapter 471, Florida Statutes, unless exempt thereunder), that the facilities have been constructed in accordance with the approved project design. Within 30 days after completion of construction of the surface water management system, the City of Lakeland shall submit the confirmation, including "as-built" construction drawings with the engineer's certification and a description of any deviations; and notify the SWFWMD that the facilities are ready for inspection for consistency with the conditions of certification and information submitted hereunder.

2. Discharges.

The discharges from the surface water management system shall meet state water quality standards as set forth in Chapter 62-302, F.A.C. for class waters equivalent to the receiving waters.

3. Minimum Standards.

This certification is predicated on the City of Lakeland's submitted information to SWFWMD which reasonably demonstrates that adverse off-site water resource related impacts will not be caused by the authorized activities. The plans, drawings, and design specifications submitted shall be considered minimum standards for compliance.

4. Post-Certification Information Submittal.

Information submitted to the SWFWMD subsequent to certification, in compliance with the conditions of this certification, shall be for the purpose of water management district monitoring and confirming compliance with the conditions of certification and the criteria contained in Rule 40D-4, F.A.C., as applicable, prior to the commencement of the subject construction, operation and/or maintenance activity, covered thereunder.

5. Liability.

Permittee shall hold and save SWFWMD harmless from any an all damages, claims, or liabilities which may arise by reason of the construction, operation, maintenance and/or use of any facility authorized by this certification, to the extent allowed under Florida law.

6. Enforcement.

Authorized representatives of the SWFWMD shall be allowed reasonable escorted access to the project site to inspect and observe any activities associated with the project construction or the operation and/or maintenance of the surface water management system(s) and stormwater facilities in order to determine compliance with the conditions of this certification.

7. Monitoring.

Post-certification monitoring requirements may be determined and specified as a result of technical review of construction information, where necessary, to demonstrate compliance with water management district regulations. If monitoring data is required by the SWFWMD in conjunction with post-certification review, it shall be submitted to the SWFWMD and to the Florida Department of Environmental Protection. Parameters to be monitored may include those listed in Chapter 62-302, Florida Administrative Code. The City of Lakeland shall, if required, provide data to SWFWMD regarding: Construction, operation, and maintenance of surface water management systems; NGVD levels; volumes and timing of water discharged, including total volume discharge during period of sampling and total and discharges from the property.

B. Construction Conditions

1. This project must be constructed in compliance with and meet all applicable requirements set forth in Chapter 373, Florida Statutes, and Chapter 40D-4, Florida Administrative Code.

2. Any surface water discharged from the site during construction of the project shall meet State water quality standards at the property boundary or point of discharge to wetlands or State waters. If the discharge does not meet these standards, the discharge will be immediately stopped and the SWFWMD shall be notified of corrective action(s) taken to correct the violation(s). Turbidity shall not exceed 29 N.T.U. above background level. Turbidity shall be monitored at least once during discharge, or more often as

determined by the project engineer or SWFWMD if needed, to ensure compliance.

3. Except as authorized by this certification for the surface water management system, any further land development, wetlands disturbance or other construction within the total land area of this site will require additional certifications in accordance with the SWFWMD's rules (Chapter 40D-4, F.A.C.).

4. All rights-of way and easement locations necessary to construct, operate, and maintain all facilities, including uplands conservation/buffer areas and wetlands, which constitute the certified surface water management system, shall be reserved for water management purposes.

5. Construction of the discharge control and water quality treatment facilities which are part of the certified surface water management system shall be completed and operational prior to beneficial occupancy and use of the project development being served.

6. Establishment and survival of littoral areas provided for stormwater quality treatment in wet detention systems shall be assured by proper and continuing maintenance procedures designed to promote viable wetlands plant growth of natural diversity and character. As-built drawings depicting the established wet detention treatment areas shall be submitted to the SWFWMD for inspection and approval upon completion of construction. Following as-built approval, perpetual maintenance shall be provided for the certified system.

7. Any existing wells in the path of construction shall be properly plugged and abandoned by a licensed water well contractor in accordance with Chapter 40D-3, and Rule 62-532.500(4), F.A.C.

8. All retention/detention pond side slopes shall be sodded and staked as necessary to prevent erosion.

9. Any system alteration, including for augmentation into or withdrawal of water from

the certified surface water management system, other than as specifically authorized by this certification, will require additional District certification consideration. The water level of stormwater detention ponds shall not be augmented by pumping or diversion of water into the ponds to artificially control their level above the design normal or beginning storage level.

10. The City of Lakeland shall perform the construction authorized in a manner so as to minimize any adverse impact on the system on fish, wildlife, natural environmental values, and water quality. The City of Lakeland shall institute necessary measures during the construction period, including full compaction of any fill material placed around newly installed structures, to reduce erosion, turbidity, nutrient loading and sedimentation in the receiving waters.

11. Off-site discharges of surface water during construction and development shall be made only through the facilities authorized by this certification.

12. In order to insure that the person who will construct the proposed work is identified as required by 373.413(2)(f), F.S., once the contract is awarded, the name, address, and telephone number of the contractor shall be submitted to the SWFWMD prior to construction.

13. The City of Lakeland shall immediately provide written notification to the SWFWMD upon beginning any construction authorized by this certification.

14. The City of Lakeland shall retain the design engineer, or other Professional Engineer registered in Florida, to conduct on-site observations of construction and assist with the as-built certification requirements of this project. The City of Lakeland shall inform the SWFWMD in writing and prior to beginning construction of the name, address, and telephone number of the Professional Engineer so employed by the City of Lakeland.

15. The operation and maintenance entity shall submit inspection reports for the

surface water management system in the form required by the SWFWMD. For systems utilizing wet detention, the inspections shall be performed two (2) years thereafter.

16. The SWFWMD verified wetland boundaries shall be clearly delineated on the site prior to initial clearing and grading activities. The delineation shall endure throughout the construction period and be readily discernable to construction personnel and SWFWMD staff.

C. Project Information Requirements

1. Subsequent modifications to the drawings and supporting calculation submitted to SWFWMD which may significantly alter the quantity and/or quality of waters discharged off site shall also be submitted to the water management district for a determination that the modifications are in compliance with Chapter 40D-4, Florida Administrative Code, as appropriate, prior to the commencement of construction. However minor deviations from construction plans deemed necessary in the field, including, but not necessarily limited to changes in the number, size, and location of culverts and other structures, shall be allowed.

2. The SWFWMD and the City of Lakeland may mutually agree to vary the information requirements.

Any party to this Notice has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, M.S.35, Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000, and by filing a copy of the Notice of Appeal accompanied by the applicable filing fee with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date that this Final Order is filed with the Department of Environmental Protection.

DONE AND ENTERED this 9th day of July, 1998 in Tallahassee, Florida.

STATE OF FLORIDA, DEPARTMENT OF ENVIRONMENTAL PROTECTION

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to S120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

[signature] 7/9/98
Clerk **Date**

for [signature]
VIRGINIA B. WETHERELL
SECRETARY
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000
Telephone: (850) 488-1554

CERTIFICATE OF SERVICE

I HEREBY CERTIFY this ~~10th~~ 9th day of July 1998, that a true and correct copy of the foregoing Final Order Modifying Conditions of Certification has been sent by mail to the following listed persons:

David S. Dee, Esq.
Landers & Parsons
P.O. Box 271
Tallahassee, FL 32302

Andrew Grayson, Esq.
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100

Plumbers and Pipe Fitters Local
No. 111
c/o Fred Stiles
4020 80th Avenue North
Pinellas Park, FL 33565

Richard T. Tschantz, Esq.
SWFWMD
2379 Broad Street
Brooksville, FL 34609-6899

Pinellas County Building
Trades Council
c/o G. Wallace
2165 Country Club Court North
St. Petersburg, FL 33710

Pinellas County Department of
Environmental Management
315 Court Street
Clearwater, FL 34616

* CORRECTED CERTIFICATE OF SERVICE ATTACHED

CORRECTED CERTIFICATE OF SERVICE

I HEREBY CERTIFY this 10th day of July 1998, that a true and correct copy of the foregoing Final Order Modifying Conditions of Certification has been sent by U.S. mail or interagency mail to the following listed persons:

Gary P.Sams, Esq.
Hopping Green Sams & Smith
P.O. Box 6526
Tallahassee, FL 32314

Norman White, Esq.
Central Florida Regional
Planning Council
555 East Church Street
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Stephanie G. Kruer, Esq.
General Counsel
Dept. of Community Affairs
2555 Shumard Oak Blvd
Tallahassee, FL 32399-2100

Richard Tschantz, Esq.
Assistant General Counsel
Southwest Florida Water
Management District
2379 Broad Street
Brooksville, FL 34609-6899

Pamela S. Leslie, Esq.
General Counsel
Department of Transportation
Haydon Burns Building
605 Suwannee Street, M.S. 58
Tallahassee, FL 32399-0450

Mark Carpanini, Esq.
Office of County Attorney
Post Office Box 60
Bartow, FL 33830-0060

Robert V. Elias, Esq.
Florida Public Service Commission
Gerald Gunter Building
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850

Andrew R. Reilly, Esq.
East Lake Parker Residents
Post Office box 2039
Lakeland, FL 33845-2039

James V. Antista
General Counsel
Game and Fresh Water Fish Comm.
Bryant Bldg.
620 S. Meridian Street
Tallahassee, FL 32399-1600

Thomas B. Tart, Esq.
Orlando Utilities Commission
500 South Orange Street
Orlando, FL 32801

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

SCOTT GOORLAND
Assistant General Counsel
Florida Bar No. 0066834

3900 Commonwealth Boulevard, MS 35
Tallahassee, Florida 32399-3000

RECEIVED
JUN 26 1998
Dept. of Environmental Protection
Office of General Counsel

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC CASE NO. 98-1407

Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Revised DRAFT Permit No.: 1050004-004-AC
(PSD-FL-245) C. D. McIntosh, Jr. Power Plant
Polk County
/

NOTICE OF WITHDRAWAL OF REQUEST FOR EXTENSION OF TIME

Lakeland Electric and Water Utilities (Lakeland) by and through undersigned counsel, hereby withdraws its Request for Extension of Time to file a petition for formal administrative proceedings or a request for mediation in accordance with Chapter 120, Florida Statutes. Lakeland filed a Request for Extension of Time on May 1, 1998, in response to the "Intent to Issue Air Construction Permit" (Permit No. 1050004-004-AC [PSD-FL-245]) for the C.D. McIntosh, Jr. Power Plant located in Polk County, Florida, to negotiate certain changes in the permit with the Department of Environmental Protection (Department). The extension was granted until June 30, 1998, by an Order issued on May 21, 1998. Lakeland withdraws its Request because the Department has agreed to issue the permit with changes negotiated with Lakeland, as reflected in the attached document received on June 22, 1998 from the Department's Bureau of Air Regulation.

Respectfully submitted this 26th day of June, 1998.

HOPPING GREEN SAMS & SMITH, P.A.

Angela R. Morrison

Angela R. Morrison, Fla. Bar No. 0855766
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500

Attorney for LAKELAND ELECTRIC & WATER UTILITIES

RECEIVED
JUN 30 1998
BUREAU OF
AIR REGULATION

111866.1

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 26th day of June, 1998:

Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

W. Douglas Beason
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Angela R. Morrison

Angela R. Morrison

From: Teresa Heron TAL 488-1344 <HERON_T@dep.state.fl.us>
To: HGSSMAIL.SMTP("FSHEL@city.lakeland.net")
Date: 6/22/98 2:45pm
Subject: Final version sent to Buck anf Howard

Farzie:

This permit was taken to Howard for signature. Last version (permit 5 as corrected around 2pm today).

Teresa

Permittee:

City of Lakeland
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Fl 33801-5079

File No.	1050004-004-AC
FID No.	1050004-004
SIC No.	4911
Permit No.	PSD-FL-245
Expires:	June 30, 2002

Authorized Representative:
Ronald W. Tomlin
Assistant Managing Director

Project and Location:

Permit for the construction of 250 megawatt (MW) simple cycle, gas-fired, stationary combustion turbine (CT), a once-through steam generator, and a 1.05 million gallon storage tank for back-up distillate fuel oil. Conditions are included for possible future conversion to a 350 megawatt combined cycle installation including a heat recovery steam generator provided there are no increases in emissions associated with the conversion. The turbine is designated as Unit No. 5 and will be located at the C.D. McIntosh, Jr., Power Plant, 3030 East Lake Parker Drive, Lakeland, Polk County. UTM coordinates are: Zone 17; 409.0 km E; 3106.2 km N.

Statement of Basis:

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

Subsection A. Facility Description

The existing facility includes: two small diesel powered electric generators; one small gas and distillate-fired combustion turbine; one 90 MW gas and fuel oil-fired steam generator; one 115 MW gas and fuel oil-fired steam generator; and one 364 MW multiple (primarily coal) fuel-fired steam generator This permit is for the installation of: a 250 MW simple cycle, gas-fired, stationary combustion turbine; a once-through steam generator; a 1.05 million gallon storage tank for back-up (0.05 percent sulfur) distillate fuel oil; and an 85-foot stack. It is possible that in the future the turbine will be converted by the addition of a heat recovery steam generator and a new stack to a 350 MW combined cycle operation without increases in emissions.

Emissions from the McIntosh Unit 5 will be initially controlled by Dry Low NOX combustors, wet injection when firing fuel oil, use of inherently clean fuels, and good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions reduced by more sophisticated Ultra Low NOX burners. Otherwise emissions will be reduced by the addition of a selective catalytic reduction (SCR) system.

subsection b. emission units

This permit addresses the following emission units:

ARMS Emission Unit No.	System	Emission Unit Description
028	Power Generation	250 Megawatt Combustion Turbine and Once Through Steam Generator
029	Fuel Storage	1.05 Million Gallon Fuel Oil Storage Tank

Subsection c. Regulatory Classification

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM10), sulfur dioxide (SO2), nitrogen oxides (NOX), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications (such as the construction of Unit 5) at the facility resulting in emissions increases greater than 40 TPY of NOX or SO2, 25/15 TPY of PM/PM10, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

Subsection d. PERMIT SCHEDULE

04/22/98 Notice of Intent published in The Ledger

04/23/98 Distributed Intent to Issue Permit

04/01/98 Application deemed complete

12/08/97 Received Application

SUBSECTION e. Relevant Documents:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

Application received on December 8, 1997

Department letters dated January 5, January 12, March 9, 1998, and April 27, 1998

Comments and letters from the National Park Service dated January 6, January 12, April 2 and April 15, 1998.

EPA letters dated February 10 and March 6, 1998

City of Lakeland letters dated March 4, March 11, March 31, and May 6, 1998

Letters from Westinghouse dated March 25, March 30, and March 31, 1998

Department's Intent to Issue and Public Notice Package dated April 22, 1998

Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District office (DEPSW), 3804 Coconut Palm Drive, Tampa, Florida 33619 and phone number 813/744-6100.

General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a conversion to combined cycle operation. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

This reassessment will be conducted for this project only if the conversion to combined cycle operation is accompanied by any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. At a minimum, conversion to combined cycle operation will require a modification of this permit to reflect the ultimate facility description, the higher power production rates and review of the actual control equipment design. [40 CFR 52.21(j)(4), Rule 62-4.070 F.A.C.]

Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Southwest District office (DEPSW). [Chapter 62-213, F.A.C.]

New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District office by March 1st of each year.

Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (7) (c) (1997 version), shall be submitted to the DEP's Southwest District office.

APPLICABLE STANDARDS AND REGULATIONS:

Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

40CFR60.7, Notification and Recordkeeping
40CFR60.8, Performance Tests
40CFR60.11, Compliance with Standards and Maintenance Requirements
40CFR60.12, Circumvention
40CFR60.13, Monitoring Requirements
40CFR60.19, General Notification and Reporting requirements

ARMS Emission Unit 028, Power Generation, consisting of a 250 megawatt combustion turbine with a once-through steam generator shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

ARMS Emission Unit 029, Fuel Storage, consisting of a 1.05 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of performance for Storage Tanks, adopted by reference in Rule 62-204.800, F.A.C.

All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District office.

GENERAL OPERATION REQUIREMENTS

Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,174 million Btu per hour (mmBtu/hr) when firing natural gas, nor 2,236 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Permitting Authority as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

Maximum allowable hours of operation for the stationary gas turbine and once-through steam generator are 8760. Fuel usage as heat input, while burning natural gas in the stationary gas turbine, shall not exceed 15.639 x 10 12 BTU (LHV) per year (rolled monthly) until the unit achieves the NOX emission limits (other than the initial ones) given in Specific Condition 21. Thereafter, only the hourly heat input limits given in Specific Condition 8 apply. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Fuel usage as heat input, while burning fuel oil in the stationary gas turbine, shall not exceed 559 x 109 BTU (LHV) per year (rolled monthly). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Control Technology

Westinghouse Dry Low NOX (DLN) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NOX) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]

The Dry Low NOX (DLN) combustors shall be replaced with Westinghouse Ultra Low NOX (ULN) combustors to accomplish further NOX control in order to achieve the emission limits specified in Specific Condition 20 and 21. A high temperature selective catalytic reduction (Hot SCR) system or a low temperature SCR system shall be installed and in operation (together with DLN or ULN combustors) not later than May 1, 2002 if the emission limits specified in Specific Condition No 20 and 21 are not achievable by ULN combustors by this date. [Design, Rules 62-4.070 and 62-212.410, F.A.C.]

The permittee shall design the stationary gas turbine, ducting, possible future heat recovery steam generator, and stack(s) to accommodate installation of SCR equipment and/or oxidation catalyst in the event that the ULN technology fails to achieve the NOX limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22 are not met. [Rule 62-4.070, F.A.C.]

A water injection system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NOX emissions. [Design, Rules 62-4.070 and 62-212.410, F.A.C.]

The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and ULN systems prior to their installation. DLN and ULN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NOX emissions and CO emissions. Operation of the DLN or ULN systems in the diffusion firing mode shall be minimized when firing natural gas. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NOX are corrected to 15% O2. Values for CO are corrected to 15% O2 only until May 1, 2002. [Rule 62-212.400, F.A.C.]

Operational Mode	NOX (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Simple Cycle	25 - NG (basis) 237 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	DLN on gas, WI on oil. Applies until 05/1/2002 . Clean fuels, good combustion
Simple Cycle	9 - NG (basis) 85 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after 05/1/2002 Clean fuels, good combustion
Simple Cycle	9 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies not later than 05/1/2002 if 9 ppm NOX not achievable by ULN. Clean fuels, good combustion.
Combined Cycle	7.5 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR unless simple cycle limits are achieved on or before 05/01/2002. Clean fuels, good combustion

Nitrogen Oxides (NOX) Emissions:

When NOX monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

Until May 1, 2002, the concentration of NOX in the exhaust gas shall not exceed 237 lb/hr (at ISO conditions) on a 24 hr block average (basis 25 ppm @ 15% O2, full load) when firing natural gas and 42 ppmvd at 15% O2 when firing fuel oil on the basis of a 3 hr average) except during periods of startup, shutdown, malfunction or fuel switching, as measured by the continuous emission monitoring system (CEMS). In addition, NOX emissions calculated as NO2 (at ISO conditions) shall exceed neither 25 ppm @15% O2 nor 237 lb/hr (gas) and shall exceed neither 42 ppm @15% O2 nor 413 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

Not later than May 1, 2002, the concentration of NOX concentrations in the exhaust gas shall not exceed 85 lb/hr (at ISO conditions) on a 24 hr block average (basis 9 ppm @ 15) when firing natural gas and 42 ppmvd at 15% O2 when firing fuel oil on the basis of a 3 hr average except during periods of startup, shutdown, malfunction or fuel switching, as measured by the CEMS In addition, NOX emissions calculated as NO2 (at ISO conditions) shall exceed neither 9 ppm @15% O2 nor 85 lb/hr (gas) and shall exceed neither 42 ppm @15% O2 nor 413 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

If Hot SCR is installed, achievable short-term NOX concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O2 when firing natural gas. NOX emissions shall not exceed 9 ppmvd at 15% O2 when firing natural gas and 15 ppmvd at 15% O2 when firing fuel oil on the basis of a 3-hr average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. In addition, NOX emissions calculated as NO2 (at ISO conditions) shall not exceed 85 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

If conventional SCR is installed in conjunction with conversion to combined cycle operation, achievable short-term NOX concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O2 when firing natural gas. If conventional SCR catalyst is installed, NOX emissions shall not exceed 7.5 ppmvd at 15% O2 when firing natural gas and 15 ppmvd at 15% O2 when firing fuel oil on the basis of 3-hr average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. In addition, NOX emissions calculated as NO2 (at ISO conditions) shall not exceed 71.1 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

<u>Carbon Monoxide (CO) emissions</u>: Prior to May 1, 2002, the concentration of CO (@15% O2) in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 145 lb/hr (gas) and 539 lb/hr (oil). [Rule 62-212.400, F.A.C.]

After May 1, 2002, the concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 106 lb/hr (gas) and 386 lb/hr (oil). [Rule 62-212.400, F.A.C.]

Sulfur Dioxide (SO2) emissions: SO2 emissions (at ISO conditions) shall not exceed 7.2 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. Emissions of SO2 shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review]

Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil.

Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as assured by EPA Methods 18, and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 10 lb/hr (gas) and 25 lb/hr (oil). -[Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C.

Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-297, F.A.C. Emission limits compliance dates shall conform to the timetable specified on Specific Condition No. 20.

Initial (I) performance tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of Ultra Low NOX burners, Hot SCR, or conventional SCR. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on Unit 5 as indicated. The following reference methods shall be used.. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).

EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).

EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NOX BACT limits (Method 7E or RATA test data may be used to demonstrate compliance for annual test requirement)

EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

Continuous compliance with the NOX emission limits: Continuous compliance with the NOX emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN or ULN technology) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not included periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NOX standard. These excess emissions periods shall be reported as required in Condition 28. A valid hourly emission rate shall be calculated for each hour in which at least two NOX concentrations are obtained at least 15 minutes apart. [Rule 62-4.070, F.A.C., 40CFR75]

Compliance with the SO2 and PM/PM10 emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO2 and PM10. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NOX test, as required. The initial NOX and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NOX required pursuant to 40 CFR 75 (required for gas only).

Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.

Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-297 F.A.C.

Test Notification: The DEP's Southwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

Test Results: Compliance test results shall be submitted to the DEP's Southwest District office no later than 45 days after completion of the last test run.

NOTIFICATION, REPORTING, AND RECORDKEEPING

Records: All measurements, records, and other data required to be maintained by the City of Lakeland Department of Electric & Water Utilities shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed with the DEP SW District Office as soon as practical, but no later than 45 days after the last sampling run is completed. [Rule 62-297.310(8), F.A.C.]. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 5. Periods when NOX emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Condition No 20 and 21, shall be reported to the DEP Southwest District Office pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the BACT standards listed in Specific Condition No. 20 and 21. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]

CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NOX CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NOX CEMS. Upon request from DEP, the CEMS emission rates for NOX on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NOX standard established in 40 CFR 60.332.

Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, and 40 CFR 60.75 including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Southwest District Office (DEPSWD) for review at least 90 days prior to installation.

Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the C.D. McIntosh , Jr. Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

Monitoring of natural gas nitrogen content shall not be required.

Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods in Specific Condition No. 32 for the measurement of sulfur in gaseous fuels, or an approved alternative method. Once Unit 5 becomes operational, monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.

Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify DEP of such excess emissions and the customized fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.

The City shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.

The City may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission) provided the test methods listed in Specific Condition E.4 are used.

Determination of Process Variables:

The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

LAKELAND ELECTRIC & WATER UTILITIES
(C.D. MCINTOSH, JR. POWER PLANT),

Petitioner,

vs. OGC CASE NO. 98-1407

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Respondent.
_______________________________/

RECEIVED
MAY 22 1998
BUREAU OF
AIR REGULATION

ORDER GRANTING REQUEST FOR EXTENSION
OF TIME TO FILE PETITION FOR HEARING

This cause has come before the Florida Department of Environmental Protection (Department) on receipt of a request made by Petitioner, Lakeland Electric & Water Utilities, to grant an extension of time to file a petition for an administrative hearing on Application No. 1050004-004-AC. See Exhibit 1.

Respondent, State of Florida Department of Environmental Protection, has no objection to it. Therefore,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until June 30, 1998, to file a petition in this matter. Filing shall be complete on receipt by the Office of General Counsel, Mail Station 35, Department of Environmental Protection, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000.

DONE AND ORDERED on this 21st day of May, 1998, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Jack Chisolm, for
F. PERRY ODOM
General Counsel

Douglas Building, MS #35
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000
Telephone: (850) 488-9314

CERTIFICATE OF SERVICE

I CERTIFY that a true copy of the foregoing was mailed to:

Robert A. Manning, Esq.
Post Office Box 6526
Tallahassee, Florida 32314

on this 21st day of May, 1998.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

W. Douglas Beason
W. DOUGLAS BEASON
Assistant General Counsel
Florida Bar No. 379239

Mail Station 35
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000
Telephone: (850) 488-9730

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079
_______________________________________/

OGC No. 98-_____

DRAFT Permit No.: 1050004-004-AC
(PSD-FL-245)
C.D. McIntosh, Jr. Power Plant
Polk County

REQUEST FOR EXTENSION OF TIME

By and through undersigned counsel, Lakeland Electric & Water Utilities (Lakeland) hereby requests, pursuant to Florida Administrative Code Rules 28-106.111(3) and 62-103.050(1), an extension of time, to and including June 1, 1998, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, Lakeland states the following:

1. On or about April 22, 1998, Lakeland received from the Department of Environmental Protection (Department) an "Intent to Issue Air Constriction Permit" (Permit No. 1050004-004-AC) (PSD-FL-245) for the C.D. McIntosh, Jr. Power Plant located in Polk County, Florida. Along with the Intent to Issue, Lakeland received a Draft Air Construction Permit and "Public Notice of Intent to Issue Air Construction Permit."

2. Based on Lakeland's review, the Draft Permit and associated documents contain several provisions that warrant clarification or correction.

3. This request is filed simply as a protective measure to avoid waiver of Lakeland's right to challenge certain conditions contained in the Draft Air Construction Permit. Grant of

this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to file a petition and proceed to a formal administrative hearing or formal mediation.

4. A.A. Linero with the Bureau of Air Regulation has agreed to an extension until June 1, 1998, on behalf of the Department. Counsel for Lakeland has attempted without success to contact W. Douglas Beason with the Office of General Counsel regarding this request.

WHEREFORE, Lakeland respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Draft Air Construction Permit for Permit No. 1050004-004-AC (PSD-FL-245) be formally extended to and including June 1, 1998.

Respectfully submitted this 1st day of May, 1998.

HOPPING GREEN SAMS & SMITH, P.A.

Robert A. Manning

Robert A. Manning
Fla. Bar. No. 0035173
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500

Attorney for LAKELAND ELECTRIC & WATER UTILITIES

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 1st day of May, 1998:

Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

W. Douglas Beason
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

A.A. Linero, P.E.
Administrator
New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Robert A. Manning

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

June 22, 1998

RECEIVED
JUN 25 1998
BUREAU OF
AIR REGULATION

Mr. Cleve Holladay
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: City of Lakeland- 501G Combustion Turbine Project
Air Permit Application and Prevention of Significant Deterioration (PSD) Analysis

Dear Mr. Holladay:

As we discussed on Friday, June 19, 1998, the maximum sulfur dioxide (SO_2) emissions of 38.4 tons per year (TPY) proposed for this project will be below the PSD significant emission rate of 40 TPY. The potential increases in pollutant emissions due to this project are presented in Table 3-3 of the application. The maximum SO_2 concentrations for the project, shown in Table 6-4 of the application, are predicted to be well below the PSD significant impact levels. These concentrations were the highest concentrations predicted for the combustion turbine firing either natural gas or distillate fuel oil using 5 years of meteorological data. Because the maximum SO_2 concentrations for the project were below the significant impact levels by more than a factor of 10, even if the project's emissions were to increase slightly, the maximum concentrations would be expected to be well below the significant impact levels.

Please call me or Mr. Ken Kosky at (352) 336-5600 if you have any questions or comments on this analysis.

Sincerely yours,

Robert C. McCann, Jr.

Robert C. McCann, Jr.
Manager, Air Resources

RCM/arz

cc: K.F. Kosky, Golder
F. Shelton, City of Lakeland
File (2)

9737594A/2

BEST AVAILABLE COPY

FACSIMILE TRANSMISSION

GOLDER ASSOCIATES, INC.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500

TELEPHONE NO. (352) 336-5600
FAX NO. (352) 336-6603

Date: 22 June 1998

JOB No.: 9737594

FAX No.: (850) 922-6979

TO: Al Linero / Terrsa Heron

FR: Ken Kosky

RE: City of Lakeland - CO calculation

Hard Copy to Follow: ☐ Yes ☑ No

Total Number of Pages (including this cover page): 2

MESSAGE:

Al / Tersa:

Attached is the CO calculation correcting the value to 15% O_2. Note that because the O_2 - actual dry is lower than 15%, the allowed actual is higher. The adjusted are a little higher than my calc's I gave over the phone since I was rounding off on Friday for speed. Call if you have questions.

Regards

Ken

City Of Lakeland McIntosh Unit 5
CO Correction to 15% O_2

Equation: $C_{corrected\ to\ 15\%\ oxygen} = C_{actual}\ 5.9/(20.9\text{-}\%O_{2\ actual\text{-}dry})$ Equation 20-4 EPA Method 20

Natural Gas Firing:

CO	25	ppmvd	Table A-2 adjusted from 50 ppm (i.e., one-half)
	105.5	lb/hr	NOx at 50 ppmvd = 211 lb/hr (vendor); 59° F turbine inlet
O_2	11.23	% volume	Table A-1
Moisture	12.44	% volume	Table A-1
O_2	12.83	% vol.-dry	% vol.-dry = % vol. x 1/(1 - % moisture/100);
CO	25	ppmvd @ 15% O_2	
	34.21	ppmvd	25 ppmvd*(20.9-% $O_{2\ actual\ dry}$)/5.9; Equation 20-4
	144.38	lb/hr	ppmvd/ppmvd @ 15% O x lb/hr @ 25 ppmvd

Fuel Oil Firing:

CO	90	ppmvd	Table A-10; 59° F turbine inlet
	386	lb/hr	Table A-10; 59° F turbine inlet; vendor
O_2	11.14	% volume	Table A-9
Moisture	12.05	% volume	Table A-9
O_2	12.67	% vol.-dry	% vol.-dry = % vol. x 1/(1 - % moisture/100);
CO	90	ppmvd @ 15% O_2	
	125.60	ppmvd	25 ppmvd*(20.9-% $O_{2\ actual\ dry}$)/5.9; Equation 20-4
	538.68	lb/hr	ppmvd/ppmvd @ 15% O x lb/hr @ 25 ppmvd

LAKELAND ELECTRIC

Farzie Shelton; chE; REM

Manager of Environmental Affairs

July 20, 2001

RECEIVED

JUL 23 2001

BUREAU OF AIR REGULATION

Mr. A.A. Linero P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
111 S. Magnolia, Suite 4
Tallahassee, Fl 32301

RE: DEP File No. 1050004-004-AC (PSD-FL-245) – Certification PA 74-06SR2
McIntosh Unit No. 5 Combustion Turbine Combined Cycle

Dear Al:

In accordance with our application and PSD permit condition, Lakeland Electric (Lakeland) is proceeding with the construction of the heat recovery steam generator for the above referenced unit. Lakeland anticipates conversion to the combined cycle to be completed sometimes in November/December 2001. Therefore, Lakeland anticipates start-up of this unit and shake down period to commence around November/December 2001 for which Lakeland will provide the Department with necessary notification in accordance with the Section II Emission Unit(s) General Requirements condition No. 5 of our permit.

Today, we are writing to confirm our understanding of our permit condition in connection with the start-up of this combined cycle. In accordance with Section III Emission Unit(s) Specific Conditions, condition No. 30, Lakeland will have a period not to exceed 100 days for shake down period (start up period) for which time excess emission is permissible prior to performing initial compliance tests. Additionally, during this 100 days Lakeland intend to relocate the Continuous Emission Monitoring (CEM) equipment on the new stack and perform the necessary certification of these equipment in accordance with the 40 CFR Part 75 of the Clean Air Act.

Therefore, we appreciate if you would confirm that condition No. 30 does provide us with the 100 days start-up period. However, if you should decide otherwise, Lakeland with this letter, is requesting modification of Unit No. 5 PSD permit to allow the necessary start-up period for commissioning of this combined cycle.

As always your cooperation and help in this matter is greatly appreciated. If you should have any questions, please do not hesitate to contact me.

Sincerely

Farzie Shelton

Cc: Mr. Hamilton Oven P.E.

City of Lakeland ● Department of Electric Utilities

501 East Lemon Street ● Lakeland, Fl 33801-5050 ● (863) 834-6603 ● Fax (863) 834-8187 ● Message System 834-6592

farzie.shelton@lakelandgov.net

To: Farzie Shelton

From: Steve Marshall
Tom Trickey

Date: July 10, 2001

Subject: Request for permit variance - for commissioning of combined-cycle conversion
McIntosh Unit 5, PA 741-06SR2, Permit No. PSD-FL-245

McIntosh Unit 5 is a 501G 250 MW combustion turbine that was manufactured by Siemens-Westinghouse Power Corporation (SWPC) and is currently operating in simple cycle configuration. In this configuration, the combustion turbine currently meets all air permit requirements.

Unit 5 will be converted to combined cycle operation in 2001. The simple cycle combustion turbine will be rendered inoperable on September 15, 2001 in order to complete the conversion to combined cycle configuration. The unit will be "mechanically complete" on or about November 8, 2001 at which time the commissioning phase of the project will begin. The unit will not be returned to commercial operation until commissioning is complete.

The 501G-Series uses steam, instead of air, to cool the metal of the transition pieces between the combustors and the first-row turbine blades at operating loads above 20% of maximum capacity; air is used for cooling when operating below 20%. Steam cooling is new combustion turbine technology that improves performance. However, the steam purity requirement for transition cooling steam is much greater than the purity requirement of steam for powering a steam turbine. This purity requirement presents some significant problems during the initial startup of the 501G combined-cycle unit.

During first-start of any new steam cycle system, time is needed to check-out the equipment, get control of the systems enough to run, and then tune the controls. This period is recognized as the shakedown period in the permit, for which 100 days was originally allowed. Also, metals and other contaminants from the surfaces of tubes, piping, and vessels in contact with the water and steam are either dissolved or picked up in suspension.

This is much worse during a first start. It takes time to blow-down the system in order to purge those contaminants. The 501G combustion turbine can not operate above 20% load until the purity of the steam needed for transition cooling is achieved. During initial startup phase, we anticipate several intermittent days of no-load operation followed by two or more weeks of non-continuous combustion turbine operation at 20% load before achieving steam purity requirements allowing transfer to steam cooling and ramping up load. These expected events may cause the combustion turbine to produce emission levels that unavoidably exceed allowable limits.

Realizing that 501G combustion turbines are tuned for full-load operation and usually have excess emissions during startup/shutdown cycles, the permit appropriately allows for excess emissions during normal startups and shutdowns. However, the permit limits the duration of those startup excess emissions to 4 hours. This limit is acceptable for a commissioned unit, but not for the first-start of a new combined cycle unit.

It is estimated that the startup, shakedown, and commissioning phases will last no longer than 100 days. It is also estimated that the initial startup phase, during which the combustion turbine will operate at 20% load or less, will take an estimated continuous maximum duration of 21 days to purge contaminants. The stack-gas emissions will probably exceed our permit limitations for most of the entire duration of running in the initial startup phase. There may also be periods of excess emissions that last longer than our permitted 4 hour duration during the shakedown and commissioning phases. Commissioning of the combined cycle unit can not be completed without exceeding the allowable emission limits.

Please confirm that a second commissioning period for the combined cycle conversion that allows for excess emissions has not been provided in the existing permit. If you concur that a second commissioning period has not been provided, then please take whatever steps are necessary to obtain as soon as possible a 100 day time frame that will allow commissioning the combined cycle unit.

Time is of the essence so please consider this request to be of very high priority and keep us informed of your progress. Thank you for your support and assistance.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of application for Permit Modification by:

Mr. Ronald W. Tomlin, Assistant Managing Director
City of Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

DEP File No. 1050004-004AC
Permit No. PSD-FL-245
C.D. McIntosh, Jr. Power Plant, Unit No. 5
Polk County

Enclosed is the Final Permit Number PSD-FL-245 to construct a 250 megawatt simple cycle combustion turbine with a once-through heat generator and a 1.05 million gallon fuel oil storage tank at the C.D. McIntosh, Jr. Power Plant, located at 3030 East Lake Parker Drive, Lakeland, Polk County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

A. A. Linero, P.E.

for C.H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7/10/98 to the person(s) listed:

Mr. Ronald W. Tomlin, City of Lakeland *
Ms. Farzie Shelton, City of Lakeland
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Bill Thomas, SWD
Mr. Buck Oven, DEP
Mr. Ken Kosky, P.E., Golder Associates
Mr. Joe King, Polk County

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 7/10/98
(Clerk) (Date)

P 265 659 386

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Mr. Ronald W. Tomlin	
Street & Number 501 E. Lemon St.	
Post Office, State, & ZIP Code Lakeland Fl. 33801	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 7-10-98 1050004-004 AC ASD-Fl-245	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Ronald W. Tomlin
501 E. Leman St.
Lakeland Fl 33801-5079

4a. Article Number
P 265 659 386

4b. Service Type
☐ Registered ☑ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
JUL 1 3 1998

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Gina M. Walker

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

PERMITTEE:

City of Lakeland
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Fl 33801-5079

File No.	1050004-004-AC
FID No.	1050004-004
SIC No.	4911
Permit No.	PSD-FL-245
Expires:	June 30, 2002

Authorized Representative:
Ronald W. Tomlin
Assistant Managing Director

PROJECT AND LOCATION:

Permit for the construction of 250 megawatt (MW) simple cycle, gas-fired, stationary combustion turbine (CT), a once-through steam generator, and a 1.05 million gallon storage tank for back-up distillate fuel oil. Conditions are included for possible future conversion to a 350 megawatt combined cycle installation including a heat recovery steam generator provided there are no increases in emissions associated with the conversion. The turbine is designated as Unit No. 5 and will be located at the C.D. McIntosh, Jr., Power Plant, 3030 East Lake Parker Drive, Lakeland, Polk County. UTM coordinates are: Zone 17; 409.0 km E; 3106.2 km N.

STATEMENT OF BASIS:

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

SUBSECTION A. FACILITY DESCRIPTION

The existing facility includes: two small diesel powered electric generators; one small gas and distillate-fired combustion turbine; one 90 MW gas and fuel oil-fired steam generator; one 115 MW gas and fuel oil-fired steam generator; and one 364 MW multiple (primarily coal) fuel-fired steam generator. This permit is for the installation of: a 250 MW simple cycle, gas-fired, stationary combustion turbine; a once-through steam generator; a 1.05 million gallon storage tank for back-up (0.05 percent sulfur) distillate fuel oil; and an 85-foot stack. It is possible that in the future the turbine will be converted by the addition of a heat recovery steam generator and a new stack to a 350 MW combined cycle operation without increases in emissions.

Emissions from the McIntosh Unit 5 will be initially controlled by Dry Low NO_X combustors, wet injection when firing fuel oil, use of inherently clean fuels, and good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions reduced by more sophisticated Ultra Low NO_X burners. Otherwise emissions will be reduced by the addition of a selective catalytic reduction (SCR) system.

SUBSECTION B. EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
028	Power Generation	250 Megawatt Combustion Turbine and Once Through Steam Generator
029	Fuel Storage	1.05 Million Gallon Fuel Oil Storage Tank

SUBSECTION C. REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications (such as the construction of Unit 5) at the facility resulting in emissions increases greater than 40 TPY of NO_X or SO_2, 25/15 TPY of PM/PM_{10}, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

SECTION I. FACILITY INFORMATION

SUBSECTION D. PERMIT SCHEDULE

- 04/22/98 Notice of Intent published in The Ledger
- 04/23/98 Distributed Intent to Issue Permit
- 04/01/98 Application deemed complete
- 12/08/97 Received Application

SUBSECTION E. RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on December 8, 1997
- Department letters dated January 5, January 12, March 9, 1998, and April 27, 1998
- Comments and letters from the National Park Service dated January 6, January 12, April 2 and April 15, 1998.
- EPA letters dated February 10 and March 6, 1998.
- City of Lakeland letters dated March 4, March 11, March 31, and May 6, 1998.
- Letters from Westinghouse dated March 25, March 30, and March 31, 1998.
- Department's Intent to Issue and Public Notice Package dated April 22, 1998.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District office (DEPSW), 3804 Coconut Palm Drive, Tampa, Florida 33619 and phone number 813/744-6100.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a conversion to combined cycle operation. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

This reassessment will be conducted for this project only if the conversion to combined cycle operation is accompanied by any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. At a minimum, conversion to combined cycle operation will require a modification of this permit to reflect the ultimate facility description, the higher power production rates and review of the actual control equipment design. [40 CFR 52.21(j)(4), Rule 62-4.070 F.A.C.]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Southwest District office (DEPSW). [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District office by March 1st of each year.

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to the DEP's Southwest District office.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Unit 028, Power Generation, consisting of a 250 megawatt combustion turbine with a once-through steam generator shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 029, Fuel Storage, consisting of a 1.05 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.

6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District office.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,174 million Btu per hour (mmBtu/hr) when firing natural gas, nor 2,236 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Southwest District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

13. Maximum allowable hours of operation for the stationary gas turbine and once-through steam generator are 8760. Fuel usage as heat input, while burning natural gas in the stationary gas turbine, shall not exceed 15.639×10^{12} BTU (LHV) per year (rolled monthly) until the unit achieves the NO_X emission limits (other than the initial ones) given in Specific Condition 21. Thereafter, only the hourly heat input limits given in Specific Condition 8 apply. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

14. Fuel usage as heat input, while burning fuel oil in the stationary gas turbine, shall not exceed 559×10^9 BTU (LHV) per year (rolled monthly). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Control Technology

15. Westinghouse Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]

16. The Dry Low NO_X (DLN) combustors shall be replaced with Westinghouse Ultra Low NO_X (ULN) combustors to accomplish further NO_X control in order to achieve the emission limits specified in Specific Condition 20 and 21. A high temperature selective catalytic reduction (Hot SCR) system or a low temperature SCR system shall be installed and in operation (together with DLN or ULN combustors) not later than May 1, 2002 if the emission limits specified in Specific Condition No 20 and 21 are not achievable by ULN combustors by this date. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

17. The permittee shall design the stationary gas turbine, ducting, possible future heat recovery steam generator, and stack(s) to accommodate installation of SCR equipment and/or oxidation catalyst in the event that the ULN technology fails to achieve the NO_X limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22 are not met. [Rule 62-4.070, F.A.C.]

18. A water injection system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

19. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and ULN systems prior to their installation. DLN and ULN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the DLN or ULN systems in the diffusion firing mode shall be minimized when firing natural gas. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15% O_2. Values for CO are corrected to 15% O_2 only until May 1, 2002. [Rule 62-212.400, F.A.C.]

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Simple Cycle	25 - NG (basis) 237 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	DLN on gas, WI on oil. Applies until 05/1/2002 . Clean fuels, good combustion
Simple Cycle	9 - NG (basis) 85 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after 05/1/2002 Clean fuels, good combustion
Simple Cycle	9 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies not later than 05/1/2002 if 9 ppm NO_X not achievable by ULN. Clean fuels, good combustion.
Combined Cycle	7.5 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR unless simple cycle limits are achieved on or before 05/01/2002. Clean fuels, good combustion

21. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- Until May 1, 2002, the concentration of NO_X in the exhaust gas shall not exceed 237 lb/hr (at ISO conditions) on a 24 hr block average (basis 25 ppm @ 15% O_2, full load) when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall exceed neither 25 ppm @15% O_2 nor 237 lb/hr (when firing natural gas) and shall exceed neither 42 ppm @15% O_2 nor 413 lb/hr (when firing fuel oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- Not later than May 1, 2002, the concentration of NO_X concentrations in the exhaust gas shall not exceed 85 lb/hr (at ISO conditions) on a 24 hr block average (basis 9 ppm @ 15% O_2) when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3 hr average as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall exceed neither 9 ppm @15% O_2 nor 85 lb/hr (when firing natural gas) and shall exceed neither 42 ppm @15% O_2 nor 413 lb/hr (when firing fuel oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If Hot SCR is installed, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O_2 when firing natural gas. NO_X emissions shall not exceed 9 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3-hr average, as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 85 lb/hr (when firing natural gas) and 148 lb/hr (when firing fuel oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If conventional SCR is installed in conjunction with conversion to combined cycle operation, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O_2 when firing natural gas. If conventional SCR catalyst is installed, NO_X emissions shall not exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of 3-hr average, as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 71.1 lb/hr (when firing natural gas) and 148 lb/hr (when firing fuel oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

22. Carbon Monoxide (CO) emissions: Prior to May 1, 2002, the concentration of CO (@15% O_2 in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 145 lb/hr (when firing natural gas) and 539 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

    After May 1, 2002, the concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 106 lb/hr (when firing natural gas) and 386 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions (at ISO conditions) shall not exceed 7.2 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. Emissions of SO_2 shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review]

24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil.

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as assured by EPA Methods 18, and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 10 lb/hr (when firing natural gas) and 25 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

27. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C.

28. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

29. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C. Emission limits compliance dates shall conform to the timetable specified on Specific Condition No. 20.

30. Initial (I) performance tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of Ultra Low NO_X burners, Hot SCR, or conventional SCR. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on Unit 5 as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

   - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (Method 7E or RATA test data may be used to demonstrate compliance for annual test requirement)
   - EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

31. <u>Continuous compliance with the NO_X emission limits</u>: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN or ULN technology) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not included periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Condition 28.

A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

32. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

33. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only).

34. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.

35. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204.800 F.A.C.

36. Test Notification: The DEP's Southwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

37. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible

emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

38. Test Results: Compliance test results shall be submitted to the DEP's Southwest District office no later than 45 days after completion of the last test run.

NOTIFICATION, REPORTING, AND RECORDKEEPING

39. Records: All measurements, records, and other data required to be maintained by the City of Lakeland Department of Electric & Water Utilities shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

40. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed with the DEP SW District Office as soon as practical, but no later than 45 days after the last sampling run is completed. [Rule 62-297.310(8), F.A.C.]. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 5. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Condition No 20 and 21, shall be reported to the DEP Southwest District Office pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the BACT standards listed in Specific Condition No. 20 and 21. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]

42. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75.

Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Southwest District Office (DEPSWD) for review at least 90 days prior to installation.

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the C.D. McIntosh , Jr. Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- Monitoring of natural gas nitrogen content shall not be required.
- Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods in Specific Condition No. 32 for the measurement of sulfur in gaseous fuels, or an approved alternative method. Once Unit 5 becomes operational, monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.
- Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify DEP of such excess emissions and the customized fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.
- The City shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.
- Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.
- The City may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission) provided the test methods listed in Specific Condition E.4 are used.

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Memorandum

Florida Department of Environmental Protection

TO: Howard Rhodes

THRU: A. A. Linero aa Lin 6/22

FROM: Teresa Heron T.H.

DATE: June 22, 1998

SUBJECT: City of Lakeland McIntosh Unit No. 5
250 MW Gas Turbine (PSD-FL-245)

Attached is the final permit package for construction of a 250 MW Westinghouse 501 G simple cycle gas-fired combustion turbine at the City of Lakeland's McIntosh Power Plant. The project includes a once-through steam generator to provide steam for cooling key turbine components and for power augmentation to reach the 250 MW level. A 1.05 million gallon storage tank will be constructed for the back-up distillate fuel that will be used for no more than 250 hours per year.

Westinghouse has provided a schedule to design, test, and implement the Ultra Low NO_X (ULN) technology so that emission limits of 9 ppm can be met by May 1, 2002 at the Lakeland site. This is about three years from start-up. Westinghouse has had some recent failures in trying to meet NO_X limits of 25 ppm by steam injection at a project in Missouri, 9 ppm by SCR at a project in Georgia, and 9-12 ppm at the FPC Hines Facility by Dry Low NO_X. The problem has not been that the NO_X numbers are too low, but rather that Westinghouse did not correctly assess the capabilities of key components in its designs. There are many units throughout the country meeting limits between 3.5 and 9 ppm using both SCR or Dry Low NO_X (GE version) technologies. The location of the Westinghouse combustion experts in Orlando will maximize the chances of success at Lakeland.

If the technology fails to achieve the requirements, the City must install Hot SCR to meet a 9 ppm limit under simple cycle operation. The City has already contracted Sargent and Lundy to evaluate the feasibility of conversion to a 350 MW combined cycle. If the unit is converted to combined cycle operation and achievement of 9 ppm by ULN or Hot SCR is not in-sight, then conventional SCR to meet a 7.5 ppm value will be required. If the unit achieves the 9 ppm value as scheduled under simple cycle operation, they do not have to take a lower limit if and when they convert to combined cycle operation.

We discussed all issues with the City and with EPA and there are no outstanding items. I recommend your approval of the attached Intent to Issue. However, please do not date since we will not actually send it out until the Site Certification is signed. The McIntosh Site Certification Modification Order will not be approved either until we give them what will be the final conditions from this permit.

AAL/th

Attachments

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

C. D. McIntosh, Jr. Power Plant
City of Lakeland Electric & Water Utilities
PSD-FL-245 and 1050004-004AC
Lakeland, Polk County, Florida

BACKGROUND

The applicant, The City of Lakeland (City), proposes to install a nominal 250 megawatt (MW) (net) new simple cycle combustion turbine at the existing C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive in Lakeland, Polk County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The unit to be installed is a 230 MW Westinghouse 501 G combustion turbine and includes a once through steam generator (OTSG) which provides steam for steam cooling of critical components and injection for further cooling and power augmentation to 250 MW. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated April 22, 1998, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on December 8, 1997 and included a proposed BACT proposal prepared by the applicant's consultant, Golder Associates Inc.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E., and Teresa Heron, Review Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil Use (250 hr/yr) Combustion Controls	9.1 lb/hr (Gas) 140 lb/hr, 0.05% sulfur (Oil)
Volatile Organic Compounds	As Above	4 ppm (Gas) 10 ppm (Oil)
Visibility	As Above	20 percent
Carbon Monoxide	As Above	50 ppm (Gas, baseload) 90 ppm (Oil, baseload)
Nitrogen Oxides	Dry Low NO_X Burners (Gas) Water Injection (Oil)	25 ppm @ 15% O_2 (Gas, baseload) 42 ppm @ 15% O_2 (Oil, baseload)

The unit, as described above, would emit approximately 852-863 tons per year (TPY) of NO_X, 761-1,264 TPY of CO, 37-94 TPY of VOC, 39 TPY of SO_2, and 41 TPY of PM/PM_{10}. The basis is 7,008 hours of operation including 250 hours of oil firing and 1050 hours at 50% load.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (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. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppm NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppm SO_2 @ 15% O_2.(or <0.8% sulfur in fuel). The BACT proposed by the City is consistent with the NSPS which allows NO_X emissions over 110 ppm for the higher efficiency unit purchased by the City of Lakeland. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

Most recent stationary gas turbine BACT determinations made to-date by EPA and the states, including the State of Florida, have been much more stringent than the requirements of the NSPS. The following table is a sample of information on recent BACT and a few Lowest Achievable Emission Rate (LAER) determinations made by EPA and the States for stationary gas turbine projects as large or larger than the one under review. LAER is required in areas where the ambient air (unlike that Florida) does not attain the National Ambient Air Quality Standards (NAAQS).

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output and Duty	NO_X Limit ppm @ 15% O_2 and Fuel	Technology	Comments
Cataula, GA	1200 MW **SC PKR**	25 - NG 42 - No. 2 FO	DLN WI	4x300 MW **WH 501G** CTs CTs rated 230 MW @ ISO, NG
Mid-GA Cogen, GA	308 MW CC **CON**	9 - NG 20 - No. 2 FO	DLN & SCR	2x119 MW **WH 501**D5A CTs
CCC, VA	398 MW **SC PKR**	42/65 - No. 2 FO	WI	3x132.5 MW CTs 2000 (500 @ Peak) hr/yr/CT
PREPA, PR	248 MW **SC CON**	10 - No. 2 FO	WI & Hot SCR	3x83 MW CTs
Tiger Bay, **FL**	270 MW CC **CON**	15/10 - NG 42 - No. 2 FO	DLN &/or SCR WI	184 MW GE MS7001FA CT DLN/15 ppm or SCR/10 ppm
Hines Polk, **FL**	485 MW CC **CON**	12 - NG 42 - No. 2 FO	DLN WI	2x165 MW **WH 501**FC CTs Canceled GE CTs
Tallahassee, **FL**	260 MW CC **CON**	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS 7231FA CT DLN Guarantee is 9 ppm
Eco-Electrica, PR	461 MW CC **CON**	7 - NG 9 - LPG, No. 2 FO	DLN & SCR	2x160 MW **WH 501**F CTs
Sithe/IPP, NY	1012 MW CC **CON**	4.5 - NG	DLN & SCR	4 x160 MW GE 7FA CTs
Hermiston, OR	474 MW CC **CON**	4.5 - NG	SCR	2x160 MW GE 7FA CTs
Berkshire, MA	272 MW CC **CON**	3.5 - NG (LAER) 9.0 - No. 2 FO	DLN & SCR WI & SCR	178 MW ABB GT24 CT

SC = Simple Cycle — CON = Continuous — DLN = Dry Low NO_X Combustion — GE = General Electric
CC = Combined Cycle — PKR = Peaking Unit — SCR = Selective Catalytic Reduction — WH = Westinghouse
NG = Natural Gas — FO = Fuel Oil — LPG = Liquefied Propane Gas — ABB = Asea Brown Bovari
CT = Combustion Turbine — ISO = 59°F — WI = Water or Steam Injection — ppm = parts per million
Factors in Common with City of Lakeland Project are bolded. All determinations are BACT unless denoted as LAER.

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Cataula, GA	25 - NG @15% O_2 75 - FO@ 15% O_2	0.01 lb/mmBtu	0.005 - NG 0.03 - FO	Clean Fuels Good Combustion
Mid-GA Cogen, GA	10 - NG 30 - FO	6 - NG 30 - FO	18 lb/hr - NG 55 lb/hr - FO	Clean Fuels Good Combustion
CCC, VA	Not PSD	Not PSD	0.0216 - FO	Clean Fuels Good Combustion
PREPA, PR	9 - FO @15% O_2	11 - FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion
Tiger Bay, FL	0.045 lb/mmBtu-NG 0.053 lb/mmBtu-FO		0.053 - NG 0.009 - FO	Clean Fuels Good Combustion
Hines Polk, FL	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG			Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Berkshire, MA	4 - NG (LAER) 5 - FO (LAER)	4 - NG 16 - FO	0.0105 - NG 0.0468 - FO	Clean Fuels CO Catalyst

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from the National Park Service dated January 6 and 12, April 2 and 15, 1998
- Letters from EPA Region IV dated February 10 and March 6, and May 21, 1998
- Decisions by the Environmental Appeals Board
- Papers and letters written by Westinghouse on the development of the 501 G combustion turbine and nitrogen oxides control technologies
- DOE website information on Advanced Turbine Systems Project
- Mitsubishi website
- City of Lakeland Website, City Commission Meeting Minutes
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in lean, near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not important for the Lakeland project because natural gas will be the primary fuel and low sulfur fuel oil will be used only for 250 hours per year.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppm @15% O_2). For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppm @15% O_2.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are about 25 ppm when firing gas and 42 ppm when firing fuel oil in large combustion turbines. These values often form the basis for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion, cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

Combustors used in Westinghouse products are shown in Figure 2. These operate according to the same principles as described above. However they have different characteristics and do not reach the so-called fully pre-mixed operation until the load is over 50 percent.

The emission characteristics of General Electric's Dry Low NO_X (DLN 2) combustors are given in Figure 3. NO_X concentrations are higher in the exhaust at lower loads because at lower loads, the combustor do not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 25 parts per million (ppm) at loads between 40 and 100 percent of capacity, but concentrations as high as 100 ppm at less than 50 percent of capacity. GE has since upgraded its combustors and this description is not precise for its more advanced DLN 2.6

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, results in a lower achievable thermal efficiency for the unit.

By using steam in a closed loop system, the fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor the nozzle and does not enter the exhaust stream. Instead it is normally sent back to the steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 4 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppm (and even lower) from gas turbines smaller than about 200 MW (simple cycle). Initial guarantees of 25 ppm by combustion controls are proposed for turbines larger than larger than 200 MW. The guaranteed values are expected to be reduced for the reasons given above. As in the case of wet injection, higher CO and hydrocarbon emissions can occur as a result of employing combustion controls to minimize NO_X.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas. As of early 1992, over 100 gas turbine installations already used SCR in the United States. No combustion turbines in Florida employ SCR. Virtually all SCR units are used in combination with wet injection or combustion controls.

Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalyst used in combined cycle, low temperature applications (conventional SCR), is usually vanadium or titanium oxide and accounts for almost all installations. For high temperature applications (Hot SCR up to 1100 ^{o}F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas.

In a manner analogous to balancing control of NO_X from the combustor with emissions of CO and hydrocarbon, similar balancing is required when controlling NO_X by SCR. Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur bearing fuels are used). Permit limits as low as 3.5 ppm NO_X have been specified for certain conventional SCR applications in ozone non-attainment areas. Recently, Southern Company proposed a 3.5 ppm NO_X limit for a project in an attainment area in Alabama.

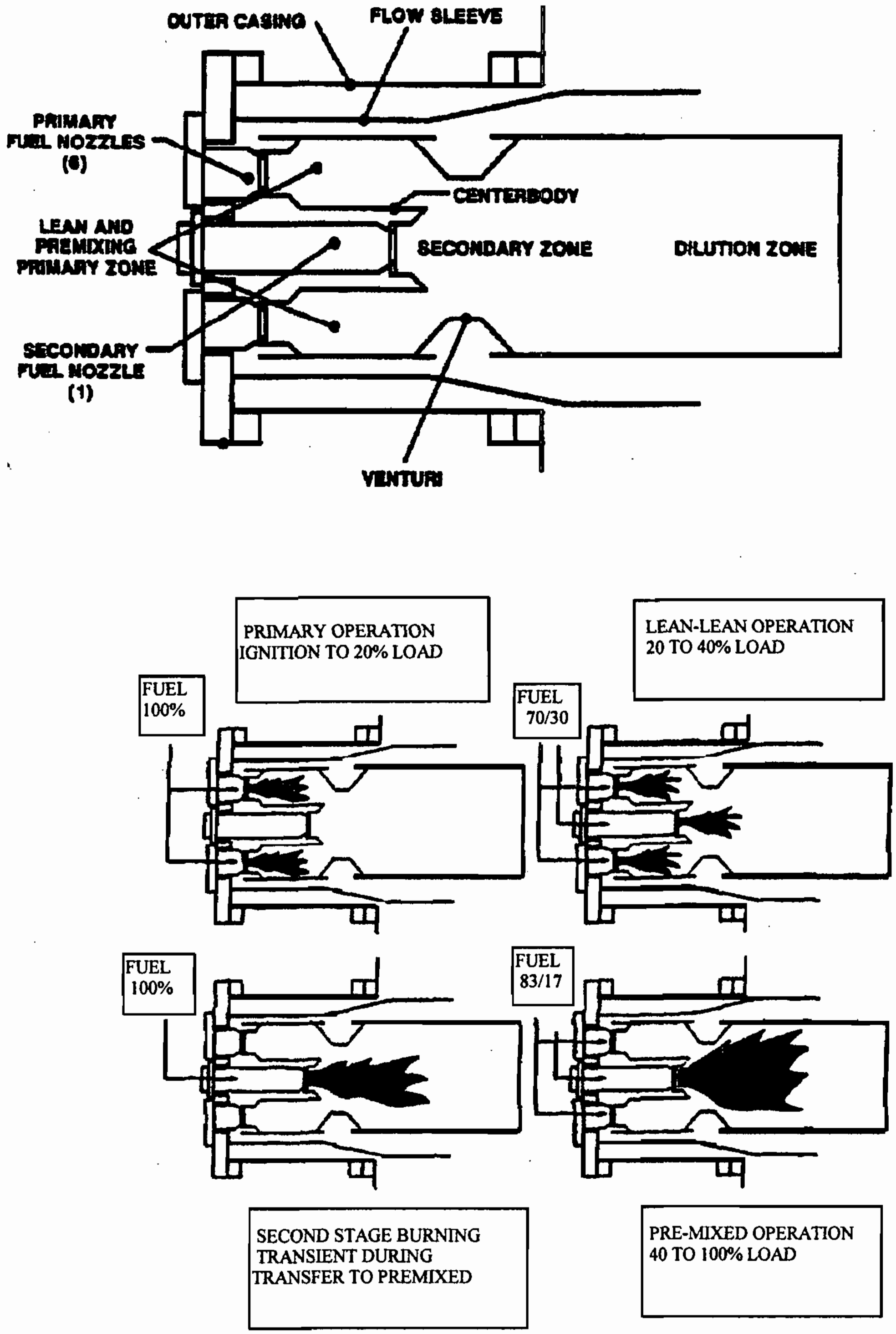

Figure 1 - Cross Sections of a Lean Premixed Can-annular Combustor

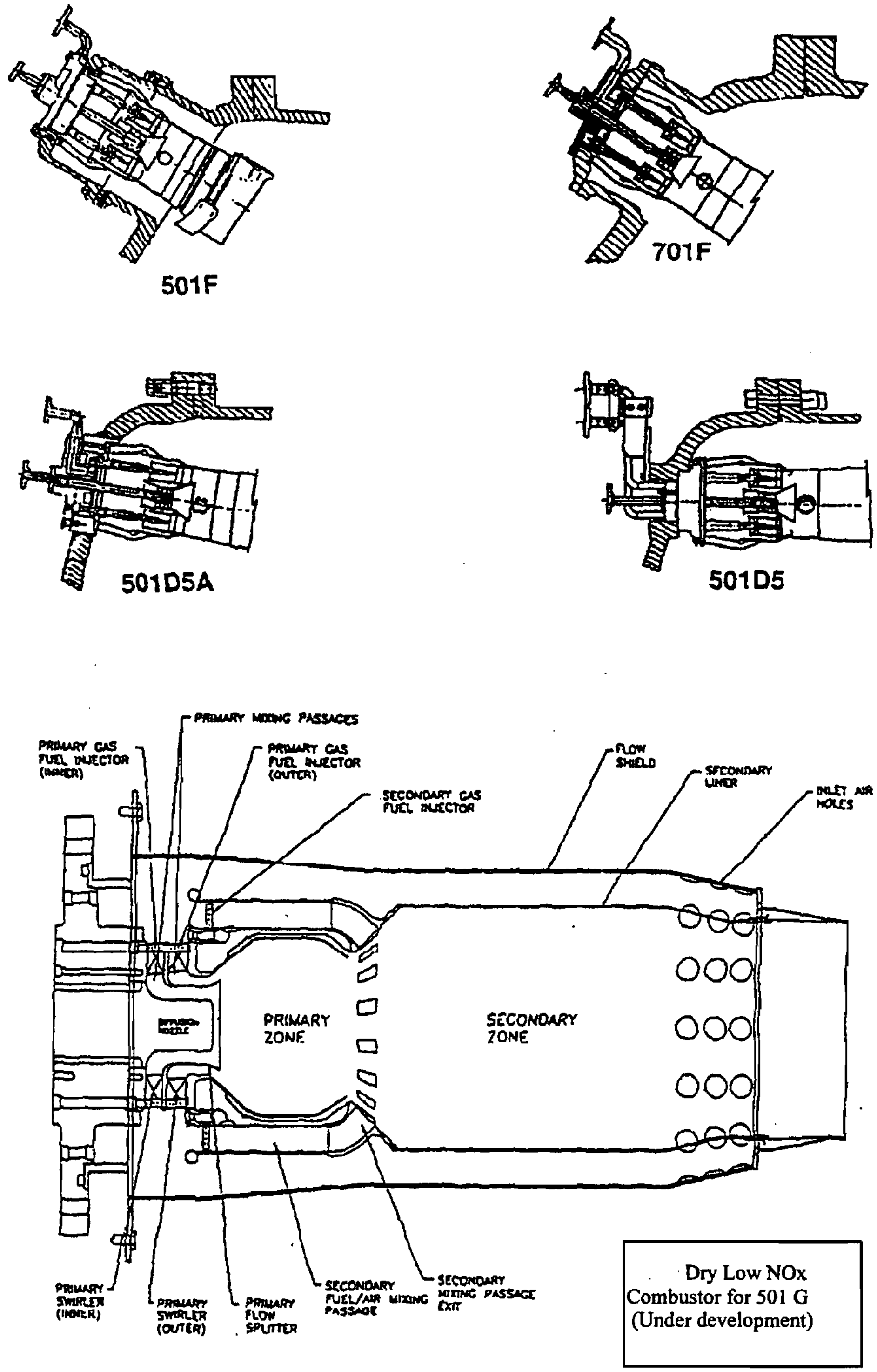

Figure 2 - Westinghouse Dry Low NOx Combustors

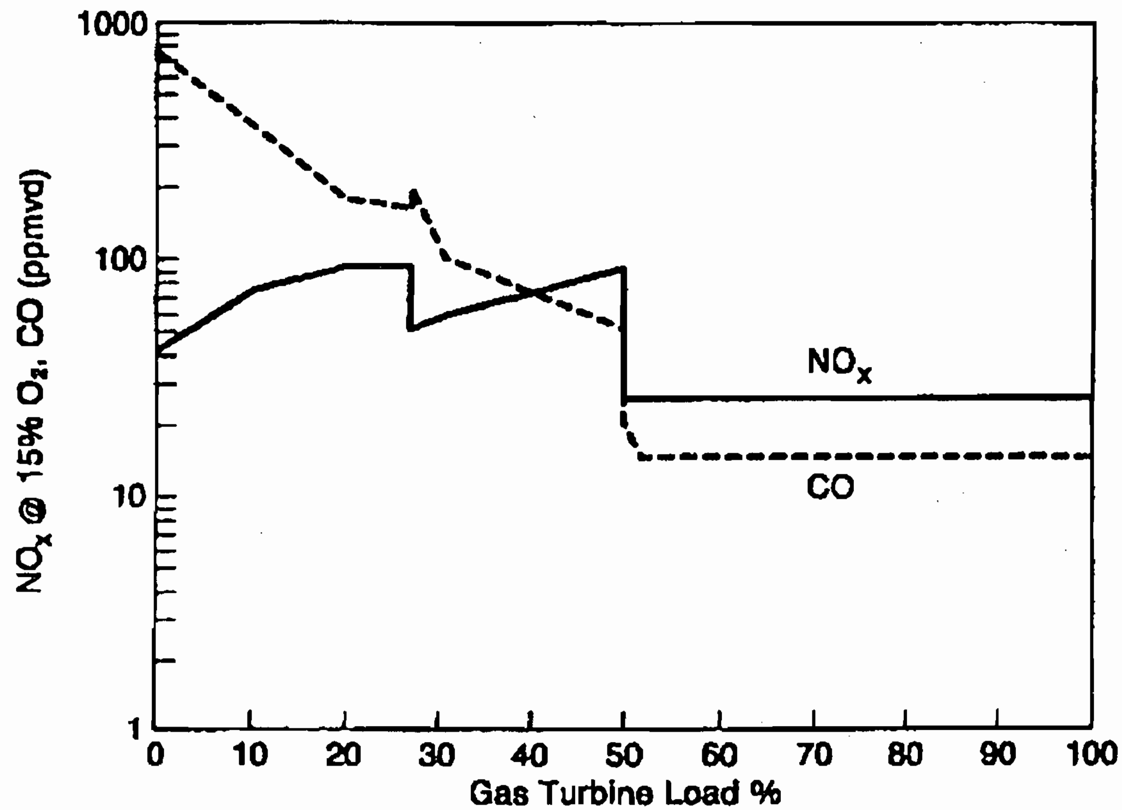

Figure 3 Emissions performance for DLN-2 combustors firing natural gas

Source: General Electric GER-3568E, 1996

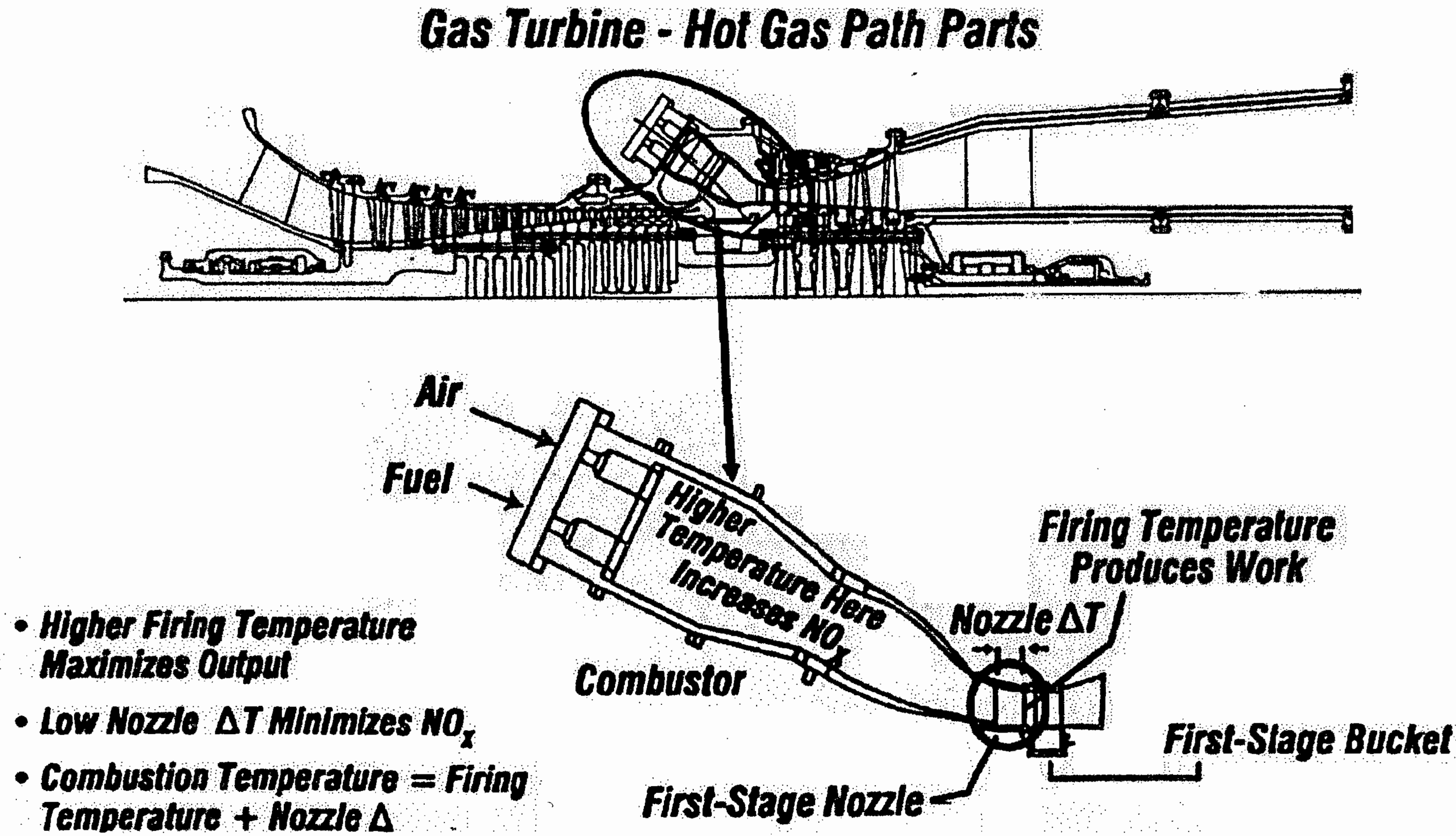

Figure 4. Relationship — combustion temperature to firing temperature

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 250 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. The City indicated that the PM_{10} emissions will not exceed 0.01 gr/scf when firing natural gas and pointed out that such a value is equal to a typical specification for baghouse design. Annual emissions of PM_{10} are expected to be approximately 30 tons for natural gas and less than 15 tons for fuel oil.

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

Most installation using catalytic oxidation are located in the Northeast. Besides the Berkshire installation listed above, CO oxidation catalyst has been installed at the 240 MW Brooklyn Navalyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the values of 50 and 90 ppm for gas and oil respectively at baseload proposed in the City's application appear high.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The limits proposed for this project are 4 and 10 ppm for gas and oil firing respectively.

BACKGROUND ON SELECTED GAS TURBINE

The City has already committed to the purchase of a 230 MW Westinghouse 501 G simple cycle gas turbine.[1] The unit was already under construction by Westinghouse and awaiting sale. The contract for the unit includes NO_X emission guarantees of 25 ppm on gas and 42 ppm on fuel oil.

The choice satisfies the City's immediate power needs and reserve capacity. If it is ultimately converted to combined cycle operation, the power generating capacity will be about 350 MW.[2] A contract was recently awarded to Sargent and Lundy to prepare bid specifications to convert the unit to combined cycle operation at the earliest opportunity.[3]

The conceptual and basic designs for the 501 G were jointly developed by Westinghouse and Mitsubishi Heavy Industries (MHI). Detailed designs were developed separately by the two companies and the units are not identical.[4] The first 501 G started operation in April of 1997 in Japan at the MHI Takasago Machinery Works 330 MW Demonstrator Combined Cycle Plant. The unit has the "highest firing temperature (1500 °C, 2732 °F) ever recorded, and a combined cycle efficiency of over 58 percent."[5] The efficiency is also the highest ever demonstrated for combined cycle turbine. NO_X emissions are controlled by multi-nozzle DLN combustor, followed by a selective catalytic reduction (SCR) system located within the heat recovery steam generator (HRSG).

The first commercial operation (i.e. not within MHI subsidiaries) of a "1500 °C" combined cycle unit will begin trial operation at the Tohoku Electric Higashui Niigata Power Plant in October, 1998.[6] The specific unit will be the "701 G," which is a larger, 50 Hertz version of the 501 G. Commercial operation will begin in July, 1999.

Westinghouse and General Electric continue to work on even larger and more efficient turbines. Westinghouse has already tested the compressor for its planned "H" Class turbine capable of achieving 60 percent efficiency while operating in combined cycle mode.[7] General Electric does not have an entry in the "G" class. However it is conducting trials in Greenville, South Carolina on the MS9001H, which is its 50 Hertz entry into the H Class. GE expects a combined cycle efficiency of 60 percent and generation of over 400 MW. GE plans to make its similar 60 Hertz MS7001H version available in 2001 or 2002.[8]

Westinghouse and General Electric are counting on further advancement and refinement of DLN technology to provide sufficient NO_X control for their turbines. In the case of the 501 G, steam cooling of the transition piece allows the unit the maintain the same NO_X formation potential as the 501 F while achieving a higher turbine inlet (firing) temperature. Examples of Westinghouse combustors are shown in Figure 2. These include their second generation of Dry Low NO_X combustors including their fully pre-mixed Piloted Ring Combustor.[9] Where required by BACT or LAER determinations of certain states, both companies incorporate SCR in combined cycle projects.[10,11]

The approach of progressively refining such technology is a proven one, even on some relatively large units. Basically this was the strategy adopted in Florida throughout the 1990's. Recently GE Frame 7 FA units (160 MW gas turbines with firing temperatures of 2400) met performance guarantees of 9 ppm with "DLN-2.6" burners at Fort St. Vrain, CO and Clark County, WA.[12]

Westinghouse will conduct two phases of testing in 1998 in its effort to develop Ultra Low NO_X (ULN) technology for its "F" Class to meet a NO_X level of 9-12 ppm by mid-2000.[13]

Both Westinghouse and General Electric are partners with the Department of Energy (DOE) in the Advanced Turbine Systems (ATS) Program.[14] The Mission/Vision Statement of ATS is to "develop base-load advanced turbine systems for commercial offering in the year 2000." Among the goals of the Program are 60 percent combined cycle efficiency while achieving NO_X emissions of 9 ppm or less.[15] The cost of producing the prototypes is estimated at $435,000,000 and $300,000,000 for the GE and Westinghouse projects respectively.[16] The goals of the ATS are reflected in the "H" Class units described above.

In simple cycle, continuous duty mode, the Westinghouse 501 G achieves an admirable efficiency of approximately 38 percent.[17] However this efficiency is much lower than what can be realized with the same unit (58 percent) when operating in combined cycle.[18] As discussed above, Sargent and Lundy have been contracted to prepare bid specifications to convert the unit to combined cycle.

The 25 ppm initial NO_X guarantee on natural gas appears high when compared with BACT determinations for continuous-duty or combined cycle units, such as those previously listed. It is also higher than the stated goal of the ATS Program. The simple cycle mode with the flexibility of switching (or not switching) to combined cycle operation, presents constraints in evaluating the feasibility and costs of various emission reduction options otherwise available. For this reason, the Department does not constrain itself to any presumed historical cost-effectiveness criteria or cost estimating procedures such as might apply to a project with a clearly defined staging schedule and final configuration. At the same time, however, the Department has a full appreciation of the goals of the ATS Program and does not want to arbitrarily impede progress toward its goals.

Westinghouse provided a technology update of the Westinghouse family of combustion turbines. It includes a schedule for the 501 G to reach low NO_X levels of 9-12 by Ultra Low NO_X. The structure of the schedule is similar to that described for their 501 F class unit. According to Westinghouse, the experience gained from the 501 F will be employed in development of Ultra LN for the 501 G. Basic design and laboratory testing of Piloted Ring Combustors (a candidate design for Ultra LN) for the 501 G is already underway. Initial field verification will be conducted beginning in mid-1999. Design modification and retesting will occur from mid-1999 through mid 2000. Additional design changes/tests will be carried out from mid-2000. Full commercial application will be implemented from 2001 through 2004.[8]

Westinghouse provided the City with a more specific schedule for the 501 G to be installed at Lakeland.[19] Westinghouse "fully anticipates having a combustion system available that meets the 9-12 NO_X requirement for the McIntosh No. 5 Unit within the next four years." That will occur in early 2002 and is within the general schedule given above. According to the same document, "since McIntosh Unit No. 5 is the demonstration project for the 501 G, there is a high probability that some field verification testing will be performed on the unit."

The proximity of Westinghouse technical staff in Orlando to the project site in Lakeland should enhance the probability of meeting Westinghouse's goal at an early date.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Lakeland project assuming full load. Values for NO_X are corrected to 15% O_2. These limits or their equivalents in terms of pounds per hour, as well as the applicable averaging times, are given in the permit Specific Conditions. The rationale for the averaging times is discussed in the Final Determination addressing comments by the City and EPA and which is being issued concurrently with this determination.

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
250 MW SC CON	25 - NG 42 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	DLN on gas, WI on oil. Applies through April 30, 2002. Clean fuels, good combustion
250 MW SC CON	9 - NG 42 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after April 30, 2002. Clean fuels, good combustion
250 MW SC CON	9 - NG 15 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies after April 30, 2002 if 9 ppm NO_X not achievable by ULN as described above. Clean fuels, good combustion.
350 MW CC CON	7.5 - NG 15 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR if converted to combined cycle, unless 9 ppm is attained by ULN or Hot SCR as described above. Clean fuels, good combustion

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The initial 25 and 42 ppm NO_X limits are guaranteed by Westinghouse.
- There is a clear plan for achieving emissions of 9-12 ppm at the Lakeland location within 4 years of April, 1998. This will occur in early 2002 - about 3 years after an early-1999 startup.
- The unit will be operated in simple cycle mode while maintaining the flexibility to expand at a future date to combined cycle operation through the addition of a 100 MW heat recovery steam generator. Therefore control options which are feasible for combined cycle units are not immediately applicable at commencement of operation. At project inception, this rules out Low Temperature (conventional) SCR which achieves a 4.5 ppm NO_X BACT limit at the Hermiston and Sithe/IPP projects above.
- The turbine has a very high exhaust temperature of about 1100 °F.[17] This is at the higher limit of the present operational temperature of Hot SCR zeolite catalyst.[20] Therefore the catalyst would have to placed *after* the OTSG. The PREPA simple cycle turbines have exhaust temperatures ranging from 824 to 1024 °F and the Hot SCR catalyst (which must achieve 10 ppm NO_X) is located *between* the turbine and the OTSG.[21]

- Hot SCR is technically feasible for gas.[22] The same evaluation states that the technology has not been demonstrated for oil. However the PREPA units have since been installed.[23] These operate solely on 0.15 percent sulfur fuel oil.[24] The Lakeland unit is proposed to operate only 250 hours per year on fuel oil of 0.05 percent sulfur.
- The levelized costs of NO_X removal by Hot SCR were estimated by the City as $5,236 per ton of NO_X removed. Other Hot and conventional SCR cost estimates submitted by the applicant are not considered in this evaluation because they are based on many conditional assumptions regarding possible ultimate project phasing scenarios which are not typically encountered when applying the methodology used by the applicant. Also the cost estimates do not consider a continuation of the actual downward trend in catalyst prices, progressively improving performance, and typically longer-than-expected life.
- The levelized costs derived in the application for Hot SCR at Lakeland are based on a quote from Engelhard. The vendor based the proposal on design operation on <u>fuel oil</u> with <u>guaranteed</u> NO_X reduction of 70 percent to 12.6 ppm @15% O_2.[25]
- In order to avoid allowing control on fuel oil to become the main design consideration, the Department obtained a budgetary estimate from Engelhard to guarantee reduction of NO_X emissions while operating on <u>gas</u> by 64 percent (from 25 to 9 ppm).[26] The replacement cost of the Hot SCR catalyst designed for gas is $1,600,000 versus the $2,800,000 estimated for the Lakeland project designed for oil. During the very few hours of operation on oil, <u>estimated</u> NO_X emissions from the 501 G controlled by Hot SCR will be approximately 13 ppm @15% O_2.
- The cost effectiveness for NO_X removal given for the PREPA simple cycle project is $2,200 per ton. The main reason for the relatively low levelized cost is that total costs are applied over a reduction of 40 ppm whereas the reduction in the Lakeland case is over a smaller reduction. The cost per ton of NO_X removed by Hot SCR at the PREPA project can be rescaled for the Lakeland project. This would involve a significant increase due lower removal. However there would be decreases due to the natural gas design, application on one large unit versus three smaller ones, and lower ammonia requirements. The resulting costs would be less than $4,000 per ton.
- Using much of the basic capital cost information developed by Lakeland, The National Park Service estimated the cost of NO_X removal by Hot SCR at $3,802 per ton (excluding the energy penalty) for the continuous duty 501 G. A further refinement of the Park Service estimate by including the energy penalty, using the revised catalyst cost data obtained by the Department, and assuming a five year <u>estimated</u> life for the catalyst (per Engelhard) would yield a cost-effectiveness closer to $3,500 per ton of NO_X removed.
- The Department concludes that Hot SCR is both technically and economically feasible now. The probability of success using this technology is at least as high as it is using the Ultra LN technology under development.
- According to Westinghouse, a heat exchange surface is required between the turbine and Hot SCR catalyst to insure an operational temperature less than 1100 °F is maintained. If a future HRSG is installed, Westinghouse indicates that the OTSG (which provides the steam for

cooling and power augmentation) will be removed. This would expose the Hot SCR system (if installed) to unacceptable temperatures. Westinghouse does not believe relocation of catalyst to the HRSG is feasible and thus the Hot SCR system would be written off and possibly replaced by a conventional SCR system in the HRSG.

- The Department notes that the specifications under development by Sargent and Lundy for conversion to combined cycle operation are not yet available to the Department for evaluation. Therefore the Department does not concur that Hot SCR is not feasible based on conceivable future development scenarios.
- According to Westinghouse, the ultimate design of their ATS-based gas turbine has options for "recuperative cycles" working within combined cycles. These cycles can lower the gas temperature entering the steam cycle and appear to provide heat exchange surface to cool the gases and protect the Hot SCR system before the HRSG.
- There are various kinds of recuperative cycles - some of which make the combined cycle less efficient and others that which make it more efficient. According to a paper heralding the arrival of the 501 G, the author writes that "what is more significant is that the 501 G has been designed to incorporate the technology advances planned in the ATS program, such as intercooling and reheat, humidification and *chemical recuperation*, as and when they are good and ready."[2]
- The Department is not aware of actual plans to incorporate recuperation cycles in Westinghouse 501 products, the likely combined cycle efficiency benefits (or penalties), or their applicability to the Lakeland project by the time of conversion to combined cycle operation. The point is that ultimate wasting of Hot SCR equipment installed at startup, is not a foregone conclusion considering that many developments can occur within the time horizon of possible future project expansion scenarios.
- It is possible, and even likely, that Hot SCR catalysts will be improved (similar to refinement of Ultra LN) and can be used to replace the initial catalyst as it degrades. By the time the OTSG is removed for combined cycle conversion (e.g. 3-5 years), replacement catalyst might be able to withstand the higher temperature regime.
- Hot SCR has environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. All factors being equal, Ultra LN is a better control strategy than Hot SCR. A three year period to refine this technology to achieve similar emissions as Hot SCR is reasonable and not unprecedented.
- The Department does not conclude at this time that achieving 9-12 ppm of NO_X in three years by Ultra LN is an overall better strategy than immediately achieving 4.5 - 7.5 ppm by conventional SCR in a combined cycle unit. However, if the 9-12 ppm value can be achieved by ULN within the three years, subsequent installation of conventional SCR during a conversion to combined cycle may not be cost-effective.
- Three years after startup is equal to the longest period of time provided to any previous applicant to achieve Department BACT limits by DLN technologies. With the accumulated knowledge and experience from DLN technologies for smaller units, it should be possible to

achieve the Department's BACT limit for this project within three years after startup (if it achievable by Ultra LN technology on the 501G).

- The approach promotes further progress of the DOE ATS Program and falls within the realm of BACT determinations made by the Department in recent years.
- The Hot SCR scenario has, nevertheless, been included in the Department's determination for implementation in case that the Ultra LN strategy fails to reach the objectives within a reasonable period of time. If the City converts the unit to combined cycle mode in the near future, conventional SCR (with the catalyst in a low temperature regime within a HRSG) becomes immediately feasible, particularly if progress is slow on Ultra LN. Conventional SCR now rather than Ultra LN in three years, would be BACT at this time if the City planned to operate the unit in combined cycle mode at startup.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of clean, low ash, low sulfur fuels; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure at the high temperature exiting the stack in simple cycle operation. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 250 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Tallahassee, Florida and the Berkshire, Massachusetts projects in the above table.
- CO emission estimates from the City's project are higher than for any pollutant. However the impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, or PM_{10}.
- The City evaluated the use of an oxidation catalyst designed for 90 percent reduction and having a two year catalyst life. The oxidation catalyst control system was estimated by the City to increase the total capital cost of the project by "about $2,000,000, with an annualized cost of $980,000 per year." The City estimated levelized costs for CO catalyst control at about $800 per ton to control CO emission to 10 ppm. This company operates three of the previously-mentioned facilities where CO catalyst is used. Catalytic CO control appears to be cost-effective for the Lakeland unit..
- In the 501 G Application Overview prepared by Westinghouse and included in the City's application for permit, the combustors have "initial emission levels less than the following:"[17]

Pollutant (ppm)	Natural Gas (no injection)	Distillate Oil (water injection)
Nitrogen Oxides	25	42
Carbon Monoxide	10	90
Unburned Hydrocarbons	5	20

- In an article included in the permit application, the author states "NO_X levels of less than 25 ppm on natural gas, less than 42 ppm on oil, while maintaining CO at less than 10 ppm will be specified for introductory machines."[2]
- Westinghouse tables of "expected performance" in the permit application for the specific unit, however, estimate CO emissions while burning natural gas as 50, 100, and 350 ppm when operating at baseload, 75% load, and 50% load respectively. While operating on oil the estimated values are 90, 125, and 350 ppm at baseload, 75%, and 50% respectively.
- The permit application states that the high emission limits are "a result of uncertainty associated with maintaining low NO_X emissions while keeping emissions of CO as low as possible over the load range of the machine." It also mentions that the Westinghouse Application Overview estimate is 10 ppm for CO and accordingly calculates a much higher alternative cost per ton of removal based on the lower expected starting point prior for catalytic oxidation.
- The Department will set CO limits achievable by good combustion equal to those set for the City of Tallahassee project of 25 ppm on gas and 90 ppm on oil. For reference, the FPC Hines Westinghouse 501 F project is limited to 25 ppm on natural gas and 30 ppm on oil. The Mid-Georgia Cogen Westinghouse 501 D5A project achieved its CO limits of 10 ppm on gas and 30 ppm on fuel oil.
- At the relatively high initial NO_X emission rate of 25 ppm, there should not be technical difficulties in achieving 25 ppm of CO with Dry Low NO_X technology. These values remain as appropriate objectives to meet with the Ultra Low NO_X technology under development. The oil case is relatively insignificant because of the limited firing time.
- It is up to the City to evaluate whether to meet the CO limits by combustion optimization or alternative lower limits achievable by catalytic oxidation. A plan describing how the limits will be met should be submitted prior to construction of the unit.
- VOC emission limits proposed by the City are at the lower end of values determined as BACT. Good Combustion is sufficient to achieve these low levels.

COMPLIANCE PROCEDURES

Pollutant	Compliance Procedure
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (3 and 24-hr averages)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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Date: 7/10/98

Approved By:

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Howard L. Rhodes, Director
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Date: 7/10/98

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FINAL DETERMINATION
LAKELAND ELECTRIC & WATER UTILITIES
MCINTOSH UNIT NO. 5
250 MW SIMPLE CYCLE COMBUSTION TURBINE

The Department distributed a public notice package on April 22, 1998 for the project to construct a 250 megawatt (MW) natural gas and fuel oil-fired combustion turbine with a once-through steam generator, a 1.05 million gallon fuel oil storage tank, and a new 85-foot at the C.D. McIntosh, Jr., Power Plant located on Lakeland, Polk County. The Public Notice of Intent to Issue was published in The Ledger on April 23, 1998.

No comments were received by the Department from the public or the National Park Service pursuant to the Notice. However the Park Service submitted substantial comments on the original application.

The City filed a request to extend the time requirement for filing petitions for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The request was granted through June 30 and was withdrawn prior to issuance of the final permit.

Comments were received from the City by letter dated May 6, 1998 and from the EPA by letter dated May 21, 1998. A meeting was held June 18, 1998 between the Department and Lakeland with EPA participation (by teleconference). The City's written comments and the Department's responses (which incorporate EPA's comments and the agreements at the meeting) follow.

The City commented only on the draft permit and not on the Technical Evaluation and Preliminary Determination or the Draft Best Available Control Technology (BACT) Determination. The City's comments are keyed to the draft permit and to the Specific Conditions contained therein.

1. *__Permit Cover Page__. The City suggests expiration date of permit be extended from December 31, 1999 to December 31, 2003.*

   The Department will extend the date to June 30, 2002. The unit will be actually installed in early 1999 and will likely be tested for compliance with the initial emission limits by mid-1999. The final emission limits must be achieved not later than May 1, 2002. An expiration date of June 30, 2002 will give the City time to test and to file for a modification of the facility Title V Operation Permit. Per Section II, Condition 12, the City, for good cause, may request extension of the construction permit per Rule 62-4.080.

2. *__Section I, Facility Information__. The City corrected the description of the coal-fired steam generator. The City corrected steam injection to wet injection. The City requested that the proper Emission Unit ID numbers be used.*

   The Department agrees with the corrections and will refer to the new emission units as ARMS emission units Nos. 028 and 029 rather than Nos. 001 and 002 throughout the permit.

3. *__Section II, Condition No. 7__. The City requests that reassessment of the BACT determination be performed if there is an increase in annual heat input limits rather than hours of operation.*

   The EPA initially recommended denial (Comment 5 of their letter) of this request on the basis that the PSD application requested and was based on 7008 hours of operation at various loads, whereas the requested fuel usage limit is equivalent to 8760 hours of operation at full load. The same BACT limits would apply assuming continuous operation. The lower (than requested) NO_X emission limits set by the Department will keep the ambient concentrations impacts below those modeled in the PSD analysis. EPA concurred with this rationale. The increased hours can theoretically cause the project to be marginally PSD-significant for SO_2. An annual limit with appropriate recordkeeping will insure it remains less than significant. For reference a PSD modeling analysis was performed and the project complies with BACT for SO_2 which is use of clean pipeline quality natural gas with minimal use of back-up 0.05 percent (or lower) fuel oil. The Department did not actually determine a SO_2-BACT for this project because it was not requested or publicly noticed.

4. *Section III, Specific Condition No. 7 and 8. The City requested to delete the No. 2 designation in reference to the fuel oil. The City suggested that this change would allow the use of No. 2 and better grades of fuel (e.g., jet -A).*

   The Department concurs with the City and modified this condition to clarify that the City may utilize No. 2 or superior grade distillate fuel oils.

5. *Section, III, Specific Condition No. 13. This issue is related to Comment 3 above. The City requested that the annual fuel heat input limits be used instead of the hours of operation. City stated that the potential emissions calculation and basis of the BACT evaluation used this fuel usage. City maintains that this limit in production would be federally enforceable and easily monitored: "the heat input or fuel usage is monitored with the digital control system and is the basis of the fuel cost (a important plant parameter). Typically there are several back-ups for fuel usage". City stated that the amount of natural gas could be included as an alternative as listed on Page 26 of the application [i.e., 16,037 million cubic feet per year at 950 Btu (LHV)/cf].*

   Refer to Comment 3 above. The condition will be modified to reflect only the heat input limits from gas while the limit from fuel oil will be addressed in Specific Condition 14 as discussed below. Therefore Specific Condition 13 will be modified as follows:

   FROM
   Hours of operation for the stationary gas turbine and once-through steam generator shall not exceed 7008 hours per year.

   TO
   Maximum allowable hours of operation for the stationary gas turbine and once-through steam generator are 8760. Fuel usage as heat input, while burning natural gas in the stationary gas turbine, shall not exceed 15.64×10^{12} Btu (LHV) per year (rolled monthly) until the unit achieves the NO_X emission limits (other than the initial ones) given in Specific Condition 21. Thereafter, only the hourly heat input limits given in Specific Condition 8 apply.

6. *Section III, Specific Condition No. 14. Basically this is the same issue as discussed in comment No. 3 above. The City requested that the annual fuel heat input limits be used instead of the hours of operation. City stated that the potential emissions calculation and basis of the BACT evaluation used this fuel usage. City maintains that this limit in production would be federally enforceable and easily monitored: "the heat input or fuel usage is monitored with the digital control system and is the basis of the fuel cost (a important plant parameter). Typically there --are several back-ups for fuel usage". City stated that the amount of natural gas could be included as an alternative as listed on Page 26 of the application [i.e., 42.558 million gallons per year at 18,500 Btu (LHV)/cf].*

   The Department will limit heat input or fuel usage to the equivalent of only 250 hours per year of operation, consistent with the application and associated emissions of sulfur dioxide and other pollutants. This includes 200 full capacity equivalent hours and 50 partial capacity (50 percent) equivalent hours. Therefore Specific Condition 14 will be modified as follows:

FROM
Hours of operation for the stationary gas turbine and once-through steam generator shall not exceed 250 hours per year while firing distillate fuel oil.

TO
Fuel usage as heat input, while burning fuel oil in the stationary gas turbine, shall not exceed 559×10^9 Btu (LHV) per year (rolled monthly).

7. Section III, Specific Condition No. 16. *The City indicates that the Ultra Low NO_X technology may not be the Piloted Ring Combustors presumed by the Department and also requests that the condition reflect a requirement to install Ultra Low NO_X technology "or equivalent." The City stated that Specific Condition No. 16 as well as Specific Conditions Nos. 20 and 21 require meeting lower NO_X emissions within 36 months of start-up. City points out that the 36 months from startup is not sufficient time since any installation or adjustments of both the DLN and Ultra Low NO_X must be within the period. City maintains that since a lower limit must be demonstrated at a future date, it must accommodate testing for the lower limit. City feels that by designating the Initial Performance Test (IPT), Westinghouse and the City could accommodate the installation of the alternative controls as well as the testing and that the IPT would also provide both the City and the Department with specific future compliance date.*

The Department agrees that the Piloted Ring Combustors may not represent the Ultra Low NO_X technology to eventually be used at this project. However the designation for the technology described by Westinghouse to meet the BACT limits is clearly Ultra Low NO_X. An "equivalent" technology can not be accepted without additional review. The alternative SCR technologies already approved by the Department are not actually "equivalent" to Ultra Low NO_X because they have higher efficiency at low loads and different emissions characteristics related to, for example, ammonia. The condition will be changed to reflect the comment about the Piloted Ring Combustors.

Regarding the date to achieve the BACT emission limit, both the Department and EPA disagree with the City that the demonstration should be made 36 months after the Initial Performance Test. As discussed in the BACT determination, correspondence from Westinghouse indicates that the technology will be available for Lakeland in early 2002. The date of the Initial Performance Test is not a fixed date and can be indefinitely delayed by unforeseen circumstances. Westinghouse claims that the technology is already under development irrespective of the Lakeland project. The date proposed here by the Department provides sufficient time to refine a technology already under development. Therefore, this condition will be changed to reflect a "date-certain" of May 1, 2002 rather than based on uncertain start-up or IPT dates. This is consistent with most if not all other permits for combustion turbines employing Dry Low NO_X technologies issued by the Department.

8. Section III, Specific Condition No. 17. *City wants to strike the reference to CO in this condition which requires that the equipment design be capable of accommodating NO_X and CO control catalysts in case the unit fails to meet the corresponding emission limits by Ultra Low NO_X (in conjunction with Clean Fuels and Good Combustion). City states that the Department has already established CO emission limits for which compliance must be demonstrated annually and that it is unnecessary to include a requirement for CO in this condition.*

The Department's intent on this condition is to require from the permittee a design that will accommodate installation of SCR and/or oxidation catalyst to achieve NO_X and CO emission limits in the event that the Ultra Low NO_X in conjunction with Clean Fuels and Good Combustion technology fails to achieve the NO_X or CO limits.

The condition is necessary because Westinghouse and the City did not provide reasonable assurance that the CO limit will be met without oxidation catalyst. This condition will not be modified as requested. Clearly the Department will not require the City to install SCR catalyst if the CO limits are not met or oxidation catalyst if the NO_X limits are not met.

9. *<u>Section III, Specific Condition No. 19</u>. The City states that the condition regarding optimization is not necessary for the following reasons: 1) it is the City's understanding that Dry Low NO_X and Ultra Low NO_X operating parameters are established by Westinghouse and the ability of "tuning" the combustors in the traditional sense is not applicable. 2) that the Distributive Control System that controls the turbine operation will automatically control the gas regulation for the pre-mix and diffusion modes. In addition, the City affirms that they will not have the ability to control these parameters and that the requirement to meet specific emission limits will dictate in part how the turbine is operated.*

   On April 27, 1998, the Department requested the combustor emission characteristics with respect to load for both the initial and ultimate combustors and an operational plan to encourage operation at 70-100 percent of full load. This was requested to be provided prior to issuance of the permit. The City, Westinghouse and Golder have not provided this information to-date. Per Figure 3 and the discussion in the Final BACT Determination, the Dry Low NO_X technology may not be fully operable at loads less than 50 percent (or even higher in the case of Westinghouse technology). The purpose was to demonstrate that the unit will be operated whenever possible in the lean pre-mix mode so that the Dry Low NO_X feature is fully engaged while carbon monoxide emissions are also minimized. The information requested in the April 27 letter must be provided to the Department as soon as it is available and prior to startup.

   Clearly the combustors will require tuning and optimization during the first three years of operation to meet the prescribed emission limits. The sentence on the diffusion firing (non lean pre-mixed) mode will not be changed. It is also in the City of Tallahassee permit and will likely be used on all future combustion turbine permits employing similar technology. The Department's rule on Circumvention, Rule 62-210.650, F.A.C., prohibits operators from allowing the emission of air pollutants without the proper operation of control equipment. Operating Dry Low NO_X burners in the diffusion mode for extended periods of time amounts to Circumvention. The condition will not be changed. The condition, together with the proposed averaging periods will discourage, though not totally prevent, short periods of operation in the diffusion mode during which NO_X emissions may well reach 50-100 ppm.

10. *<u>Section III, Specific Condition No. 20 - Compliance Date and Correction of CO</u>. The City proposes to revise the table with respect to the time to achieve BACT emission limits. The City proposes the same CO BACT limits as proposed by the Department, but corrected to 15 percent(%) oxygen.*

    The time to achieve the BACT limit was addressed in Item 7 above. The uncorrected CO emission limit reflects industry convention and the practice of most agencies. The value is equal to that determined for the City of Tallahassee project and appears to be less stringent than the value set for the FPC Hines project. It is much less stringent than the Hermiston or Sithe/IPP projects which did not employ oxidation catalysts. If high values are approved, oxidation catalyst (and thus even lower CO limits) becomes feasible based on the application submitted by the City. Various references were cited by the City and the Department regarding claims by Westinghouse that the unit can meet 10 ppm of CO. The Department does not expect this to occur at all times. Therefore the higher levels of 25 ppm on gas and 50 ppm on fuel oil are proposed by the Department. To provide greater flexibility in minimizing the relatively high NO_X emissions until May 1, 2002, the CO limit can be corrected to 15 percent O_2. Thereafter the emissions can not be corrected, otherwise the limit would not represent BACT.

11. *<u>Section III, Specific Condition No. 20 - NO_X Averaging Time</u>. The City believes that compliance with a limit of 9 ppm for a short-term period is not consistent with the Department's recent decisions for the City of Tallahassee. The City states that the BACT evaluation and impact analyses for NO_X use even longer averaging times (i.e., annual) than the 30-day rolling average, and that the 30-day basis is more stringent than the air quality impact of BACT evaluations. The City adds that the 30-day average is a rolling average for which compliance is evaluated each day The City proposes to revise the table with respect to the time to achieve BACT emission limits..*

The requirements of BACT and PSD are not identical. The Department only intended to require a demonstration that the unit can achieve the stated level, which is typical of a performance guarantee. Although the Department did not set a 9 ppm limit for the City of Tallahassee, General Electric did guarantee such a limit for that project. Tallahassee also requested a facility-wide cap on future NO_X emissions (including the new unit) equal to total past actual emissions from the units already on the site. Discussions with EPA indicated that the NO_X (and SO_2) caps might have exempted these pollutants from PSD Review and BACT Requirements.

Based on statistics and probability, if the unit cannot be demonstrated to achieve a short-term guarantee of 9 ppm, it will not likely meet the Department's proposed 30-day, 12 ppm value. The 9 ppm value is a short term emission limit to be demonstrated by a stack emission test. It was the Department's intent (with which EPA disagrees) that continuous compliance will be determined by the longer-term standard.

The Department agrees that NO_X impacts are calculated over even longer averaging times than 30-days. However the Department notes that NO_X is also a pre-cursor of ozone for which short-term standards apply. In fact, during the month of May, 1998, there were various days during which ozone levels approached the National Ambient Air Quality Standard in Polk County and exceeded them in adjacent Hillsborough County. Therefore the City's argument is not sufficient to dissuade the Department from requiring at least a demonstration that a low short-term value can be demonstrated (if not necessarily maintained) for Dry Low NO_X and Ultra Low NO_X technology.

EPA (refer to their Comment 2) objects to the higher 12 ppm emission limit when using a 30-day averaging time proposed by the Department. EPA believes the longer-term limit should be no greater than 9 ppm and points out that typical averaging times used by states other than Florida are short-term such as 1 or 3 hours. Because of the emission characteristics of Dry Low NO_X technology (which is not fully operable at loads less than 50 percent and possibly higher), the unit may, at times, exhibit higher average NO_X emissions than the lowest achievable emission rate that can be demonstrated for the unit.

The Department agrees in general with EPA's assessment that longer averaging times should result in lower average emissions than short-term emission limits. This would occur when using technologies such as SCR that operate throughout the entire operating range. Realistically, the Ultra

Low NO_X unit will probably achieve 9 ppm over most 30-day averaging periods. However, flexibility is needed for situations governed by electrical dispatching priorities, demand, and spinning reserve requirements that can occasionally result in limited operation at lower loads where the lean pre-mixed mode is not fully employed. Such occurrences will be minimal because the City will have to operate the unit at 9 ppm (or lower) to compensate for the periods of diffusion mode operation.

During the initial operation, the limit is 25 ppm NO_X. During that period, the Department proposed a 24-hour limit to discourage any prolonged operation in the diffusion mode. The City requested that this limit also be based on a 30-day basis. Instead, the Department will switch to a pound per hour limit averaged over 24 hours. The limit will be based on 25 ppm at full load, but will allow higher emission concentrations as long as the hourly emission limits are met on a 24-hour basis. This will avoid prolonged periods of high emissions, but still allow for temporary operation in the diffusion mode. It will satisfy the need for low short-term mass limits consistent with the need to minimize ozone pre-cursors while the Ultra Low NO_X technology development is completed. In view of EPA's comments, the Department will add a pound per hour limit averaged over 24 hour equal to continuous operation at full load and at 9 ppm. This condition will be modified accordingly.

12. <u>*Section III, Specific Condition No. 20 - Combined Cycle Operation*</u>. *The City suggests that the use of Ultra Low NO_X should also list combined cycle.*

Per the table in Specific Condition 20, the intent is to describe the applicable technology for the various modes of operation rather than to describe all the modes of operation that correspond to a particular control technology. It is already clear under the combined cycle operational mode, that Ultra Low NO_X technology will be acceptable if it is achieves the BACT limit before the deadline of 36 months (now May 1, 2002). The Department will make it clearer in the table that, based on specific circumstances, Ultra Low NO_X, Conventional SCR or Hot SCR are appropriate technologies for combined cycle operation.

If SCR is employed, the Department requires compliance with the 9 ppm (Hot SCR) or 7.5 ppm (Conventional SCR) NO_X limits on a 3-hour averaging time. This is consistent with EPA's comments and reflects the ability to match ammonia use to load and NO_X load from the turbine. EPA recommends that the Department set the NO_X emission limit, under the Conventional SCR case, at the time of actual conversion to combined cycle. In Comment 4 in its letter to the Department, EPA suggests that the limit may be less than 7.5. EPA pointed out that an application had been received from Southern Company by the State of Alabama for a combined cycle with Conventional SCR control and a NO_X emission limit of 3.5 ppm.

The Department notes that the lowest NO_X value to-date for such units in Florida, Alabama, Mississippi, or Georgia is 9 ppm. The Department has reviewed the BACT proposal by the Southern Company and concludes that the objective is to propose a BACT limit that is beyond question and to minimize modeling requirements so that it may obtain the permit as soon as possible. The 3.5 value is equal to the Lowest Achievable Emission Rate (LAER) limits cited in the Department's BACT Determination for comparable projects. For example, no cost data were provided because the company used the "top technology."

It is the Department's conclusion that such a low value for a combined cycle unit using Conventional SCR technology with a 3.5 ppm limit, will provide very little additional benefit to the environment. For example, the New Source Performance Standard for such units is about 110 ppm of NO_X for gas combustion. Values of 6-12 ppm (especially when achieved by Dry Low NO_X processes) clearly represent very clean technology. For example, a combined cycle combustion turbine achieving a 7 ppm limit would emit only about one-fifth as much NO_X on a kilowatt-hour basis as a new coal-fired unit achieving a BACT emission limit of 0.10 pounds of NO_X per million Btu heat input. The additional ammonia injection to achieve and maintain even lower values probably provides only negligible overall benefits considering the increased ammonia emissions and fine particulate matter. Additional restrictions tend to discourage the more efficient combined cycle units that use inherently clean fuels and emit less greenhouse gases (CO_2). Requiring SCR, irrespective of the possible low emissions achieved by Dry Low NO_X, also discourages development of the latter technology.

As discussed in the Final BACT Determination, Sargent and Lundy are already evaluating for the City, options to convert it to combined cycle operation. The Department believes that its proposed limit of 7.5 ppm will represent BACT for this project scenario.

During the teleconference, EPA advised that there should still be at least 70 percent reduction by SCR if it used at all. The City and Department explained that if Ultra Low NO_X technology fails to meet limits, it is most likely that other combustors will be used that emit higher NO_X but are more compatible with optimum unit operation. This relates to minimizing flame instability and flashback. In that case, the SCR technology will likely have to achieve an efficiency of about 80 percent. With this explanation, the issue was resolved.

13. <u>Section III, Specific Condition No. 21 - NO_X Hourly versus Annual Emission Limits</u>. *The City repeated many of the same comments already discussed above and proposed specific language implementing those comments. The City also proposes that the pound per hour (lb/hr) limitations be replaced with annual emissions (tonnage). The City states that the basis of the impact evaluation for NO_X is the annual emissions which were demonstrated to achieve the national ambient air quality standards (NAAQS). The City points out that the 30-day rolling concentration average and tons/year limits are consistent with the City of Tallahassee PSD determination recently made by the Department (PSD -FL-239/PA97-36 and the PPSA). The City refers to the 863 tons per year (25 ppmvd @ 15% O_2) that is contained in the application (page 2-9) and to the 436 tons/year based on 12 ppmvd at 15% oxygen for gas firing and the 42 ppmvd at 15% oxygen for oil firing.*

EPA addressed this item in Comment 3 of its letter. According to EPA, "to ensure that the PSD permit is practically enforceable, short-term BACT emission limits need to be provided in the PSD permit as opposed to 'ton/year' limits." The purpose of the annual tonnage limit in the Tallahassee permit was to maintain the cap which was requested by the City of Tallahassee to avoid an emissions increase and (in their view) avoid PSD.

14. <u>Section III, Specific Condition No. 22 - Correction of CO</u>. *The City proposes to correct emissions to 15% O_2. The City states that the provision for correcting to 15% O_2 would provide some margin for increased efficiency of the "G" turbine technology. The City adds that more efficient turbines have lower O_2 with less emissions per MW generated (as described in the application and subsequent information transmitted to the Department and that the use of the oxygen correction would be equivalent of adjusting the "G" turbine performance to the "F" class turbine. The City refers to the CO emission limits contained and approved by the Department for the City of Tallahassee's "F" class turbines. The City believes that there is no appropriate reason for adding lb/hr or tons/year limits for CO and that the environmental impacts are extremely low even with much higher emissions. The City refers to the recent City of Tallahassee PSD approval that did not contain lb/hr or ton/year limits for CO.*

Refer to Comment 10 above. During the initial period of operation, the correction will be allowed to provide flexibility in minimizing NO_X emissions. The reason is not to adjust for greater efficiency of the "G Class" versus the "F Class" technology. During the initial operation the efficiency will be 38 percent while the Tallahassee and FPC Hines Combined Cycle Units will achieve 56 percent efficiency. After conversion to combined cycle, the efficiency of the City's unit will reach a theoretical maximum of 58 percent. As previously mentioned, continuation of the corrected CO limit would not constitute BACT and, per the application, might make the use of oxidation catalyst and an even lower CO value appear cost-effective.

For reference, the CO limits set for the Tallahassee project applied to both full load and partial load conditions.

15 Section III, Specific Condition No. 23 - SO_2. Hourly Emission Limits. *The City states that with the use of clean fuels and not having a BACT determination, it is unnecessary to establish SO_2 lb/hr limits. The City adds that the modeling demonstrates that compliance with NAAQS is readily achieved and refers to the City of Tallahassee permit approval without hourly limits.*

The City of Tallahassee sulfur dioxide limits are based on an emission cap limit for the facility (Unit 8, Unit 7, GT1, GT2 and auxiliary boiler). The short term emission limit for the McIntosh's emission unit 5 is to provide reasonable assurance that the TPY limit will not be exceeded and to ensure that the PSD permit is practically enforceable (refer to EPA's letter of May 21, 1998, page 3, item 3). The Department agrees with the City that a BACT analysis was not conducted for this pollutant. This condition will not be changed. Refer to comment 3.

16 Section III, Specific Condition No. 24 - Opacity. *The City states that the Westinghouse guarantees provide for 10 percent or less opacity for gas and 20 percent or less opacity for oil and that these levels are consistent with other permits using such fuels (e.g., Hardee Unit 3 using Westinghouse 501F turbines). The City points to the fact that the use of oil is limited to only 250 hours/year and that it is very infrequent.*

The very low particulate emissions and VOC emissions expected from the combustion turbine under any development any operational scenario, suggest the expectation of low opacity. Because the Department does not require particulate testing, it is important to set opacity limits representative of the low emissions for the other mentioned parameters. The Department set a 10 percent opacity limit for the City of Tallahassee project and the FPC Hines project that has a Westinghouse 501F unit.

It is the Department's function to set BACT emission limits rather than by manufacturer's guarantee. Westinghouse's contractual guarantees to the City did not represent BACT for NO_X either and the Department provided additional time to allow the company to develop the technology to come into compliance with BACT. Since the unit will operate a fairly short time on fuel oil, there is not a great deal of risk to the City. Ten percent opacity is the Department's BACT determination for operation on oil. There is no reason to expect a 20% opacity plume from a clean unit.

17. Section III, Specific Condition No. 25 - VOC limitations. *The City states that since there is no PSD applicability for VOC at these emission limits (i.e., emissions are 37 tons/year; see page 2-9 in application), there should be no lb/hr or tons/year emission limits. The City adds that there is no NAAQS and the ppmvd levels provide sufficient basis.*

For the BACT analysis, the Department based its determination on the BACT limits proposed by the City on the application submitted on December 8, 1997. Refer to Page 4-12 of the application. However, the Department agrees with the City that by imposing these emissions limits, annual TPY will be under the PSD threshold. It is better to have the limits in the permit from the BACT Determination. The estimate is very close to the PSD threshold and could easily be exceeded based on the level of accuracy of the estimate. It is still better to include the BACT permit conditions so that a new BACT determination for VOC will not be necessary should the City increase usage of the unit in the future resulting in total VOC emissions greater than 40 tons per year.

18. *Section III, Specific Condition Nos. 29 and 30 - Initial Performance Test. The City proposed that the initial performance test (IPT) shall be conducted after installation or modification of equipment used to achieve the emission limits specified in Conditions 20 and 21 and that the IPT shall be conducted within the time periods specified in Condition 29.* The City's rationale is that this *condition should be constructed around the time periods in Conditions 20 and 21 and allow a similar period for performing initial performance tests. The City states that the term "shake down" has no regulatory meaning and 100 days seems arbitrary.*

    Refer to Item 7, Specific Condition No. 16 above. Implementing the request creates uncertainty about the achievement of the BACT emission limits. It would mean that installation of any equipment at any time would restart the clock on an IPT. The date-certain requirement now proposed by the Department makes more sense. An initial performance test must be carried out within the requirements of the New Source Performance Standards. Compliance with the final limits must be demonstrated by May 1, 2002.

19. *Section III, Specific Condition No. 26 and 31. In Specific Condition 26, the City stated that in accordance with the NSPS, excess emission resulting from startup, shutdown, malfunction or fuel switching is not limited to any specific period or duration. The City affirms that this statement is also consistent with the EPA's comments (and FDEP agreement) on proposed Title V permits for the FPL's facilities. In condition 31, the City proposed that an operating day shall consist of at least 18 hours of operation and that periods of allowable excess emissions as provided for in Conditions 26, 27 and 28 shall be excluded from the 30 day average [Rule 62-4.070, F.A.C., 40CFR75]. The City believes that the periods of allowable excess emissions as provided for in Conditions 26, 27, and 28 shall be excluded from the 30 day average. The City feels that this wording clarifies the intent of the condition and that it also provides a definition of operating day similar to the NSPS.*

    This emission unit (s) shall comply with all applicable rule requirements including the Department's excess emission rule. These conditions, as written, are supported by EPA in its comments of May 21, 1998. These conditions will not be modified as requested.

20. *Section III, Specific Condition No. 33. The City proposes suggested wording for clarification (IPT instead of initial test).*

    Please see responses to Comments 7 and 18 above.

21. *Section III, Specific Condition No. 34. The City states that the VOC emission limits established by the Department would result in emissions below the PSD significant emission rates and therefore BACT is not applicable. The City suggests that this should also be addressed in the BACT determination.*

Refer to Comment 17 above regarding Specific Condition No. 25.

22. *<u>Section III, Specific Condition No. 41</u>. The City proposes to add the "30 -days rolling average" wording through this condition. The City proposes that periods of startup, shutdown, malfunction, and fuel switching shall be excluded from the 30 day averages but monitored, recorded, and reported as excess emissions when emission levels cause the 30 day average to exceed the BACT standards following the format of 40 CFR 60.7 (1997 version).*

    Refer to Comment 19. This condition will be modified to reflect a 24-hr and 3-hr averaging time instead of the 30-day rolling average.

23. *<u>Section III, Specific Condition No. 42</u>. The City states that the NSPS NO_X emission limits are at least 4 times higher than the BACT emission limits and that the potential for requiring some correction to ISO conditions is unnecessary and, if required, would add unnecessary costs and reporting complications.*

    The City is correct to affirm that, for this unit, the NSPS NO_X emissions limits are at least 4 times higher than the BACT. However, the requirement for ISO correction is an NSPS requirement with which all Subpart GG turbines need to comply. Therefore, this condition will not be modified as requested. The Department position is further affirmed by EPA's comments.

24. *<u>Section III, Specific Condition No. 43</u>. The City proposed to add the 40 CFR Part 75 wording to this condition as a basis for equipment and performance specifications.*

    The Department agrees with the City and this condition will be modified as requested.

25. *<u>Section III, Specific Condition No. 46</u>. The City adds language to this condition that was cut off from the original text.*

    The Department agrees with the City and adds the remainder text to this condition: "process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C.]."

CONCLUSION

The Final action of the Department is to issue the permit with the changes described upon withdrawal by the City of its request for extension of time to file for a petition and issuance of the Site Certification Modification Order.

LAKELAND ELECTRIC & WATER

(813) 499-6603

Excellence Is Our Goal, Service Is Our Job

December 5, 1997

Farzie Shelton
CHEMICAL ENGINEER

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-FI-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

Enc.

cc: Al Linero, DEP
Ken Kosky, Golder Associates Inc.

CC: T. Heron, BAR
EPA
NPS
SWD
Polk Co.

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
Signature

12/04/97
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.

Signature: Norman F. Kohl — Date: 29 November 1997

Signature (seal)

* 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	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 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

__Rule Applicability Analysis__ (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.

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.**

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: ______ [ ] Previously Submitted, Date: ______		[x] Not Applicable
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.

11-26-97

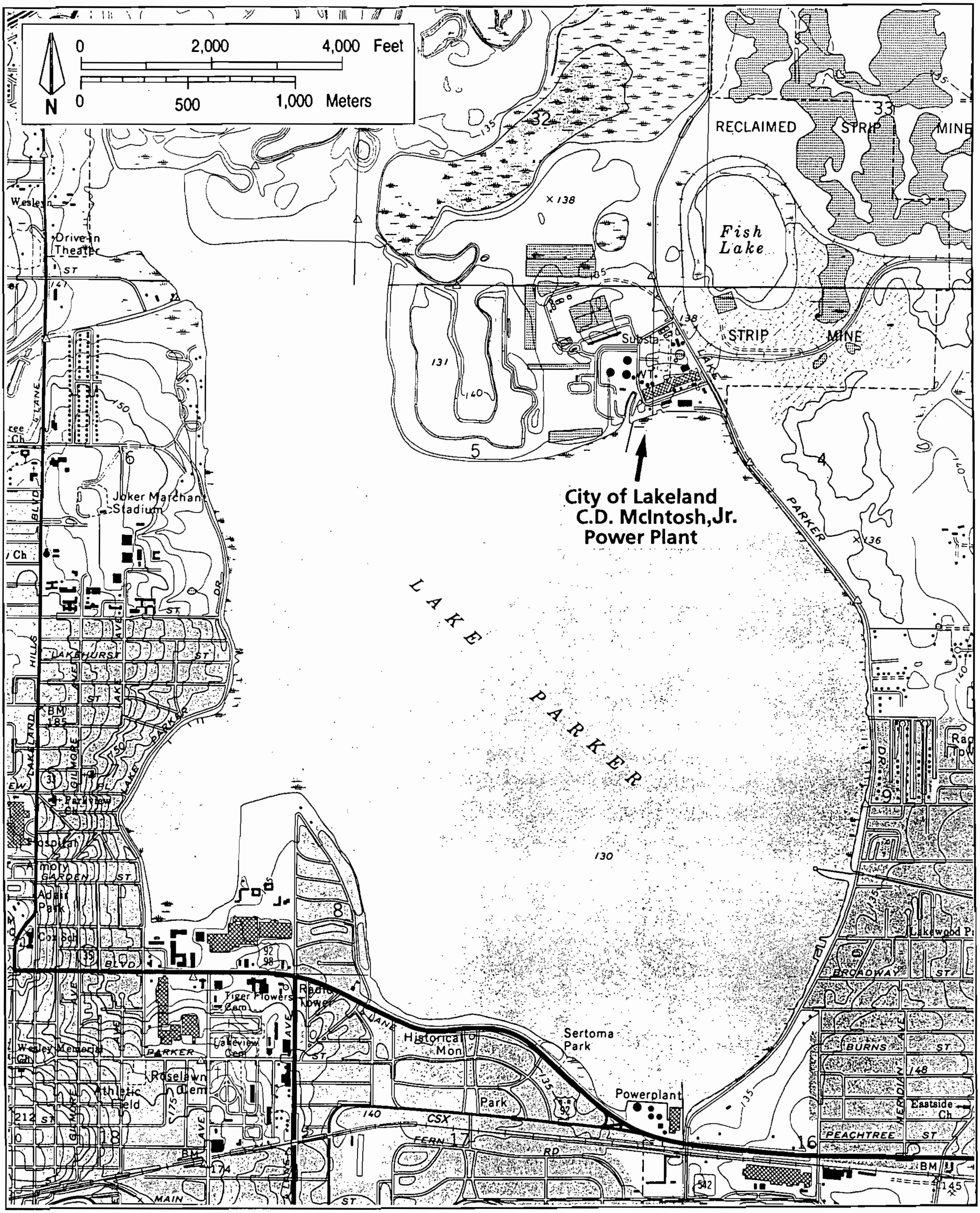


Figure 1-1
Location of McIntosh Plant

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

	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)	1,128	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

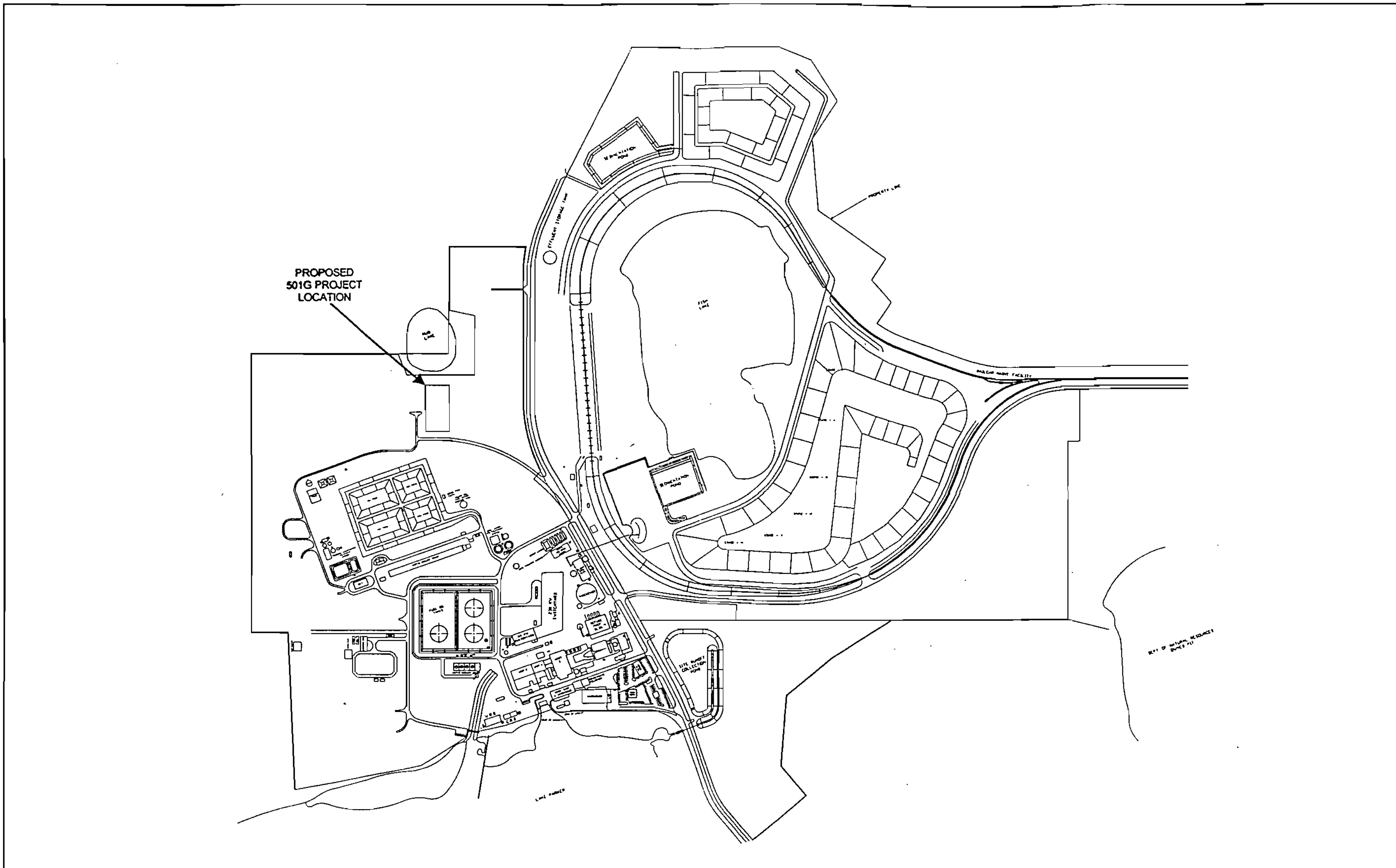
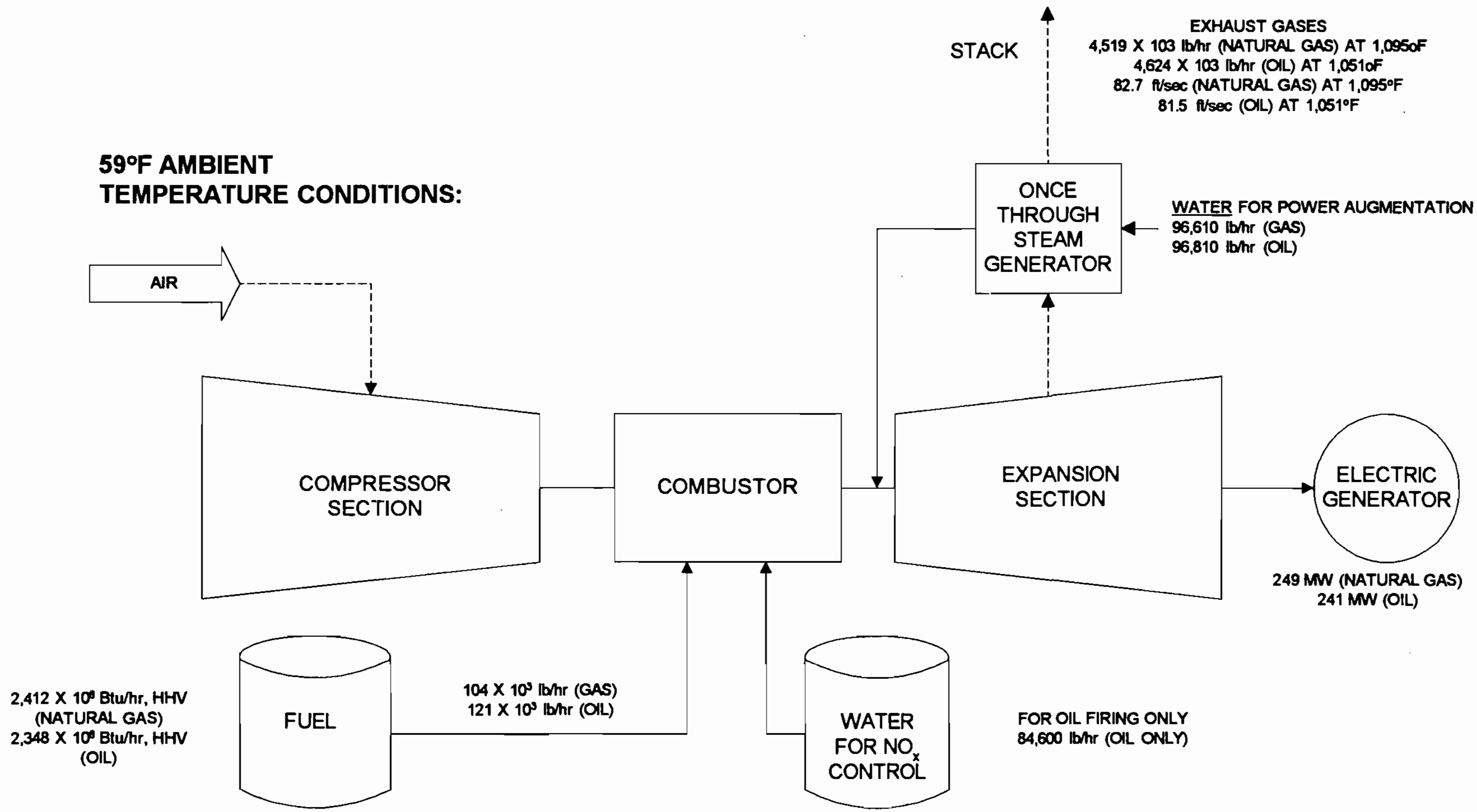


Figure 2-1 McIntosh Plant Boundary and Adjacent Properties Source: City of Lakeland, 1997; Golder, 1997.	*Process Area:* Plant Site Map *Filename:* 9737594C/FIGURES2.VSD (#1) *Latest Revision Date:* 11/25/97	Golder Associates



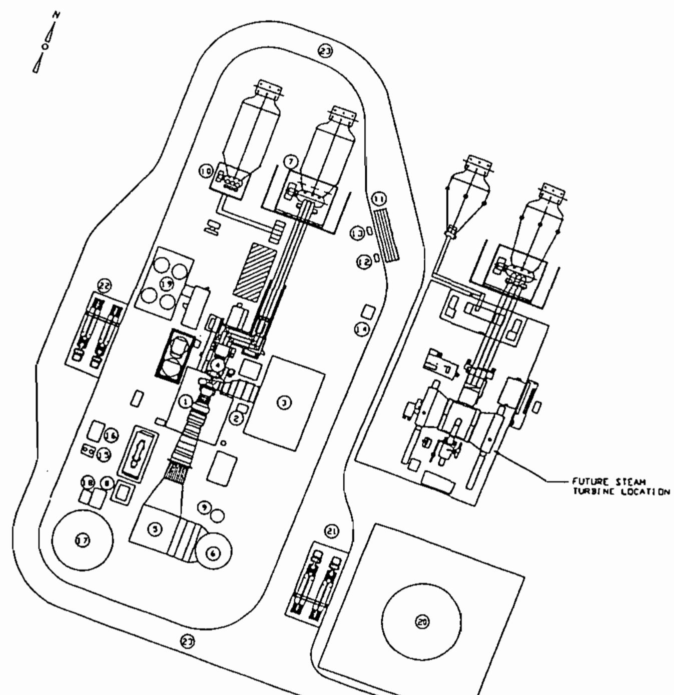
NOTE: SEE ATTACHMENT A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL. BASED ON FLOW RATES PROVIDED BY WESTINGHOUSE.

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



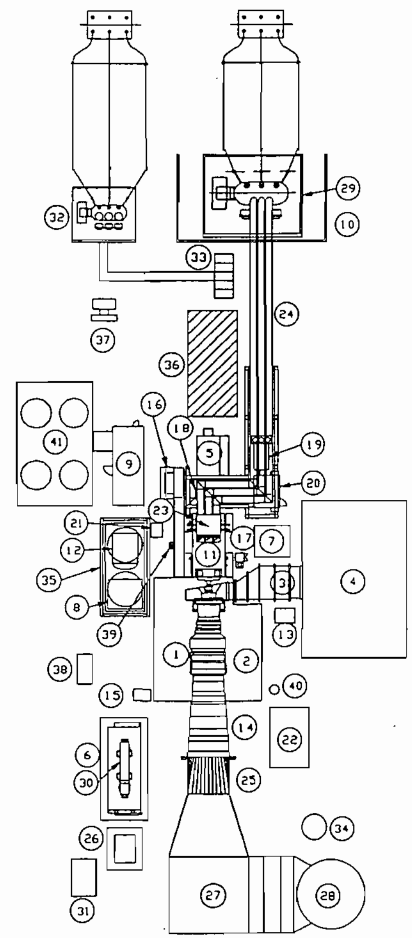
NOTES

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.

LEGEND

1 V501G COMBUSTION TURBINE
2 COMBUSTION TURBINE ENCLOSURE
3 TURBINE AIR INLET FILTER
4 GENERATOR (HYDROGEN COOLED)
5 OTSG
6 OTSG STACK
7 MAIN STEP-UP TRANSFORMER
8 BOILER FEED PUMPS
9 FLASH TANK
10 AUXILLIARY TRANSFORMER
11 HYDROGEN TUBE TRAILER PARKING
12 HYDROGEN VALVE MANIFOLD
13 NITROGEN VALVE MANIFOLD
14 CO2 CYLINDER STORAGE
15 OILY WATER SEPARATOR
16 OILY WATER SEPARATOR EFFLUENT FILTER
17 DEMINERALIZED WATER STORAGE (450,000 GALLON)
18 DEMINERALIZED WATER FORWARDING PUMPS
19 GENERATOR GLYCOL COOLER
20 FUEL OIL STORAGE TANK (1.05 MIL. GALS)
21 FUEL UNLOADING AREA
22 DEMINERALIZED WATER TRAILER PARKING
23 ROAD



DETAIL VIEW

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.

LEGEND

1 W501G COMBUSTION TURBINE
2 COMBUSTION TURBINE ENCLOSURE
3 TURBINE AIR INLET AND SILENCER
4 TURBINE AIR INLET FILTER
5 STARTING PACKAGE
6 ROTOR AIR COOLER (AIR/AIR)
7 GENERATOR SEAL OIL SKID
8 LUBE OIL PUMP SKID
9 ELECTRICAL PACKAGE
10 TRANSFORMER FIRE WALL
11 GENERATOR (HYDROGEN COOLED)
12 LUBE OIL RESERVOIR
13 HYDRAULIC SKID
14 TURBINE EXHAUST MANIFOLD
15 COMPRESSOR WASH SKID
16 GENERATOR AUXILIARY CONTROL PANEL
17 NEUTRAL GROUNDING CUBICLE
18 COLLECTOR (BELOW ISOPHASE BUS)
19 EXCITATION TRANSFORMER (BELOW ISOPHASE BUS)
20 EXCITATION SKID (BELOW ISOPHASE BUS)
21 INSTRUMENT AIR COMPRESSOR
22 FUEL OIL PUMP & FO/WI SKID
23 GENERATOR MAIN & NEUTRAL LEAD ENCLOSURE
24 ISOPHASE BUS
25 EXHAUST TRANSITION
26 STAGE TWO AIR COOLER
27 OTSG
28 OTSG STACK
29 MAIN STEP-UP TRANSFORMER
30 ROTOR AIR RECUPERATOR (GAS PREHEATER)
31 BOILER FEED PUMPS
32 AUXILIARY TRANSFORMER
33 MEDIUM VOLTAGE MOTOR STARTERS AND SWITCHGEARS
34 FLASH TANK
35 LUBE OIL COOLER (FIN-FAN)
36 GENERATOR MAINTENANCE AREA
37 LOW VOLTAGE TRANSFORMER AND BREAKER
38 FALSE START DRAIN TANK
39 GENERATOR SEAL OIL VAPOR SKID
40 FUEL GAS FILTER/SEPARATOR
41 GENERATOR GLYCOL COOLER

PRELIMINARY

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

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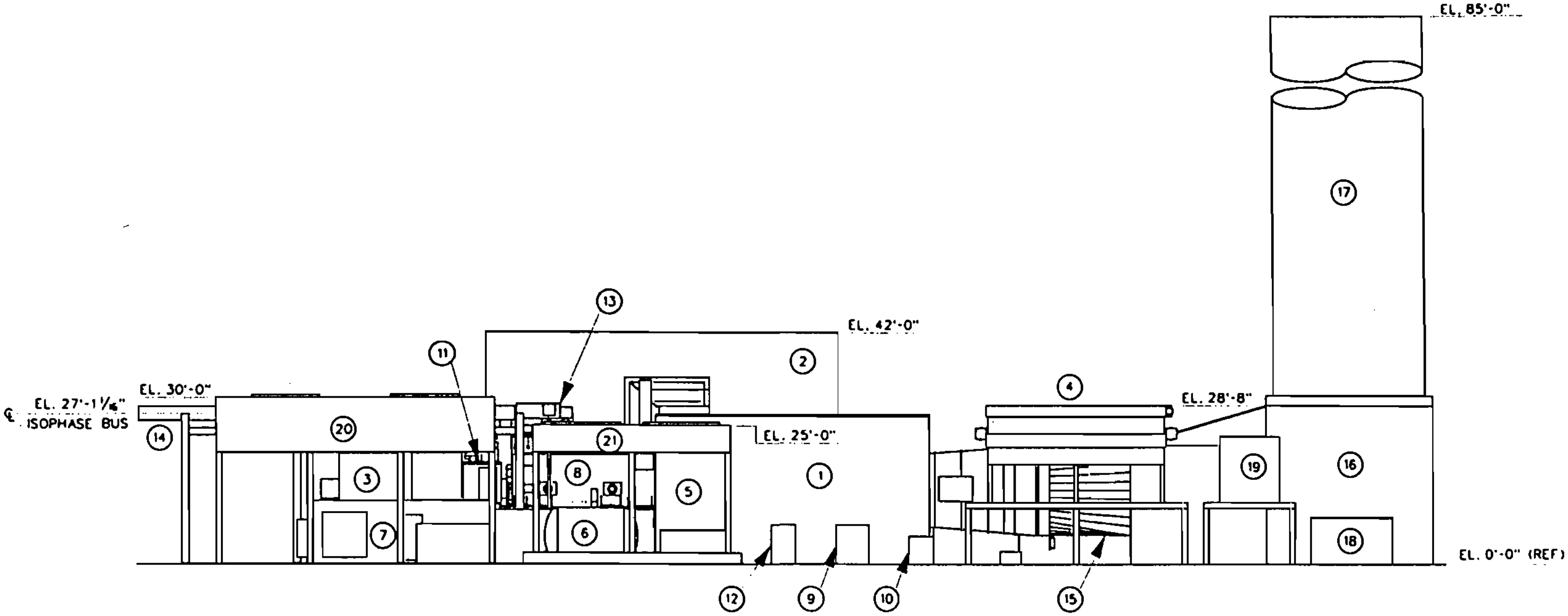

LEGEND

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

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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.
[c] 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 x 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
NO_x 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

		Maximum Impact (µg/m³)- Natural gas-Firing (1)				Maximum Impact (µg/m³)- Fuel oil-Firing (1)				EPA PSD Class II Significant Impact Levels (µg/m³)
	Averaging	Base Load		50 % Load		Base Load		50 % Load		
Pollutant	Time	90 °F	30 °F	90 °F	30 °F	90 °F	30 °F	90 °F	30 °F	
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

		Maximum Impact (µg/m³)- Natural gas-Firing (1)				Maximum Impact (µg/m³)- Fuel oil-Firing (1)				Proposed EPA PSD Class I Significant Impact Levels (µg/m³)	Recommended NPS Class I Significant Impact Levels (µg/m³)
	Averaging	Base Load		50 % Load		Base Load		50 % Load			
Pollutant	Time	90 °F	30 °F	90 °F	30 °F	90 °F	30 °F	90 °F	30 °F		
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

	Emission Rates (1)		Maximum Predicted Concentrations (µg/m³) (2)						Impact / Florida ARC			Predicted Impact Complies With Florida ARC?
	Maximum	Annual	8-Hour		24-Hour		Annual					
Pollutant	(lb/hr)	(TPY)	Impact	Florida ARC	Impact	Florida ARC	Impact	Florida ARC	8-Hour	24-Hour	Annual	
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:

$$b_{exts} = 0.003\ (\text{comp})\ f(RH)$$

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

	Maximum Predicted Concentration (µg/m³)	
Hour	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)/ft²

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
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)	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)/ft²

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
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	0.2	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)/ft²

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
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	0.2	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]

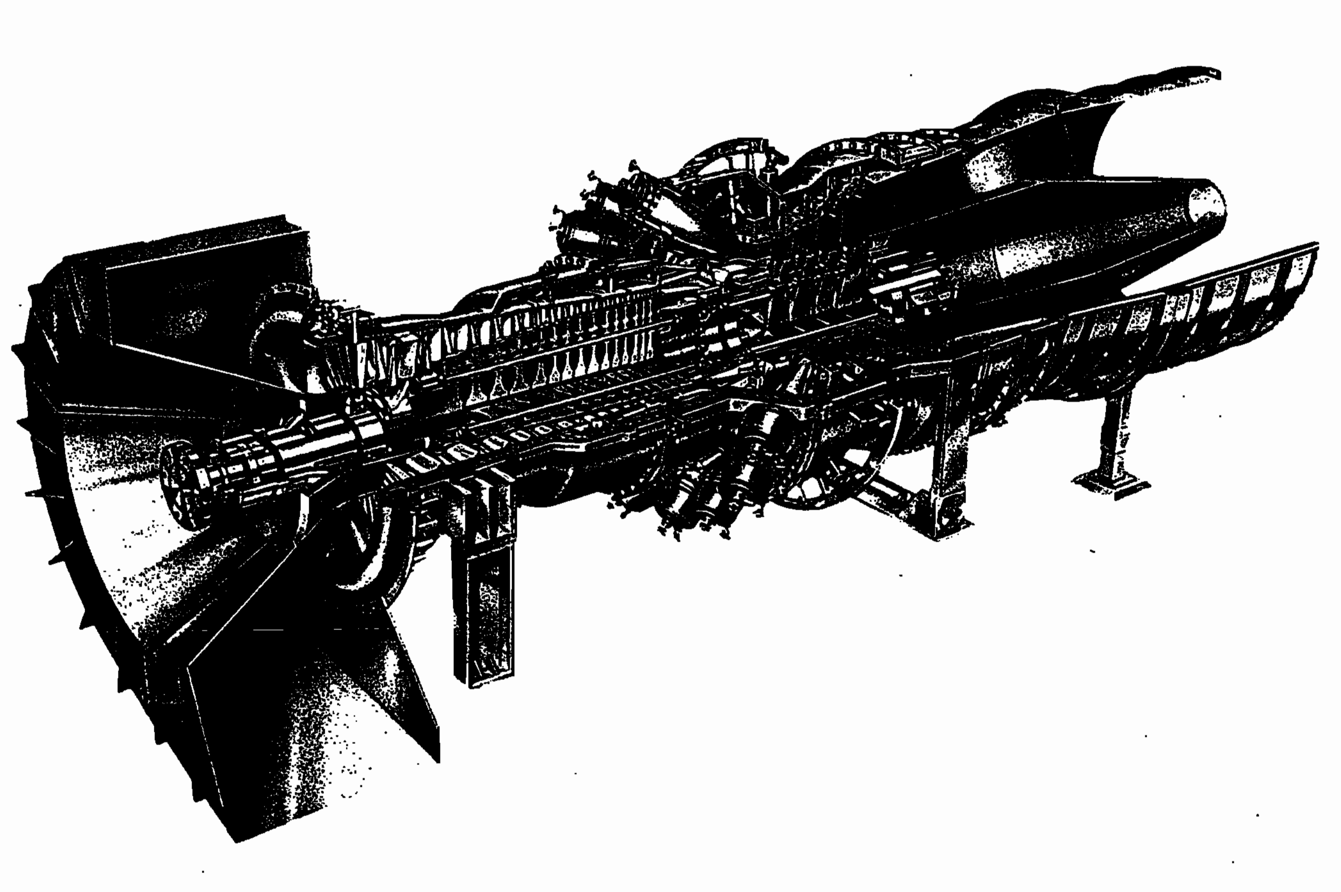
Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the fuel procurement specification

MPS

MODERN POWER SYSTEMS

August 1994



ADVANCED GAS TURBINES
Westinghouse offers 230MW 501G

Westinghouse Electric Corporation
Power Generation Business Unit
4400 Alafaya Trail
Orlando, Florida 32826-2599 U.S.A.

407 281 2000

Steam cooled 60 Hz W501G generates 230 MW

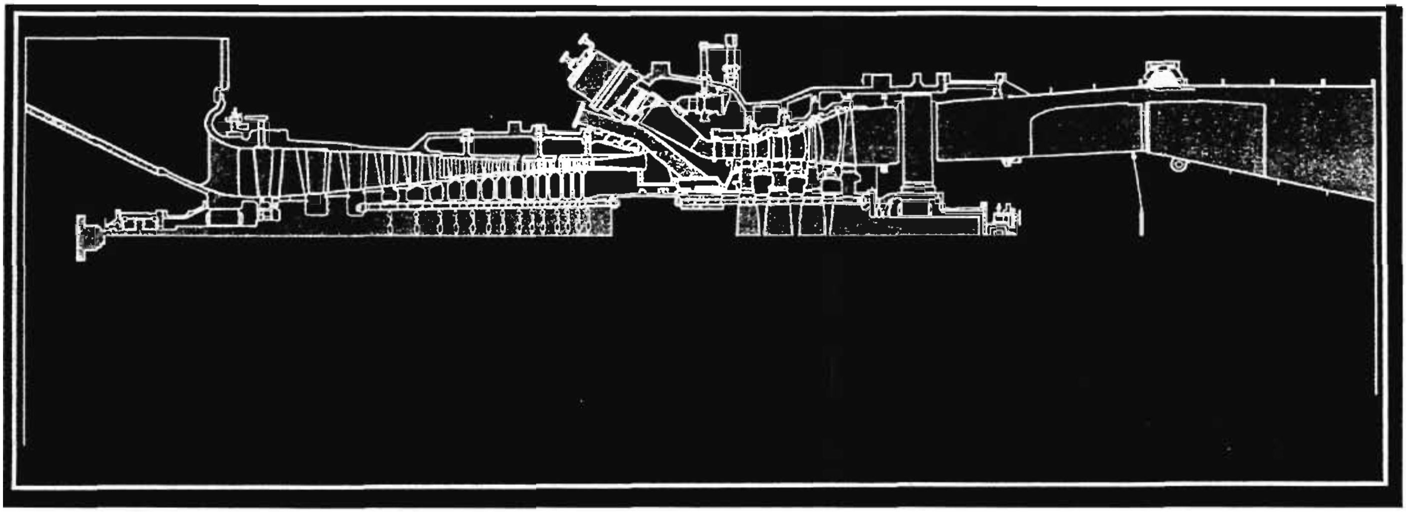


Figure 1. Sectional drawing of the new Westinghouse 501G gas turbine design

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-

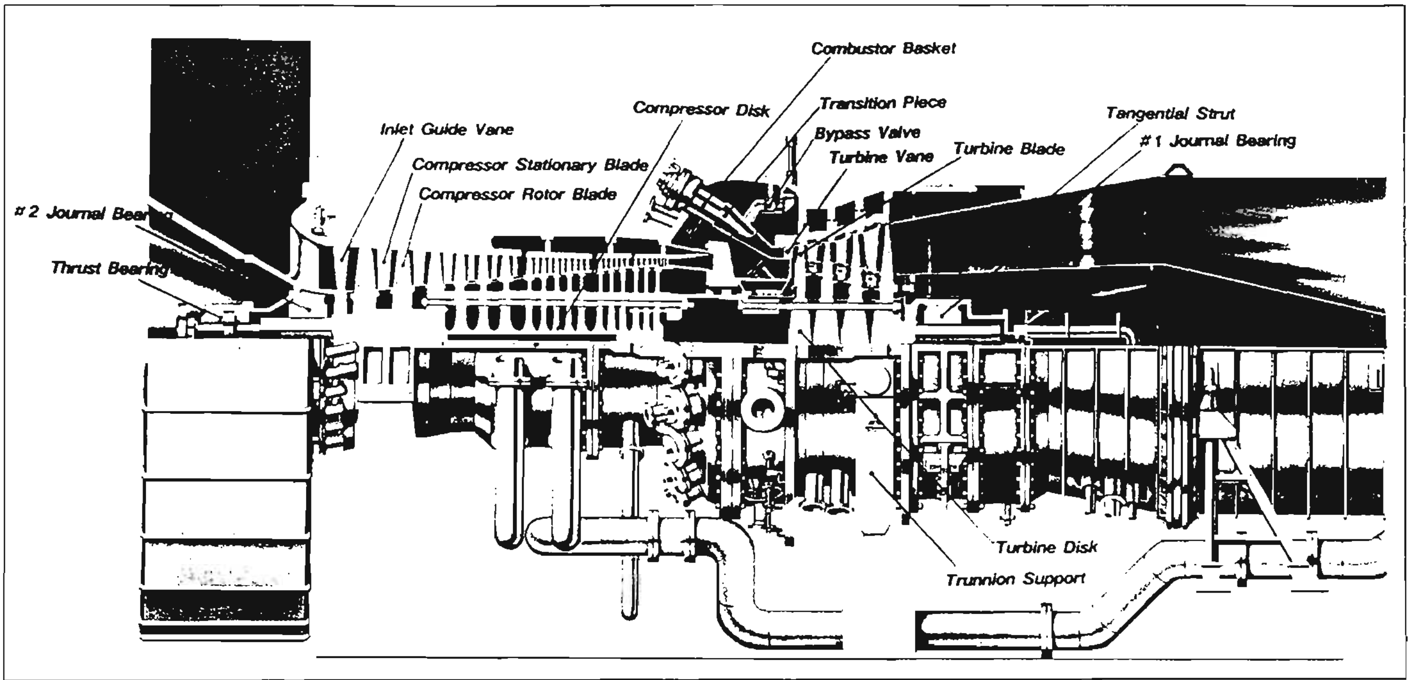


Figure 2. Section through the 701F gas turbine

Table 1. Main technical parameters of Westinghouse 'F' and 'G' machines (ISO base load)

MODEL	(Unit)	501D5	501F	501G (projected)	701F
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	4
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	(%)	48.59	53.1	58	52.9
Exhaust flow	(kg/s)	388	449.4	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

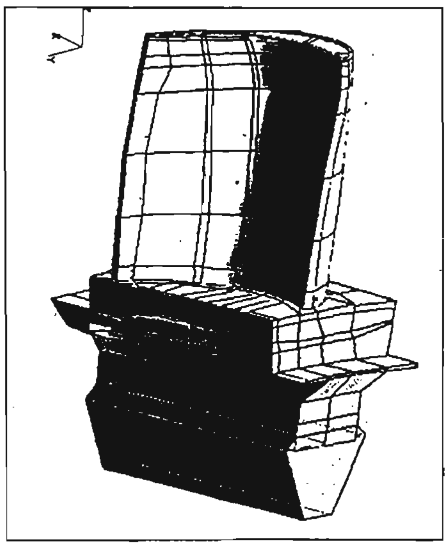


Figure 3. Row 1 turbine blade shape

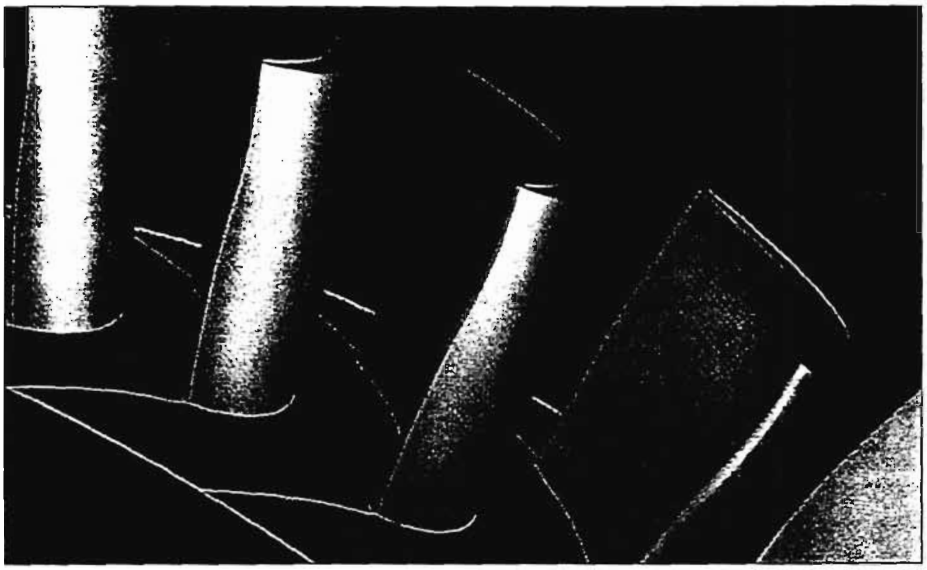


Figure 4. Three dimensional flow field for Row 1 turbine blade

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. □

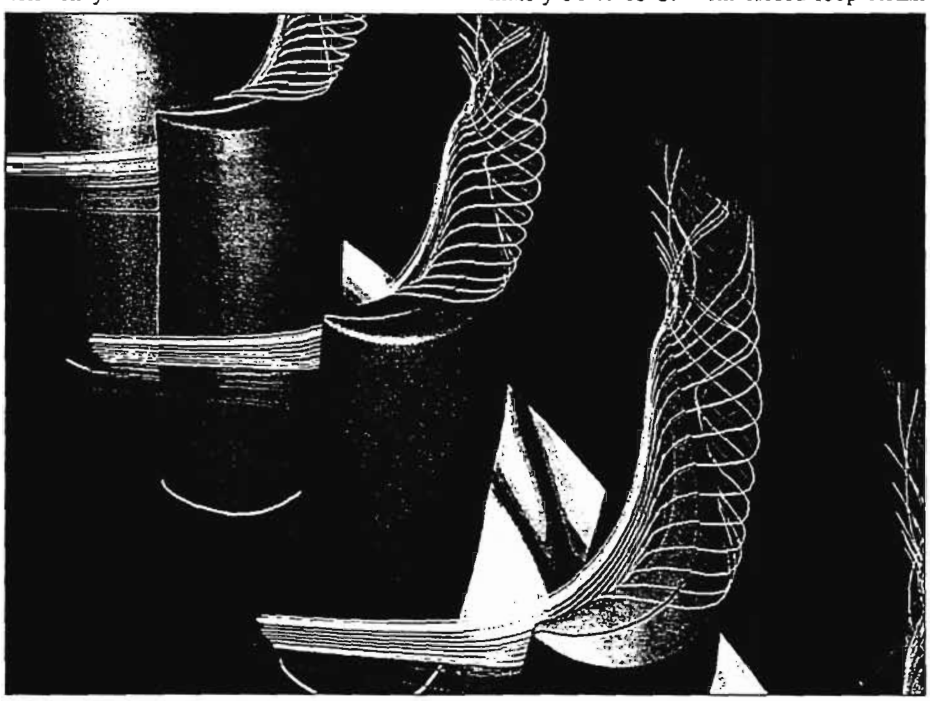


Figure 5. Particle streams — three dimensional flow field for Row 1 turbine blade

City of Lakeland - McIntosh Project

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Expected 501G Combustion Turbine Performance
Simple Cycle / Dry Low NOx Combustor
97x168 (45 psi) Hydrogen Cooled Generator (0.90 PF)

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	4,518,595	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
97x168 (45 psi) Hydrogen Cooled Generator (0.90 PF)

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SITE CONDITIONS:	CASE 1	CASE 2	CASE 3
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	5.6	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	188,540	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	3,749,389
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	4.08	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}, 0.16% 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
97x168 (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	9.68	8.61
NITROGEN	70.48	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	56.72	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, 2.481% C_2H_6, 0.38% 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.
- 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-1568C 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	93,830	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.

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)

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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	7.6
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/ft^3	0.0238	0.0246	0.0250
Exhaust Volumetric Flow, ft^3/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.

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-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	106,950	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	28.46	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.

501G APPLICATION OVERVIEW

501G Application Overview

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

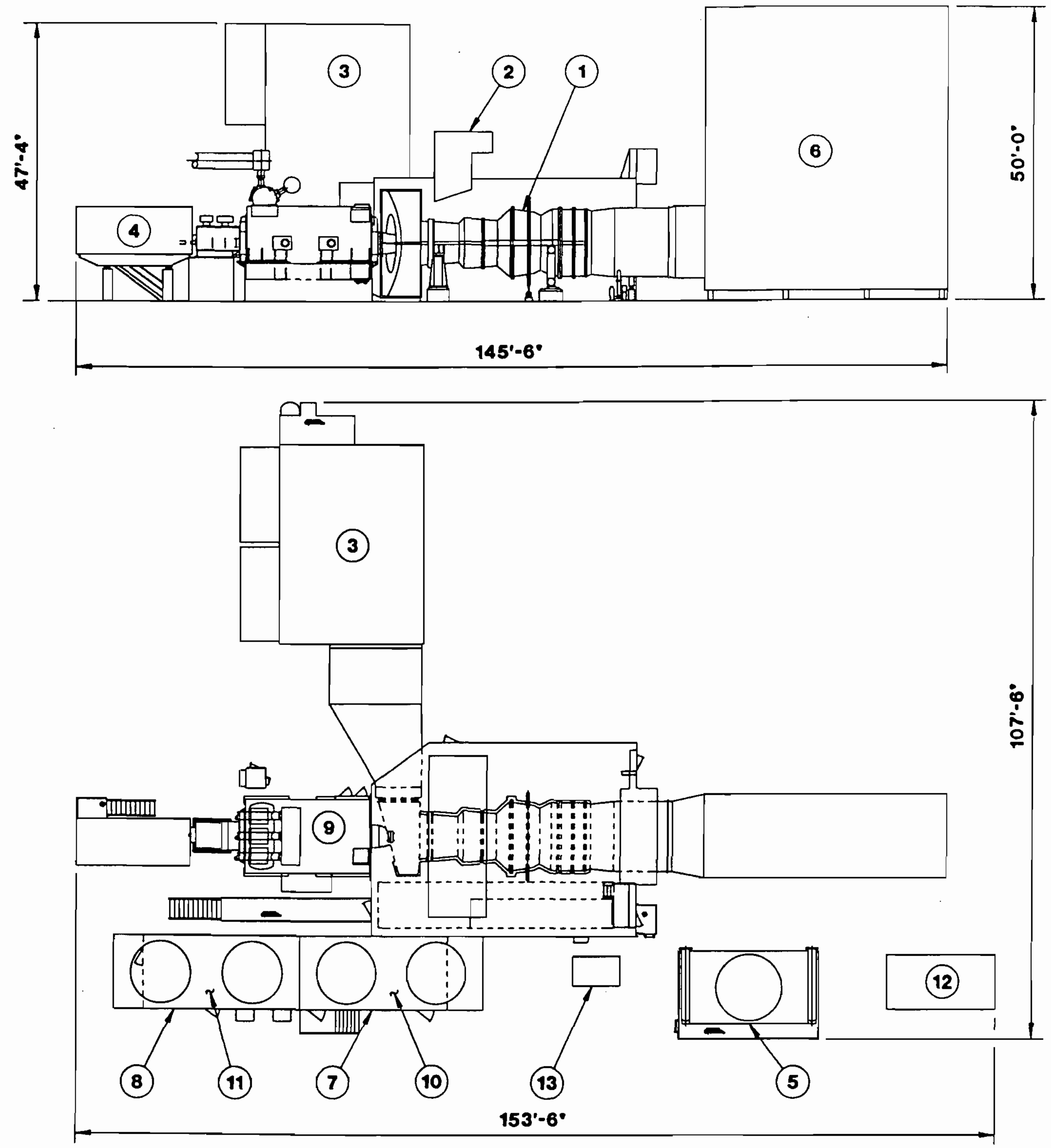
The auxiliary power transformer (optional) may be included as part of the ECONOPAC bill of material. The transformer can be located at any point in the system beyond the isolated phase bus.

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'_{dI}	31.3%
	X'_{qv}	43.8%
	X'_{qI}	49.8%
	X''_{dv}	22.8%
	X''_{dI}	24.8%
	X''_{qv}	22.6%
	X''_{qI}	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% CH_4 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.

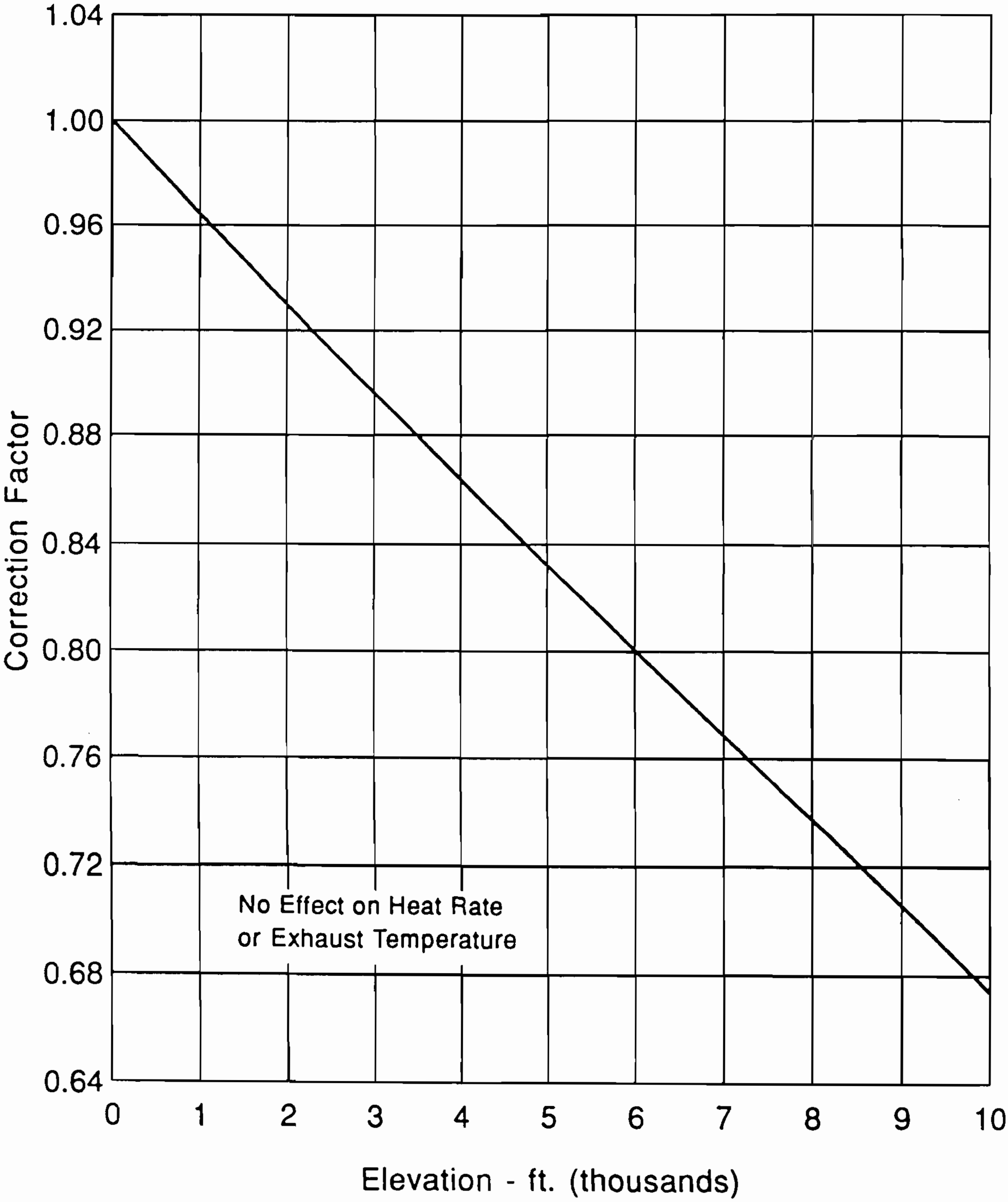
8. Performance Correction Curves

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



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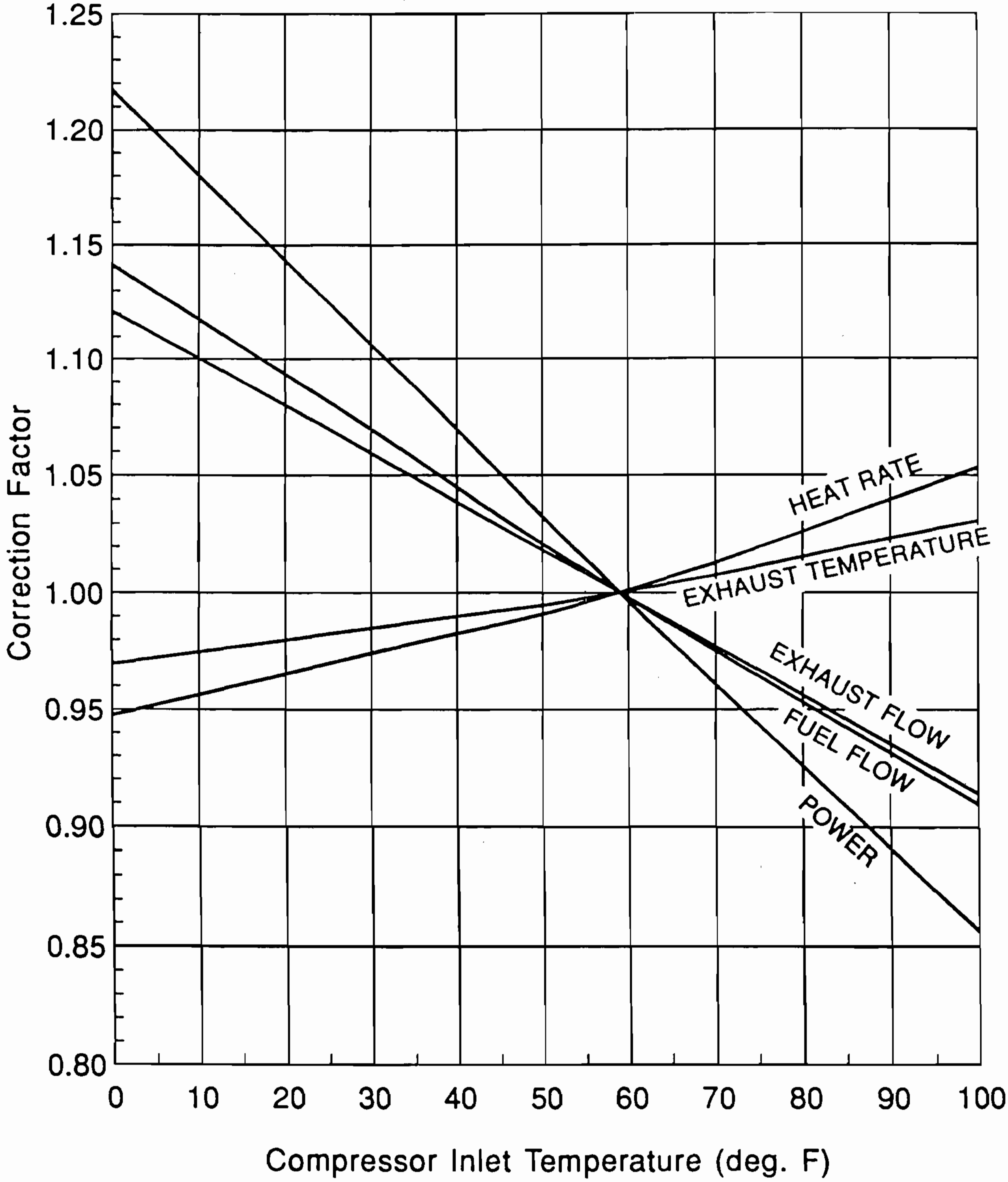
501G ECONOPAC SYSTEM PERFORMANCE

Exhaust Temperature and Correction to ISO Performance VS. Compressor Inlet Temperature



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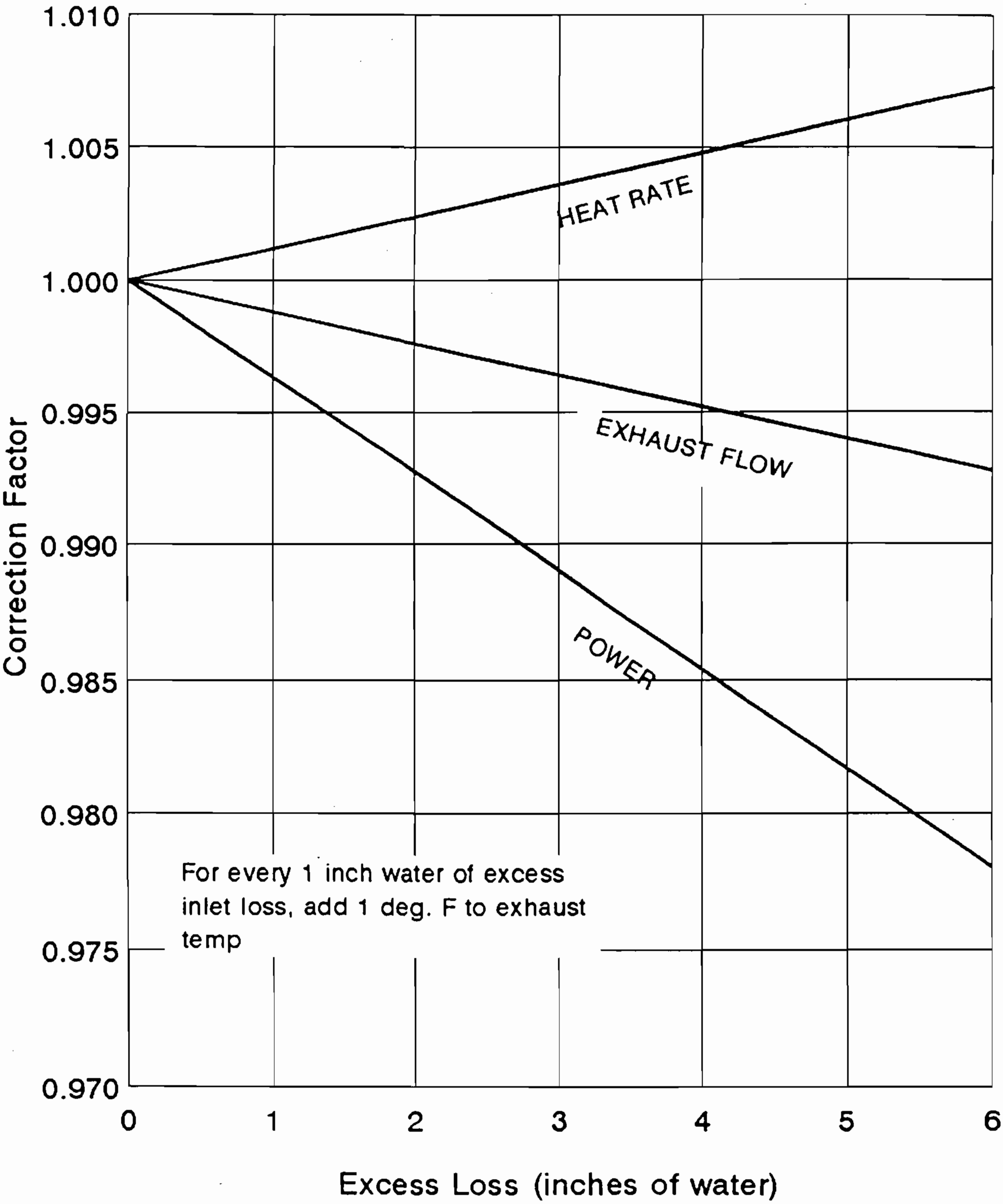
501G ECONOPAC SYSTEM PERFORMANCE
Correction to ISO Performance for Excess Inlet Loss



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06/21/94
Rev. 1

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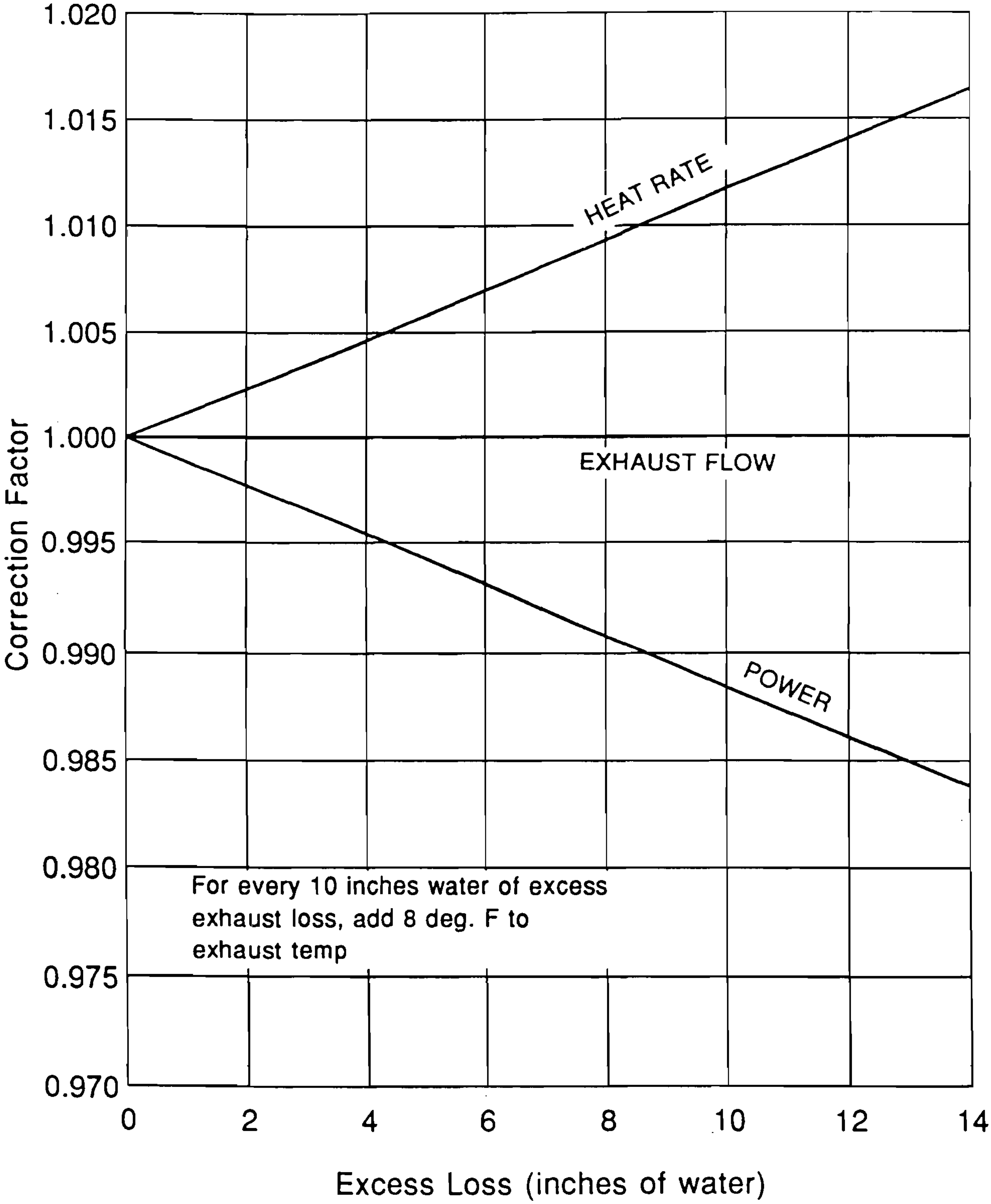
501G ECONOPAC SYSTEM PERFORMANCE

Correction to ISO Performance for Excess Exhaust Loss



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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:

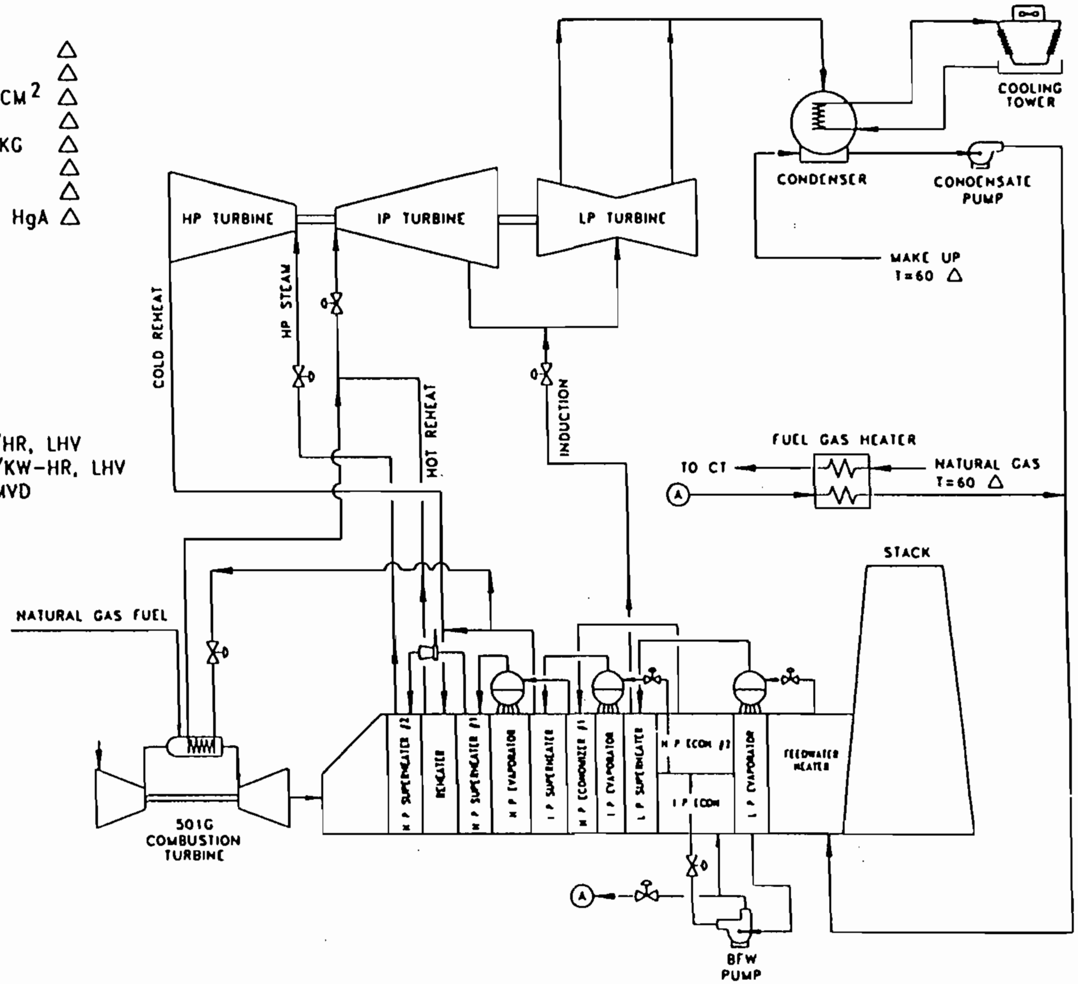
AMBIENT TEMPERATURE	59 °F	15 °C	△
RELATIVE HUMIDITY	60 %	60 %	△
BAROMETRIC PRESSURE	14.696 PSIA	1.033 KG/CM^2	△
FUEL TYPE	NATURAL GAS	NATURAL GAS	△
FUEL HEATING VALUE, LHV	21520 BTU/LB	50056 KJ/KG	△
GENERATOR POWER FACATOR	0.9	0.9	△
FUEL HHV/LHV	1.109	1.109	△
STEAM TURBINE BACKPRESSURE	1.5 in HgA	38.1 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 PROPRIETARY

WESTINGHOUSE 1X1 501G REFERENCE PLANT

DATE 01/03/95	DRAFTER L. MONROE
ENGINEER S C WILLIS S. Willis	
APPROVED BY T S BALDWIN	
PERF. LEVEL 1	CALC. 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 | ISSUE 05 | Page 1 of 1

OPERATING CONDITIONS:

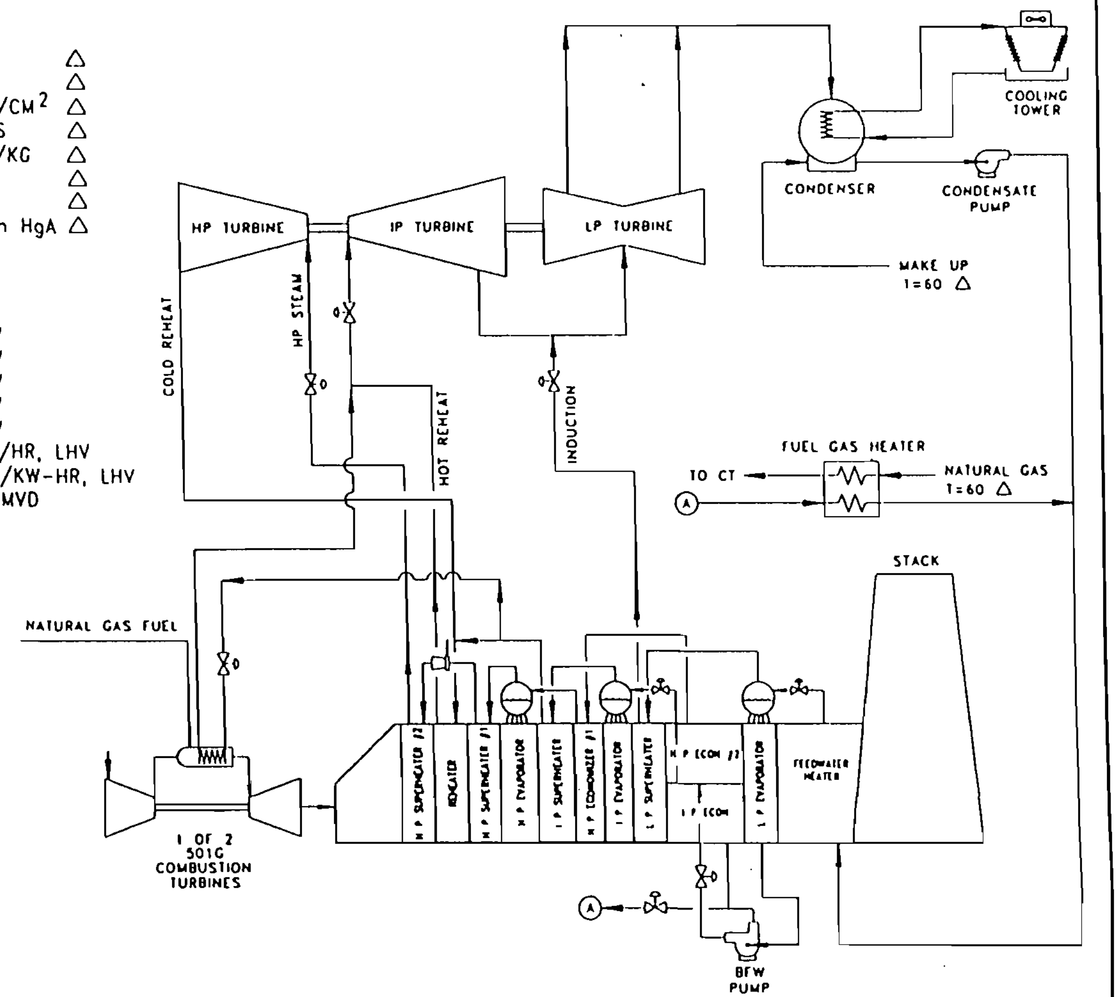
AMBIENT TEMPERATURE	59 °F	15 °C	△
RELATIVE HUMIDITY	60 %	60 %	△
BAROMETRIC PRESSURE	14.696 PSIA	1.033 KG/CM^2	△
FUEL TYPE	NATURAL GAS	NATURAL GAS	△
FUEL HEATING VALUE, LHV	21520 BTU/LB	50056 KJ/KG	△
GENERATOR POWER FACATOR	0.9	0.9	△
FUEL HHV/LHV	1.109	1.109	△
STEAM TURBINE BACKPRESSURE	1.5 in HgA	38.1 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
ENGINEER S C WILLIS	S. Willis
APPROVED BY T S BALDWIN	
PERF. LEVEL 1	CALC. CODE P
CUST NO. 94506	

Westinghouse Electric Corporation
Power Generation Projects Division

2X1 501G REHEAT COMBINED CYCLE
DRY LOW NOx COMBUSTORS
PLANT PERFORMANCE EST

Drawing No. HB2128.5 | 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.

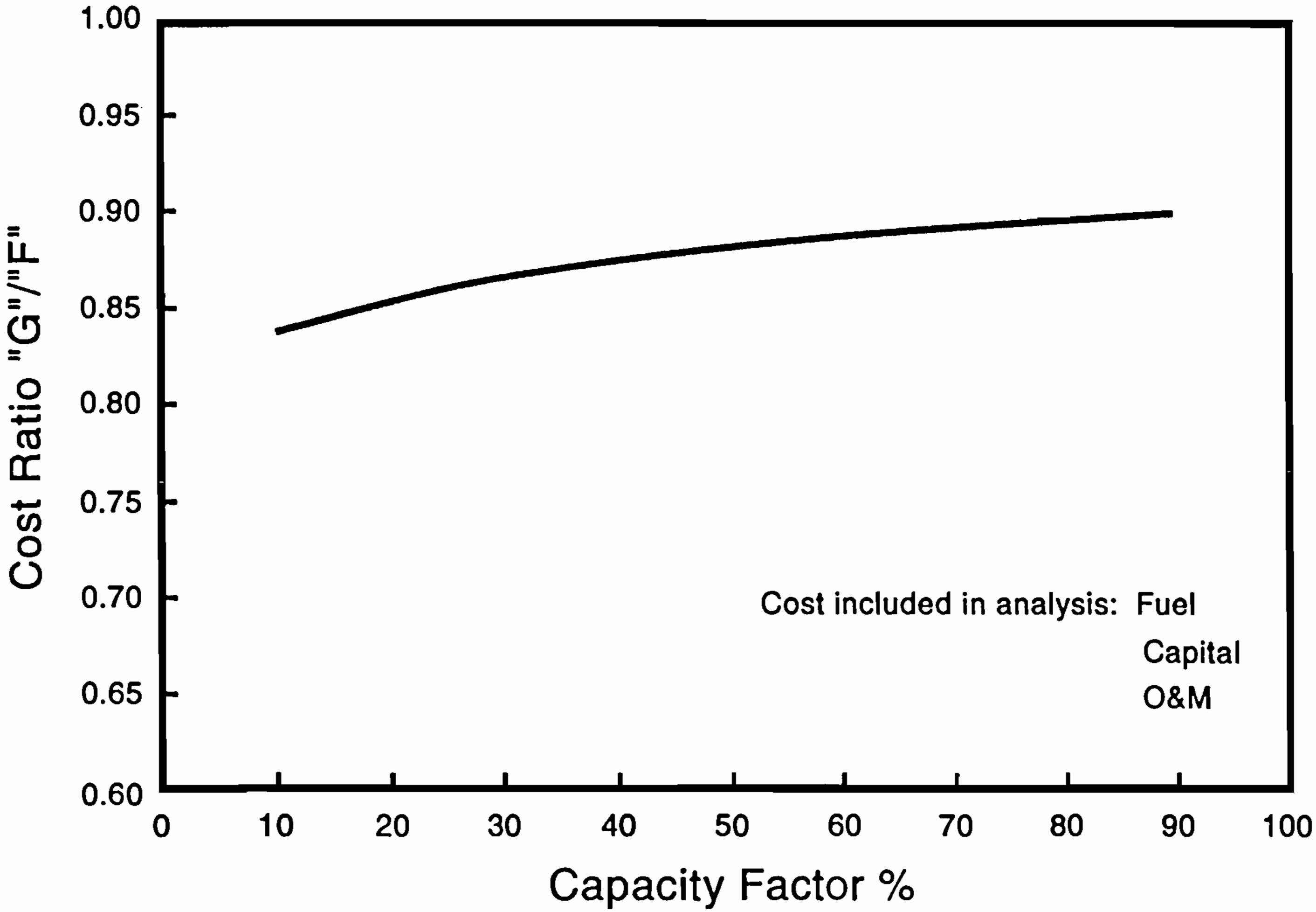
To achieve a pre-defined 20% IRR for 'F' technology, the selling price of electricity, including both capacity payment and energy payment, was varied. Then the 501G IRR was calculated using the same selling price of electricity. Some of the key financial assumptions, shown on a separate page, are conservative. 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



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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

32409.39L

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%

32409.50L

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.

Selective Catalytic Reduction (SCR)--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.

<u>NO_xOUT Process</u>--The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + \frac{1}{2} O_2 \dashrightarrow 2N_2 + CO_2 + 2H_2O$$

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.

<u>Thermal DeNO_x</u>--Thermal DeNO_x is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO_x requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications of Thermal DeNO_x are on 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.

Nonselective Catalytic Reduction--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.

Technology Determination--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 SCR Cost Estimates

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	916O 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 6.4 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	36.0 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	82.0 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

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, 87.4 LB/HR	no controls	0	BACT-OTHER
Orange Cogeneration Lp	FL	Dec-1993	Turbine, Natural Gas, 2	368 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	80	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	1815 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	926 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	56 MW	25.0 PPM @ 15% O2	combustion controls	83	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) (Naturel 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.	68	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	468 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	69.7 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	60	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

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)	1817 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)	1840 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 8	33 MW	25.0 PPM @ 15% O2	water injection	0	OTHER
Cimarron Chemical	CO	Mar-1991	Turbine #2, Ge Frame 8	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	85.0 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	87 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 8	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	21.8 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	21.8 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 Pglm 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	80	BACT
Union Oil Co. Of California	AK	Aug-1989	Turbine, Gtm 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 Setum, 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	85.0 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	418 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 8	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	8000 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 8	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	36.0 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	18 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	18.3 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 Burnar	72 MMBTU/H	42.0 PPM @ 15% O2 GAS	water injection	0	BACT-PSD
Baf Energy	CA	Jul-1987	Turbine, Generator	887 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 8, 3 Ea	40 MW	9.8 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	380 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, 8	4900 HP	115.0 PPMVD AT 15% O2	dry controls	0	BACT-PSD
Arco Alaska Kuparuk Central Prod. Fac. #3	AK	Nov-1988	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	418 MMBTU/H	125.0 PPMV	scr	71	BACT-PSD
Wichita Falls Energy Investments, Inc.	TX	Jun-1986	Turbine, Gas, 3 Ea	20 MW	884.0 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	185.4 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	80	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 Coalwater 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	85	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	1.8 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

Table B-4. Annualized Cost for Selective Catalytic Reduction for 501G Project; Simple Cycle Operation Only

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	372.46	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 16 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	27.8 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 V84.3 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

Table B-5. Summary of BACT Determinations for CO.

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)	2.8 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	1850 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	78.0 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)	850 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	475.8 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	80.0 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	87 MW	15.0 PPM @ 15% O2	co catalyst	80	BACT-PSD

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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	36.0 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	418 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	0.8 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	416 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	38 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	185.0 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 practicas	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	1338 MMBTU/H	125.0 LB/H	combustion controls	0	BACT-PSD
Gulf States Utility	LA	Jan-1981	Turbine, Combustion, 2	1338 MMBTU/H	218.0 LB/H	combustion controls	0	BACT-PSD
Florida Power	FL	Jan-1981	Turbine Peaking Units, 4 Ea	63 MW	86.0 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

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
Diirect 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

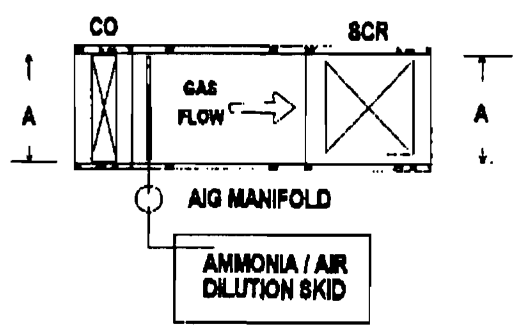
ENGELHARD

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.

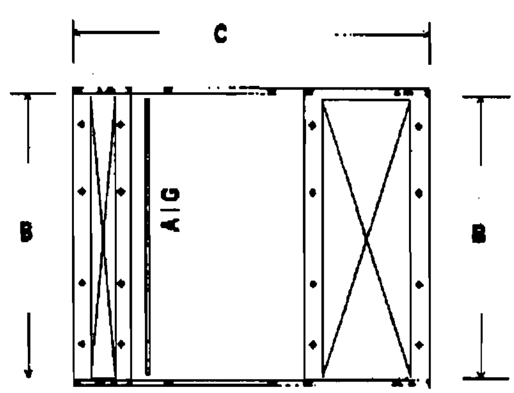
- Engelhard CAMET® CO metal substrate catalyst modules;
- Engelhard NOxCAT™ ZNX™ SCR catalyst modules;
- Internal support structures for catalyst modules; includes all hardware and gaskets for catalyst module installation;
- Internally insulated Ductwork with stainless steel liner to house CO catalyst, 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"



AFFIDAVIT OF PUBLICATION

THE LEDGER

Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared Nelson Kirkland, who on oath says that he is Classified Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

Public Notice Of Intent

in the matter of

DEP File No. 1050004-002AC (PSD-FL-245)

in the

Court, was published in said newspaper in the issues of

April 23;

1998

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed ....
Nelson Kirkland
Classified Advertising Manager
By Nelson Kirkland who is personally known to me

Sworn to and subscribed before me this 27TH
day of APRIL A.D. 19 98

(Seal) Donald Ray Jenkins
Notary Public

DONALD RAY JENKINS
MY COMMISSION # CC 586345
EXPIRES: September 18, 2000
Bonded Thru Notary Public Underwriters

My Commission Expires

Order#693059
S Jones B447

Attach Notice Here

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050004-002AC (PSD-FL-245)

City of Lakeland Electric and Water Utilities Department
C.D. McIntosh, Jr. Power Plant - Unit No. 5.
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to The City of Lakeland Electric & Water Utilities Department. The permit is to construct a 250 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine with a once-through steam generator, a 1.05 million gallon fuel oil storage tank, and a new 85-foot stack at the C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), volatile organic compounds (VOC) and carbon monoxide (CO) pursuant to Rules 62-212.400 and 410, F.A.C. and 40 CFR 52.21. The applicant's name and address are The City of Lakeland Electric and Water Utilities Department, 501 East Lemon Street, Lakeland, Florida 33801-5079.

The new unit is a Westinghouse 501 G, 250 MW turbine which will operate in simple cycle mode as a continuous duty unit. It will be the largest and most efficient simple cycle gas turbine installed in the United States to-date. The unit will operate primarily on natural gas and will be permitted to operate 7008 hours per year of which no more than 250 will be on 0.05 percent sulfur distillate fuel oil.

During the first three years of operation, NO_x emissions will be controlled by "Advanced Dry Low NO_x" technology combustors capable of achieving emissions of 25 parts per million by volume at 15 percent oxygen (ppm @15% O_2). "Ultra Low NO_x" technology consisting of Piloted Ring Combustors is under development to achieve a limit of 9 ppm @15% O_2 (12 ppm averaged over 30 days) three years after start-up. Emissions of NO_x will be controlled under the minimal back-up fuel oil operation by water injection. SO_2 and PM/PM_{10} will be limited by use of clean fuels. Emissions of VOC will be controlled by good combustion practices. Emissions of CO will be similarly controlled unless the City chooses to install an oxidation catalyst.

The maximum potential annual emissions in tons per year based on the original application are summarized below. NO_x emissions will be reduced by over half after installation of the Ultra Low NO_x combustors. CO emissions will also be substantially lower as a result of the Department's BACT determination.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM10	41	25/15
SO_2	38	40
NO_x	863	40
VOC	93	40
CO	1264	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the Department shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

The Department will issue FINAL Permit with the conditions of the DRAFT Permit unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth below. Mediation is not available for the proposed action.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9370, fax: 904/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the Department's action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection	Florida Department of Environmental Protection	City of Lakeland Electric and Water Utilities
Bureau of Air Regulation	Southwest District Office	Attention: Ms. Farzie Shelton
111 S. Magnolia Drive, Suite 4	3804 Coconut Drive	501 East Lemon Street
Tallahassee, Florida, 32301	Tampa, Florida 33619-8218	Lakeland, Florida 33801-5079
Telephone: (850) 488-1344	Telephone: (813) 744-6100	Telephone: (941) 499-6603
Fax: (850) 922-6979	Fax: (813) 744-6084	Fax: (941) 603-6335

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 904/488-1344, for additional information.
B-447 - 4-23; 1998

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of application for Permit Modification by:

Mr. Ronald W. Tomlin, Assistant Managing Director
City of Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079
______________________________/

DEP File No. 1050004-004AC
Permit No. PSD-FL-245
C.D. McIntosh, Jr. Power Plant, Unit No. 5
Polk County

Enclosed is the Final Permit Number PSD-FL-245 to construct a 250 megawatt simple cycle combustion turbine with a once-through heat generator and a 1.05 million gallon fuel oil storage tank at the C.D. McIntosh, Jr. Power Plant, located at 3030 East Lake Parker Drive, Lakeland, Polk County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

A A Linero, P.E.
for C.H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7/10/98 to the person(s) listed:

Mr. Ronald W. Tomlin, City of Lakeland *
Ms. Farzie Shelton, City of Lakeland
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Bill Thomas, SWD
Mr. Buck Oven, DEP
Mr. Ken Kosky, P.E., Golder Associates
Mr. Joe King, Polk County

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 7/10/98
(Clerk) (Date)

P 265 659 386

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Mr. Ronald W. Tomlin	
Street & Number 501 E. Lemon St.	
Post Office, State, & ZIP Code Lakeland Fl. 33801	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 7-10-98 1050004-004 AC PSD-Fl-245	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Ronald W. Tomlin
501 E. Lemon St.
Lakeland Fl. 33801-5079

4a. Article Number
P 265 659 386

4b. Service Type
☐ Registered ☑ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
JUL 15 1998

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Gina M. Walker

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

Florida Department of
Environmental Protection

Memorandum

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ronald W. Tomlin
Lakeland Electric + Water
501 E. Lemon Street
Lakeland, Fl 33801-5079

4a. Article Number
P 265 659 340

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
APR 30 1998

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Bonnie Brown

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 340

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Ronald Tomlin	
Street & Number Lakeland Electric	
Post Office, State, & ZIP Code + Water	
Postage Lakeland, Fl	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	

PS Form **3800**, April 1995

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

April 22, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric and Water Utilities Department
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
250 Megawatt Combustion Turbine

Dear Mr. Tomlin:

Enclosed is one copy of the Draft Air Construction Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the referenced project at the C. D. McIntosh, Jr Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. The Department's Intent to Issue Air Construction Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" must be published within 30 (thirty) days of receipt of this letter. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit modification.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please call Ms. Teresa Heron at 850/921-9529 or Mr. Linero at 850/921-9523.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/aal

Enclosures

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ronald W. Jonlin
Assistant Managing Director
Lakeland Electric & Water U.D.
501 E. Lemon St.
Lakeland, Fl 33801-5079

4a. Article Number
P 265 659 339

4b. Service Type
☐ Registered ☑ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
MAY 1 1998

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Bonnie Pitt

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 339

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	Ronald Jonlin
Street & Number	Lakeland Electric
Post Office, State, & ZIP Code	& Water
Postage	Lakeland, Fl $
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	4-24-98 1050004-002-AC

PS Form **3800**, April 1995

Memorandum

Florida Department of
Environmental Protection

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
MR. RONALD TOMLIN
LAKELAND ELECTRIC + WATER
501. E. LEMON ST
LAKELAND, FL 33801-5079

4a. Article Number
P265 659 327

4b. Service Type
☐ Registered ☐ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
4-6-98

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X Bonnie Bren

8. Addressee's Address *(Only if requested and fee is paid)*

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 327

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to RONALD TOMLIN	
Street & Number LAKELAND ELECTRIC	
Post Office, State, & ZIP Code + WATER	
Postage LAKELAND	$, FL
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$ 4-3-98
Postmark or Date 10 5004-004-AC PSD-FL-245	

PS Form **3800**, April 1995

[redacted]

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ronald W. Jomlin
Assistant Managing Dir
Lakeland Electric & Water
501 E. Lemon St.
Lakeland, Fl 33801-5079

4a. Article Number
P 265 659 304

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
3-12-98

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X [signature]

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 304

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Ronald Jomlin	
Street & Number Lakeland Electric	
Post Office, State, & ZIP Code & Water	
Postage Lakeland, Fl	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 3-10-98	

1050004-004-AC
PSD-FL-245

PS Form **3800**, April 1995

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

January 12, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-004-AC (PSD-FL-245)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

Attached are the comments we received by Fax from the Air Quality Branch of the Fish and Wildlife Service. We will send you a copy of the signed version when we receive it. Please note their comments regarding the proposed Best Available Control Technology (BACT) nitrogen oxides (NO_X)emission limit of 25 ppm. They also have requested some additional modeling which would might not be necessary if the emissions were lower.

We have reviewed the BACT information in the application in more detail. It appears that it would not be necessary to write off high temperature SCR (installed at start-up) if and when a heat recovery steam generator (HRSG) were installed in the future. Therefore additional costs of future Dry Low-NO_X (DLN) technology and/or low temperature SCR do not need to be summed into the long term cost of pollution control by hot SCR.

High temperature SCR could be installed by start-up. Westinghouse would not then need to attempt to refine its DLN technology (for this project) to achieve lower NO_X emissions at higher temperature and pressure ratios under such challenges as pressure pulsation and lower flame stability. Low temperature SCR might not need to be installed later. In fact, HRSG operation would likely be simplified by one-piece construction instead of having separate components with a low temperature SCR module in-between. This approach would allow the City to proceed with the planned staged project, satisfy BACT requirements for NO_X, and defer the decision on installation of a HRSG until a future date consistent with the PSD application.

We are still awaiting comments from EPA If you have any questions regarding this matter, please contact Teresa Heron (review engineer) or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A A Linero 1/12

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/aal

Attachment

cc: Brian Beals, EPA
John Bunyak, NPS
Bill Thomas, SWD
Joe King, Polk County
Farzie Shelton, City of Lakeland
Ken Kosky, Golder Associates

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water
501 E. Lemon St.
Lakeland, Fl
33801-5079

4a. Article Number
P 265 659 279

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
1-14-98

5. Received By: *(Print Name)*
Diane Mullis

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Diane Mullis

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 279

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Ronald Tomlin	
Street & Number Lakeland Electric	
Post Office, State, & ZIP Code Lakeland Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 1-12-98	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ronald W. Tomlin, AMD
Lakeland Electric & Water
501 E. Lemon St.
Lakeland, Fl
33801-5079

4a. Article Number
P 265 659 276

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
1-7-98

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Bonnie Brown

PS Form **3811,** December 1994 Domestic Return Receipt

Thank you for using Return Receipt Service.

P 265 659 276

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	Ronald Tomlin
Street & Number	Lakeland Electric
Post Office, State, & ZIP Code	& Water
Postage	Lakeland, Fl $
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	1-5-97 1050004-004-AC PSD-Fl-245

PS Form **3800**, April 1995

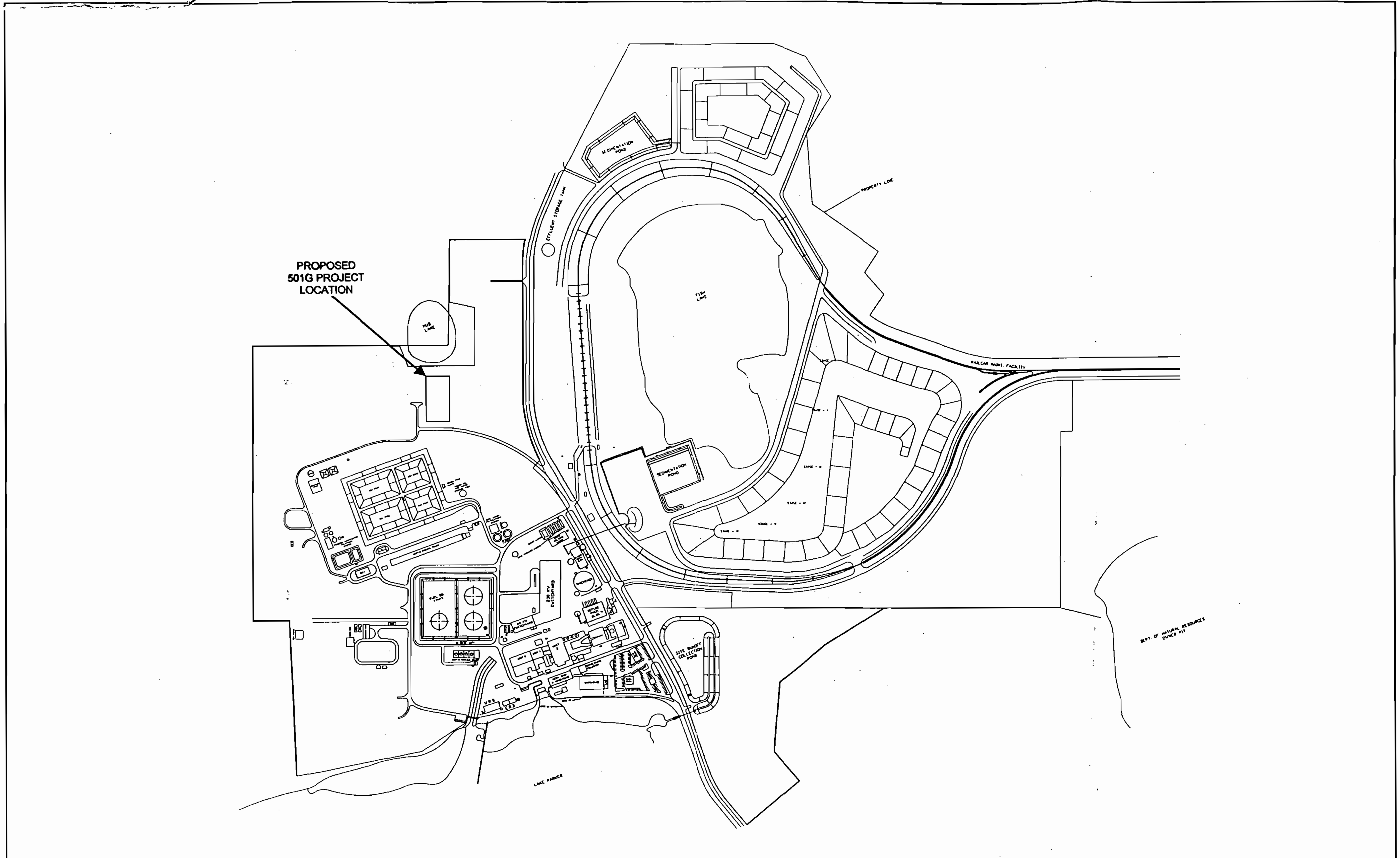


Figure 2-1
McIntosh Plant Boundary and Adjacent Properties

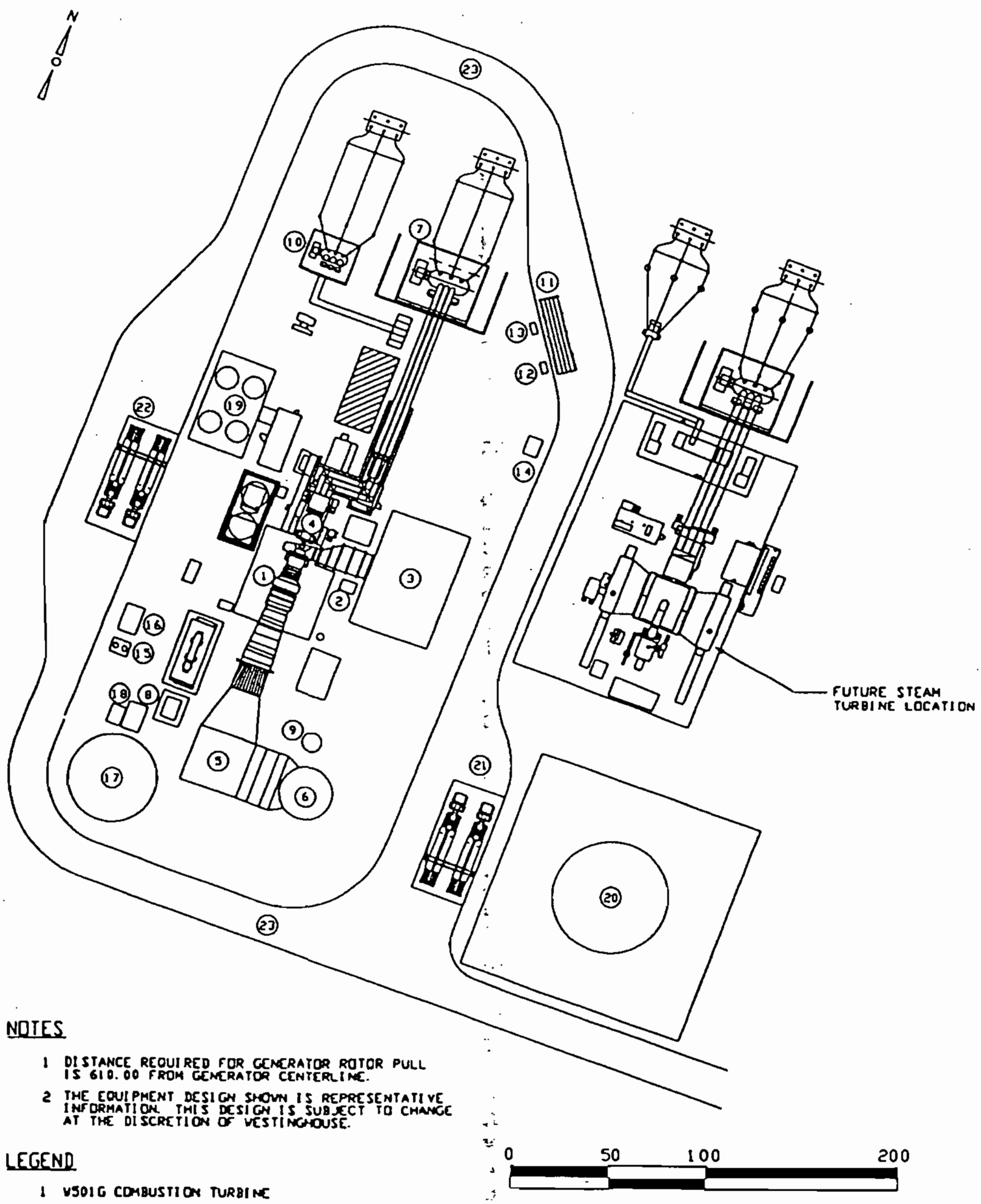
Source: City of Lakeland, 1997; Golder, 1997.

Process Area: Plant Site Map

Filename: 9737594C/FIGURES2.VSD (#1)

Latest Revision Date: 11/25/97

Golder Associates



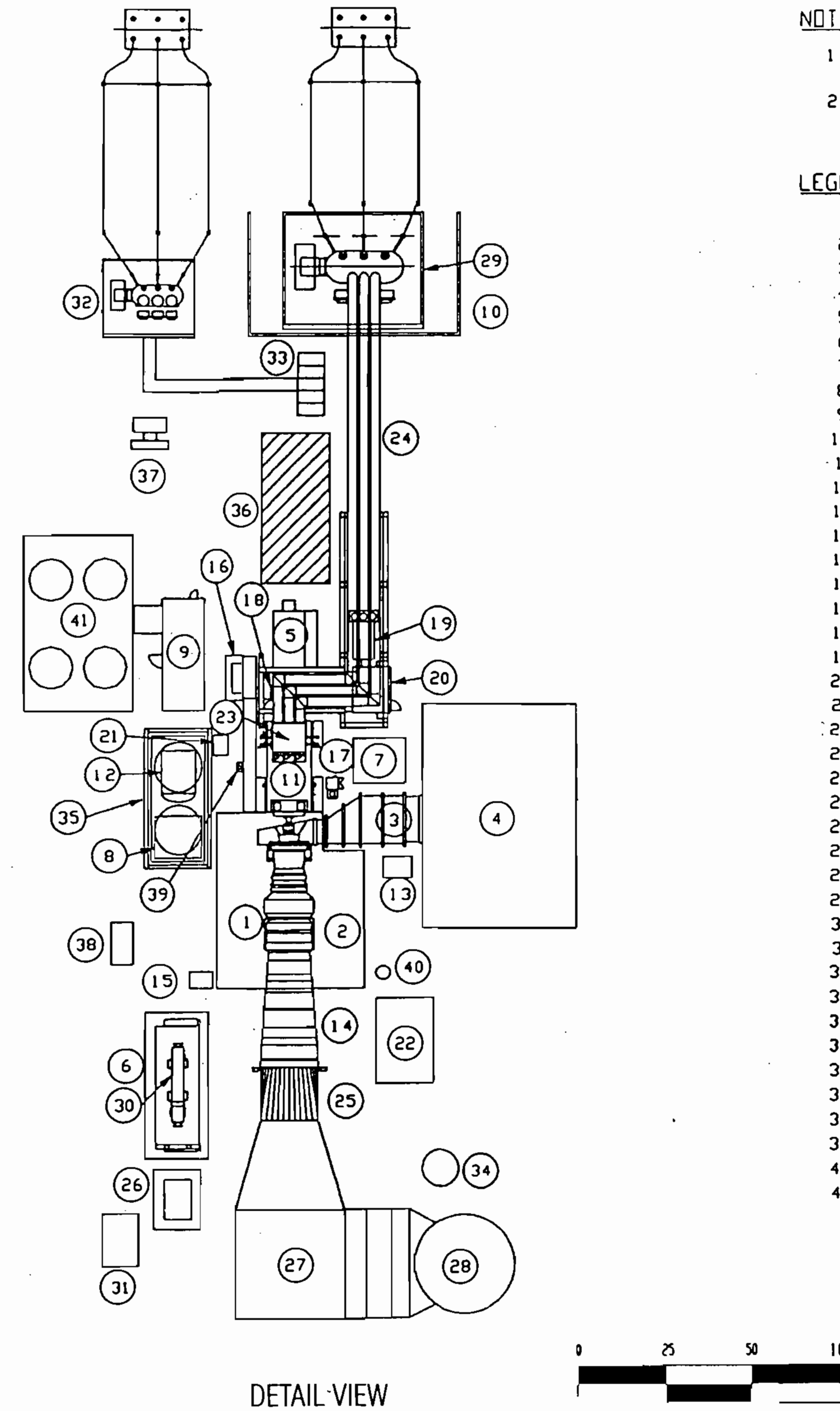
NOTES

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.

LEGEND

1 W501G COMBUSTION TURBINE
2 COMBUSTION TURBINE ENCLOSURE
3 TURBINE AIR INLET FILTER
4 GENERATOR (HYDROGEN COOLED)
5 OTSG
6 OTSG STACK
7 MAIN STEP-UP TRANSFORMER
8 BOILER FEED PUMPS
9 FLASH TANK
10 AUXILLIARY TRANSFORMER
11 HYDROGEN TUBE TRAILER PARKING
12 HYDROGEN VALVE MANIFOLD
13 NITROGEN VALVE MANIFOLD
14 CO2 CYLINDER STORAGE
15 OILY WATER SEPARATOR
16 OILY WATER SEPARATOR EFFLUENT FILTER
17 DEMINERALIZED WATER STORAGE (450,000 GALLON)
18 DEMINERALIZED WATER FORWARDING PUMPS
19 GENERATOR GLYCOL COOLER
20 FUEL OIL STORAGE TANK (1.05 MIL. GALS.)
21 FUEL UNLOADING AREA
22 DEMINERALIZED WATER TRAILER PARKING
23 ROAD



DETAIL VIEW

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.

LEGEND

1 W501G COMBUSTION TURBINE
2 COMBUSTION TURBINE ENCLOSURE
3 TURBINE AIR INLET AND SILENCER
4 TURBINE AIR INLET FILTER
5 STARTING PACKAGE
6 ROTOR AIR COOLER (AIR/AIR)
7 GENERATOR SEAL OIL SKID
8 LUBE OIL PUMP SKID
9 ELECTRICAL PACKAGE
10 TRANSFORMER FIRE WALL
11 GENERATOR (HYDROGEN COOLED)
12 LUBE OIL RESERVOIR
13 HYDRAULIC SKID
14 TURBINE EXHAUST MANIFOLD
15 COMPRESSOR WASH SKID
16 GENERATOR AUXILIARY CONTROL PANEL
17 NEUTRAL GROUNDING CUBICLE
18 COLLECTOR (BELOW ISOPHASE BUS)
19 EXCITATION TRANSFORMER (BELOW ISOPHASE BUS)
20 EXCITATION SKID (BELOW ISOPHASE BUS)
21 INSTRUMENT AIR COMPRESSOR
22 FUEL OIL PUMP & FO/WI SKID
23 GENERATOR MAIN & NEUTRAL LEAD ENCLOSURE
24 ISOPHASE BUS
25 EXHAUST TRANSITION
26 STAGE TWO AIR COOLER
27 OTSG
28 OTSG STACK
29 MAIN STEP-UP TRANSFORMER
30 ROTOR AIR RECUPERATOR (GAS PREHEATER)
31 BOILER FEED PUMPS
32 AUXILIARY TRANSFORMER
33 MEDIUM VOLTAGE MOTOR STARTERS AND SWITCHGEARS
34 FLASH TANK
35 LUBE OIL COOLER (FIN-FAN)
36 GENERATOR MAINTENANCE AREA
37 LOW VOLTAGE TRANSFORMER AND BREAKER
38 FALSE START DRAIN TANK
39 GENERATOR SEAL OIL VAPOR SKID
40 FUEL GAS FILTER/SEPARATOR
41 GENERATOR GLYCOL COOLER

PRELIMINARY

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

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

December 9, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ronald W. Tomlin
Assistant Managing Director
Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-008-AC (PSD-FL-245C)
McIntosh Unit No. 5 Combustion Turbine

Dear Mr. Tomlin:

The Department reviewed your letter to EPA dated September 16, 1999 requesting extension of the deadline to demonstrate compliance with 40CFR60 Subpart GG, "Standards of Performance for New Stationary Gas Turbines" and EPA's response dated October 18, 1999. It is our understanding that the unit has not operated since July and is under inspection, modification and re-assembly. The Department hereby modifies the referenced permit as follows:

SPECIFIC CONDITION 29

FROM:

Compliance with the allowable emission limiting standards shall be determined for applicable New Source Performance Standards in accordance with the most recent approved EPA schedule Compliance shall be determined by February 15, 2000 for all other emissions limits, for gas-firing and not later than 90 days after the first oil firing that occurs after October 14, 1999 for oil firing. Initial and subsequent annual compliance shall be demonstrated as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C. Emission limits compliance dates shall conform to the timetable specified on Specific Condition No. 20. **[EPA Region IV. Initial Performance Test Schedule – Unit 5. March 22, 1999]**

TO:

Compliance with the allowable emission limiting standards shall be determined for applicable New Source Performance Standards in accordance with the most recent approved EPA schedule. Initial compliance with all other applicable emission limiting standards shall be determined concurrently with the demonstration of compliance with the New Source Performance Standards with the exception that compliance with emissions limits applicable to fuel oil firing shall be determined not later than 90 days after the first oil firing that occurs after December 8, 1999. Initial and subsequent annual compliance shall be demonstrated as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C. Emission limits compliance dates shall conform to the timetable specified on Specific Condition No. 20. **[EPA Region IV. Initial Performance Test Extension – Unit 5. October 18, 1999]**

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

Any party to this permitting decision (order) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12/13/99 to the person(s) listed:

Ronald W. Tomlin, City of Lakeland*
Farzie Shelton, City of Lakeland
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Hamilton Oven DEP PPSO

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 12/13/99
(Clerk) (Date)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

OCT 1 8 1999

4APT-ARB

Mr. Howard L. Rhodes, Director
Department of Environmental Protection
Division of Air Resources Management
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Initial Performance Test Extension Request for Unit No. 5 at the Lakeland Electric McIntosh Power Plant, Lakeland, Florida

Dear Mr. Rhodes:

The purpose of this letter is to provide you with comments regarding an initial performance test extension that Lakeland Electric requested for the referenced combustion turbine (CT) which is subject to 40 C.F.R. Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines). According to a September 16, 1999, letter that Lakeland Electric sent to the Environmental Protection Agency (EPA), Region 4 and to the Florida Department of Environmental Protection, Unit No. 5 started up on April 14, 1999. Based upon this startup date, the deadline for conducting an initial performance test on this CT would be October 11, 1999 (i.e., no later than 180 days after startup). As a result of serious damage that occurred to the unit during operational testing that was conducted following its startup, Unit No. 5 has been shutdown for repairs since July 30, 1999, and Lakeland Electric does not anticipate restarting the unit before mid-November. Therefore, it will be impossible to conduct the initial performance test by the applicable deadline, and Lakeland Utilities has requested an extension of the deadline for conducting its initial test. Specifically, the company has requested that the deadline for testing be extended until 60 days following the restart of the unit, and based upon our review of the relevant facts, we have concluded that the proposed testing extension is reasonable.

The EPA has previously granted initial testing extensions to owners and operators of facilities that could not be tested by the deadlines in 40 C.F.R. §60.8(a) due to mechanical breakdowns that prevented them from operating. In all of the previous determinations that we are aware of, companies were allowed to delay their initial performance test until 30 days after the facility resumed operation following the completion of repairs made to correct the mechanical breakdown(s) that prevented the company from completing the test by the applicable deadline. Although Lakeland Electric has requested a longer initial testing extension than EPA has granted in the past, we have concluded that allowing this additional time to complete the testing at Lakeland Electric is justified due to the nature of the repairs and modifications the company will have to make to Unit No. 5 before it can be restarted.

According to the September16, 1999, letter from Lakeland Electric, Unit No. 5 is the first Westinghouse 501G turbine to be built. Due to its large size (250 Megawatts) it had to be assembled onsite, and this prevented it from being factory tested prior to its installation at Plant McIntosh. During the operational testing period earlier this year, vibration problems damaged turbine equipment on two occasions, and on the second occasion, multiple components were affected when part of a broken compressor diaphragm passed through the unit and damaged other downstream equipment. In addition to redesigning and testing new equipment to correct the vibration problems that caused this damage, Lakeland Electric is also in the process of replacing fuel gas control valves that did not work properly during the previous startup testing.

When equipment failures prevent the owner or operator of an affected facility from completing an initial performance test by the deadline established in 40 C.F.R. §60.8(a) extending the deadline for initial testing until 30 days following the restart of the facility provides sufficient time to complete the testing if the repairs made prior to restarting the unit do not affect its operating characteristics significantly. In the case of Unit No. 5 at Plant McIntosh, however, a substantial number of equipment changes are being made, and much of the operational testing conducted by Lakeland Electric prior to the shutdown of the unit will probably have to be repeated before the unit can be safely run across its entire range of operation. Since the amount of operational testing that will have to be conducted when the unit restarts may be comparable to that which would have to be conducted on an entirely new unit, we have concluded that Lakeland Electric's request that the deadline for conducting an initial performance test on Unit No. 5 be extended until 60 days following the restart of the unit is reasonable.

If you have any questions about the issues addressed in this letter, please contact Mr. David McNeal of the Region 4 staff at (404) 562-9102.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: Mr. Clair Fancy, FL DEP
Mr. Hamilton Oven, FL DEP
Mr. Al Linero, FL DEP
Mr. Michael Harley, FL DEP