Progress Energy

March 2, 2005

RECEIVED
MAR 03 2005
BUREAU OF AIR REGULATION

Mr. Michael Halpin, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Re: **Hines Energy Complex - Power Block 4**
PSD/Air Construction Permit Application
File No. 1050234-010-AC
Comments on Draft Permit

Dear Mr. Halpin:

Please find below Progress Energy Florida's (PEF) comments on the above referenced draft permit.

<u>Comments:</u>

- Section III, Condition No. 7: PEF requests that the CO emission limits noted in this condition be revised from 2.5 ppmvd to 3.5 ppmvd (when gas fired) and from 5.0 ppmvd to 7.0 ppmvd (when oil fired). This is consistent with limits recently established for this type of contingency for Power Blocks 2 and 3 at the facility.

- Section III, Condition 8: PEF requests that the reference value for MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 degrees F, the HHV of the fuel, and 100% load) be revised from 2,020 to 2,122. This revision better reflects to current understanding of the predicted operation of these units when firing distillate oil. This revision will not have an impact on the unit's annual potential to emit, as this is still limited in the same manner by the restriction on total distillate oil consumption found in Condition 9.b.

- Section III, Condition 10.c.: The last sentence should be reflected as a Permitting Note.

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

- Section III, Condition 10.d.: PEF requests that the language regarding ammonia slip be changed from "ammonia slip of less than 5 ppmvd" to "ammonia slip of no more than 5 ppmvd".

- Section III, Condition 14: In an effort to further clarify the averaging basis of this Condition's emission limits, PEF requests that the word "rolling" be inserted prior to the term "24 hour average basis". Additionally, a reference needs to be made to clarify that compliance with emission limits during startup/shutdown periods containing less than 24 hours of operation (e.g., failed starts) is not required. Alternatively, the Condition should be modified to allow for non-operating hours (zero emission hours) to be included in the calculation of the 24-hour rolling average.

- Section III, Condition 15: To more clearly reflect the rule language found in 62-210.700, F.A.C., PEF requests that the phrase "unless specifically authorized by the Department for longer duration" be added to the end of the last sentence.

- Section III, Condition 16.a.: The underlining found here should be removed.

- Section III, Condition 21.a.: The 5,473,000 gallons of distillate fuel oil value should be revised to 6,140,000 gallons to accurately reflect potential oil consumption at the 200 hour per year per turbine rate referenced in the associated Permitting Note for this Condition.

- Section III, Condition 22.f.: The following should be added to the end of this Condition to clarify that data that is used to calculate the alternate emissions standards found in Condition 14 should not also be used in the determination of compliance with the 24-hour block average emission standards found in Condition 10.

  "Additionally, data used in the determination of the alternate standards covering startup and/or shutdown operations shall be excluded from the determination of the 24-hour block emission rate values."

- Section III, Condition 22: The comment regarding water injection that follows the Permitting Note section should be removed.

- Section III, Condition 26.a. and b.: Where test methods are referenced, the associated caveat should allow both "more recent" and "equivalent" versions of the test methods to be used in lieu of those specifically stated in the Condition.

- Section III, Condition 28: The parenthetical reference to Subpart GG emission limits should be double checked for accuracy.

- Section III: PEF requests that the following Condition be added into the "Emission Performance Testing" section of the permit:

  <u>*Additional Ammonia Slip Testing*</u>*: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:*

  a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

  b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

  c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

  Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

- Section IV: PEF requests that the rating on the Auxiliary Boiler referenced in this Section be revised from 20 MMBtu to 99 MMBtu. As summarized in the Permitting Note found in this section, this revision will not change the category of rules (or conditions) applicable to this source.

Please contact me at (727) 820-8764 if you have any questions or need additional information.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

c: Hamilton Oven, FDEP Siting - Tallahassee

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RECEIVED
FEB - 1 2005
DEPT. OF ENVIRONMENTAL PROTECTION
OFFICE OF GENERAL COUNSEL

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In re Matter of an
Application for Permit by:

Progress Energy Florida
Hines Energy Complex, Power Block 4
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Polk County - AP
Air Permit No. PSD-FL-342
DEP File No. 1050234-010-AC
OGC Case No. 05-0197

/

REQUEST FOR ENLARGEMENT OF TIME

PROGRESS ENERGY FLORIDA (PEF) by and through undersigned counsel, and pursuant to Florida Administrative Code Rule 62-110.106(4), hereby requests an enlargement of time, to and including March 11, 2005, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, PEF states:

1. On or about January 18, 2005, the Department of Environmental Protection (Department) issued to PEF an "Intent to Issue Air Permit" and accompanying "Draft Permit", and "Technical Evaluation and Preliminary BACT Determination" regarding the construction of Power Block 4 at the existing Hines Energy Complex.

2. PEF is reviewing the draft permit and expects to submit to the Department comments on the draft permit, identifying provisions that may warrant clarification or correction by the Department. Additional time is needed to allow the Department to review PEF's comments on the draft permit and to allow discussion of PEF's comments. Accordingly, PEF is requesting an extension of time through and until March 11, 2005, in which to file a petition for administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes

3. This request is filed simply as a protective measure to avoid waiver of PEF's right to challenge certain provisions of the draft permit in the event a mutually agreeable resolution of the issues cannot be reached. 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.

WHEREFORE, PROGRESS ENERGY FLORIDA respectfully requests that the time for filing of a Petition for Administrative Proceedings regarding the Department's Intent to Issue the above-referenced Permit be formally extended to and including March 11, 2005. If the Department denies this Request, PEF respectfully requests an opportunity to file a Petition for Administrative Proceeding within 10 days of such denial.

Respectfully submitted this 1st day of February, 2005.

HOPPING GREEN & SAMS, P.A.

By: ______________________

Douglas S. Roberts
Fla. Bar No. 0559466
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314
Phone: (850) 222-7500

Attorneys for PROGRESS ENERGY FLORIDA

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that the original and one copy of the foregoing has been furnished by hand-delivery to the Clerk of the Department of Environmental Protection, 3900 Commonwealth Blvd., Tallahassee, Florida 32399, and that copies of the foregoing have been furnished to the following by hand delivery or U.S. Mail on this 1st day of February, 2005:

Mike Halpin
Bureau of Air Regulation
Florida Department of Environmental
Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

Scott A. Goorland, Esq.
Office Of General Counsel
Department of Environmental
Protection
3900 Commonwealth Blvd.
Tallahassee, FL 32399-3000

Attorney

Mike

Best Available Copy

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

PROGRESS ENERGY FLORIDA,
Hines Energy Complex,

Petitioner,

v.

OGC #05-0197
DEP Permit 1050234-010-AC

DEPARTMENT OF ENVIRONMENTAL
PROTECTION,

Respondent.

______________________________/

ORDER GRANTING REQUEST FOR EXTENSION
OF TIME TO FILE PETITION FOR HEARING

This cause has come before the Florida Department of Environmental Protection upon receipt of a request made by Petitioner, Progress Energy Florida, to grant an extension of time to file a petition for an administrative hearing to allow time to discuss with FDEP several specific permit conditions for its facility in Polk County, Florida. Because the request shows good cause for the extension of time,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until **March 11, 2005**, to file a petition in this matter. Filing shall be complete on receipt by the Office of General Counsel, Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

DONE AND ORDERED on this 16th day of February, 2005, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

JACK CHISOLM, Deputy General Counsel
3900 Commonwealth Boulevard. M.S. 35
Tallahassee, Florida 32399-3000
850-245-2242 facsimile 850-245-2302

Best Available Copy

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via _ U. S. Mail ✓ facsimile ✓ only, this 16th day of February, 2005, to:

Douglas S. Roberts
Hopping Green & Sams, P.A. Fax 850-224-8551
P. O. Box 6526
Tallahassee, FL 32314

W. Douglas Beason

W. Douglas Beason, Assistant General Counsel
STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION
3900 Commonwealth Boulevard - Mail Station 35
Tallahassee, FL 32399-3000
850-245-2242 facsimile 850-245-2302

with a courtesy copy to:

Trina L. Vielhauer facsimile: 850-921-9533
Chief
Bureau of Air Regulation

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

ORIG: Mike Halpin
XC: Jim Pennington

MAR 0 2 2005

RECEIVED
MAR 07 2005
BUREAU OF AIR REGULATION

4APT-APB

Mr. Jim Pennington
Florida Department of
Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Pennington:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for Florida Power Corporation (FPC) - Hines Energy Complex, dated January 18, 2005. The draft PSD permit is for the proposed construction and operation of two combined cycle combustion turbines (CTs) with a total nominal generating capacity of 530 MW to be located near Fort Meade, FL. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. The CTs will primarily combust pipeline quality natural gas with 0.05 percent sulfur fuel oil combusted as backup fuel. As proposed, the CTs will be allowed to fire natural gas up to 8,760 hours per year per CT and to fire fuel oil a combined maximum of 1,000 hours per year for both CTs. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC).

Based on our review of the PSD permit application, preliminary determination, and draft PSD permit, we have the following comments:

1. According to the recently issued PSD permit for Florida Power & Light (FP&L) - Turkey Point, the Florida Department of Environmental Protection (FDEP) has determined through a rigorous best available control technology (BACT) evaluation that NO_x and CO emissions from combined cycle CTs of this type are as follows:

    - NO_x emission limits of 2.0 ppmvd and 8.0 ppmvd for natural gas and fuel oil firing, respectively. Compliance with these emission limits will be determined using a continuous emission monitoring systems (CEMS).

    - CO emission limits of 8.0 ppmvd (24-hour average) and 6.0 ppmvd (12-month rolling average) for both natural gas and fuel oil firing. Compliance with these emission limits will be determined using a CEMS. Additional CO emission limits of 4.1 ppmvd and 7.6 ppmvd are based on 3-hour stack tests and apply while firing natural gas in normal mode and duct burning mode, respectively.

The NO_x and CO BACT emission limits proposed by FDEP in the draft PSD permit for FPC - Hines are as follows:

- NO_x emission limits of 2.5 ppmvd and 10.0 ppmvd for natural gas and fuel oil firing, respectively. Compliance with these emission limits will be determined using a CEMS.

- CO emission limits of 8.0 ppmvd (24-hour average) and 12.0 ppmvd (24-hour average) for natural gas and fuel oil firing, respectively. Compliance with these emission limits will be determined using a CEMS.

While we understand the applicant's and FDEP's desire for simplicity when setting BACT emission limits, the FPC - Hines BACT limits are not consistent with, nor as stringent as, those in the recently issued FP&L - Turkey Point PSD permit. At a minimum, FDEP should include an explanation in the final PSD determination regarding the differing conclusion reached by the FPC - Hines BACT evaluation. Furthermore, FDEP should consider revising the BACT emission limits in the final FPC - Hines PSD permit to be more consistent with other recent combined cycle combustion turbine PSD permits issued by FDEP.

2. It is unclear whether or not draft PSD permit Condition 14, titled "Alternative Emission Limits," is supposed to replace the emission limits in Condition 10 when the CTs start up or shut down during a 24-hour period. Additionally, it is unclear if the excess emission allowances detailed in Condition 15 apply to the emission limits in Condition 14 as well as those in Condition 10. To clarify when each set of emissions limits apply, FDEP should add language to one or more of the permit conditions to better define the relationship among them. Furthermore, EPA notes that this method of dealing with startup and shutdown excess emissions is not consistent with previous PSD permits issued by FDEP for combustion turbines. FDEP should consider adopting a more standardized method of addressing startup and shutdown emissions in PSD permits.

3. In the preliminary determination, FDEP agrees with the applicant that use of low sulfur fuel oil (0.05% S) is BACT for SO_2 emissions when firing fuel oil. According to the PSD permit application, ultra low sulfur fuel oil (0.0015% S) was not even considered as a BACT option for controlling SO_2 emissions. Since ultra low sulfur fuel oil will be widely available in the near future, EPA believes that a fuel sulfur concentration of 0.0015% is the point at which any fuel oil combustion BACT analysis must begin.

If you have any questions regarding these comments or need additional information, please contact Katy Forney at 404-562-9130.

Sincerely,

Gregg M. Worley

Gregg M. Worley
Chief
Air Permits Section

Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer

THRU: J. K. Pennington JKP

FROM: M. P. Halpin MH

DATE: January 7, 2005

SUBJECT: Progress Energy Florida – Hines Energy Complex
530-Megawatt Combined Cycle Project
DEP File No. 1050234-010-AC

Progress Energy has submitted a permit application, requesting permission to add another 530 megawatts of combined cycle power to the existing Hines Energy complex. Unlike the prior three power blocks, Progress has elected to install General Electric F-frame combustion turbines for this expansion. Based upon the submittals, it is apparent that some of the emissions are lower than the Siemens Westinghouse F-frame combustion turbines and this is reflected within the BACT and draft permit.

The attached draft documents reflect a proposed NO_X limit of 2.5 ppmvd and a proposed CO limit of 8 ppmvd, both while firing natural gas and measured by CEMS. The applicant has requested permission to fire 0.05% sulfur fuel oil for up to 1000 hours per year, which is higher in sulfur content than the Department's most recent fuel oil permitting actions. However, given that this is the expansion of an existing facility which currently stores and fires 0.05% sulfur oil, the draft BACT permits this fuel use.

Attached is the public notice package for the subject project. I recommend your approval.

JKP/mph

Attachments

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

January 18, 2005

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida – Hines Energy Complex
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Re: Draft Air Permit No. PSD-FL-342
Project No. 1050234-010-AC
Hines Energy Complex, Power Block 4
Generating Capacity Increase

Dear Mr. Zirkle:

On August 6, 2004, Progress Energy Florida submitted an application to add a nominal 530 MW of generating capacity to the existing Hines Energy Complex, which is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, Florida. Enclosed are the following documents: "Technical Evaluation and Preliminary BACT Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary BACT Determination" summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit, as well as the Department's proposed BACT Determination. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The "Public Notice of Intent to Issue Air Permit" is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

As this project is subject to the power plant site certification requirements, a final permit cannot be issued until after the required hearing on this project. If you have any questions, please contact the Project Engineer, Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Trina Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

TV/jp/mh

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Progress Energy Florida
Hines Energy Complex
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733

Authorized Representative:
Mr. Roger Zirkle, Plant Manager

Draft Air Permit No. PSD-FL-342
Project No. 1050234-010-AC
Hines Energy Complex
Power Block 4
Polk County, Florida

Facility Location: Progress Energy Florida operates an existing power plant located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade.

Project: The applicant proposes to install two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, a single 190 MW steam turbine-electrical generator, a small auxiliary boiler and other miscellaneous support equipment. Upon completion of this project (Power Block 4), the plant will have a total generating capacity of approximately 2,090 MW. Therefore, the project subjects the facility to the power plant site certification requirements of the Department. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary Determination".

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary BACT Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the project file is available at the Air Resource Section of the Department's Southwest District Office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 (Phone: 813/744-6100).

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue Air Permit" (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet 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 Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (7) days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all email or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the

Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the 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 with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen (14) days of publication of the attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) 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, F.A.C.

A petition that disputes the material facts on which the Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue Air Permit is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary 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 1/18/05 to the persons listed below.

Mr. Jamie Hunter, Progress Energy *
Mr. Scott Osbourn, Golder
Mr. Jim Little, EPA Region 4
Mr. Buck Oven, DEP-Siting
Mr. Jerry Kissel, DEP-SWD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 1/18/05 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 1050234-010-AC (PA 92-33) / Draft Air Permit No. PSD-FL-342
Hines Energy Complex – Power Block 4
Polk County, Florida

Applicant: The applicant for this project is Progress Energy Florida. The applicant's authorized representative is Mr. Roger Zirkle, the Plant Manager of the Hines Energy Complex. The applicant's mailing address is P.O. Box 14042, MAC BB1A, St. Petersburg, Florida 33733.

Facility Location: Progress Energy Florida operates the existing Hines Energy Complex located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade.

Project: The existing Hines Energy Complex currently consists of two operating electrical generating units (Power Blocks 1 and 2) and another electrical generating unit currently under construction (Power Block 3). Power Block 1 is a 500 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2 is similar in design; the existing facility (inclusive of both Power Blocks) has a total generating capacity of 1,030 MW. Power Block 3, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 4), the plant will have a total generating capacity of approximately 2,090 MW.

The existing power plant is located in Polk County, an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. The power plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, new projects at the existing facility must be reviewed for PSD applicability.

In August of 2004, the Department received a PSD permit application for the existing facility that would increase the generating output of the facility from 1560 to 2090 megawatts of output. Based on potential emissions increases, the project is subject to PSD preconstruction review for carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, and sulfuric acid mist. The Department has made a preliminary determination of the Best Available Control Technology (BACT) for each of these pollutants based on the following air pollution control equipment: low-NOx burners and a selective catalytic reduction system to reduce nitrogen oxides emissions; and the efficient combustion of clean, low-sulfur fuels to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist and sulfur dioxide. Based on the supporting air quality analysis of the potential impacts from increased operation, the applicant provided the Department with reasonable assurance that the project would not significantly contribute to or cause a violation of any state or federal ambient air quality standards and would not significantly contribute to or cause a violation of any PSD Class I or Class II increments. However, the project does require a PSD permit to authorize the requested construction, and upon completion of the project the plant will have an increase in steam-generated electrical capacity of approximately 190 MW. Therefore, the project is subject to the power plant site certification requirements of the Department.

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114 and fax number is 850/921-9533.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the project file is available at the Air Resource Section of the Department's Southwest District Office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 (Phone: 813/744-6100).

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all e-mail or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the 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 with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen (14) days of publication of the attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) 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, F.A.C.

A petition that disputes the material facts on which the Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue Air Permit is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S.

Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

DRAFT

PERMITTEE:

Progress Energy Florida
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Authorized Representative:
Roger Zirkle, Plant Manager – Hines Energy Complex

Hines Energy Complex, Power Block 4
Project No. 1050234-010-AC
Air Permit No. PSD-FL-342
Power Plant Siting Case No. PA 92-33
SIC No. 4911
Expires: June 30, 2009

PROJECT AND LOCATION

This permit authorizes the construction of Power Block 4 at the existing Hines Energy Complex, a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values.}*

UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10")

STATEMENT OF BASIS

This PSD air pollution 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.). Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The project was processed in accordance with Florida's program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment 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.

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Michael Cooke, Director
Division of Air Resource Management

(Date)

FACILITY DESCRIPTION

The existing Hines Energy Complex currently consists of two operating electrical generating units (Power Blocks 1 and 2) and another electrical generating unit currently under construction (Power Block 3). Power Block 1 is a 500 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2 is similar in design; the existing facility (inclusive of both Power Blocks) has a total generating capacity of 1,030 MW. Power Block 3, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 4), the plant will have a total generating capacity of approximately 2,090 MW.

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
018	Power Block 4, CT 4A (170 MW gas turbine with unfired HRSG)
019	Power Block 4, CT 4B (170 MW gas turbine with unfired HRSG)
020	Natural Gas-fired auxiliary boiler

{Permitting Note: The Hines Energy Complex, Power Block 4 (Power Block 4, or "the project") consists of 2 gas turbine-electrical generator sets (Units CT 4A and CT 4B), 2 unfired HRSGs, and a single steam-turbine electrical generator.}

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Each Power Block 4 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY. (See Appendix YYYY.)

Title IV: The facility operates emissions units subject to the acid rain provisions of the Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million British thermal units (MMBtu) per hour of heat input," which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP, or "the

Department") at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's Southwest District Air Program, Compliance/Enforcement Section, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix TEBD	Final BACT Determinations and Emissions Standards
Appendix GC	General Conditions
Appendix GG	NSPS Subpart GG Requirements for Gas Turbines
Appendix XS	Semiannual NSPS Excess Emissions Report
Appendix YYYY	NESHAP Subpart YYYY

REVIEWING AND PROCESSING SCHEDULE

- Received Site Certification and PSD application on August 6, 2004;
- Additional information requested on August 19, 2004;
- Received request for additional time to respond on November 8, 2004;
- Received revised application and responses on December 6, 2004;
- Intent to Issue PSD Permit distributed January 18, 2005.

RELEVANT DOCUMENTS

The documents listed below are not attached; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application
- Department's request for additional information (Office of Siting Coordination sufficiency questions)
- Applicant's additional information
- Department's Intent to Issue

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit 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.; Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C.; and 40 CFR Parts 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the F.A.C. 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. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or 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. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of BACT for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

4. New or Additional Conditions: 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.]

5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]

6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation with a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

This section of the permit addresses the following emissions units.

Emission Units 018 and 019

Description: Emission units 018 and 019 each consist of a General Electric Model 7FA gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel.

Generating Capacity: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NOx emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

Stack Parameters: Each HRSG has a stack that is 125 feet tall and 18 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,021 British thermal units (Btu) per standard cubic feet of natural gas and 19,075 Btu/lb of fuel oil.

Fuel	Heat Input Rate (HHV)	Compressor Inlet Temp	Exhaust Temperature	Exit Velocity	Flow Rate
Gas	1,806 MMBtu/hour	59 °F	202 °F	67.9 ft/sec	1,036,271 acfm
Oil	1,962 MMBtu/hour	59 °F	295 °F	80.0 ft/sec	1,220,938 acfm

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of BACT were made for CO, NOx, PM/PM_{10}, sulfuric acid mist (SAM) and SO_2. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. New Source Performance Standards (NSPS): The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR part 60, subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements. [Rule 62-204.800(7), F.A.C.]

3. National Emission Standards for Hazardous Air Pollutants (NESHAP): The Department determines that compliance with the stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY (currently stayed) is required. See Appendix YYYY of this permit.

EQUIPMENT

4. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two General Electric Model 7FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall have dual-fuel capability. The gas turbines will utilize DLN combustors. [Application; Design]

5. Gas Turbine NOx Controls
   a. *DLN Combustion*: The permittee shall operate and maintain the DLN combustion system to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
   c. *SCR System*: The permittee shall install, tune, operate, and maintain a SCR system to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

   [Design; Rule 62-212.400(BACT), F.A.C.]

6. HRSGs: The permittee is authorized to install, operate, and maintain two HRSGs. Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 4A or CT 4B) and deliver steam to the steam turbine-electrical generator through a common manifold. *{Permitting Note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}* [Application; Design]

7. CO Controls: The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 2.5 ppmvd corrected to 15% oxygen when natural gas is fired and 5.0 ppmvd corrected to 15% oxygen when distillate oil is fired. [Rule 62-4.070(3), F.A.C.]

PERFORMANCE RESTRICTIONS

8. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,915 MMBtu per hour when firing natural gas and 2,020 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial

compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

9. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

   a. *Hours of Operation*: Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 30,700,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 1,000 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}*

   c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

   d. *Ammonia Injection*: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

   [Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

10. Emissions Standards: Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO [a]	8.0	12.0	24 hour block
NOx [b]	2.5	10.0	24 hour block
VOC [c]	1.3	3.0	3 hours
Ammonia [d]	5.0	5.0 [g]	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM_{10} [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO_2 [f]	Fuel specifications.

   a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be* *based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data. The Department shall revise the CO emissions standards following any future installation of an oxidation catalyst pursuant to Condition No. 7 of this section.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as propane. *Compliance with this standard is adequate to avoid a PSD/BACT Review.*

d. Each SCR system shall be designed and operated with an ammonia slip of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

e. The fuel specifications established in Condition No. 9 of this section combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in Condition No. 9 of this section effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 26 of this section.

g. Although the ammonia slip limit is established at 5.0 ppm, compliance shall be demonstrated while combusting natural gas.

{Permitting Note: Informational only - the concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):

- *CO = 32.1 lb/hr for natural gas firing and 57.2 lb/hr for distillate fuel oil firing,*
- *NOx = 17.7 lb/hr for natural gas firing and 82.4 lb/hr for distillate fuel oil firing,*
- *VOC =3.1 lb/hr for natural gas firing and 8.1 lb/hr for distillate fuel oil firing,*
- *PM_{10} = 10.1 lb/hr for natural gas firing and 39.1 lb/hr for distillate fuel oil firing, and*
- *SO_2 = 5.4 lb/hour for natural gas firing and 109.2 lb/hr for distillate fuel oil firing.*

SAM emissions are estimated to be less than 10% of the SO_2 emissions.} [Rule 62-212.400(BACT), F.A.C.]

STARTUP, SHUTDOWN, AND MALFUNCTION EMISSIONS

11. Operating Procedures: The BACT determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the

guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

12. Excess Emissions Prohibited: Excess emissions caused 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

13. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

14. Alternate CO and NOx Emissions Standard: During any period containing 24 hours of continuous operation, in which at least one hour of startup or shutdown operation has occurred, the following alternative emission limits shall apply on a 24 hour average basis:

a) An alternative NOx limit of 125 lb/hr shall apply if natural gas is the exclusively fired fuel;

b) An alternative NOx limit of 370 lb/hr shall apply if any fuel oil is fired; and

c) An alternative CO limit of 175 lb/hr shall apply when firing either natural gas of fuel oil.

15. Allowed Excess Emissions: Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, oil-to-gas fuel switching, or documented malfunction. Excess emissions shall in no case exceed two hours in any 24-hour period.

[Rule 62-210.700, F.A.C.]

16. CEMS Data Exclusion: As provided in this paragraph, NOx and CO emissions data recorded during periods of oil-to-gas fuel switches and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of Condition No. 10 of this section.

a. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.

b. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that meets the notification requirements specified in Condition No. 27 of this section.

c. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented.

[Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

17. CEMS Data Exclusion – DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

18. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or EPA Method 320	*Procedure for Collection and Analysis of Ammonia in Stationary Sources* This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	*Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)*
9	*Visual Determination of the Opacity of Emissions from Stationary Sources* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.
18	*Measurement of Gaseous Organic Compound Emissions by Gas Chromatography* (Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	*Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines*
25A	*Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at http://www.epa.gov/ttn/emc/ctm.html. The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

19. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. Each unit shall be tested when firing natural gas and when firing distillate fuel oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NOx standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1., F.A.C. and 40 CFR 60.8]

20. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. *{Permitting Note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of PM/PM_{10} and VOC.}* [Rule 62-212.400 (BACT), F.A.C.]

21. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

a. *Visible Emissions.* Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}*

b. *Ammonia.* Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.} [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

22. CEMS: The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NOx from the combined cycle gas turbine. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

a. *CO Monitors.* Except as otherwise specified by this condition, the CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of Section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 50 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

b. *NOx Monitors.* Except as otherwise specified by this condition, the NOx monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

c. *Diluent Monitors.* The oxygen or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

d. *Moisture Correction.* Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the permittee may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). If the CEMS measures concentration on a wet basis and the diluent monitor measures CO_2 on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

f. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NOx emissions depending on the use of alternate fuels}.* [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16 and 17 of this section.

h. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

{Permitting Note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

The water injection monitoring is no longer necessary due to the NSPS, Subpart GG revisions.

23. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by

comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

24. Monitoring of Operation: To demonstrate compliance with the fuel consumption limits of Condition No. 9 of this section, the permittee shall record the distillate fuel oil consumption on a rolling 12-month basis. [Rules 62-4.070(3) and 62-212.400, F.A.C., and BACT]

25. Frequency of Recordkeeping: Condition No. 22 of this section requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C.]

26. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

27. Malfunction Notification: Within one working day of a malfunction for which CEMS data is excluded pursuant to Condition No. 16 of this section, the permittee shall notify the Compliance Authority by telephone, facsimile transmittal, or electronic mail. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C.]

28. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and

fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Appendix XS. [40 CFR 60.7(c)]

29. Quarterly Data Exclusion and Monitor Availability Report: The permittee shall quarterly submit a report to the Compliance Authority summarizing all periods of valid hourly CO and NOx emissions data excluded from the 24-hour block average compliance determinations pursuant to Condition Nos. 16 and 17 of this section. In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Appendix XS. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7(c) and (d)]

POWER BLOCK 4 AUXILIARY BOILER (EU 020)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
020	Gas-fired, auxiliary boiler rated at 20 MMBtu per hour capacity

EQUIPMENT SPECIFICATIONS

1. Auxiliary Boiler: The permittee is authorized to install one auxiliary boiler designed to produce adequate steam for the cold startup of the combustion turbines. The boiler shall be designed for a nominal heat input rate of 20 MMBtu per hour from the firing of natural gas. The boiler shall fire natural gas as the exclusive fuel and this shall be considered as BACT for the emissions of particulate matter and sulfur dioxide. [Applicant Request; Design; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

2. Restricted Operation: The hours of operation of the auxiliary boiler are limited to 500 hours per year. [62-210.200(PTE), F.A.C.]

FEDERAL NSPS SUBPART DC STANDARDS

{Permitting Note: Subpart Dc regulates emissions of particulate matter and sulfur dioxide from each steam generating unit with a maximum design heat input rate of 10 MMBtu per hour or more, but less than 100 MMBtu per hour. Subpart Dc defines a steam generating unit as, "... a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." However, Subpart Dc does not specify any emissions standards for units that combust only natural gas. Therefore, the auxiliary boiler is subject only to the following NSPS Subpart Dc requirements for notification and record keeping.}

3. Reporting and Recordkeeping Requirements of 40 CFR 60.48c: *{Original numbering is retained.}*

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

STATE STANDARDS

4. Visible Emissions – 20 percent opacity except for either one six-minute period per hour during which opacity shall not exceed 27 percent. [62-296.406 (PTE), F.A.C.]

TECHNICAL EVALUATION
AND
PRELIMINARY BACT DETERMINATION

Progress Energy Florida
Hines Power Block 4

530-Megawatt Combined Cycle Power Project

Polk County

DEP File No. 1050234-010-AC / PSD-FL-342 (PA 92-33)

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
North Permitting Section

January 7, 2005

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Progress Energy Florida
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733

Authorized Representative:
Roger Zirkle, Plant Manager

1.2 Processing Schedule

- Received Site Certification and PSD application on August 6, 2004;
- Additional information requested on August 19, 2004;
- Received request for additional time to respond on November 8, 2004;
- Received revised application and responses on December 6, 2004.

1.3 Facility Description and Location

Power Block 1 consists of two combined cycle combustion turbines with heat recovery steam generators (HRSGs), for a nominal total of 500 MWs, a 99 MMBtu/hr auxiliary boiler, a 1,300 kW diesel generator and a 97,570 barrel fuel oil storage tank. Emissions from each CT and HRSG combination are vented through a single stack for each. Power Block 2 consists of two combined cycle combustion turbines with unfired heat recovery steam generators (HRSGs), and a single steam-turbine electrical generator. The existing facility (inclusive of both Power Blocks) has a total generating capacity of 1030 MW. Power Block 3 is under construction at the existing Hines Energy Complex. It is a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator.

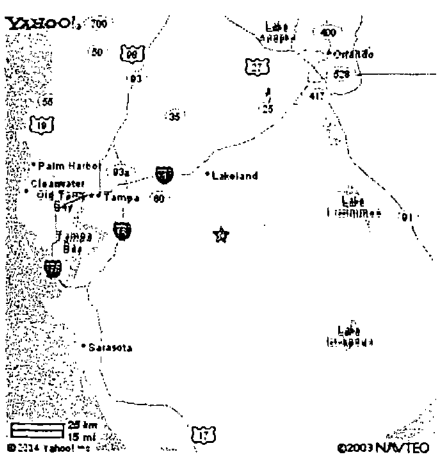


FIGURE 1 – Facility Location

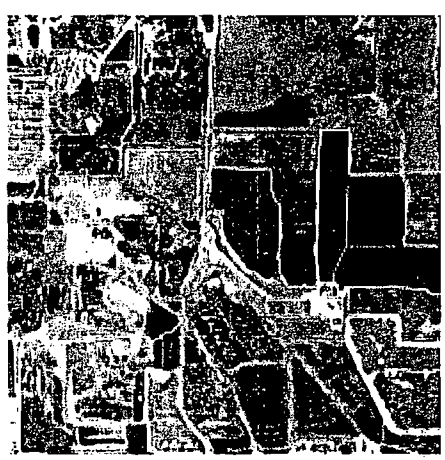


FIGURE 2 – Satellite Image

FIGURE 3 – 1999 Close-up

The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10").

1.4 Regulatory Categories

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project does not trigger the requirements for a case-by-case determination of the Maximum Available Control Technology (MACT) under Section 112(g) of the Clean Air Act (CAA, or "the Act"). Each Power Block 4 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY, which is currently stayed.

Title IV: The facility operates emissions units subject to the acid rain provisions of the Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million British thermal units (MMBtu) per hour of heat input," which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

2. PROPOSED PROJECT

2.1 Project Description

The applicant proposes to construct a "2-on-1" combined cycle unit consisting of the following equipment and specifications: two 170 MW combustion turbine-electrical generator sets; two un-fired heat recovery steam generators; two exhaust stacks between 125 feet in height; a common steam-electrical generator (190 nominal MW); a 20 MMBtu auxiliary boiler; and other associated support equipment.

Combustion Turbine/HRSG Units: Each gas turbine/HRSG unit consists of a nominal 170 MW General Electric 7FA gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system and an un-fired heat recovery steam generator (HRSG). Following are additional project characteristics.

- Fuels: Each gas turbine will fire natural gas as the primary fuel (0.05% Sulfur) and distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests 1000 hours per year per gas turbine (or equivalent) for oil firing.

- Generating Capacity: Each of the two gas turbines has a nominal generating capacity of 170 MW for gas firing. Each of the two heat recovery steam generators (HRSGs) provides steam to the single steam turbine electrical generator, which has a nominal capacity of 190 MW. The total nominal generating capacity of the "2-on-1" combined cycle unit is 530 MW.

- Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and restricting the amounts of low sulfur distillate oil. NO_X emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.

- Continuous Monitors: Each gas turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. CO monitors are also proposed by the applicant. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.

- Stack Parameters: Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is at 125 feet tall with a nominal diameter of 18 feet. The following summarizes the exhaust characteristics:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	1806 MMBtu/hour	59° F	202° F	1,036,271
Oil	1962 MMBtu/hour	59° F	295° F	1,220,938

2.2 Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressors of the GE 7FA combustion turbines proposed for this project. The air is compressed by a pressure ratio of about 15 times atmospheric pressure. A portion of the compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

The hot combustion gases are then diluted with additional cool air from the compressor and directed to the turbine section at temperatures of approximately 2600 °F. 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. Turbine exhaust gas is discharged at a temperature greater than 1100 °F and high excess oxygen and is available for additional energy recovery.

All units will ultimately operate in combined cycle mode in which the combustion turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator (HRSG). The steam, in-turn, drives a separate steam turbine-electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

Figure 4 is a simplified diagram of combined cycle operation.

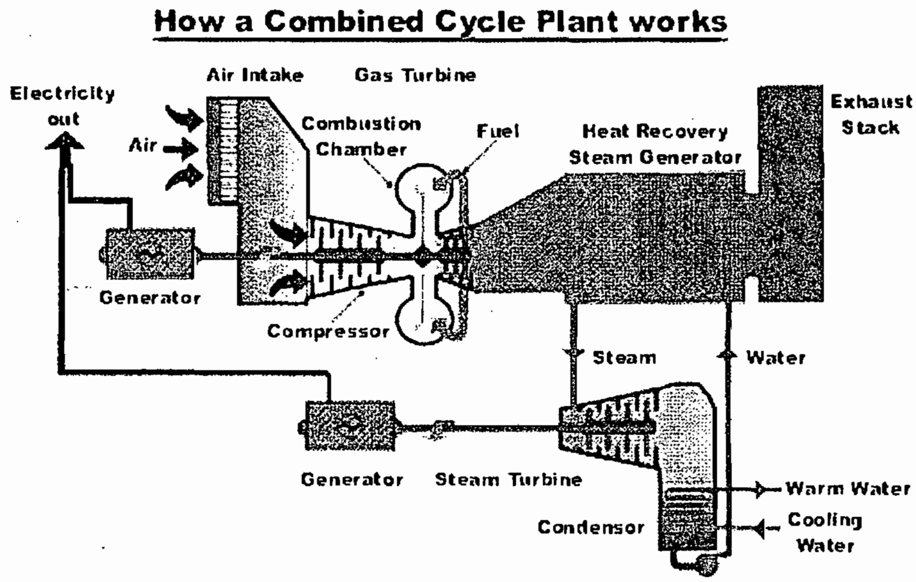


Figure 4. Key Components of a Combined Cycle Unit

2.3 Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines, duct burners, and cooling tower).

Table 1. Applicant's Estimated Annual Emissions

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	297	100	**Yes**
Pb	0.026	0.6	No
NO_X	205	40	**Yes**
PM/PM_{10}	116	15/25	**Yes**
SO_2	142	40	**Yes**
SAM	21.7	7	**Yes**
VOC	30.1	40	No

3. RULE APPLICABILITY

3.1 State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the Florida

Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

3.2 Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 63	National Emission Standards for Hazardous Air Pollutants (NESHAP)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

3.3 Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project are required for NO_X, CO, SO_2, SAM and PM/PM_{10}.

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"Best Available Control Technology" or "BACT" - An emission limitation, including a visible emissions 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 each such pollutant.

a. *If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit 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.*

b. *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

3. *A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, in making the BACT determination, the Department shall give consideration to:

1. *Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, 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).*
2. *All scientific, engineering, and technical material and other information available to the Department.*
3. *The emission limiting standards or BACT determinations of any other state.*

4. *The social and economic impact of the application of such technology.*

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA.

4.2 NO_X BACT Determination

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 near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

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, lowers achievable thermal efficiency for the unit.

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.

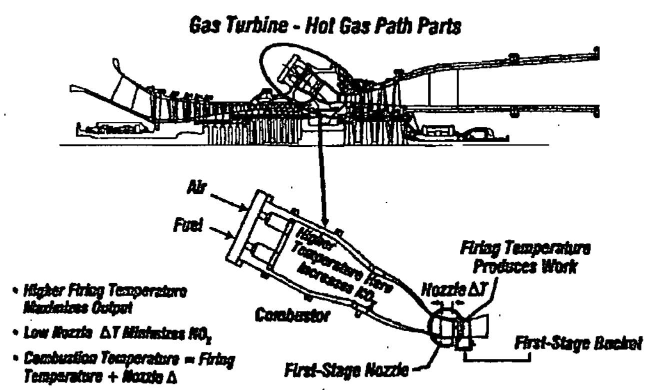


Figure 5 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as this Progress Energy project.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the Progress project. The proposed NO_X controls will reduce these emissions significantly. For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_X emissions from large utility gas turbines such as the GE7FA is approximately 105 ppmvd @15%O_2. This constitutes the legal floor (absolute maximum NO_X value) in a "Top/Down" BACT determination.

Descriptions of Available NO_X Controls

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low NO_X (DLN)

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 incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 6.

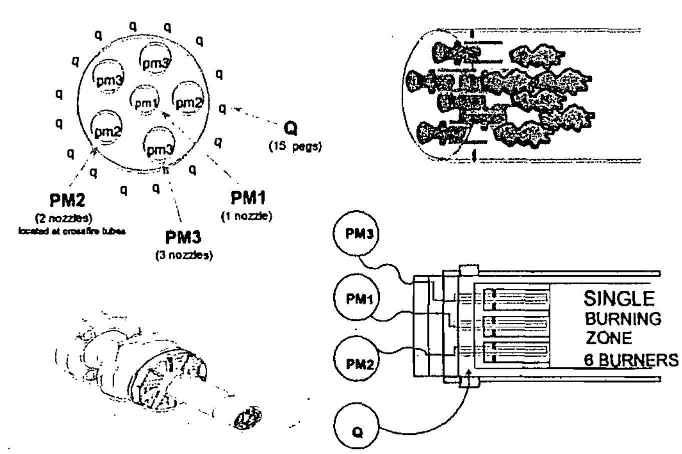


Figure 6 – DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 6 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X. Actual emissions of CO and VOC are actually much less than suggested by the diagram. However the diagram also suggests the need to minimize operation at low load conditions.

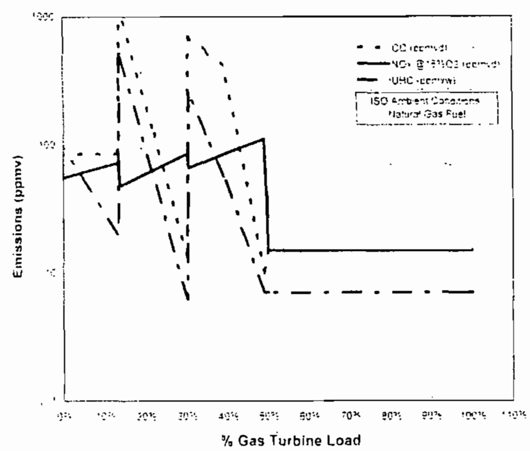


Figure 7 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_X)

The combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.

Table 2. Test Results for GE 7FA Gas Turbine, TECO Polk Power (Simple Cycle)

Percent of Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd	VOC, ppmvd
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1

Following are the results for testing of the GE7FA combined cycle unit at the City of Tallahassee Purdom Plant.

Table 3. Test Results for GE 7FA Gas Turbine, City of Tallahassee's Purdom Station

Percent of Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd
70	7.2	ND
80	6.1	ND
90	6.6	ND
100	8.7	0.85

The test results at the TECO and Tallahassee projects confirm NO_X, CO, and VOC emissions substantially less than typical guarantees as discussed below.

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 7 from an EPRI report. Developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 7.

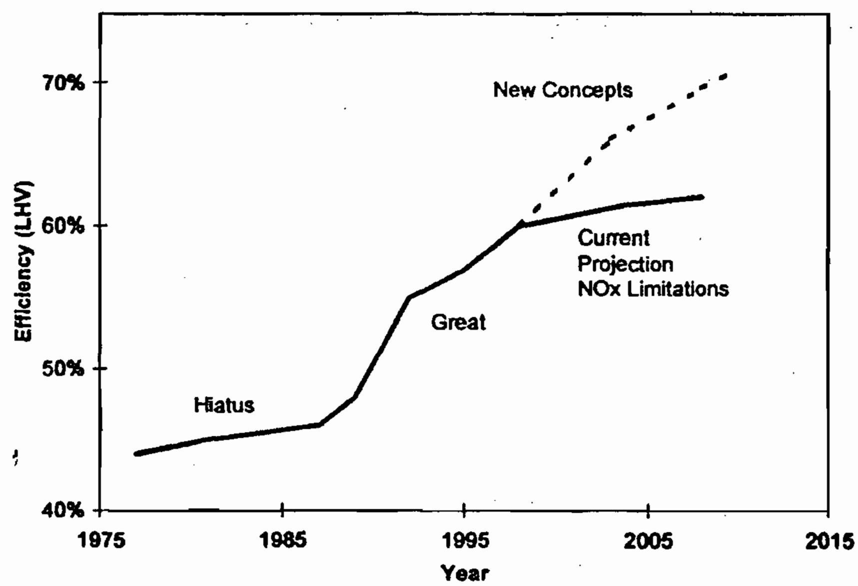


Figure 8 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by Progress. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

Numerous 7FA units with DLN technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95 percent compared with uncontrolled emissions and a reduction greater that 90 percent compared with the previously mentioned NSPS limit of approximately 105 ppmvd.

A DLN technology known as Low Emissions Combustor (LEC) has been developed by Power Systems Manufacturing, LLC (PSM) for retrofitting existing units. LEC has been demonstrated to achieve NO_X emissions less than 5 ppmvd on combustion turbines as large as a GE7EA (nominal 85 MW excluding steam electrical production). Low emissions of CO were also achieved. The company is working on versions suitable for the large GE7FA and Siemens Westinghouse products.

DLN is technically possible for fuel oil, but requires a very large and expensive atomization rig and is feasible only where water is virtually unavailable. Therefore, dual fuel combustors employ wet injection to reduce NO_X emissions when firing fuel oil as discussed above.

Catalytic Combustion - XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X. In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™. The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation. By now, five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm. Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for the Progress Energy Hines Power Block 4 project.

Selective Catalytic Reduction (SCR)

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 in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available and being applied in Florida. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Kissimmee Utilities Authority (KUA) installed an SCR system at the Cane Island Unit 3 project. The KUA project complies with a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued to Competitive Power Ventures (CPV), Calpine, Progress Energy, and Tampa Electric to achieve 3.5 ppmvd. More recently, permits were issued to El Paso Merchant Energy Company for facilities in Broward, Manatee and Palm Beach counties and to CPV for its Pierce facility with a limit each of 2.5 ppmvd @15% O_2 by SCR. Similarly permits were issued in 2003 to FPL for projects in Manatee and Martin County each with a limit of 2.5 ppmvd @15%O_2 by SCR.

Figure 8 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 9 is a photograph of the Progress Energy Hines Power Block I. The external lines to the ammonia injection grid are easily visible.

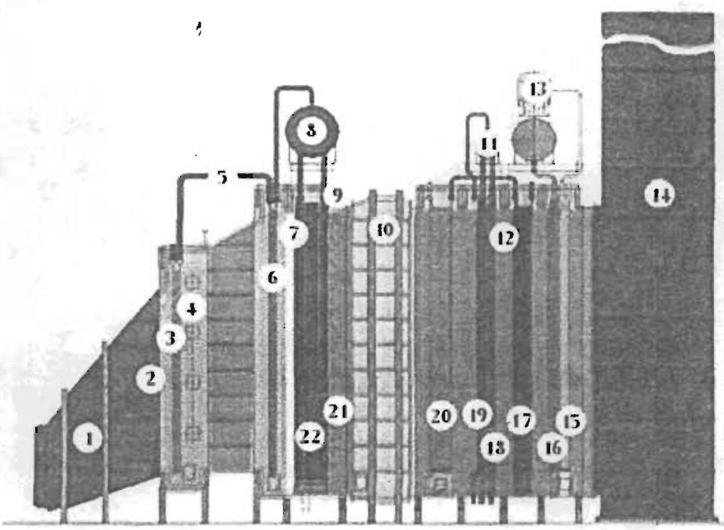


Figure 9 – Key HRSG Components (10 is SCR)

Figure 10 – Hines Power Block 1

If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Obviously this is not a problem with natural gas or even low sulfur fuel oil, whether distillate or residual. However, ammonia slip will gradually increase over the life of the system due to degradation of the catalyst.

The catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

Following are test results from one project that is cited by EPA Region 9 to show that NO_X emissions less than 2.0 ppmvd @15% O_2 (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR. The units consist of two nominal 180 MW gas combustion turbine-electrical generators with unfired HRSG's, and PA capability.

Table 4. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA

% Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd	VOC, ppmvd	NH_3 ppmvd
50	1.4 – 1.7	0.5 – 0.8	0.2 – 0.4	0.08 – 0.2
75	1.5 – 1.6	< 0.1	0.2 - 0.4	0.02 – 0.06
87	1.4 – 1.7	~ 0 – 0.3	0.1	0.05 – 0.1

It is noteworthy as well that the low NO_X emissions were achieved with minimal ammonia (NH_3) emissions. It would be reasonable to expect the ammonia emissions to increase over time to the guaranteed value of 2.0 ppmvd. The project employed Englehard oxidation catalyst for CO and VOC control. In the previous examples, it is noted that the GE 7FA achieved similarly low values throughout the same load range without oxidation catalyst.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_X emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order 95 to 99%.

SCONO$_X$^{TM}

This technology is an NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

SCONO$_X$^{TM} systems were installed at seven sites ranging in capacity from 5 to 43 MW. Alstom Power was not successful in marketing the product at large facilities.

SCONO$_X$^{TM} technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx^{TM} has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx^{TM} systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO$_X$^{TM} can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from natural gas reforming unit.

Table 5 contains averaged cost values for SCONO$_X$™ and SCR developed by the California Air Resources Board for their Legislature. The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 5. Cost Comparison between SCR and SCONO$_X$ for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	SCONO$_X$™	SCR/CO	SCONO$_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with SCONO$_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the SCONO$_X$™ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Estimates provided by Progress for the proposed project claim slightly greater cost differences between the two technologies. While the Department does not accept or reject either set of figures, it appears that SCONO$_X$™ is not cost-effective for the present project.

Applicant's NO$_X$ BACT Proposal

The applicant originally proposed a BACT NO$_X$ limit of 2.5 ppmvd @15% O_2. Progress proposed to meet the BACT emission while burning natural gas by a combination of DLN technology and SCR. Progress proposed a BACT NO$_X$ emission limit of 10 ppmvd @15% O_2 while burning backup low sulfur fuel oil by a combination of wet injection and SCR.

Department's Draft NO$_X$ BACT Determinations

Table 6 includes some recent BACT determinations in Florida and other states as well as some Lowest Achievable Emission Rate determinations. All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average.

It is noteworthy that the Department has recently issued a draft BACT Determination for FPL Turkey Point Unit 5, establishing 2.0 ppmvd and 8.0 ppmvd as emission limits for gas and oil respectively. The FPL facility is (nearly) adjacent to the Everglades National Park (ENP), and as such, the most stringent emission limits are appropriate. Notwithstanding this, the Department agrees that Progress's proposal of 2.5 ppmvd @15% O_2 on a 24-hour basis and minimization of fuel oil use represents BACT for this project. The limits of 2.5 and 10.0 ppmvd @15% O_2 represent reductions of well over 90% for the gas and oil cases when compared with the applicable New Source Performance Standard at 40 CFR 60, Subpart GG.

Table 6. Recent NO_X Standards for "F-Class" Combined Cycle Gas Turbine Projects

Project Location	**Capacity MW**	**NO_X Limit ppmvd @ 15% O_2 and Fuel**	**Comments**
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2x170 MW GE 7FA
Sithe Mystic, MA	775	2.0 – NG (1-hr)	2x250 MW WH 501G & DBs
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3x175 MW GE 7FA & DBs
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4x180 MW GE 7FA & DBs
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2x180 MW ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4x160 MW GE 7FA &DBs
Progress Hines PB4	530	2.5 – NG (24-hr) 10 - FO	2x170 MW GE 7FA
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2x180 MW ABB GT-24
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2x182 MW WH 501F
Cogen Tech, NJ	181	2.5 (1-hr)	181 MW GE 7FA
FPL Manatee, FL	1,150	2.5 – NG (24-hr)	4x170 MW GE 7FA & DBs
FPL Martin, FL	1,150	2.5 – NG (24-hr) 12 - FO	4x170 MW GE 7FA & DBs
Progress Hines PB3, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW WH501F
El Paso Manatee, FL	250	2.5 – NG (24-hr)	175 MW GE 7FA
Metcalf Energy, CA	600	2.5 – NG	2x170 MW WH 501F & DBs
Enron/Ft. Pierce, FL	~250	3.5 – NG (3-hr) 10 - FO	170 MW MHI 501F

MHI = Mitsubishi Heavy Industries NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse ABB = Asea Brown Bovari

4.3 CO BACT Determination

CO and VOC Formation and Control Options

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls without an oxidation catalyst, much lower emissions are typically reported for very large combustion turbines (at least for full load operation) without the use of oxidation catalyst.

Based on testing discussed in the NO_X technology section above, GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone that were equipped with oxidation catalyst.

Similarly, VOC emissions less than 1 ppm have consistently been measured at new GE7FA units throughout the state. Again the results are roughly equal to those at ANP Blackstone.

CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE7FA. Performance guarantees are only now "catching up" with the field experience.

GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units. The following statement was taken from the report:

"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation - thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas."

The following figure from GE's article is consistent with the data collected by the Department and supports the Department's analysis of this technical issue.

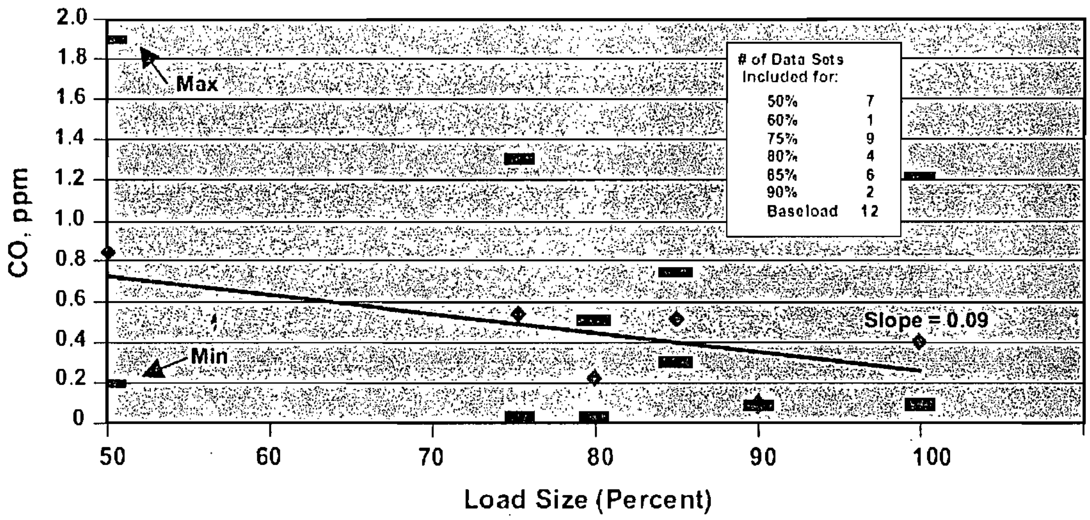


Figure 11. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Low Load and Fuel Oil Considerations

Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (1,100 to 1,200 °F) and high excess air (> 12% O_2). The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 °F. VOC such as ethane and propane ignite at temperatures less than 900 °F. All of the necessary conditions are present to minimize further CO production by the duct burner and, possibly, to incinerate CO and VOC in the TEG. Certain configurations (NovelEdge™) are marketed to take advantage of these possibilities and to make it unnecessary to install oxidation catalyst for VOC and CO control because of destruction by the duct burner. Basically, the claim is that a "3 on 1" configuration (3 CT's & 1 HRSG) producing 750 MW can be replaced with a "2 on 1" configuration by adding very large Coen "Power Plus" DBs in a Nooter Eriksen HRSG and still produce 750 MW. Basically the capital investments are much lower, overall efficiency is higher and the DBs destroy VOC and CO to the point that oxidation catalyst can be avoided. In summary, the installation of duct burners can have the positive effect of *reducing* CO emissions. As noted herein, the proposed project excludes duct burners and power augmentation.

Following is a table with the results of CO and VOC testing recently completed at the Gulf Power Lansing Smith Plant. The units tested were GE7FA combustion turbines (CT) of the same type that FP&L will install at the Manatee Power Plant. Tests were conducted on each combustion turbine while using duct burners (DB).

Table 7. CO and VOC Emissions - Gulf Power Plant Smith GE 7FA Units (ppmvd@15% O_2)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CT & DB)	1.21	0.15
Gulf Smith Unit 5 (CT & DB)	1.26	0.31
Gulf Smith Unit 4 (CT & PA)	5.18	0.61
Gulf Smith Unit 5 (CT & PA)	8.61	0.38

As seen from Table 7, emissions of CO and VOC are very low when the DBs are used and without power augmentation (PA). The Gulf Smith units also provide an example of power augmentation (PA) with the duct burners (DB) off.

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in the Table below. No appreciable differences are noted for large combustion turbines when they are operated on fuel oil versus natural gas. This conclusion is noteworthy because wet injection for basic NO_X control is practiced on all such units when firing fuel oil.

Table 8. CO, VOC Test Results. GE 7FA Gas Turbines firing Fuel Oil. (ppmvd @15% O_2)

Facility/Unit (load %)	CO	VOC
Martin Unit 8A (100%)	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)	2.1	1.1
Stanton A – Unit 25 (100%)	1.0	1.1
Stanton A – Unit 26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%)	0.04	0.18
Reliant Osceola Unit 2 (100%)	0.02	0.01
Reliant Osceola Unit 3 (100%)	0.54	0.00
Oleander Power Unit 1 (100%)	1.8	< 0.7
Oleander Power Unit 2 (100%)	1.1	< 0.7
Oleander Power Unit 3 (100%)	3.8	< 0.7
Oleander Power Unit 4 (100%)	2.7	< 0.7

Another consideration is "low load" operation. Several operators in Florida installed, will install, or are considering installing oxidation catalyst because: the supplier could not guarantee low CO emissions at medium loads (50 to 70 percent); the units actually exhibited high emissions at such loads; or the units required very long warm-up periods under low load (< 50% and very high CO) conditions. These include Lakeland McIntosh Unit 3, Seminole Payne Creek, Enron Fort Pierce (deferred), and Progress Energy Hines Power Block II and III. This is in contrast to the proposed GE 7FA units that exhibit low CO emissions at 50 percent.

Determinations CO, VOC, and PM/PM_{10} Emission Limit Determination

The following table is a list of recent CO and VOC (and PM) determinations for project throughout the country. The Progress proposal is included for comparison.

Table 9. CO, VOC, and PM Standards for "F-Class" Combined Cycle Units [1]

Project Location	**CO - ppmvd (@15% O_2)**	**VOC - ppmv (@15% O_2)**	**PM - lb/mmBtu (or gr/dscf or lb/hr)**
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	1.0	0.008
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)	1.0 (DB off) 1.7 (DB on))	0.008 (NH_3 = 2.0 ppmvd)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	1.0 (DB off) 2.0 (DB on))	0.01
Duke Morro, CA	2.0 (Ox-Cat)	1.15 (DB off) 2.0 (DB on)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	1.4	0.002 (NH_3 = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	1.0 (DB off) 1.64 (DB on))	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
Progress Hines PB4 (applicant proposal)	8.0 – NG 15.0 – FO	1.3 – NG 3.0 – FO	10.1 lb/hr – NG (Front ½) [2] 39.1 lb/hr – FO (Front ½) [2]
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	3 – 7.5 lb/hr	0.011
Calpine OEC, PA	10 (1-hr)	1.8	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	1.2	
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH_3 = 5
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH_3 = 5
Progress Hines PB3, FL	10 - NG (3.5 if Ox-Cat) 20 – FO (7 if Ox-Cat)	2 – NG 10 – FO	10% Opacity NH_3 = 5
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	1.1 - NG	20 lb/hr – (Front & Back) [2] 5 ppmvd Ammonia Slip
Metcalf Energy, CA	6 - NG (100% load)	0.00126 lb/mmBtu	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity

1. FPL Turkey Point draft BACT Determination established co emission limits of 8 ppmvd for gas and oil.
2. Front half means filterable and back half means condensible.

Abbreviations: NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse ABB = Asea Brown Bovari

Department's CO BACT Proposal

Based on the data available to the Department, Progress's respective proposed CO emission limits for gas and fuel oil firing of 8.0 and 15.0 ppmvd @ 15% O_2 seem slightly high, particularly the proposed oil limit. A detailed cost assessment would reveal that the cost to achieve lower CO emissions by installation of oxidation catalyst is not warranted. This cost has been estimated by the applicant at approximately $7,500 per ton. While the Department does not necessarily accept the estimate, oxidation catalyst is likely not cost-effective for the proposed GE machine.

The Department will set a continuous 24-hr CO limit of 8.0 ppmvd and 12.0 ppmvd (corrected to 15% O_2) for gas and oil-firing, respectively. The proposed VOC emission limits (1.3 ppmvd and 3.0 ppmvd for gas and oil respectively) are adequate to insure that a BACT review is not required; hence the Department accepts them as proposed.

4.4 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

For this project the applicant has proposed as BACT the limited use of low sulfur fuel oil (0.05 percent sulfur) with natural gas as the main fuel. For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8% by weight.

The applicant estimated total emissions for the project at 142 tons per year of SO_2 and 21.7 tons per year of sulfuric acid mist. The Department accepts Progress Energy's BACT proposal for SO_2 and SAM.

4.5 Particulate Matter (PM/PM_{10}) BACT Determination and Ammonia (NH_3) Control

PM/PM_{10} Formation and Control Options

PM and PM_{10} are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ultra low sulfur distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Clean 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 low sulfur fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 1000 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

The following table is a summary of PM_{10} emissions provided by General Electric to FP&L from GE 7FA units operating on natural gas or fuel oil.

Table 10. PM_{10} Emissions from GE 7FA Units (pounds per hour)

Fuel	Range	Average	Std. Deviation
Natural Gas - Front-half (filterable)	0 – 17	4.8	
Natural Gas - Back-half (condensable)	0 - 15	14	
Natural Gas Total	1 - 29	7.5	
Fuel Oil - Front-half (filterable)	1 - 20	10	4
Fuel Oil Back-half (condensable)	3 - 21	14	6
Fuel Oil Total	4 - 37	24	9

Recent PM/PM_{10} emission limits are included in Table 9. Comparison is not simple because some of the limits represent filterable particulate matter while some of the limits represent the sum of filterable and condensable matter.

As previously discussed, there will be emissions of NO_X, SO_2 and SAM. These pollutants are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. The NO_X control technology of SCR can increase PM/PM_{10} emissions from the stack due to formation of ammonium sulfates prior to exiting.

Formation of ammonium species emitted from the stacks can be minimized by limiting the emissions of ammonia (known as slip). Elevated levels of ammonia slip may indicate a degrading catalyst. Almost all jurisdictions include a slip limit in conjunction with NO_X control technologies that rely on ammonia injection. Very low values ($\leq$ 0.2 ppmvd) were achieved at the ANP Blackstone project as described in Table 4.

It is noted that NH_3 emissions from the Stanton project ranged from 0.1 to 0.9 ppmvd @15% O_2 while firing natural gas. NH_3 and NO_X emissions while burning fuel oil were approximately 3 and 8 ppmvd respectively. Results from tests at KUA Unit 3 indicate that NH_3 emissions were 1.5 ppmvd @15% O_2 when firing fuel oil. The Department proposes an ammonia limit during gas firing of 5 ppmvd @15% O_2.

Applicant's PM/PM_{10} Proposal

Progress proposes PM/PM_{10} BACT equal to 10.1 pounds per hour (lb/hr, front-half) when firing natural gas. They additionally propose a limit of 39.1 lb/hr (front-half) when firing fuel oil. They also propose an opacity limit of 10% on natural gas (20% on fuel oil).

Department's Draft PM/PM_{10} BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The gas turbines may fire distillate oil as a restricted alternate fuel ($\leq$ 1000 hours per year), which shall contain no more than 0.05% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average, regardless of fuel.
- Ammonia emissions (slip) shall not exceed 5 ppmvd while firing natural gas.

4.6 Summary of Department Draft BACT Determination

Emissions from each gas turbine shall not exceed the values given in the following table.

Table 11. Draft BACT Determination – Progress Energy Hines Power Block 4

Pollutant	Fuel	Stack Test, 3-Run Average		CEMS Block Average
		ppmvd @ 15% O_2	lb/hr	ppmvd @ 15% O_2
CO	Oil	12.0	57.2	12.0, 24-hr
	Gas	8.0	32.1	8.0, 24-hr
NO_X	Oil	10.0	82.4	10.0, 24-hr
	Gas	2.5	17.7	2.5, 24-hr
PM/PM_{10}	Oil/Gas	Fuel Specifications		
		Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2	Oil/Gas	2 gr S/100 SCF of gas, 0.05% sulfur fuel oil		
Ammonia	Gas	5	NA	NA

Note: The Department accepts as BACT, the applicant's proposal for natural gas as the exclusively fired fuel in order to control emissions of PM and SO2 from the auxiliary boiler.

5. NEW SOURCE PERFORMANCE STANDARDS

Small boilers rated at 20 MMBtu per hour as subject to the Federal New Source Standard in Subpart Dc of 40 CFR 60 and 62-296.406 of the Florida Administrative Code. The subject requirements will be specified in the permit.

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NO_X (gas) ≤ 110 ppmvd @ 15% O_2 (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NO_X (oil) ≤ 103 ppmvd @ 15% O_2 (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations.

6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The Hines Energy Center is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines would be subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY. EPA has stayed the applicability of YYYY to units such as those proposed for the Hines project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

Based on the same GE technical cited in the Section 4.3 above, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. Progress proposes to meet the limit proposed in YYYY of 91 ppmvd.

The very low VOC and CO emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_X technology employed by these units insure that formaldehyde emissions will be at the lowest end of the spectrum.

The draft permit will reflect the present status of the rule. The final permit will reflect Subpart YYYY to the extent that it is applicable on the date the Department issues its final decision on the present application.

7. PERIODS OF EXCESS EMISSIONS

7.1 Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

7.2 Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Operation of the General Electric Frame 7FA gas turbine in lean premix mode is achieved by at least 50% of base load conditions. Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%), which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases. For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.
- During any period containing 24 hours of continuous operation, in which at least one hour of startup or shutdown operation has occurred, the following alternative emission limits shall apply on an average basis:

  NO_X (gas) – 125 lbs/hr

  NO_X (oil) – 370 lbs/hr

  CO (gas or oil) – 175 lbs/hr
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

8. AIR QUALITY IMPACT ANALYSIS

8.1 Introduction

The proposed project will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, VOC and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimus monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimus monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimus monitoring levels for SAM and VOC. However, VOC is a precursor to a criteria pollutant, ozone; and any net increase of 100 tons per year of VOC requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

8.2 Significant Impact Analysis

For PM/PM_{10}, CO, NO_X and SO_2, which have significant impact levels defined for them, a significant impact analysis is performed. In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described in <u>Models and Meteorological Data Used in the Air Quality Analysis</u>, later in this section. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas.

If this modeling at worst load conditions show significant impacts, additional modeling, which includes the emissions from surrounding facilities, or multi-source modeling is required to

determine the project's impacts on any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.
The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels." These values are tabulated below and compared with the National Ambient Air Quality Standards.

Table 12. Maximum Project Air Quality Impacts from the Hines Power Block 3 Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.04	1	60	NO
	24-Hour	2.7	5	260	NO
	3-Hour	13	25	1300	NO
PM_{10}	Annual	0.04	1	50	NO
	24-Hour	1.6	5	150	NO
CO	8-Hour	23	500	10,000	NO
	1-Hour	63	2000	40,000	NO
NO_2	Annual	0.07	1	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective ambient air quality standards. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area (CNWA) located about 118 km to the north. The applicant's initial PM/PM_{10}, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels" for the Class I area. These values are tabulated below. Note that the values are miniscule if compared with the ambient air quality standards given in the previous table. Since these impacts are less than the respective significant impact levels, no further detailed modeling efforts are required in this Class I area.

Table 13. Maximum Project Air Quality Impacts from the Hines Power Block 3 Project Compared with PSD Class I Significant Impact Levels (Chassahowitzka)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.001	0.2	NO
	24-hour	0.12	0.3	NO
NO_2	Annual	0.001	0.1	NO
SO_2	Annual	0.001	0.1	NO
	24-hour	0.17	0.2	NO
	3-hour	0.5	1	NO

8.3 Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimus impact levels. These are levels which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the table below, the maximum predicted impacts for all pollutants with listed de minimus impact levels were less than these levels. Therefore no pre-construction monitoring is required for those pollutants.

Table 14. Maximum Project Air Quality Impacts for Comparison to the *de minimus* Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimus Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimus?
PM_{10}	24-hour	2.5	10	~ 100	NO
NO_2	Annual	0.1	14	~ 15	NO
SO_2	24-hour	2.7	13	~ 40	NO
CO	8-hour	23	575	~ 2000	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC. However, the pollutant associated with VOC is actually ozone. Projects exhibiting VOC emissions greater than 100 tons per year (TPY) are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The proposed Power Block 4 project VOC emissions are predicted to be no more than 57 TPY, therefore an analysis, including ambient monitoring for ozone is not required.
Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project is an analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

8.4 Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area. The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It 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 satisfied 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 Tampa International Airport and Ruskin respectively (surface and upper air data). The 5-year period of meteorological data was from 1991 through 1995. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, 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.

PSD Class I Area. Since the closest PSD Class I area, the Chassahowitzka National Wilderness Area (CNWA) is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. Meteorological data were obtained and processed for the calendar years of 1990, 1992 and 1996, the years for which MM4 and MM5 data are available. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

8.5 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife. Very low emissions are expected from this natural gas-fired, with backup fuel oil, combustion turbine in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS).
The project impacts are also less than the significant impact levels for PM_{10}, CO, NO_X, and SO_2, which in-turn, are less than the applicable allowable increments for each pollutant.

Because the AAQS are designed to protect both the public health and welfare, and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Effects from sulfuric acid mist are also expected to be minor due to the low emissions expected from the Hines Energy Complex Power Block 4. The combination of low NO_X and VOC emissions insures that the project will not contribute significantly to regional ozone levels or to any impacts caused by such ozone levels.

According to the application, native Floridian species of vegetation, such as cypress, slash pine, live oak, and mangrove, will not be visibly damaged when exposed to 1300 ug/m^3 of SO_2 for 8 hours. This proposed project is predicted to have a maximum impact of 17 ug/m^3 of SO_2 over a 3-hour period and 4 ug/m^3 of SO_2 over a 24-hour period.

The maximum predicted nitrogen (N) and sulfur (S) depositions are well below the significant impact levels for N and S deposition.

Impact on Visibility. Pipeline natural gas is a clean fuel and produces little particulate emissions. The backup fuel oil will be limited to 0.05 percent sulfur and will exhibit relatively low particulate emissions. The very low NO_X, SO_2, and ammonia emissions will also minimize plume opacity and any effects on regional visibility.

The Class I Chassahowitzka NWA, where visibility impacts are normally of greater concern, is about 118 kilometers from the proposed site. A regional haze analysis using the CALPUFF model predicted impacts less than the federal land manager's visibility impairment criteria; therefore impacts on visibility are expected to be insignificant.

Growth-Related Air Quality Impacts. According to the applicant, the project will require about 6 additional permanent employees, some of who will be drawn from the local labor force. Therefore, residential growth due to this project will be minimal. This project is a response to statewide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint." After construction of the proposed project, Polk County is expected to remain below the National Ambient Air Quality Standards.

9. 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.

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.

In making this preliminary determination, the Department has also included herein a determination of Best Available Control Technology that may be modified based on comments from the applicant, agencies, or the public.

Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR Part 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.

The Power Block 4 gas turbines are regulated as emissions units 018 and 019. Each Power Block 4 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG. [40 CFR 60.330(a) and (b), Applicability and Designation of Affected Facility.]

Emissions units subject to a NSPS are also subject to the applicable requirements of 40 CFR Part 60, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(g) ISO standard day conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \cdot \frac{(14.4)}{Y} + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NOx emission allowance for fuel-bound nitrogen as defined in § 60.332(a)(3).

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx 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).

Department requirement: **While firing gas, the "F" value shall be assumed to be 0.**

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 9.6 for both natural gas and fuel oil. The equivalent emission standards are 112.5 ppmvd at 15% oxygen. The BACT limits of this permit are more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

§ 60.333 Standard for Sulfur Dioxide.

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with the following:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

[Note: The BACT limits of this permit are more stringent than this requirement.]

§ 60.334 Monitoring of Operations.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: **The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.**

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: The requirement to monitor the nitrogen content of natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator is allowed to determine the sulfur content of the pipeline quality natural gas semi-annually, because the owner or operator has the results of bimonthly and quarterly natural gas sulfur content analyses from the operation of the existing Power Block 1.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in 40 CFR 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emission monitoring by CEMS shall substitute for the requirements of paragraph (c)(1) because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 as described in this permit.

Department requirement: NOx and CO monitor availability shall not be less than 95% in any calendar quarter. The report required by this permit shall be used to demonstrate compliance with this requirement.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

§ 60.335 Test Methods and Procedures.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\, e^{19(Ho-0.00633)}\, (288°K/Ta)^{1.53}$$

where:

NOx = emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

Po = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H_2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

<u>Department requirement</u>: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

<u>Department requirement</u>: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEMS data, provided that compliance be based on a

minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in this permit shall be used instead of the span value of 300 ppm specified by paragraph (3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: **This permit requires the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.**

[Note: This requirement establishes different analysis methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The 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.

[Note: The fuel analysis requirements of this permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

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 extent 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.

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)* SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ______________________ to ______________________

Company: ______________________

Emission Limitation: ______________________

Address: ______________________

Monitor Manufacturer: ______________________

Model No. : ______________________

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ______________________

Total source operating time in reporting period [1]: ______________________

Emission data summary [1]	CMS performance summary [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions.................. ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration........................ ____
d. Other known causes...................................... ____	d. Other known causes...................................... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. [Total duration of excess emissions] x (100) / [Total source operating time] .... ____ %[2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ %[2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

[2] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: *On a separate page, describe any changes since the last in CMS, process or controls.*

I certify that the information contained in this report is true, accurate, and complete.

Name: ______________________

Signature: ______________________ *Date*: ______________________

Title: ______________________

APPLICABILITY

The Power Block 4 gas turbines are regulated as emissions units 018 and 019. Each Power Block 4 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY, which is currently stayed.

Emissions units subject to a NESHAP are also subject to the applicable requirements of 40 CFR Part 63, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

TIMING AND REQUIREMENTS

The combustion turbines NESHAP was proposed on January 14, 2003, and it was signed by the Administrator on August 27, 2003. On August 18, 2004 the final rule was stayed (see Federal Register / Vol. 69, No. 159 / Wednesday, August 18, 2004 / Rules and Regulations).

The permittee shall be responsible for ensuring timely compliance with relevant requirements of 40 CFR 63, Subparts A and YYYY.

[Rule 62-4.070(3), F.A.C. See also 40 CFR 60.6085, proposed at 68 FR 1888, January 14, 2003.]

P.E. Certification Statement

Progress Energy Florida
Hines Energy Complex Power Block 4
Polk County

DEP File No.: PSD-FL-342, PA 92-33
Facility ID No.: 1050234

Project: PSD Permit – Addition of 530 MW combined cycle power

I HEREBY CERTIFY that the engineering features described in the above referenced application and related additional information submittals, if any, 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).

(Seal)

Michael P. Halpin

Michael P. Halpin, P.E.
Registration Number: 31970

1-6-05
Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Progress Energy

February 10, 2005

RECEIVED

2005

BUREAU OF AIR REGULATION

Mr. Michael Halpin, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
FEB 11 2005
BUREAU OF AIR REGULATION

Dear Mr. Halpin:

Re: **Hines Energy Complex - Power Block 4**
PSD/Air Construction Permit Application
File No. 1050234-010-AC
Public Notice – Proof of Publication

Please find enclosed the "proof of publication" for the public notice of the above referenced draft permit. The notice was published in the Lakeland Ledger on February 2, 2005.

Please contact me at (727) 820-8764 if you have any questions or need additional information.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

Enclosure

c(w/enc): Hamilton Oven, FDEP Siting - Tallahassee

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared C. Morgan Miller, who on oath says that he is Display Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being an

Public Notice of Intent

....

in the matter **Hines Energy Complex at Power Block 4**....................

....

....

Concerning **Project No. 1050234-010-AC** ....

....

was published in said newspaper in the issues of **2-2; 2005**................

....

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.............C. Morgan Miller
C. Morgan Miller
Display Advertising Manager
Who is personally known to me.

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

day of February .... A.D. 20 05 ....

Patricia Ann Rouse
Notary Public

PATRICIA ANN ROUSE
MY COMMISSION # DD 330015
EXPIRES: October 17, 2008
Bonded Thru Notary Public Underwriters

(Seal)

My Commission Expires Oct 17, 2008

M119

Attach Ad Here

Public Notice of Intent to Issue Air Permit

Florida Department of Environmental Protection
Project No. 1050234-010-AC (PA 92-33) / Draft Air Permit No. PSD-FL-342
Hines Energy Complex @ Power Block 4
Polk County, Florida

Applicant: The applicant for this project is Progress Energy Florida. The applicant's authorized representative is Mr. Roger Zirkle, the Plant Manager of the Hines Energy Complex. The applicant's mailing address is P.O. Box 14042, MAC BB1A, St. Petersburg, Florida 33733.

Facility Location: Progress Energy Florida operates the existing Hines Energy Complex located in the southwest portion of Polk County, Florida, approximately 7miles south-southwest of Bartow and 5miles west-northwest of Fort Meade.

Project: The existing Hines Energy Complex currently consists of two operating electrical generating units (Power Blocks1 and 2) and another electrical generating unit currently under construction (Power Block3). Power Block1 is a 500MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2 is similar in design; the existing facility (inclusive of both Power Blocks) has a total generating capacity of 1,030 MW. Power Block3, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530MW power generation unit. After completion of this project (Power Block4), the plant will have a total generating capacity of approximately 2,090MW.
The existing power plant is located in Polk County, an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. The power plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, new projects at the existing facility must be reviewed for PSD applicability.

In August of 2004, the Department received a PSD permit application for the existing facility that would increase the generating output of the facility from 1560 to 2090 megawatts of output. Based on potential emissions increases, the project is subject to PSD preconstruction review for carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, and sulfuric acid mist. The Department has made a preliminary determination of the Best Available Control Technology (BACT) for each of these pollutants based on the following air pollution control equipment: low-NOx burners and a selective catalytic reduction system to reduce nitrogen oxides emissions; and the efficient combustion of clean, low-sulfur fuels to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist and sulfur dioxide. Based on the supporting air quality analysis of the potential impacts from increased operation, the applicant provided the Department with reasonable assurance that the project would not significantly contribute to or cause a violation of any state or federal ambient air quality standards and would not significantly contribute to or cause a violation of any PSD Class I or Class II increments. However, the project does require a PSD permit to authorize the requested construction, and upon completion of the project the plant will have an increase in steam-generated electrical capacity of approximately 190 MW. Therefore, the project is subject to the power plant site certification requirements of the Department.

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114 and fax number is 850/921-9533.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the project file is available at the Air Resource Section of the Department's Southwest District Office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 (Phone: 813/744-6100).

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all e-mail or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the 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 with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen (14) days of publication of the attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) 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, F.A.C.

A petition that disputes the material facts on which the Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue Air Permit is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S.

Mediation: Mediation is not available in this proceeding.

M119 2-2; 2005

FAX Cover Sheet

US EPA - Region 4
61 Forsyth St., SW
Atlanta, Georgia 30303

TO: Mike Halpin & Jim Pennington
FDEP

FAX #: 850-922-6979

RE: FPC-Hines PSD Comments

FROM: Katy R. Forney
Air Permits Section, US EPA - Region 4

Phone #: 404-562-9130

Date: 3/2/05

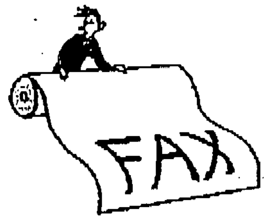
# of Pages (including cover): 4

COMMENTS:

Mike, I am out until next Thursday, but if you want to talk about anything (I am not sure if you will be in KY) but leave me a voicemail and I will try to call you back.

Thanks, K

If this FAX is poorly received, please call
Katy R. Forney @ 404-562-9130



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

MAR 0 2 2005

4APT-APB

Mr. Jim Pennington
Florida Department of
Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Pennington:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for Florida Power Corporation (FPC) - Hines Energy Complex, dated January 18, 2005. The draft PSD permit is for the proposed construction and operation of two combined cycle combustion turbines (CTs) with a total nominal generating capacity of 530 MW to be located near Fort Meade, FL. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. The CTs will primarily combust pipeline quality natural gas with 0.05 percent sulfur fuel oil combusted as backup fuel. As proposed, the CTs will be allowed to fire natural gas up to 8,760 hours per year per CT and to fire fuel oil a combined maximum of 1,000 hours per year for both CTs. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC).

Based on our review of the PSD permit application, preliminary determination, and draft PSD permit, we have the following comments:

1. According to the recently issued PSD permit for Florida Power & Light (FP&L) - Turkey Point, the Florida Department of Environmental Protection (FDEP) has determined through a rigorous best available control technology (BACT) evaluation that NO_x and CO emissions from combined cycle CTs of this type are as follows:

   - NO_x emission limits of 2.0 ppmvd and 8.0 ppmvd for natural gas and fuel oil firing, respectively. Compliance with these emission limits will be determined using a continuous emission monitoring systems (CEMS).

   - CO emission limits of 8.0 ppmvd (24-hour average) and 6.0 ppmvd (12-month rolling average) for both natural gas and fuel oil firing. Compliance with these emission limits will be determined using a CEMS. Additional CO emission limits of 4.1 ppmvd and 7.6 ppmvd are based on 3-hour stack tests and apply while firing natural gas in normal mode and duct burning mode, respectively.

The NO_x and CO BACT emission limits proposed by FDEP in the draft PSD permit for FPC - Hines are as follows:

- NO_x emission limits of 2.5 ppmvd and 10.0 ppmvd for natural gas and fuel oil firing, respectively. Compliance with these emission limits will be determined using a CEMS.

- CO emission limits of 8.0 ppmvd (24-hour average) and 12.0 ppmvd (24-hour average) for natural gas and fuel oil firing, respectively. Compliance with these emission limits will be determined using a CEMS.

While we understand the applicant's and FDEP's desire for simplicity when setting BACT emission limits, the FPC - Hines BACT limits are not consistent with, nor as stringent as, those in the recently issued FP&L - Turkey Point PSD permit. At a minimum, FDEP should include an explanation in the final PSD determination regarding the differing conclusion reached by the FPC - Hines BACT evaluation. Furthermore, FDEP should consider revising the BACT emission limits in the final FPC - Hines PSD permit to be more consistent with other recent combined cycle combustion turbine PSD permits issued by FDEP.

2. It is unclear whether or not draft PSD permit Condition 14, titled "Alternative Emission Limits," is supposed to replace the emission limits in Condition 10 when the CTs start up or shut down during a 24-hour period. Additionally, it is unclear if the excess emission allowances detailed in Condition 15 apply to the emission limits in Condition 14 as well as those in Condition 10. To clarify when each set of emissions limits apply, FDEP should add language to one or more of the permit conditions to better define the relationship among them. Furthermore, EPA notes that this method of dealing with startup and shutdown excess emissions is not consistent with previous PSD permits issued by FDEP for combustion turbines. FDEP should consider adopting a more standardized method of addressing startup and shutdown emissions in PSD permits.

3. In the preliminary determination, FDEP agrees with the applicant that use of low sulfur fuel oil (0.05% S) is BACT for SO_2 emissions when firing fuel oil. According to the PSD permit application, ultra low sulfur fuel oil (0.0015% S) was not even considered as a BACT option for controlling SO_2 emissions. Since ultra low sulfur fuel oil will be widely available in the near future, EPA believes that a fuel sulfur concentration of 0.0015% is the point at which any fuel oil combustion BACT analysis must begin.

If you have any questions regarding these comments or need additional information, please contact Katy Forney at 404-562-9130.

Sincerely,

Gregg M. Worley

Gregg M. Worley
Chief
Air Permits Section

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

RE:

PROGRESS ENERGY FLORIDA
HINES ENERGY COMPLEX – POWER BLOCK 4
PA 92-33SA3

STAFF ANALYSIS REPORT

February 16, 2005

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

RE:

PROGRESS ENERGY FLORIDA
HINES ENERGY COMPLEX – POWER BLOCK 4
PA 92-33SA3

RECOMMENDATION

If Progress Energy Florida agrees to abide by the Conditions of Certification, attached and incorporated herein as Staff Analysis Report, Appendix I, the Department of Environmental Protection would recommend certification of the Hines Energy Complex Power Block 4 Electric Power Generation Project to be constructed and operated in Polk County, Florida for generation of up to 530 MW (nominal) electric power to be generated by two natural gas fired, light oil back-up, 170 MW combustion turbines, two heat recovery steam generators, and a 190 MW steam turbine and generator.

DONE AND ISSUED this _____ day of February, 2005 at Tallahassee, Florida.

For

Hamilton S. Oven, Jr., P.E.
Administrator, Siting Coordination Office

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INTRODUCTION

On August 5, 2004, Progress Energy Florida (PEF) filed a Supplemental Site Certification Application (SSCA) with the Department of Environmental Protection (DEP) pursuant to the Florida Electrical Power Plant Siting Act (PPSA), Sections 403.501 through 403.518, Florida Statutes (F.S.). The SSCA is for the Hines Energy Complex Power Block 4 which is part four of six parts of the ultimate site capacity certified as PA92-33 on January 27, 1994. The SSCA proposes the construction and operation of a 530 MW (nominal) electric power generation facility. This facility would consist of two natural gas fired (with light oil as a back-up fuel) 170 MW combustion turbines, four heat recovery steam generators with duct burners, a 190 MW steam turbine and generator, and ancillary equipment. The proposed facility is known as Hines Energy Complex Power Block 4 and is located on a 5 acre site which is entirely within the existing 8,200 acre PEF Hines Energy Complex site. The site is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade – UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10").

Power Block 1 consists of two combined cycle combustion turbines with heat recovery steam generators (HRSGs), for a nominal total of 500 MWs, a 99 MMBtu/hr auxiliary boiler, a 1,300 kW diesel generator and a 97,570 barrel fuel oil storage tank. Emissions from each CT and HRSG combination are vented through a single stack for each pair. Power Block 2 consists of two combined cycle combustion turbines with unfired heat recovery steam generators (HRSGs) for a nominal total of 340 MWs, and a single steam-turbine electrical generator for a nominal total of 190 MWs. The existing facility (inclusive of both Power Blocks) has a total generating capacity of 1030 MW. Power Block 3 is under construction at the existing Hines Energy Complex. It is a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, a single 190 MW steam turbine-electrical generator, and related facilities.

2 SITE CERTIFICATION PROCESS

2.1 Determination of Need

Section 403.519, FS requires a formal "Determination of Need" be made by the Florida Public Service Commission (PSC) prior to certification of an electric power generating facility subject to the "Power Plant Siting Act" (sections 403.501-518, Florida Statutes). The issues evaluated in the PSC's determination proceedings include conservation measures that might mitigate the need for additional power, load management, load demand growth estimates and other, potentially more cost effective, alternatives for producing needed power. This determination serves as the report required of the PSC as part of the power plant site certification proceedings. The Department of Environmental Protection (DEP) must balance the determination of need with the social and environmental impacts when preparing overall recommendations for final approval or disapproval of a Supplemental Site Certification Application (SSCA).

On August 5, 2004, Progress Energy Florida filed a petition with the Florida Public Service Commission (PSC) for a determination of need for the Hines Energy Complex Power Block 4 pursuant to Section 403.519, F.S. On November 23, 2004, the Public Service Commission issued a final order granting the petition for determination of need for the Hines Energy Complex Power Block 4. The complete Order is attached as Appendix IIA. The following is excerpted from the PSC Order:

> ... it is...
>
> ORDERED by the Florida Public Service Commission that Progress Energy Florida, Inc.'s petition for determination of need for its proposed Hines Unit 4 is granted. It is further...
>
> ORDERED that this docket shall be closed if no appeal is filed within the time permitted for filing an appeal of this order..

2.2 Site Certification Application Review

The procedures and requirements for granting or denying a certification to construct and operate an electric power generating facility in the state of Florida are set forth in the "Florida Power Plant Siting Act", Sections 403.501-518, Florida Statutes, and the "Power Plant Siting Rule", Chapter 62-17, Florida Administrative Code. The statute establishes the certification agent to be the Siting Board which shall be composed of the Governor and Cabinet of Florida.

The Department of Environmental Protection (DEP) has been designated as the lead agency for the review and evaluation of Supplemental Site Certification Applications (SSCAs) and is charged with preparing a SSCA impact analysis report (*Staff Analysis Report*) and a recommendation to the Siting Board for granting or denying the requested certification. A recommendation to grant certification shall include a Conditions of Certification statement that specifies all requirements and restrictions of the Certification that will apply to the construction and operation of the proposed facility.

Specific concerns to be addressed in the review of a SSCA shall include but not be limited to:

- Determination of Need for electric power;
- nearfield and farfield impacts on air quality;
- impacts on surface water or groundwater quality;
- impacts on terrestrial and aquatic ecosystems;
- impacts from solid waste or hazardous waste disposal;
- impacts from domestic or industrial wastewater disposal;
- impacts from stormwater management;
- impacts from site modification such as noise or meteorological changes;
- impacts on water supply;
- impacts on traffic;
- impacts on public lands and submerged lands;
- environmental and public health risk assessments;
- impacts on archaeological sites and historic preservation areas;
- accessibility to transmission corridors;
- proximity to transportation systems;
- fuel and fuel transportation and on-site storage requirements;
- cooling system requirements;
- soil and foundation conditions;
- construction and operational safeguards; and
- any site specific concerns identified in the review process.

Although the DEP is designated as the lead agency, many of the concerns that are to be addressed in the SSCA impact assessment are outside the purview of DEP. Consequently, the Power Plant Siting Act ("Siting Act") requires several other state agencies to participate in the review process. Each of these agencies is directed to review the SSCA with regard to compliance with the statutory and administrative requirements of the reviewing agency. Each of these agencies is further directed to prepare a written report to the DEP explaining their findings and specifying any restrictions or requirements that should be included in the Conditions of Certification. These agencies are:

- Department of Community Affairs (DCA);
- Public Service Commission (PSC);
- Water Management District (WMD) with jurisdiction over the site;
- all local governments with jurisdiction over the site;
- Fish and Wildlife Conservation Commission;
- Regional Planning Council with jurisdiction over the site; and
- any other agency if requested by DEP.

Other agencies or interest groups are encouraged to provide information, expertise and comment relating to the impact assessment. Comments, concerns and issues raised by these agencies, interest groups and the general public are integrated into the overall review and are addressed in the DEP *Staff Analysis Report* where appropriate. Written comments received prior to the publication date of the report are included in their entirety in Appendix 3.

Throughout the course of the SSCA review process there are several formal public and administrative hearings required by the Siting Act. Among these are:

- Public Hearing on the SCA;
- Administrative Hearing on the DEP impact assessment and Conditions of Certification; and
- Certification Hearing before the Siting Board.

Subsequent to the issuance of a Certification, the licensed facility is required to participate in a Post Certification Review that determines compliance with the Conditions of Certification. Furthermore, the Certification may be modified by the Siting Board or the Department at the request of the facility. However, any modification request requires a formal application and is subject to the same scrutiny as the original SSCA.

On August 5, 2004, PEF filed a SSCA with the DEP for the Hines Energy Complex Power Block 4 pursuant to the PPSA. The impact assessment and Conditions of Certification for the proposed facility are the subjects of this report.

3 PROPOSED GENERATION AND TRANSMISSION FACILITIES

3.1 Site Location

The proposed facility is known as Hines Energy Complex Power Block 4 and is located on a 5 acre site which is entirely within the existing 8,200 acre PEF Hines Energy Complex site. The site is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade.

3.2 Fuel

Each gas turbine (CT) shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. While firing natural gas each CT may operate 8,760 hours per year. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 30,700,000 gallons in any consecutive 12 month period.

3.3 Air Emissions and Control

3.3.1 *Air Emissions Types and Sources*

Annual emissions for the Project are expected to exceed the PSD significant net emission increase thresholds. Based on the proposed emissions for the Project, PSD review is required for each of the following regulated pollutants:

- PM as total suspended particulate matter (TSP),
- Particulate matter with aerodynamic diameter of 10 microns or less (PM_{10}),
- SOx,
- NOx,
- CO,
- VOCs, and
- Sulfuric acid mist.

Polk County has been designated as an attainment area for all criteria pollutants (i.e., O_3, PM_{10}, SO_2, and NO_2) and is classified as PSD Class II area for PM_{10}, SO_2, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from new or modified facilities. The following analyses related to PSD are required for each pollutant emitted in significant amounts:

- Control technology review,
- Source impact analysis,

Table 1

Maximum Project Air Quality Impacts

Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.04	1	60	NO
	24-Hour	2.7	5	260	NO
	3-Hour	13	25	1300	NO
PM_{10}	Annual	0.04	1	50	NO
	24-Hour	1.6	5	150	NO
CO	8-Hour	23	500	10,000	NO
	1-Hour	63	2000	40,000	NO
NO_2	Annual	0.07	1	100	NO

- Air quality analysis (monitoring),
- Source information, and
- Additional impact analyses.

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 the Best Available Control Technology (BACT) be applied to control emissions from the source. 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. In addition, 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 air modeling approaches used by PEF demonstrate that the Project will comply with all Ambient Air Quality Standards (AAQS) and PSD Class I and II increments. As seen in Tables 1 and 2, the maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts. Therefore no further detailed modeling efforts are required for these pollutants.

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction

Table 2

Maximum Project Air Quality Impacts

Comparison to the PSD Class I Significant Impact Levels

Comparison to the PSD Class I Significant Impact Levels				
Pollutant	**Averaging Time**	**Max. Predicted Impact at Class I Area (ug/m^3)**	**Class I Significant Impact Level (ug/m^3)**	**Significant Impact?**
PM_{10}	Annual	0.001	0.2	NO
	24-hour	0.12	0.3	NO
NO_2	Annual	0.001	0.1	NO
SO_2	Annual	0.001	0.1	NO
	24-hour	0.17	0.2	NO
	3-hour	0.5	1	NO

---

ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the Table 3, the maximum predicted impacts for all pollutants with listed *de minimis* impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC emissions from the project to be 68 tons per year. Therefore, preconstruction monitoring for ozone is not required.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area (CNWA) located about 118 km to the north. The applicant's initial PM/PM_{10}, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels" for the Class I area. These values are tabulated in Table 1. Note that the values are miniscule if compared with the ambient air quality standards.

Table 3

Maximum Project Air Quality Impacts

Comparison to the *de minimus* Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimus Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimus?
PM_{10}	24-hour	2.5	10	~ 100	NO
NO_2	Annual	0.1	14	~ 15	NO
SO_2	24-hour	2.7	13	~ 40	NO
CO	8-hour	23	575	~ 2000	NO

Very low emissions are expected from this natural gas-fired, with backup fuel oil, combined cycle unit in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS).

The project impacts are also less than the significant impact levels for PM_{10}, CO, NO_X, and SO_2, which in-turn, are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare, and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Effects from sulfuric acid mist are also expected to be minor due to the low emissions expected from the Hines Energy Complex Power Block 4. The combination of low NO_X and VOC emissions insures that the project will not contribute significantly to regional ozone levels or to any impacts caused by such ozone levels.

According to the application, native Floridian species of vegetation, such as cypress, slash pine, live oak, and mangrove, will not be visibly damaged when exposed to 1300 ug/m^3 of SO_2 for 8 hours. This proposed project is predicted to have a maximum impact of 17 ug/m^3 of SO_2 over a 3-hour period and 4 ug/m^3 of SO_2 over a 24-hour period. The maximum predicted nitrogen (N) and sulfur (S) depositions are well below the significant impact levels for N and S deposition.

Pipeline natural gas is a clean fuel and produces little particulate emissions. The backup fuel oil will be limited to 0.05 percent sulfur and will exhibit relatively low particulate emissions. The very low NO_X, SO_2, and ammonia emissions will also minimize plume opacity and any effects on regional visibility.

3.3.2 *Air Emissions Controls*

The use of clean fuel, i.e., natural gas and low sulfur distillate oil, and dry-low-NOx (DLN) combustion controls will minimize air emissions to ensure compliance with applicable emission-limiting standards. Selective catalytic reduction (SCR) will be used to control NO_x levels when the CTs are operating in combined cycle mode.

Nitrogen oxides emissions are due to NO_X in the fuel and to the formation of NO_X when the fuel is combusted in air at high temperatures. DLN controls thermal NO_X formation by introducing excess air for lean combustion which 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.

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 in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. SCR units are typically used in combination with DLN combustion controls.

Construction activities will result in the generation of fugitive particulate matter (PM) emissions and vehicle exhaust emissions. Fugitive PM emissions will result primarily from land clearing and grubbing, ground excavation, grading, cut and fill operations, and vehicular travel over paved and unpaved roads.

3.4 Heat Dissipation System

An existing cooling reservoir currently occupies about 722 acres of the site and is being expanded to approximately 1,200 acres The expansion operation began in May 2004 and is anticipated to be completed in December 2005. The cooling reservoir is comprised of mine pit areas that have been regraded to accommodate this use.

The cooling water reservoir provides the source of water for circulating condenser cooling purposes for the heat recovery steam generators/steam turbines (HRSG/ST) in the combined cycle (CC) units. The major consumption and/or loss of water is evaporation from the cooling pond. The reservoir is adequate for the needs of Power Blocks 1, 2, 3, and 4.

3.5 Plant Water Use

3.5.1 *Domestic/Sanitary Wastewater*

Additional domestic/sanitary wastewater generated by Hines Energy Complex Power Block 4 will be handled by the existing Hines Energy Complex systems. No new facilities are planned.

3.5.2 *Potable Water Systems*

The existing permitted Hines Energy Complex potable water supply will be sufficient to incorporate the needs of the Power Block 4. Potable supply quantities will be provided on-site through treatment of groundwater withdrawals.

3.5.3 *Process Water Systems*

Demineralized water will be needed as makeup to the steam system to replace HRSG blowdown and steam losses. Demineralized water will also be used when firing the CTs on fuel oil to control NOx emissions.

Raw water from the cooling reservoir will be used as the feed to the demineralizer, which will reduce dissolved solids to required levels. Reverse osmosis units and mobile ion exchange units will be used for water demineralization. Regeneration of the ion exchange units will take place off-site. The reverse osmosis reject will be routed to the existing brine pond.

3.6 Solid and Hazardous Waste

3.6.1 *Solid Wastes*

Only a small amount of solid waste will be generated by the Hines Energy Complex Power Block 4 and will be limited to municipal solid waste and infrequent change of inlet air filters. This material is non-hazardous and is sent to an off-site landfill for disposal. Periodic replacement of SCR catalyst will be recycled or disposed of according to applicable requirements.

3.6.2 *Hazardous Wastes*

The Hines Energy Complex Power Block 4 will generate a small amount of hazardous waste limited to periodic chemical cleaning and spent solvents, paints, and other maintenance chemicals. These wastes will be managed in accordance with Chapter 62-730, F.A.C, and 40 CFR 262.34.

3.7 On-Site Drainage System

The surface water management facilities serving the entire power plant project, including Power Block 4, with the exception of the buffer and drainage enhancement areas, capture and utilize all the rain falling within the site boundaries. This water is routed to the cooling pond system and offsets groundwater withdrawals. On an annual average daily basis, approximately 6.5 MGD of rainwater is captured by the cooling reservoir from direct precipitation and runoff from other areas surrounding the reservoir.

4 AGENCY COMMENTS

4.1 General

Copies of the PEF Supplemental Site Certification Application for the Hines Energy Complex Power Block 4 site were sent to the following agencies with a request for comments:

- Public Service Commission
- Department of Environmental Protection
- Department of Community Affairs
- Fish and Wildlife Conservation Commission
- Southwest Florida Water Management District
- Central Florida Regional Planning Council
- Polk County
- Department of Agriculture and Consumer Services
- Department of Transportation
- Department of State, Division of Historical Resources
- Department of Health

Copies were also sent to the Division of Administrative Hearings for the Administrative Law Judge's information and to the U.S. Environmental Protection Agency.

4.2 Public Service Commission

On November 23, 2004, the Public Service Commission (PSC) submitted their report containing a copy of the PSC Order granting Determination of Need for the electric power to be generated by the Hines Energy Complex Power Block 4. The PSC final report is discussed in section 2.1 of this report. A copy of the PSC's report is attached as Appendix II.

4.3 Department of Community Affairs

On January 11, 2005, the Department of Community Affairs (DCA) submitted their final report on the Hines Energy Complex Power Block 4 Supplemental Site Certification Application. A copy of the DCA's report is attached as Appendix III.

The DCA does not object to approval of the Hines Energy Complex Power Block 4. The DCA is not aware of any significant inconsistencies between the Hines Energy Complex Power Block 4 and the applicable local government comprehensive plans, land development regulations, or the Coastal Zone Management Program.

Subject to suggested conditions of certification, the DCA did not object to certification of the SSCA.

4.4 Fish and Wildlife Conservation Commission

No report was filed. The FWCC did not object to certification of the site.

4.5 Southwest Florida Water Management District

On April 15, 2004, the Southwest Florida Water Management District (SWFWMD) submitted their final report on the Hines Energy Complex Power Block 4 Supplemental Site Certification Application. A copy of the SWFWMD's report is attached as Appendix IV.

Subject to suggested conditions of certification, the SWFWMD recommended approval of the Hines Energy Complex Power Block 4.

4.6 Central Florida Regional Planning Council

No report was filed. The CFRPC did not object to certification of the SSCA.

4.7 Polk County

No report was filed. Polk County did not object to certification of the SSCA.

4.8 Department of Agriculture and Consumer Services

No report was filed. DACS did not object to certification of the SSCA.

4.9 Department of Transportation

On January 7, 2005, the Department of Transportation (DOT) submitted their final report on the Hines Energy Complex Power Block 4 Supplemental Site Certification Application. A copy of the DOT's report is attached as Appendix V.

Subject to suggested conditions of certification, the DOT recommended approval of the Hines Energy Complex Power Block 4.

4.10 Department of State, Division of Historical Resources

No report was filed. DHR did not object to certification of the SSCA.

4.11 Department of Health

No report was filed. The Department of Health did not object to certification of the SSCA.

5 GENERAL SITE SUITABILITY CONCERNS

5.1 Impact on Area Land Use

The Project area is comprised of five acres wholly contained within the existing 8,200 acre Hines Energy Complex site. The overall Hines Energy Complex site was evaluated for impacts on land use during the initial certification process. In 1993, the Siting Board found that the overall site to be in compliance with all applicable zoning ordinances and Comprehensive Plan requirements of Polk County and would meet the objectives, goals and policies of the State Comprehensive Plan.

5.2 Impact on Surrounding Populations

The proposed project should not adversely affect the general health, safety, or welfare of the surrounding neighborhood or County as a whole. The highway network will be temporarily impacted during the construction phase by construction related traffic.

The power plants, cooling reservoir, and other facilities will occupy approximately 8,200 acres of previously mined phosphate land adjacent to the headwaters of McCullough Creek and Camp Branch, which are tributaries of the Peace River. The site includes 900 acres of power generating and ancillary facilities and a 722-acre cooling reservoir that will be expanded to approximately 1,200 acres. The cooling reservoir expansion operation began in May 2004 and it is anticipated to be completed in December 2005.

Approximately 2,000 acres are designated as buffer areas along the east and southeast portions of the site and approximately 520 acres along the west and southwest portions of the site have been reclaimed to enhance drainage to McCullough Creek.

According to the applicant, the project will require about 6 additional permanent employees, some of who will be drawn from the local labor force. Therefore, residential growth due to this project will be minimal. This project is a response to statewide and regional growth and also accommodates more growth. The type of project proposed has a small overall physical footprint.

The Hines Energy Complex has been designed to comply with the applicable provisions of the Polk County zoning ordinances and Comprehensive Plan requirements. The impact of Power Block 4 on the existing land uses outside of the larger Hines Energy Complex site was contemplated as part of the Ultimate Site Certification process when the site was certified in 1994. All the facilities associated with the project are needed for and related to the generation of electricity.

5.3 Accessibility to Transmission Corridors

The new generating unit will connect to the existing electrical transmission line network at the Hines substation within the existing Hines Energy Complex site. No new transmission lines are to be constructed as part of this site certification.

5.4 Proximity to and Impacts on Transportation Systems

There will be no construction of new temporary or permanent roads that connect offsite or of new onsite railroads. The existing Hines Energy Complex entrance will be used for Project construction. PEF states that no permanent capacity-enhancing improvements are necessary to accommodate the total traffic conditions associated with the average peak construction employment for Hines Energy Complex Power Block 4.

5.5 Soil Bearing Strength

Mined areas within the site have been filled with overburden and then covered with engineered fill to provide support for the plant foundations, piping, electrical duct banks, trenches, and manholes. No adverse impact is expected to soil stability or bearing strength since the power block foundation will be supported by concrete piles seated into underlying dense carbonate silts and clays of the intermediate aquifer.

5.6 Karst Hydrogeology

Current features at the project area of the Power Block 4 site reflect past and present power plant related activities. It is not anticipated that any Power Block 4 activities will enhance the formation of sinkholes.

5.7 Flood Potential

The project area is located in the Peace River drainage basin. No part of the proposed site is inside the 100-year flood zone.

5.8 Impact on Public Lands

There are no impacts to Public Lands.

5.9 Impact on Archaeological Sites and Historical Preservation Areas

The Division of Historic Resources has found no significant archaeological or historical resources and does not indicate that any are likely to be found at the project site.

5.10 Impacts on Environmental Resources

. The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It 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, referred to as the regulatory options, were used by the applicant in their analysis. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied 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 Tampa International Airport and Ruskin respectively (surface and upper air data). The 5-year period of meteorological data was from 1991 through 1995. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, 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.

Since the closest PSD Class I area, the Chassahowitzka National Wilderness Area (CNWA) is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. Meteorological data were obtained and processed for the calendar years of 1990, 1992 and 1996, the years for which MM4 and MM5 data are available. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Pipeline natural gas is a clean fuel and produces little particulate emissions. The backup fuel oil will be limited to 0.05 percent sulfur and will exhibit relatively low particulate emissions. The very low NO_X, SO_2, and ammonia emissions will also minimize plume opacity and any effects on regional visibility. The Class I Chassahowitzka NWA, where visibility impacts are normally of greater concern, is about 118 kilometers from the proposed site. A regional haze analysis using the CALPUFF model predicted impacts less than the federal land manager's visibility impairment criteria; therefore impacts on visibility are expected to be insignificant.

Very low emissions are expected from this natural gas-fired, with backup fuel oil, unit in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS).

The project impacts are also less than the significant impact levels for PM_{10}, CO, NO_X, and SO_2, which in-turn, are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare, and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Effects from sulfuric acid mist are also expected to be minor due to the low emissions expected from the Hines Energy Complex Power Block 4. The combination of low NO_X and VOC emissions insures that the project will not contribute significantly to regional ozone levels or to any impacts caused by such ozone levels.

According to the application, native Floridian species of vegetation, such as cypress, slash pine, live oak, and mangrove, will not be visibly damaged when exposed to 1300 ug/m^3 of SO_2 for 8 hours. This proposed project is predicted to have a maximum impact of 17 ug/m^3 of SO_2 over a 3-hour period and 4 ug/m^3 of SO_2 over a 24-hour period.
The maximum predicted nitrogen (N) and sulfur (S) depositions are well below the significant impact levels for N and S deposition.

SWFWMD reviewed the cumulative, i.e., all existing legal water users within the modeled domain, U.S.G.S. McDonald-Harbaugh Modular Three-Dimensional Finite-Difference Ground-Water Flow Model (MODFLOW) submitted as part of the SSCA. It was determined that the modeling was sufficient in scope and detail to predict impacts to surface environmental features, off-site land uses, and to existing legal users. The simulation provided predicted drawdowns in the potentiometric surface of the Upper Floridan and intermediate aquifers and the water table of the surficial aquifer. Based on the cumulative model results, the predicted drawdown impacts in the water table of the surficial aquifer are 0.2 feet at the property boundary. The predicted drawdowns in the intermediate and Upper Floridan aquifers are 3.8 and 5.2 feet, respectively, at the property boundaries. These predicted impacts on the water table of the surficial aquifer and the potentiometric surfaces of the intermediate and Upper Floridan aquifers were not deemed to be adverse impacts to existing legal users, on- and off-site wetlands, and to off-site land uses.

6 FACILITY SPECIFIC CONCERNS

6.1 Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the eighteen-stage compressor of the GE 7FA where it is compressed by a pressure ratio of about 15 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 14 separate can-annular combustors.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (^{o}F). Units such as the 7FA operate at lower flame temperatures which minimizes NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 ^{o}F. 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.

Power Block 4 is designed to operate in the combined cycle mode. In this mode each gas turbine directly drives an electric generator then the exhausted gases are used to produce steam in a heat recovery steam generator (HRSG). The steam produced in the two HRSGs is then combined to drive a single steam turbine-electrical generator.

Steam exiting the steam turbine is either returned for reheating in the high pressure section of the HRSG or sent to the condenser. Cooling water to the condenser is provided from the cooling reservoir. Demineralized makeup water is added to the condensed water which is returned to the steam cycle. Blowdown from the steam cycle is sent to the existing cooling reservoir.

In simple cycle mode, the thermal efficiency of the GE 7FA line of combustion turbines is about 35 percent. In combined cycle mode, with all steam used to generate electrical power, efficiencies of 56 percent are possible.

At high ambient temperature the units cannot generate as much power because of lower compressor inlet density. To compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures) an evaporative chiller may be installed ahead of the combustion turbine inlet. At an ambient temperature of 102 ^{o}F and low relative humidity, roughly 10 MW of power can be regained by using the chillers.

6.2 Air Resources

6.2.1 PSD Analysis

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

A "major facility" is defined as any one of twenty-eight named source categories that has the potential to emit at least 100 TPY, or any other stationary facility that has the potential to emit at least 25 TPY of any pollutant regulated under the CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

PSD review is used to determine whether significant air quality deterioration will result from the 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 essentially identical to federal regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)]. Major facilities are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

- Control technology review
- Source impact analysis,
- Air quality analysis,
- Source information, and
- Additional impact analyses.

6.2.2 *Project Description*

The Hines Energy Complex Power Block 4 is a 530 MW (nominal) electric power generation facility. This facility would consist of two natural gas fired, 170 MW, GE 7FA combustion turbines, two heat recovery steam generators, a 190 MW steam turbine and generator, and ancillary equipment. The proposed facility is to be located on a five acre site which is entirely within the existing Hines Energy Complex site.

The project site is located in Polk County, which has been designated by EPA and the Department as an attainment area for all criteria pollutants. Polk County and surrounding counties are designated as PSD Class II. The site is located approximately 118 km from the closest part of the Chassahowitzka National Wilderness Area.

Table 4

BACT Determination

Pollutant	Fuel	Stack Test, 3-Run Average		CEMS Block Average
		ppmvd @ 15% O_2	lb/hr	ppmvd @ 15% O_2
CO	Oil	12.0	57.2	12.0, 24-hr
	Gas	8.0	32.1	8.0, 24-hr
NO_X	Oil	10.0	82.4	10.0, 24-hr
	Gas	2.5	17.7	2.5, 24-hr
PM/PM_{10}	Oil/Gas	Fuel Specifications		
		Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2	Oil/Gas	2 gr S/100 SCF of gas, 0.05% sulfur fuel oil		
Ammonia	Gas	5	NA	NA

Note: The Department accepts as BACT, the applicant's proposal for natural gas as the exclusively fired fuel in order to control emissions of PM and SO2 from the auxiliary boiler.

6.2.3 *Emission Limitations*

Table 4 gives the BACT limits determined for the Power Block 4 assuming full load. Values for NO_X , VOC and CO are corrected to 15% O_2 on a dry volume basis. These emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are specified in the PSD permit and therefore in the Conditions of Certification.

6.3 Water Resources

6.3.1 *Review of Consumptive Uses of Water*

An original estimate of groundwater needed for the ultimate site capacity project was 40 MGD. Quantities were reduced due to utilizations of rainwater cropping and internal reuse of wastewater. In its original application, PEF intended to fuel the Hines Energy Complex using pulverized coal, which would have had an estimated groundwater use of 31.6 MGD. Through switching to burning natural gas and/or coal gas as fuels rather than pulverized coal, and by agreeing to develop and use alternative sources, including reuse water from the City of Bartow and locating an additional 1.1 MGD from an undetermined source, PEF reduced the requested groundwater needs to 17.5 MGD. If SWUCA groundwater withdrawals are capped ,12.5 MGD of this must be offset.

Table 5
Groundwater Withdrawals

	Ultimate (PB 1, 2, 3, 4, 5, & 6) Permitted Groundwater Withdrawal(1) (gpd)	Existing (PB 1, 2, & 3) Total Groundwater Withdrawal (gpd)	Proposed (PB No. 4) Groundwater Withdrawal (gpd)	Proposed (PB 1, 2, 3, & 4) Total Groundwater Withdrawal (gpd)
AVERAGE DAILY	17,500,000	2,619,000	2,400,000	5,019,000
PEAK MONTHLY	17,500,000	4,435,000	4,400,000	8,835,000
MAXIMUM DAILY	N/A	N/A	N/A	N/A

Note: (1) Only 5.0 MGD are permitted if groundwater withdrawal within the SWUCA becomes fixed.

All groundwater pumped onsite, except for groundwater produced for personnel/sanitary uses, will be pumped directly to the cooling water reservoir to replace evaporative losses, seepage losses, and losses associated with industrial uses. Reuse water from the City of Bartow, rainfall captured on site and other sources of water are also pumped directly into the cooling water reservoir to compensate for those losses.

The total water demand at the Hines Energy Complex for process make-up, cooling, and potable and sanitary purposes is 23.6 MGD. Of this total demand, the quantity that is allowed to be pumped from the Upper Floridan aquifer is indicated in Table 5.

The cooling water reservoir provides the source of water for circulating condenser cooling purposes for the heat recovery steam generators/steam turbines (HRSG/ST) and combined cycle (CC) units. The major consumption and/or loss of water is evaporation from the cooling pond. Groundwater for the cooling reservoir is supplied through five onsite wells (SWFWMD ID Nos. 1, 2, 3, 4, and 5). A sixth well (SWFWMD ID No. 6) will provide all potable and domestic service water system needs of the power plant.

Process wastewater streams from the overall project facilities will be treated on-site and returned to the cooling reservoir. The facility is designed for zero discharge to the surface waters of the state and should pose no pollution threat to surface waters.

6.3.2 *Groundwater Resources*

Activities associated with site preparation and construction are expected to produce minimal changes to groundwater quality, quantity or levels in the site vicinity. No adverse impacts to groundwater resources from dewatering activities are expected. However, if harm occurs to other previously permitted users by the Power Block 4 withdrawals, PEF will be required to mitigate that harm, or to reduce or cease the withdrawal of Floridan aquifer water.

6.3.3 *Potential Wetland Impacts*

Construction and operation of Power Block 4 will not impact any wetland areas.

6.3.4 *Existing Legal Uses*

The area surrounding the project site is currently rural and relatively undeveloped. No interference to existing legal uses due to the withdrawals of water is anticipated.

6.3.5 Water Conservation

Power Block 4 uses combined cycle technology. With combined cycle technology, the steam used to generate electricity will be condensed and reused in a continuous loop. Generally, Combined Cycle technology is conservatively estimated to require 53 percent less water than a traditional steam-generation. In addition, because the primary source of fuel for the plant is natural gas, the need for pollutant stripping-related water use is greatly reduced.

All waters used in the steam cycle will be recycled back to the cooling reservoir. In addition, stormwater, and process water recovered from the combustion turbine and heat recovery steam generators will be collected and pumped into the cooling reservoir. These measures are indicative of the conservation measures included under the SSCA.

6.4 Noise Impacts

PEF will maintain all operational sound levels of the plant in compliance the Polk County requirements. Any recurring exceedences will be immediately addressed by PEF and mitigated.

6.5 Traffic Impacts

The proposed expansion should not adversely affect the general health, safety, or welfare of the surrounding neighborhood or County as a whole. The highway network will be temporarily impacted during the construction phase by construction related traffic. All construction employees will use the main plant entrance. PEF states that no permanent capacity-enhancing improvements are necessary to accommodate the total traffic conditions associated with the average peak construction employment.

7 CONSTRUCTION AND OPERATIONAL SAFEGUARDS

As outlined in the application, construction procedures, including run-off control facilities and practices to avoid contamination of state waters, will be implemented. The construction site will be isolated from the general public by appropriate means which may include fences and guards. Compliance with OSHA standards and the provisions of Section 440.56, F.S., should adequately protect construction workers and operating personnel.

The conceptual design of the major pollution control equipment appears sufficient to protect the public and the environment from significant harm.

8 COMPLIANCE AND VARIANCES

There are no variances requested for this project.

9 CONCLUSIONS

9.1 Construction Impacts

Construction of the proposed Hines Energy Complex Power Block 4 would have the following impacts:

- Disruption of lands most of which have been previously disturbed.
- Construction and operation noise levels should not be an annoyance to outside activities at the nearest residences.
- Construction traffic to and from the site should not cause any significant congestion in the plant vicinity.

9.2 Operation Impacts

The Hines Energy Complex Power Block 4 will burn natural gas with light oil as a backup. Impacts on air quality will include emissions such as sulfur dioxide, oxides of nitrogen, particulate matter and other minor constituents such as hydrocarbons. These emissions will be limited by use of control technology considered to be the best available. Fugitive dust from vehicles and heavy equipment will be controlled by a variety of methods to comply with federal and state emission limitations. The plant is not expected to contribute to violations of ambient air quality standards or to significantly impact public health and the environment.

The facility is designed for zero discharge to the waters of the state and should pose no pollution threat to surface waters. There should be sufficient water available from the Upper Floridan aquifer and from reclaimed wastewater to supply the volume requirements of the facility.

Findings of the reviewing agencies are:

- The Public Service Commission has concluded that a need exists for the 530 MW of the facility.
- The SWFWMD recommended approval of the proposed project subject to compliance with the Recommended Conditions of Certification.
- The Department of Community Affairs concluded that, subject to compliance with the Conditions of Certification, the proposed facility would meet the objectives, goals and policies of the State Comprehensive Plan.
- The Department of Transportation has given conditional approval to the project.
- Polk County did not object to certification.
- Fish and Wildlife Conservation Commission did not object to certification.
- Central Florida Regional Planning Council did not object to certification.
- Department of State Division of Historical Resources did not object to certification.

- Department of Environmental Protection recommended approval of the proposed project subject to compliance with the Recommended Conditions of Certification.
- Department of Agricultural and Consumer Services did not object to certification.
- Department of Health did not object to certification.

In conclusion, we find that, subject to compliance with the Conditions of Certification, the proposed design offers reasonable assurance that the standards of the Department of Environmental Protection and other affected regulatory agencies will be met.

APPENDICES

APPENDIX I

CONDITIONS OF CERTIFICATION

CONDITIONS OF CERTIFICATON
SUPPLEMENTAL APPLICATION PA 92-33SA3
PROGRESS ENERGY FLORIDA – HINES ENERGY COMPLEX – POWER BLOCK 4

State of Florida
Department of Environmental Protection
Hines Energy ~~Center~~ Complex: ~~-For~~ Power Block 1, 2, - 3, and 4
PA 92-33

Conditions of Certification **~~09/11/2003~~ February 16, 2005**

I through **XII** no change.

XIII. AIR

The construction and operation of Hines Energy Complex (Project) shall be in accordance with all applicable provisions of Chapters 62-210 to 297, F.A.C. and New Source Performance Standards (NSPS) Subparts GG, Dc, and Kb. The following emission limitations and conditions reflect Emission Limit determinations for Power Block 1 - 485 MW (two combined cycle combustion turbines and auxiliary equipment) as contained in permit 1050234-AV, Power Block 2 – 530 MW (two combined cycle combustion turbines and auxiliary equipment) of generating capacity for which the need has been determined governed by permit 1050234-001-AV, ~~and~~ Power Block 3 - 530 MW (two combined cycle combustion turbines and auxiliary equipment) of generating capacity governed by ~~draft~~ permit1050234-006-AC, and Power Block 4 - 530 MW (two combined cycle combustion turbines and auxiliary equipment) of generating capacity governed by draft permit1050234-010-AC. Emission limit determinations for the remaining phases will be made upon review of supplemental applications. In addition to the foregoing, the Project shall comply with the following conditions of certification as indicated.

A. General Requirements

1. The maximum heat input (HHV) to each combustion turbine (CT) in Power Block 1 at an ambient temperature of 59 °F shall neither exceed 1,757 MMBtu/hr while firing natural gas, nor 1,846 MMBtu/hr while firing fuel oil. Heat input may vary depending on ambient conditions and the CT characteristics. The maximum heat input rates based on the higher heating value of the fuels (HHV) to each combustion turbine (CT) in Power Blocks 2, ~~and~~ 3, and 4 at an ambient temperature of 59 °F shall not exceed 1,915 MMBtu/hr while firing natural gas, nor 2,020 MMBtu/hr while firing distillate fuel oil. The maximum heat input rates for the CTs in Power Blocks 1, 2, ~~and~~ 3, and 4 will vary depending on ambient conditions and the combustion turbine characteristics that are described by the manufacturer's curves required by condition ~~XIII.C.3~~. **XIII.*G*.**8 Operation of these units at less than 60% capacity (based on heat input rates) is not allowed, except as required to cycle the units through periods of startup, shutdown and malfunction. The terms startup, shutdown and malfunction are defined in rule 62-210.200, F.A.C.

2. Each of the CTs in Power Blocks 1, 2, ~~and~~ 3, and 4 may operate continuously, i.e., 8,760 hrs/year.

3. through 10. no change.

B. ~~Emission Limits~~ Power Blocks 1 and 2: Installation and Operation

ID	Emission Unit Description
	Power Block 1, CT 1A and 1B (two 250 MW gas turbine with unfired HRSGs)
	Auxiliary boiler
	Diesel generator (1,300 kW)
014	Power Block 2, CT 2A (170 MW gas turbine with unfired HRSG)
015	Power Block 2, CT 2B (170 MW gas turbine with unfired HRSG)

1. through 5. no change.

C. Power Block 3: Installation and Operation

ID	Emission Unit Description
016	Power Block 3, CT 3A (170 MW gas turbine with unfired HRSG)
017	Power Block 3, CT 3B (170 MW gas turbine with unfired HRSG)

1 through 12 no change.

D. Power Block 4: Installation and Operation

These Conditions of Certification authorize construction and installation of the following new emissions units.

ID	Emission Unit Description
018	Power Block 4, CT 4A (170 MW gas turbine with unfired HRSG)
019	Power Block 4, CT 4B (170 MW gas turbine with unfired HRSG)
020	Natural Gas-fired auxiliary boiler

{Permitting Note: The Hines Energy Complex, Power Block 4 (Power Block 4, or "the project") consists of 2 gas turbine-electrical generator sets (Units CT 4A and CT 4B), 2 unfired HRSGs, and a single steam-turbine electrical generator.}

1. The Permittee is authorized to install, tune, operate, and maintain two General Electric Model 7FA gas turbine-electrical generator sets each with a nominal generating

capacity of 170 MW. Each gas turbine shall have dual-fuel capability. The gas turbines will utilize dry low-NOx (DLN) combustors.

2. Gas Turbine NOx Controls

a. The Permittee shall operate and maintain the DLN combustion system to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. The Permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

c. The Permittee shall install, tune, operate, and maintain a SCR system to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

3. The Permittee is authorized to install, operate, and maintain two heat recovery steam generators (HRSGs). Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 4A or CT 4B) and deliver steam to the steam turbine-electrical generator through a common manifold. *{Permitting Note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}*

4. The Permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 2.5 ppmvd corrected to 15% oxygen when natural gas is fired and 5.0 ppmvd corrected to 15% oxygen when distillate oil is fired.

5. Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 30,700,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 1,000 hours of operation per year per turbine, based on 59 °F annual average*

temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}

6. Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

7. Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

8. Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO [a]	8.0	12.0	24 hour block
NOx [b]	2.5	10.0	24 hour block
VOC [c]	1.3	3.0	3 hours
Ammonia [d]	5.0	5.0 [g]	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM_{10} [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO_2 [f]	Fuel specifications.

Notes:

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data. The Department shall revise the CO emissions standards following any future installation of an oxidation catalyst pursuant to condition* **XIII.*D.***4.*}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as NO2. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as propane. *Compliance with this standard is adequate to avoid a PSD/BACT Review.*

d. Each SCR system shall be designed and operated with an ammonia slip of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs.

Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

e. The fuel specifications established in condition **XIII.*D.*5.** of this section combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in condition **XIII.*D.*5.** of this section effectively limit the potential emissions of SAM and SO2 from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in condition **XIII.*J.*6.**

g. Although the ammonia slip limit is established at 5.0 ppm, compliance shall be demonstrated while combusting natural gas.

{Permitting Note: Informational only - the concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):

- *CO = 32.1 lb/hr for natural gas firing and 57.2 lb/hr for distillate fuel oil firing,*
- *NOx = 17.7 lb/hr for natural gas firing and 82.4 lb/hr for distillate fuel oil firing,*
- *VOC =3.1 lb/hr for natural gas firing and 8.1 lb/hr for distillate fuel oil firing,*
- *PM10 = 10.1 lb/hr for natural gas firing and 39.1 lb/hr for distillate fuel oil firing, and*
- *SO2 = 5.4 lb/hour for natural gas firing and 109.2 lb/hr for distillate fuel oil firing.*

SAM emissions are estimated to be less than 10% of the SO2 emissions.}

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9. All operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.

10. Excess emissions caused 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data.

11. Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity.

12. During any period containing 24 hours of continuous operation, in which at least one hour of startup or shutdown operation has occurred, the following alternative emission limits shall apply on a 24 hour average basis:

a. An alternative NOx limit of 125 lb/hr shall apply if natural gas is the exclusively fired fuel;

b. An alternative NOx limit of 370 lb/hr shall apply if any fuel oil is fired; and

c. An alternative CO limit of 175 lb/hr shall apply when firing either natural gas or fuel oil.

13. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, oil-to-gas fuel switching, or documented malfunction. Excess emissions shall in no case exceed two hours in any 24-hour period

14. As provided in this paragraph, NOx and CO emissions data recorded during periods of oil-to-gas fuel switches and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of condition **XIII.*D*.8.**

a. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.

b. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that meets the notification requirements specified in condition **XIII.*J*.8.**

c. The Permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented.

15. CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the Permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.

E. Power Block 5: Installation and Operation (Reserved)

F. Power Block 6: Installation and Operation (Reserved)

~~D~~G. Performance Testing

1. no change.

2. Test Methods for ~~Emission Units 016 and 017~~ Power Block 3, and 4: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Sources This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources

Method	Description of Method and Comments
	(Instrumental Analyzer Procedure)
9	Visual Determination of the Opacity of Emissions from Stationary Sources The test shall be conducted for a minimum of 30 minutes.
10	Determination of Carbon Monoxide Emissions from Stationary Sources This method shall be based on a continuous sampling train.
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography (Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at http://www.epa.gov/ttn/emc/ctm.html. The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

3. Initial Compliance Determinations ~~EU 016 and 017~~ Power Block 3, and 4: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. Each unit shall be tested when firing natural gas and when firing distillate fuel oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NOx standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the Permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7) (a)1., F.A.C. and 40 CFR 60.8]

4. Continuous Compliance ~~EU 016 and 017~~ Power Block 3, and 4: The Permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the Permittee shall submit a report to the DEP SW District Office summarizing results of the RATA. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

a. through b. no change.

5. Additional Ammonia Slip Testing ~~EU 016 and 017~~ Power Block 3, and 4: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the Permittee shall:

5.a.. through 7. no change.

8. Emission Tests Required for ~~Emission units 014 and 015~~ Power Block 2: The owner or operator shall demonstrate compliance with the emission limits of this section for ~~Unit 014 and 015~~ Power Block 2 for the following pollutants, by testing each emissions unit at the frequencies and using the test methods specified below. Initial emissions testing shall be performed separately for each of the allowable fuels. Annual emissions testing while firing distillate fuel oil is not required during any federal fiscal year (October 1 – September 30) during which less than 5,480,000 gallons of distillate fuel oil is fired in both emissions units combined.

[Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year for each turbine.]

Pollutant	Test Method [1]	Test Frequency
PM/PM10	Method 5 [2]	Initially and annually
Ammonia	CTM-027 [3]	Initially and annually
VE	Method 9 [4]	Initially and annually
VOC	Method 25A, and optional Method 18 [5]	Initially and prior to renewal of each subsequent operation permit

[1] Test methods are from 40 CFR 60 Appendix A, except for Method CTM-027, "Procedure for Collection and Analysis of Ammonia in Stationary Sources," which is an EPA conditional test method.

[2] For tests conducted while firing gas, the sampling time for each run shall be a minimum of two hours and the sampling volume shall be a minimum of 60 dscf. For tests conducted while firing oil, the sampling time for each run shall be a minimum of one hour and the sampling volume shall be a minimum of 30 dscf. Only an analysis of the "front half catch" is required.

[3] The test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd.

[4] The test shall be conducted for a minimum of 30 minutes simultaneously with one run of the Method 5 test.

[5] Method 18 may be used simultaneously with Method 25A to determine the concentration of methane and ethane which may be subtracted from the results of the Method 25A analysis, with all results expressed on a common basis.

In addition to the requirements of condition 16 of Section II of Permit PSD-FL-296, permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average turbine inlet temperature during the test (with 100 percent represented by a curve depicting heat input vs. turbine inlet temperature provided by the turbine manufacturer).

Manufacturer's curves that relate combustion turbine heat input to turbine inlet temperature shall be provided to the Department's Bureau of Air Regulation and the Southwest District Office within 45 days of completing the initial compliance testing.

Replacement of the major components of the air pollution control equipment, such as SCR catalyst or the combustors, may be used by the Department as justification to require a special compliance test pursuant to the requirements of condition 22 of Section II of Permit PSD-FL-296. [Rules 62-4.070(3), 62-212.400 and 62-297.310, F.A.C.]

9. Continuous Emission Monitoring System for ~~Units 014, 015, 016 and 017~~ Power Block 2, 3, and 4:

a. through g. no change.

h. Diluent Monitors for ~~EU 016 and 017~~ Power Block 3 and 4. The oxygen or carbon dioxide (CO2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

i. Moisture Correction for ~~EU 016 and 017~~ Power Block 3 and 4. Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the Permittee may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). If the CEMS measures concentration on a wet basis and the diluent monitor measures CO2 on a wet basis, then the Permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

j. 1-Hour Block Averages for ~~EU 016 and 017~~ Power Block 3 and 4. Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The Permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

k. 24-hour Block Averages for ~~EU 016 and 017~~ Power Block 3 and 4: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted.

Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block.

l. Data Exclusion for ~~EU 016 and 017~~ Power Block 3 and 4. Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 13 and 14 of this section.

m. Availability for ~~EU 016 and 017~~ Power Block 3 and 4. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the Permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The Permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department.

10. Water Injection Monitoring Requirements for ~~EU 016 and 017~~ Power Block 3 and 4: In accordance with the manufacturer's specifications, the Permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The Permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx CEMS downtimes or malfunctions, the Permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition.

11. no chamge.

12. Monitoring of Operation: To demonstrate compliance with the fuel consumption and sulfur content limits of conditions ~~XIII.A.3., 6. and XIIIC.6(b)~~ **XIII.*A*., XIII.*B*., XIII.*C*. and XIII.*D*.** the owner or operator shall monitor and record the rates of consumption and sulfur content of each of the allowable fuels in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the heat input limits of conditions ~~XIII.A.1 and XIII.C.5.~~ **XIII.*A*.,-XIII.*B*., XIII.*C*. and XIII.*D*.** of this section, the owner or operator shall monitor and record the operating rate of each emissions unit on a daily average basis, considering the number of hours of operation during each day, including the duration of startup, shutdown and malfunction episodes. To demonstrate compliance with the 60% turbine capacity limit of condition 3 of this section, the owner or operator shall monitor and record the operating rate of each emissions unit on an hourly average basis for each operating hour, excluding the duration of episodes of startup, shutdown and malfunction that are permitted to be excluded pursuant to condition C.8. of this section. Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each of the allowable fuels in accordance with the provisions of 40 CFR 75 Appendix D. For Emission Units 016 and 017, to demonstrate compliance with the fuel consumption limits of Condition No. C.6., the Permittee shall record the distillate fuel oil

consumption on a rolling 12-month total basis. [Rules 62-4.070(3) and 62-212.400, F.A.C., and BACT]

13. Frequency of Recordkeeping for units ~~014, 015, 016 and 017~~ Power Block 2, 3, and 4: The owner or operator shall maintain records required to demonstrate compliance with the 24-hour block emission limits of this certification on a daily basis. ~~Condition No. D.9. of this section requires the calculation of one or more 24-hour block average emission rates for each operating day.~~ Within 24 hours of the conclusion of each operating day, the Permittee shall complete the calculations and record the results for that operating day.

~~E~~H. NSPS Subpart GG Requirements

[Note: Inapplicable provisions of the Federal Permit have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in bold immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

1. through 4. no change.

~~F~~I. Monitoring Requirements

For each combined cycle unit, the Permittee shall install, operate, and maintain a continuous emission monitoring system (CEMS) (in accordance with 40 CFR 60, Appendix F or 40 CFR 75) or use other DEP approved alternate methods to monitor nitrogen oxides and, if necessary, a diluent gas (CO2 or O2). The Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective for the CTs.

1. through 5. no change.

~~G~~J. Notification, Reporting and Recordkeeping

1. through 9. no change.

~~I~~K. Modifications

PEF 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.

XIV through **XXVI.A.**17. no change.

18. During drilling of SWFWMD ID Nos. 1 and 5 (PEF ID Nos. P-1 & P-5), water quality samples shall be collected at intervals of 50 feet or less, from 300 feet to a maximum depth of five feet above the bottom of the well. Regardless of the specified sample collection interval, a sample shall be collected from the depth which corresponds to five feet above the bottom of the well. Samples shall be collected during reverse air drilling, or other appropriate method with prior approval by the Bartow Regulation Department Director, which will allow representative samples for each depth to be collected.

Samples shall be analyzed by a certified laboratory for chlorides, sulfates, and TDS. PEF's sampling procedure shall follow the handling and chain of custody procedures designated by the certified laboratory which will undertake the analysis. Reports of the analyses shall be submitted to the Permit Data Section (using SWFWMD forms) by the tenth day of the second month following sampling, and shall include the signature of an authorized representative and the certification number of the Florida Department of Health certified laboratory, utilizing the standards and methods applicable to the parameters analyzed and to the water use pursuant to Chapter 64E-1, Florida Administrative Code, "Certification of Environmental Laboratories".

Analyses shall be performed according to procedures outlined in the current edition of Standard Methods for the Examination of Water and Wastewater by the American Public Health Association-American Water Works Association-Water Pollution Control Federation (AQHA-AWWA-WPCF) or Methods of Chemical Analyses for Water and Wastes by the U.S Environmental Protection Agency (EPA).

19. PEF shall maintain a continuous recording rain gauge and an evaporation pan at Latitude 27° 47' ~~28"~~ 30" and Longitude 81° 52' ~~17"~~02", SWFWMD ID No. 141. Total daily rainfall and daily evaporation shall be recorded at this station and submitted to the Permit Data Section, Records and Data Department, on SWFWMD forms on or before the tenth day of the following month. The reporting period for each report shall begin on the first day of each month and end on the last day of each month.

20. through 24. no change

25. PEF is authorized to develop a new water resource through the construction of an Aquifer Recharge and Recovery Project on the Hines Energy Complex site (Hines ARRP) that treats surface water and wastewater and injects or recharges that water, subject to FDEP approval, into the Upper Floridan aquifer, which will be used to store and convey this water for subsequent withdrawal and use. The Hines ARRP shall be operated to offset future groundwater withdrawals as provided in condition XXVI.A.14.b.ii(2)~~ii~~. The Hines ARRP shall be developed pursuant to the following criteria:

a. Captured rainwater, reclaimed domestic wastewater effluent ~~from the City of Bartow's Douglas H. Allen Reclaimed Water Facility~~, treated industrial waste discharges from ALCOA, and water from the Hines Energy Complex cooling pond, treated to applicable groundwater quality standards for recharge to the Floridan aquifer, may be used for injection into the Upper Floridan aquifer.

b. through e. no change.

26. PEF shall continue to maintain SWFWMD-approved staff gauge(s) and report measurements of water levels, as indicated in the table below. Water levels shall be recorded and reported to the Permit Data Section, Records and Data Department, (on SWFWMD forms) on or before the tenth day of the following month. To the maximum extent possible, water levels shall be recorded as indicated in the table below. The frequency of recording may be modified by the Bartow Regulation Department Director, as necessary to ensure the protection of the resource.

SWFWMD ID No.	PEF ID No.	Water Body/Wetland	Latitude/ Longitude	Recording Frequency
121	HSG-1	Cooling Pond	27°47'~~41"~~31"/81° ~~51'59"~~52'03"	Weekly
122	SG-P-1	Rain Cropping Area	27°49'02"/81°54'39"	Weekly
123	SG-WC-1	Rain Cropping Area	27°49'30"/81°53'14"	Weekly
124*	SG-WC-2	Rain Cropping Area	27°47'33"/81°50'45"	Weekly
125	SG-WC-3	Rain Cropping Area	27°47'02"/81°51'54"	Weekly
126	SG-MC-1	Rain Cropping Area	27°46'52"/81°52'32"	Weekly
127	SG-CB-1	Rain Cropping Area	27°47'31"/81°50'13"	Weekly

Water Level Recording Timetable: Weekly Same day of each week
* This location may be removed when this area is incorporated into the Cooling Pond.

27. no change.

28. PEF shall record meter readings from each reuse line on a monthly basis within the last week of the month. The meter reading(s) shall be reported to the Permit Data Section, Records and Data Department (using SWFWMD scanning forms, unless SWFWMD has approved another arrangement for submission of this data) on or before the tenth day of the following month. If a metered reuse line is not utilized during a given month, the meter report shall be submitted to SWFWMD indicating the same meter reading as was submitted the previous month. The following reuse lines shall be metered:

a. PEF shall install meters on reuse line, SWFWMD ID No. 52, PEF ID No. ATB-1, within 90 days of completion of construction of the reuse delivery system. In metering and reporting the quantities conveyed through this line, PEF shall meter or estimate the amount of reuse water contributed by each of the following components: industrial wastewater from ALCOA; industrial wastewater from the Tiger Bay Cogeneration Facility; fresh groundwater for pipe flushing; and fresh groundwater for water supply shortage at the Hines Energy Complex. PEF shall submit two copies of the report, one for the Hines Energy Complex, and one for the Tiger Bay Cogeneration Facility.

If there is more than one episode of conveyance in one month for any of the flow components, the report should contain the corresponding information (meter readings, quantities, and dates, related to each episode in addition to the net quantities conveyed during the month for ~~the~~ each of the flow components.

b. PEF shall install meters on previously un-metered existing reuse line SWFWMD ID No. 51, PEF ID No. BED, prior to October 1, 2003. The meter at the City of Bartow's Douglas H. Allen Reclaimed Water Facility used to monitor flows directed to the Hines Energy Complex is sufficient to meet this requirement.

28.c. through 31.g. no change.

h. PEF shall undertake diligent efforts to investigate and, if feasible, modify the Hines Energy Complex watercrop system or otherwise locate sources of water, other than potable groundwater, to eliminate or substantially reduce the need to transfer groundwater from the Tiger Bay facility. PEF's diligent efforts shall include, but not be limited to, investigating the feasibility of the following: modifying or making changes to the Hines Energy Complex's watercrop system to increase runoff or storage; transferring industrial wastewater from the Tiger Bay facility; obtaining industrial wastewater from US Agri-Chemicals Corporation (USAC) to transfer to the Hines Energy Complex; increasing the amount of impervious surface at the Plant Island portion of the Hines Energy Complex to increase surface water runoff flows into the cooling pond; transferring industrial wastewater from the nearby ALCOA facility; withdrawing water from surface water sources; and locating and using other sources of reclaimed domestic wastewater and/or treated industrial wastewater.

By August 31, 2005, PEF shall provide a ~~two~~ written report~~s~~ to the SWFWMD Permits Data Section regarding its efforts to locate additional sources of water pursuant to this condition. ~~The first report shall be provided no later than December 30, 2003, and the second no later than December 30, 2004.~~ The ~~Each~~ report shall detail PEF's efforts to obtain additional water sources pursuant to this condition, any impediments PEF has encountered, and PEF's efforts or plans for overcoming those impediments if possible, and, if additional sources will be secured, the time frame for delivering water from those sources.

i. no change.

~~32. By February 1, 2004, PEF shall install SWFWMD-approved staff gauges and report measurements of water levels at the water bodies as indicated in the table below. The staff gauges shall be surveyed and referenced to the National Geodetic Vertical Datum (NGVD), and a copy of the survey including location shall be submitted with the first water level data report. The staff gauges shall be sealed in one-tenth foot increments and shall be sized and~~

~~placed so as to be clearly visible from an easily accessible point of land. Water levels shall be recorded on a frequency as indicated in the table below and reported to the Permit Data Section, Records and Data Department (on SWFWMD forms) on or before the tenth day of the following month. To the maximum extent possible, water levels shall be recorded on the same day of each week. The frequency of recording may be modified by the Bartow Regulation Department Director, Resource Regulation, as necessary to ensure the protection of the resource.~~

~~SWFWMD ID No.~~	~~PEF ID No.~~	~~Water Body/ Wetland~~	~~Latitude/ Longitude~~	~~Recording Frequency~~
~~122~~	~~SG-P-1~~	~~Rain Cropping Area~~	~~27° 48' 48"~~49'02"/~~81° 53' 46"~~54'39"	~~Weekly~~
~~123~~	~~SG-WC-1~~	~~Rain Cropping Area~~	~~27° 49' 30"/81° 53' 10"~~14"	~~Weekly~~
~~124~~	~~SG-WC-2~~	~~Rain Cropping Area~~	~~27° 47' 49"~~33"/~~81° 50' 52"~~45"	~~Weekly~~
~~125~~	~~SG-WC-3~~	~~Rain Cropping Area~~	~~27° 48' 41"~~47'02"/~~81° 51' 54"~~	~~Weekly~~
~~126~~	~~SG-MC-1~~	~~Rain Cropping Area~~	~~27° 47' 02"~~46'52"/~~81° 52' 24"~~32"	~~Weekly~~
~~127~~	~~SG-CB-1~~	~~Rain Cropping Area~~	~~27° 47' 29"~~31"/~~81° 50' 15"~~13"	~~Weekly~~

~~Water Level Recording Timetable:~~

~~Weekly — Same day of each week~~

32~~33~~. Within **90** days of construction of the withdrawal facility, PEF shall install a backflow prevention system on SWFWMD ID Nos. **1, 2, 3, 4,** and **5**, PEF ID Nos. **P-1, P-2, P-3, P-4, and P-5.**

33~~34~~. Within **90** days of construction of the withdrawal facility, an automated flow control system shall be installed on the groundwater flow from ~~SWFWMD ID Nos. **1 and 2**, PEF ID No. P-1 and P-2.~~ SWFWMD ID Nos. **1, 2, 3, 4,** and **5**, PEF ID Nos. **P-1, P-2, P-3, P-4, and P-5.**

The automated flow control system (i.e., the automated shutoff device) shall be properly maintained at all times to control the wells' water flow into the Cooling Pond, such that no discharge into the pond would take place when the elevation in the Cooling Pond is at or above 160.0 feet NGVD.

34~~35~~. PEF shall perform a feasibility study to explore and utilize ~~exploit~~ groundwater resources of the Lower Floridan aquifer at the Hines Energy Complex. The Lower Floridan aquifer is defined as the Oldsmar formation, the Cedar Keys formation, or lower formations. The objective of this feasibility study is to determine whether such formations are alternative sources for the fresh groundwater of the Upper Floridan aquifer. The feasibility study shall initially include at least one deep test well in the Lower Floridan aquifer for an initial determination of hydrogeological parameters and characteristics of the Lower Floridan aquifer at the project site. In order to assess the potential for use of the Lower Floridan, the study shall determine the water quality of the Lower Floridan aquifer and assess its feasibility as an alternative source, including prospects for brines disposal if need be, and once-through, non-contact cooling by re-circulation of the Lower Floridan aquifer water. If the use of the Lower Floridan aquifer water is determined to be feasible based on water quality, transmissivity, and/or re-circulation through the aquifer, additional study of the yield and the degree of interconnection between the Lower and Upper Floridan aquifers shall be undertaken. ~~The feasibility study must be completed prior to submitting a Supplemental Site Certification Application requesting more than a total Annual Average quantity of 5.0 MGD, not including any offsets outlined in Condition XXVI.A.14.b.ii.2. PEF shall submit a plan for use of the Lower Floridan aquifer if it is deemed a feasible water source~~. Any Lower Floridan aquifer exploratory work ~~study~~ conducted by the SWFWMD at the Hines Energy Complex site ~~shall satisfy~~ may be used by PEF toward satisfying PEF's requirement to conduct the feasibility study outlined in this condition. However, such SWFWMD exploratory work shall not necessarily constitute in itself all that is required to satisfy the requirements of this condition. Analysis and interpretation of the results of exploratory work conducted by SWFWMD will still be required to be conducted by PEF as part of the required feasibility study.

At least 90 days prior to the initiation of implementation of the exploration and feasibility study, PEF shall submit for approval by the Director of the District's Bartow Regulation Department an "Exploratory and Feasibility Study Plan of the Lower Floridan Aquifer (E&FS Plan)." The implementation of the approved plan, evaluation of the data, and the submittal of the feasibility study to SWFWMD ~~The feasibility study~~ must be completed prior to submitting a Supplemental Site Certification Application requesting more than a total Annual Average quantity of 5.0 MGD, not including any offsets outlined in Condition XXVI.A.14.b.ii.2. If deemed a feasible water source, any such Supplemental Site Certification Application ~~PEF~~ shall include ~~submit~~ a plan for use of the Lower Floridan aquifer. ~~if it is deemed a feasible water source.~~

35~~36~~. PEF shall develop and implement a measurement and monitoring plan for the existing on-site rainwater capture and reuse system (known as the watercrop system) approved by Condition XXVI.A.14.c. The watercrop system measurement and monitoring plan shall be designed to obtain information that can be used to establish accurate estimates of water production yields from the watercrop system under various rainfall events and to determine flows leaving the site to supply natural systems (including runoff discharges from buffer areas). PEF FPC shall submit the watercrop system measurement and monitoring plan to SWFWMD for review and approval by November 15, 2003. The plan shall contain a timetable for the installation and operation of gauges, meters, recorders, and other equipment that the plan sets forth to use in measuring and monitoring the watercrop system. The plan shall also set forth a schedule for collecting data and reporting that data to SWFWMD. Upon receiving SWFWMD approval, PEF shall implement the watercrop system measurement and monitoring plan according to the timeframes set forth in the approved plan.

By April 1 of each year, PEF shall submit an "Annual Water Crop System Report for the Hines Energy Complex" summarizing the data collected per the approved "Measurement and Monitoring Plan for the Water Crop System". The report shall document estimates of water production yields from the watercrop system under various rainfall events, and estimates of flows leaving the site to supply natural systems (including runoff discharges from buffer areas). The report shall present an overall evaluation of the functioning of the system and recommendations for its improvement.

36~~37~~. The Annual Average Daily (AAD) and Peak Month Daily (PMD) quantities for each of SWFWMD ID Nos. 1 ~~and 2~~, 2, and 3, PEF's ID Nos. P-1 ~~and P-2~~, P-2, and P-3, shall be limited to an AAD quantity of ~~2,600,000~~ 5,000,000 gallons per day (gpd) and a PMD quantity of ~~4,400,000~~ 8,800,000 gpd. PEF may make adjustments in pumpage distribution as necessary up to the quantities indicated specifically for each withdrawal provided that the combined total quantities will not exceed ~~2,600,000~~ 5,000,000 gpd on an AAD basis and ~~4,400,000~~ 8,800,000 gpd on a PMD basis, as long as adverse environmental impacts do not result and other Conditions of this Site Certification are complied with. In all cases, the total average annual daily withdrawal and the total peak monthly daily withdrawal are limited to the quantities set forth above.

37~~38~~. PEF shall not utilize groundwater through the withdrawals SWFWMD ID Nos. 1 and 2, PEF's ID Nos. P-1 and P-2, until Power Block 3 becomes operational. PEF shall not utilize groundwater through the withdrawal SWFWMD ID No~~s~~. 3, PEF~~'s~~ ID No~~s~~. P-3, until Power Block 4 becomes operational. In addition, PEF shall only utilize groundwater through the withdrawals SWFWMD ID Nos. 1, 2 and 3, PEF's ID Nos. P-1, P-2 and P-3, ~~and only~~ when the elevation of the water level in the Cooling Pond, as measured weekly at SWFWMD ID No. 121, PEF ID No. HSG-1, is below 160.00 feet NGVD. Minor withdrawals associated with routine pump maintenance and water quality sampling are exempt from this requirement.

38~~39~~. For Power Blocks 1, 2, and 3, PEF shall not utilize groundwater through SWFWMD ID Nos. 1 and 2, PEF's ID Nos. P-1 and P-2, at the PMD rate of 4,400,000 gpd except when and only when the elevation of the water level in the Cooling Pond, as weekly measured at SWFWMD ID No. 121, PEF ID No. HSG-1, is below 159.00 feet NGVD. For Power Blocks 1, 2, 3, and 4, PEF shall not utilize groundwater through SWFWMD ID Nos. 1, 2 and 3, PEF's ID Nos. P-1, P-2 and P-3, at the PMD rate of 8,800,000 gpd except when and only when the elevation of the water level in the Cooling Pond, as weekly measured at SWFWMD ID No. 121, PEF ID No. HSG-1, is below 159.00 feet NGVD.

39. ~~40.~~ In the event that PEF exceeds during a drought year the Annual Average Daily (AAD) quantity of 2,619,000 ~~2.600,000~~ gpd and the Peak Month Daily (PMD) quantity of 4,435,000 ~~4,400,000~~ gpd from the onsite groundwater withdrawals after ~~for~~ PB 3 becomes operational, or the Annual Average Daily (AAD) quantity of 5,019,000 gpd and the Peak Month Daily (PMD) quantity of 8,835,000 gpd from the onsite groundwater withdrawals after PB 3 and

PB 4 become operational, then PEF shall submit a report, based on but not limited to the information cited in Condition XXVI.A.30, explaining and analyzing, subject to SWFWMD approval, the conditions under which those quantities were exceeded. PEF shall not discharge any amount of groundwater into the Cooling Pond at the Hines Energy Complex when the water level in the Cooling Pond is at or above 160.0 feet NGVD. ~~If the report is approved by SWFWMD, then PEF is not in violation of Condition No. XXVI.A.28.~~ If PEF demonstrates that the recurrence of over-pumpage is unlikely and no adverse impacts have occurred, no action will be taken. If PEF continues to exceed the quantities permitted without obtaining a modification, SWFWMD may take appropriate enforcement action.

XXVII.*A.* through ***F.*** no change.

G. Permittee shall update its current Hines Energy Complex hurricane preparation and recovery plan to include ~~the proposed~~ Power Block 1, 2, 3, and 4. The updated plan shall be submitted to the Department of Community Affairs and the Polk County Office of Emergency Management no later than completion of building construction code compliance review of Hines Power Block ~~3~~ 4 by Polk County. The Permittee shall formally update the plan every 5 years following commercial operation of Power Block ~~3~~ 4 or whenever an additional electrical generating unit is brought into commercial service at the Hines Plant site and shall submit these updated versions of the plan to the Department of Community Affairs and the Polk County Office of Emergency Management. These updating and submittal requirements should be noted in the plan. If the Department deems the plan or any of its periodic updates not to be in compliance with the requirements of this condition, it may petition for enforcement of this condition pursuant to the Florida Electrical Power Plant Siting Act.

XXVIII through **XXIX.*G***. no change.

H. Access management to the State Highway System: No new access to the State Highway System is proposed in the supplemental site certification application for Power Block 2 3, and 4. If new access is later proposed, access permitting as defined in Rule chapters 14-96, State Highway System Connection Permits, Administrative Process, and 14-97, State Highway System Access Management Classification System and Standards, Florida Administrative Code, will be required.

XXVIII.*I* through **XXXI** no change.

APPENDIX II

Public Service Commission

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Hines 4 power plant in Polk County by Progress Energy Florida, Inc.	DOCKET NO. 040817-EI ORDER NO. PSC-04-1168-FOF-EI ISSUED: November 23, 2004

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, Chairman
J. TERRY DEASON
LILA A. JABER
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

ORDER GRANTING PETITION FOR DETERMINATION OF NEED FOR PROPOSED ELECTRICAL POWER PLANT

BY THE COMMISSION:

Background

On August 5, 2004, Progress Energy Florida (Progress) filed a petition for determination of need for a proposed electrical power plant pursuant to Section 403.519, Florida Statutes, and Rules 25-22.080 and 25-22.081, Florida Administrative Code. The proposed plant is a winter-rated 517 megawatt (MW) natural gas-fired, combined cycle unit to be located at the Hines Energy Complex (Hines Unit 4) in Polk County, Florida. Progress proposes to place the unit in commercial service by December 2007.

This matter was set for a formal administrative hearing held November 3, 2004. No persons intervened in this docket. At hearing, after taking all evidence, we were presented with agreement among our staff and Progress concerning the appropriate resolution of all issues identified for this proceeding. At that time, we approved the agreed positions by bench vote, resolving all issues in this docket and granting Progress' petition for determination of need. This Order reflects our decision on Progress' petition and serves as our report on this matter as required by Section 403.507(2)(a)2., Florida Statutes.

Standard of Review

Section 403.519, Florida Statutes, sets forth those matters that we must consider in a proceeding to determine the need for an electrical power plant:

> In making its determination, the commission shall take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective

> alternative available. The commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant and other matters within its jurisdiction which it deems relevant.

Findings

Need for Electric System Reliability and Integrity

We find that there is a need for Progress' proposed Hines Unit 4, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes. Through its planning process, Progress identified Hines Unit 4 as its next planned generating addition. Progress needs Hines Unit 4 to meet its 20 percent reserve margin planning criterion for winter 2007/2008 and beyond. In reaching this conclusion, Progress developed a ten-year load forecast. We find that Progress' forecast assumptions, regression models, and the projected system peak demands are appropriate for use in this docket. Progress' forecasted 2.3 percent and 2.2 percent annual growth rates of winter peak demand and net energy for load, respectively, appear to be a reasonable extension of historical trends.

Without the Hines Unit 4 capacity addition, Progress' reserve margin will decrease to approximately 19 percent in 2007/2008 and 16 percent by 2008/2009. The Hines Unit 4 addition allows Progress to satisfy its commitment to maintain a minimum 20 percent reserve margin, and it will do so by improving not just the quantity, but also preserving the quality, of its total reserves, maintaining an appropriate portion of physical generating assets in Progress' overall resource mix. The addition of Hines Unit 4 will increase Progress' share of physical reserves to approximately one half of total reserve capacity, which includes dispatchable demand-side management (DSM) programs. In the winter of 2007/2008, this level of reserve capacity is sufficient to maintain coverage of an unplanned outage of Progress' largest generating unit. Hines Unit 4 will also add diversity to Progress' fleet of generating assets, in terms of fuel, technology, age, and functionality of the unit. The dual-fuel capability of the unit provides operational flexibility.

Need for Adequate Electricity at a Reasonable Cost

We find that there is a need for the proposed Hines Unit 4, taking into account the need for adequate electricity at a reasonable cost, as this criterion is used in Section 403.519, Florida Statutes. As stated above, Progress needs Hines Unit 4 to meet its 20 percent reserve margin planning criterion for winter 2007/2008 and beyond. Moreover, Progress determined to seek approval to build Hines Unit 4 only after conducting an internal review of supply-side and demand-side options and after soliciting and evaluating competing proposals submitted by interested third-party suppliers. The fuel price forecasts used in Progress' planning analysis appear to be reasonable for planning purposes. Based on responses to discovery conducted by our staff, Progress has provided assurance that natural gas transportation and natural gas supply will adequately be provided at reasonable costs to Hines Unit 4. The results of Progress' resource planning analysis show that the economics favor combined cycle units over combustion turbines or coal-fueled technology when a generator is needed to run more than approximately 20 percent of the time. Hines Unit 4 is projected to operate as an intermediate unit, with capacity factors ranging from 50 to 70 percent over the life of the unit. The unit also has the flexibility to serve as an economical base load unit, if needed.

After a thorough analysis of the bids it received in response to its request for proposals (RFP), Progress concluded that Hines Unit 4 was the most cost-effective supply-side alternative available to Progress to meet its need for power. No protests were filed with this Commission regarding Progress' RFP. Hines Unit 4 is a state-of-the-art, highly efficient, and reliable combined cycle unit producing low-cost electricity for Progress' customers. It is the lowest cost option available to meet the needs of Progress' customers for the winter of 2007/2008 and beyond.

No Mitigating Conservation Measures

We find that there are no conservation measures taken by or reasonably available to Progress which could avoid or defer the need for the proposed Hines Unit 4. This Commission approved Progress' demand-side management (DSM) Goals and DSM Plan in Docket Nos. 971005-EG and 991789-EG, respectively. These dockets established the cost-effective level of demand and energy savings reasonably achievable by Progress through DSM programs. Progress' DSM Plan consists of five residential programs, eight commercial and industrial programs, and one research and development program. Through its efforts in these programs, Progress has successfully met its approved DSM goals. Progress anticipates that it will meet its approved goals in the future.

The anticipated demand and energy savings from Progress' DSM goals and programs, as established in Docket Nos. 971005-EG and 991789-EG, were appropriately included in Progress' resource planning process. However, Progress' analysis showed that the savings from these programs will not avoid or defer the need for Hines Unit 4.

Subsequent to Progress' resource planning process for Hines Unit 4, we approved new numeric DSM goals for Progress for the period 2005 through 2014, in Docket No. 040031-EG, as well as a DSM Plan designed to meet these goals. Progress' new goals are generally lower than those established in Docket No. 971005-EG. This would tend to increase Progress' forecasted winter and summer peak demand, further establishing a need for Hines Unit 4.

Most Cost-Effective Alternative Available

We find that the proposed Hines Unit 4 is the most cost-effective alternative available, as the criterion is used in Section 403.519, Florida Statutes. Progress conducted a careful screening of various other supply-side alternatives as part of its Resource Planning process before identifying Hines Unit 4 as its next-planned generating alternative. Progress screened out less cost-effective supply-side alternatives, identifying Hines Unit 4 as the most cost-effective alternative available.

Progress engaged in an extensive capacity solicitation process through its RFP. Progress received five proposals from four bidders. In addition, one of the bidders provided two alternatives to its proposal. One proposal did not pass the threshold requirements and was eliminated, but one proposal from each of the four bidders was put on the short list and compared to the self-build alternative, Hines Unit 4. Progress performed a significant amount of analysis, evaluating the price and non-price attributes of the alternatives. The final evaluation of the non-price attributes demonstrated Hines Unit 4 to be one of the top two ranked alternatives in nearly all of the categories. The detailed economic analysis found Hines Unit 4 to be approximately \$55 million (in 2004 dollars) less expensive than the least cost alternative proposal, a combination existing and new unit proposal. The least cost New Unit Proposal (another combined cycle plant) was found to be more than \$95 million (in 2004 dollars) more expensive than Hines Unit 4. Progress demonstrated that the self-build option had reduced costs due to the economies of scale associated with siting Hines Unit 4 at the existing Hines site with three similar units and due to the favorable equipment pricing that Progress was able to negotiate. Sensitivity analyses were run, which either gave advantages to the third-party proposals by assuming decreases in their costs or assuming increases in the costs associated with Hines Unit 4. In all cases, Hines Unit 4 was the least cost alternative.

As a result of Progress' detailed evaluation of the supply-side alternatives available to it in the RFP evaluation process, Hines Unit 4 was selected because it is the most cost-effective alternative for meeting the needs of Progress' customers for the winter of 2007/2008 and beyond.

Conclusion and Additional Requirements

Based on the foregoing, we grant Progress' petition for determination of need for its proposed Hines Unit 4. Progress shall continue to monitor the cost-effectiveness of Hines Unit 4 prior to committing substantial capital dollars.

In addition, Progress shall annually report the budgeted and actual cost compared to the \$286.1 million estimated total in-service cost of Hines Unit 4. Progress shall provide such information on an annual basis with the understanding that some costs may be higher than estimated and other costs may be lower. Providing this information on an annual basis will allow us to monitor Progress' progress toward achieving its estimated cost of \$286.1 million. The categories to be reported are: Major Equipment/EPC, Permitting, Transmission Interconnection and Integration, Natural Gas Infrastructure Upgrades, Operations and Start-Up, Project Management, Owners Cost, and AFUDC. Pursuant to Rule 25-22.082, Florida Administrative Code, Progress would need to demonstrate that costs in addition to the \$286.1 million were prudently incurred and were due to extraordinary circumstances in order for such additional costs to be recoverable. Alternatively, if the actual cost is less than \$286.1 million, customers will receive the benefit of such cost under-runs.

It is therefore

ORDERED by the Florida Public Service Commission that Progress Energy Florida, Inc.'s petition for determination of need for its proposed Hines Unit 4 is granted. It is further

ORDERED that Progress Energy Florida, Inc. shall annually report the budgeted and actual cost compared to the $286.1 million estimated total in-service cost of Hines Unit 4. It is further

ORDERED that this docket shall be closed if no appeal is filed within the time permitted for filing an appeal of this Order.

By ORDER of the Florida Public Service Commission this 23rd day of November, 2004.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

(S E A L)

WCK

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

APPENDIX III

Department of Community Affairs

DEPARTMENT OF ENVIRONMENTAL PROTECTION

JAN 11 2005

SITING COORDINATION

STATE OF FLORIDA

DEPARTMENT OF COMMUNITY AFFAIRS

"Dedicated to making Florida a better place to call home"

JEB BUSH
Governor

THADDEUS L. COHEN, AIA
Secretary

January 7, 2005

Mr. Hamilton S. Oven
Department of Environmental Protection
Siting Coordination Section
2600 Blair Stone Road
Tallahassee, Florida 32399

Dear Mr. Oven:

Re: Progress Energy Florida Hines Energy Complex Power Block 4 supplemental site certification application

Progress Energy Florida (PEF) proposes to construct a new 530–megawatt combined cycle generating unit (Power Block 4) at its existing Hines Energy Complex site in Polk County. In order to do this, PEF has applied for certification of the Hines Power Block 3 project, pursuant to the Florida Electrical Power Plant Siting Act, sections 403.501 – 403.518 of the Florida Statutes. This letter will serve as the report of the Department of Community Affairs on the Hines Power Block 4 supplemental site certification application.

After reviewing the Hines Power Block 4 supplemental site certification application, the Department concludes that the proposed construction and operation of this project on the existing PEF Hines Energy Complex site does not raise any land use issues of concern to the Department. There is, however, an additional issue within the purview of the Department which should be addressed during the certification process for the Hines Power Block 4 project: the issue of emergency management, especially in reference to hurricanes.

Because of the importance of reliable electric power during and especially after a hurricane, it is essential that the applicant have in place a hurricane preparation and recovery plan for Hines Power Block 4, as a part of the PEF Hines Energy Complex. PEF has in place a general hurricane preparation and recovery plan for the Hines Energy Complex, prepared in response to a condition of certification for Hines Power Block 1. The Department previously reviewed this August 2000 plan and determined that it satisfied the need at that time for a hurricane preparation and recovery plan.

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.dca.state.fl.us

CRITICAL STATE CONCERN FIELD OFFICE
2796 Overseas Highway, Suite 212
Marathon, FL 33050-2227
(305) 289-2402

COMMUNITY PLANNING
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
(850) 488-2356

EMERGENCY MANAGEMENT
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
(850) 413-9969

HOUSING & COMMUNITY DEVELOPMENT
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
(850) 488-7956

In order to update the existing hurricane preparation and recovery plan for the Hines Energy Complex, the Department recommends the following condition of certification for Hines Power Block 4:

> Permittee shall update its current Hines Energy Complex hurricane preparation and recovery plan to include the proposed Power Block 4. The updated plan shall be submitted to the Department of Community Affairs and the Polk County Office of Emergency Management no later than completion of building construction code compliance review of Hines Power Block 4 by Polk County. The Permittee shall formally update the plan every 5 years following commercial operation of Power Block 4 or whenever an additional electrical generating unit is brought into commercial service at the Hines Plant site and shall submit these updated versions of the plan to the Department of Community Affairs and the Polk County Office of Emergency Management. These updating and submittal requirements should be noted in the plan. If the Department deems the plan or any of its periodic updates not to be in compliance with the requirements of this condition, it may petition for enforcement of this condition pursuant to the Florida Electrical Power Plant Siting Act.

If you have any questions regarding this report, please communicate directly with Mr. Paul Darst of this office. His telephone number is (850) 922-1764.

Sincerely,

Charles Gauthier, AICP
Chief, Office of Comprehensive Planning

APPENDIX IV

Southwest Florida Water Management District

Southwest Florida
Water Management District

2379 Broad Street, Brooksville, Florida 34604-6899
(352) 796-7211 or 1-800-423-1476 (FL only)
SUNCOM 628-4150 TDD only 1-800-231-6103 (FL only)
On the Internet at: WaterMatters.org

An Equal Opportunity Employer

Bartow Service Office
170 Century Boulevard
Bartow, Florida 33830-7700
(863) 534-1448 or
1-800-492-7862 (FL only)
SUNCOM 572-6200

Lecanto Service Office
3600 West Sovereign Path
Suite 226
Lecanto, Florida 34461-8070
(352) 527-8131
SUNCOM 667-3271

Sarasota Service Office
6750 Fruitville Road
Sarasota, Florida 34240-9711
(941) 377-3722 or
1-800-320-3503 (FL only)
SUNCOM 531-6900

Tampa Service Office
7601 Highway 301 North
Tampa, Florida 33637-6759
(813) 985-7481 or
1-800-836-0797 (FL only)
SUNCOM [illegible]

December 15, 2004

Mr. Hamilton Oven, P.E., Administrator
Office of Siting Coordination
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Subject: Progress Energy Florida
Hines Energy Complex – Power Block 4
PA-33SA3

Dear Mr. Oven:

Enclosed please find a copy of the Agency Report submitted by the Southwest Florida Water Management District for the above-referenced supplemental site certification application. The District Governing Board approved the Agency Report at its meeting yesterday. Included as an attachment to the Agency Report are the proposed revised Conditions of Certification as recommended by the District.

An electronic copy of the enclosures will also be sent to you this date. If you have any questions concerning the Report or the proposed revised Conditions of Certification, please do not hesitate to contact me at the District's Brooksville headquarters or Michael Balser, Water Use Regulation Manager, or Said Abusada, P.G., at the District's Bartow Service Office.

Sincerely,

Diana D. Kimlin
for
Martha A. Moore
Senior Attorney

MAM
Enclosures

cc: Brian Starford   Michael Balser   Said Abusada
Jamie Hunter, Lead Environmental Specialist, Environmental Services, Progress Energy Florida, Inc., Post Office Box 14042, St. Petersberg, FL 33733-14042
Eric T. Olsen, Esq., Hopping Green & Sams, 123 S. Calhoun Street, Tallahassee, FL 32301
Service List

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SOUTHWEST FLORIDA WATER MANAGEMENT DISTRICT
Comprehensive Staff Report
PROGRESS ENERGY FLORIDA, INC. (HINES ENERGY COMPLEX)
Supplemental Site Certification, PA 92-33 SA 3, Power Blocks 1-4 (WUP No. 20010944.003)

STAFF RECOMMENDATION - APPROVAL

I. ABSTRACT

Progress Energy Florida (PEF), previously known as Florida Power Corporation (FPC), submitted on August 5, 2004, an application to the Florida Department of Environmental Protection (FDEP) seeking Supplemental Certification for the construction and operation of Power Block (PB) 4. This power block represents an additional 530 megawatts (MW) of electric power generation which, when approved, would bring the total licensed capacity, for PB Nos.1, 2, 3, and 4, to a total of 2,060 MW, i.e., approximately 68.7 percent of total ultimate MW capacity under the corresponding Site Certification.

This Staff Report contains analysis of the impacts associated with the construction and operation of PB 4 of the Hines energy complex, and those Conditions of Certification considered necessary to provide reasonable assurances that the proposed water use for PB 4 is a reasonable-beneficial use, will not interfere with any presently existing legal use of water, is consistent with the public interest, and is consistent with the substantive requirements of Chapters 373, Parts II, III and IV, Florida Statutes, Rule Chapters 40D-2, 40D-3, and 40D-4, Florida Administrative Code (F.A.C.). To present the integral licensing picture of the site, the report makes reference to PB 1, PB 2 and PB 3 which where licensed per the original Site Certification and two subsequent Supplemental Site Certifications granted by the Governor and his cabinet acting as the Siting Board.

	Ultimate Permitted Ground Water Quantities(1) (gpd) for PB Nos. 1 through 6	Existing Total Ground Water Quantities (gpd) for PB Nos. 1, 2, & 3	Proposed Groundwater Quantities (gpd) for PB No. 4	Proposed Total Ground Water Quantities (gpd) for PB Nos. 1 through 4
AVERAGE DAY	17,500,000	2,619,000	2,400,000	5,019,000
PEAK MONTH	17,500,000	4,435,000	4,400,000	8,835,000
MAXIMUM DAILY	N/A	N/A	N/A	N/A

(1) Only 5.0 MGD are permitted if groundwater withdrawal within the SWUCA becomes fixed.

The water use associated with this application is located within the Southern Water Use Caution Area (SWUCA).

In 1994, the Governor and Cabinet, sitting as the Siting Board, granted certification to PEF, to construct and operate PB 1 to generate 470 megawatts (MW) and for 3,000 MW of ultimate site capacity at the Hines Energy Complex. The Hines Energy Complex is being constructed in six "power blocks" or units of generating capacity over time. The power blocks have been or will be brought online sequentially to generate electricity up to the ultimate capacity of 3,000 MW as follows:

Power Block No.	Generation Capacity (MW)	Construction Initiation Date Date	Operation Initiation Date	Cumulative Average Ground Water Use (GPD)
1	470	August 1995	April 1999	19,000
2	530	February 2002	December 2003	19,000
3	530	February 2004	December 2005	2,619,000
4	530	January 2006	December 2007	5,019,000

Groundwater withdrawals are required for make-up requirements of an existing 722-acre (Phase-I) cooling reservoir, personal and sanitary needs of employees and visitors, and for various plant processes associated with 900 acres of power generation and ancillary facilities.

II. INTRODUCTION

This staff report recommends approval by the Governing Board of newly added and modified existing Conditions of Certification (CoC) based on the evaluation by staff of the Application for Supplemental Siting Certification for PB 4.

The Siting Act requires that entities proposing to develop power generation facilities submit one application encompassing the regulatory issues of all relevant agencies to the Florida Department of Environmental Protection (FDEP). As part of the certification process, SWFWMD reviews the proposal to ensure that the project meets all SWFWMD permitting criteria set forth in Chapter 40D-2, F.A.C., Consumptive Use of Water, and Chapter 40D-3, F.A.C., Regulation of Wells. Provisions relating to Chapter 40D-4, F.A.C., are addressed in on a post-certification basis.

The FDEP will prepare a written analysis based on all regulatory agencies' reports, and submit that analysis for consideration at a certification hearing held before an Administrative Law Judge (ALJ). The ALJ will conduct an evidentiary hearing on all issues raised by the application and make a recommendation to the Siting Board. SWFWMD does not take final agency action on the application; rather, SWFWMD is a statutory party to the proceedings before the ALJ and Siting Board and provides an Agency Report to the FDEP.

III. HISTORY

PEF's Hines Energy Complex is an existing regulated utility (non-merchant) power plant located at a former phosphate mine site in an unincorporated area of southern Polk County. To select this site, in 1989 PEF formed an Environmental Advisory Committee (EAC) consisting of representatives from industry, universities, and environmental organizations. PEF informed the EAC of its power generation needs. After extensive deliberations (considering over 50 sites), the EAC recommended this already impacted inland location away from the coast.

An estimate of groundwater needed for the project in the District's December 1992 Needs & Sources report was 40 MGD. Quantities were reduced due to utilizations of rainwater cropping and internal reuse of wastewater. In 1992, PEF applied to FDEP under the Florida Electric Power Plant Siting Act to certify the Hines Energy Complex. In its original application, PEF intended to fuel the Hines Energy Complex using pulverized coal, which would have had an estimated groundwater use of 31.6 MGD. Through switching to burning natural gas as fuel instead of pulverized coal, and by agreeing to develop and use alternative sources, including reuse water from the City of Bartow and locating an additional 1.1 MGD from an undetermined source, PEF reduced the requested groundwater needs to 17.5 MGD of which 12.5 MGD must be offset if SWUCA groundwater withdrawals are capped.

In 1994, per the Site Certification Application PA 92-33, the Governor and Cabinet certified the Hines Energy Complex for the construction of an initial 470 megawatt combined cycle unit (PB 1) and for an ultimate site (power generation) capacity of 3,000 megawatts. In May 2001, the Governor and Cabinet certified PB 2 of the Hines Energy Complex, per the Supplemental Certification PA 92-33 SA 1. PB 2 consists of a 530 megawatt combined cycle electrical generating plant that began operating in December 2003.

In September 2003, the Governor and Cabinet certified PB 3 per Supplemental Certification PA 92-33 SA 2, thus bringing the total licensed capacity of the Hines Energy Complex to a total of 1,530 MW. A subsequent modification to the Conditions of Certification allowed transfer on an **interim** basis, until November 30, 2005, permitted unused groundwater from the Tiger Bay Cogeneration Facility to the Cooling Pond at the Hines Energy Complex. The modification also included provisions for the implementation of the Aquifer Recharge and Recovery Project (ARRP), and transfer of industrial reuse water from the Tiger Bay Cogeneration Facility and Alcoa to the cooling reservoir at the Hines Energy Complex. The pipeline has been used to transfer reclaimed water quantities of 26.6 million gallons (MG) in 2003 and 15.2 MG from January to October in 2004 from Alcoa. Additionally, 242,200 gallons of groundwater from wells located at the Tiger Bay Cogeneration Facility have been used to flush the pipeline in 2004.

IV. PROJECT DESCRIPTION

The power plants, cooling reservoir, and other facilities will occupy approximately 8,200 acres of previously mined phosphate land adjacent to the headwaters of McCullough Creek and Camp Branch, which are tributaries of the Peace River. The site includes 900 acres of power generating and ancillary facilities and a 722-acre cooling reservoir that will be expanded to approximately 1,200 acres. The cooling reservoir expansion operation began in May 2004 and it is anticipated to be completed in December 2005.

Approximately 2,000 acres are designated as buffer areas along the east and southeast portions of the site and approximately 520 acres along the west and southwest portions of the site have been reclaimed to enhance drainage to McCullough Creek.

Any groundwater requirements for the proposed power facility at its ultimate built-out capacity of 3,000 MW will be provided by one proposed 8-inch diameter well and five proposed 20-inch diameter Upper Floridan aquifer production wells.

During the review of the original application in 1992, PEF proposed that no groundwater would be required for the first two phases of power generation capability, a total of 1,000 MW. SWFWMD staff did not propose first and second phase (PB 1 and PB 2) Annual Average Daily (AAD) and Peak Month Daily (PMD) quantities for process and cooling water make-up. The water for the process and cooling water make-up was to come from reuse water from the Douglas H. Allen Reclaimed Water Facility of the City of Bartow and from onsite rainwater cropping. An AAD quantity of 19,000 gpd and a PMD quantity of 35,000 gpd were proposed for the potable and sanitary needs of staff at the proposed facility.

Under the preceding Supplemental Siting Certification (PA 92-33 SA 2), groundwater use for cooling and process water at the Hines Energy Complex was allowed to be initiated due to adding Power Bock 3 (530 MW capacity), which is anticipated to be operational in late 2005. The groundwater quantities determined to be required for that phase are an AAD quantity of 2.6 MGD and a PMD quantity of 4.4 MGD.

Under the current Supplemental Site Certification Application (PA 92-33 SA 3), due to the proposed addition of PB 4, groundwater use for cooling and process water at the Hines Energy Complex is proposed to be increased by the AAD and PMD quantities of 2,400,000 gpd and 4,400,000 gpd respectively, thus bringing the total AAD and PMD quantities for PBs 1 - 4 to 5,019,000 gpd and 8,835,000 gpd, respectively.

A CoC provided in the existing certification is maintained to regulate the use of these quantities such that there will be no groundwater pumped from any of the production wells when the elevation of the water level in the Cooling Pond is at or above 160.0 feet NGVD, and that no groundwater would be pumped at the aforesaid PMD rate when the elevation of the water level in the Cooling Pond is at or above 159.0 feet NGVD.

Prior to any increases in the number of megawatts produced above 2,060 MW, i.e., the combined generating capacity of PB 1, PB 2, PB 3, and PB 4, PEF must receive approval from the Public Service Commission (PSC). Any increase in the number of megawatts produced above 2,060 MW will require a corresponding increase in water for process and cooling needs. PEF must receive approval from the Siting Board prior to any incremental increases in groundwater use. CoCs are maintained requiring PEF to regularly report and demonstrate that they will minimize groundwater withdrawals to the greatest extent practicable by implementing all technologically and economically practicable water conservation practices prior to increasing groundwater withdrawals. PEF shall submit a Water Conservation Report (WCR) describing the implemented and planned water conservation activities every two years as of the issuance of the Supplemental Certification.

Before adding PB 5 or PB 6, PEF will submit a detailed feasibility analysis to evaluate the potential for the exploitation of lower quality groundwater resources in the Lower Floridan aquifer. PEF must submit this feasibility analysis to SWFWMD for review and approval. If use of these resources is deemed feasible, PEF must submit a plan with time frames to begin to use this source, for the process and cooling needs of PB 5 and PB 6.

PEF was required, per a CoC, to develop and implement a measurement and monitoring plan, subject to SWFWMD approval, for the existing onsite water crop rainwater capture and reuse system. The plan calls for PEF to monitor quantities of water harvested and determine flows leaving the site to supply the natural systems. On September 6, 2004, the District approved the revised Plan.

V. BACKGROUND

A. Applicant:	Progress Energy Florida, Inc.
B. Project Name:	Hines Energy Complex
C. Type of Water Use:	Industrial/Commercial
D. Type of Land Use:	Industrial/Commercial
E. Location of Property:	Polk County, approximately 3.5 miles northwest of Fort Meade, 3 miles south of Bartow. The project site is bordered on the north by County Road 640 with CR 555 running through the site (see location map).

F. Production Wells:

SWFWMD ID No.	PEF ID No.	Diameter (Inches)	Cased Depth (Feet)	Total Depth (Feet)	Use[(2)]
1[(1)]	P-1	20	360	880	I
2[(1)]	P-2	20	360	880	I
3[(1)]	P-3	20	360	880	I
4[(1)]	P-4	20	360	880	I
5[(1)]	P-5	20	360	880	I
6[(3)]	P-6	8	360	500	I

(1) Proposed wells to be constructed for PB 3 through Pb-6
(2) Industrial/Commercial (Power Generation)
(3) Existing well for personnel/sanitary use

G. Recharge Wells:

SWFWMD ID No.	PEF ID No.	Diameter (inches)	Cased Depth (Feet)	Total Depth (Feet)	Use[(2)]
21[(1)]	AR-1[(1)]	24	360	900	R
22	AR-2	24	360	900	R
23	AR-3	24	360	900	R
24	AR-4	24	360	900	R
25	AR-5	24	360	900	R
26	AR-6	24	360	900	R

(1) Proposed exploratory injection well that may be converted into an injection/recharge well
(2) Aquifer recharge

H. Property Description: 8,200 total acres. The site consists of all or part of the following Sections: (Sections 33, 34, 35, and 36 Township 30 South, Range 24 East, Section 31, Township 30 South, Range 25 East, Sections 1, 2, 3, 4, 10, 11, 12, 13, 14, and 23, Township 31 South, Range 24 East, and Sections 6, 7, 8, 17, and 18, Township 31 South, Range 25 East).

VI. PROPOSED FACILITIES

The project is an existing power plant on which an additional power-generating unit is proposed to be constructed. The existing power plant involves the use of a set of integrated facilities consisting of a proposed power generation plant, cooling reservoir, brine pond, fuel storage areas, overhead electrical transmission lines and associated surface water management systems.

The property owned is 8,200 acres. The power plant island occupies approximately 900 acres, and an existing cooling reservoir currently occupies about 722 acres and will be expanded to approximately 1,200 acres. The power plant facilities are located in the southwest portion of the site just north of the headwaters of McCullough Creek. The cooling reservoir to the north and east is comprised of mine pit areas that have been regraded to accommodate this use. Approximately 311 acres are utilized for a brine pond and a water quality treatment pond and approximately 900 acres could be used for solid waste disposal if PEF implements the Coal Gas fuel option for future units. The buffer and drainage enhancement areas are comprised of approximately 2,500 acres.

The surface water management facilities serving the entire power plant project, with the exception of the buffer and drainage enhancement areas to the east, southeast, west and southwest, capture and utilize all the rain falling within the site boundaries. This water is routed to the cooling pond system and offsets groundwater withdrawals. The cooling pond is adjacent to and west of the eastern buffer area. The eastern buffer area includes the previously mined, reclaimed, and released area known as Tiger Bay, located at the southeast corner of the project site. The reservoir containment dams are above the adjacent reclaimed land surface elevation. The normal reservoir water level is proposed to range between 159 and 163 feet NGVD. The ground elevation on the downstream side of the dam is indicated to be approximately 150 feet NGVD. The site, with the exception of the buffer and drainage enhancement areas, is intended to be a zero discharge facility and, therefore, no provisions have been made for overflow discharges. Rainfalls in excess of the 25 year - 24 hour storm event would be allowed to accumulate in disposal areas, if necessary, to ensure there are no off-site discharges from the plant site facilities.

To implement the ARRP, PEF proposed to construct 6 artificial recharge wells, SWFWMD ID Nos. 21 through 26, PEF ID Nos. AR-1 through AR-6. The first well will be used as an exploratory injection well to be converted to an injection well after two years of conducting specific exploratory work on injection, water quality and water treatment. The wells shall be equipped with flow meters to measure the amounts of water injected though these wells. The source of injected water shall be treated reclaimed water from the wastewater treatment plant(s), onsite harvested rainwater, and industrial wastewater. The aquifer in which the water will be injected is the Upper Floridan aquifer, after the water is properly treated to meet primary and secondary water quality standards. The treatment may possible include, but will not be limited to, passage through a wetland, filtration through a tailing sand filter basin, etc. Water recovery shall be effected through the production wells, SWFWMD ID Nos. 1 through 5, PEF ID Nos. P-1 through P-5. These wells will also be metered and pumpage through them at any time shall not exceed the permitted groundwater quantities under the corresponding Supplemental Siting Certification. Additionally, on a cumulative basis, no more than 85 percent of the injected water quantities shall be withdrawn. SWFWMD ID No. 6, PEF ID No. P-6 will be used for potable/sanitary water supply.

PEF installed a 6-inch diameter pipeline approximately 2,680 feet in length to convey industrial wastewater from ALCOA (Segment "A") and a 10-inch diameter pipeline approximately 2,840 feet in length to convey groundwater and/or industrial wastewater from the Tiger Bay Cogeneration Facility (Segment "B"). Both of these two pipelines connect to a 10-inch diameter pipeline approximately 21,900 feet in length which conveys water to the Cooling Pond at the Hines Energy Complex.

VII. EVALUATION * 40D-2, F.A.C., Consumptive Use of Water

A. WATER USE

Under the existing CoCs, including the Supplemental Site Certification (PA 92-33 SA 2) to add PB 3, the allocated AAD and PMD quantities are 2,619,000 gpd and 4,435,000 gpd, respectively. Under the current Supplemental Site Certification (PA 92-33 SA 3) to add PB 4, the additionally allocated AAD and PMD quantities are 2,400,000 gpd and 4,400,000 gpd, respectively. Thus, the total AAD and PMD ground water quantities allocated for the site, including Power Block 4, will be 5,019,000 gpd and 8,835,000 gpd, respectively.

In the original 1994 approval, SWFWMD did not propose AAD and PMD ground water withdrawal quantities for cooling water make-up for the first two power blocks (PB 1 and PB 2). To meet the potable and sanitary needs of the facility, quantities of 19,000 gpd AAD and 35,000 gpd PMD were permitted. PEF has negotiated an agreement with the City of Bartow to receive up to 5 MGD of reuse water for the life of the plant. The available reuse quantities along with onsite water cropping were deemed to be sufficient for the first two phases, i.e., PB 1 and PB 2, of the project. The total build-out proposed quantities of water use are based on an ultimate power generating capacity of

3,000 MW. The five proposed wells (SWFWMD ID Nos. 1, 2, 3, 4, and 5) and the existing well SWFWMD ID No. 6, reuse water, water cropping of onsite rainfall, and a cooling reservoir were the originally planned and/or existing sources to provide the water requirements for the site. There is a CoC requiring PEF to explore the feasibility of other sources for make-up water. To enable PEF to compensate for water supply shortage situations as PB 2 became operational, a CoC was proposed providing the transfer on an interim basis ending on November 30, 2005, up to an AAD quantity of 0.8 MGD and a PMD quantity of 1.0 MGD for permitted unused groundwater associated with the Tiger Bay Cogeneration Facility. The combined water to be used at and transferred from the Tiger Bay Cogeneration Facility shall not exceed its permitted quantities, i.e., an AAD quantity of 1.7 MGD and a PMD quantity of 2.1 MGD. Other sources of water supply, e.g., industrial reuse water supply from Alcoa, and the ARRP were also addressed in CoCs.

At built-out, all ground water to be produced onsite, except for the ground water produced for personnel/sanitary uses, will be pumped directly to the cooling water reservoir to provide make-up water for evaporative losses, seepage losses, and losses associated with industrial uses. Reuse water from the City of Bartow or other potential sources will also be pumped directly into the cooling water reservoir to compensate and/or provide for those losses and uses. The total water demand at the Hines Energy Complex from offsite and Upper Floridan aquifer sources for process, cooling, potable and sanitary purposes is 23.6 MGD. Of this total demand, the quantities that will be produced from onsite Upper Floridan aquifer withdrawals from this aquifer will be only 5.0 MGD if withdrawals are fixed and 17.5 MGD if withdrawals are not fixed under SWUCA. In the latter case, PEF shall seek to provide the balance of 6.1 MGD from a combination of treated wastewater effluent from the City of Bartow, estimated at 5.0 MGD, and other offsite non-potable sources of water to provide the remainder of 1.1 MGD. To the extent that PEF obtains more than 6.1 MGD through reuse of treated wastewater effluent from offsite sources, the excess amount shall serve to reduce the use of 17.5 MGD of water from the Upper Floridan aquifer. On the other hand, to the extent that onsite Upper Floridan aquifer withdrawals are fixed at 5.0 MGD per the SWUCA, then any amount to be produced from that aquifer in excess of that quantity must be either offset by mandatory retirement of permitted quantities, or approved as a "competing application" under the applicable standards of Section 373.233, F.S. In order for quantities to be eligible for consideration as offset quantities, they must be actively used within the SWUCA and they must be made available pursuant to agreements between PEF and other permittees, subject to review by SWFWMD.

The cooling water reservoir provides the source of water for circulating condenser cooling purposes for the heat recovery steam generators/steam turbines (HRSG/ST) and combined cycle (CC) units. The major consumption and/or loss of water is evaporation from the cooling pond. The sixth well (SWFWMD ID No. 6) will provide all potable and domestic service water system needs of the power plant.

Process wastewater streams from the overall project facilities will be treated on-site and reused within the condenser cooling system (i.e., cooling reservoir).

B. <u>WATER CONSERVATION</u>

As stipulated, during the operation of PB 1, from 1999 to present time, and PB 2, from late 2003 to present time, PEF has not used any Upper Floridan aquifer groundwater as the primary source for cooling water make-up. Currently, PB 3 is under construction and PB 4 is proposed. The water supply is currently obtained from the use of rainfall (i.e., water cropping) and reuse water from the City of Bartow, although the actual supply from both sources has been less than predicted. However, when PB 2 became operational in late 2003, permitted unused water at the Tiger Bay Cogeneration Facility was proposed to be used on an interim basis, until November 30, 2005, subject to certain constraints as stipulated in a CoC for this purpose. In the meantime, PEF continues to evaluate water use and potential reuse sources for the proposed power plant. Potable supply quantities will be provided on-site through treatment of groundwater withdrawals.

PEF has designed the proposed power plant as a "zero discharge" facility. PEF has recycled and will continue to recycle all of the wastewater streams (i.e., boiler blowdown, water treatment equipment waste, equipment/floor drains, etc.) by using on-site treatment facilities. None of these wastewater streams is discharged off site. PEF has also changed the generating technology utilized at the Hines Energy Complex by eliminating the pulverized coal units from the ultimate capacity technology options on the site. Elimination of these units has significantly lowered the volume of water required for cooling water makeup purposes that would be required for the initially planned pulverized coal generating units.

On an annual average daily basis, approximately 8.4 MGD of rainwater is captured by the cooling reservoir from direct precipitation and runoff from other areas surrounding the reservoir. The capture and reuse of this source is an integral part of the effort PEF is making to reduce dependency on the Upper Floridan aquifer as a source of water. A CoC requires PEF to submit an Annual Water Crop System Report for the Hines Energy Complex" summarizing the data collected per the "Measurement and Monitoring Plan for the Water Crop System", dated May 5, 2004, received by the District on May 27, 2004, and approved on September 8, 2004. The report shall document estimates of water production yields from the watercrop system under various rainfall events, and estimates of flows leaving the site to supply natural systems (including runoff discharges from buffer areas). The report shall present an overall evaluation of the functioning of the system, its impacts, and recommendations for its improvement.

Additionally, PEF proposed to conduct tests on and implement the ARRP with the objective of treating reuse water and storm water and storing the treated water in the Upper Floridan aquifer when quantities from such sources are available in excess of the actual need, and recover no more than 85 percent of the artificially recharged water from the aquifer when needed in the future. CoCs require PEF to provide documentation to SWFWMD of FDEP's approval of the water quality for aquifer recharge water and to account for quantities recharged and quantities withdrawn so as not to exceed 85 percent of the recharged water were stipulated.

The water transfer by pipeline of permitted unused groundwater from the Tiger Bay Facility to the cooling pond at the Hines Energy Complex includes transfer of industrial wastewater generated at ALCOA, and also at the Tiger Bay Cogeneration Facility. Such transfer would enable PEF to handle water shortage situations until November 30, 2005. Such shortage may potentially arise in view of the fact that electric power generation at PB 1 and PB 2 is totally dependent on rainwater and reuse water from the Douglas H. Allen Reclaimed Water Facility of the City of Bartow. Additionally, the average reuse water supply from the City of Bartow is currently close to 2.0 MGD, which is well below the 5.0 MGD anticipated to be received at the Hines Energy Complex. Ground water use will be initiated at an AAD quantity of 2,619,000 gpd and a PMD quantity of 4,435,000 gpd as PB 3 becomes operational in December 2005. Groundwater use will be increased to the total AAD and PMD quantities of 5,019,000 gpd and 8,835,000 gpd, respectively, as PB 4 becomes operational in December 2007. A CoC addressing cooling pond water level monitoring, reporting requirements and the conditions under which water transfer may be conducted and/or discontinued was also stipulated.

An existing CoC stipulates that PEF shall not use onsite groundwater to supply makeup water into the Cooling Pond unless the water level therein is below certain levels depending on the pumping rate. For example, no makeup water from a groundwater source shall be added to the pond when the water level elevation therein is at or above 160 feet NGVD, and no such water may be added at the PMD rate when that level is at or above 159 feet NGVD. Another existing CoC stipulates biennial reporting on conservation efforts to procure more reclaimed water and water cropping. Another existing CoC requires PEF to conduct a feasibility evaluation for the exploitation of brackish water resources from the Lower Floridan aquifer and deeper formations in order to minimize the use of fresh groundwater resources from the Upper Floridan aquifer for cooling pond make-up water.

C. <u>MODELING & IMPACT ANALYSIS</u>

Under the existing Siting Certification PA 92-33, SWFWMD staff prepared groundwater flow modeling and reviewed the cumulative (i.e., all existing legal users within the modeled domain were included in the model) U.S.G.S. McDonald-Harbaugh Modular Three-Dimensional Finite-Difference Ground-Water Flow Model (MODFLOW) submitted as part of the SCA and determined that it was sufficient in scope and detail to predict impacts to surface environmental features, off-site land uses, and to existing legal users. The simulation provided predicted drawdowns in the potentiometric surface of the Upper Floridan and intermediate aquifers and the water table of the surficial aquifer. Based on the cumulative model results, the predicted drawdown impacts in the water table of the surficial aquifer are 0.2 feet at the property boundary. The predicted drawdowns in the intermediate and Upper Floridan aquifers are 3.8 and 5.2 feet, respectively, at the property boundaries. These predicted impacts on the water table of the surficial aquifer and the potentiometric surfaces of the intermediate and Upper Floridan aquifers were not deemed to be adverse impacts to existing legal users, on- and off-site wetlands, and to off-site land uses. A CoC requires PEF to conduct an aquifer performance test (APT) prior to the initiation of groundwater production for PB 3. Based on the results of such an APT, additional groundwater modeling may be required.

The combined ground water withdrawals under the preceding and current Supplemental Certification Applications, i.e., PA 92-33 SA 2 and PA 92-33 SA 3, respectively, represent approximately 29 percent of the total withdrawals of 17.5 MGD, for which impacts were evaluated as provided above for the entire built-out capacity of 3,000 MW at the Hines Energy Complex. Additionally, the proposed ARRP upon approval by the FDEP, would result in a net benefit of 15 percent as no more than 85 percent of the total injected water quantities shall be recovered through the production wells. The combined pumpage of permitted groundwater quantities and recovery of no more than 85 percent of the injected quantities shall not exceed a total of 17.5 MGD which were simulated under the existing SCA and which were found not to cause adverse impacts to legal existing users, on- and off-site wetlands, and to off-site land uses.

D. <u>RULE CRITERIA</u>

The Siting Application meets all permitting criteria of 40D-2.301, F.A.C.

VIII. <u>REFERENCES</u>

Duerr, A. D., Hunn, J. D., Lewelling, B. R., and Trommer, J. T., 1988, Geohydrology and 1985 Water Withdrawals of the Aquifer Systems in Southwest Florida, With Emphasis on the Intermediate Aquifer System.

Florida Geological Survey, 1986, Hydrogeological Units of Florida, Special Publication No. 28.

Gilboy, A. E., March 1985, Hydrogeology of the Southwest Florida Water Management District.

Ryder, P. D., Hydrology of the Floridan Aquifer System in West-Central Florida: U.S.G.S. Open File Report 84-611.

IX. VISUAL DISPLAYS

Location Maps: Figure 1 - Project Site
Figure 2 – Project Site, Tiger Bay Cogeneration Facility, USAC and ALCOA

X. RECOMMENDATION

PB 4 is recommended provided that the Conditions of Certification contained in Exhibit "A" are adopted and issued by FDEP.

Staff recommends **approval**, subject to the conditions as proposed in Recommendation X above.

Prepared by:

_______________ Date: _______
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Water Use Regulation Manager
Bartow Regulation Department

_______________ Date: _______
Said M. Abusada, P.G.
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David C. Carpenter, E.S.
Environmental Science Manager
Bartow Regulation Department

_______________ Date: _______
Mark Hurst , Senior E.S.
Bartow Regulation Department
Bartow Regulation Department

A. *Water Use Regulation Conditions*

1. If any of the statements in the application and in the supporting data are found to be untrue and/or inaccurate, or if Progress Energy Florida (PEF) fails to comply with all of the provisions of Chapter 373, Florida Statutes (F.S.), Chapter 40D, Florida Administrative Code (F.A.C.), or the conditions set forth herein, the Southwest Florida Water Management District (SWFWMD) shall initiate action for suspension or revocation of Certification.

2. This certificate is issued based on information provided by PEF demonstrating that the use of water is reasonable and beneficial, consistent with the public interest, and will not interfere with any existing legal use of water. If it is determined by SWFWMD that the use is not reasonable and beneficial, in the public interest, or does impact an existing legal use of water, SWFWMD shall initiate action for suspension or revocation of Certification.

3. PEF shall not deviate from any of the water use related terms or conditions of the Site Certificate without written approval by SWFWMD.

4. In the event SWFWMD declares that a Water Shortage exists pursuant to Chapter 40D-21, F.A.C., SWFWMD shall initiate any required action to alter, modify, or declare inactive all or parts of this Certification as necessary to address the water shortage.

5. SWFWMD shall collect water samples from any withdrawal point listed in the Certificate or shall require PEF to submit water samples when SWFWMD determines there is a potential for adverse impacts to water quality.

6. SWFWMD shall initiate any necessary action to require PEF to cease or reduce withdrawal if water levels in aquifers fall below the minimum levels established by the Governing Board.

7. PEF shall practice water conservation to increase the efficiency of transport, application, and use, as well as to decrease waste and to minimize runoff from the property. At such time as the Governing Board adopts specific conservation requirements for PEF's water use classification, SWFWMD

shall initiate any required action to make this certification subject to those requirements upon notice and after a reasonable period for compliance.

8. SWFWMD may establish special regulations for permits within the region designated a Water Use Caution Area (WUCA). If SWFWMD has established, or establishes in the future, a WUCA for the region that encompasses this certificate, at such time as the Governing Board adopts such special regulations, SWFWMD shall initiate any required action to make PEF subject to them upon notice and after a reasonable period for compliance.

9. PEF shall mitigate, to the satisfaction of SWFWMD, any adverse impact to existing legal uses caused by withdrawals. When adverse impacts occur or are imminent, SWFWMD shall require PEF to mitigate the impacts. Adverse impacts include, but are not limited to:

a. A reduction in water levels which impairs the ability of a well to produce water;
b. Significant reduction in levels or flows in water bodies such as lakes, impoundments, wetlands, springs, streams or other watercourses; or
c. Significant inducement of natural or manmade contaminants into a water supply or into a usable portion of any aquifer or water body.

10. PEF shall mitigate to the satisfaction of SWFWMD any adverse impact to environmental features or off-site land uses as a result of withdrawals. When adverse impacts occur or are imminent, SWFWMD shall require PEF to mitigate the impacts. Adverse impacts include the following:

a. Significant reduction in levels or flows in water bodies such as lakes, impoundments, wetlands, springs, streams, or other watercourses;
b. Sinkholes or subsidence caused by reduction in water levels;
c. Damage to crops and other vegetation causing financial harm to the owner; and
d. Damage to the habitat of endangered or threatened species.

11. A SWFWMD identification tag shall be prominently displayed at each withdrawal point by permanently affixing the tag to the withdrawal facility.

12. PEF must notify SWFWMD within 30 days of the sale or transfer of permitted water withdrawal facilities or the land on which the facilities are located.

13. All reports required by the certificate shall be submitted to SWFWMD on or before the tenth day of the second month following data collection and shall be addressed to:

Permit Data Section, Resource Regulation
Southwest Florida Water Management District
2379 Broad Street
Brooksville, Florida 34604-6899

Unless otherwise indicated, three copies of each plan or report, with the exception of pumpage, rainfall, evapotranspiration, water level or water quality data which require one copy, are required by the permit.

14. The water balance for ultimate site capacity (approximately 3,000 MW of generating capacity) at PEF's Hines Energy Complex demonstrates a requirement of 23.6 MGD from offsite and Upper Floridan aquifer sources for process, cooling, domestic and sanitary purposes.

a. PEF shall obtain 6.1 MGD of this amount from a combination of treated wastewater effluent from the City of Bartow's Douglas H. Allen Reclaimed Water Facility and other offsite nonpotable sources of water. To the extent that PEF obtains more than 6.1 MGD through reuse of treated wastewater effluent from offsite sources, the excess amount shall serve to reduce the use of 17.5 MGD of water from the Upper Floridan aquifer which is authorized by Condition XXVI.A.14b below.

b. PEF is authorized to withdraw from the Upper Floridan aquifer and use for process, cooling, domestic and sanitary purposes, in support of ultimate site capacity at its Hines Energy Complex, an amount of water not to exceed 17.5 MGD, subject to the following conditions:

i. Except as approved by SWFWMD under circumstances constituting an emergency, or per an interim water supply shortage as defined in Condition XXVI.A.31, no process or cooling water shall be withdrawn from the Upper Floridan aquifer in support of the first 1,000 MW of generating capacity. PEF is authorized to withdraw up to 19,000 gpd Annual Average Daily and 35,000 gpd Peak Month Daily from the Upper Floridan aquifer for domestic and sanitary purposes for the life of the facility. The authorized sources of process and cooling water in support of such generating capacity shall consist of existing water on site, on-site rainwater and stormwater capture, reuse of internal wastewater streams, and reuse of treated wastewater from the Douglas H. Allen Water Reclamation Facility of the City of Bartow or other reuse sources.

ii. The total quantity of water that PEF is authorized to withdraw from the Upper Floridan aquifer shall be limited to 17.5 MGD Annual Average Daily, which amount is determined by SWFWMD not to have an adverse effect on other legal existing users provided, however, that withdrawal for process or cooling purposes of any water from the Upper Floridan aquifer shall be subject to the following additional conditions, which shall be applied during review pursuant to Section 403.517, Florida Statutes, of any supplemental application for the construction and operation of a further increment of generating capacity at the Hines Energy Complex :

1) PEF shall demonstrate that any incremental quantity of process or cooling water which it proposes to withdraw from the Upper Floridan aquifer in support of that increment of generating capacity will be minimized to the greatest extent practicable by prudent technologically and economically feasible water conservation practices consistent with those generally required within the Southern Water Use Caution Area (SWUCA) of SWFWMD, including but not limited to the following:

a) Minimization of loss of water from the site during construction;

b) Use of water-conserving electric generation and pollution control technologies;

c) On-site rainwater and stormwater capture and management;

d) Reuse of internal wastewater streams of technologically suitable quality;

e) Reuse of treated wastewater of technologically suitable quality available from other sources, such as publicly-owned sewage treatment facilities, which PEF shall diligently pursue; and

f) Use of other available sources of nonpotable water of technologically suitable quality.

2) To the extent that maximum total groundwater use in the SWUCA is fixed in a manner which limits the withdrawal of Upper Floridan aquifer water for PEF's Hines Energy Complex, withdrawal by PEF from that source of any quantity greater than 5 MGD, which amount is determined not to have an adverse effect on regional water resources, must be either:

a) Offset by mandatory retirement of permitted quantities which are actively used within the SWUCA, to the extent such quantities are eligible to provide offset, pursuant to agreements between PEF and other Permittees which are subject to review by SWFWMD for conformity with generally applicable standards; or

b) Offset through recharge and subsequent withdrawal of water pursuant to the Aquifer Recharge and Recovery Project described in Condition XXVI.A.25: or

c) Approved as a "competing application" under the applicable standards of Section 373.233, F.S.

3) To the extent that maximum total groundwater use in the SWUCA is not fixed in a manner which limits the withdrawal of Upper Floridan aquifer water for PEF's Hines Energy Complex, PEF may withdraw from that source up to 17.5 MGD subject to the requirements of Condition XXVI.A.14.a., 14.b.i., and 14.b.ii.1), but not subject to those of Condition XXVI.A.14.b.ii.2).

iii. PEF's current development schedule for ultimate site capacity at the Hines Energy Complex estimates incremental additions of generating capacity at an approximate average rate of 500 MW (range of 450 to 550 MW) every four years for the period 1998 through 2018, both inclusive, for a total of approximately 3,000 MW. The following additional requirements shall apply in order to ensure that PEF's actual water needs are accurately reflected within the Conditions of Sections XXVI.A and do not unnecessarily deprive other users of groundwater:

1) In each supplemental application for the construction and operation of a further increment of generating capacity at the Hines Energy Complex, PEF, shall indicate (i) whether it has determined not to install any prior or subsequent increment of generating capacity, (ii) the basis for delay in the installation of any increment of generating capacity for more than 5 years beyond the estimated schedule, and (iii) the quantity of groundwater from the Upper Floridan aquifer which any such increment of capacity that has been eliminated or delayed would have required.

2) If PEF has determined not to install any increment of generating capacity or in the absence of a reasonable basis for a delay greater than 5 years, the quantity of groundwater which PEF is authorized to withdraw from the Upper Floridan aquifer in support of ultimate site capacity may be reduced accordingly.

c. On-site rainwater and stormwater capture and use, reuse of internal wastewater streams, reuse of available treated wastewater sources, and use of other sources (excluding the Upper Floridan aquifer and intermediate aquifers) of nonpotable water shall constitute reasonable and beneficial uses of water; as such uses are set forth in the SCA and approved in the site certification process, and are hereby authorized as required in support of ultimate capacity at PEF's Hines Energy Complex ; provided, however, that use or reuse of nonpotable water shall be deemed unreasonable if it will result in degradation of cooling pond water quality below the levels proposed by PEF in support of the ultimate site capacity certification or any water quality standard made applicable by federal or state law.

15. PEF shall continue to investigate the feasibility of using reclaimed water as a water source and submit a report to SWFWMD describing the feasibility no later than March 31, 2005, and every two years thereafter. PEF shall also submit a reclaimed water feasibility report to SWFWMD in connection with each subsequent application submitted pursuant to Condition XXVI.A.14. except when such application is filed within six months of submittal of the last biennial feasibility report required by this Condition. If the subsequent application is

submitted within six months of submittal of the last biennial feasibility report required by this Condition, the application shall reference the previous feasibility report and provide any updates of reclaimed water feasibility. All reuse feasibility reports PEF submits shall contain an analysis of reclaimed water sources for the area, including the relative location of these sources to PEF's property, the quantity of reclaimed water available, the projected date(s) of availability, costs associated with obtaining the reclaimed water, an explanation of PEF's efforts to obtain such reclaimed water, names of individuals PEF has contacted at each reclaimed water provider, a description of any impediments to obtaining that reclaimed water and PEF's efforts to overcome those impediments, and an implementation schedule for reuse, if feasible. Infeasibility shall be supported with a detailed explanation.

16. PEF shall meter withdrawals from surface waters and/or the ground water resources, and meter readings from each withdrawal shall be recorded on a monthly basis within the last week of the month. The meter reading(s) shall be reported to the Permit Data Section, Records and Data Department (using SWFWMD scanning forms, unless SWFWMD has approved another arrangement for submission of this data) on or before the tenth day of the following month for which the data is being submitted. If a metered withdrawal is not utilized during a given month, the meter report shall be submitted to SWFWMD indicating the same meter reading as was submitted the previous month. The following withdrawals shall be metered as applicable:

a. PEF shall install meters on SWFWMD ID Nos. 1, 2, 3, 4, and 5, PEF ID Nos. P-1, P-2, P-3, P-4, and P-5, within 90 days of completion of construction of the withdrawal.

b. PEF shall continue to maintain and operate existing, non-resettable, totalizing flow meter(s) or other flow measuring device(s) as approved by the Bartow Regulation Department Director on SWFWMD ID No. 6, PEF ID No. P-6.

c. The meters shall adhere to the following requirements and shall be installed or maintained as follows:

(i) The meter(s) shall be non-resettable, totalizing flow meter(s). If other measuring device(s) are proposed, prior to installation, approval shall be obtained in writing from the Bartow Regulation Department Director.

(ii) Meters shall be installed on all stand by withdrawal facilities prior to activation.

(iii) The flow meter(s) or other approved device(s) shall have and maintain an accuracy within five percent of the actual flow as installed.

(iv) The meter shall either be tested for accuracy on-site, as installed, every two years beginning from the date of installation unless PEF demonstrates to the satisfaction of SWFWMD that a longer period of time for testing is warranted, or alternatively, the meter may be replaced with a factory calibrated or re-calibrated meter. If testing is performed as the means of ensuring accuracy of in-service metering, the test shall be performed by a person certified in the equipment used. If the actual flow is found to vary greater than 5% from the measured flow, PEF shall have the meter re-calibrated or replaced, whichever is necessary. Documentation of the test and a certificate of re-calibration, if applicable, shall be submitted within 30 days of each test or re-calibration.

(v) The meter shall be installed in a straight length of pipe where there is a least an upstream length equal to ten (10) times the outside pipe diameter and a downstream length equal to two (2) times the outside pipe diameter. Where there is not at least a length equal to ten (10) times the diameter upstream available, flow straightening vanes shall be used in the line.

(vi) If the meter or other flow measuring device has malfunctioned or has to be removed from the withdrawal for maintenance or repair, PEF shall notify SWFWMD within 30 days of discovering the necessity to replace or repair the meter and shall replace it with a repaired or new meter, subject to the same specifications as provided herein, within 30 days of its removal from the withdrawal.

(vii) When the meter has malfunctioned or has been removed the withdrawal, the PEF shall request instruction on how to estimate use from the Permit Data Section. The estimate of the number of gallons used each month during that period shall be submitted according to the instructions received from SWFWMD.

(viii) In the event a new meter is installed to replace a broken meter, the new meter and its installation shall meet the specifications of this condition. PEF shall notify SWFWMD of the replacement with the first submittal of meter readings from the new meter.

17. Water quality samples shall be collected and analyzed, for parameter(s), and frequency(ies) specified below. Water quality samples from production wells shall be collected whether or not the well is being used, unless infeasible. If sampling is infeasible, PEF shall indicate the reason for not sampling on the water quality data form. Water quality samples shall be analyzed by a laboratory certified by the Florida Department of Health utilizing the standards and methods applicable to the parameters analyzed and to the water use pursuant to Chapter 64-E-1, Florida Administrative Code, "Certification of Environmental Laboratories". At a minimum, water quality samples shall be collected after pumping the well at its normal rate for a pumping time specified in the table below, or to a constant temperature, pH, and conductivity. In addition, PEF's sampling procedure shall follow the handling and chain of custody procedures designated by the certified laboratory which will undertake the analysis. Any variance in sampling and/or analytical methods shall have prior approval of the Bartow Regulation Department Director. Reports of the analyses shall be submitted to the Permits Data Section (using SWFWMD forms) on or before the tenth day of the second month following data collection, and shall include the signature of an authorized representative and certification number of the certified laboratory which undertook the analysis. The parameters and frequency of sampling and analysis may be modified by the Bartow Regulation Department Director, as necessary to ensure the protection of the resource.

SWFWMD ID No.	PEF ID No.	Minimum Pumping Time (minutes)	Parameter	Sampling Frequency
1	P-1	30	Chlorides, Sulfates, Total Dissolved Solids (TDS)	Feb., May, Aug. & Nov.

Water quality samples shall be collected based on the following timetable:
Quarterly Same week of months specified

Analyses shall be performed according to procedures outlined in the current edition of Standard Methods for the Examination of Water and Wastewater by the American Public Health Association-American Water Works Association-Water Pollution

Control Federation (AQHA-AWWA-WPCF) or Methods of Chemical Analyses for Water and Wastes by the U.S. Environmental Protection Agency (EPA).

18. During drilling of SWFWMD ID Nos. 1 and 5 (PEF ID Nos. P-1 & P-5), water quality samples shall be collected at intervals of 50 feet or less, from 300 feet to a maximum depth of five feet above the bottom of the well. Regardless of the specified sample collection interval, a sample shall be collected from the depth which corresponds to five feet above the bottom of the well. Samples shall be collected during reverse air drilling, or other appropriate method with prior approval by the Bartow Regulation Department Director, which will allow representative samples for each depth to be collected.

Samples shall be analyzed by a certified laboratory for chlorides, sulfates, and TDS. PEF's sampling procedure shall follow the handling and chain of custody procedures designated by the certified laboratory which will undertake the analysis. Reports of the analyses shall be submitted to the Permit Data Section (using SWFWMD forms) by the tenth day of the second month following sampling, and shall include the signature of an authorized representative and the certification number of the Florida Department of Health certified laboratory, utilizing the standards and methods applicable to the parameters analyzed and to the water use pursuant to Chapter 64E-1, Florida Administrative Code, "Certification of Environmental Laboratories".

Analyses shall be performed according to procedures outlined in the current edition of Standard Methods for the Examination of Water and Wastewater by the American Public Health Association-American Water Works Association-Water Pollution Control Federation (AQHA-AWWA-WPCF) or Methods of Chemical Analyses for Water and Wastes by the U.S Environmental Protection Agency (EPA).

19. PEF shall maintain a continuous recording rain gauge and an evaporation pan at Latitude 27° 47' ~~28"~~ 30" and Longitude 81° 52' ~~17"~~02", SWFWMD ID No. 141. Total daily rainfall and daily evaporation shall be recorded at this station and submitted to the Permit Data Section, Records and Data Department, on SWFWMD forms on or before the tenth day of the following month. The reporting period for each report shall begin on the first day of each month and end on the last day of each month.

20. Any wells not in use, and in which pumping equipment is not installed shall be capped or valved in a watertight manner in accordance with Chapter 62-532.500(3)(a)(4), F.A.C.

21. PEF shall construct the proposed wells according to the surface diameter and casing depth specifications below. The casing depth specified is to prevent the unauthorized interchange of water between different water bearing zones. If a total depth is listed below, this depth is an estimate, based on best available information, of the depth at which high producing zones are encountered. However, it is PEF's responsibility to have the water in the well sampled during well construction, before reaching the estimated total depth. Such sampling is necessary to ensure that the well does not encounter water quality that cannot be utilized by PEF, and to ensure that withdrawals from the well will not cause salt-water intrusion.

SWFWMD ID No.	PEF ID No.	Surface Diameter	Minimum Casing Depth	Estimated Total Depth
1	P-1	20 in.	300 ft.	880 ft.
2	P-2	20 in.	300 ft.	880 ft.
3	P-3	20 in.	300 ft.	880 ft.
4	P-4	20 in.	300 ft.	880 ft.
5	P-5	20 in.	300 ft.	880 ft.
21	AR-1	24 in.	300 ft.	880 ft.
22	AR-2	24 in.	300 ft.	880 ft.
23	AR-3	24 in.	300 ft.	880 ft.
24	AR-4	24 in.	300 ft.	880 ft.
25	AR-5	24 in.	300 ft.	880 ft.
26	AR-6	24 in.	300 ft.	880 ft.

a. The casing shall be continuous from land surface to the minimum depth stated above.

b. All well casing (including liners and submit a report to the depth specified above.

c. The proposed well(s) shall be constructed of materials that are resistant to degradation of the casing/grout due to interaction with the water of lesser quality. A minimum grout thickness of two (2) inches is required on wells four (4) inches or more in diameter.

d. A minimum of twenty (20) feet overlap and two (2) centralizers is required for Public Supply wells, and all wells six (6) inches or more in diameter.

e. The finished well casing depth shall not vary from these specifications by greater than ten (10) percent unless advance approval is granted by the Bartow Regulation Department Director, or the Manager of the Well Construction Permitting Section in Brooksville.

f. Advance approval from the Bartow Regulation Department Director, is necessary should PEF propose to change the well location or casing diameter.

22. At least one year prior to the planned production from the first of P-1 through P-5, and prior to initiation of the Aquifer Recharge and Recovery Project, PEF shall submit a detailed plan for a long-term aquifer performance test (APT) for approval by the Bartow Regulation Department Director~~,~~ The test shall be conducted for a sufficient period of time to determine the leakance parameter between the surficial and intermediate aquifers and the leakance parameter between the intermediate and Upper Floridan aquifers. The test shall be conducted for a minimum of seven days (fourteen days is preferable), and shall include collection of water quality data (see Special Condition XXVI.A.17 for water quality parameters). Attempts will be made to conduct the test during a period of minimal adjacent pumpage and during a period of minimal rainfall to minimize interference with the test. This test shall take place prior to initiation of pumpage from these wells~~-~~and prior to any recharge of the Upper Floridan aquifer. For review and approval by SWFWMD, a report of the results of the test, including all raw data and analyses, shall be provided to the Permit Data Section within 30 days of the completion of the test.

If any of the approved aquifer characteristics vary significantly from those used in the groundwater flow model submitted with the Certification, PEF shall submit an updated groundwater flow model upon notification by the Bartow Regulation Department Director. This model is subject to SWFWMD approval and shall utilize the actual approved aquifer characteristics determined during the APT to predict impacts due to groundwater withdrawals at this site. If the new modeling (if required) indicates that there are adverse impacts not indicated in the SCA, PEF may be required to amend the Site Certification.

23. Prior to dewatering within 2,640 feet of a property boundary, PEF shall comply with one of the following two alternatives:

a. Secure written consent from all adjacent property users for lowering the water table below their lands. Three copies of the consent shall be submitted in writing to the Bartow Regulation Department Director prior to dewatering within the specified distance. This alternative cannot be used if adjacent lands contain wetlands or other water bodies within 2,640 feet of PEF's dewatering activity.

b. Implement a procedure to mitigate impacts by maintaining the water table at historic levels at the property boundary. Prior to implementation of the proposed dewatering plan submitted June 28, 1993, PEF must obtain approval from the Bartow Regulation Department Director. The procedure shall include items a, b, c, d, and e under Condition XXVI.A.24.

24. Prior to dewatering within 2,640 feet of on- or off-site wetlands that will not be disturbed in association with this certification, PEF shall implement a procedure to mitigate impacts by maintaining the water table at historic levels beneath such wetlands or at the property boundary for off-site wetlands. Prior to implementation of the proposed dewatering plan submitted June 28, 1993, PEF must obtain approval, in writing, from the Bartow Regulation Department Director. The procedure shall include:

a. A water table monitoring network, approved by the Bartow Regulation Department Director, designed to demonstrate that water table drawdown does not adversely impact on- or off-site wetlands.

b. Collection of water table level data after construction of the approved monitor well network for at least two years prior to the initiation of dewatering in the area, to obtain background data. During this time period, water level data shall be recorded on a weekly basis and submitted monthly.

c. If a rim-ditch system is proposed to recharge the water table near on-site wetlands that will not be disturbed, design and operation details must be submitted to demonstrate that the water table will be maintained at appropriate levels based on the background data collected. Rim-ditch systems must also be accompanied by a monitor well network to verify water table maintenance.

d. At least one month prior to the anticipated date of dewatering an area within the setback distance, water level data shall be recorded and submitted on a weekly basis.

e. Data collection shall continue for six months following completion of dewatering and reclamation or until SWFWMD staff determine that background or steady-state levels are attained. During this time period, water level data shall be recorded on a weekly basis and reported monthly. Water elevations shall be reported in feet relative to the National Geodetic Vertical Datum (NGVD). Data shall be submitted in both tabular and graphical format. The tabular format will include SWFWMD Identification Number, water level readings relative to the NGVD, the date the readings were taken, the amount of drawdown that has occurred for each monitoring point for that respective month, and dates dewatering started and stopped. The graphical format shall contain on the x-axis the dates the water level readings were taken and the respective SWFWMD Identification Number. The y-axis shall include the water level elevations relative to the NGVD. Each graph should be representative of a specified dewatered area, and will indicate the elevation, for each season, that should be maintained relative to the NGVD, and the dates when dewatering started and stopped.

25. PEF is authorized to develop a new water resource through the construction of an Aquifer Recharge and Recovery Project on the Hines Energy Complex site (Hines ARRP) that treats surface water and wastewater and injects or recharges that water, subject to FDEP approval, into the Upper Floridan aquifer, which will be used to store and convey this water for subsequent withdrawal and use. The Hines ARRP shall be operated to offset future groundwater withdrawals as provided in condition XXVI.A.14.b.ii(2)~~ii~~. The Hines ARRP shall be developed pursuant to the following criteria:

a. Captured rainwater, reclaimed domestic wastewater effluent ~~from the City of Bartow's Douglas H. Allen Reclaimed Water Facility~~, treated industrial waste discharges from ALCOA, and water from the Hines Energy

Complex cooling pond, treated to applicable groundwater quality standards for recharge to the Floridan aquifer, may be used for injection into the Upper Floridan aquifer.

b. Existing on-site areas at the Hines Energy Complex may be used as water reservoirs and treatment areas, subject to FDEP approval, for the ARRP;

c. On-site recharge wells shall be constructed in accordance with applicable regulatory standards;

d. Withdrawal amounts from the new water resource developed through the Hines ARRP shall be as follows:

(1) Withdrawals from the Upper Floridan aquifer as offsets generated by the Hines ARRP shall be limited to 85 percent of the total amount of water recharged through the Hines ARRP, as of the date of withdrawal, and shall not exceed the rate authorized in Condition of Certification XXVI.A.14.b., and shall be operated in a manner that results in no adverse impact to off-site existing legal users; and

(2) If the results of the APT stipulated in Condition No. XXVI.A.22 makes it necessary to submit new groundwater models and the new models show adverse impacts at the rate authorized in Condition of Certification XXVI.A.14.b, the authorized rate shall be reduced accordingly.

e. PEF shall annually submit an ARRP Performance Report which will contain, but shall not be limited to, the following:

(1) An account of the cumulative water quantities recharged through the recharge well(s) and the cumulative quantities of water produced through the production wells confirming, based on the monthly injections and pumpage reports, that the cumulative injection/pumpage quantities balance is such that injection exceeds pumpage by no less than 15% at any point in time during the ARRP operation; and

(2) A narrative and analysis of the overall performance of the ARRP, addressing strengths, weaknesses, problems, and future plans with time frames for improvement.

26. PEF shall continue to maintain SWFWMD-approved staff gauge(s) and report measurements of water levels, as indicated in the table below. Water levels shall be recorded and reported to the Permit Data Section, Records and Data Department, (on SWFWMD forms) on or before the tenth day of the following month. To the maximum extent possible, water levels shall be recorded as indicated in the table below. The frequency of recording may be modified by the Bartow Regulation Department Director, as necessary to ensure the protection of the resource.

SWFWMD ID No.	PEF ID No.	Water Body/Wetland	Latitude/ Longitude	Recording Frequency
121	HSG-1	Cooling Pond	27°47'~~41"~~31"/81° ~~51'59"~~52'03"	Weekly
122	SG-P-1	Rain Cropping Area	27°49'02"/81°54'39"	Weekly
123	SG-WC-1	Rain Cropping Area	27°49'30"/81°53'14"	Weekly
124*	SG-WC-2	Rain Cropping Area	27°47'33"/81°50'45"	Weekly
125	SG-WC-3	Rain Cropping Area	27°47'02"/81°51'54"	Weekly
126	SG-MC-1	Rain Cropping Area	27°46'52"/81°52'32"	Weekly
127	SG-CB-1	Rain Cropping Area	27°47'31"/81°50'13"	Weekly

Water Level Recording Timetable: Weekly Same day of each week
* This location may be removed when this area is incorporated into the Cooling Pond.

27. PEF shall meter injections of water into the Upper Floridan aquifer, and meter readings from each injection well shall be recorded on a monthly basis within the last week of the month. The meter reading(s) shall be reported to the Permit Data Section, Records and Data Department (using SWFWMD scanning forms, unless SWFWMD has approved another arrangement for submission of this

data) on or before the tenth day of the following month. If a metered injection well is not utilized during a given month, the meter report shall be submitted to SWFWMD indicating the same meter reading as was submitted the previous month. The following injection wells shall be metered as applicable:

a. PEF shall install meters on SWFWMD ID Nos. 21, 22, 23, 24, 25, and 26, PEF ID Nos. AR-1, AR-2, AR-3, AR-4, AR-5, and AR-6, within 90 days of completion of construction of the injection well.

b. The meters shall adhere to the following requirements and shall be installed or maintained as follows:

(1) The meter(s) shall be non-resettable, totalizing flow meter(s). If other measuring device(s) are proposed, prior to installation, approval shall be obtained in writing from the Bartow Regulation Department Director.

(2) Meters shall be installed on all standby injection facilities prior to activation.

(3) The flow meter(s) or other approved device(s) shall have and maintain an accuracy within five percent of the actual flow as installed.

(4) The meter shall be tested for accuracy on-site, as installed, every two years beginning from the date of issuance unless PEF demonstrates to the satisfaction of SWFWMD that a longer period of time for testing is warranted. The test shall be performed by a person certified in the equipment used. If the actual flow is found to vary greater than 5% from the measured flow, PEF shall have the meter re-calibrated or replaced, whichever is necessary. Documentation of the test and a certificate of re-calibration, if applicable, shall be submitted within 30 days of each test or re-calibration.

(5) The meter shall be installed in a straight length of pipe where there is a least an upstream length equal to ten (10) times the outside pipe diameter and a downstream length equal to two (2) times the outside pipe diameter. Where there is not at least a length equal to ten (10) times the diameter upstream available, flow straightening vanes shall be used in the line.

(6) If the meter or other flow measuring device malfunctions or has to be removed from the withdrawal for maintenance or repair, PEF shall notify SWFWMD within 30 days of discovering the necessity to replace or

repair the meter and shall replace it with a repaired or new meter, subject to the same specifications as provided herein, within 30 days of its removal from the injection well.

(7) When the meter has malfunctioned or has been removed from the withdrawal, PEF shall request instruction on how to estimate use from the Permit Data Section. The estimate of the number of gallons injected each month during that period shall be submitted according to the instructions received from SWFWMD.

(8) In the event a new meter is installed to replace a broken meter, the new meter and its installation shall meet the specifications of this condition. PEF shall notify SWFWMD of the replacement with the first submittal of meter readings from the new meter.

28. PEF shall record meter readings from each reuse line on a monthly basis within the last week of the month. The meter reading(s) shall be reported to the Permit Data Section, Records and Data Department (using SWFWMD scanning forms, unless SWFWMD has approved another arrangement for submission of this data) on or before the tenth day of the following month. If a metered reuse line is not utilized during a given month, the meter report shall be submitted to SWFWMD indicating the same meter reading as was submitted the previous month. The following reuse lines shall be metered:

a. PEF shall install meters on reuse line, SWFWMD ID No. 52, PEF ID No. ATB-1, within 90 days of completion of construction of the reuse delivery system. In metering and reporting the quantities conveyed through this line, PEF shall meter or estimate the amount of reuse water contributed by each of the following components: industrial wastewater from ALCOA; industrial wastewater from the Tiger Bay Cogeneration Facility; fresh groundwater for pipe flushing; and fresh groundwater for water supply shortage at the Hines Energy Complex. PEF shall submit two copies of the report, one for the Hines Energy Complex, and one for the Tiger Bay Cogeneration Facility.

If there is more than one episode of conveyance in one month for any of the flow components, the report should contain the corresponding information (meter readings, quantities, and dates, related to each episode in addition to the net quantities conveyed during the month for ~~the~~ each of the flow components.

b. PEF shall install meters on previously un-metered existing reuse line SWFWMD ID No. 51, PEF ID No. BED, prior to October 1, 2003. <u>The meter at the City of Bartow's Douglas H. Allen Reclaimed Water Facility used to monitor flows directed to the Hines Energy Complex is sufficient to meet this requirement.</u>

c. The meters shall adhere to the following requirements and be installed or maintained as follows:

(1) The meter(s) shall be non-resettable, totalizing flow meter(s). If other measuring device(s) or other accounting methods are proposed, the PEF shall submit documentation that the other measuring devices or accounting methods meet the stipulations listed in this condition, prior to installation. Approval for other measuring devices or accounting methods shall be obtained in writing from the Bartow Regulation Department Director.

(2) The flow meter(s) or other approved device(s) shall have and maintain an accuracy within five percent of the actual flow as installed.

(3) The meter shall be tested for accuracy on-site, as installed, every two years beginning from the date of issuance, unless the PEF submits documentation to the satisfaction of SWFWMD that a longer period of time for testing is warranted. The test shall be performed by a person certified to use the test equipment. If the actual flow is found to vary than 5% from the measured flow, the PEF shall have the meter re-calibrated or replaced, whichever is necessary. Documentation of the test and a certificate of re-calibration, if applicable, shall be submitted within 30 days of each test or re-calibration. If the alternative accounting method involves a meter belonging to another entity or to the reclaimed water supplier, the PEF shall submit documentation from the owner/ supplier that the meter readings continue to be accurate to 5% of the actual flow as installed. Such documentation is subject to approval by SWFWMD.

(4) The meter shall be installed in a straight length of pipe where there is at least an upstream length equal to ten (10) times the outside pipe diameter and a downstream length equal to two (2) times the outside pipe diameter. Where there is not at least a length of ten diameters upstream available, flow straightening vanes shall be used in the upstream line.

(5) If the meter or other flow measuring device malfunctions or has to be removed from the reuse line for maintenance or repair,

PEF shall notify SWFWMD within 30 days of discovering the necessity to replace or repair the meter, and shall replace it with a repaired or new meter, subject to the same specifications given above, within 30 days of its removal from the reuse line.

(6) While the meter is off the reuse line, PEF shall request instructions on how to estimate use from the Permit Data Section. The estimate of the number of gallons used each month during that period shall be submitted according to the instructions received from SWFWMD.

(7) In the event a new meter is installed to replace a broken meter, the new meter and its installation shall meet the specifications of this condition. PEF shall notify SWFWMD of the replacement with the first submittal of meter readings from the new meter.

29. PEF is limited to an Annual Average Daily withdrawal of 800,000 gpd and Peak Month Daily withdrawal of 1,000,000 gpd of groundwater to be transferred from the Tiger Bay Cogeneration Facility for Power Block 1 and Power Block 2 at the Hines Energy Complex as a water supply shortage contingency.

30. PEF shall submit by April 1 of each year a Cooling Pond Performance Report for the preceding calendar year. The report shall include graphs and narratives describing and analyzing the performance of the cooling pond in terms of the pond water level in relation to precipitation, evaporation, ambient temperature, water quality, itemized estimates of inflows, itemized estimates of outflows (including seepage losses), and electric power production. Based on these reports, limits on groundwater pumpage into the Cooling Pond in relation, but not limited, to precipitation and Cooling Pond water elevation levels may be adjusted or introduced by SWFWMD.

31. An interim water supply shortage as used in Condition No. XXVI.A.14.b., shall mean a shortage of previously authorized process and cooling water sources which results in the inability of PEF to prevent the operational water level of the Hines cooling pond from being lowered below an elevation of 158.5 feet National Geodetic Vertical Datum (NGVD). If the water level becomes less than 158.5 feet NGVD, despite all reasonable efforts by PEF to prevent such lowering of water level by utilizing all previously authorized water sources to the greatest extent practicable, as identified in Condition No. XXVI.A.14.b.i, PEF is authorized until November 30, 2005, to transfer Upper Floridan aquifer groundwater authorized to be

used at PEF's Tiger Bay facility pursuant to PA 97-37 Conditions of Certification, to the Hines cooling pond, subject to the following:

a. PEF must notify SWFWMD Bartow Regulation Department Director, in writing, that a water supply shortage has occurred or is expected to occur and that it intends to transfer Tiger Bay groundwater to the Hines cooling pond. This notification must be provided at least ten (10) days in advance of the actual transfer of Tiger Bay groundwater.

b. PEF must concurrently provide a copy of the notification to the FDEP, Office of Siting Coordination.

c. PEF shall include in its notification documentation that all previously authorized sources of water, as identified in condition XXVI.A.14.b.i, are being used to the greatest extent practicable. Additionally, such notification shall include details on any water conservation measures which were being implemented in an effort to avoid a water supply shortage and which will be continued in order to reduce the amount of transferred withdrawals needed to alleviate the water supply shortage. PEF will account in its Tiger Bay monthly pumpage reports any groundwater quantities used for transfer to Hines to alleviate the interim water supply shortage.

d. PEF shall equip the water transfer pipeline from Tiger Bay to the Hines cooling pond with non-resettable totalizing flow meters, or other flow measuring devices as approved by SWFWMD Bartow Regulation Department Director, and shall monitor and record the amount of transferred groundwater used to alleviate the water supply shortage. The flow meter(s) shall comply with the content of Condition No. XXVI.A.16 and be capable of separately calculating transferred Tiger Bay groundwater from other sources of water or wastewater to be conveyed via the pipe to the Hines cooling pond. The reporting of the quantities thus measured shall be in accordance with Condition XXVI.A.28.a.

e. When the water level in the Hines cooling pond rises to an elevation of 158.5 feet NGVD, and PEF is able to successfully maintain the water level at or above 158.5 feet NGVD for seven (7) consecutive days, the water supply shortage shall be considered to have ended and PEF shall discontinue the use of transferred groundwater from Tiger Bay.

f. Within 30 days of cessation of groundwater transfers during a water supply shortage, PEF shall provide written notification to SWFWMD Bartow Regulation Department Director of the cessation of these transfers. This notification shall provide the number of days that Tiger Bay groundwater was transferred to the Hines cooling pond and the total volume of groundwater transferred. Additionally, this notification shall include a report, including tabulated data and a graph showing the rate at which water was supplied compared to the change occurring in the cooling pond level, through the entire duration of the groundwater transfer. The pond water level during a water shortage event shall be measured daily. The graphic report shall present these measurements for the entire duration of the water supply shortage.

g. The quantity of groundwater authorized for use at the Tiger Bay facility shall be reduced by the amount of that source being transferred to the Hines cooling pond during the water supply shortage. At no time will the groundwater quantities produced at the Tiger Bay facility exceed the permitted quantities for that facility. The monthly groundwater pumpage reports required to be submitted to SWFWMD per the Condition of Certification XIV.D.4 of the Siting Certification No. PA 97-36 of the Tiger Bay Cogeneration Facility, shall include a breakdown of quantities produced for use at the Tiger Bay facility, water shortage transfer to the Cooling Pond at the Hines Energy Complex, and for flushing the pipelines associated with water conveyance to the Hines Energy Complex.

h. PEF shall undertake diligent efforts to investigate and, if feasible, modify the Hines Energy Complex watercrop system or otherwise locate sources of water, other than potable groundwater, to eliminate or substantially reduce the need to transfer groundwater from the Tiger Bay facility. PEF's diligent efforts shall include, but not be limited to, investigating the feasibility of the following: modifying or making changes to the Hines Energy Complex's watercrop system to increase runoff or storage; transferring industrial wastewater from the Tiger Bay facility; obtaining industrial wastewater from US Agri-Chemicals Corporation (USAC) to transfer to the Hines Energy Complex; increasing the amount of impervious surface at the Plant Island portion of the Hines Energy Complex to increase surface water runoff flows into the cooling pond; transferring industrial wastewater from the nearby ALCOA facility; withdrawing water from surface water sources; and locating and using other sources of reclaimed domestic wastewater and/or treated industrial wastewater.

By August 31, 2005, PEF shall provide a ~~two~~ written report~~s~~ to the SWFWMD Permits Data Section regarding its efforts to locate additional sources of water pursuant to this condition. ~~The first report shall be provided no later than December 30, 2003, and the second no later than December 30, 2004.~~ The ~~Each~~ report shall detail PEF's efforts to obtain additional water sources pursuant to this condition, any impediments PEF has encountered, and PEF's efforts or plans for overcoming those impediments if possible, and, if additional sources will be secured, the time frame for delivering water from those sources.

i. PEF's authorization to receive groundwater from Tiger Bay for the Hines Energy Complex pursuant to this Condition shall end on November 30, 2005.

~~32. By February 1, 2004, PEF shall install SWFWMD-approved staff gauges and report measurements of water levels at the water bodies as indicated in the table below. The staff gauges shall be surveyed and referenced to the National Geodetic Vertical Datum (NGVD), and a copy of the survey including location shall be submitted with the first water level data report. The staff gauges shall be scaled in one-tenth foot increments and shall be sized and placed so as to be clearly visible from an easily accessible point of land. Water levels shall be recorded on a frequency as indicated in the table below and reported to the Permit Data Section, Records and Data Department (on SWFWMD forms) on or before the tenth day of the following month. To the maximum extent possible, water levels shall be recorded on the same day of each week. The frequency of recording may be modified by the Bartow Regulation Department Director, Resource Regulation, as necessary to ensure the protection of the resource.~~

~~SWFWMD ID No.~~	~~PEF ID No.~~	~~Water Body/ Wetland~~	~~Latitude/ Longitude~~	~~Recording Frequency~~
~~122~~	~~SG P-1~~	~~Rain Cropping Area~~	~~27° 48' 48"49'02"/81° 53' 46"54'39"~~	~~Weekly~~

~~123 SG WC 1 Rain Cropping Area 27° 49' 30"/81° 53' 10"14" Weekly~~
~~124 SG WC 2 Rain Cropping Area 27° 47' 49"33"/81° 50' 52"45" Weekly~~
~~125 SG WC 3 Rain Cropping Area 27° 48' 41"47'02"/81° 51' 54" Weekly~~
~~126 SG MC 1 Rain Cropping Area 27° 47' 02"46'52"/81° 52' 24"32" Weekly~~
~~127 SG CB 1 Rain Cropping Area 27° 47' 29"31"/81° 50' 15"13" Weekly~~

~~Water Level Recording Timetable:~~

~~Weekly Same day of each week~~

32~~33~~. Within **90** days of construction of the withdrawal facility, PEF shall install a backflow prevention system on SWFWMD ID Nos. **1, 2, 3, 4,** and **5**, PEF ID Nos. **P-1, P-2, P-3, P-4, and P-5.**

33~~34~~. Within **90** days of construction of the withdrawal facility, an automated flow control system shall be installed on the groundwater flow from ~~SWFWMD ID Nos. **1 and 2,** PEF ID No. P-1 and P-2.~~ SWFWMD ID Nos. **1, 2, 3, 4,** and **5**, PEF ID Nos. **P-1, P-2, P-3, P-4, and P-5.**

The automated flow control system (i.e., the automated shutoff device) shall be properly maintained at all times to control the wells' water flow into the Cooling Pond, such that no discharge into the pond would take place when the elevation in the Cooling Pond is at or above 160.0 feet NGVD.

34~~35~~. PEF shall perform a feasibility study to explore and utilize ~~exploit~~ groundwater resources of the Lower Floridan aquifer at the Hines Energy Complex. The Lower Floridan aquifer is defined as the Oldsmar formation, the Cedar Keys formation, or lower formations. The objective of this feasibility study is to determine whether such formations are alternative sources for the fresh groundwater of the Upper Floridan aquifer. The feasibility study shall initially include at least one deep test well in the Lower Floridan aquifer for an initial determination of hydrogeological parameters and characteristics of the Lower

Floridan aquifer at the project site. In order to assess the potential for use of the Lower Floridan, the study shall determine the water quality of the Lower Floridan aquifer and assess its feasibility as an alternative source, including prospects for brines disposal if need be, and once-through, non-contact cooling by re-circulation of the Lower Floridan aquifer water. If the use of the Lower Floridan aquifer water is determined to be feasible based on water quality, transmissivitivity, and/or re-circulation through the aquifer, additional study of the yield and the degree of interconnection between the Lower and Upper Floridan aquifers shall be undertaken. ~~The feasibility study must be completed prior to submitting a Supplemental Site Certification Application requesting more than a total Annual Average quantity of 5.0 MGD, not including any offsets outlined in Condition XXVI.A.14.b.ii.2. PEF shall submit a plan for use of the Lower Floridan aquifer if it is deemed a feasible water source.~~ Any Lower Floridan aquifer exploratory work ~~study~~ conducted by the SWFWMD at the Hines Energy Complex site ~~shall satisfy~~ may be used by PEF toward satisfying PEF's requirement to conduct the feasibility study outlined in this condition. However, such SWFWMD exploratory work shall not necessarily constitute in itself all that is required to satisfy the requirements of this condition. Analysis and interpretation of the results of exploratory work conducted by SWFWMD will still be required to be conducted by PEF as part of the required feasibility study.

At least 90 days prior to the initiation of implementation of the exploration and feasibility study, PEF shall submit for approval by the Director of the District's Bartow Regulation Department an "Exploratory and Feasibility Study Plan of the Lower Floridan Aquifer (E&FS Plan)." The implementation of the approved plan, evaluation of the data, and the submittal of the feasibility study to SWFWMD ~~The feasibility study~~ must be completed prior to submitting a Supplemental Site Certification Application requesting more than a total Annual Average quantity of 5.0 MGD, not including any offsets outlined in Condition XXVI.A.14.b.ii.2. If deemed a feasible water source, any such Supplemental Site Certification Application ~~PEF~~ shall include ~~submit~~ a plan for use of the Lower Floridan aquifer. ~~if it is deemed a feasible water source.~~

35~~36~~. PEF shall develop and implement a measurement and monitoring plan for the existing on-site rainwater capture and reuse system (known as the watercrop system) approved by Condition XXVI.A.14.c. The watercrop system measurement and monitoring plan shall be designed to obtain information that can be used to establish accurate estimates of water production yields from the watercrop system under various rainfall events and to determine flows leaving the site to supply natural systems (including runoff discharges from buffer areas). PEF FPC shall submit the watercrop system measurement and monitoring plan to SWFWMD for review and approval by November 15, 2003. The plan shall contain a timetable for the installation and operation of gauges, meters, recorders, and other equipment that the plan sets forth to use in measuring and monitoring the watercrop system. The plan shall also set forth a schedule for collecting data and reporting that data to SWFWMD. Upon receiving SWFWMD approval, PEF shall implement the watercrop system measurement and monitoring plan according to the timeframes set forth in the approved plan.

By April 1 of each year, PEF shall submit an "Annual Water Crop System Report for the Hines Energy Complex" summarizing the data collected per the approved "Measurement and Monitoring Plan for the Water Crop System". The report shall document estimates of water production yields from the watercrop system under various rainfall events, and estimates of flows leaving the site to supply natural systems (including runoff discharges from buffer areas). The report shall present an overall evaluation of the functioning of the system and recommendations for its improvement.

36~~37~~. The Annual Average Daily (AAD) and Peak Month Daily (PMD) quantities for each of SWFWMD ID Nos. 1 ~~and 2~~, 2, and 3, PEF's ID Nos. P-1 ~~and P-2~~, P-2, and P-3, shall be limited to an AAD quantity of ~~2,600,000~~ 5,000,000 gallons per day (gpd) and a PMD quantity of ~~4,400,000~~ 8,800,000 gpd. PEF may make adjustments in pumpage distribution as necessary up to the quantities indicated specifically for each withdrawal provided that the combined total quantities will not exceed ~~2,600,000~~ 5,000,000 gpd on an AAD basis and ~~4,400,000~~ 8,800,000 gpd on a PMD basis, as long as adverse environmental impacts do not result and other Conditions of this Site Certification are complied with. In all cases, the total average annual daily withdrawal and the total peak monthly daily withdrawal are limited to the quantities set forth above.

37~~38~~. PEF shall not utilize groundwater through the withdrawals SWFWMD ID Nos. 1 and 2, PEF's ID Nos. P-1 and P-2, until Power Block 3 becomes operational. PEF shall not utilize groundwater through the withdrawal SWFWMD ID No~~s~~. 3, PEF~~'s~~ ID No~~s~~. P-3, until Power Block 4 becomes operational. In addition, PEF shall only utilize groundwater through the withdrawals SWFWMD ID Nos. 1, 2 and 3, PEF's ID Nos. P-1, P-2 and P-3, ~~and only~~ when the elevation of the water level in the Cooling Pond, as measured weekly at SWFWMD ID No. 121, PEF ID No. HSG-1, is below 160.00 feet NGVD. Minor withdrawals associated with routine pump maintenance and water quality sampling are exempt from this requirement.

38~~39~~. For Power Blocks 1, 2, and 3, PEF shall not utilize groundwater through SWFWMD ID Nos. 1 and 2, PEF's ID Nos. P-1 and P-2, at the PMD rate of 4,400,000 gpd except when and only when the elevation of the water level in the Cooling Pond, as weekly measured at SWFWMD ID No. 121, PEF ID No. HSG-1, is below 159.00 feet NGVD. For Power Blocks 1, 2, 3, and 4, PEF shall not utilize groundwater through SWFWMD ID Nos. 1, 2 and 3, PEF's ID Nos. P-1, P-2 and P-3, at the PMD rate of 8,800,000 gpd except when and only when the elevation of the water level in the Cooling Pond, as weekly measured at SWFWMD ID No. 121, PEF ID No. HSG-1, is below 159.00 feet NGVD.

39. ~~40.~~ In the event that PEF exceeds during a drought year the Annual Average Daily (AAD) quantity of 2,619,000 ~~2,600,000~~ gpd and the Peak Month Daily (PMD) quantity of 4,435,000 ~~4,400,000~~ gpd from the onsite groundwater withdrawals after ~~for~~ PB 3 becomes operational, or the Annual Average Daily (AAD) quantity of 5,019,000 gpd and the Peak Month Daily (PMD) quantity of 8,835,000 gpd from the onsite groundwater withdrawals after PB 3 and PB 4 become operational, then PEF shall submit a report, based on but not limited to the information cited in Condition XXVI.A.30, explaining and analyzing, subject to SWFWMD approval, the conditions under which those quantities were exceeded. PEF shall not discharge any amount of groundwater into the Cooling Pond at the Hines Energy Complex when the water level in the Cooling Pond is at or above 160.0 feet NGVD. ~~If the report is approved by SWFWMD, then PEF is not in violation of Condition No. XXVI.A.28.~~ If PEF demonstrates that the recurrence of over-pumpage is unlikely and no adverse impacts have occurred, no action will be taken. If PEF continues to exceed the quantities permitted without obtaining a modification, SWFWMD may take appropriate enforcement action.

APPENDIX V

Department of Transportation

DEPARTMENT OF
ENVIRONMENTAL PROTECTION

JAN 07 2005

SITING COORDINATION

Florida Department of Transportation

JEB BUSH
GOVERNOR

605 Suwannee Street
Tallahassee, FL 32399-0450
Office of the General Counsel
Mail Station 58
(850) 414-5265

JOSÉ ABREU
SECRETARY

January 6, 2005

By U.S. Mail

Mr. Hamilton S. Oven, P.E., Administrator
Sting Coordination Office
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road, MS 58
Tallahassee, Florida 32399-2400

Re: Progress Energy Florida Hines Energy Center
Power Block 4, Power Plant Siting Application PA92-33SA3
DOAH Case No. 04-2817EPP
DEP Case No. 04-1449

Dear Mr. Oven:

Enclosed is the Florida Department of Transportation's Agency Report for the above referenced siting application. If there are any questions, please call me at (850) 414-5386 or Sandra Whitmire, Siting Coordinator, at (850) 414-4812. Thank You.

Sincerely,

Sheauching Yu
Assistant General Counsel

cc: All parties of record
Sandra Whitmire
John J. Czerepak, D1

FLORIDA DEPARTMENT OF TRANSPORTATION
AGENCY REPORT ON PROGRESS ENERGY FLORIDA HINES ENERGY CENTER
POWER BLOCK 4, POWER PLANT SITING APPLICATION NO. PA 92-33SA3
DOAH CASE NO. 04-2817EPP
DEP CASE NO. 04-1449
JANUARY 2005

SECTION I. CORRIDOR LOCATION ISSUES

No outstanding issues.

SECTION II. OUTSTANDING SUFFICIENCY ISSUES

No outstanding issues.

SECTION III. VARIANCES TO STANDARDS

No variances requested.

SECTION IV. SPECIAL USE PERMISSIONS

No special use permissions requested.

SECTION V. RECOMMENDATION FOR CERTIFICATION

The Florida Department of Transportation recommends the certification of the proposed power plant expansion. This recommendation is made contingent upon the conditions of Section VI being addressed/met.

SECTION VI. PROPOSED CONDITIONS OF CERTIFICATION

6.1 REQUEST FOR RESTRICTED AREAS

No requests for restricted areas are necessary.

6.2 POST CERTIFICATION REVIEW OF SPECIFIC PROBLEMS

Access Management to the State Highway System: No new access to the State Highway System is proposed in the site certification application. If new access is later proposed, access permitting as defined in Rule Chapters 14-96, State Highway System Connection Permits, Administrative Process, and 14-97, State Highway System Access Management Classification System and Standards, Florida Administrative Code, will be required.

Overweight or Overdimensional Loads: Operation of overweight or overdimensional loads by the applicant on State transportation facilities during construction and operation of the utility facility will be subject to safety and permitting requirements as defined in Chapter 316, Florida Statutes, and Rule Chapter 14-26, Safety Regulations and Permit Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code.

Use of State of Florida Right of Way or Transportation Facilities: Any use of State of Florida right of way and certain activities on State transportation facilities will be subject to the requirements of the Department of Transportation's Utility Accommodation Manual (Document 710-020-001) and Rule Chapter 14-46, Utilities Installation or Adjustment, Florida Administrative Code.

Drainage: Any drainage onto State of Florida right of way and transportation facilities will be subject to the requirements of Rule Chapter 14-86, Drainage Connections, Florida Administrative Code, including the attainment of any permit required thereby

Future Widening: The segment of US 98 in the area where the applicant proposes to cross the Department's right of way with the Hines-west Lake Wales Transmission Line is currently a four-lane, divided facility. The annual average daily traffic (AADT) is 16,600 vehicles, with the level of service being "A". Although there is no major widening of the facility segment planned in the foreseeable future, due to the status of this roadway as a Florida Intrastate Highway System (FIHS) facility, the placement of the transmission line should take into consideration the possible widening of this facility. If future widening should be required, the cost of relocating the transmission line will be borne by the applicant.

SECTION VII BEST MANAGEMENT PRACTICES

Traffic control will be maintained during plant construction and maintenance in compliance with the standards contained in the Manual of Uniform Traffic Control Devices; Rule Chapter 14-94, Statewide Minimum Level of Service Standards, Florida Administrative Code; Florida Department of Transportation's Roadway and Traffic Design Standards; and Florida Department of Transportation's Standard Specifications for Road and Bridge Construction, whichever is more stringent.

If the applicant uses contractors for the delivery of any overweight or overdimensional loads to the site during construction, the applicant should ensure that its contractors adhere to the necessary standards and receive the necessary permits required under Chapter 316, Florida Statutes, and Rule Chapter 14-26, Safety Regulations and Permit Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code.

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Hopping Green & Sams

Progress Energy

December 1, 2004

RECEIVED
DEC 06 2004
BUREAU OF AIR REGULATION

Mr. Michael Halpin, P.E.
North Permitting Section
DARM/BAR
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

RE: DRAFT PSD PERMIT NO. 1050234-010-AC
HINES ENERGY COMPLEX, POWER BLOCK 4

Dear Mr. Halpin:

Progress Energy Florida (PEF) is in receipt of your letter dated August 19, 2004. The letter indicates that the Department has begun review of our recent PSD application for the above-referenced facility. The Department has deemed the application incomplete due to the need for additional information. In addition, in a letter to the Department, dated November 4, 2004, PEF provided notification that a decision was made to use combustion turbines other than those generally represented in the original permit application. To more accurately describe the project, as it stands today, this letter also serves to transmit amended permit application forms (Attachment 1), revised emission tables (Attachment 2) and revised BACT tables for CO and NOx (Attachment 3).

The Department's requests and comments, per the August 19, 2004 letter, are addressed below in the order in which they were received.

DEP Comment

Progress has requested permission to operate for up to 3,000 hours per year below 60% output, however within Appendix A "Emission Estimates", data was provided for only the 100%, 80% and 60% (65% for distillate) output cases.

A) Please provide the same data for the 50% 30% and 10% CT output cases for natural gas.

B) Should Progress desire to be permitted for any operation below 65% CT output while firing distillate oil, then FDEP requires the same data (50%, 30% and 10% output) for the distillate oil cases.

C) Please indicate the lowest CT output (%) at which continuous operation is sought (on each fuel).

D) Please provide CT/HRSG/Steam Turbine heat balance diagrams (see attached 'example' from a conventional steam plant) for each of the CT outputs defined above (10%, 30%, 50%, 60%, 80%, and 100%).

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

Response

As indicated above, during final equipment selection for this project, a decision was made to use combustion turbines other than those generally represented in the original permit application. The characteristics of the combustion turbine model selected (GE 7FA) are slightly different than those upon which the original application was based (SW 501F). The GE 7FA turbine model is able to meet defined emission characteristics within a load range of 50 to 100 percent of rated load on both fuels. The amended permit application, submitted in conjunction with this letter, provides data sufficient to address the Department's above comments.

Comparisons of the stack, operating, and emission data for natural gas-firing and distillate oil-firing for the GE 7FA combustion turbine to those for the SW 501F combustion turbine are presented in Tables 1 and 2, respectively. Details of the design information and stack parameters for the GE 7FA combustion turbines are presented in revised Tables A-1 to A-29 of Appendix 10.1.5 of the Site Certification Application (SCA). Information for firing natural gas in the combustion turbines are presented in Tables A-1 to A-12 for 100%, 75%, and 50% loads at ambient temperatures of 20°F, 59°F, and 95°F. Information for firing distillate fuel oil in the combustion turbines are presented in Tables A-13 to A-24 for 100%, 75%, and 50% loads at ambient temperatures of 20°F, 59°F, and 95°F. A summary of the maximum potential annual emissions for the two combustions turbines and one auxiliary boiler is presented in Table A-25. Supporting information for estimating formaldehyde emissions for the combustion turbines is presented in Tables A-26 to A-28. Finally, emission estimates for the auxiliary boiler are presented in Table A-29.

In general, PEF is requesting that no restrictions be placed on operations at any load, since continuous emissions monitoring of both NOx and CO will be performed. Demonstration of continuous compliance with these parameters is sufficient to restrict the overall operation of the unit.

Based on the maximum annual emissions presented in Table A-25, there will be a decrease in annual emissions for all pollutants except sulfur dioxide (SO_2) and nitrogen oxides (NO_x). For SO_2 and NO_x, the maximum increase in annual emissions are about 5 and 4 TPY, respectively, from those presented in the SCA. The increases in those pollutant emissions are primarily due to oil-firing. No additional Prevention of Significant Deterioration (PSD) review requirements will be triggered with the GE 7FA combustion turbines and auxiliary boiler. In fact, the volatile organic compound (VOC) emissions are estimated to be below the PSD significant emission rate of 40 TPY, requiring no PSD review for that pollutant.

In addition, no additional air quality impact analyses are required for the project with the GE 7FA combustion turbines since the air quality impacts for these turbines are expected to be similar to or lower than those predicted for the SW 501F combustion turbines. The exhaust gas flow rates, velocities, and temperatures for each combination of operating load and ambient temperature are higher for the GE 7FA turbines than those for the SW 501F turbines, resulting in more dilution and dispersion of the sources' plumes for the GE turbines. It should be noted that while the stack height remains the same for the GE turbine, the stack diameter is slightly smaller than that of the SW turbine (18 ft compared to 19 ft).

For natural gas-firing, since the maximum hourly emissions for the GE turbines are equal to or less than those for the SW turbines, the air quality impacts for the GE turbines will be lower than those for the SW turbines. For distillate oil-firing, the maximum hourly emissions for the GE turbines are also lower than those for the SW turbines except for SO_2 and NO_x. For SO_2, the maximum hourly emissions increase from about 3 percent at 20°F to 8 percent at 95 °F. For NO_x, the maximum hourly emissions increase from about 5 percent at 59°F to 8 percent at 95 °F. Even if the maximum air quality impacts for these pollutants were increased by 8 percent and no account was made for the increased exhaust gas flow rates and temperatures associated with the GE turbines, the air quality impacts for the GE turbines would still remain below the PSD Class II and I significant impact levels shown in Tables 5.6.1.-1 and 5.6.1-2 of the SCA (see also Tables 7-1 and 7-2 in Appendix 10.5.1). In addition, the 24-hour average visibility impairment and sulfur and nitrogen deposition predicted for the project are also expected to be below the trigger criteria that would require additional analyses (see Tables 8-5 and 8-6 in Appendix 10.5.1).

DEP Comment

Progress has requested up to eight hours per day of combined excess emissions for a cold start-up and up to five hours of combined excess emissions per day for any steam turbine shutdown. Further, Progress wishes to define a cold start-up as 'following a shutdown of the steam turbine lasting at least 48 hours.'

A) Based upon prior guidance from EPA Region 4, the department is not inclined to grant such lengthy time periods for unlimited excess emissions. Instead, the Department is will consider the development of alternative emission limits for routine operations where full-load emission limits cannot be achieved (this includes periods such as start-up and shut-downs, and perhaps even extended periods of operation during low load, as has been requested herein). In order for the Department to evaluate alternative emission limits for such operations, actual emission estimates will be required. Therefore, for any pollutant whereby Progress expects to be unable to meet a "full load" BACT established emission limit (but specifically during a steam turbine shutdown and cold start-up). The Department will need to be provided with estimated emission curves during those time periods. This should include each of the stages of event (e.g. cold startup) including the purpose, operating load, duration at that operating load, and estimated emissions at that operating load.

B) Please support the (above) proposed definition of a cold start-up ('following a shutdown of the steam turbine lasting at least 48 hours,) by providing:

1) The manufacturers criteria for what constitutes a cold start-up (e.g. turbine manufacturers typically identify the first stage metal temperature on the steam turbine) and
2) The additional operational measures which the equipment manufacturer requires to be taken as a result of the cold-start-up criteria being met.

Response

As the Department has indicated above, the development of alternative emission limits to address periods of non-routine operations, such as startup/shutdown is acceptable. PEF withdraws its request for allowable hours of excess emissions during startup/shutdown periods, contingent upon the development of acceptable alternative emission limits that cover these periods of operation. PEF requests the following alternative emissions limits, based on a 24-hour average:

NOx (gas): 125 lbs/hour
NOx (oil): 370 lbs/hour

CO (gas & oil): 175 lbs/hour

DEP Comment

Within Section 2 of the PSD application, Progress states "At present there are no confirmed test data of formaldehyde emissions from similar Siemens Westinghouse or equivalent combustion turbines". In order to be thorough, the Department requests that Progress contact the manufacturer (Siemens Westinghouse) to obtain test data for formaldehyde emissions on 501F machines. Should Westinghouse not have access to any such data, please request that they provide written confirmation to this effect.

Response

As previously indicated, PB 4 will be employing GE 7FA combustion turbines. GE was contacted and requested to address the Department's comment. Their response is provided as Attachment 4 to this letter.

DEP Comment

Regarding the proposed BACT Determination for CO:

A) Please confirm the evaluated placement position of the oxidation catalyst (within the flue gas stream) for Hines Power Block 4 is directly after the CT (and before the HRSG), as suggested in Appendix B, page 14. If this is not the desired placement, please specify the position in the flue gas stream as precisely as possible.

B) The Department notes the following discrepancies between the provided cost effectiveness calculation and the OAQPS Control Cost Manual:
   1) Indirect Costs are to be based upon a percentage of the Direct Capital Costs (TDCC in your supplied calculation), exclusive of the Direct Installation Costs (TDIC). The submitted evaluation shows indirect costs as based upon the sum of TDCC and TDIC (referred to as Total Capital Costs).
   2) The "Inventory Cost" associated with the Catalyst Replacement Cost is not an acceptable entry.
   3) The Capital Recovery (referred to as Annualized Total Direct Capital in the submitted evaluation) should exclude the initial cost of the catalyst (times freight and sales tax).
   4) Heat Rate Penalty – Please provide the Department with the assumed fuel cost (in $MMBtu) which was utilized as a basis for adding $3/MMBtu in the "Heat Rate Penalty" calculation.

C) Please provide the basis for the estimated net TPY of CO removed which was utilized in the submitted cost effectiveness of $3,773 per ton.

D) Please provide the basis for the estimated net TPY emission reduction, which was utilized in the submitted cost effectiveness of $4,070 per ton.

Response

A) While PEF is not proposing to install a CO catalyst, the power block will be constructed with space available to accommodate the installation of a CO catalyst, if required in the future. The proposed location to accommodate the potential future addition of a CO catalyst is within the HRSG, immediately prior to the SCR section.

B-1) The Indirect Costs for CO catalyst cost analysis have been revised to be a percentage of the Total Direct Capital Costs (TDCC). The CO catalyst cost analysis has also been revised to reflect final equipment selection of GE 7FA combustion turbines. The revised CO cost analysis (Tables B-8 to B-11) are included as Attachment 3 to this letter.

B-2) The "Inventory Cost" associated with the Catalyst Replacement Cost has been removed from the Annualized Cost Table.

B-3) The catalyst and the catalyst support system have different life expectancies, 3 years and 15 years, respectively. Therefore, the annualized cost for CO catalyst has been revised to reflect a capital recovery of 7% for 15 years for the "Total Direct, Indirect, and Capital" costs for the CO catalyst system minus the capital cost, sales tax, and shipping cost of the catalyst.

A separate annual cost for the catalyst has been estimated based on a capital recovery of 7% for 3 years, based on the life expectancy of the catalyst.

B-4) The addition of a CO catalyst adds back pressure to the system resulting in decreased MW output of the CT Unit. The CO catalyst is estimated to decrease the output by 0.2%, resulting in a corresponding 0.2% decrease in electricity sales. Based on a rated 181.7 MW CT output, the result is a loss of $159,170 per year. This loss is based on $0.05/kW per EPA's OAQPS Control Cost Manual.

In addition, a heat rate penalty of 0.2% results from the CO catalyst. Based on a heat input of 1,806 MMBtu/hr and an updated fuel cost of $6/MMBtu (see Attachment 5), the result is an additional fuel cost of $189,850 per year. Therefore, the total "Heat Rate Penalty" is equal to the loss in MW output plus the loss in heat input and is approximately $350,000 per year.

C) As stated previously, the CO catalyst cost analysis has been revised to reflect final equipment selection of GE 7FA combustion turbines. The revised cost effectiveness, based on GE CTs, is estimated to be $6,500 per ton CO removed. Reduced baseline CO emissions from the GE CTs compared to the Siemens Westinghouse CTs (9 ppmvd vs. 12 ppmvd and 20 ppmvd vs.30 ppmvd for gas and oil firing, respectively) result in a significantly higher cost effectiveness for GE Units. The basis for estimating the net TPY of CO removed resulting in the revised GE cost effectiveness of $6,500 per ton is as follows:

1. Uncontrolled Emissions = 148 TPY
    i. 9 ppmvd gas firing
    ii. 29.7 lb/hr gas firing, for 7,760 hour per year
    iii. 20 ppmvd oil firing
    iv. 66 lb/hr oil firing, for 1,000 hours per year
2. Controlled Emissions = 29 TPY
    i. 2.0 ppmvd gas firing
    ii. 80.5 % reduction

D) The basis for estimating the net TPY of CO removed that results in the revised GE cost effectiveness of $7,500 per ton is the total incremental emissions from Table B-11 equal to 103.5 TPY. The 103.5 TPY emissions include reduction of CO emissions and increase in PM, NO_x, and SO_2 emissions.

Attachment 3 also presents updated SCR and $SCONO_x$ cost analysis tables to reflect the final equipment selection of GE 7FA combustion turbines. As shown in Tables B-3 through B-6, the cost effectiveness of SCR with GE 7FA CTs is higher than the previously submitted Siemens Westinghouse CT analysis. The cost effectiveness is higher in GE CTs due to lower baseline emissions on gas (9 ppmvd for GE compared to 25 ppmvd for Siemens Westinghouse). As a result, the NO_x BACT analysis conclusions remain the same and are as follows:

The proposed BACT for combined cycle operation is advanced DLN combustion technology and SCR. The proposed NOx emissions level using this technology is 2.5 ppmvd corrected to 15 percent O_2 when firing natural gas and 10 ppmvd corrected to 15 percent O_2 when firing distillate fuel oil. This combination of technology can achieve the maximum amount of emission reduction available, technically feasible and demonstrated for the Project. SCR cannot be rejected based on the economic, environmental, and energy impacts, given the recent BACT decisions on other similar projects.

The project also includes the addition of a 20 MMBtu/hr gas-fired auxiliary boiler. The auxiliary boiler will fire natural gas only and will be used primarily for cold startup of the combustion turbines. The auxiliary boiler will operate less than 500 hours per year. The emissions from the boiler are a result of the combustion process and trace elements in the fuel. Based on the size of the unit and expected annual operation, there are no technically or economically feasible methods for controlling emissions other than the inherent quality of the fuel. Therefore, BACT for the proposed auxiliary boiler is based on fuel quality specs and limiting operation to no more than 500 hours per year.

DEP Comment

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

Response

As PEF has received no additional comments, it's our understanding that the EPA and the NPS have no further comments on the original application.

DEP Comment

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Permit applicants are advised that Rule 62-213.420(1)(b), F.A.C., requires applicants to respond to requests for information within 90 days, unless the applicant has requested in writing, and has been granted, additional time within 90 days.

Response

In a letter to the Department, dated November 4, 2004, PEF had requested, and was granted, an extension of the 90 day timeframe, until December 3, 2004. This response, submitted within the approved timeframe, along with the associated permit application form revisions, signed and certified by a Florida PE, addresses the above comment.

PEF appreciates you consideration of the above responses. If you should have any questions, please don't hesitate to contact me at (727) 826-4363.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

Attachment

cc: Jim Pennington, FDEP- DARM/BAR
Hamilton Oven, FDEP- Siting
Scott Osbourn, P.E., Golder Associates Inc.
Roger Zirkle, Progress Energy Florida

ATTACHMENT 1

Revised Application Forms

Department of
Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Progress Energy Florida**
2. Site Name: **Hines Energy Complex**
3. Facility Identification Number: **1050234**
4. Facility Location...:
   Street Address or Other Locator: **7700 County Road 555**
   City: **Bartow** County: **Polk** Zip Code: **33830**
5. Relocatable Facility?
   ☐ Yes ☒ No
6. Existing Title V Permitted Facility?
   ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Jamie Hunter, Lead Environmental Specialist**
2. Application Contact Mailing Address...
   Organization/Firm: **Progress Energy Florida**
   Street Address: **PO Box 14042, MAC BB1A**
   City: **St. Petersburg** State: **FL** Zip Code: **33733-4042**
3. Application Contact Telephone Numbers...
   Telephone: **(727) 826-4363** ext. Fax: **(727) 826-4216**
4. Application Contact Email Address:

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Project Number(s):	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Power Block 4 consists of two nominal 170 MW GE Frame 7FA combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), one 190 MW steam turbine; nominal rating of 530 MW combined cycle unit, and one 20 MMBtu/hr gas-fired auxiliary boiler. See PSD Application. Fee included with Site Certification Application.

Projected or Actual Date of Commencement of Construction: January 2006
Projected Date of Completion of Construction: December 2007

This application has been submitted and will be reviewed within the Florida Power Plant Siting Act (PPSA). See PSD Application. Power Block 1 has permit PA-92-33; PSD-FL-195A. Power Block 2 has permit PA-92-33SA; PSD-FL-296A. Power Block 3 has permit PA-92-33SA2; PSD-FL-330.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
--	CT - 4A; Power Block 4	AC1A	
--	CT - 4B; Power Block 4	AC1A	
--	Auxiliary Boiler	AC1f	

Application Processing Fee

Check one: ☐ Attached - Amount: $________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Roger Zirkle, Plant Manager**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: Progress Energy Florida Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**
4.	Owner/Authorized Representative Email Address:
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. 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 and all other requirements identified in this application to which the facility is subject. 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 the facility or any permitted emissions unit.* Roger B Zirkle 12-3-04 Signature Date

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1.	Application Responsible Official Name:
2.	Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3.	Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4.	Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5.	Application Responsible Official Email Address:
6.	Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. 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 and all other applicable requirements identified in this application to which the Title V source is subject. 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 the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Scott Osbourn** Registration Number: **57557**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **5100 West Lemon St., Suite 114** City: **Tampa** State: **FL** Zip Code: **33609**
3.	Professional Engineer Telephone Numbers... Telephone: **(813) 287-1717** ext.**211** Fax: **(813) 287-1716**
4.	Professional Engineer Email Address: **sosbourn@golder.com**
5.	Professional Engineer Statement:

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

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

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

(3) If the purpose of this application is to obtain a Title V 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 plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, 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.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal 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 ____________ Date 12/3/04

(seal)

SCOTT H. OSBOURN
CERTIFICATE
NO. 57557
STATE OF FLORIDA
PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
**** Board of Professional Engineers Certificate of Authorization #00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **414.4** North (km) **3073.9**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27 / 47 / 19** Longitude (DD/MM/SS) **81 / 52 / 10**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment : **Operation of Power Block 1 began in 1999. Power Block 1 is a nominal 470 MW combined cycle unit consisting of 2 CTs, 2 HRSGs and 1 steam turbine. The CTs fire natural gas with distillate oil as backup. The HRSGs are unfired. Power Blocks 2 and 3 are each a nominal 530 MW combined-cycle generating unit consisting of 2 CTs, 2 HRSGs, and 1 steam turbine. This application is for the addition of Power Block 4, an additional nominal 530 MW combined-cycle application. See PSD Application.**			

Facility Contact

1. Facility Contact Name: **Roger Zirkle, Plant Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**
3. Facility Contact Telephone Numbers: Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**
4. Facility Contact Email Address:

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☐ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Applicable NSPS: 40 CFR Part 60, Subpart GG, 40 CFR Part 60, Subpart Dc.** **62-212.400, F.A.C. See PSD Application.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter - PM	**A**	
Sulfur Dioxide -SO_2	**A**	
Nitrogen Oxides - NO_x	**A**	
Carbon Monoxide - CO	**A**	
Volatile Organic Compounds - VOC	**A**	
Sulfuric Acid Mist - SAM	**B**	

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-1, PSD** ☐ Previously Submitted, Date:____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-2, PSD** ☐ Previously Submitted, Date:____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **PSD Applic.** ☐ Previously Submitted, Date:____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **Fig 1-1, PSD** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☐ Attached, Document ID:____
3.	Rule Applicability Analysis: ☐ Attached, Document ID:____
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:____ ☒ Not Applicable (revision application)
2.	Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:____ ☒ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☒ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:____ ☒ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:____ ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (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).

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

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

2. Description of Emissions Unit Addressed in this Section:
   CT-4A; Power Block 4

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	☒ Yes ☐ No

9. Package Unit: **GE Frame 7FA**
   Manufacturer: **GE** Model Number: **Frame 7FA**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
    GE Frame 7FA combustion turbine firing natural gas with distillate oil back up.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low NO_X combustion-natural gas firing** **Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.** **Water Injection – distillate oil firing**
2. Control Device or Method Code(s): **25, 65, 28**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,806** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input at HHV, 59°F turbine inlet temperature and 100% load; For oil firing, heat input is 1,962 MMBtu/hr (HHV) at 59°F turbine inlet temperature and 100% load; MW nominal rating.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Fig 2-1**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **202**°F	9. Actual Volumetric Flow Rate: **1,036,271** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 1 and 2 and revised Appendix A for PSD application.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.90**	5. Maximum Annual Rate: **15,507**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **16.3**	5. Maximum Annual Rate: **15,352**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **127.8**
10. Segment Comment: **Btu based on HHV of 127.8 MMBtu/1,000 gallons and density of 6.7 lb/gal; maximum hourly at 20°F; annual at 59°F. Aggregate fuel usage of 30,700,000 gallons per year requested for Power Block 4, equates to 1,000 hr/CT/yr.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x	025, 028	065	EL
CO			EL
VOC			EL
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **39.1** lb/hour **57.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **10.1** lb/hour **44.0** tons/year
5. Method of Compliance: **EPA Method 9; initially and annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: **39.1** lb/hour **18.9** tons/year
5. Method of Compliance: **EPA Method 9; when oil firing greater than 400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

<u>Allowable Emissions</u> Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **109.2** lb/hour **71.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **5.4** lb/hour **22.1** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **109.2** lb/hour **56.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: 82.4 lb/hour 102.4 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2004	7. Emissions Method Code: 2
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **17.7** lb/hour **72.3** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **82.4** lb/hour **38.4** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 71.4lb/hour 148 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2004	7. Emissions Method Code: 2
8. Calculation of Emissions: See Tables 1 and 2 and revised Appendix A for PSD Application.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **32.1** lb/hour **130** tons/year
5. Method of Compliance: **EPA Method 10; based on 9 ppmvd**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **15 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **71.4** lb/hour **33** tons/year
5. Method of Compliance: **EPA Method 10; based on 20 ppmvd; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.0** lb/hour **14.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **3.1** lb/hour **12.6**tons/year
5. Method of Compliance: **EPA Method 25A; based on 1.4 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **8.0** lb/hour **3.7** tons/year
5. Method of Compliance: **EPA Method 25A; based on 3.5 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

<u>Allowable Emissions</u> Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **10.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **10% SO_2** Reference: **Golder, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Emission Factor is converted to SAM. See Tables 1 and 2 and revised Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **0.83** lb/hour **3.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **16.7** lb/hour **7.85** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Gas Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Oil Firing**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Not yet determined** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **NO_x CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **GE or equivalent** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request Part 75 NO_x CEM in lieu of WTF monitoring.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Fig 2-2 ☐ Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Tables 2-4/2-5 ☐ Previously Submitted, Date ____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Section 4.0 ☐ Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: See PSD Application ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable	

EMISSIONS UNIT INFORMATION
Section [1] of [3]
CT-4A; Power Block 4

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (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).

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

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

2. Description of Emissions Unit Addressed in this Section:
   CT-4B; Power Block 4

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **GE Frame 7FA**
   Manufacturer: **GE** Model Number: **Frame 7FA**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
   GE Frame 7FA combustion turbine firing natural gas with distillate oil back up.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low NO_X combustion-natural gas firing** **Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.** **Water Injection – distillate oil firing**
2. Control Device or Method Code(s): **25, 65, 28**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,806** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input at HHV, 59°F turbine inlet temperature and 100% load; For oil firing, heat input is 1,962 MMBtu/hr (HHV) at 59°F turbine inlet temperature and 100% load; MW nominal rating.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Fig 2-1**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **202**°F	9. Actual Volumetric Flow Rate: **1,036,271** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 1 and 2 and revised Appendix A for PSD application.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.90**	5. Maximum Annual Rate: **15,507**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **16.3**	5. Maximum Annual Rate: **15,352**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **127.8**
10. Segment Comment: **Btu based on HHV of 127.8 MMBtu/1,000 gallons and density of 6.7 lb/gal; maximum hourly at 20°F; annual at 59°F. Aggregate fuel usage of 30,700,000 gallons per year requested for Power Block 4, equates to 1,000 hr/CT/yr.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x	025, 028	065	EL
CO			EL
VOC			EL
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **39.1** lb/hour **57.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **10.1** lb/hour **44.0** tons/year
5. Method of Compliance: **EPA Method 9; initially and annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: **39.1** lb/hour **18.9** tons/year
5. Method of Compliance: **EPA Method 9; when oil firing greater than 400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 109.2 lb/hour 71.0 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: GE, 2004	7. Emissions Method Code: 2
8. Calculation of Emissions: See Tables 1 and 2 and revised Appendix A for PSD Application.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **5.4** lb/hour **22.1** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **109.2** lb/hour **56.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **82.4** lb/hour **102.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **17.7** lb/hour **72.3** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **82.4** lb/hour **38.4** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4**lb/hour **148** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **32.1** lb/hour **130** tons/year
5. Method of Compliance: **EPA Method 10; based on 9 ppmvd**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **15 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **71.4** lb/hour **33** tons/year
5. Method of Compliance: **EPA Method 10; based on 20 ppmvd; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.0** lb/hour **14.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **3.1** lb/hour **12.6**tons/year
5. Method of Compliance: **EPA Method 25A; based on 1.4 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **8.0** lb/hour **3.7** tons/year
5. Method of Compliance: **EPA Method 25A; based on 3.5 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **10.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **10% SO_2** Reference: **Golder, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Emission Factor is converted to SAM. See Tables 1 and 2 and revised Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **0.83** lb/hour **3.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **16.7** lb/hour **7.85** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Gas Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Oil Firing**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Not yet determined** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **NO_x CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **GE or equivalent** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request Part 75 NO_x CEM in lieu of WTF monitoring.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Fig 2-2** ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Tables 2-4/2-5** ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Section 4.0** ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____
   ☒ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☐ Attached, Document ID: _____ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID: _____
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (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).

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

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

2. Description of Emissions Unit Addressed in this Section:
   20 MMBtu/hr Gas-Fired Auxiliary Boiler

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **Auxiliary Boiler**
   Manufacturer: **To be determined** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    20 MMBtu/hr auxiliary boiler for cold startup of GE Frame 7FA combustion turbines

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: 20 million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day days/week weeks/year 500hours/year	
6. Operating Capacity/Schedule Comment:	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Aux Boiler**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **60** feet	7. Exit Diameter: **2.5** feet
8. Exit Temperature: **332**°F	9. Actual Volumetric Flow Rate: **6,485** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.0195**	5. Maximum Annual Rate: **9.79**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); 500 hours per year**		

Segment Description and Rate: Segment _ of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x			
CO			
VOC			
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.0**lb/hour **0.5**tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.10 lb/MMBtu** Reference:	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables A-29.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5 tons/year**	4. Equivalent Allowable Emissions: **2.0**lb/hour **0.5**tons/year
5. Method of Compliance: **Limitation of operation to less than 500 hours per year**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ____ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable	

Additional Requirements Comment

ATTACHMENT 2

Revised Emission Tables

Table 1. Comparison of Stack, Operating, and Emission Data- GE Frame 7FA vs. SW 501F, Combined Cycle Operation
Natural Gas- Firing

Parameter	Basis/ Units		GE Frame 7FA			SW 501F		
Stack Data	Height	ft	125	125	125	125	125	125
	Diameter	ft	18.0	18.0	18.0	19.0	19.0	19.0
Ambient Conditions	Temperature	°F	20 °F	59 °F	95 °F	20 °F	59 °F	90°F
Operating Data	Load	%	100	100	100	100	100	100
	HIR (HHV)	MMBtu/hr	1,941	1,806	1,644	2,012	1,830	1,705
	Temperature	°F	203	202	201	190	190	190
	Velocity	ft/sec	72.8	67.9	62.2	63.3	59.2	55.4
PM/PM_{10}	lb/hr		10.1	10.0	9.9	8.46	7.86	7.18
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		5.43	5.05	4.60	5.63	5.12	4.77
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		17.7	16.5	15.0	18.0	16.5	15.1
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		32.1	29.7	26.8	46	42	37
	ppmvd		9.0	9.0	9.0	12.4	12.2	12.4
	ppmvd @15% O2		7.5	7.4	7.4	10.0	10.0	10.0
VOC (as methane)	lb/hr		3.09	2.88	2.65	4.65	4.35	3.75
	ppmvw		1.4	1.4	1.4	2.4	2.4	2.5
	ppmvd @15% O2		1.3	1.3	1.3	1.8	1.8	1.8
Sulfuric Acid Mist	lb/hr		0.83	0.77	0.70	0.86	0.78	0.73
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	75	75	75	80	80	80
	HIR (HHV)	MMBtu/hr	1,594	1,473	1,361	1,537	1,534	1,419
	Temperature	°F	203	204	205	190	190	190
	Velocity	ft/sec	54.9	54.8	51.8	57.0	54.0	51.3
PM/PM_{10}	lb/hr		9.9	9.8	9.8	7.49	7.09	6.32
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		4.46	4.12	3.81	4.30	4.29	3.97
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		14.4	13.3	12.2	14.7	13.7	12.6
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		24.1	23.9	22.2	38	35	33
	ppmvd		9.0	9.0	9.0	11.2	11.1	10.9
	ppmvd @15% O2		6.9	7.4	7.5	10.0	10.0	10.0
VOC (as methane)	lb/hr		2.33	2.32	2.19	4.9	4.6	4.2
	ppmvw		1.4	1.4	1.4	2.8	2.8	2.8
	ppmvd @15% O2		1.2	1.3	1.3	2.3	2.3	2.3
Sulfuric Acid Mist	lb/hr		0.68	0.63	0.58	0.66	0.66	0.61
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	50	50	50	60	60	60
	HIR (HHV)	MMBtu/hr	1,257	1,179	1,085	1,347	1,280	1,178
	Temperature	°F	175	178	182	190	190	190
	Velocity	ft/sec	44.4	43.5	42.1	46.0	44.0	42.3
PM/PM_{10}	lb/hr		9.7	9.7	9.6	6.08	5.84	5.48
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		3.52	3.30	3.03	3.77	3.58	3.30
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		11.2	10.5	9.7	12.0	11.4	10.5
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		20.4	19.9	18.8	154	146	134
	ppmvd		9.0	9.0	9.0	57	57	55
	ppmvd @15% O2		7.5	7.8	8.0	50	50	50
VOC (as methane)	lb/hr		1.96	1.92	1.84	5.3	5	4.6
	ppmvw		1.4	1.4	1.4	3.7	3.7	3.6
	ppmvd @15% O2		1.3	1.3	1.4	3.0	3.0	3.0
Sulfuric Acid Mist	lb/hr		0.54	0.51	0.46	0.58	0.55	0.50
	% SO2 from CT		10	10	10	10	10	10

[a] PM10 includes conversion of SO2 to SO3 in the SCR to form ammonium sulfate

Table 2. Comparison of Stack, Operating, and Emission Data- GE Frame 7FA vs. SW 501F, Combined Cycle Operation
Distillate Oil- Firing

Parameter	Basis/ Units		GE Frame 7FA			SW 501F		
Stack Data	Height	ft	125	125	125	125	125	125
	Diameter	ft	18.0	18.0	18.0	19.0	19.0	19.0
Ambient Conditions	Temperature	°F	20 °F	59 °F	95 °F	20 °F	59 °F	105 °F
Operating Data	Load	%	100	100	100	100	100	100
	HIR (HHV)	MMBtu/hr	2,086	1,962	1,769	2,100	1,932	1,707
	Temperature	°F	297	295	294	270	270	270
	Velocity	ft/sec	86.2	80.0	72.7	69.4	67.0	60.0
PM/PM_{10}	lb/hr		39.1	37.8	35.7	64.8	59.6	52.5
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		109.2	102.8	92.6	105.6	97.1	85.8
	Sulfur content	%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		82.4	76.7	69.9	77.0	73.0	64.4
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		71.4	66.0	59.0	112	106	91
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		14.2	14.1	13.9	22.2	22.4	22.2
VOC (as methane)	lb/hr		8.01	7.45	6.79	22	21	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.8	2.8	2.8	7.9	8.1	8.1
Sulfuric Acid Mist	lb/hr		16.7	15.7	14.2	16.2	14.9	13.1
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	75	75	75	80	80	80
	HIR (HHV)	MMBtu/hr	1,594	1,473	1,361	1,644	1,524	1,364
	Temperature	°F	271	274	278	270	270	270
	Velocity	ft/sec	61.5	59.9	58.1	68.9	65.2	58.5
PM/PM_{10}	lb/hr		35.1	34.0	32.4	52.36	48.57	44.35
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		89.4	84.0	76.3	85.6	79.4	71.0
	Sulfur content		0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		66.8	62.7	57.0	64.4	60.0	53.3
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		52.2	50.6	48.3	111	103	89
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		12.8	13.2	13.9	26.6	26.9	26.6
VOC (as methane)	lb/hr		5.91	5.74	5.53	21	22	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.5	2.6	2.8	9.4	9.6	9.6
Sulfuric Acid Mist	lb/hr		13.7	12.9	11.7	13.1	12.2	10.9
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	50	50	50	65	65	65
	HIR (HHV)	MMBtu/hr	1,257	1,179	1,085	1,385	1,296	1,182
	Temperature	°F	256	259	268	270	270	270
	Velocity	ft/sec	50.1	49.6	48.3	63.1	59.8	55.3
PM/PM_{10}	lb/hr		31.0	30.2	29.1	43.5	40.9	37.2
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		69.1	65.5	59.6	72.1	67.5	61.5
	Sulfur content		0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		51.2	48.5	44.1	54.1	50.6	46.2
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		44.2	43.4	41.3	101	94	86
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		14.2	14.7	15.4	29.3	29.5	29.2
VOC (as methane)	lb/hr		4.92	4.85	4.66	20	19	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.8	2.9	3.0	10.3	10.4	10.4
Sulfuric Acid Mist	lb/hr		10.6	10.0	9.1	11.0	10.3	9.4
	% SO2 from CT		10	10	10	10	10	10

[a] PM10 includes conversion of SO2 to SO3 in the SCR to form ammonium sulfate

Table A-1. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Combustion Turbine Performance			
Power output (MW)	193.1	173.8	154.8
Heat rate (Btu/kWh, LHV)	9,055	9,360	9,570
(Btu/kWh, HHV)	10,051	10,390	10,623
Heat Input (MMBtu/hr, LHV)- provided	1727.7	1607.1	1463.3
Heat Input (MMBtu/hr, LHV)- with margin	1,749	1,627	1,481
(MMBtu/hr, HHV)	1,941	1,806	1,644
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	3,929,264	3,650,916	3,333,093
- provided	3,882,000	3,607,000	3,293,000
Temperature (°F)	1,074	1,113	1,154
Moisture (% Vol.)	7.55	8.37	9.88
Oxygen (% Vol.)	12.75	12.57	12.34
Molecular Weight	28.48	28.38	28.22
CT 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)	3,929,264	3,650,916	3,333,093
Temperature (°F)	1,074	1,113	1,154
Molecular weight	28.48	28.38	28.22
Volume flow (acfm)- calculated	2,574,253	2,461,202	2,318,987
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)	1,749	1,627	1,481
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	83,119	77,317	70,399
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,900,799	1,768,116	1,609,909
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,929,264	3,650,916	3,333,093
HRSG Stack Temperature (°F)	203	202	201
Molecular weight	28.48	28.38	28.22
Volume flow (acfm)	1,112,097	1,036,271	949,721
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	72.8	67.9	62.2

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2004 - CT Performance Data

Table A-2. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Particulate from CT and SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	5.4	5.1	4.6
Conversion (%) from SO_2 to SO_3	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.12	1.04	0.95
Total CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total HRSG emission rate (lb/hr) [a + b]	10.1	10.0	9.9
(lb/mmBtu, HHV)	0.0052	0.0056	0.0061
Sulfur Dioxide			
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,900,799	1,768,116	1,609,909
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	5.4	5.1	4.6
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	9	9	9
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
CT Emission rate (lb/hr)	63.6	59.4	53.8
(lb/hr)- provided	63.0	59.0	53.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	17.7	16.5	15.0
(lb/MMBtu)	0.0091	0.0091	0.0091
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 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	9	9	9
Basis, ppmvd @ 15% O2 - calculated	7.47	7.39	7.37
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
HRSG Emission rate (lb/hr)	32.1	29.7	26.8
(lb/hr)- provided	32.0	29.0	26.0

Table A-2. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 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, ppmvw	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.3	1.26	1.3
Moisture (%)	7.55	8.37	9.88
Oxygen (%) wet	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
HRSG Emission rate (lb/hr)	3.09	2.88	2.65
(lb/hr)- provided	3.00	2.80	2.60
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	5.4	5.1	4.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.83	0.77	0.70
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants forthe Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Total	1,941	1,806	1,644
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	2.33E-09	2.17E-09	1.97E-09
(TPY)	1.02E-08	9.49E-09	8.64E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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 [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Emission Rate (lb/hr)	1.55E-06	1.44E-06	1.32E-06
(TPY)	6.80E-06	6.33E-06	5.76E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Total	1,941	1,806	1,644
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	1.55E-03	1.44E-03	1.32E-03
(TPY)	6.80E-03	6.33E-03	5.76E-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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	1.94E-02	1.81E-02	1.64E-02
(TPY)	8.50E-02	7.91E-02	7.20E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-5. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	144.8	132.2	116.1
Heat rate (Btu/kWh, LHV)	9,915	10,040	10,560
(Btu/kWh, HHV)	11,006	11,144	11,722
Heat Input (MMBtu/hr, LHV)- provided	1,419	1,311	1,211
Heat Input (MMBtu/hr, LHV)- with margin	1,436	1,327	1,226
(MMBtu/hr, HHV)	1,594	1,473	1,361
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,956,564	2,941,381	2,762,226
- provided	2,921,000	2,906,000	2,729,000
Temperature (°F)	1,200	1,159	1,190
Moisture (% Vol.)	8.13	8.26	9.8
Oxygen (% Vol.)	12.11	12.60	12.43
Molecular Weight	28.44	28.41	28.22
CT 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)	2,956,564	2,941,381	2,762,226
Temperature (°F)	1,200	1,159	1,190
Molecular weight	28.44	28.41	28.22
Volume flow (acfm)- calculated	2,099,089	2,039,302	1,964,313
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)	1,436	1,327	1,226
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	68,258	63,081	58,270
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,560,950	1,442,570	1,332,551
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,956,564	2,941,381	2,762,226
HRSG Stack Temperature (°F)	203	204	205
Molecular weight	28.44	28.41	28.22
CT volume flow (acfm)	837,992	836,001	791,320
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	54.9	54.8	51.8

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft^3

Source: GE, 2004 - CT Performance Data

Table A-6. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

	CT Only		
	Turbine Inlet Temperature		
Parameter	20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	4.5	4.1	3.8
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.90	0.83	0.77
Total CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total HRSG emission rate (lb/hr) [a + b]	9.9	9.8	9.8
(lb/mmBtu, HHV)	0.0062	0.0067	0.0072
Sulfur Dioxide			
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,560,950	1,442,570	1,332,551
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	4.5	4.1	3.8
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100].- Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flc 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	9	9	9
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr)	51.7	47.8	44.1
(lb/hr)- provided	51.0	47.0	44.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	14.4	13.3	12.2
(lb/MMBtu)	0.0090	0.0090	0.0090
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 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	9	9	9
Basis, ppmvd @ 15% O2 - calculated	6.88	7.41	7.46
Moisture (%)	8.13	8.26	9.80
Oxygen (%)	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
HRSG Emission rate (lb/hr)	24.1	23.9	22.2
(lb/hr)- provided	24.0	24.0	22.0

Table A-6. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 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, ppmvw	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.2	1.3	1.3
Moisture (%)	8.13	8.26	9.80
Oxygen (%) wet	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
HRSG Emission rate (lb/hr)	2.33	2.32	2.19
(lb/hr)- provided	2.4	2.2	2.2
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	4.5	4.1	3.8
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.68	0.63	0.58
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-7. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Total	1,594	1,473	1,361
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.91E-09	1.77E-09	1.63E-09
(TPY)	8.38E-09	7.74E-09	7.15E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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 [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Emission Rate (lb/hr)	1.28E-06	1.18E-06	1.09E-06
(TPY)	5.59E-06	5.16E-06	4.77E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-8. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Total	1,594	1,473	1,361
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.28E-03	1.18E-03	1.09E-03
(TPY)	5.59E-03	5.16E-03	4.77E-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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-8. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.59E-02	1.47E-02	1.36E-02
(TPY)	6.98E-02	6.45E-02	5.96E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12) .
Emission factors for metals are questionable and not used .

Table A-9. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	96.6	88.2	77.4
Heat rate (Btu/kWh, LHV)	11,730	12,050	12,620
(Btu/kWh, HHV)	13,020	13,376	14,008
Heat Input (MMBtu/hr, LHV)- provided	1,119	1,050	965
Heat Input (MMBtu/hr, LHV)- with margin	1,133	1,062	977
(MMBtu/hr, HHV)	1,257	1,179	1,085
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,498,048	2,433,269	2,325,978
- provided	2,468,000	2,404,000	2,298,000
Temperature (°F)	1,200	1,200	1,200
Moisture (% Vol.)	7.54	7.96	9.37
Oxygen (% Vol.)	12.77	12.94	12.92
Molecular Weight	28.48	28.42	28.25
CT 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)	2,498,048	2,433,269	2,325,978
Temperature (°F)	1,200	1,200	1,200
Molecular weight	28.48	28.42	28.25
Volume flow (acfm)- calculated	1,770,983	1,728,651	1,662,592
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)	1,133	1,062	977
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	53,834	50,496	46,445
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,231,113	1,154,760	1,062,124
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,498,048	2,433,269	2,325,978
HRSG Stack Temperature (°F)	175	178	182
Molecular weight	28.48	28.42	28.25
CT volume flow (acfm)	677,774	663,865	643,203
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	44.4	43.5	42.1

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-10. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	3.5	3.3	3.0
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.71	0.67	0.61
CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total emission rate (lb/hr) [a + b]	9.7	9.7	9.6
(lb/mmBtu, HHV)	0.0077	0.0082	0.0089
Sulfur Dioxide			
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,231,113	1,154,760	1,062,124
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	3.5	3.3	3.0
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flov 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	9	9	9
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	40.3	37.8	34.8
(lb/hr)- provided	40.0	37.0	34.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	11.2	10.5	9.7
(lb/MMBtu)	0.0089	0.0089	0.0089
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 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	9	9	9
Basis, ppmvd @ 15% O2 - calculated	7.49	7.76	7.99
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	20.4	19.9	18.8
(lb/hr)- provided	20	20	19

Table A-10. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 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, ppmvw	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.3	1.3	1.4
Moisture (%)	7.54	7.96	9.37
Oxygen (%) wet	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	1.96	1.92	1.84
(lb/hr)- provided	2.00	1.80	1.80
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	3.5	3.3	3.0
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.54	0.51	0.46
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-11. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Total	1,257	1,179	1,085
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.51E-09	1.42E-09	1.30E-09
(TPY)	6.61E-09	6.20E-09	5.70E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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 [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Emission Rate (lb/hr)	1.01E-06	9.43E-07	8.68E-07
(TPY)	4.41E-06	4.13E-06	3.80E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-12. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Total	1,257	1,179	1,085
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.01E-03	9.43E-04	8.68E-04
(TPY)	4.41E-03	4.13E-03	3.80E-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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-12. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	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	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.26E-02	1.18E-02	1.08E-02
(TPY)	5.51E-02	5.17E-02	4.75E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12) .
Emission factors for metals are questionable and not used .

Table A-13. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	193.5	181.5	158.9
Heat rate (Btu/kWh, LHV)	10,050	10,080	10,380
(Btu/kWh, HHV)	10,778	10,810	11,132
Heat Input (MMBtu/hr, LHV)- provided	1,945	1,830	1,649
Heat Input (MMBtu/hr, LHV)- with margin	1,945	1,830	1,649
(MMBtu/hr, HHV)	2,086	1,962	1,769
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
Fuel density (lb/gal)	6.69	6.69	6.69
CT Exhaust Flow	127808.542		
Mass Flow (lb/hr)- with margin	4,055,000	3,766,000	3,407,000
- provided	4,055,000	3,766,000	3,407,000
Temperature (°F)	1,053	1,093	1,143
Moisture (% Vol.)	10.87	11.46	13.07
Oxygen (% Vol.)	11.24	11.11	10.77
Molecular Weight	28.36	28.30	28.12
CT 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)	4,055,000	3,766,000	3,407,000
Temperature (°F)	1,053	1,093	1,143
Molecular weight	28.36	28.30	28.12
Volume flow (acfm)- calculated	2,631,766	2,514,188	2,362,720
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)	1,945	1,830	1,649
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	109,234	102,764	92,647
(gal/hr)	16,318	15,352	13,840
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	4,055,000	3,766,000	3,407,000
HRSG Stack Temperature (°F)	297	295	294
Molecular weight	28.36	28.30	28.12
Volume flow (acfm)	1,316,753	1,221,963	1,110,611
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	86.2	80.0	72.7

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-14. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	109.2	102.8	92.6
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	22.08	20.77	18.73
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG emission rate (lb/hr) [a + b]	39.1	37.8	35.7
(lb/mmBtu, HHV)	0.0187	0.0193	0.0202
Sulfur Dioxide			
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100			
Fuel oil Sulfur Content	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	109,234	102,764	92,647
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	109.2	102.8	92.6
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (ac 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	42	42	42
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
CT Emission rate (lb/hr)	345.9	322.3	293.5
(lb/hr)- provided	345.0	323.0	293.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10
(lb/hr)	82.4	76.7	69.9
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 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	20	20	20
Basis, ppmvd @ 15% O2 - calculated	14.24	14.13	13.86
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
HRSG Emission rate (lb/hr)	71.4	66.0	59.0
(lb/hr)- provided	71.0	66.0	59.0

Table A-14. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 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, ppmvw	3.5	3.5	3.5
Basis, ppmvd @ 15% O2 - calculated	2.8	2.8	2.8
Moisture (%)	10.87	11.46	13.07
Oxygen (%) wet	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
HRSG Emission rate (lb/hr)	8.01	7.45	6.79
(lb/hr)- provided	8.00	7.50	7.00
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	109.2	102.8	92.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	16.73	15.74	14.19
(lb/hr)- provided	10.6	9.9	9.0
Lead			
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Emission Rate Basis (lb/10^{12} Btu)	14	14	14
Emission rate (lb/hr)	0.0272	0.0256	0.0231

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-15. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	2,086	1,962	1,769
	2,086	1,962	1,769
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	7.93E-07	7.46E-07	6.72E-07
(TPY)	3.96E-07	3.73E-07	3.36E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.90E-04	6.49E-04	5.86E-04
(TPY)	3.45E-04	3.25E-04	2.93E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.79E-02	6.38E-02	5.76E-02
(TPY)	3.39E-02	3.19E-02	2.88E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.49E-01	4.23E-01	3.81E-01
(TPY)	2.25E-01	2.11E-01	1.91E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	2,086	2,086	2,086
Emission Rate (lb/hr)	1.31E-03	1.31E-03	1.31E-03
(TPY)	6.53E-04	6.53E-04	6.53E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-16. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	2,086	1,962	1,769
	2,086	1,962	1,769
Arsenic (lb/hr) = Basis (lb/10^12 Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^12 Btu			
Basis [a], lb/10^12 Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.65E-02	1.55E-02	1.40E-02
(TPY)	8.25E-03	7.76E-03	7.00E-03
Benzene (lb/hr) = Basis (lb/10^12 Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^12 Btu			
Basis [a], lb/10^12 Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	2.29E-03	2.16E-03	1.95E-03
(TPY)	1.15E-03	1.08E-03	9.73E-04
Cadmium (lb/hr) = Basis (lb/10^12 Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^12 Btu			
Basis [a], lb/10^12 Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.76E-03	6.36E-03	5.73E-03
(TPY)	3.38E-03	3.18E-03	2.87E-03
Chromium (lb/hr) = Basis (lb/10^12 Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^12 Btu			
Basis [a], lb/10^12 Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.41E-02	1.33E-02	1.20E-02
(TPY)	7.05E-03	6.63E-03	5.98E-03
Cobalt (lb/hr) = Basis (lb/10^12 Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^12 Btu			
Basis [b], lb/10^12 Btu	37	37	37
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	7.72E-02	7.26E-02	6.54E-02
(TPY)	3.86E-02	3.63E-02	3.27E-02
Manganese (lb/hr) = Basis (lb/10^12 Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^12 Btu			
Basis [a], lb/10^12 Btu	432	432	432
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	9.01E-01	8.48E-01	7.64E-01
(TPY)	4.50E-01	4.24E-01	3.82E-01
Nickel (lb/hr) = Basis (lb/10^12 Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^12 Btu			
Basis [b], lb/10^12 Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.80E-01	1.69E-01	1.53E-01
(TPY)	9.00E-02	8.47E-02	7.63E-02
Phosphorous (lb/hr) = Basis (lb/10^12 Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^12 Btu			
Basis [b], lb/10^12 Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	0.625683712	0.588619505	0.530674508
(TPY)	3.13E-01	2.94E-01	2.65E-01

Table A-16. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.80E-02	4.51E-02	4.07E-02
(TPY)	2.40E-02	2.26E-02	2.03E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.94E-01	4.65E-01	4.19E-01
(TPY)	2.47E-01	2.33E-01	2.10E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA,1996 (AP-42,Table 3.1-4)

Table A-17. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	145.1	135.5	119.2
Heat rate (Btu/kWh, LHV)	10,970	11,030	11,400
(Btu/kWh, HHV)	11,765	11,829	12,226
Heat Input (MMBtu/hr, LHV)- provided	1,592	1,495	1,359
Heat Input (MMBtu/hr, LHV)- with margin	1,592	1,495	1,359
(MMBtu/hr, HHV)	1,707	1,603	1,457
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,991,000	2,898,000	2,783,000
- provided	2,991,000	2,898,000	2,783,000
Temperature (°F)	1,196	1,200	1,200
Moisture (% Vol.)	11.72	11.85	12.65
Oxygen (% Vol.)	10.34	10.57	10.86
Molecular Weight	28.32	28.29	28.16
CT 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)	2,991,000	2,898,000	2,783,000
Temperature (°F)	1,196	1,200	1,200
Molecular weight	28.32	28.29	28.16
Volume flow (acfm)- calculated	2,127,478	2,068,807	1,995,375
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)	1,592	1,495	1,359
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	89,406	83,952	76,330
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,991,000	2,898,000	2,783,000
HRSG Stack Temperature (°F)	271	274	278
Molecular weight	28.32	28.29	28.16
CT volume flow (acfm)	938,994	914,512	886,499
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	61.5	59.9	58.1

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-18. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	89.4	84.0	76.3
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	18.07	16.97	15.43
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	35.1	34.0	32.4
(lb/mmBtu, HHV)	0.0203	0.0210	0.0220
Sulfur Dioxide			
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100			
Fuel oil Sulfur Content	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	89,406	83,952	76,330
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	89.4	84.0	76.3
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	42	42	42
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
CT Emission rate (lb/hr)	280.5	263.5	239.3
(lb/hr)- provided	280.0	263.0	239.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10.0
(lb/hr)	66.8	62.7	57.0
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 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	20	20	20
Basis, ppmvd @ 15% O2 - calculated	12.84	13.24	13.94
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
HRSG Emission rate (lb/hr)	52.2	50.6	48.3
(lb/hr)- provided	52.0	51.0	48.0

Table A-18. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 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, ppmvw	3.5	3.5	3.5
Basis, ppmvd @ 15% O2 - calculated	2.5	2.6	2.8
Moisture (%)	11.72	11.85	12.65
Oxygen (%) wet	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
HRSG Emission rate (lb/hr)	5.91	5.74	5.53
(lb/hr)- provided	6.00	5.50	5.50
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	89.4	84.0	76.3
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	13.69	12.86	11.69
(lb/hr)- provided	8.70	8.10	7.40
Lead			
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Emission Rate Basis (lb/10^{12} Btu)	14	14	14
Emission rate (lb/hr)	0.0223	0.0209	0.0190

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

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-19. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,707	1,603	1,457
	1,707	1,603	1,457
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	6.49E-07	6.09E-07	5.54E-07
(TPY)	3.24E-07	3.05E-07	2.77E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.65E-04	5.31E-04	4.82E-04
(TPY)	2.83E-04	2.65E-04	2.41E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.55E-02	5.22E-02	4.74E-02
(TPY)	2.78E-02	2.61E-02	2.37E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	3.68E-01	3.45E-01	3.14E-01
(TPY)	1.84E-01	1.73E-01	1.57E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,707	1,707	1,707
Emission Rate (lb/hr)	1.07E-03	1.07E-03	1.07E-03
(TPY)	5.34E-04	5.34E-04	5.34E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-20. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,707	1,603	1,457
	1,707	1,603	1,457
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.35E-02	1.27E-02	1.15E-02
(TPY)	6.75E-03	6.34E-03	5.76E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.88E-03	1.76E-03	1.60E-03
(TPY)	9.39E-04	8.82E-04	8.02E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.53E-03	5.19E-03	4.72E-03
(TPY)	2.77E-03	2.60E-03	2.36E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.15E-02	1.08E-02	9.85E-03
(TPY)	5.77E-03	5.42E-03	4.93E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	6.32E-02	5.93E-02	5.39E-02
(TPY)	3.16E-02	2.97E-02	2.70E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	7.37E-01	6.92E-01	6.30E-01
(TPY)	3.69E-01	3.46E-01	3.15E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.47E-01	1.38E-01	1.26E-01
(TPY)	7.37E-02	6.92E-02	6.29E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	0.51211023	0.480869479	0.437209645
(TPY)	2.56E-01	2.40E-01	2.19E-01

Table A-20. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	3.93E-02	3.69E-02	3.35E-02
(TPY)	1.96E-02	1.84E-02	1.68E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	4.05E-01	3.80E-01	3.45E-01
(TPY)	2.02E-01	1.90E-01	1.73E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA,1996 (AP-42,Table 3.1-4)

Table A-21. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	96.7	90.3	79.4
Heat rate (Btu/kWh, LHV)	12,730	12,920	13,370
(Btu/kWh, HHV)	13,652	13,856	14,339
Heat Input (MMBtu/hr, LHV)- provided	1,231	1,167	1,062
Heat Input (MMBtu/hr, LHV)- with margin	1,231	1,167	1,062
(MMBtu/hr, HHV)	1,320	1,251	1,139
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,499,000	2,457,000	2,353,000
- provided	2,499,000	2,457,000	2,353,000
Temperature (°F)	1,200	1,200	1,200
Moisture (% Vol.)	10.19	10.38	11.37
Oxygen (% Vol.)	11.30	11.54	11.73
Molecular Weight	28.44	28.40	28.26
CT 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)	2,499,000	2,457,000	2,353,000
Temperature (°F)	1,200	1,200	1,200
Molecular weight	28.44	28.40	28.26
Volume flow (acfm)- calculated	1,774,396	1,747,217	1,681,491
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	1,167	1,062
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	69,146	65,534	59,630
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,499,000	2,457,000	2,353,000
HRSG Stack Temperature (°F)	256	259	268
Molecular weight	28.44	28.40	28.26
CT volume flow (acfm)	765,021	756,777	737,121
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	50.1	49.6	48.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-22. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	69.1	65.5	59.6
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	13.98	13.25	12.05
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	31.0	30.2	29.1
(lb/mmBtu, HHV)	0.0235	0.0242	0.0255
Sulfur Dioxide			
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100			
Fuel oil Sulfur Content	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	69,146	65,534	59,630
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	69.1	65.5	59.6
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	42	42	42
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	215.0	203.7	185.2
(lb/hr)- provided	215.0	203.0	185.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10.0
(lb/hr)	51.2	48.5	44.1
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 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	20	20	20
Basis, ppmvd @ 15% O2 - calculated	14.19	14.71	15.39
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	44.2	43.4	41.3
(lb/hr)- provided	44.0	43.0	41.0

Table A-22. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 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, ppmvw	3.5	3.5	3.5
Basis, ppmvd @ 15% O2 - calculated	2.8	2.9	3.0
Moisture (%)	10.19	10.38	11.37
Oxygen (%) wet	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	4.92	4.85	4.66
(lb/hr)- provided	5.00	5.00	4.50
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	69.1	65.5	59.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	10.59	10.03	9.13
(lb/hr)- provided	6.70	6.30	5.80
Lead			
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Emission Rate Basis (lb/10^{12} Btu)	14	14	14
Emission rate (lb/hr)	0.0172	0.0163	0.0149

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-23. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,320	1,251	1,139
	1,320	1,251	1,139
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	5.02E-07	4.75E-07	4.33E-07
(TPY)	2.51E-07	2.38E-07	2.16E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.37E-04	4.14E-04	3.77E-04
(TPY)	2.18E-04	2.07E-04	1.88E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.30E-02	4.07E-02	3.70E-02
(TPY)	2.15E-02	2.04E-02	1.85E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	2.84E-01	2.70E-01	2.45E-01
(TPY)	1.42E-01	1.35E-01	1.23E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,320	1,320	1,320
Emission Rate (lb/hr)	8.26E-04	8.26E-04	8.26E-04
(TPY)	4.13E-04	4.13E-04	4.13E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-24. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,320	1,251	1,139
	1,320	1,251	1,139
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.04E-02	9.90E-03	9.01E-03
(TPY)	5.22E-03	4.95E-03	4.50E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.45E-03	1.38E-03	1.25E-03
(TPY)	7.26E-04	6.88E-04	6.26E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.28E-03	4.05E-03	3.69E-03
(TPY)	2.14E-03	2.03E-03	1.84E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	8.92E-03	8.46E-03	7.70E-03
(TPY)	4.46E-03	4.23E-03	3.85E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.88E-02	4.63E-02	4.21E-02
(TPY)	2.44E-02	2.31E-02	2.11E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	5.70E-01	5.41E-01	4.92E-01
(TPY)	2.85E-01	2.70E-01	2.46E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.14E-01	1.08E-01	9.83E-02
(TPY)	5.70E-02	5.40E-02	4.91E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	0.396059366	0.375371619	0.341556965
(TPY)	1.98E-01	1.88E-01	1.71E-01

Table A-24. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	3.04E-02	2.88E-02	2.62E-02
(TPY)	1.52E-02	1.44E-02	1.31E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	3.13E-01	2.97E-01	2.70E-01
(TPY)	1.56E-01	1.48E-01	1.35E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA,1996 (AP-42,Table 3.1-4)

Table A-25 Summary of Maximum Potential Annual Emissions for the CT/HRSG

	Maximum Hourly Emissions (lb/hr)[a]			Maximum Annual Emissions (tons/year)[b]						PSD
Pollutant Load:	Natural Gas 100%	Natural Gas 50%	Distillate Oil 100%	Case A	Case B	Case C	Case D	Auxiliary Boiler	TOTAL	Significant Emission Rates
One Combustion Turbine- Combined Cycle										
SO_2	5.1	3.3	102.8	22.1	19.5	71.0	68.4	0.014	71.0	40
PM/PM_{10}	10.0	9.7	37.8	44.0	43.4	57.8	57.3	0.025	57.9	25/15
NO_x	16.5	11	77	72.3	63.3	102.4	93.4	0.50	103	40
CO	29.7	19.9	66.0	130.1	115.3	148.2	133.5	0.25	148	100
VOC (as methane)	2.9	1.9	7.5	12.6	11.2	14.9	13.5	0.25	15.2	40
Sulfuric Acid Mist	0.77	0.5	15.7	3.4	3.0	10.9	10.5	0.002	10.9	7
Lead	0.00E+00	0.00E+00	2.56E-02	0.00E+00	0.00E+00	1.28E-02	1.28E-02	0.00E+00	1.28E-02	0.6
Mercury	1.44E-06	9.43E-07	1.31E-03	6.33E-06	5.58E-06	6.58E-04	6.58E-04	Neg.	6.58E-04	0.1
MWC Organics (as 2,3,7,8-TCDD)	2.17E-09	1.42E-09	7.46E-07	9.49E-09	8.36E-09	3.81E-07	3.80E-07	Neg.	3.81E-07	3.50E-06
MWC Metals (Be & Cd)	0.00E+00	0.00E+00	7.01E-03	0.00E+00	0.00E+00	3.50E-03	3.50E-03	0.00E+00	3.50E-03	15
MWC Acid Gases (HCl)	0.00E+00	0.00E+00	0.42	0.00E+00	0.00E+00	2.11E-01	2.11E-01	0.00E+00	2.11E-01	40
Total HAPs	0.41	0.30	2.54	1.79	1.63	2.86	2.70	0.40	3.26	25
Two Combustion Turbines- Combined Cycle										
SO_2	10.1	6.6	205.5	44.3	39.0	142.0	136.7	0.014	142	40
PM/PM_{10}	20	19	76	88	87	116	115	0.025	116	25/15
NO_x	33	21	153	145	127	205	187	0.50	205	40
CO	59	40	132	260	231	296	267	0.25	297	100
VOC (as methane)	5.8	3.8	14.9	25.2	22.3	29.8	26.9	0.25	30.1	40
Sulfuric Acid Mist	1.5	1.01	31.47	6.78	5.97	21.74	20.93	0.002	21.7	7
Lead	0.00E+00	0.00E+00	5.12E-02	0.00E+00	0.00E+00	2.56E-02	2.56E-02	0.00E+00	2.56E-02	0.6
Mercury	2.89E-06	1.89E-06	2.61E-03	1.27E-05	1.12E-05	1.32E-03	1.32E-03	Neg.	1.32E-03	0.1
MWC Organics (as 2,3,7,8-TCDD)	4.33E-09	2.83E-09	1.49E-06	1.90E-08	1.67E-08	7.62E-07	7.60E-07	Neg.	7.62E-07	3.50E-06
MWC Metals (Be & Cd)	0.00E+00	0.00E+00	1.40E-02	0.00E+00	0.00E+00	7.01E-03	7.01E-03	0.00E+00	7.01E-03	15
MWC Acid Gases (HCL)	0.0	0.00	0.85	0.00	0.00	4.23E-01	4.23E-01	0.00E+00	4.23E-01	40
Total HAPs	0.8	0.60	5.09	3.59	3.26	5.72	5.40	0.4	6.12	25

[a] Based on 59 °F compressor inlet air temperature

[b] Maximim emission cases:

	Number of Hours for Operation			
Operation	Case A	Case B	Case C	Case D
100 % Load- Gas	8,760	5,760	7,760	4,760
50% Load- Gas	0	3000	0	3,000
100 % Load- Oil	0	0	1,000	1,000
Total hours	8,760	8,760	8,760	8,760

Table A-26. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature and Load 100% 20 °F	 100% 59 °F	 100% 95 °F
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Turbine Flow (acfm)	2,574,253	2,461,202	2,318,987
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT Emission rate (lb/hr)	0.420	0.392	0.355
Heat Input (MMBtu/hr, HHV)	1941	1806	1644
CT Emission rate (lb/10^{12} Btu)	216.1	216.9	215.9

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

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Table A-27. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	CT Only Turbine Inlet Temperature and Load 50% 20 °F	 50% 59 °F	 50% 95 °F
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Turbine Flow (acfm)	1,770,983	1,728,651	1,662,592
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	0.266	0.249	0.229
Heat Input (MMBtu/hr, HHV)	1,257	1,179	1,085
CT/DB Emission rate (lb/10^{12} Btu)	211.6	211.5	211.5

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

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Table A-28. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	CT Only Turbine Inlet Temperature and Load 100% 20 °F	 100% 59 °F	 100% 95 °F
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Turbine Flow (acfm)	2,631,766	2,514,188	2,362,720
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT Emission rate (lb/hr)	0.489	0.455	0.415
Heat Input (MMBtu/hr, HHV)	2,086	1,962	1,769
CT Emission rate (lb/10^{12} Btu)	234.4	232.1	234.5

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

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Table A-29. Auxiliary Boiler Emissions for the Hines Energy Complex, Power Block 4

Parameter	Value		
Conditions			
Ambient Temperature (°F)	72		
Load Condition (%)	100		
Hear Input Rate (MMBtu/hr), maximum	20		
Fuel Usage			
Heat content (Btu/cf, HHV)	1,021		
Fuel usage (cf/hr)- calculated	19,585		
Hours of Operation	500		
Sulfur content (gr/100 scf)	1		
Emissions [a]	lb/MMBtu	lb/hr	TPY
SO_2	0.0028	0.056	0.014
PM/PM_{10}	0.005	0.10	0.025
NO_x	0.10	2.00	0.5
CO	0.049	0.98	0.25
VOC (as methane)	0.049	0.98	0.25
Sulfuric Acid Mist [c]	0.00043	0.0086	0.0021
Lead	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.
Benzene [b]	0.002	0.04	0.01
Formaldehyde [b]	0.075	1.50	0.38
Toluene [b]	0.003	0.07	0.02
Stack Parameters			
Height (ft)	60		
Diameter (ft)	2.5		
Exit gas temperature (°F)	332		
Exit gas flow rate (acfm)	6,485		
Exit gas velocity (ft/s)	22.0		

[a] Emissions based on maunufacturer's data (Black & Veatch, 1992).

[a] Emissions based on natural gas combustion from AP-42, Compilation of Air Pollutant Emission Factors for Stationary Sources, Chapter 1.4 (U.S. EPA, 1998).

[c] Based on 10 peercent of SO2 emissions.

ATTACHMENT 3

Revised BACT Tables

Table B-3. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA Combined Cycle Combustion Turbine
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$968,481	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$127,782	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$58,109	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$48,424	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,297,301	$16,492,225	
Direct Installation Costs			
Foundation and supports	$103,784	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$181,622	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$51,892	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$25,946	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$12,973	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$12,973	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$409,190	$4,967,668	
Total Capital Costs (TCC)	$1,706,491	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$129,730	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$64,865	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$129,730	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$25,946	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$12,973	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$38,919	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$452,163	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,158,654	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-3b. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA Combined Cycle Combustion Turbine
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™		Basis of Cost Component
Direct Capital Costs				
Pollution Control Equipment	$1,065,329	$14,750,000		Vendor Estimates
Ammonia Storage Tank	$127,782	$0	$35	per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725		Vatavauk,1990
Instrumentation	$50,000	$50,000		Additional NO_x Monitor and System
Taxes	$63,920	$885,000	6%	of SCR Associated Equipment and Catalyst
Freight	$53,266	$737,500	5%	of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,404,802	$16,492,225		
Direct Installation Costs				
Foundation and supports	$112,384	1,319,378	8%	of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$196,672	2,308,912	14%	of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$56,192	659,689	4%	of TDCC and RCC;OAQPS Cost Control Manual
Piping	$28,096	329,845	2%	of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$14,048	164,922	1%	of TDCC and RCC;OAQPS Cost Control Manual
Painting	$14,048	164,922	1%	of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000		Engineering Estimate
Buildings	$15,000	$15,000		Engineering Estimate
Total Direct Installation Costs (TDIC)	$441,441	$4,967,668		
Total Capital Costs (TCC)	$1,846,243	$21,459,893	Sum of TDCC, TDIC and RCC	
Indirect Costs				
Engineering	$140,480	$1,649,223	10%	of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0		Engineering Estimate
Construction and Field Expense	$70,240	$824,611	5%	of TDCC; OAQPS Cost Control Manual
Contractor Fees	$140,480	$1,649,223	10%	of TDCC; OAQPS Cost Control Manual
Start-up	$28,096	$329,845	2%	of TDCC; OAQPS Cost Control Manual
Performance Tests	$14,048	$164,922	1%	of TDCC; OAQPS Cost Control Manual
Contingencies	$42,144	$494,767	3%	of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$485,489	$5,112,590		
Total Direct, Indirect and Capital Costs (TDICC)	$2,331,731	$26,572,482	Sum of TCC and TInCC	

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-4. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA in Combined Cycle Operation
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$18,720	$37,440	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$2,808	$5,616	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$114,985	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$19,384	$29,076	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times SCR
Catalyst Cost	$176,540	$264,810	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$10,423	$10,108	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$357,860	$347,051	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$221,431	$666,860	0.20 % output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/mmBtu
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$249,463	$1,476,245	
Indirect Annual Costs			
Overhead	81,908	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	21,587	265,725	1% of Total Capital Costs
Insurance	21,587	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	237,020	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$362,101	$3,474,942	
Total Annualized Costs	$969,425	$5,298,237	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (9 to 3.5)	$3,672	$20,070	per ton of NO_x Removed
Incremental Cost Effectiveness (9 to 3.5)	$3,672	$20,070	per incremental ton of NO_x Removed
	263.99	263.99	tons NOx removed /year; 3.5 ppmvd corrected to 15% oxygen

Source: Golder 2002. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-4b. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$31,200	$62,400	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$4,680	$9,360	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$126,139	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$25,728	$38,592	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times !
Catalyst Cost	$234,317	$351,475	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$13,112	$13,855	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$450,176	$475,682	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCOI
MW Loss and Heat Rate Penalty	$265,718	$666,860	0.24 % output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90%
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$293,750	$1,476,245	
Indirect Annual Costs			
Overhead	97,211	43,056	60% of Operating/Supervision Labor and Ammonia
Property Taxes	23,317	265,725	1% of Total Capital Costs
Insurance	23,317	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	256,024	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sur
Total Indirect Annual Costs (TIAC)	$399,870	$3,492,164	
Total Annualized Costs	$1,143,795	$5,444,091	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (9 to 2.5)	$3,950	$18,799	per ton of NO_x Removed
Incremental Cost Effectiveness (3.5 to 2.5)	$6,809	$5,696	per incremental ton of NO_x Removed
	289.60	289.60	tons NOx removed /year; 2.5 ppmvd corrected to 15% oxygen

Source: Golder 2002. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-5. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (3.5 ppmvd corrected)	DLN with SCONOx™ (3.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,158,654	$26,572,482
Annualized Costs	included	$969,425	$5,298,237
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$3,672	$20,070
Environmental Impact [b]			
Total NOx (TPY)	392	128.0	128.0
NOx Reduction (TPY)	NA	264	264
Ammonia Emissions (TPY)	0	113	0
PM Emissions (TPY)	0	12.2	0
Secondary Emissions (TPY)	0	4.4	40.4
Net Emission Reduction (TPY)	NA	-134	-224
Addition Greenhouse Gas (as CO2; tons/year)	0	2,437	22,404
Energy Impacts [c]			
Energy Use (kWh/yr) - Total	0	3,872,631	35,597,336
Energy Use (kWh/yr) - Back Pressure	0	3,171,831	9,552,254
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	323	2,966
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	38,483	353,740
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	38	354
Energy Use (percent of combustion turbine output)	0	0.24%	2.24%

[a] See Tables B-3, B-4, and B-5 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] 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 for SCR is based on 0.3 percent of 181 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-5b. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (2.5 ppmvd corrected)	DLN with SCONOx™ (2.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrat	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,331,731	$26,572,482
Annualized Costs	included	$1,143,795	$5,444,091
Cost Effectiveness (per ton of Nox removed)			
Incremental from 2.5 ppm	NA	$6,809	$5,696
Environmental Impact [b]			
Total NOx (TPY)	392	102.4	102.4
NOx Reduction (TPY)	NA	290	290
Ammonia Emissions (TPY)	0	113	0
PM Emissions (TPY)	0	12.3	0
Secondary Emissions (TPY)	0	5.1	40.4
Net Emission Reduction (TPY)	NA	-159	-249
Additional Greenhouse Gas (as CO_2; tons/year)	0	2,837	22,404
Energy Impacts [c]			
Energy Use (kWh/yr)	0	4,506,997	35,597,336
Energy Use (kWh/yr) - Back Pressure	0	3,806,197	9,552,254
Energy Use (kWh/yr) - Other	0	700,800	24,643,482
Energy Use (Equivalent Residential Customers/year)	0	376	2,966
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	44,787	353,740
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	45	354
Energy Use (percent of combustion turbine output)	0	0.28%	2.24%

[a] See Tables B-3b, B-4b, and B-5b for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] 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 for SCR is based on 0.34 percent of 181 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™

	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOx™		
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	12.17	0.14	12.31		1.28	1.28
Sulfur Dioxide		0.05	0.05		0.48	0.48
Nitrogen Oxides	-263.99	2.57	-261.43	-263.99	23.58	-240.41
Carbon Monoxide		1.54	1.54		14.15	14.15
Volatile Organic Compounds		0.10	0.10		0.93	0.93
Ammonia	113.04					
Total:	-138.78	4.40	-134.38	-263.99	40.42	-223.57
Carbon Dioxide (all energy requirements)		2,437.28	2,437.28		22,403.56	22,403.56

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	38,483	353,740 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6b. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR)
(2.5 ppm)

	Incremental Emissions (tons/year) of SCR					
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	12.17	0.16	12.33		1.28	1.28
Sulfur Dioxide		0.06	0.06		0.48	0.48
Nitrogen Oxides	-289.60	2.99	-286.62	-289.60	23.58	-266.02
Carbon Monoxide		1.79	1.79		14.15	14.15
Volatile Organic Compounds		0.12	0.12		0.93	0.93
Ammonia	113.04					
Total:	-164.39	5.12	-159.27	-289.60	40.42	-249.18
Carbon Dioxide (all energy requirements)		2,836.53	2,836.53		22,403.56	22,403.56

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	44,787	353,740 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment Minus Catalyst	$99,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$77,300	10% of SCR Associated Equipment
Sales Tax	$5,940	6% of SCR Associated Equipment/Catalyst
Freight	$4,950	5% of SCR Associated Equipment/Catalyst
CO Catalyst	$674,000	Vendor Quote
Sales Tax	$40,440	6% of SCR Associated Equipment/Catalyst
Freight	$33,700	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$979,835	
Direct Installation Costs		
Foundation and supports	$78,387	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$137,177	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$39,193	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$19,597	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,798	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,798	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$298,951	
Total Capital Costs	$1,278,786	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$97,984	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$48,992	5% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$97,984	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
Start-up	$19,597	2% of Total Direct Capital Costs; OAQPS Cost Control Manual
Performance Tests	$9,798	1% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contingencies	$29,395	3% of Total Direct Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$303,749	
Total Direct, Indirect and Capital Costs (TDICC)	$1,582,535	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst, GE 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Annualized Catalyst Replacement (Catalyst+Tax+Shipping)	$285,041	38.10% Capital Recovery Factor of 7% over 3 yrs times sum of TDICC
Contingency	$8,767	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$300,984	
Energy Costs		
Heat Rate Penalty	$349,051	0.2% of MW output, $0.05/kW; EPA, 1993 (Page 6-20) and $6/mmBtu added fuel costs (DOE,2004)
Total Energy Costs (TDEC)	$349,051	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$15,825	1% of Total Capital Costs
Insurance	$15,825	1% of Total Capital Costs
Annualized Total Direct Capital Minus Catalyst	$91,617	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$127,573	
Total Annualized Costs	$777,608	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$6,517	per ton of CO Removed
	$7,510	per ton of Net Emission Reduction

Table B-10. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG

	Alternative BACT Control Technologies	
	DLN Only	DLN with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs	included	$1,582,535
Annualized Costs	included	$777,608
Cost Effectiveness		
CO Removed (per ton of CO)	NA	$6,517
Environmental Impact [b]		
Total CO (TPY)	148	29
CO Reduction (TPY)	NA	119
Net Pollutant Reduction	NA	104
Additional Greenhouse Gas (CO2; tons/yr)	--	2,004
Energy Impacts [c]		
Energy Use (kWh/yr)	0	3,184,085
Energy Use (Equivalent Residential Customers/year)	0	265
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	31,641
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	32

[a] See Tables B-8 and B-9 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-11.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year.
Lost energy is based on 0.2 percent of 166 MW.

Table B-11. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst

		Incremental Emissions (tons/year) of SCR		
Pollutants		Primary	Secondary	Total
Particulate		12.17	0.11	12.29
Sulfur Dioxide			0.04	0.04
Nitrogen Oxides		0.00	2.11	2.11
Carbon Monoxide		-119.3	1.27	-118.1
Volatile Organic Compounds			0.08	0.08
	Total:	-107.2	3.62	-103.5
Carbon Dioxide (additional from gas firing)			2,003.9	2,003.9

Basis:

Lost Energy (mmBtu/year)	31,641

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

ATTACHMENT 4

GE Formaldehyde Data

GE Energy

Jeanne M. Beres
Manager – Environmental & Acoustic Engineering
Global Power Plant Systems

1 River Road, Bldg. 2-506
Schenectady, NY 12345
USA

T 518 385 0554
F 518 381 2706
jeanne.beres@ge.com

Kevin Murray
Manager, Project Engineering
Progress Energy, Inc.
Plant Construction Department
410 South Wilmington Street – PEB 9A
Raleigh, NC 27601
kevin.murray@pgnmail.com

October 6, 2004

Dear Mr. Murray:

In response to increased requests for formaldehyde emissions for GE combustion turbines in light of the promulgation of the combustion turbines MACT standard (40 CFR Part 63, Subpart YYYY), GE offers the following information.

GE is not prepared at this time to offer a formaldehyde emissions guarantee pending the outcome of the petition to de-list natural gas fired combustion turbines from the MACT. GE believes that making a commercial guarantee during the MACT de-listing petitioning process may imply industry's support of the MACT standard and could possibly jeopardize the approval of the petition. Such a guarantee may also prompt state and local agencies to require permit limits that would be similar to, or more stringent than, the forthcoming MACT level. Furthermore, EPA has published a "stay" of the MACT rule, as it applies to combustion turbines covered in the de-list petition, which basically excludes such units from compliance with the MACT until the de-listing petition status is approved or rejected by the EPA.

GE has conducted formaldehyde emissions testing on a very limited number of combustion turbines, all of which were Frame 7 DLN units firing natural gas, and in a couple of instances, on distillate oil.

All of the measured formaldehyde levels from our testing are below the MACT standard level of 91 ppbvd at 15% O_2 using CARB Method 430 with modified reporting protocol due to the low level concentrations. The MACT recommends FTIR but allows for other agency-approved methods.

In summary, for the reasons stated above, GE can offer no formaldehyde emissions guarantee for GE Frame 7 DLN units. However, GE expects to meet the 91 ppbvd @ 15% O_2 formaldehyde (HCOH) level on its Frame 7 DLN combustion turbines in normal premix operation on natural gas (without add-on controls). GE expects the same to be true on our Frame 7 units when firing on distillate oil with a water injection rate set to achieve a NOx level of 42 ppm @ 15% O_2 or higher. Please note these statements are based on the condition that emissions testing is conducted using the modified CARB 430 method, or an FTIR designed with proper cell path length and elimination of sample-line interference / off-gassing.

We would be happy to discuss this further with you at any time. Please do not hesitate to contact me if you have any questions.

Best regards,

Jeanne M. Beres

Jeanne M. Beres
Manager – Env. & Acoustic Eng.

cc: F. Brooks
J. Chalfin
J. Almstead

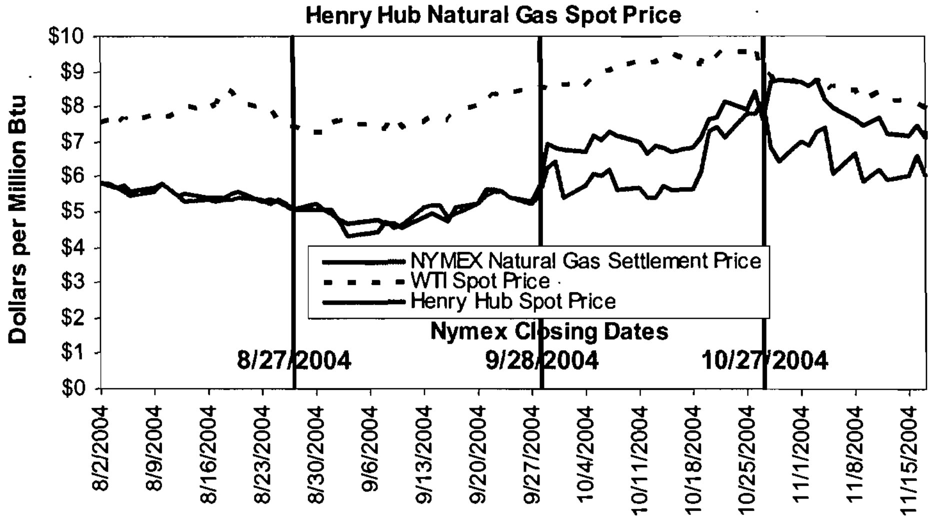
ATTACHMENT 5

Fuel Cost Data
DOE Natural Gas Weekly

Overview: Thursday, November 18 (No issue Thanksgiving week; next release 2:00 p.m. on December 2)

Natural gas spot and futures prices fell for a third consecutive week (Wednesday to Wednesday, November 10-17), as temperatures for most of the nation continued to be moderate to seasonal. At the Henry Hub, the spot price declined 6 cents on the week, for the smallest week-on-week decrease in the nation. Spot gas traded there yesterday (Wednesday, November 17) at $6.06 per MMBtu. Price declines at the majority of market locations ranged from around a dime to nearly 60 cents per MMBtu. On the NYMEX, the price for the near-month natural gas futures contract (for December delivery) fell by almost 40 cents on the week, settling yesterday at $7.283 per MMBtu. EIA reported that working gas inventories in underground storage were 3,321 Bcf as of Friday, November 12, which is 9 percent greater than the previous 5-year average. The spot price for West Texas Intermediate (WTI) crude oil declined for a fourth consecutive week, dropping $1.85 per barrel ($0.32 per MMBtu), or nearly 4 percent, from last Wednesday's level, to trade yesterday at $46.85 per barrel ($8.08 per MMBtu).

NYMEX Natural Gas Futures Near-Month Contract Settlement Price, West Texas Intermediate Crude Oil Spot Price, and Henry Hub Natural Gas Spot Price



Note: The West Texas Intermediate crude oil price, in dollars per barrel, is converted to $/MMBtu using a conversion factor of 5.80 MMBtu per barrel. The dates marked by vertical lines are the NYMEX near-month contract settlement dates.
Source: NGI's *Daily Gas Price Index* (http://intelligencepress.com)

Prices:

Spot prices declined significantly for the week at all market locations, as generally mild weather coupled with the industry's strong inventory position exerted downward pressure on prices. Price declines were largest in the West and Midcontinent and smallest in Gulf coast production areas and the Northeast. In California, high-inventory operational flow orders of varying length and condition imposed by both PG&E and SOCAL, and reports of high linepack on the Kern River Transmission pipeline, underscored the paucity of swing demand, as night-time temperatures in much of the West continue to be well above normal. The average price for Rocky Mountain locations showed the nation's largest drop for the week, at $0.48 per MMBtu, to an average of $5.25 in yesterday's trading. Spot prices at market locations in West Texas fell an average of 42 cents per MMBtu, to the low $5 range, while California points dropped 36 cents, to $5.62 per MMBtu. Thanks to a significant warming trend beginning over the weekend, prices in the Midcontinent declined from 40 to over 60 cents per MMBtu, and ranged between $5.29 and $5.88 per MMBtu in yesterday's trading. Cooler-than-expected temperatures over the weekend in the Northeast and parts of the Mid-Atlantic contributed to increased demand and boosted prices at Gulf Coast supply locations and in the Northeast region on Monday and Tuesday (November 15-16). This partially offset yesterday's large declines, leaving these market areas with smaller week-on-week decreases, which averaged 15 and 17 cents per MMBtu, respectively. The average spot price for Louisiana market locations was $5.98 per MMBtu yesterday, while spot gas for delivery to New York citygates was $6.59.

Spot Prices ($ per MMBtu)	Thur. 11-Nov	Fri. 12-Nov	Mon. 15-Nov	Tue. 16-Nov	Wed. 17-Nov
Henry Hub	6.18	5.89	6.01	6.57	6.05
New York	6.74	6.72	6.77	7.25	6.59
Chicago	6.32	6.02	6.16	6.61	5.86
Cal. Comp. Avg.*	6.01	5.70	5.90	6.29	5.64
Futures ($/MMBtu)					
December delivery	7.236	7.176	7.436	7.124	7.283
January delivery	7.944	7.866	8.047	7.757	7.954

*Avg. of NGI's reported avg. prices for: Malin, PG&E citygate, and Southern California Border Avg.
Source: NGI's Daily Gas Price Index (http://intelligencepress.com).

On the NYMEX, the December contract settlement price declined $0.395 per MMBtu on the week, or just over 5 percent, as the near-month contract settled yesterday at $7.283. This follows the 12 percent decrease during the previous week. Since becoming the near-month contract on October 28, the December contract has fallen 16 percent in value. The futures contracts for delivery in the remaining heating-season months have shown similar declines over the same period (13 to 15 percent). Nevertheless, the basis spread between the Henry Hub spot price and the settlement prices for these contracts continues to be notably large: about $1.23, $1.91, $1.93, and $1.65, respectively, for the December through March contracts as of yesterday. This continues to provide financial incentive coast production areas and the Northeast. In California, high-inventory operational flow orders of varying length and condition imposed by both PG&E and SOCAL, and reports of high linepack on the Kern River Transmission pipeline, underscored the paucity of swing demand, as night-time temperatures in much of the West continue to be well above normal. The average price for Rocky Mountain locations showed the nation's largest drop for the week, at $0.48 per MMBtu, to an average of $5.25 in yesterday's trading. Spot prices at market locations in West Texas fell an average of 42 cents per MMBtu, to the low $5 range, while California points dropped 36 cents, to $5.62 per MMBtu. Thanks to a significant warming trend beginning over the weekend, prices in the Midcontinent declined from 40 to over 60 cents per MMBtu, and ranged between $5.29 and $5.88 per MMBtu in yesterday's trading. Cooler-than-expected temperatures over the weekend in the Northeast and parts of the Mid-Atlantic contributed to increased demand and boosted prices at Gulf Coast supply locations and in the Northeast region on Monday and Tuesday (November 15-16). This partially offset yesterday's large declines, leaving these market areas with smaller week-on-week decreases, which averaged 15 and 17 cents per MMBtu, respectively. The average spot price for Louisiana market locations was $5.98 per MMBtu yesterday, while spot gas for delivery to New York citygates was $6.59.

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Cal. Comp. Avg,*	6.01	5.70	5.90	6.29	5.64
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*Avg. of NGI's reported avg. prices for: Malin, PG&E citygate, and Southern California Border Avg.
Source: NGI's Daily Gas Price Index (http://intelligencepress.com).

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Other Market Trends:

New Incentives to Help Boost Production in the Gulf of Mexico: In its first 10-year forecast for oil and gas production in the federal waters of the Gulf of Mexico, the Minerals Management Service (MMS) on November 15th said that it expects a 13-percent increase in natural gas production over the next decade. Oil production over the same timeframe will increase by approximately 43 percent, according to the agency. MMS attributed the production increase to new incentives encouraging energy companies to explore and develop difficult-to-reach areas of the Gulf of Mexico. There have been incentive programs for deep-water areas since 2001, and more recent incentives offer developers royalty relief to tap into pockets of natural gas deep under shallow waters in the Gulf. Energy companies are responding positively to the new incentives, according to MMS. By 2011, most oil production in the Gulf likely will come from deep-water wells, while natural gas will come from both the deep-water and shallow-water areas. This is the ninth year of expansion of the deep-water frontier in the Gulf, and this trend is expected to continue over the next 10 years. More than 100 development projects have begun production and new discoveries that have occurred in the past three years are expected to be developed. Natural gas production is expected to increase to 13 billion cubic feet (Bcf) per day by 2011 from current levels of about 12 Bcf per day. However, in the short term, there will be a decline in natural gas production, as old fields begin to be exhausted. This year's production estimate by MMS is based on a new methodology, which analyzes recent deep-water discoveries and projected deep-water reserves in addition to surveying oil and gas companies.

Summary:

Spot and futures prices continued on a downward trend for the third consecutive week, as the lack of significant heating demand and high inventory levels exerted downward price pressure. The basis spreads of futures prices over the Henry Hub spot price continued to be relatively large. EIA reported the first implied net withdrawal of the heating season, as of the week ended Friday, November 12.

Progress Energy

RECEIVED
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BUREAU OF AIR REGULATION

November 4, 2004

Mr. Michael Halpin, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Re: **Hines Energy Complex - Power Block 4**
Supplemental Site Certification Application to PA 92-33
PSD/Air Construction Permit Application
File No. 1050234-010-AC

Dear Mr. Halpin:

As discussed with you, Progress Energy Florida, during final equipment selection for this project, has made the decision to use combustion turbines other than those generally represented in the original permit application. To more accurately describe the project, as it stands today, PEF will be submitting an amended permit application. In order to allow PEF, and it's consultant, time to develop this amended application and address (where still applicable) the Request for Additional Information items provided in your letter dated August 19, 2004, PEF requests an extension of time until December 3, 2004 to address these issues.

Should you have any questions regarding this information, please do not hesitate to contact me at (727) 826-4363.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

c: Jim Pennington, FDEP – DARM/BAR
Hamilton Oven, FDEP – Siting
Scott Osbourn – Golder
Roger Zirkle – Progress Energy Florida

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

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Progress Energy

Mr. Michael Halpin, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

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Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

BB/A

Hopping Green & Sams
Attorneys and Counselors

Writer's Direct Dial No.: (850) 425-2346

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AUG 23 2004
BUREAU OF AIR REGULATION

DEPARTMENT OF
ENVIRONMENTAL PROTECTION
AUG 17 2004
SITING COORDINATION

MEMORANDUM

TO: Hamilton S. Oven, Jr.

FROM: Carolyn Raepple Carolyn

RE: Substitute Pages for Hines 4 Application

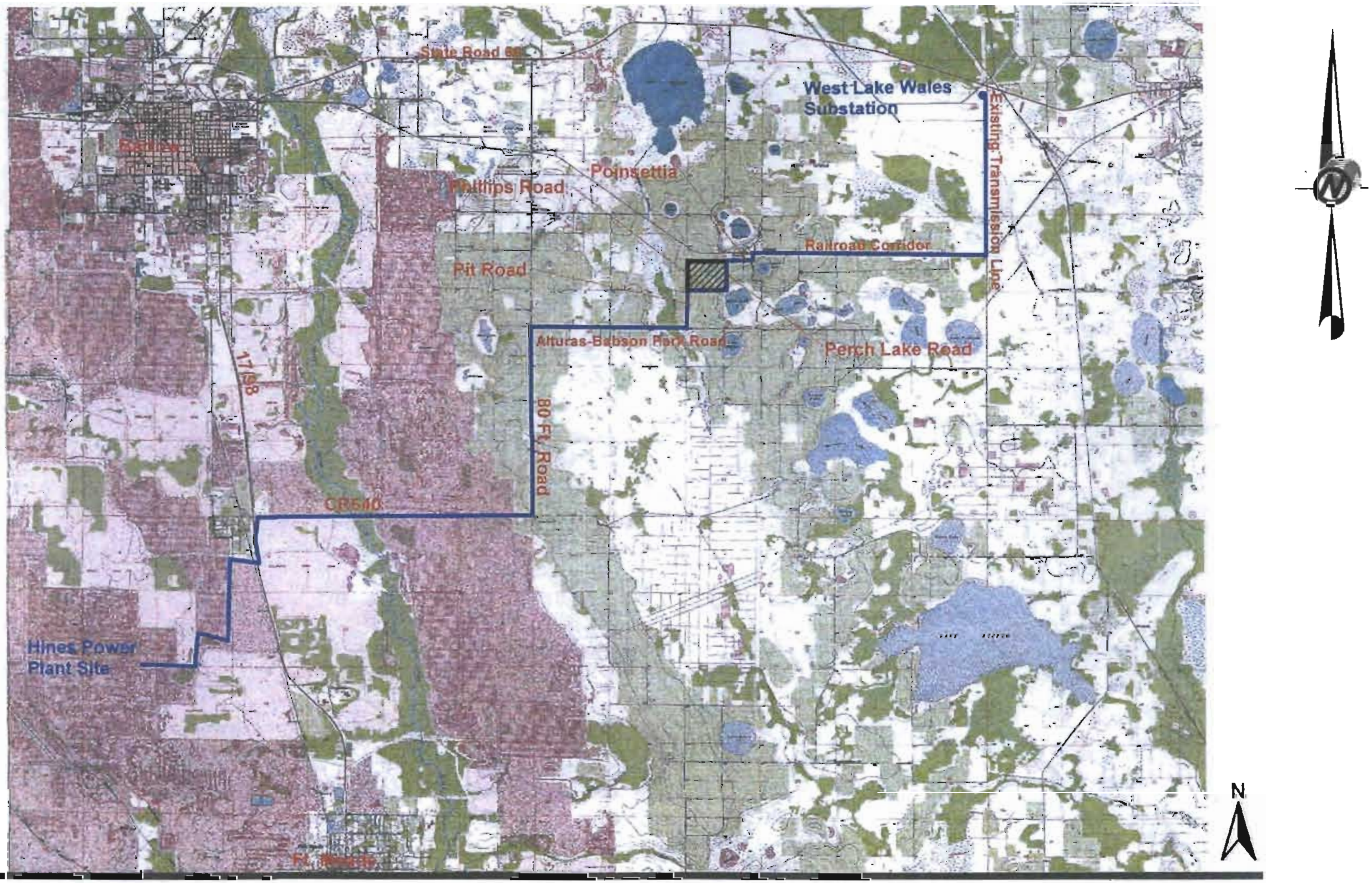
DATE: August 17, 2004

Enclosed are five copies of the substitute color figures that we discussed by telephone earlier this week. Please substitute these pages in the copies of the Progress Energy Florida Hines 1 certification application. The additional copies that will be distributed to other agencies will have these color figures, not black and white ones.

Thanks.

Mike,
These replace the indicated pages in your copy of the SCA.
Thanks,

Post Office Box 6526 Tallahassee, Florida 32314 123 South Calhoun Street (32301) 850.222.7500 850.224.8551 fax www.hgslaw.com
Post Office Box 6526 Tallahassee, Florida 32314 123 South Calhoun Street (32301) 850.222.7500 850.224.8551 fax www.hgslaw.com

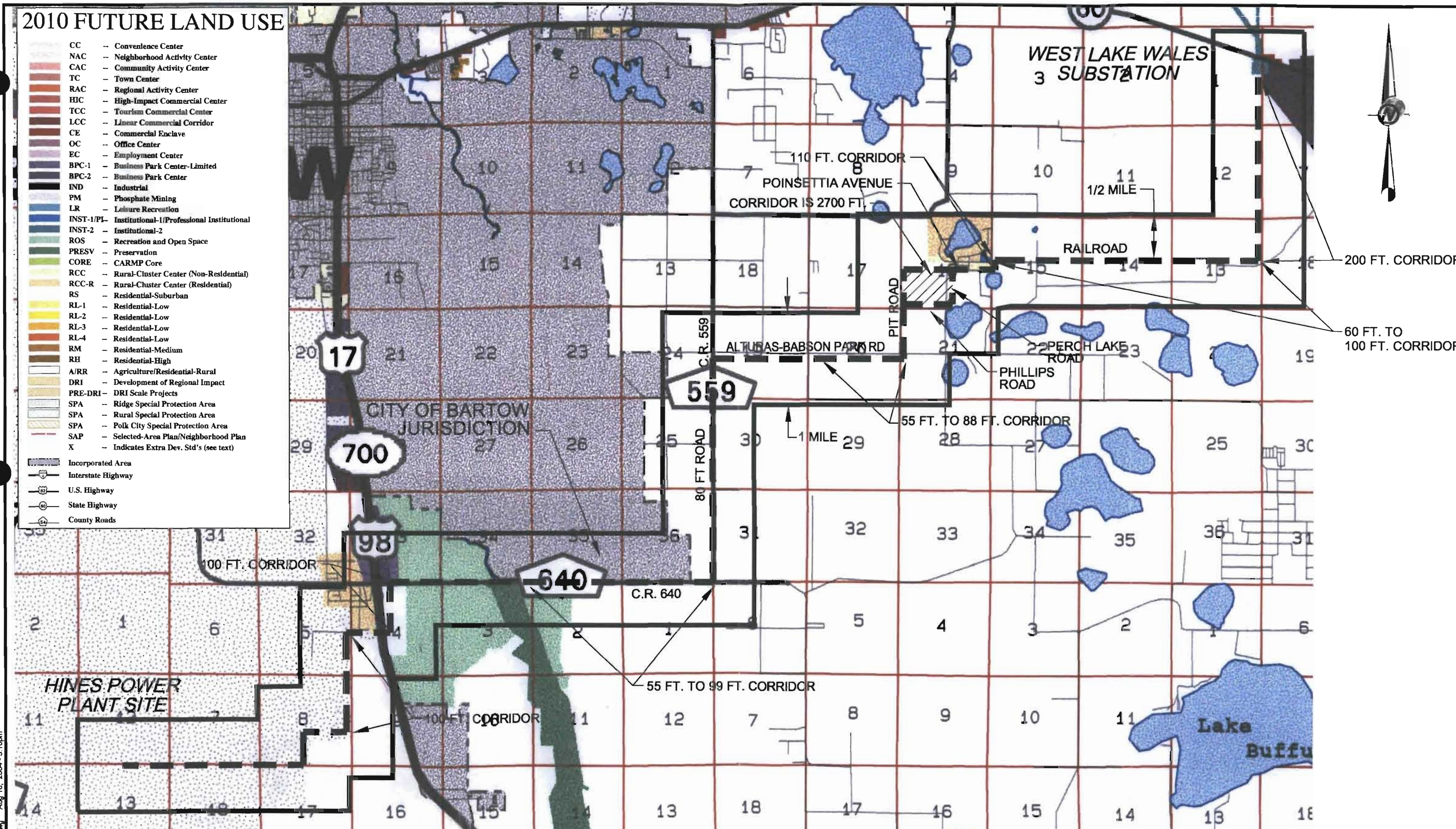


Proposed Hines-West Lake Wales Transmission Line

Polk County

Progress Energy	SCALE AS SHOWN	TITLE **PROPOSED HINES-WEST LAKE WALES TRANSMISSION LINE CORRIDOR ROUTE**
	DATE 8/10/04	
	DESIGN MM	
	CADD KT	
FILE No. 0439518 ALT ROUTES.dwg	CHECK SO	
PROJECT No. 043-9518 REV. 1	REVIEW MM	HINES ENERGY COMPLEX — FIGURE 6.1

Drawing file: 0439518 ALT ROUTES.dwg Aug 16, 2004 - 3:07pm



SOURCE: COMPREHENSIVE PLAN, POLK COUNTY, FLORIDA, GENERALIZED FUTURE LAND USE; PREPARED BY THE BOCC PLANNING DIVISION (PLOT DATE: 6/23/04)

Progress Energy

LEGEND

NEW 230 kV TRANSMISSION LINE CORRIDOR (55 FT. EXCEPT WHERE NOTED)

Golder Associates
Tampa, Florida

SCALE	1" = 1 MILE'
DATE	08/03/04
DESIGN	MM
CADD	KT
CHECK	REW
REVIEW	MM

FILE No. 0439518 FIG 6-1-6-1.dwg

PROJECT No. 043-9518 REV. 1

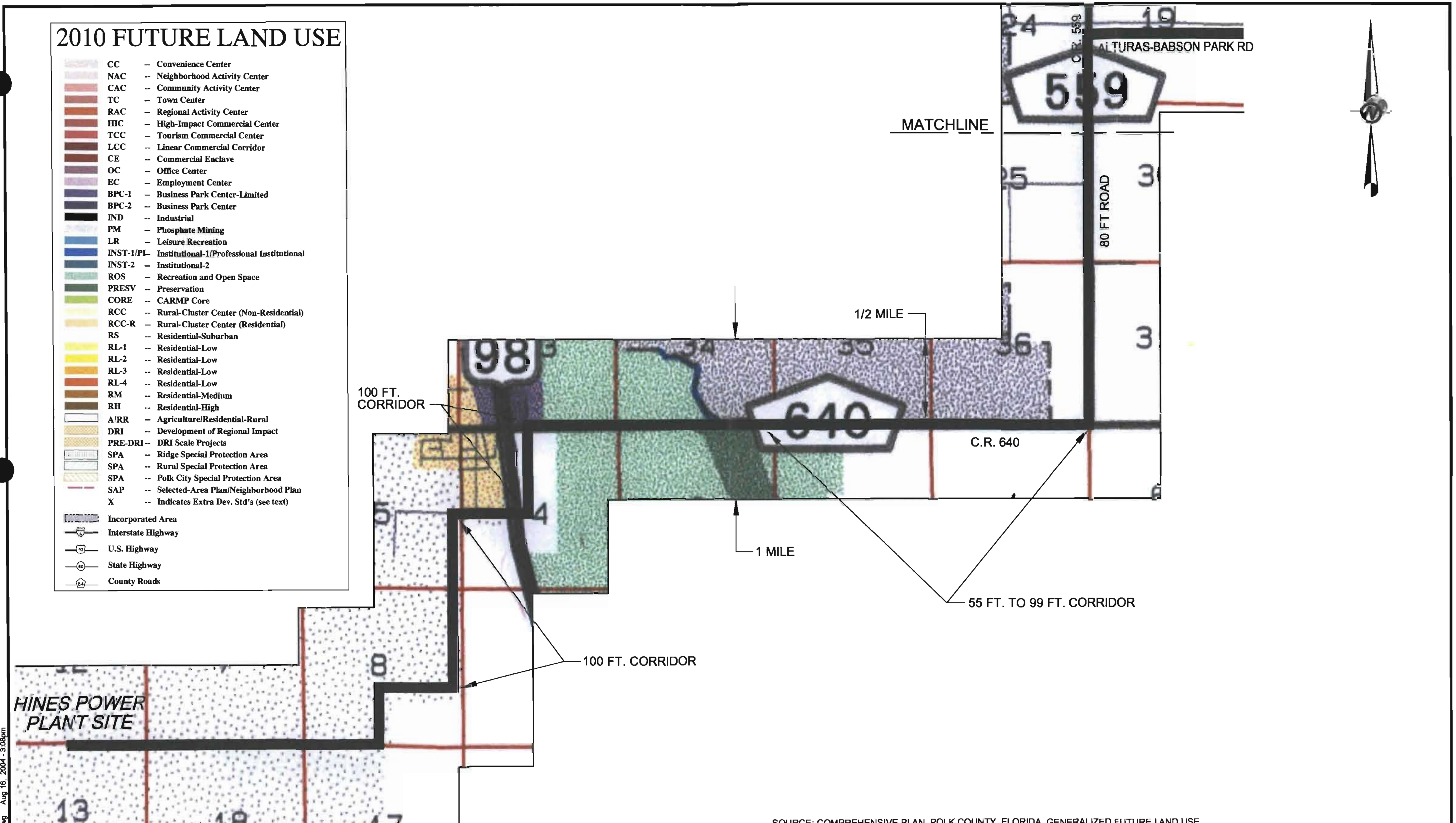
TITLE

GOVERNMENTAL JURISDICTIONS POLK COUNTY

HINES ENERGY COMPLEX

FIGURE 6.1.6.1

Drawing file: 0439518-6-1.dwg Aug 16, 2004 - 3:10pm



SOURCE: COMPREHENSIVE PLAN, POLK COUNTY, FLORIDA, GENERALIZED FUTURE LAND USE PREPARED BY THE BOCC PLANNING DIVISION (PLOT DATE: 6/23/04)

Progress Energy

LEGEND

NEW 230 kV TRANSMISSION LINE CORRIDOR (55 FT. EXCEPT WHERE NOTED)

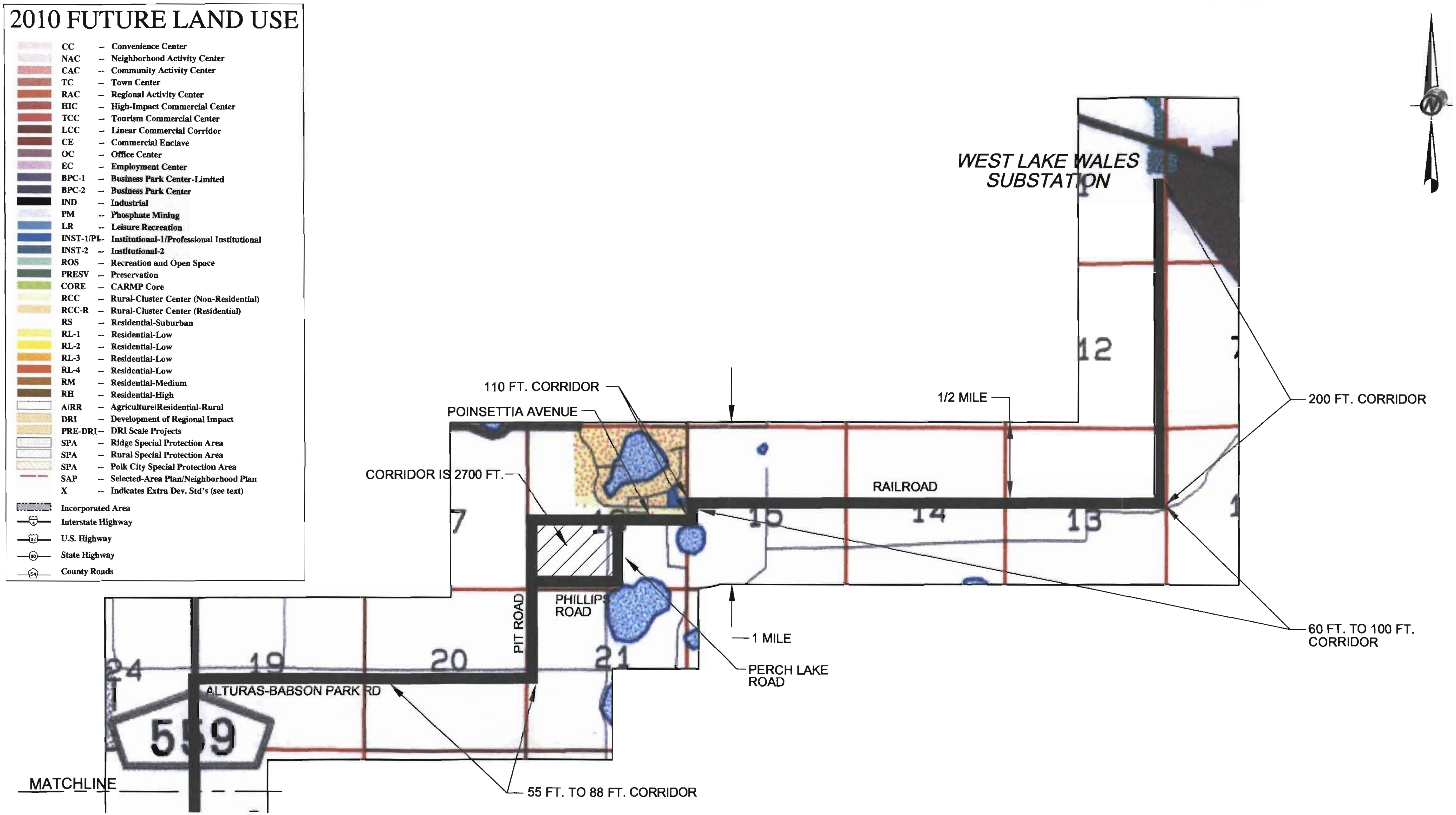
Golder Associates
Tampa, Florida

SCALE	1" = 3,000'	TITLE	2010 FUTURE LAND USE PLAN CATEGORIES AND CORRIDOR POLK COUNTY
DATE	08/03/04		
DESIGN	MM		
CADD	KT		
CHECK	REW		
REVIEW	MM		HINES ENERGY COMPLEX

FILE No. 0439518 FIG 6-1-6-2.dwg
PROJECT No. 043-9518 REV. 1

FIGURE 6.1.6.2A

Drawing file: 0439518 6-2.dwg Aug 16, 2004 - 3:08pm



SOURCE: COMPREHENSIVE PLAN, POLK COUNTY, FLORIDA, GENERALIZED FUTURE LAND USE PREPARED BY THE BOCC PLANNING DIVISION (PLOT DATE: 6/23/04)

Progress Energy

LEGEND

NEW 230 kV TRANSMISSION LINE CORRIDOR (55 FT. EXCEPT WHERE NOTED)

Golder Associates
Tampa, Florida

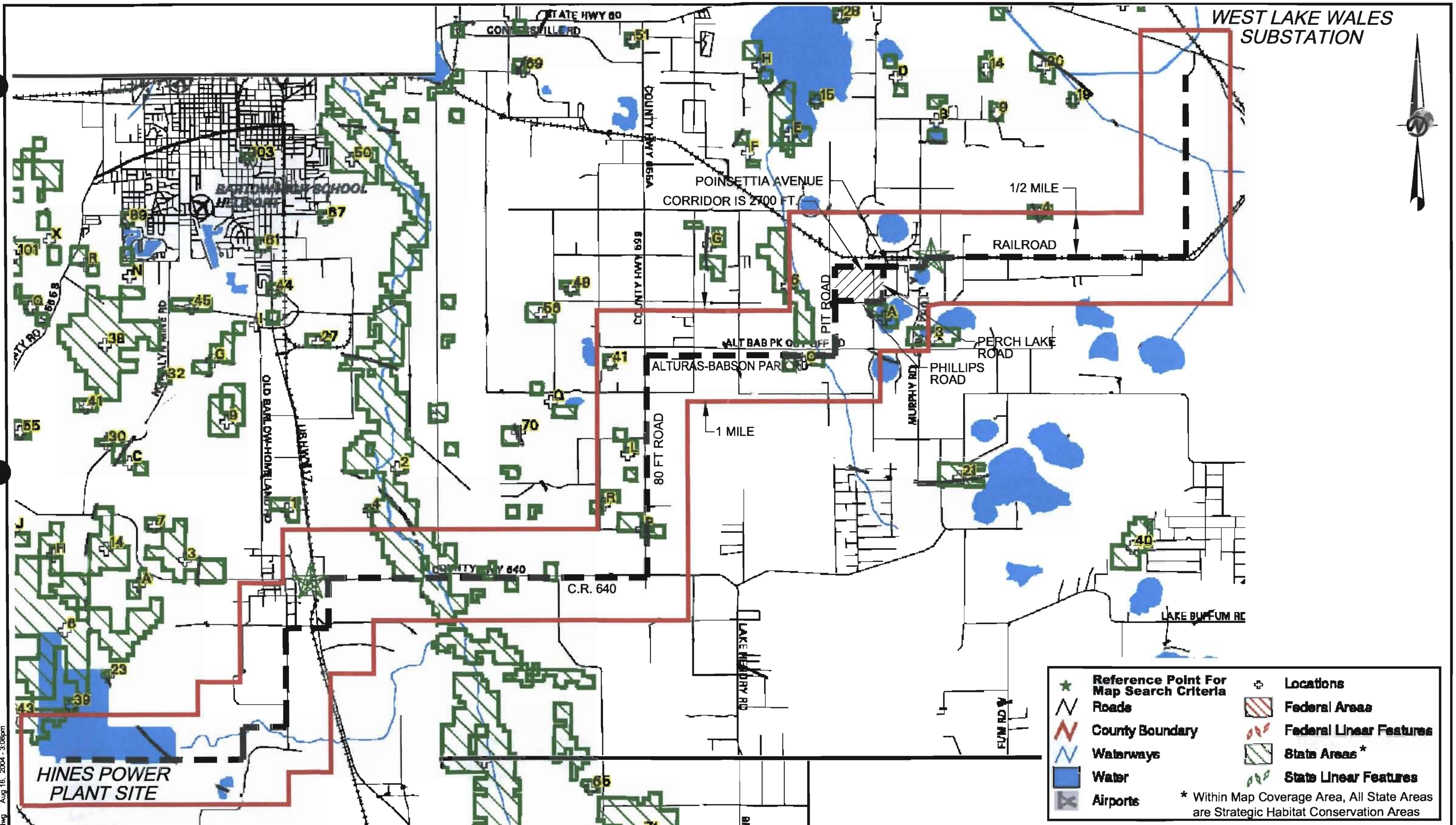
SCALE	1" = 3,000'	TITLE	2010 FUTURE LAND USE PLAN CATEGORIES AND CORRIDOR POLK COUNTY
DATE	08/03/04		
DESIGN	MM		
CADD	KT		
CHECK	REW		
REVIEW	MM		HINES ENERGY COMPLEX

FILE No. 0439518 FIG 6-1-6-2.dwg

PROJECT No. 043-9518 REV. 1

FIGURE 6.1.6.2B

Drawing file: 0439518 6-2.dwg Aug 16, 2004 - 3:08pm



SOURCE: EDR, INC., NEPA CHECK, 8/3/04.

Progress Energy

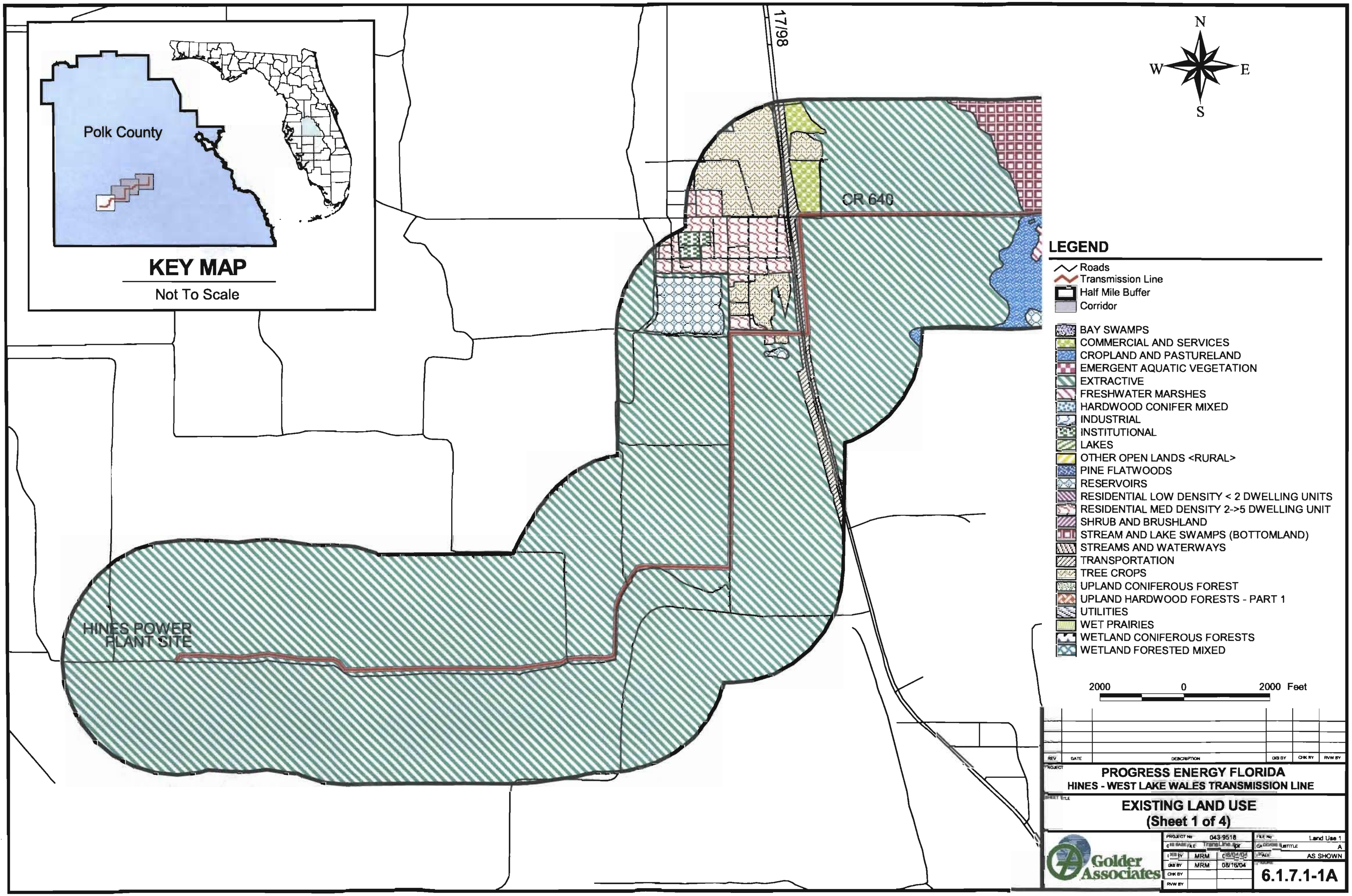
LEGEND

NEW 230 kV TRANSMISSION LINE CORRIDOR (WIDTH NOT TO SCALE)

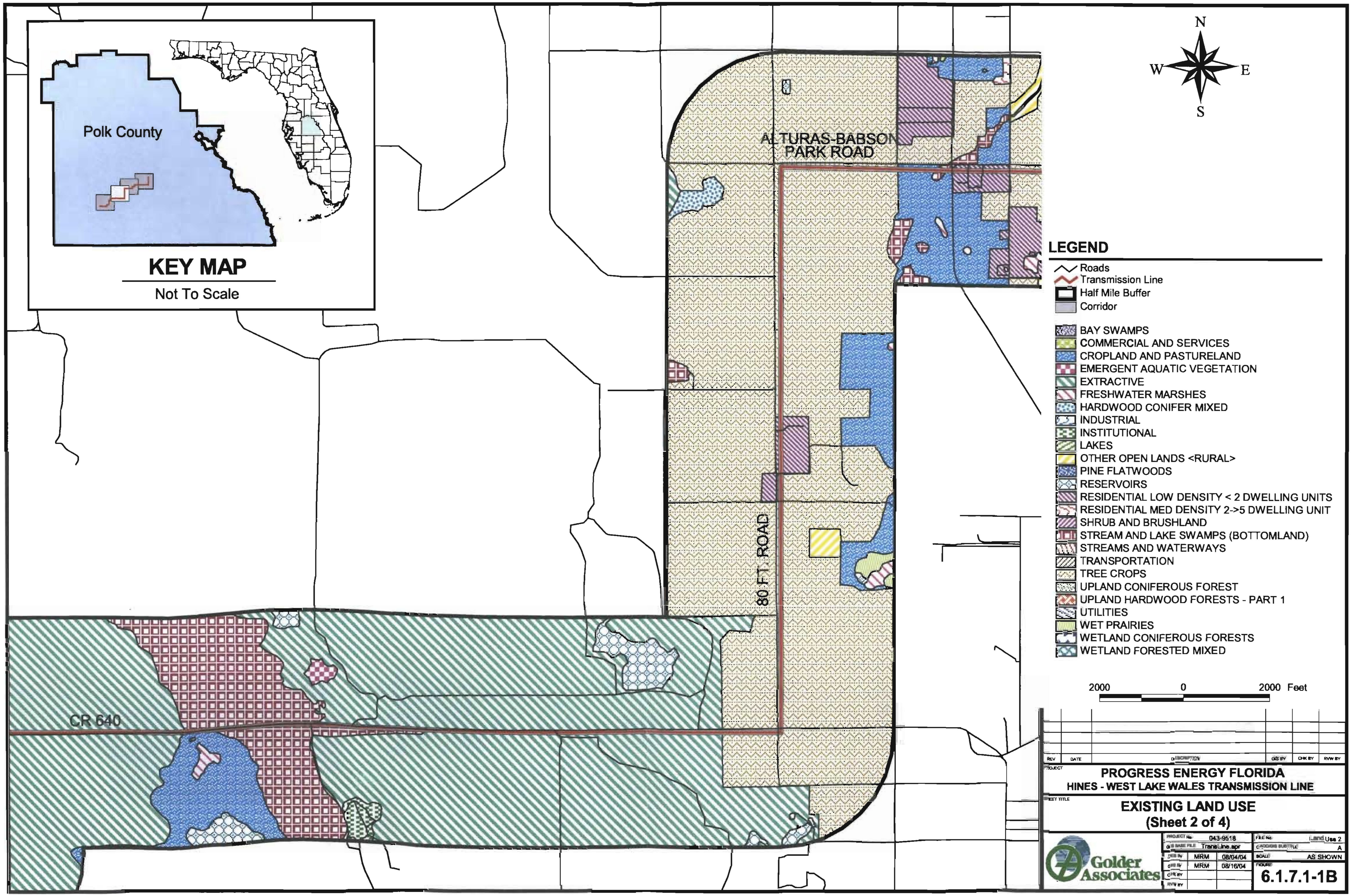
Golder Associates
Tampa, Florida

SCALE	1" = 1 MILE	TITLE	SCENIC, CULTURAL AND NATURAL LANDMARKS
DATE	08/03/04		
DESIGN	MM		
CADD	KT		
CHECK	REW		
REVIEW	MM		HINES ENERGY COMPLEX
FILE No.	0439518 FIG 6-1-6-4.dwg	FIGURE	6.1.6.4
PROJECT No.	043-9518	REV.	1

Drawing file: 0439518...1-6-4.dwg Aug 16, 2004 - 3:08pm



17/98
CR 640
HINES POWER PLANT SITE
N
W
E
S
Polk County
KEY MAP
Not To Scale
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
BAY SWAMPS
COMMERCIAL AND SERVICES
CROPLAND AND PASTURELAND
EMERGENT AQUATIC VEGETATION
EXTRACTIVE
FRESHWATER MARSHES
HARDWOOD CONIFER MIXED
INDUSTRIAL
INSTITUTIONAL
LAKES
OTHER OPEN LANDS <RURAL>
PINE FLATWOODS
RESERVOIRS
RESIDENTIAL LOW DENSITY < 2 DWELLING UNITS
RESIDENTIAL MED DENSITY 2->5 DWELLING UNIT
SHRUB AND BRUSHLAND
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
TRANSPORTATION
TREE CROPS
UPLAND CONIFEROUS FOREST
UPLAND HARDWOOD FORESTS - PART 1
UTILITIES
WET PRAIRIES
WETLAND CONIFEROUS FORESTS
WETLAND FORESTED MIXED
2000 0 2000 Feet
REV
DATE
DESCRIPTION
GIS BY
CHK BY
RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
EXISTING LAND USE
(Sheet 1 of 4)
Golder Associates
PROJECT No 043-9518
FILE No Land Use 1
MRM
GIS BY MRM 08/16/04
CHK BY
RVW BY
AS SHOWN
6.1.7.1-1A



KEY MAP
Not To Scale
Polk County
N
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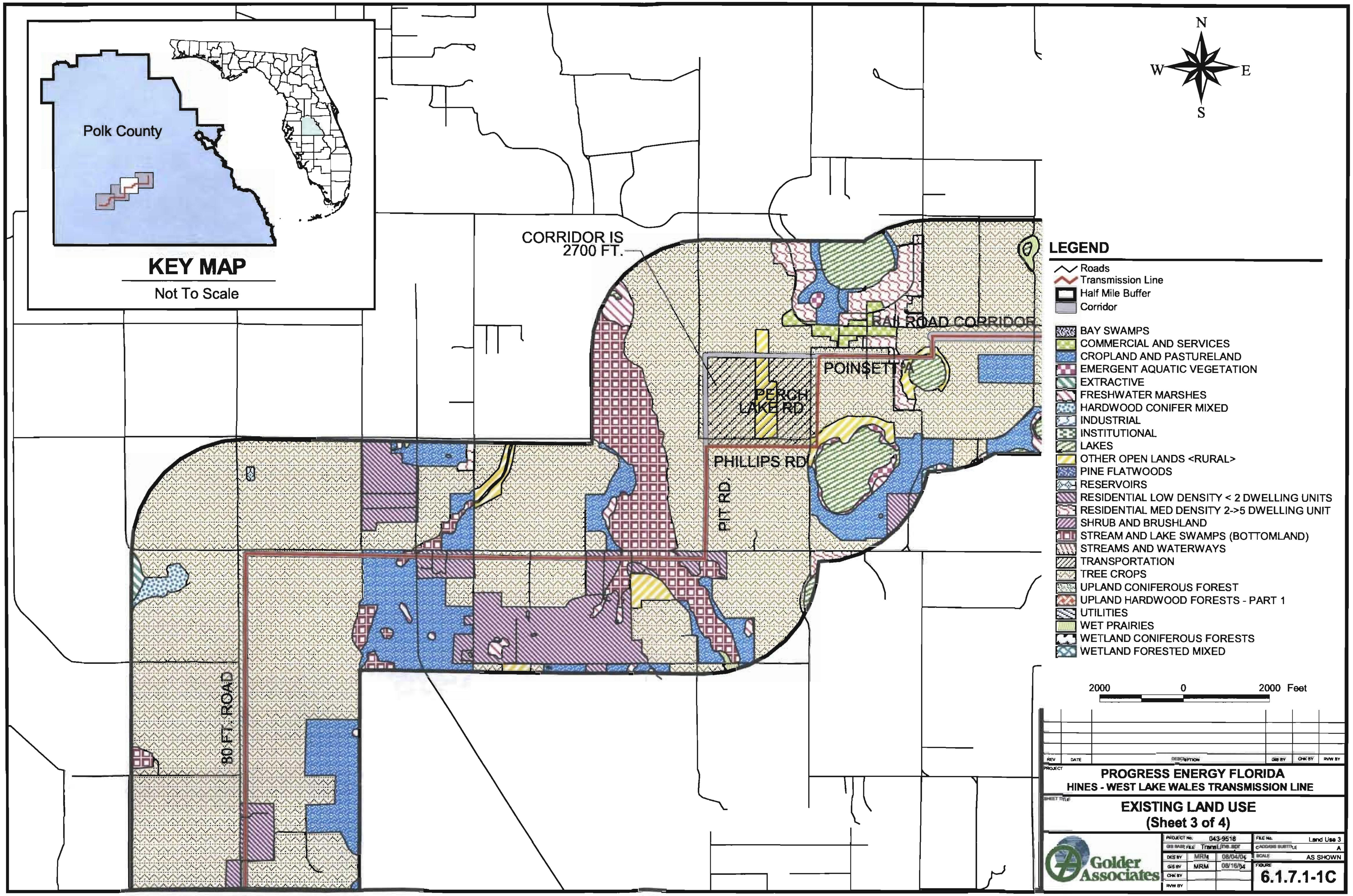
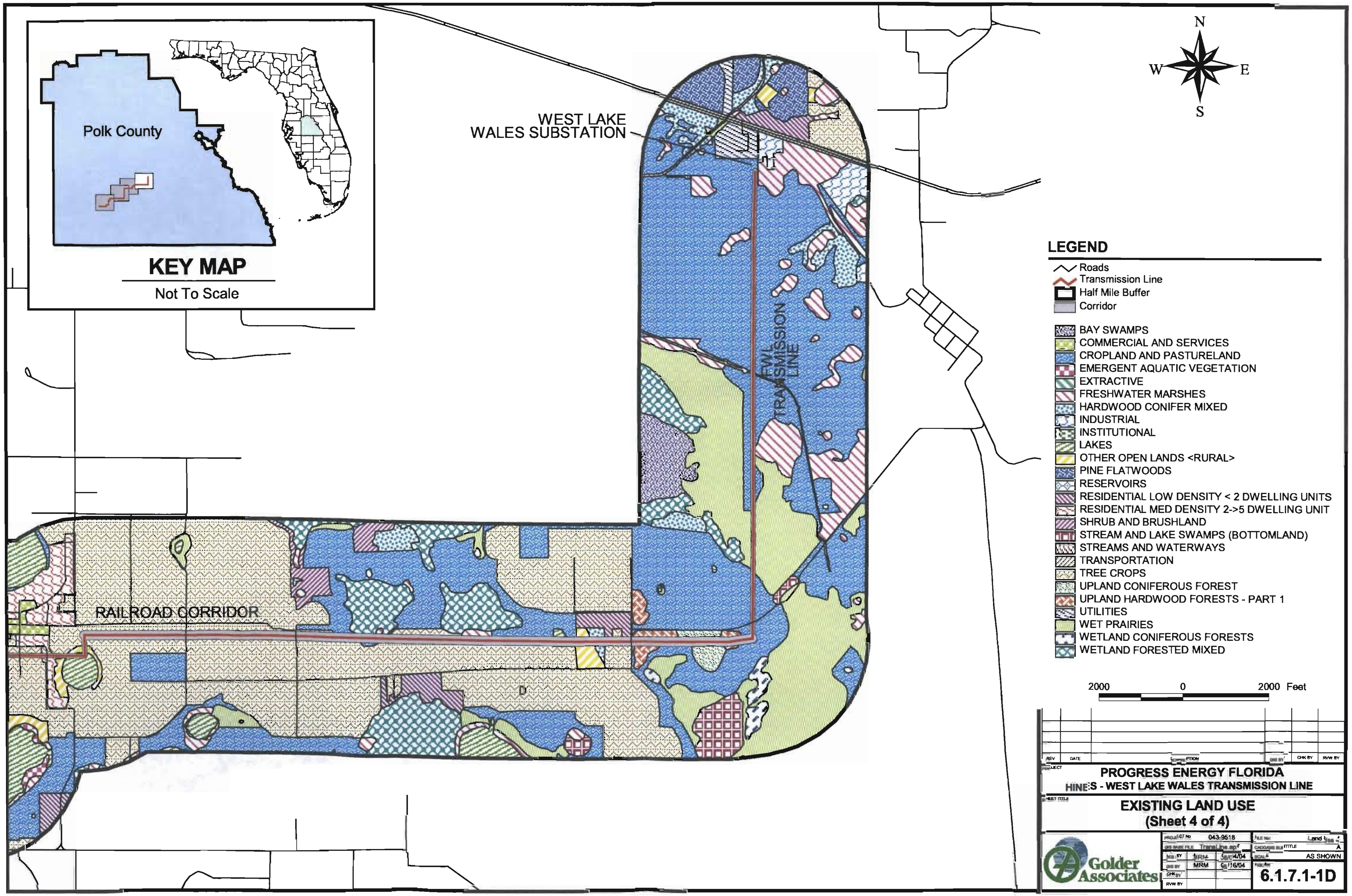
S
ALTURAS-BABSON PARK ROAD
80 FT. ROAD
CR 640
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
BAY SWAMPS
COMMERCIAL AND SERVICES
CROPLAND AND PASTURELAND
EMERGENT AQUATIC VEGETATION
EXTRACTIVE
FRESHWATER MARSHES
HARDWOOD CONIFER MIXED
INDUSTRIAL
INSTITUTIONAL
LAKES
OTHER OPEN LANDS <RURAL>
PINE FLATWOODS
RESERVOIRS
RESIDENTIAL LOW DENSITY < 2 DWELLING UNITS
RESIDENTIAL MED DENSITY 2->5 DWELLING UNIT
SHRUB AND BRUSHLAND
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
TRANSPORTATION
TREE CROPS
UPLAND CONIFEROUS FOREST
UPLAND HARDWOOD FORESTS - PART 1
UTILITIES
WET PRAIRIES
WETLAND CONIFEROUS FORESTS
WETLAND FORESTED MIXED
2000 0 2000 Feet
REV DATE DESCRIPTION GIS BY CHK BY RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
EXISTING LAND USE
(Sheet 2 of 4)
Golder Associates
PROJECT No. 043-9518
GIS BASE FILE TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Land Use 2
CADD/GIS SUBTITLE A
SCALE AS SHOWN
FIGURE
6.1.7.1-1B



KEY MAP
Not To Scale
Polk County
N
S
E
W
CORRIDOR IS 2700 FT.
RAILROAD CORRIDOR
POINSETTIA
PERCH LAKE RD
PHILLIPS RD
PIT RD
80 FT. ROAD
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
BAY SWAMPS
COMMERCIAL AND SERVICES
CROPLAND AND PASTURELAND
EMERGENT AQUATIC VEGETATION
EXTRACTIVE
FRESHWATER MARSHES
HARDWOOD CONIFER MIXED
INDUSTRIAL
INSTITUTIONAL
LAKES
OTHER OPEN LANDS <RURAL>
PINE FLATWOODS
RESERVOIRS
RESIDENTIAL LOW DENSITY < 2 DWELLING UNITS
RESIDENTIAL MED DENSITY 2->5 DWELLING UNIT
SHRUB AND BRUSHLAND
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
TRANSPORTATION
TREE CROPS
UPLAND CONIFEROUS FOREST
UPLAND HARDWOOD FORESTS - PART 1
UTILITIES
WET PRAIRIES
WETLAND CONIFEROUS FORESTS
WETLAND FORESTED MIXED
2000 0 2000 Feet
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
EXISTING LAND USE
(Sheet 3 of 4)
043-9518
Land Use 3
A
AS SHOWN
MRM 08/04/04
MRM 08/16/04
Golder Associates
6.1.7.1-1C



Polk County
KEY MAP
Not To Scale
N
W
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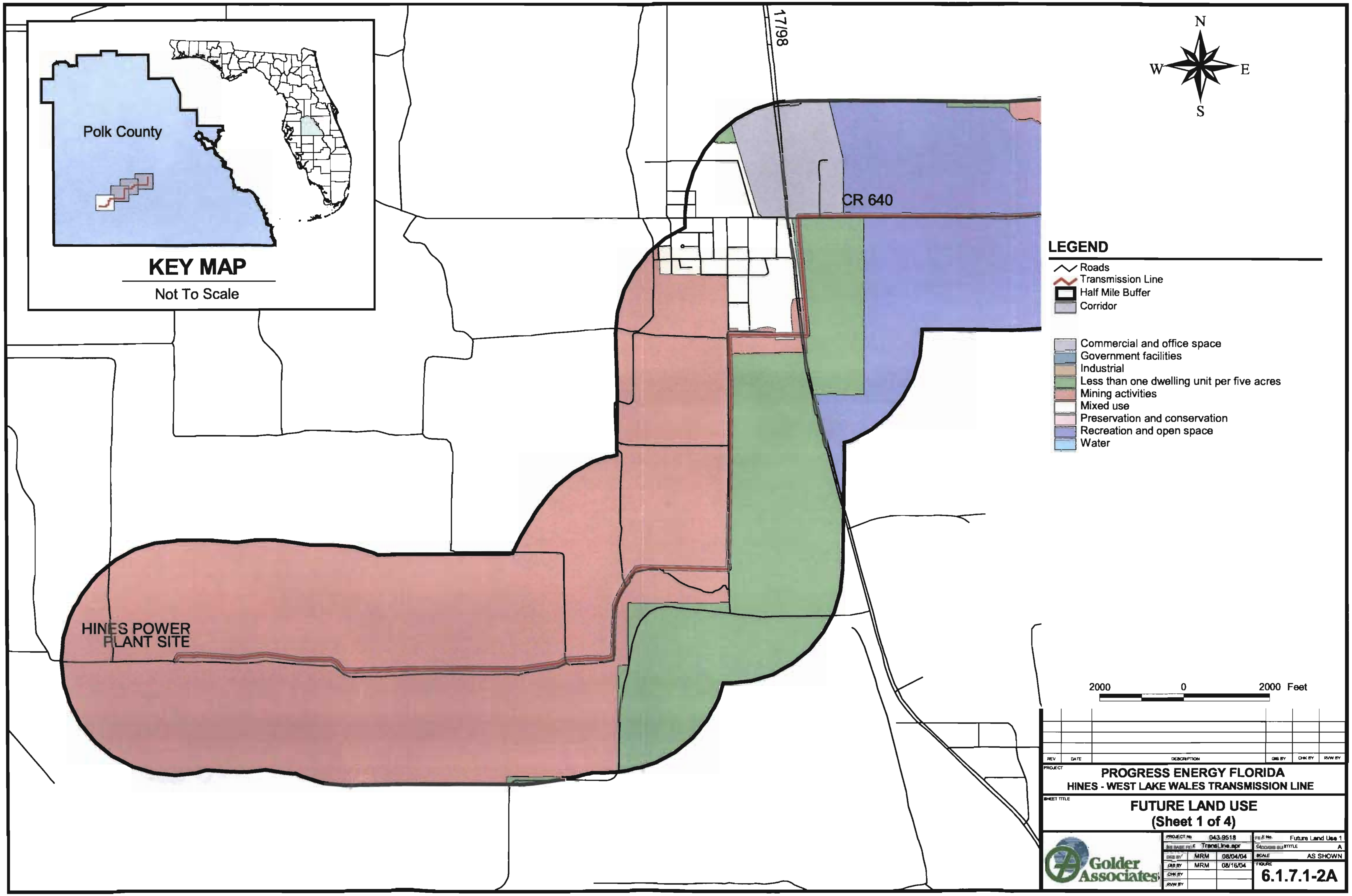
S
WEST LAKE WALES SUBSTATION
RAILROAD CORRIDOR
WL TRANSMISSION LINE
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
BAY SWAMPS
COMMERCIAL AND SERVICES
CROPLAND AND PASTURELAND
EMERGENT AQUATIC VEGETATION
EXTRACTIVE
FRESHWATER MARSHES
HARDWOOD CONIFER MIXED
INDUSTRIAL
INSTITUTIONAL
LAKES
OTHER OPEN LANDS <RURAL>
PINE FLATWOODS
RESERVOIRS
RESIDENTIAL LOW DENSITY < 2 DWELLING UNITS
RESIDENTIAL MED DENSITY 2->5 DWELLING UNIT
SHRUB AND BRUSHLAND
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
TRANSPORTATION
TREE CROPS
UPLAND CONIFEROUS FOREST
UPLAND HARDWOOD FORESTS - PART 1
UTILITIES
WET PRAIRIES
WETLAND CONIFEROUS FORESTS
WETLAND FORESTED MIXED
2000 0 2000 Feet
REV
DATE
CHK BY
RVW BY
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
EXISTING LAND USE
(Sheet 4 of 4)
Golder Associates
043-9518
MRM
MRM
AS SHOWN
RVW BY
6.1.7.1-1D



REV	DATE	DESCRIPTION	GIS BY	CHK BY	RVW BY

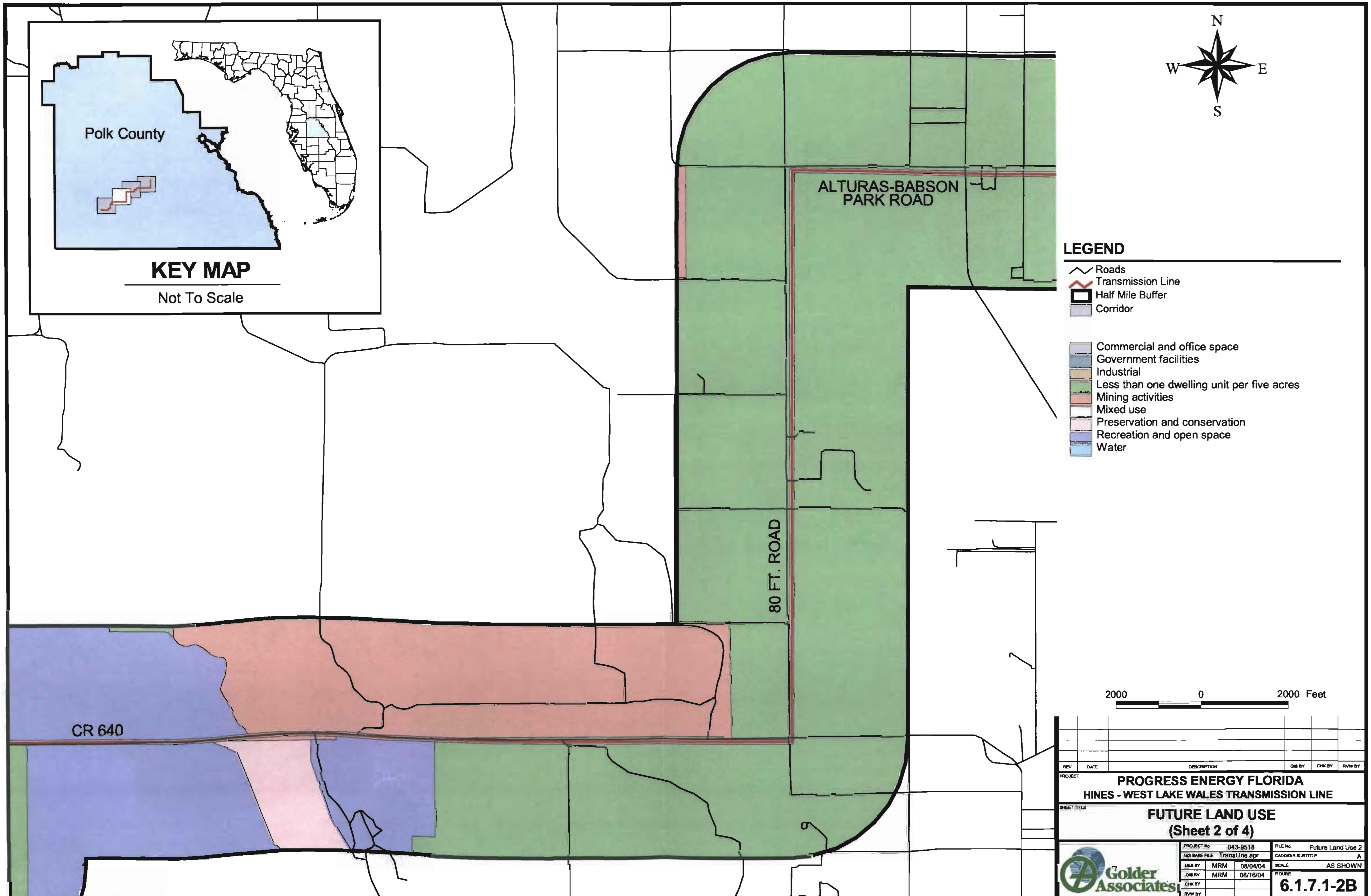
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE

SHEET TITLE
FUTURE LAND USE
(Sheet 1 of 4)

Golder Associates

PROJECT No.	043-9518	
GIS BASE FILE	TransLine.apr	
DES BY	MRM	08/04/04
GIS BY	MRM	08/16/04
CHK BY		
RVW BY		

FILE No.	Future Land Use 1
CADD/GIS SUBTITLE	A
SCALE	AS SHOWN
FIGURE	6.1.7.1-2A



KEY MAP
Not To Scale
Polk County
N
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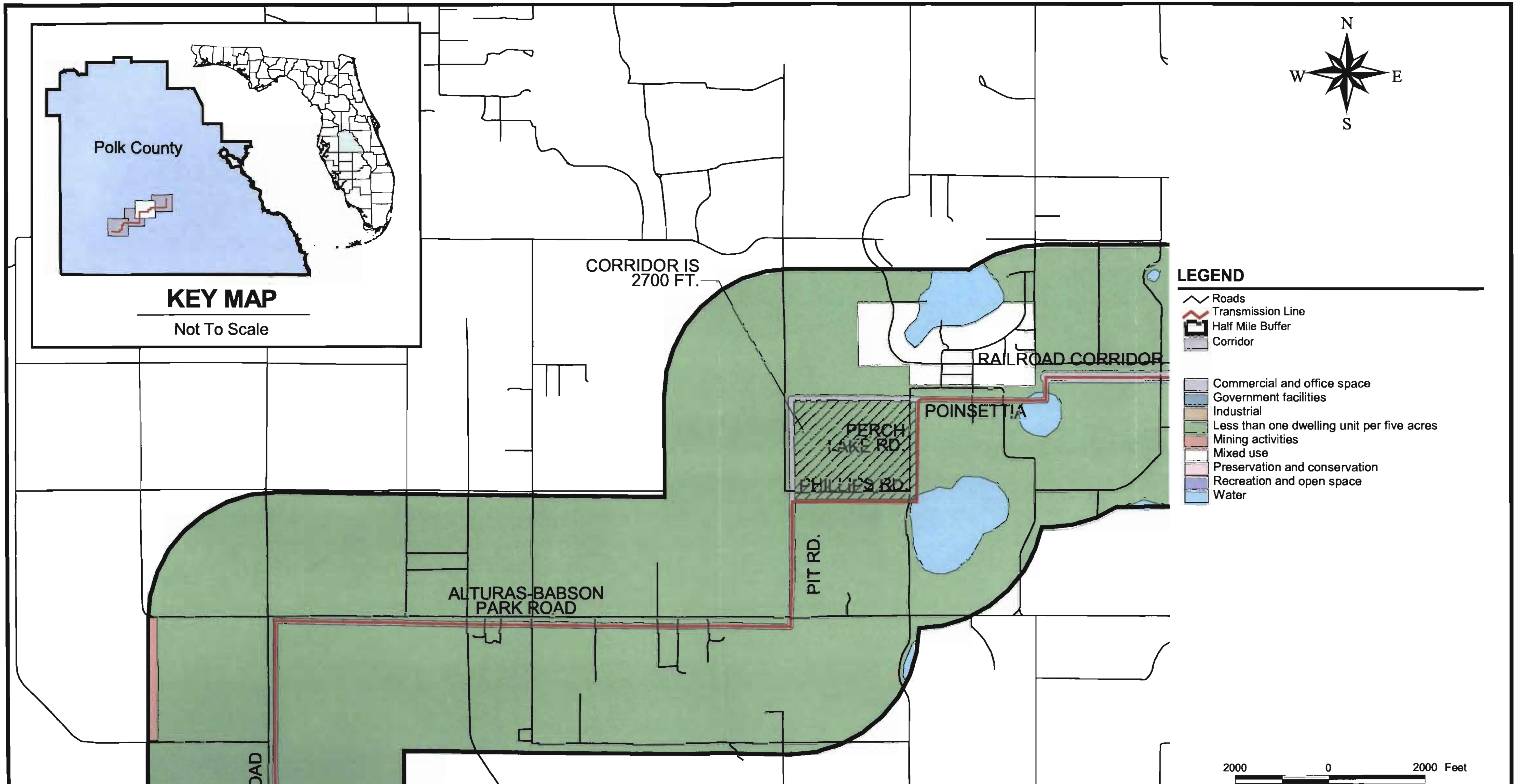
S
ALTURAS-BABSON PARK ROAD
80 FT. ROAD
CR 640
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
Commercial and office space
Government facilities
Industrial
Less than one dwelling unit per five acres
Mining activities
Mixed use
Preservation and conservation
Recreation and open space
Water
2000 0 2000 Feet
REV
DATE
DESCRIPTION
GIS BY
CHK BY
RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
FUTURE LAND USE
(Sheet 2 of 4)
Golder Associates
PROJECT No 043-9518
GIS BASE FILE TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Future Land Use 2
CADD/GIS SUBTITLE A
SCALE AS SHOWN
FIGURE
6.1.7.1-2B



REV	DATE	DESCRIPTION	GIS BY	CHK BY	RVW BY

PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE

SHEET TITLE
FUTURE LAND USE
(Sheet 3 of 4)

Golder Associates

PROJECT No.	043-9518		FILE No.	Future Land Use 3
GIS BASE FILE	TransLine.apr		CADD/GIS SUBTITLE	A
DES BY	MRM	08/04/04	SCALE	AS SHOWN
GIS BY	MRM	08/16/04	FIGURE	6.1.7.1-2C
CHK BY				
RVW BY				


KEY MAP
Not To Scale
Polk County
N
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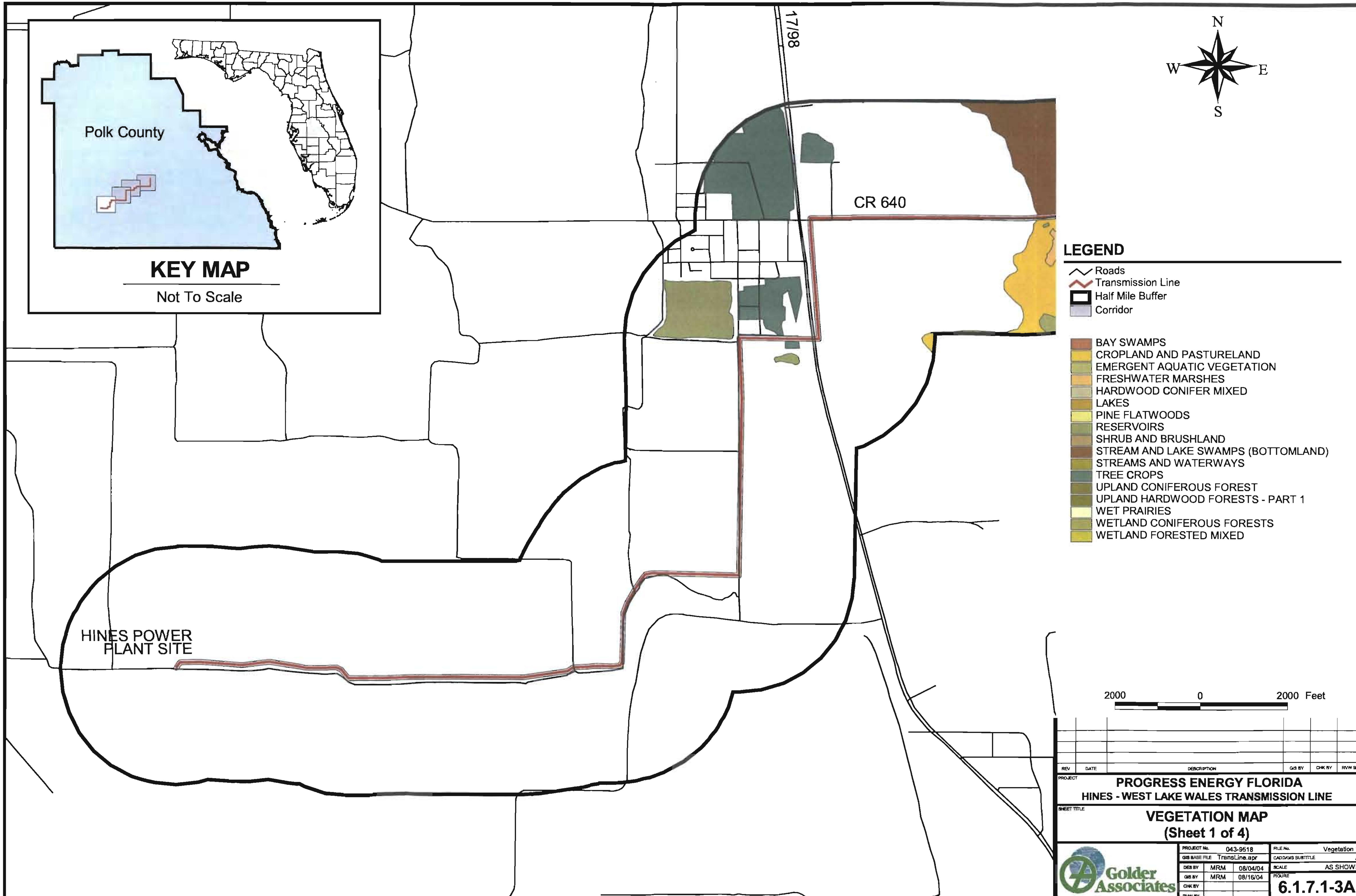
WEST LAKE
WALES SUBSTATION
RAILROAD CORRIDOR
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
Commercial and office space
Government facilities
Industrial
Less than one dwelling unit per five acres
Mining activities
Mixed use
Preservation and conservation
Recreation and open space
Water
2000 0 2000 Feet
REV
DATE
DESCRIPTION
GIS BY
CHK BY
RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
FUTURE LAND USE
(Sheet 4 of 4)
Golder Associates
PROJECT No. 043-9518
GIS BASE FILE TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Future Land Use 4
SCALE AS SHOWN
FIGURE
6.1.7.1-2D



KEY MAP
Not To Scale
Polk County
17/98
CR 640
HINES POWER PLANT SITE
N
W
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LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
BAY SWAMPS
CROPLAND AND PASTURELAND
EMERGENT AQUATIC VEGETATION
FRESHWATER MARSHES
HARDWOOD CONIFER MIXED
LAKES
PINE FLATWOODS
RESERVOIRS
SHRUB AND BRUSHLAND
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
TREE CROPS
UPLAND CONIFEROUS FOREST
UPLAND HARDWOOD FORESTS - PART 1
WET PRAIRIES
WETLAND CONIFEROUS FORESTS
WETLAND FORESTED MIXED
2000 0 2000 Feet
REV DATE DESCRIPTION GIS BY CHK BY RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
VEGETATION MAP
(Sheet 1 of 4)
PROJECT No. 043-9518
GIS BASE FILE TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Vegetation 1
CADD/GIS SUBTITLE A
SCALE AS SHOWN
FIGURE
6.1.7.1-3A
Golder Associates

REV	DATE	DESCRIPTION	GIS BY	CHK BY	RVW BY

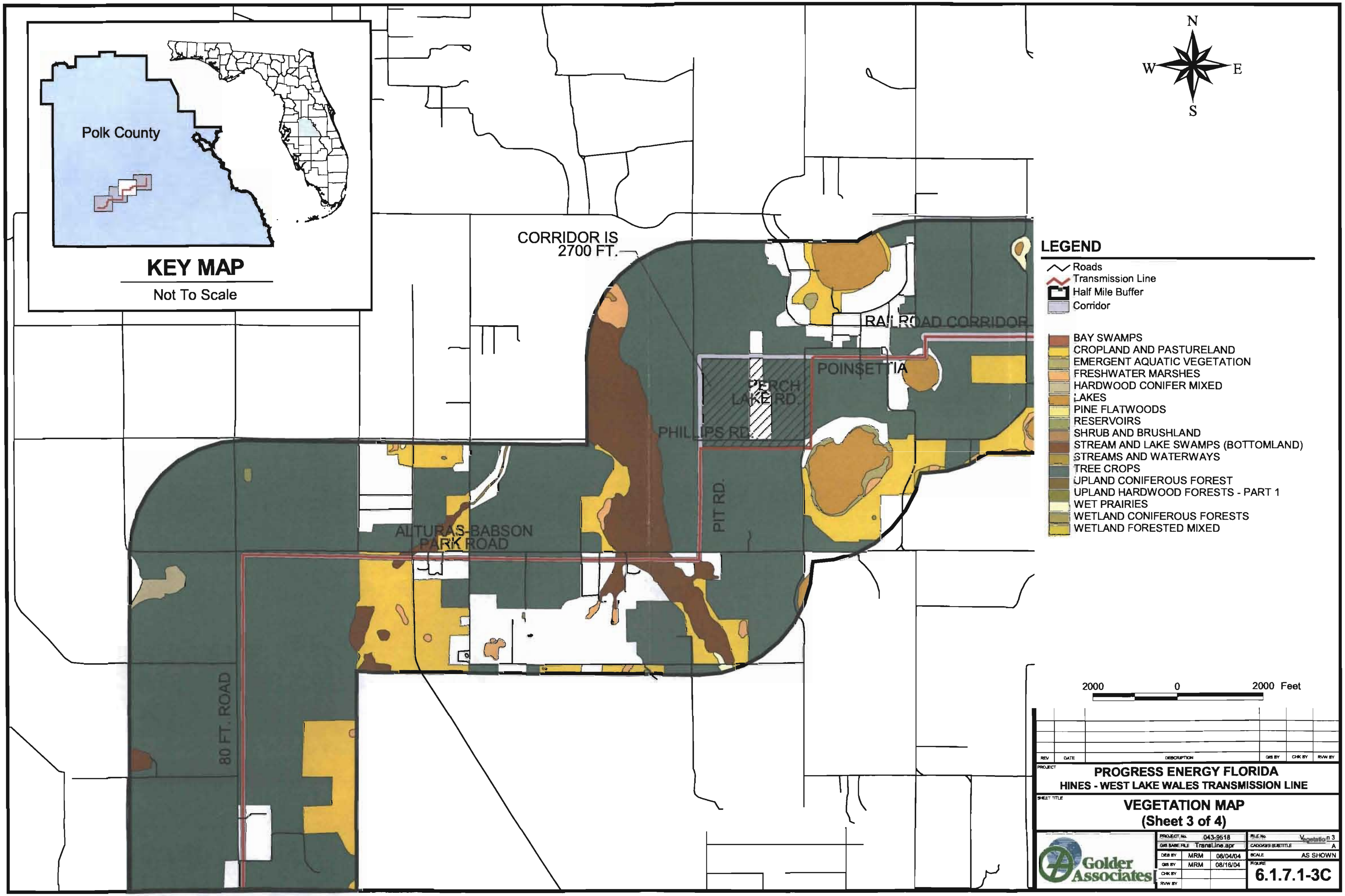
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE

SHEET TITLE
VEGETATION MAP
(Sheet 2 of 4)

Golder Associates

PROJECT No.	043-9518	
GIS BASE FILE	TransLine.apr	
DES BY	MRM	08/04/04
GIS BY	MRM	08/16/04
CHK BY		
RVW BY		

FILE No	Vegetation 2
CADD/GIS SUBTITLE	A
SCALE	AS SHOWN
FIGURE	6.1.7.1-3B



KEY MAP
Not To Scale
Polk County
N
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W
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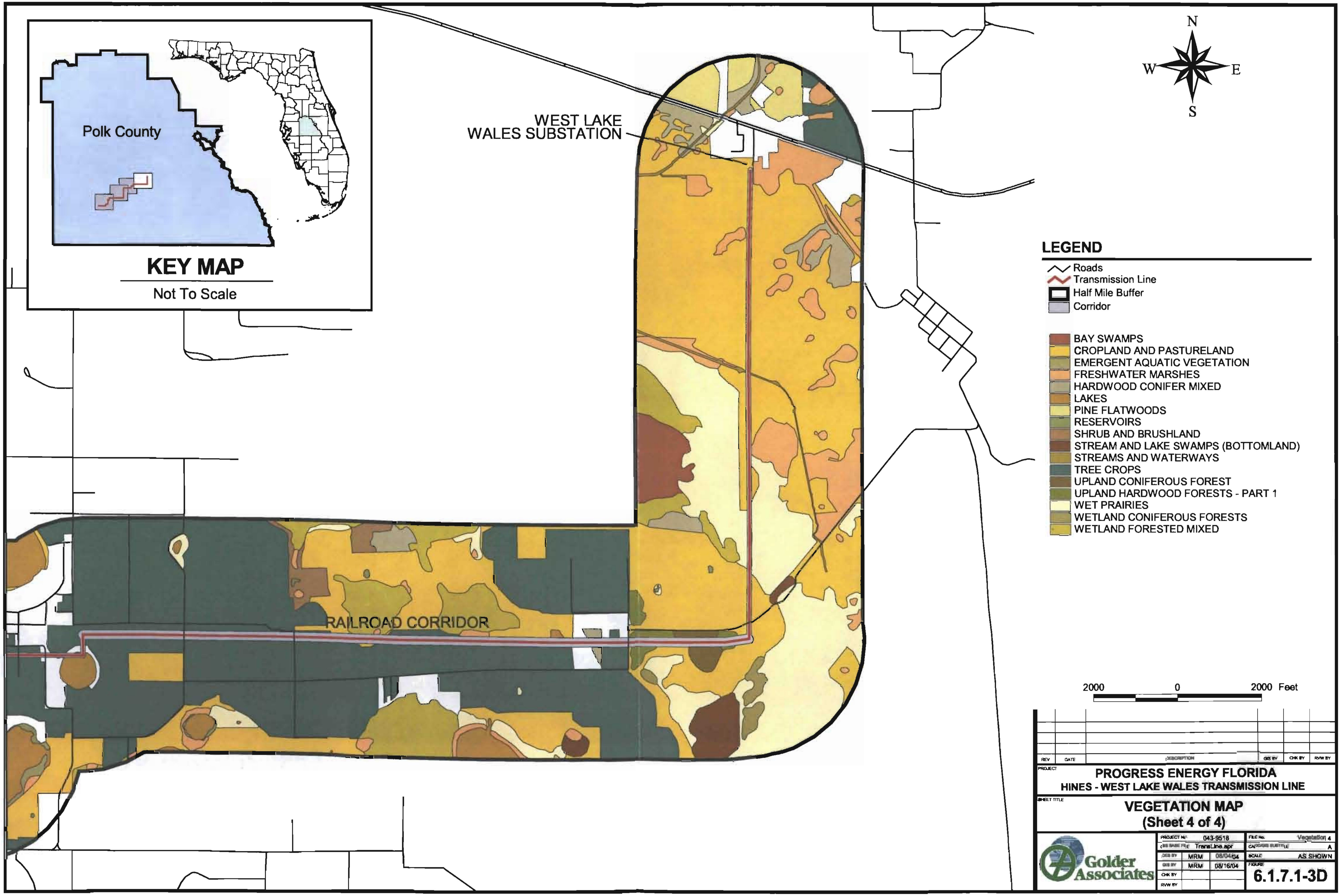
CORRIDOR IS 2700 FT.
RAILROAD CORRIDOR
POINSETTIA
PERCH LAKE RD.
PHILLIPS RD.
PIT RD.
ALTURAS-BABSON PARK ROAD
80 FT. ROAD
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
BAY SWAMPS
CROPLAND AND PASTURELAND
EMERGENT AQUATIC VEGETATION
FRESHWATER MARSHES
HARDWOOD CONIFER MIXED
LAKES
PINE FLATWOODS
RESERVOIRS
SHRUB AND BRUSHLAND
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
TREE CROPS
UPLAND CONIFEROUS FOREST
UPLAND HARDWOOD FORESTS - PART 1
WET PRAIRIES
WETLAND CONIFEROUS FORESTS
WETLAND FORESTED MIXED
2000 0 2000 Feet
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
VEGETATION MAP
(Sheet 3 of 4)
Golder Associates
043-9518
TransLine.apr
MRM 08/04/04
MRM 08/16/04
AS SHOWN
6.1.7.1-3C



Polk County
KEY MAP
Not To Scale
WEST LAKE
WALES SUBSTATION
RAILROAD CORRIDOR
N
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LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
BAY SWAMPS
CROPLAND AND PASTURELAND
EMERGENT AQUATIC VEGETATION
FRESHWATER MARSHES
HARDWOOD CONIFER MIXED
LAKES
PINE FLATWOODS
RESERVOIRS
SHRUB AND BRUSHLAND
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
TREE CROPS
UPLAND CONIFEROUS FOREST
UPLAND HARDWOOD FORESTS - PART 1
WET PRAIRIES
WETLAND CONIFEROUS FORESTS
WETLAND FORESTED MIXED
2000
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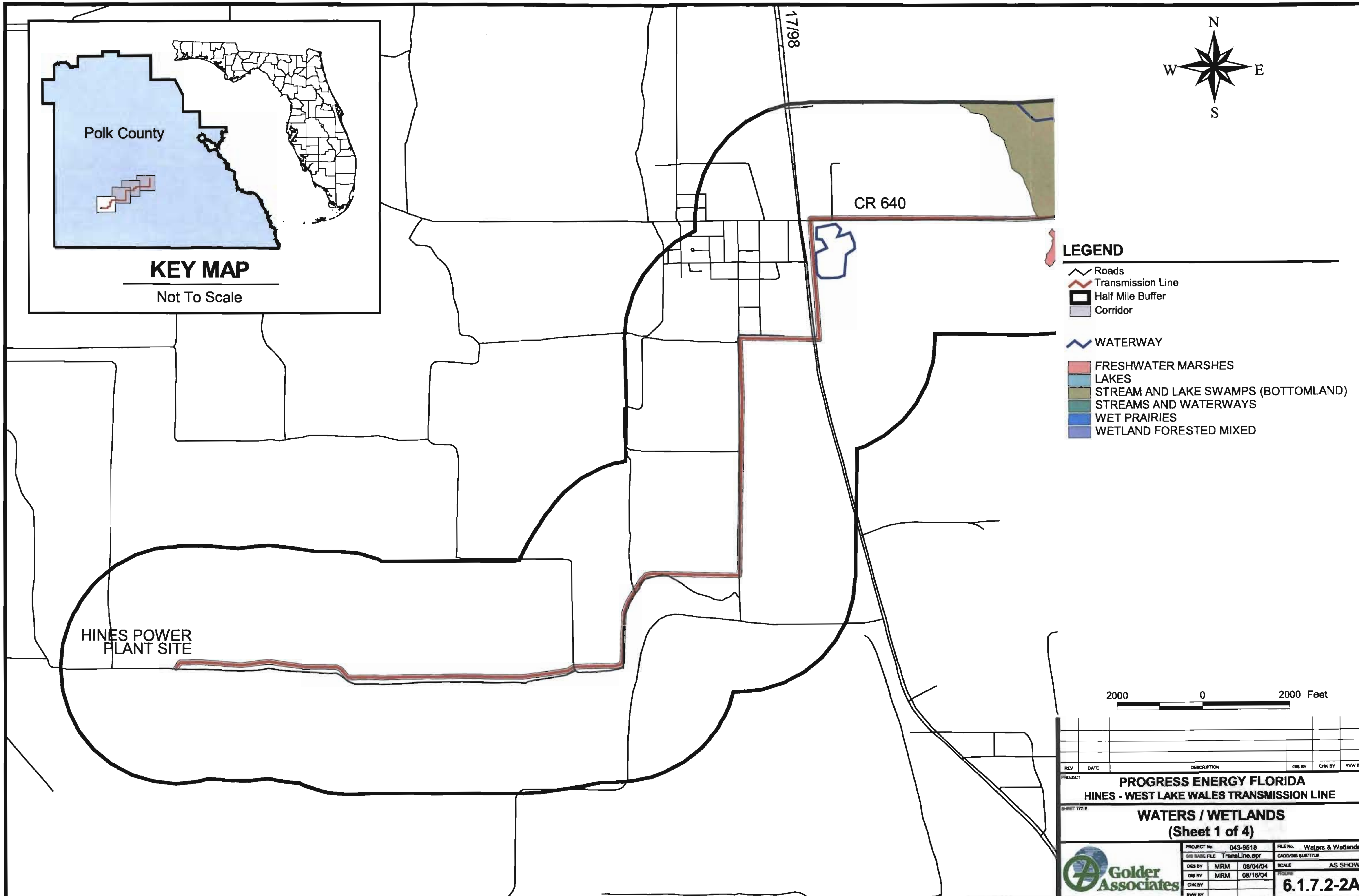
2000 Feet
REV
DATE
GIS BY
CHK BY
RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
VEGETATION MAP
(Sheet 4 of 4)
Golder Associates
PROJECT No. 043-9518
TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Vegetation 4
A
SCALE AS SHOWN
FIGURE
6.1.7.1-3D



Polk County
KEY MAP
Not To Scale
17/98
CR 640
N
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E
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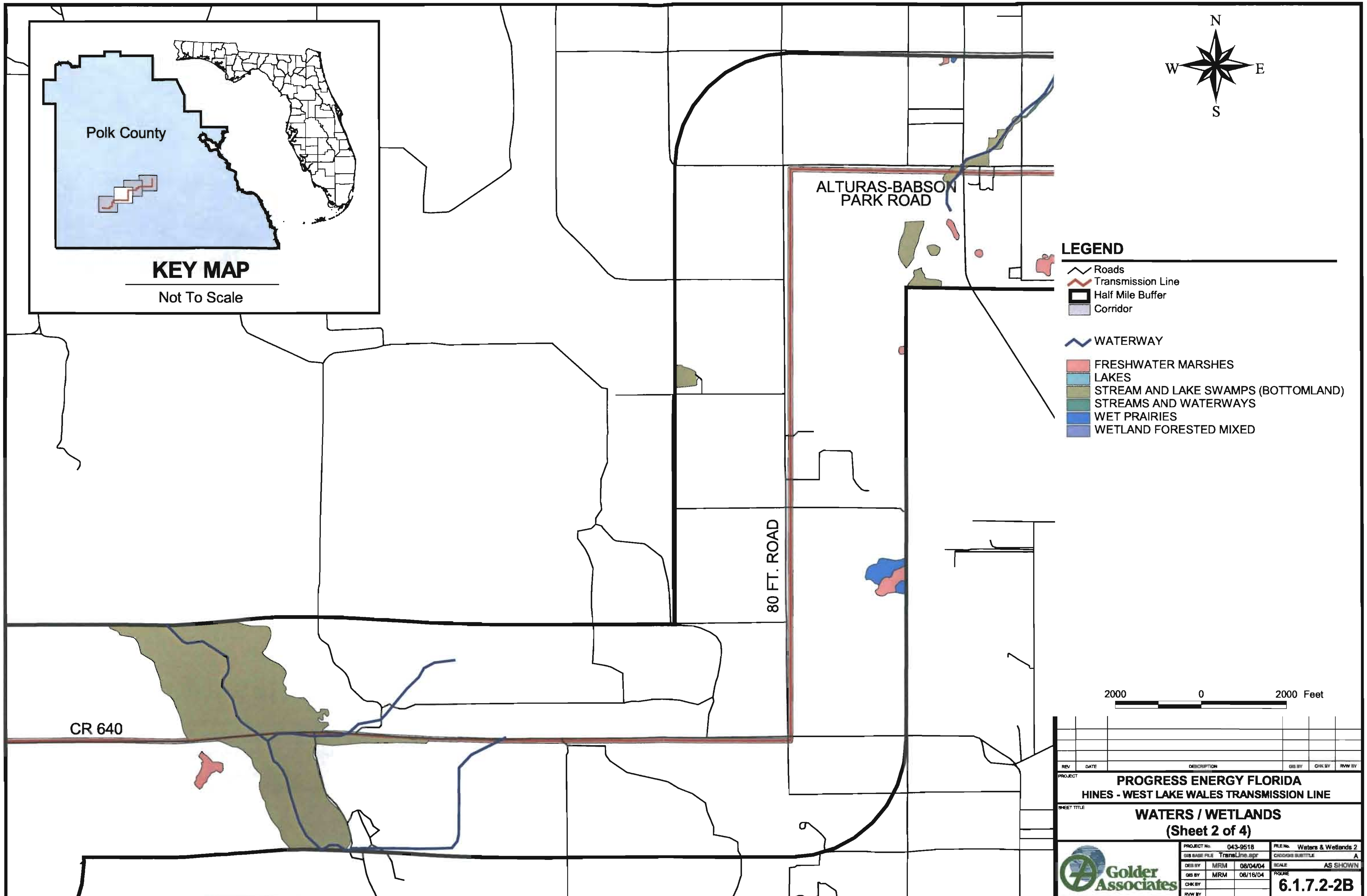
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
WATERWAY
FRESHWATER MARSHES
LAKES
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
WET PRAIRIES
WETLAND FORESTED MIXED
HINES POWER PLANT SITE
2000 0 2000 Feet
REV
DATE
DESCRIPTION
GIS BY
CHK BY
RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
WATERS / WETLANDS
(Sheet 1 of 4)
Golder Associates
PROJECT No. 043-9518
GIS BASE FILE TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Waters & Wetlands 1
CADD/GIS SUBTITLE A
SCALE AS SHOWN
FIGURE
6.1.7.2-2A



Polk County
KEY MAP
Not To Scale
N
W
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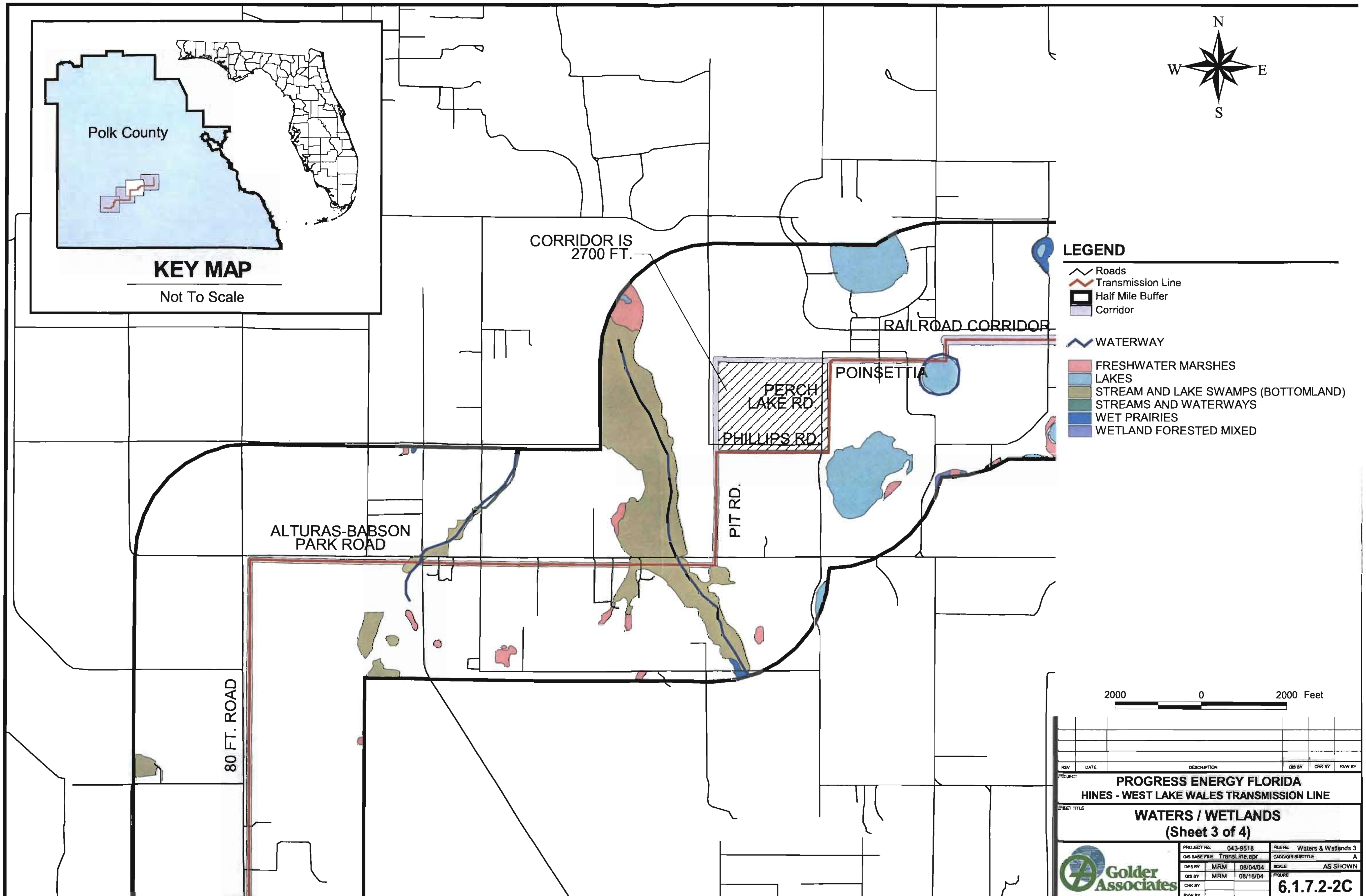
ALTURAS-BABSON PARK ROAD
80 FT. ROAD
CR 640
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
WATERWAY
FRESHWATER MARSHES
LAKES
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
WET PRAIRIES
WETLAND FORESTED MIXED
2000 0 2000 Feet
REV DATE DESCRIPTION GIS BY CHK BY RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
WATERS / WETLANDS
(Sheet 2 of 4)
Golder Associates
PROJECT No. 043-9518
GIS BASE FILE TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Waters & Wetlands 2
CADD/GIS SUBTITLE A
SCALE AS SHOWN
FIGURE
6.1.7.2-2B


Polk County
KEY MAP
Not To Scale
N
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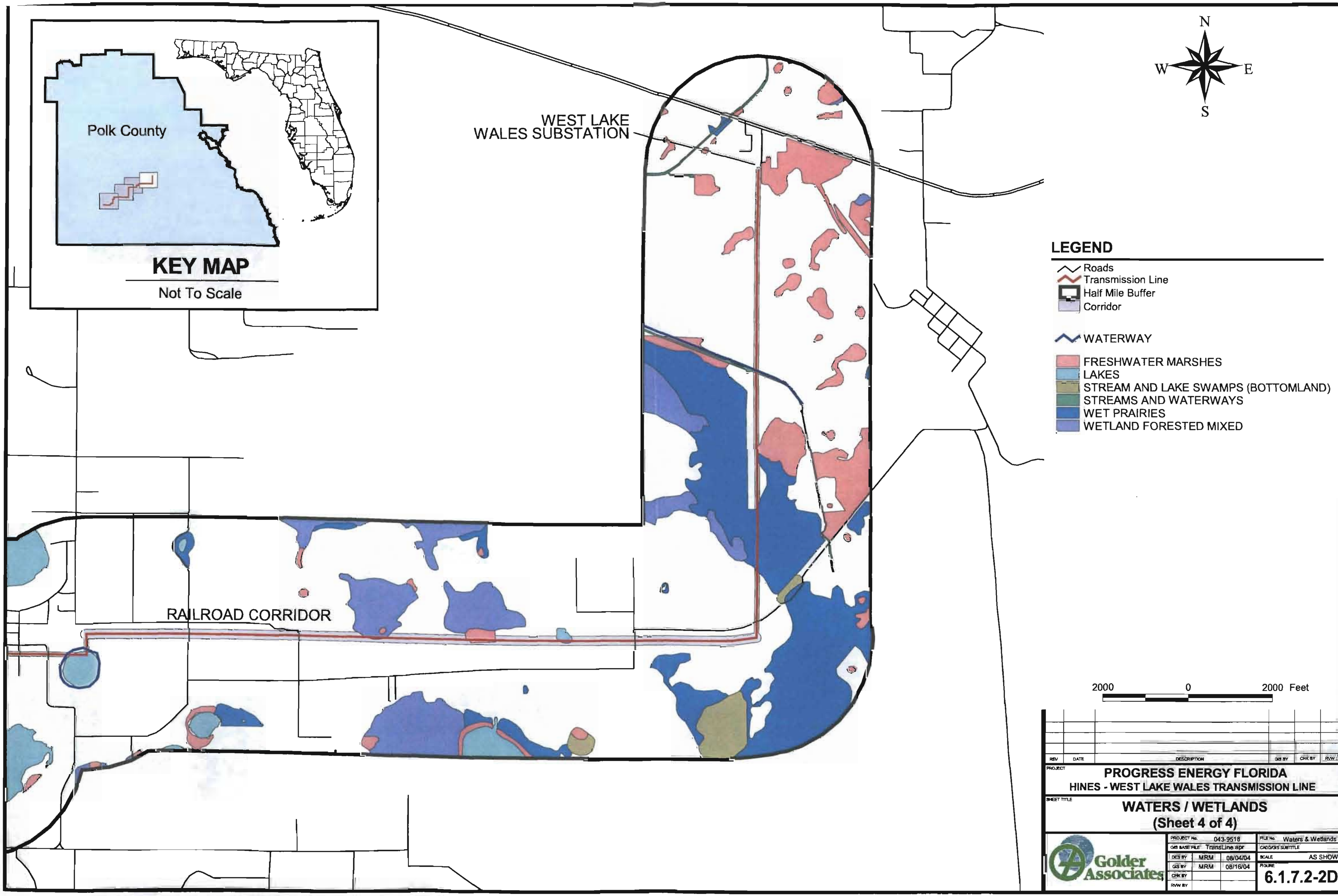
CORRIDOR IS
2700 FT.
RAILROAD CORRIDOR
POINSETTIA
PERCH
LAKE RD.
PHILLIPS RD.
PIT RD.
ALTURAS-BABSON
PARK ROAD
80 FT. ROAD
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
WATERWAY
FRESHWATER MARSHES
LAKES
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
WET PRAIRIES
WETLAND FORESTED MIXED
2000
0
2000 Feet
REV
DATE
DESCRIPTION
GIS BY
CHK BY
RVW BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
WATERS / WETLANDS
(Sheet 3 of 4)
Golder Associates
PROJECT No. 043-9518
GIS BASE FILE TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Waters & Wetlands 3
CADD/GIS SUBTITLE A
SCALE AS SHOWN
FIGURE
6.1.7.2-2C



Polk County
KEY MAP
Not To Scale
WEST LAKE
WALES SUBSTATION
RAILROAD CORRIDOR
N
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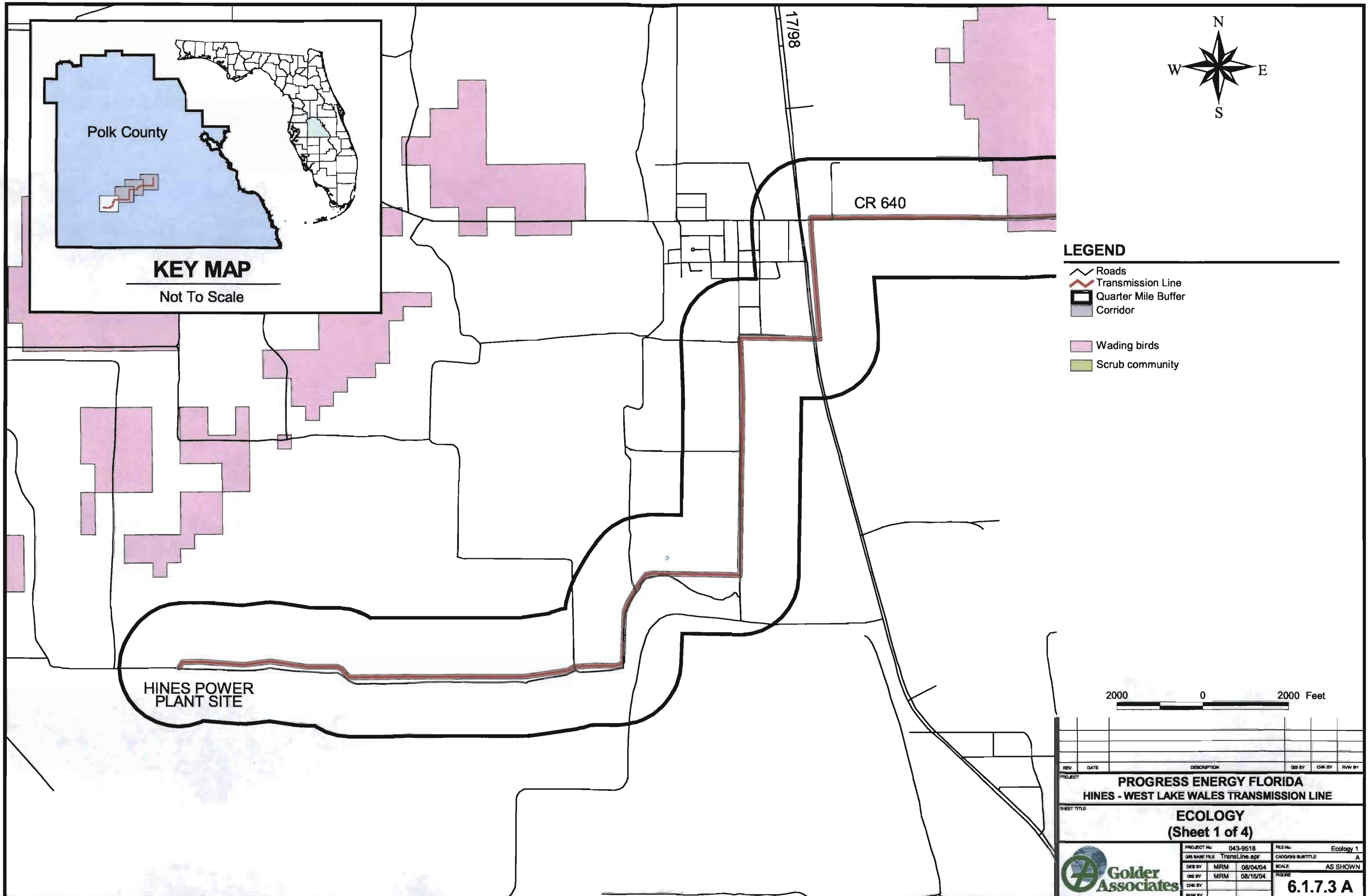
E
S
LEGEND
Roads
Transmission Line
Half Mile Buffer
Corridor
WATERWAY
FRESHWATER MARSHES
LAKES
STREAM AND LAKE SWAMPS (BOTTOMLAND)
STREAMS AND WATERWAYS
WET PRAIRIES
WETLAND FORESTED MIXED
2000
0
2000 Feet
REV
DATE
DESCRIPTION
GIS BY
CHK BY
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
WATERS / WETLANDS
(Sheet 4 of 4)
Golder Associates
PROJECT No. 043-9518
GIS BASE FILE TransLine.apr
DES BY MRM 08/04/04
GIS BY MRM 08/16/04
CHK BY
RVW BY
FILE No. Waters & Wetlands 4
CADD/GIS SUBTITLE A
SCALE AS SHOWN
FIGURE
6.1.7.2-2D



KEY MAP
Not To Scale
Polk County
17/98
CR 640
HINES POWER PLANT SITE
N
S
E
W
LEGEND
Roads
Transmission Line
Quarter Mile Buffer
Corridor
Wading birds
Scrub community
2000 0 2000 Feet
REV
DATE
DESCRIPTION
PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
ECOLOGY
(Sheet 1 of 4)
Golder Associates
PROJECT No. 043-9518
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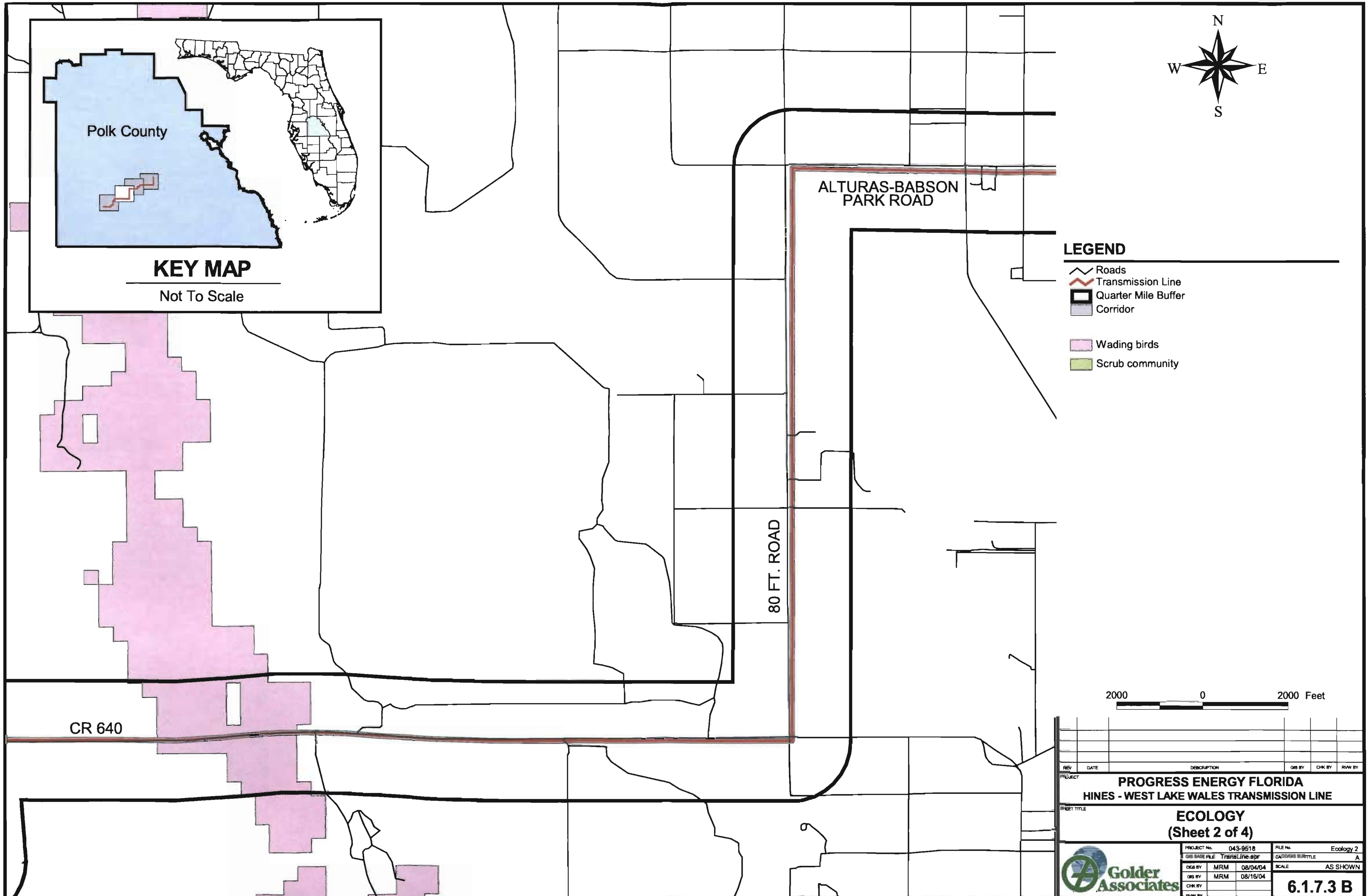
FIGURE
6.1.7.3 A



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CR 640
LEGEND
Roads
Transmission Line
Quarter Mile Buffer
Corridor
Wading birds
Scrub community
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PROJECT
PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE
SHEET TITLE
ECOLOGY
(Sheet 2 of 4)
Golder Associates
PROJECT No. 043-9518
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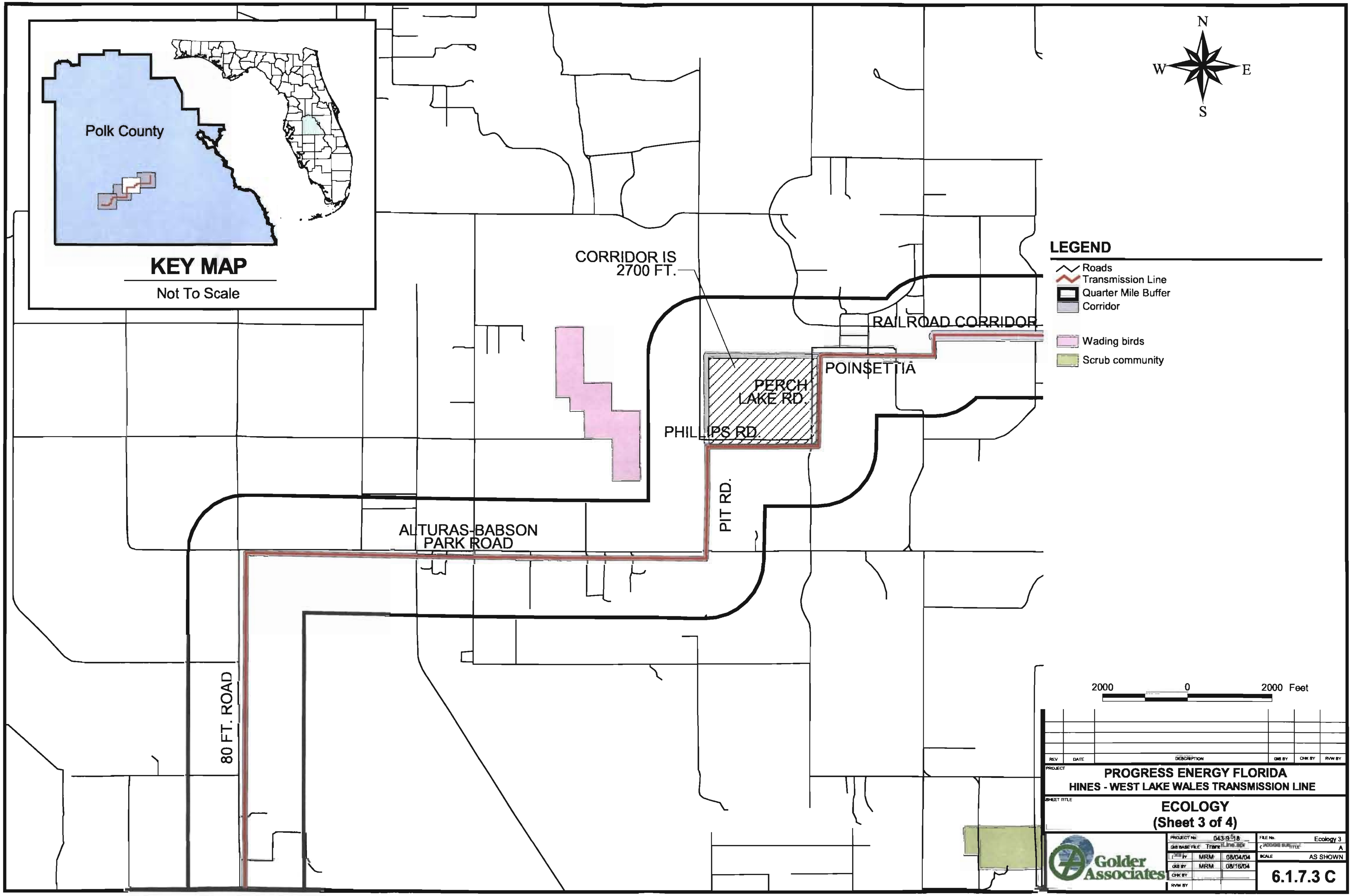
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(Sheet 3 of 4)
Golder Associates
PROJECT No. 043-9518
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FILE No. Ecology 3
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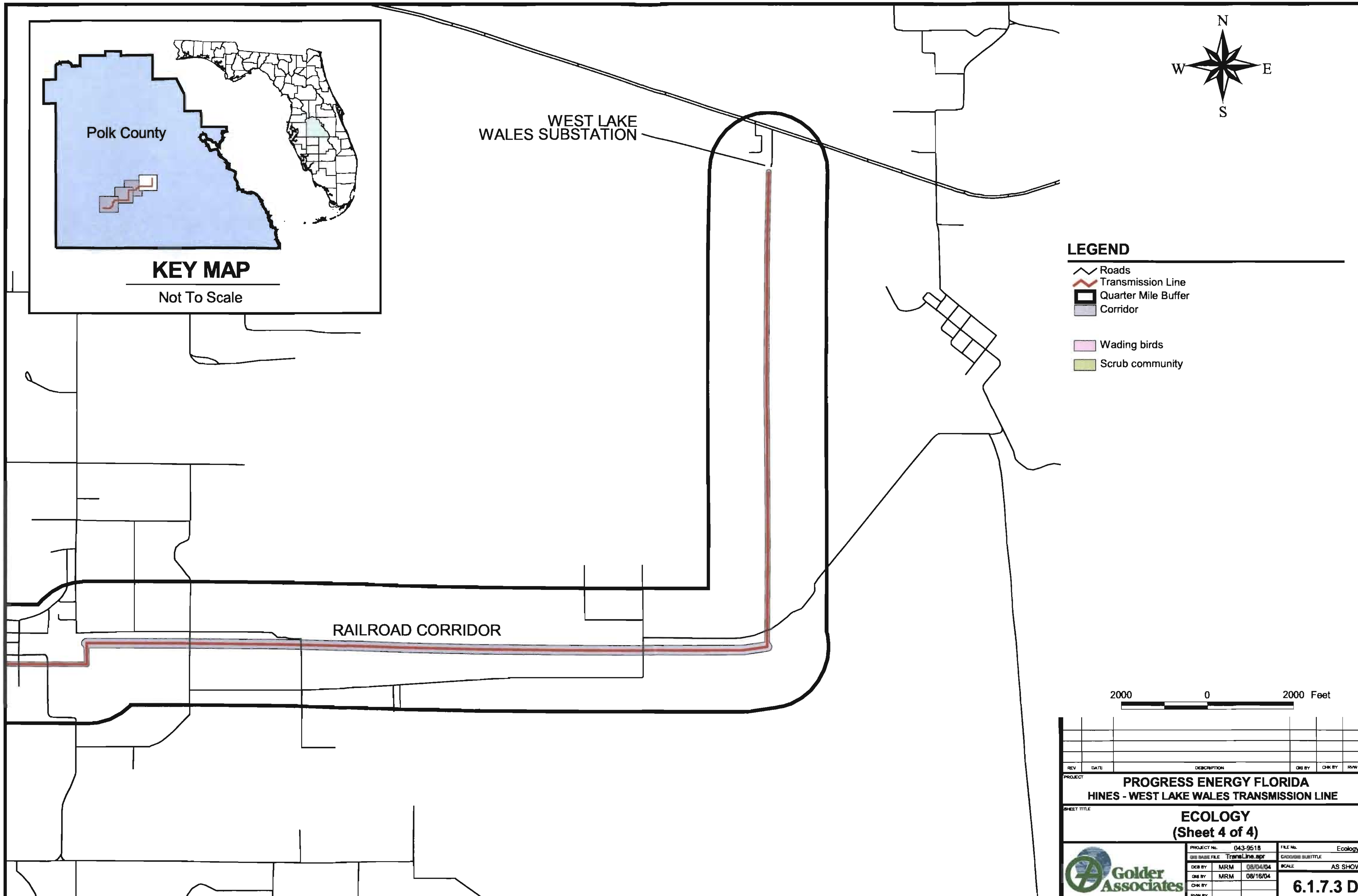
6.1.7.3 C



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PROGRESS ENERGY FLORIDA
HINES - WEST LAKE WALES TRANSMISSION LINE

SHEET TITLE
ECOLOGY
(Sheet 4 of 4)

Golder Associates

PROJECT No.	043-9518		FILE No.	Ecology 3
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Progress Energy

RECEIVED

AUG 23 2004

BUREAU OF AIR REGULATION

August 17, 2004

Mr. Jim Pennington, P.E., Administrator
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Re: **Progress Energy Florida - Hines Energy Complex**
Power Block 4
Supplemental Site Certification Application to PA 92-33
PSD/Air Construction Permit Application - Figures

Dear Mr. Pennington:

On August 5, 2004 you were provided four copies of the PSD/Air Construction permit application that was filed in conjunction with the Supplemental Site Certification Application (SSCA) for the addition of the Hines Power Block 4 project to the existing Hines Energy Complex in Polk County. The air permit application is also included as Appendix 10.1.5 in the SSCA filed with the Department's Office of Siting Coordination.

In the four copies of the air permit application document provided to you under the August 5th cover letter, the associated document "figures" were inadvertently left out of the final version during document production. Please find enclosed four sets of the document figures. These figures should be placed in the document immediately prior to "Appendix A".

Please note that these figures were included in the version of the air permit application included as Appendix 10.1.5 in the SSCA filed with the Department's Siting Office.

We apologize for any confusion this may have created. Should you have any questions regarding this application, please do not hesitate to contact me at (813) 826-4363.

Sincerely,

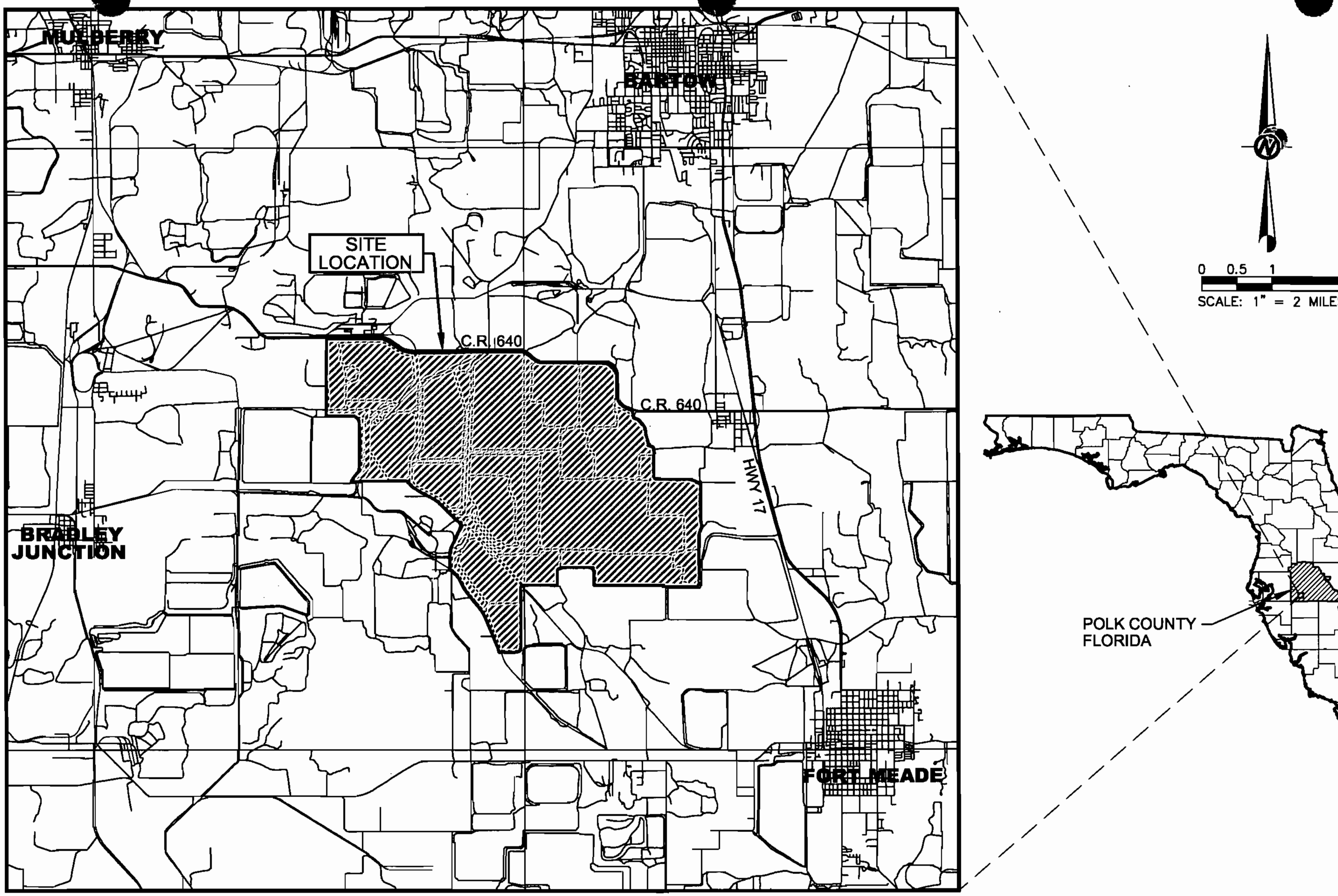
Jamie Hunter
Lead Environmental Specialist
Environmental Services

Enclosures

c: Hamilton Oven, FDEP Siting Office

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

FIGURES



SOURCE: GOLDER, 2004.

Progress Energy

Golder Associates
Tampa, Florida

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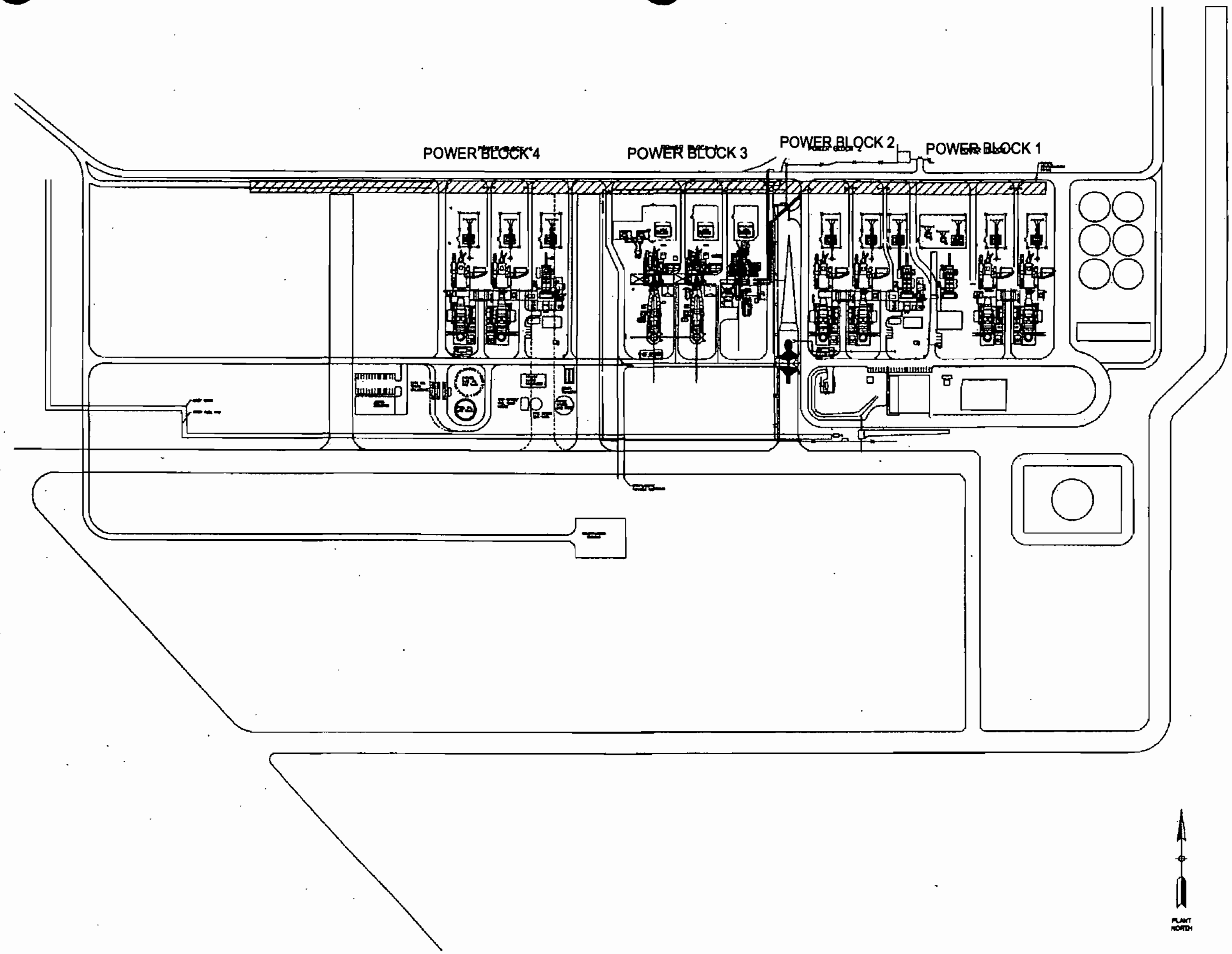
FILE No.	0439518A003.DWG
PROJECT No.	043-9518
REV.	0

TITLE

SITE LOCATION MAP

HINES ENERGY COMPLEX

FIGURE 1-1



SOURCE: GOLDER, 2004.

Progress Energy

Golder Associates
Tampa, Florida

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DESIGN	MM		
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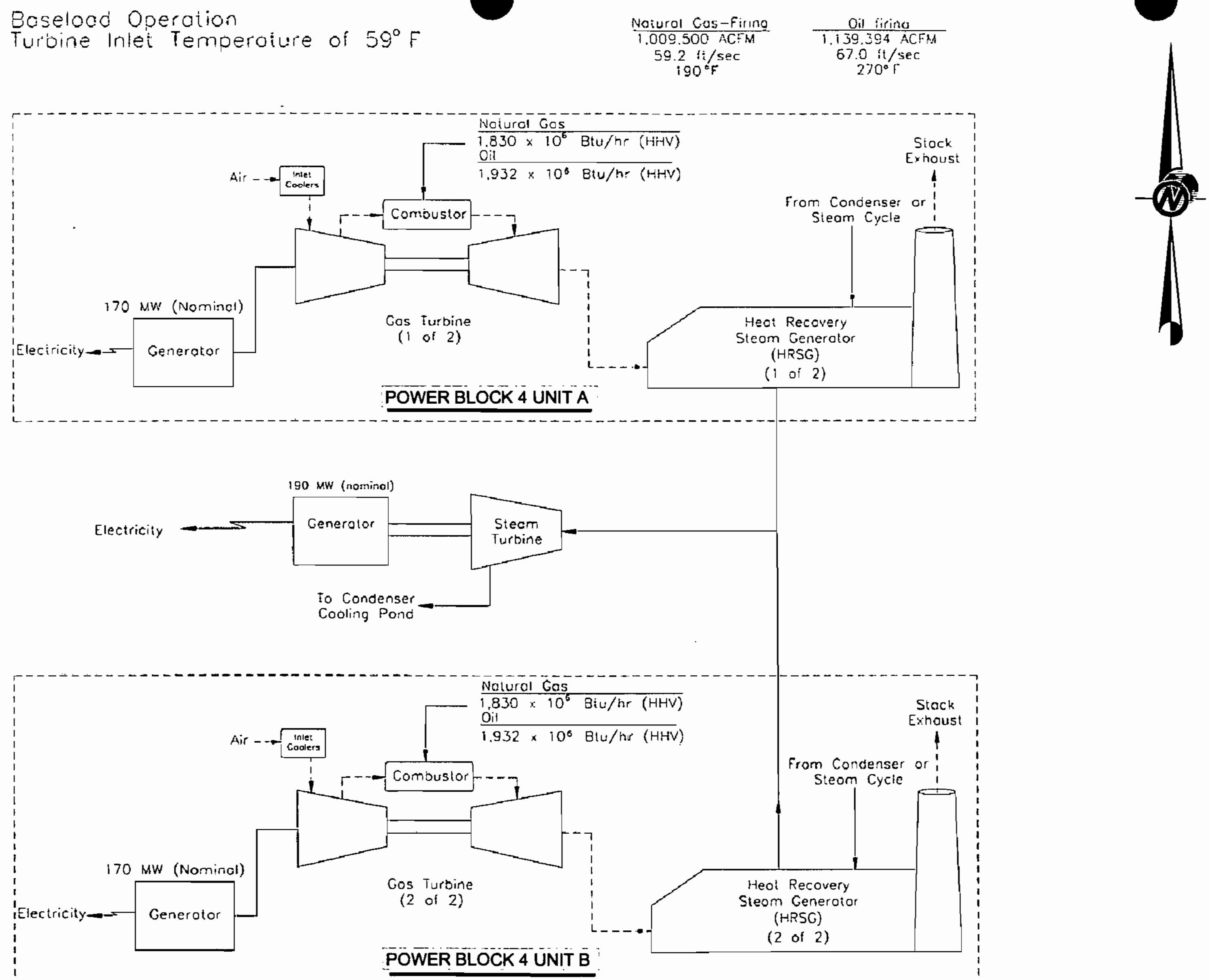
FILE No. 0439518A004.DWG	CHECK		
PROJECT No. 043-9518 REV. 0	REVIEW	HINES ENERGY COMPLEX	FIGURE 2-1



Golder Associates
Tampa, Florida

SCALE	AS SHOWN	TITLE	PROCESS FLOW DIAGRAM
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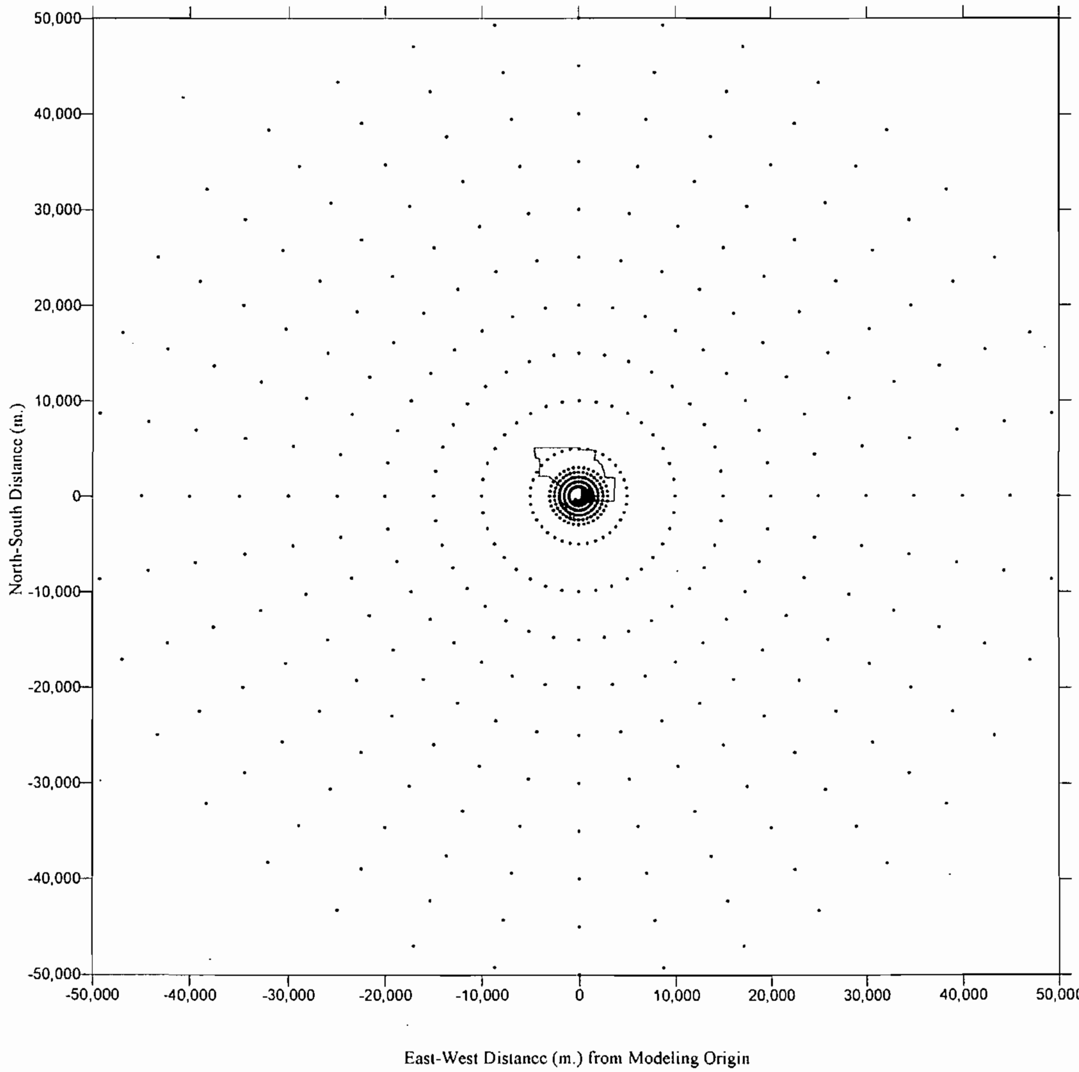
FILE No. 0439518 FIG 2-2.DWG
PROJECT No. 043-9518 REV. 0

Drawing file: 0439518 FIG 2-2.dwg Aug 16, 2004 - 1:40pm



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	DESIGN MM		
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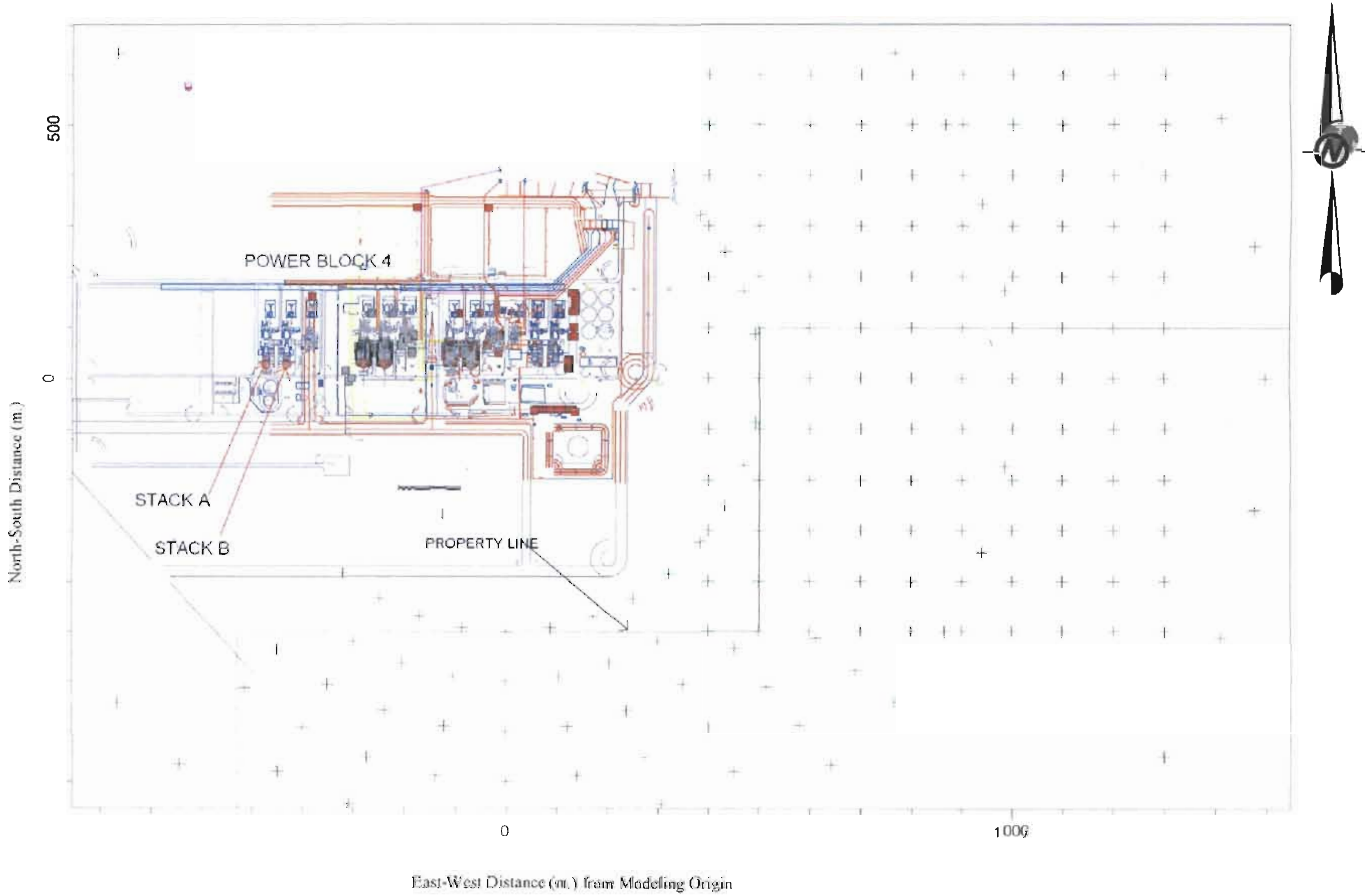
FILE No. 0439518 FIG 6-1.DWG	CHECK SO		
PROJECT No. 043-9518 REV. 0	REVIEW MM	HINES ENERGY COMPLEX	FIGURE 6-1

Drawing file: 0439518 FIG 6-1.dwg Aug 16, 2004 - 1:41pm



Golder Associates
Tampa, Florida

FILE No.	0439518 FIG 6-2.DWG		
PROJECT No.	043-9518	REV.	0

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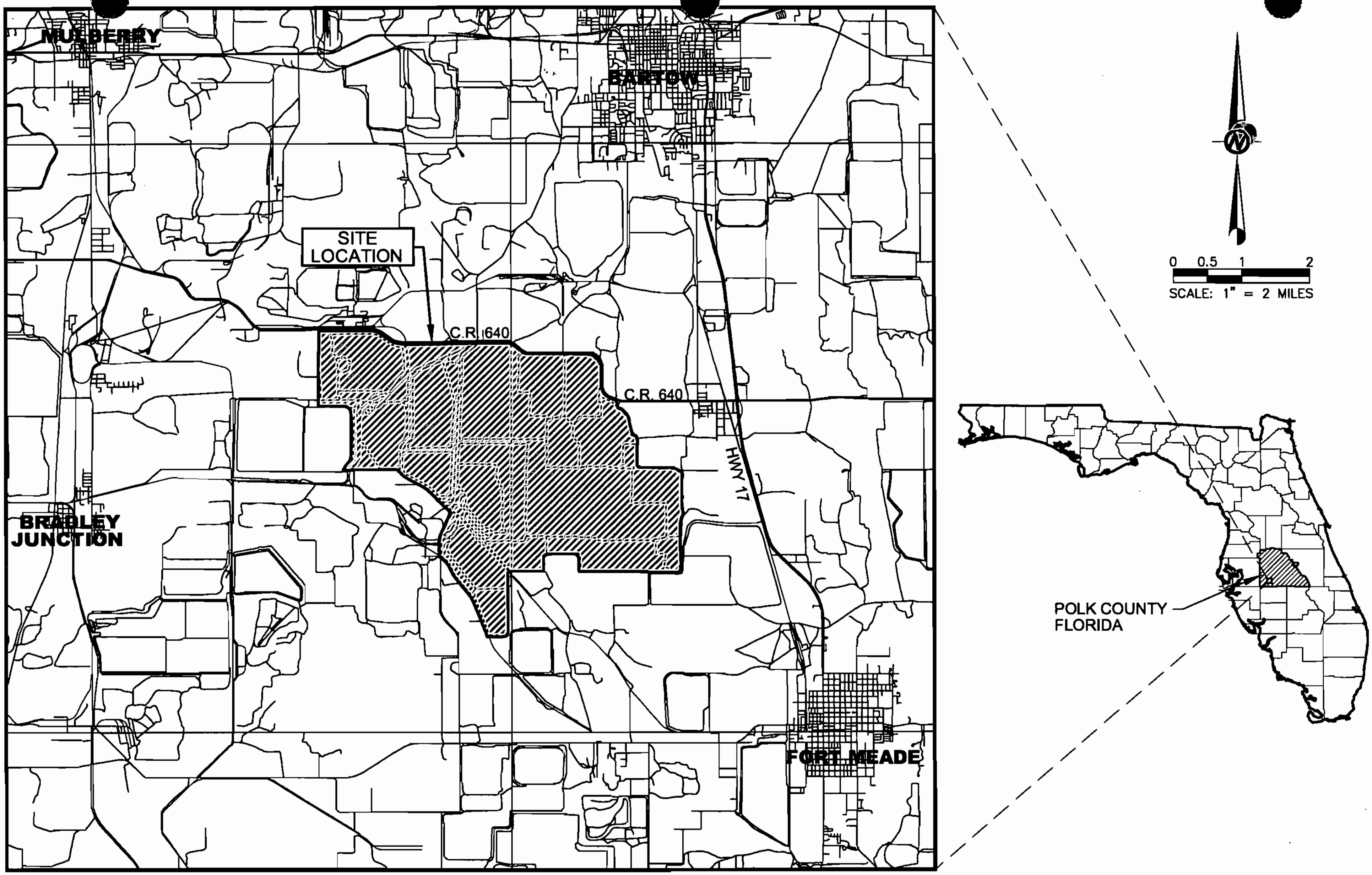
NEAR FIELD RECEPTOR GRID

HINES ENERGY COMPLEX

FIGURE **6-2**

Drawing file: 0439518 FIG 6-2.dwg Aug 16, 2004 - 1:41pm

FIGURES



SOURCE: GOLDER, 2004.

Progress Energy

Golder Associates, Tampa, Florida	SCALE 1" = 2 MILES	TITLE	
	DATE 07/13/04	SITE LOCATION MAP	
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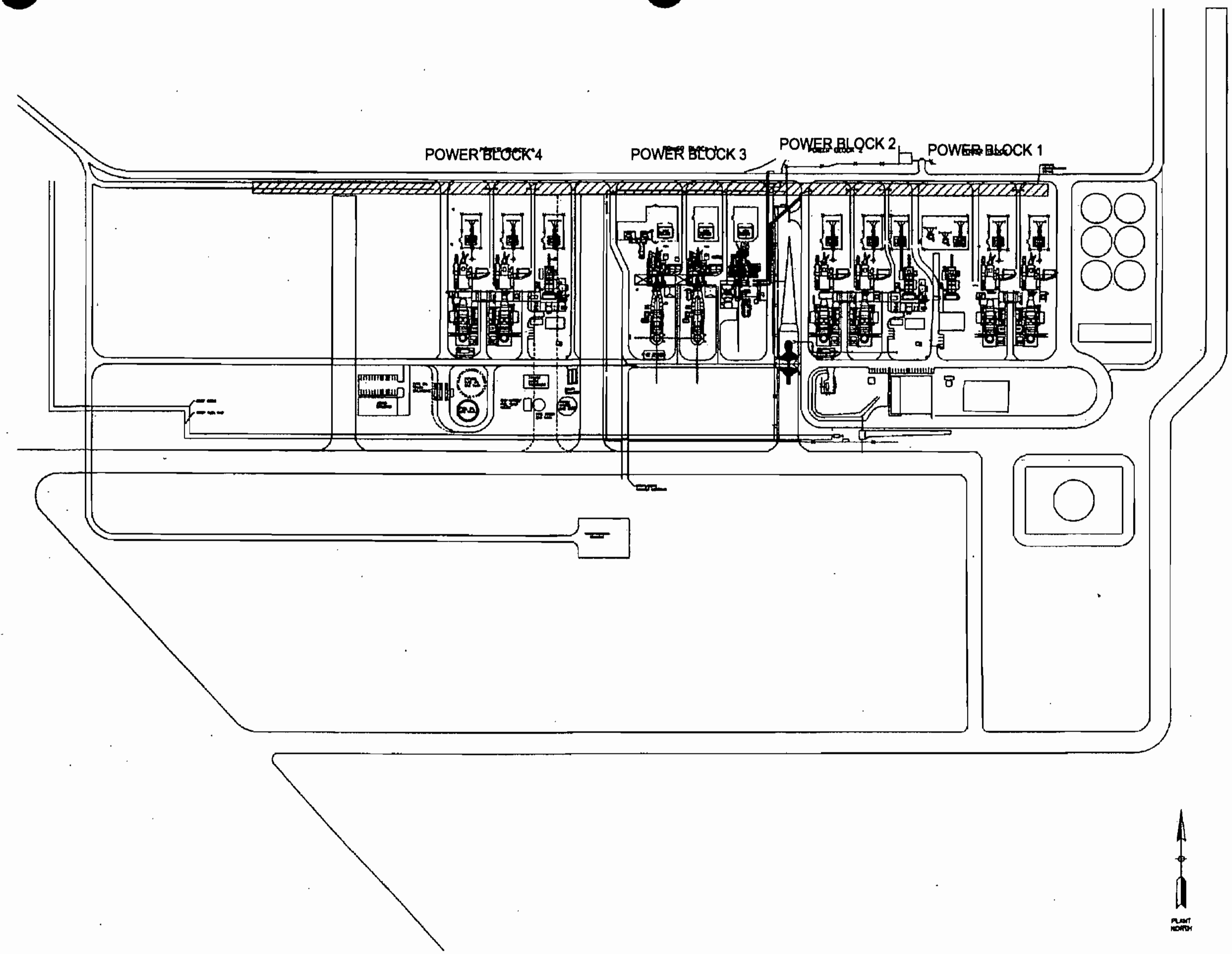
PROJECT No. 043-9518 REV. 0	REVIEW	HINES ENERGY COMPLEX	FIGURE 1-1



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Progress Energy

Golder Associates
Tampa, Florida

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PROJECT No.	043-9518	REV.	0

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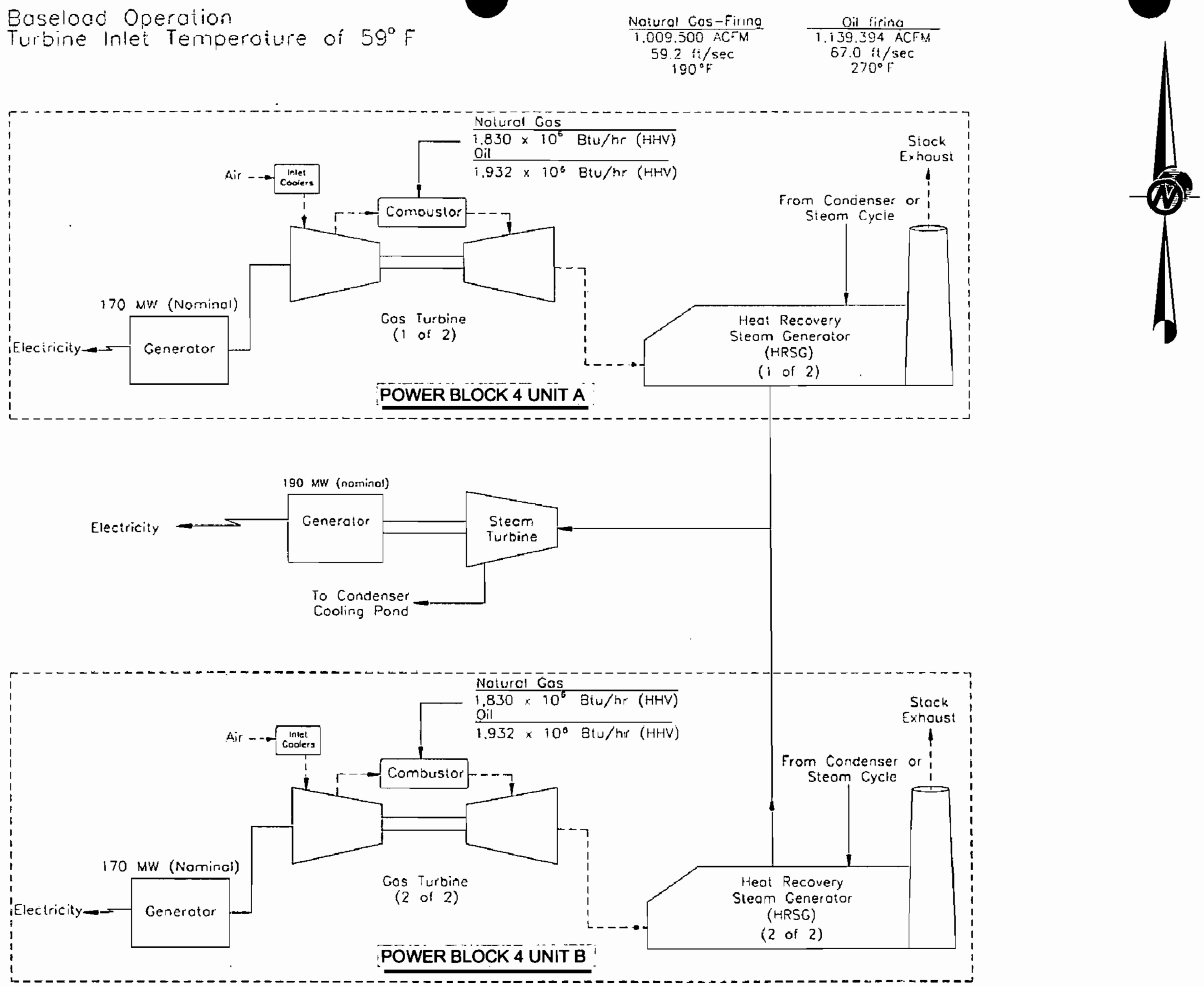
TITLE

SITE ARRANGEMENT PLAN

HINES ENERGY COMPLEX

FIGURE 2-1



Golder Associates
Tampa, Florida

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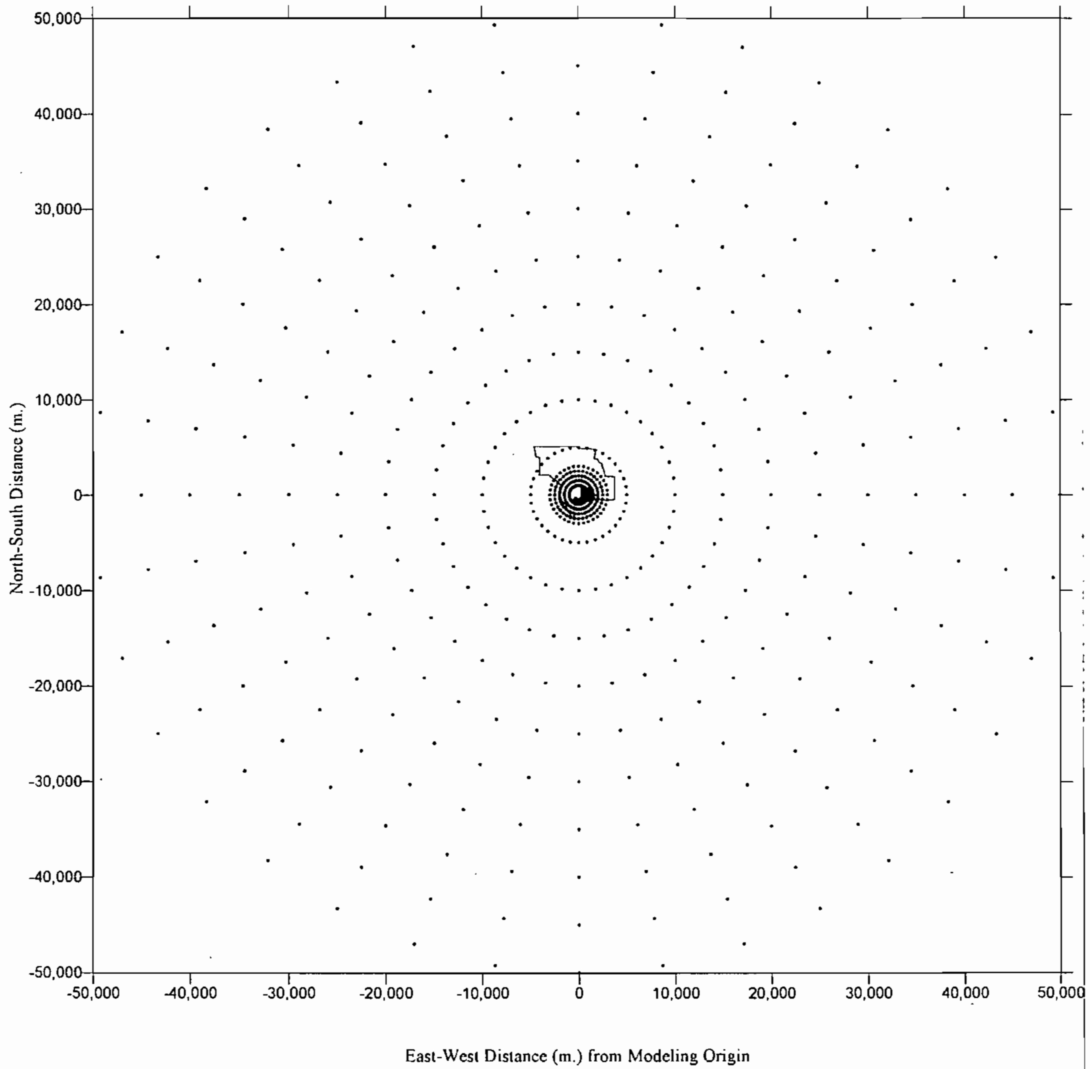
Drawing file: 0439518 FIG 2-2.dwg Aug 16, 2004 - 1:40pm



Drawing file: 0439518 FIG 6-1.dwg Aug 16, 2004 - 1:41pm

Golder Associates, Tampa, Florida	SCALE AS SHOWN	TITLE
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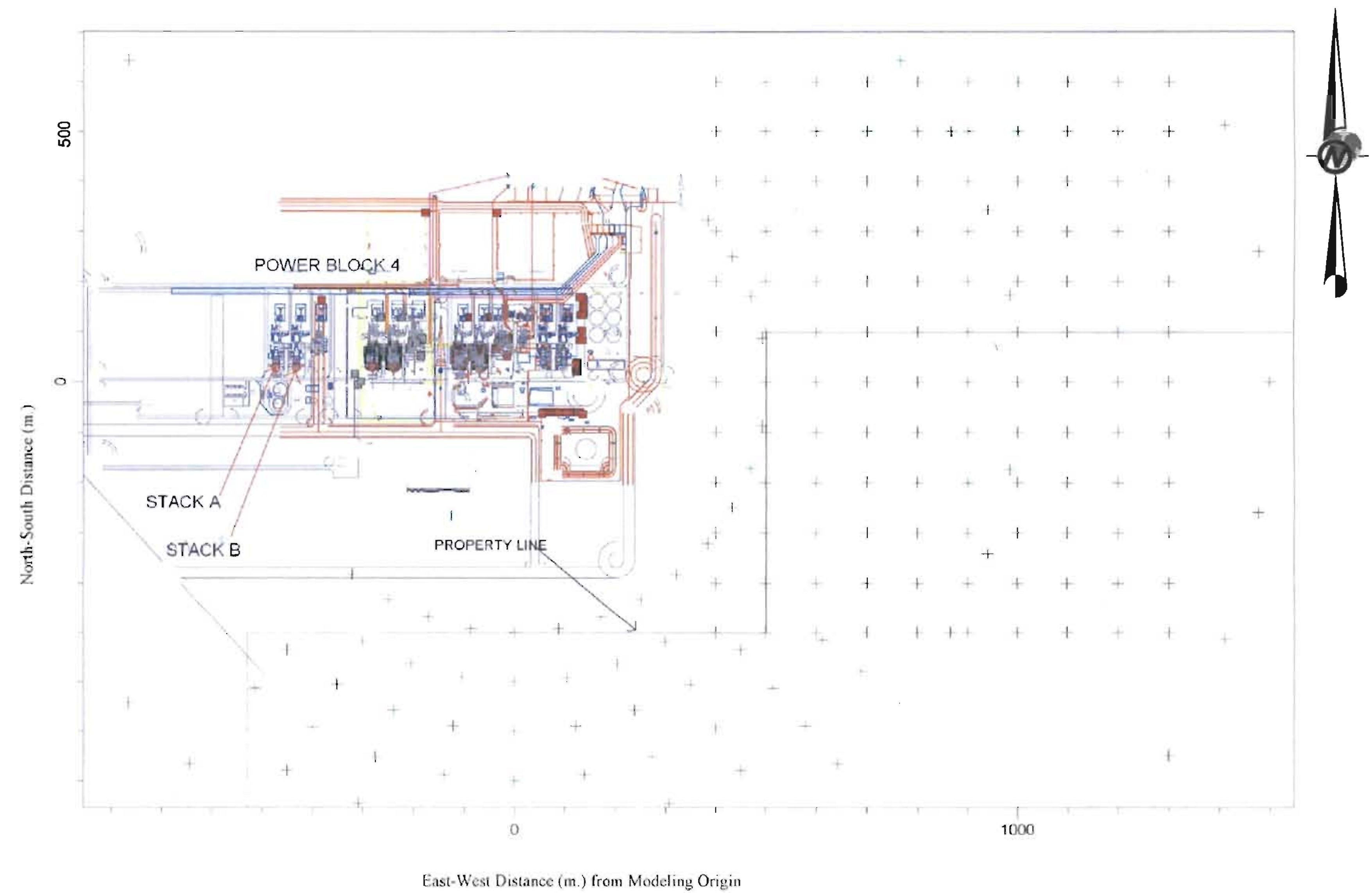
FILE No. 0439518 FIG 6-1.DWG	CHECK SO	
PROJECT No. 043-9518 REV. 0	REVIEW MM	HINES ENERGY COMPLEX — FIGURE 6-1



Drawing file: 0439518 FIG 6-2.dwg Aug 16, 2004 - 1:41pm

Golder Associates Tampa, Florida	SCALE AS SHOWN	TITLE	
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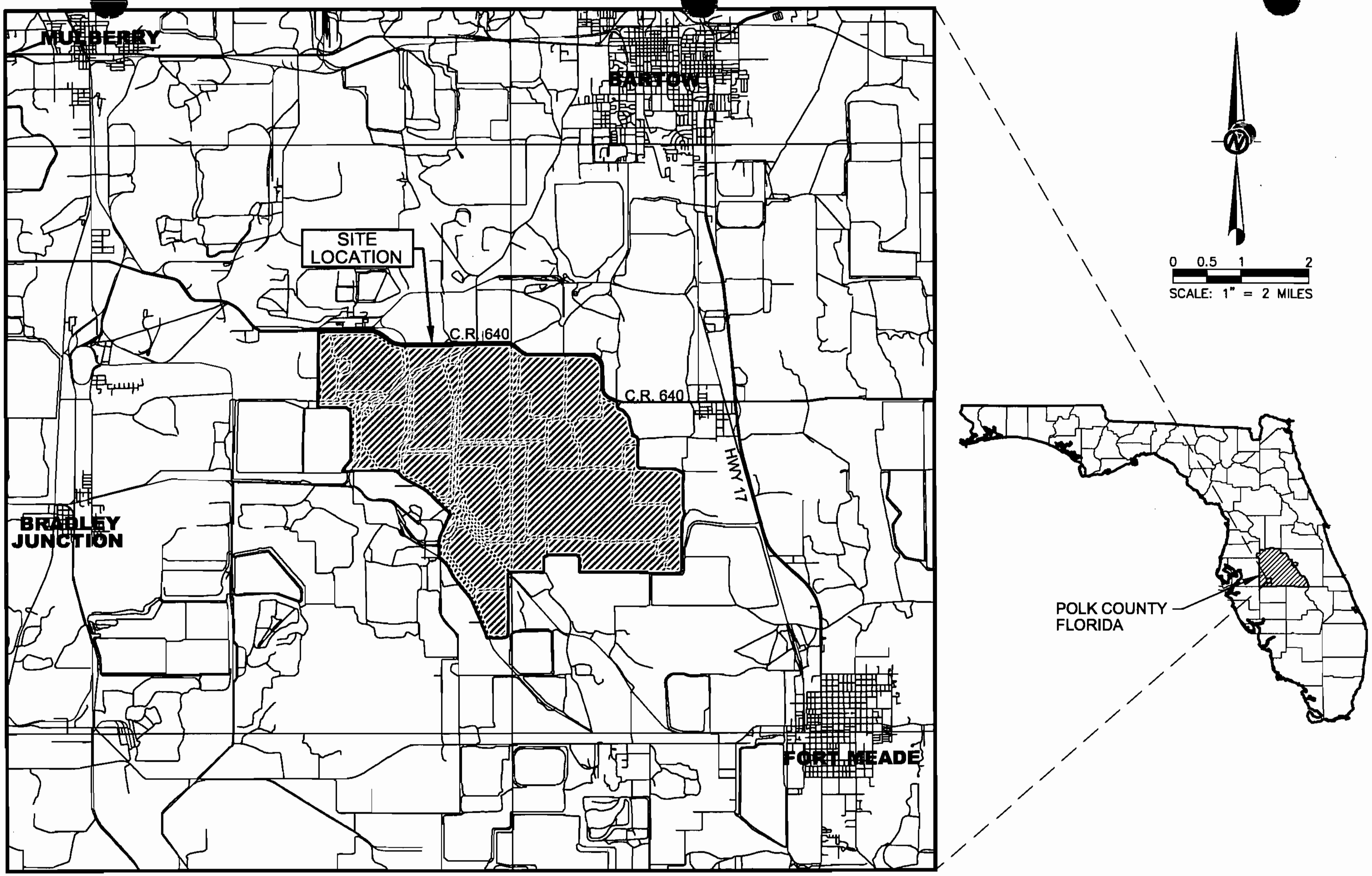
FILE No. 0439518 FIG 6-2.DWG	CHECK		
PROJECT No. 043-9518 REV. 0	REVIEW	HINES ENERGY COMPLEX	FIGURE 6-2

FIGURES



SOURCE: GOLDER, 2004.

Progress Energy

Golder Associates
Tampa, Florida

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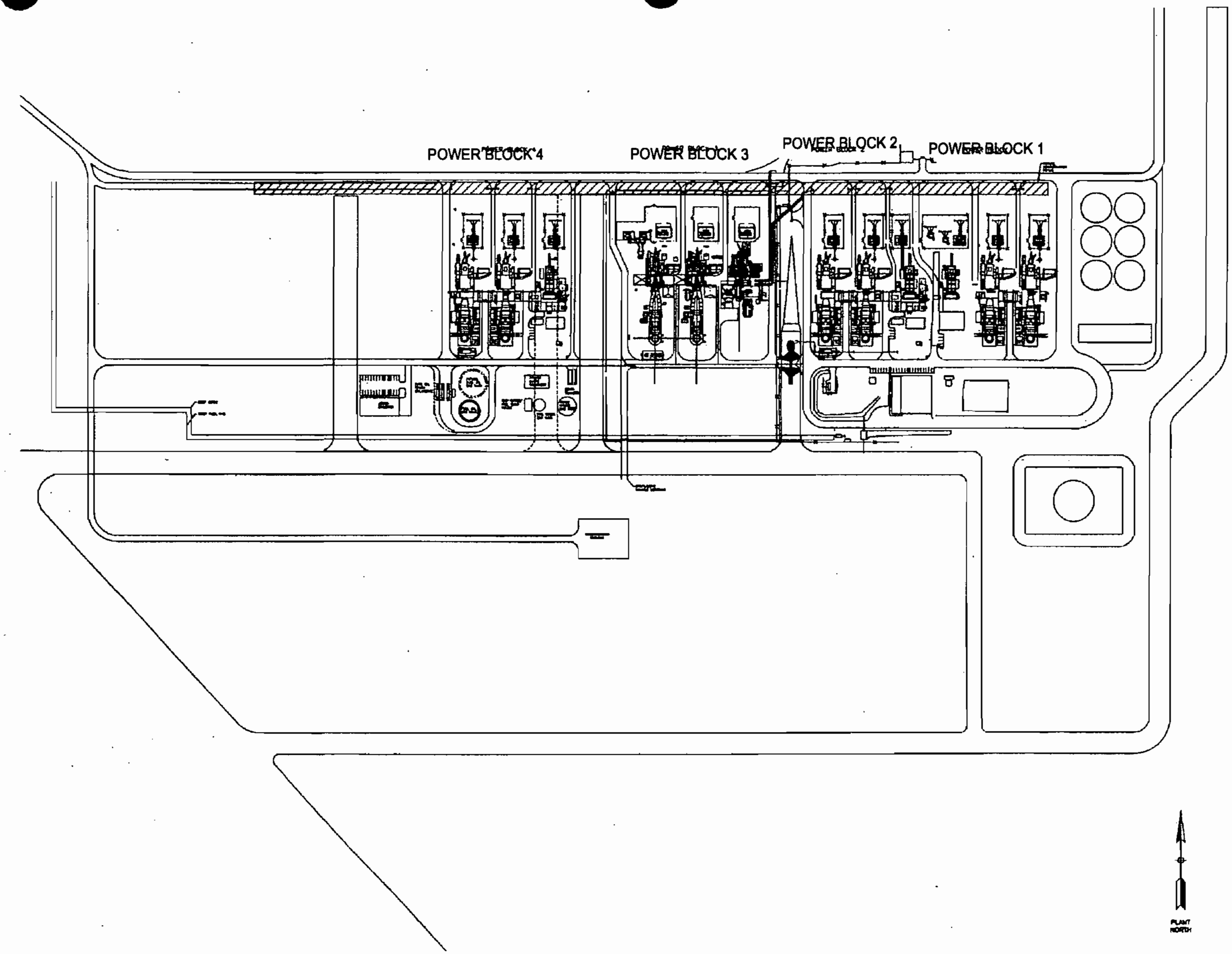
HINES ENERGY COMPLEX

FIGURE 1-1



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Progress Energy

Golder Associates
Tampa, Florida

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FILE No. 0439518A004.DWG

PROJECT No. 043-9518 REV. 0

TITLE

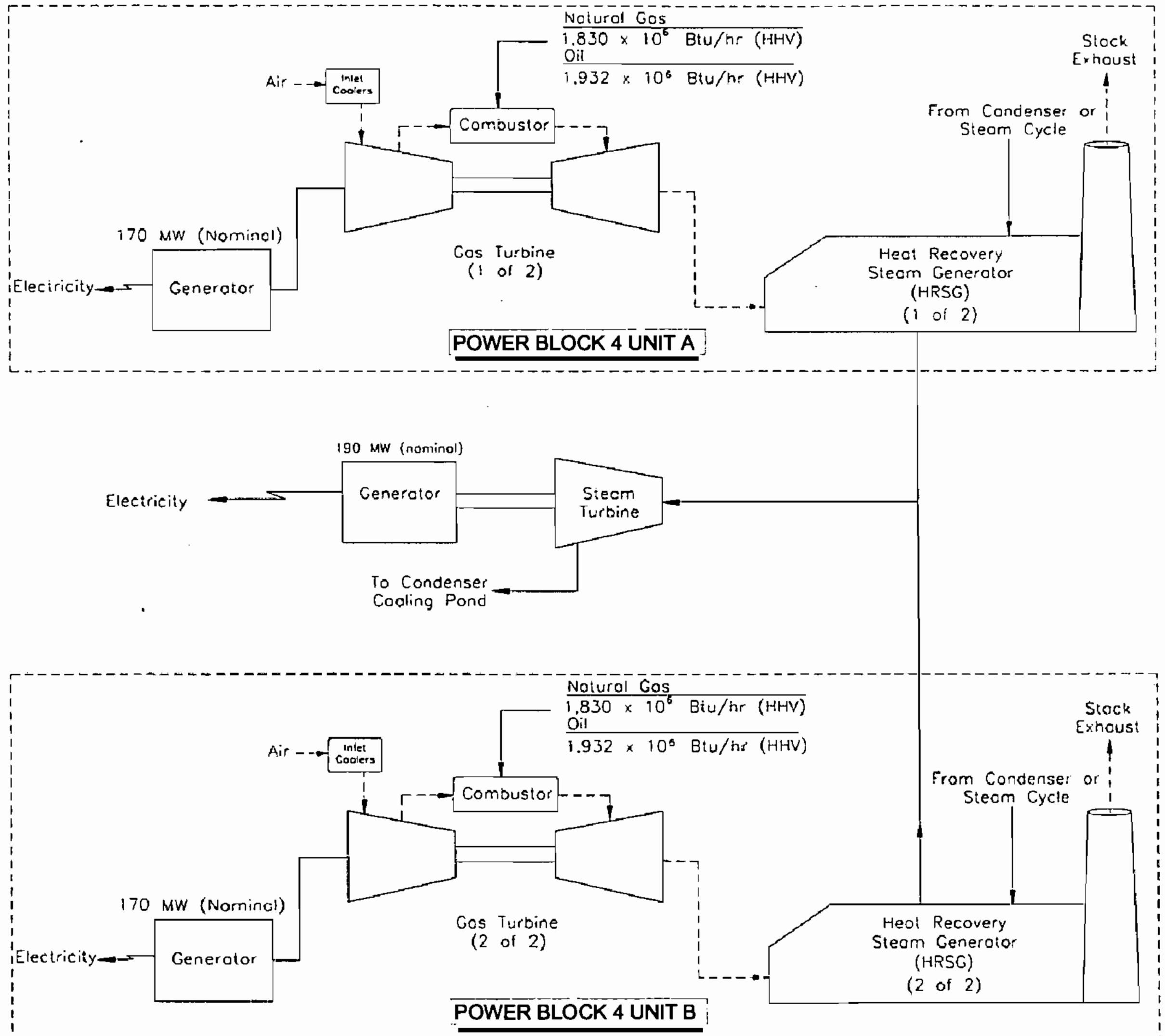
SITE ARRANGEMENT PLAN

HINES ENERGY COMPLEX

FIGURE 2-1

Baseload Operation
Turbine Inlet Temperature of 59° F

Natural Gas–Firing	Oil firing
1,009,500 ACFM	1,139,394 ACFM
59.2 ft/sec	67.0 ft/sec
190°F	270°F



Golder Associates, Tampa, Florida			
SCALE	AS SHOWN	TITLE	PROCESS FLOW DIAGRAM
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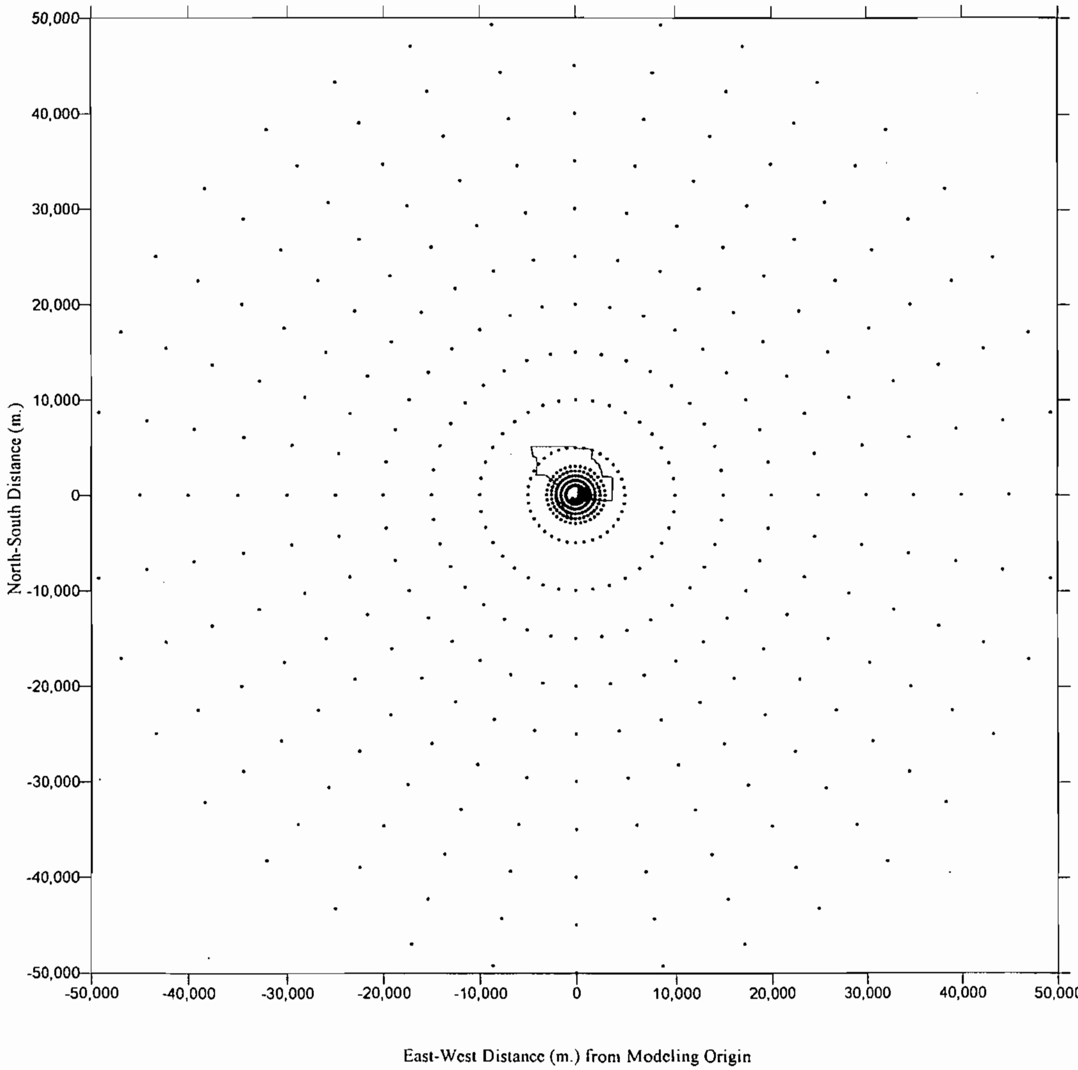
FILE No. 0439518 FIG 2-2.DWG	CHECK	SO	
PROJECT No. 043-9518 REV. 0	REVIEW	MM	HINES ENERGY COMPLEX — FIGURE 2-2

Drawing file: 0439518 FIG 2-2.dwg Aug 16, 2004 - 1:40pm



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	DATE: 7/30/04		
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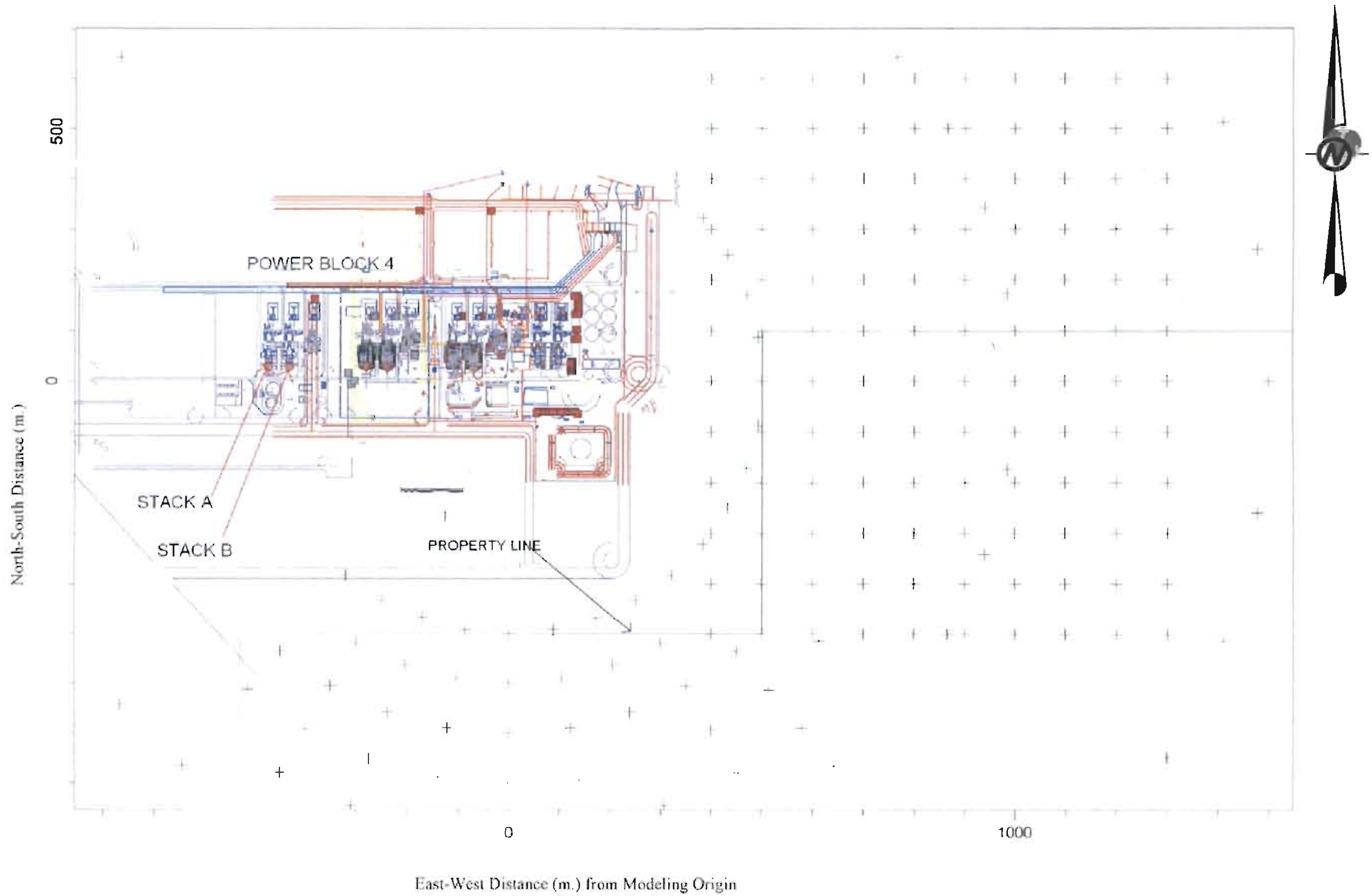
FILE No.: 0439518 FIG 6-1.DWG	CHECK: SO		
PROJECT No.: 043-9518 / REV.: 0	REVIEW: MM	HINES ENERGY COMPLEX	FIGURE: 6-1

Drawing file: 0439518 FIG 6-1.dwg Aug 16, 2004 - 1:41pm



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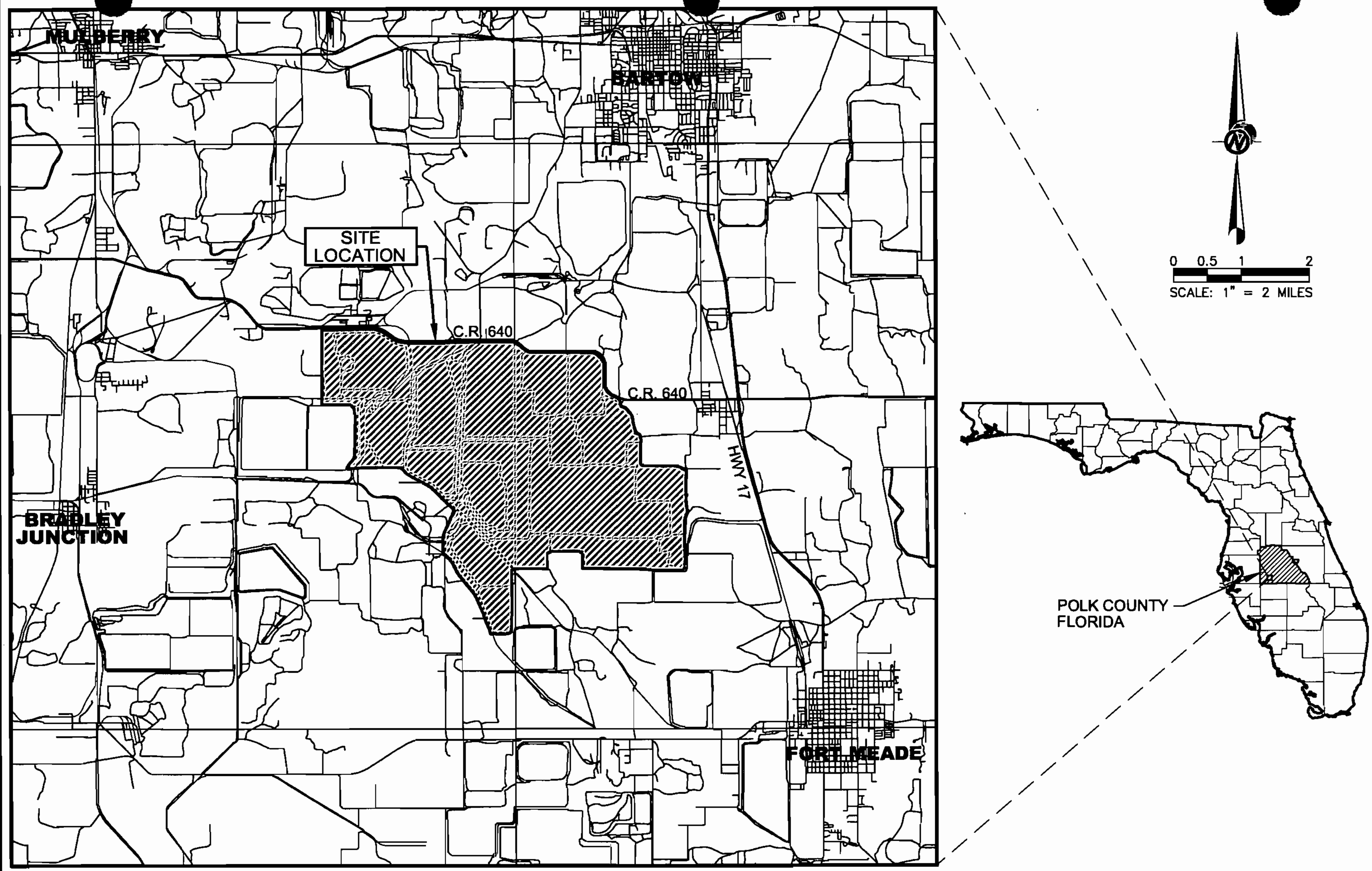
FILE No. 0439518 FIG 6-2.DWG	CHECK		
PROJECT No. 043-9518 / REV. 0	REVIEW	HINES ENERGY COMPLEX	FIGURE 6-2

Drawing file: 0439518 FIG 6-2.dwg Aug 16, 2004 - 1:41pm

FIGURES



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Progress Energy

Golder Associates
Tampa, Florida

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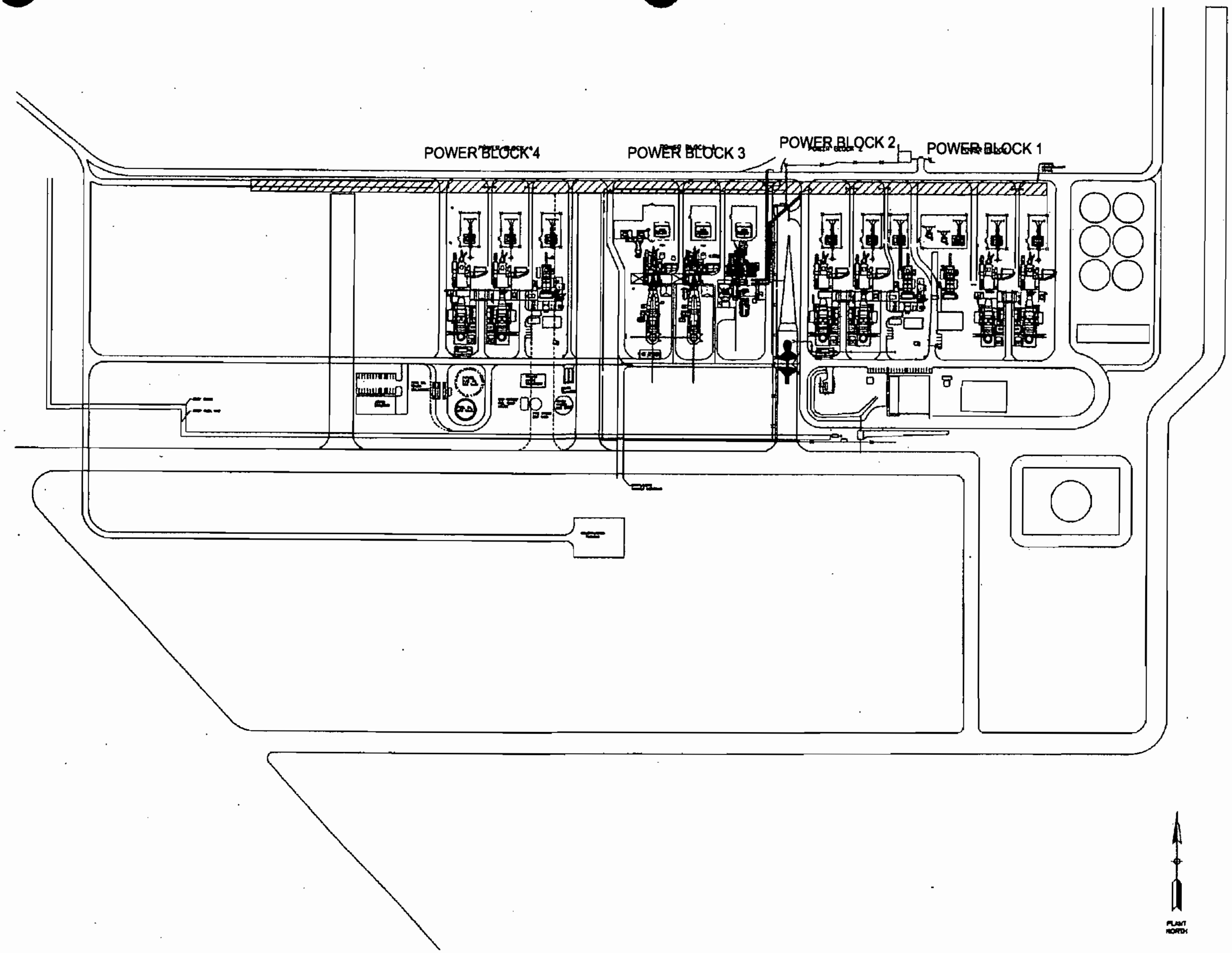
PROJECT No. 043-9518 REV. 0	REVIEW	HINES ENERGY COMPLEX	FIGURE 1-1



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Progress Energy

Golder Associates
Tampa, Florida

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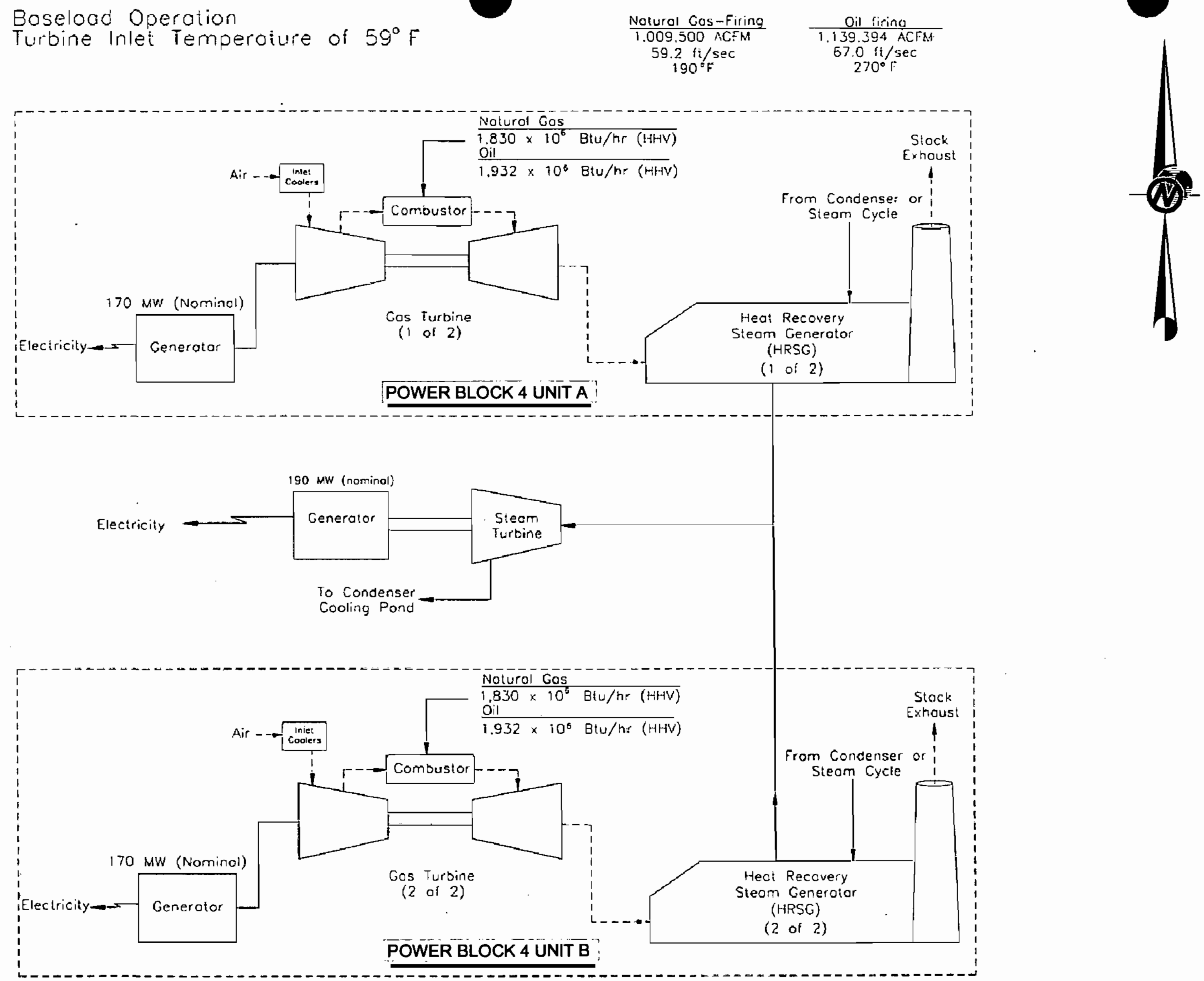
PROJECT No.	043-9518	REV. 0	REVIEW

HINES ENERGY COMPLEX

FIGURE 2-1



Golder Associates
Tampa, Florida

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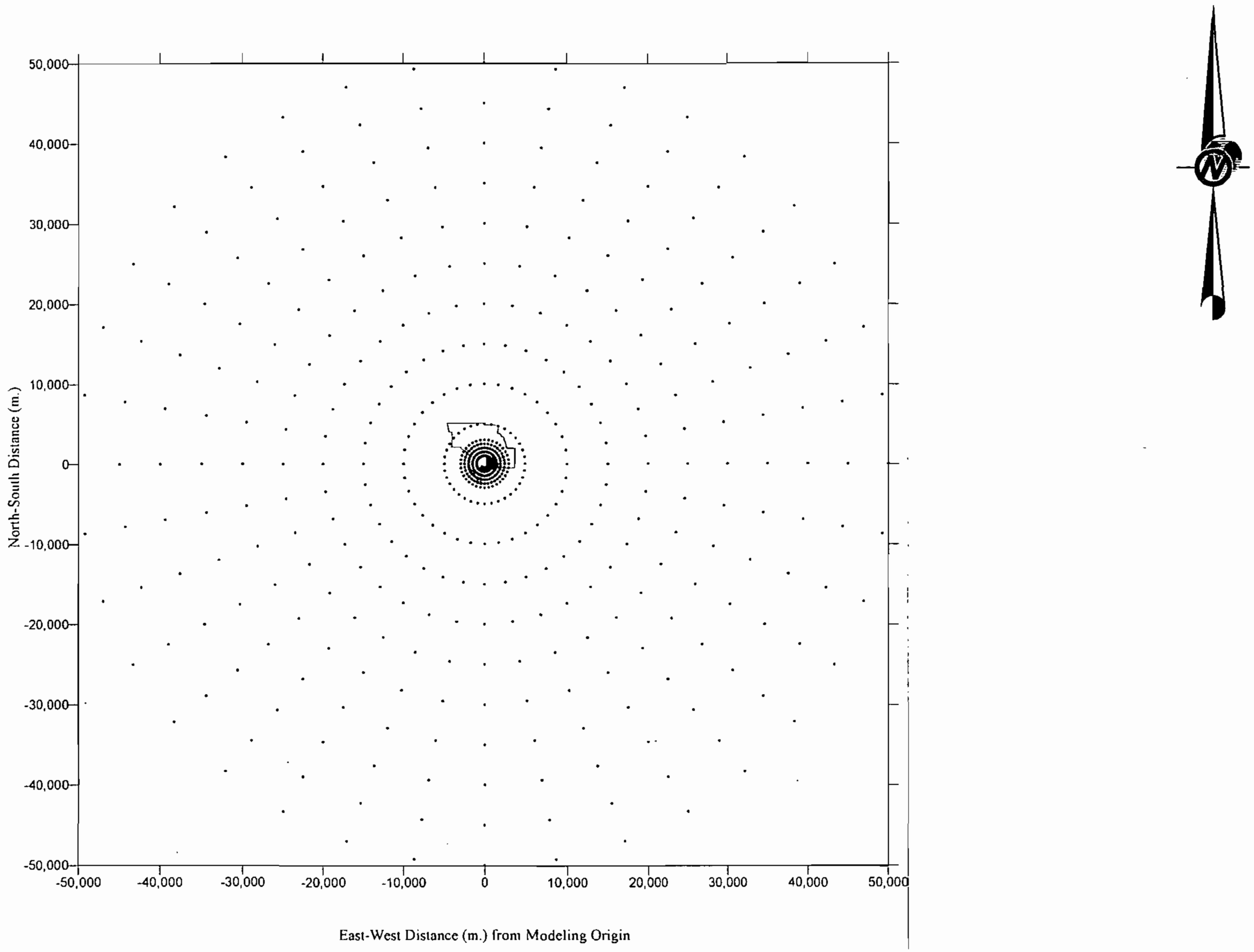
FILE No.	0439518 FIG 2-2.DWG	CHECK	SO
PROJECT No.	043-9518	REV.	0
REVIEW	MM	HINES ENERGY COMPLEX	FIGURE 2-2

Drawing file: 0439518 FIG 2-2.dwg Aug 16, 2004 - 1:40pm



Drawing file: 0439518 FIG 6-1.dwg Aug 16, 2004 - 1:41pm

Golder Associates
Tampa, Florida

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FILE No. 0439518 FIG 6-1.DWG

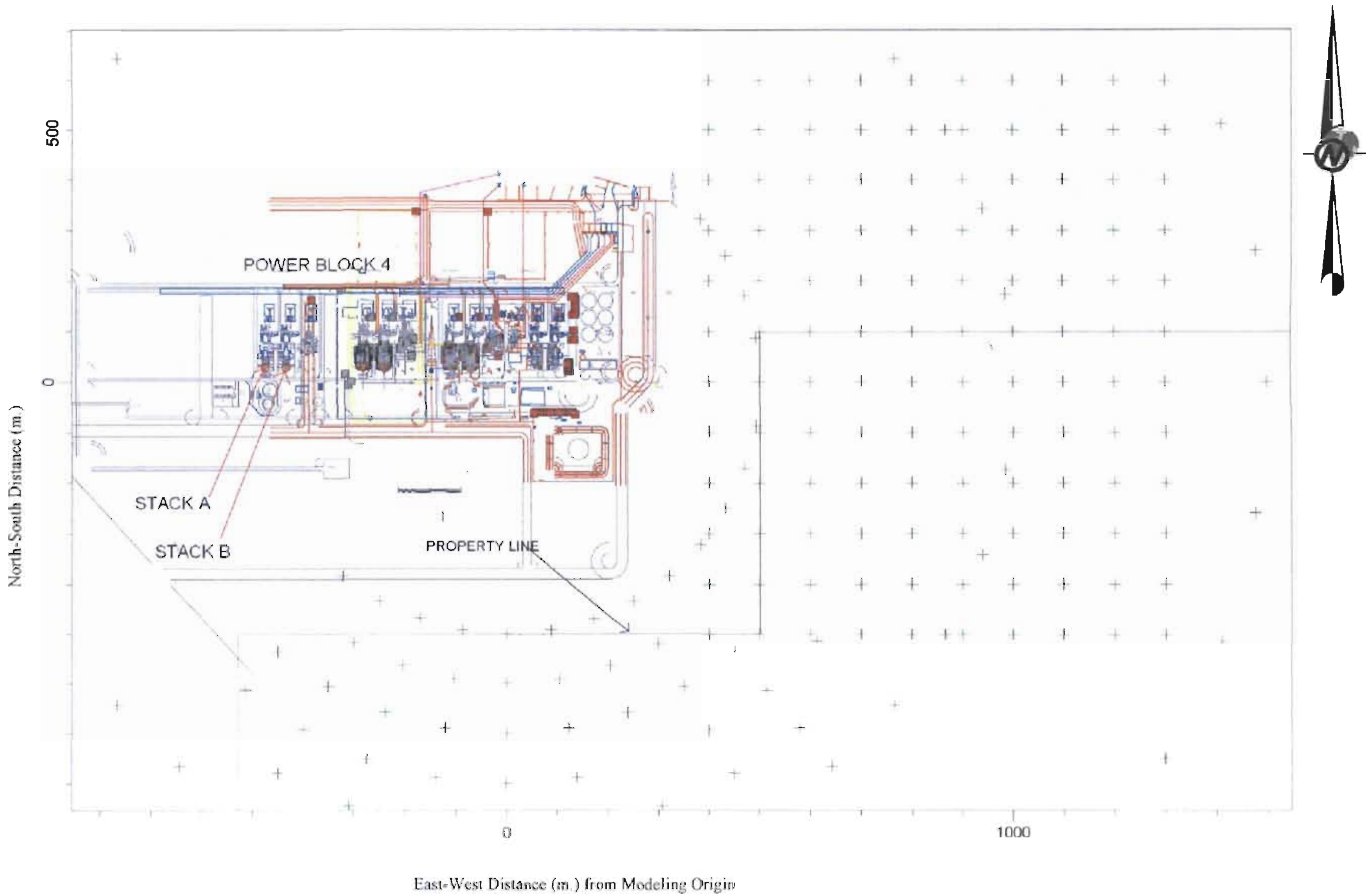
PROJECT No. 043-9518 REV. 0

TITLE

RECEPTOR GRID FOR SIGNIFICANT IMPACT ANALYSIS

HINES ENERGY COMPLEX

FIGURE 6-1



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FILE No.: 0439518 FIG 6-2.DWG	CHECK		
PROJECT No.: 043-9518 REV. 0	REVIEW	HINES ENERGY COMPLEX	FIGURE 6-2

Drawing file: 0439518 FIG 6-2.dwg Aug 16, 2004 - 1:41pm

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

August 19, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida
100 Central Avenue
St. Petersburg, FL 33701

Re: Request for Additional Information
Hines Energy Complex Power Block 4
File No. 1050234-010-AC

Dear Mr. Zirkle:

The Department is in receipt of your PSD application, however in order to continue processing the application, we will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

<u>Request for permit revisions</u>

I. Progress has requested permission to operate for up to 3000 hours per year below 60% output, however within Appendix A "Emission Estimates", data was provided for only the 100%, 80% and 60% (65% for distillate) output cases.

A) Please provide the same data for the 50% 30% and 10% CT output cases for natural gas.
B) Should Progress desire to be permitted for any operation below 65% CT output while firing distillate oil, then FDEP requires the same data (50%, 30% and 10% output) for the distillate oil cases.
C) Please indicate the lowest CT output (%) at which continuous operation is sought (on each fuel).
D) Please provide CT/HRSG/Steam Turbine heat balance diagrams (see attached 'example' from a conventional steam plant) for each of the CT outputs defined above (10%, 30%, 50%, 60%, 80% and 100%)

II. Progress has requested up to eight hours per day of combined excess emissions for a cold start-up and up to five hours of combined excess emissions per day for any steam turbine shutdown. Further, Progress wishes to define a cold start-up as 'following a shutdown of the steam turbine lasting at least 48 hours'.

A) Based upon prior guidance from EPA Region 4, the Department is not inclined to grant such lengthy time periods for unlimited excess emissions. Instead, the Department will consider the development of alternative emission limits for routine operations where full-load emission limits cannot be achieved (this includes periods such as start-up and shut-downs, and perhaps even extended periods of operation during low load, as has been requested herein). In order for the Department to evaluate alternative emission limits for such operations, actual emission estimates will be required. Therefore, for any pollutant whereby Progress expects to be unable to meet a "full load" BACT established emission limit (but specifically during a steam turbine shutdown and cold start-up), the Department will need to be provided with estimated emission curves during those time periods. This should include each of the stages of the event (e.g. cold startup) including the purpose, operating load, duration at that operating load, and estimated emissions at that operating load.
B) Please support the (above) proposed definition of a cold start-up ('following a shutdown of the steam turbine lasting at least 48 hours') by providing:
   1) The manufacturers criteria for what constitutes a cold start-up (e.g. turbine manufacturers typically identify the first stage metal temperature on the steam turbine) and
   2) The additional operational measures which the equipment manufacturer requires to be taken as a result of the cold-start-up criteria being met.

III. Within Section 2 of the PSD application, Progress states "At present there are no confirmed test data of formaldehyde emissions from similar Siemens Westinghouse or equivalent combustion turbines." In order to be thorough, the Department requests that Progress contact the manufacturer (Siemens Westinghouse) to obtain test data for formaldehyde emissions on 501F machines. Should Westinghouse not have access to any such data, please request that they provide written confirmation to this effect.

IV. Regarding the proposed BACT Determination for CO:

A) Please confirm the evaluated placement position of the oxidation catalyst (within the flue gas stream) for Hines Power Block 4 is directly after the CT (and before the HRSG), as suggested in Appendix B, page 14. If this is not the desired placement, please specify the position in the flue gas stream as precisely as possible.

B) The Department notes the following discrepancies between the provided cost effectiveness calculation and the OAQPS Control Cost Manual:

1) Indirect Costs are to be based upon a percentage of the Direct Capital Costs (TDCC in your supplied calculation), exclusive of the Direct Installation Costs (TDIC). The submitted evaluation shows indirect costs as based upon the sum of TDCC and TDIC (referred to as Total Capital Costs).
2) The "Inventory Cost" associated with the Catalyst Replacement Cost is not an acceptable entry.
3) The Capital Recovery (referred to as Annualized Total Direct Capital in the submitted evaluation) should **exclude** the initial cost of the catalyst (times freight and sales tax).
4) Heat Rate Penalty – Please provide the Department with the assumed fuel cost (in $/MMBtu) which was utilized as a basis for adding $3/MMBtu in the "Heat Rate Penalty" calculation.

C) Please provide the basis for the estimated TPY of CO removed which was utilized in the submitted cost effectiveness of $3,773 per ton

D) Please provide the basis for the estimated net TPY emission reduction, which was utilized in the submitted cost effectiveness of $4,070 per ton

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin
Michael P. Halpin, P.E.
DARM/BAR
North Permitting Section

Jamie Hunter, Progress
Scott Osbourn, Golder
Jim Little, EPA Region 4
Buck Oven, DEP-Siting
Jerry Kissel, DEP-SWD

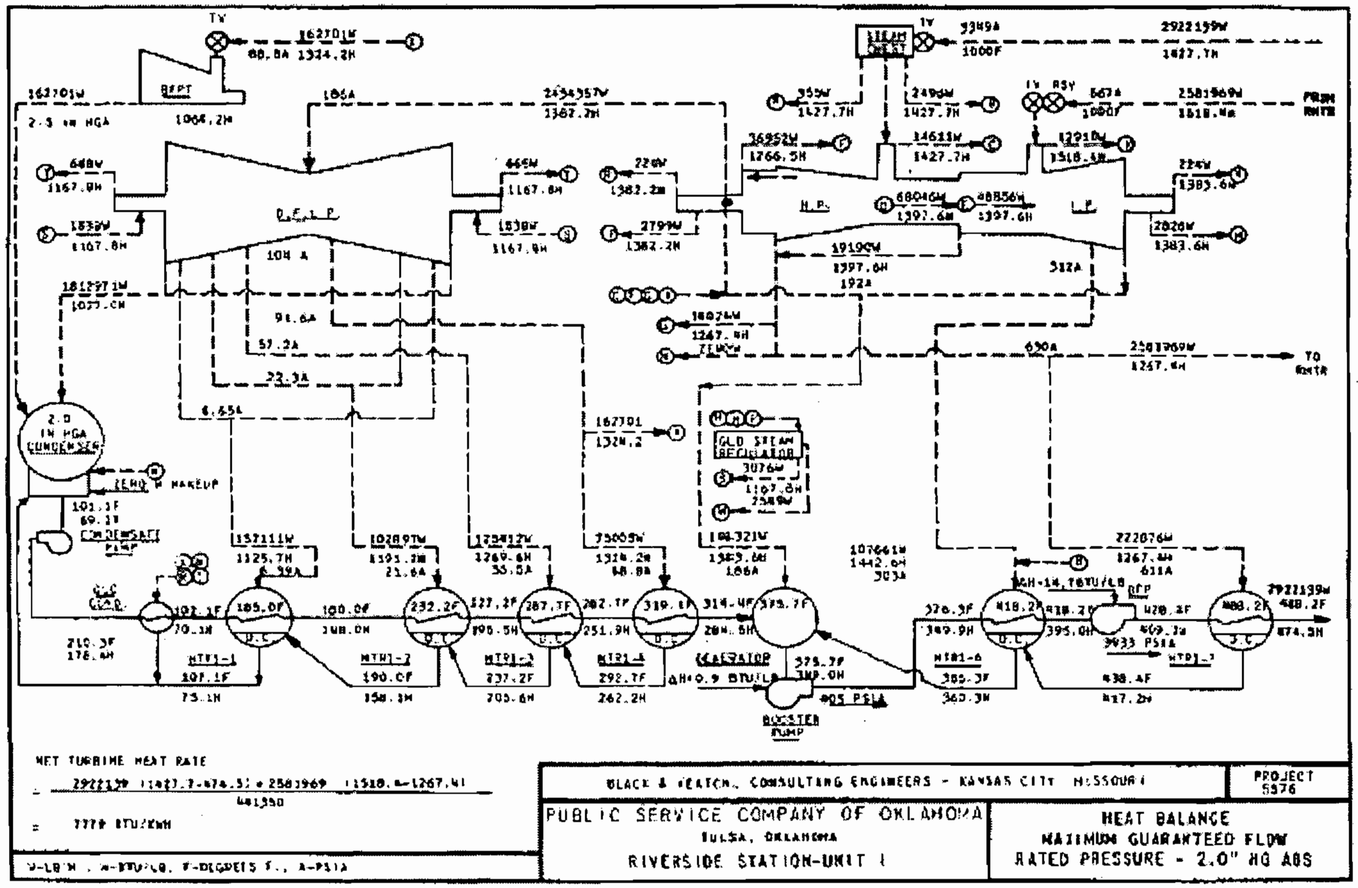

FIGURE 2.13 Thermodynamic properties and flow rates in a modern natural-gas-burning steam power plant—PSO Riverside Station Unit #1. (Courtesy of Public Service Company of Oklahoma.)

FAX TRANSMITTAL

TO	NAME: Mike Halpern	
	ORGANIZATION:	
	MAIL STOP:	
	Fax Number 850 Area Code 921 9533	Number
	Verification Number Area Code	Number

U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 9
AIR DIVISION
75 HAWTHORNE STREET
SAN FRANCISCO, CA 94105

FROM	NAME: Barbara Toole O'Neil / Ed Pike	
	SECTION:	
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	Verification Number Area Code 415	Number
Date:		
# Of Pages	(Including Cover)	
SUBJECT:		
NOTES:		

Bay Area Air Quality Management District

MEMORANDUM
July 30, 2002

COPY FOR FILE

To: D. Jang – BAAQMD Permit Services Division

Via: Ken Kunaniec COMM FOR K. K. 8/5/02

Via: Chuck McClure COMM 8/5/02

From: Marco Hernandez

Subject: Review of startup PAH and Formaldehyde sampling tests to determine compliance with BAAQMD and California Energy Commission standards. Sampling was conducted on April 26, 2002 at Calpine Pittsburg, LLC (Calpine Delta Energy Center). Plant # 12095, Application # 4965, Sources # S-1, S-3 & S-5 (Power plant gas turbines # 1 through # 3), Condition # 17154.

The startup emission compliance test report referenced above, performed by The Avogadro Group, LLC and submitted via Calpine has been reviewed. Staff comments resulting from review of the report follow:

1. Test series were conducted to satisfy part 45 of the Authority to Construct. The following analyte emissions were to be determined: Formaldehyde, Benzene and Polycyclic Aromatic Hydrocarbons (PAH) at turbine maximum load operating conditions. Benzene analysis was not conducted because the sampling team forgot to request the laboratory to do so.

2. Numerous errors were found throughout PAH emissions calculations. Especially elements of the acceptance criterion from CARB Method 429 section 8.2 was not follow. For these reasons Avogadro calculations are not included in this memo but instead BAAQMD spreadsheet is presented with final results.

3. Lab analysis (Air Toxics LTD) did not report formaldehyde by spices (formaldehyde and acetaldehyde) as stated by CARB Method 430.

4. Included in the report are substantiating documentation confirming required equipment calibration and chain of custody procedures were correctly performed. Quality assurance, lab data interpretation and emission calculations were poorly performed.

5. Attachments A and B are BAAQMD spreadsheets utilized to validate test data development.

Conclusion

The submitted test documentation although marginal is accepted and indicates representative samples of emissions were obtained.

Attachments: Table # 4-3: Emission Test Results Summary (The Avogadro Group).
Attachment A: PAH Calculations CARB Method 429, BAAQMD spreadsheet.
Attachment B: Formaldehydes, CARB Method 430, BAAQMD spreadsheet.

TABLE 4-3, EMISSION TEST RESULTS SUMMARY
FORMALDEHYDE EMISSIONS
GAS TURBINE UNIT 3, DELTA ENERGY CENTER, APRIL 2002

Run Number	1-F-3	2-F-3	3-F-3	Average
100% Load with Duct Burners and Steam Augmentation				
Date:	4-26-02	4-26-02	4-26-02 to 4-27-02	
Time:	1210-1610	1955-2155	2339-0139	
Turbine Gross Output, MegaWatts	199	198	202	200
Fuel Flow, Kscf/hr	2,095.1	2,090.6	2068.7	2084.8
Unit Heat Input, MMBTU/hr	2,155.5	2,101.1	2,079.0	2,095.2
Stack Gas				
Flow, dscfm	830,313	819,729	812,815	820,953
Temperature, °F	206	206	203	205
O_2, % vol. dry	13.28	13.20	13.21	13.23
CO_2, % vol. dry	4.31	4.33	4.33	4.32
H_2O, % vol	13.2	12.9	12.9	13.1
Formaldehyde				
Concentration, ppb vol. dry	74 ✓	ND< 8 ✓	7 ✓	< 30 ✓
Emission Rate, lb/hr	0.2860	ND< 0.0324	0.0281	<0.1155
Emission Rate, lb/MMBTU	1.36E-4	ND<1.55E-5	1.36E-5	<4.13E-5

Note: The results presented here are based on the field and laboratory data and on the calculations presented in the Appendices of the report. The Formaldehyde results were calculated from the blank-corrected concentrations, rather than from the method reporting limit.

ok
7-22-02

Formaldehyde and Acetaldehyde
CARB Method 430

Run #	Std Sample volume, cf	DSCFM	Aldehydes, µg HCHO		Aldehydes, µg CH_3CHO			ppbv HCHO	lb/hr HCHO	ppbv CH_3CHO	lb/hr CH_3CHO
1	3.304	834,031	3 6.1	9.1	N/A N/A		#VALUE!	78.19	0.3038	#VALUE!	#VALUE!
2	3.304	806,387	< 1.0 < 0.5	< 1.5	N/A N/A		#VALUE!	< 12.9	< 0.048	#VALUE!	#VALUE!
3	3.304	839,809	0.84 < 0.5	< 1.34	N/A N/A		#VALUE!	< 11.5	< 0.045	#VALUE!	#VALUE!
MW			30.03		44.05						
Averages								34.20	0.1324	#VALUE!	#VALUE!

Blank Corrections:

Run #	Std Sample volume, cf	Aldehydes, µg HCHO	Aldehydes, µg CH_3CHO	Blanks ppbv HCHO	Blanks ppbv CH_3CHO	Mass ratio Samp/blk	Corrections ppbv HCHO	Corrections ppbv CH_3CHO			
1	3.304	0.86	N/A	7.39	N/A	9.9	72.86	**#VALUE!**			
2	3.304	< 0.5	N/A	4.30	N/A	1.8	7.56	**#VALUE!**			
3	3.304	< 0.5	N/A	4.30	N/A	1.4	6.19	**#VALUE!**			
Averages				5.33	#DIV/0!	5.42	**28.87**	**#VALUE!**	**0.11**	lb/hr	HCHO
Final concentrations:							N/A	**#VALUE!**			

BAAQMD
Source Test

Calpine Delta Energy C...
4/26/0...

Attachment A
Determination of Polycyclic Aromatic Hydrocarbons (PAH) Emissions from Stationary Sources
CARB Method 429
Turbine T-3 (Source # 73)
100 % Load with Duct Burners and Steam Augmentation

Analyte	Lab Results (ng/sample)				Sample/Blank PAH mass ratio $^{\alpha}$			Corrected reporting limit for PAH (ng/sample) $^{\beta}$			Reporting Limit PAH (µg/dscm)			Average	Average
	Blank	Run 1	Run 2	Run 3	Run 1	Run 2	Run 3	Run 1	Run 2	Run 3	Run 1	Run 2	Run 3	(µg/dscm)	(lb/hr)
Naphthalene	31.2	74.4	4770	< 156.0	*2.4*	152.9	5.0	156	4770	< 156.0	0.03435	1.1036	< 0.03457	**< 0.391**	**< 1.21E-03**
2-methylnaphthalene	< 10.0	16.4	689	20.6	*1.6*	68.9	*2.1*	< 50.0	689	< 50.0	< 0.01101	0.1594	< 0.01108	**< 0.060**	**< 1.87E-04**
Acenaphthylene	< 10.0	21.3	90.6	10.1	*2.1*	9.1	*1.0*	< 50.0	90.6	< 50.0	< 0.01101	0.0210	< 0.01108	**< 0.014**	**< 4.44E-05**
Acenaphthene	< 10.0	< 10.0	14.4	< 10.0	*1.0*	*1.4*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Fluorene	< 10.0	< 10.0	88	< 10.0	*1.0*	8.8	*1.0*	< 50.0	88	< 50.0	< 0.01101	0.0204	< 0.01108	**< 0.014**	**< 4.38E-05**
Phenanthrene	< 25.0	86.3	< 250.0	70.6	*3.5*	10.0	*2.8*	< 125.0	< 250.0	< 125.0	< 0.02753	< 0.05784	< 0.02770	**< 0.038**	**< 1.17E-04**
Anthracene	< 10.0	< 10.0	< 100.0	< 10.0	*1.0*	10.0	*1.0*	< 50.0	< 100.0	< 50.0	< 0.01101	< 0.02314	< 0.01108	**< 0.015**	**< 4.66E-05**
Fluoranthene	< 10.0	70.8	< 100.0	38.7	7.1	10.0	*3.9*	70.8	< 100.0	< 50.0	0.01559	< 0.02314	< 0.01108	**< 0.017**	**< 5.14E-05**
Pyrene	< 10.0	81.8	< 100.0	47	8.2	10.0	*4.7*	81.8	< 100.0	< 50.0	0.01801	< 0.02314	< 0.01108	**< 0.017**	**< 5.39E-05**
Benz(a)anthracene $^{\phi}$	< 10.0	< 10.0	< 10.0	< 10.0	*1.0*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Chrysene	< 10.0	10.9	< 10.0	< 10.0	*1.1*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Benzo(b)fluoranthene $^{\phi}$	< 10.0	11.4	< 10.0	< 10.0	*1.1*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Benzo(k)fluoranthene $^{\phi}$	< 10.0	< 10.0	< 10.0	< 10.0	*1.0*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Benzo(e)pyrene	< 10.0	< 10.0	< 10.0	< 10.0	*1.0*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Benzo(a)pyrene $^{\phi}$	< 10.0	< 10.0	< 10.0	< 10.0	*1.0*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Perylene	< 10.0	< 10.0	< 10.0	< 10.0	*1.0*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Indeno(1,2,3-c,d)pyrene $^{\phi}$	< 10.0	< 10.0	< 10.0	< 10.0	*1.0*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Dibenz(a,h)anthracene $^{\phi}$	< 10.0	< 10.0	< 10.0	< 10.0	*1.0*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.01101	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**
Benzo(g,h,I)perylene	< 10.0	< 10.0	< 10.0	< 10.0	*1.0*	*1.0*	*1.0*	< 50.0	< 50.0	< 50.0	< 0.0	< 0.01157	< 0.01108	**< 0.011**	**< 3.47E-05**

M. Hernandez :
Blue italic format means the mass ratio was less than 5.

		Run 1	Run 2	Run 3
Sampled volume (dscf) =		**160.370**	**152.642**	**159.372**
Stack temp, °F		**208.3**	**205.3**	**210.3**
Turbine gross output, MW		**199**	**198**	**202**
Fuel Flow, Kscf/hr		**2095.1**	**2090.6**	**2068.7**
Unit heat input, MMBtu/hr		**2155.5**	**2101.1**	**2079.0**
Avg flow rate (dscfm) =	**826,742**			

			Average (µg/dscm)	Average (lb/hr)
Total PAH average $^{\phi}$	*< 9.86E-08*	*lb/MMBtu*	*< 0.067*	*< 2.08E-04*
Total PAH average	**< 1.01E-06**	**lb/MMBtu**	**< 0.690**	**< 2.13E-03**

Sampled time per run **240 min**

Notes:

" < " Indiques non detected, reporting limit (RL) is being used.

" α " CARB equation 429-27

" β " CARB equation 429-30, If the sample/blank mass ratio is lower than 5 then RL shall be 5 times the field blank concentration.

" ϕ " Total PAH average results represent the sum of 6 PAH compounds specified in the BAAQMD permit.

Average concentration for O_2 = 13.23 %, CO_2 = 4.32 % and H_2O = 13.1 %.

c:\2002\reportsreview\07\delta\CARB429(PAH)&430.xls

ENGELHARD

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ISELIN, NJ 08830
732-205-5000

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BEL AIR, MD 21015
PHONE 410-569-0297
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E-Mail Fred_Booth@ENGELHARD.COM

DATE:	September 8, 2000	NO. PAGES	3
TO:	ECT ATTN: Tom Davis ENGELHARD ATTN: Nancy Ellison	via e-mail	
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841	

RE: **ECT 000105-0300-1100 / Calpine-Blue Heron**
Camet® CO and NOxCAT™ VNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00928

We provide Engelhard Budgetary Proposal EPB00928 for Engelhard **Camet®** CO and **NOxCAT™ VNX™** vanadia-titania SCR Catalyst systems per your e-mail request of August 24, 2000.

Our Proposal is based on:

- CO Catalyst for 90% CO reduction;
- SCR Catalyst for NOx reduction from given inlet levels to 3.5 ppmvd @ 15% O_2 with ammonia slip of 9 ppmvd @ 15% O_2;
- Assumed HRSG inside liner dimensions of 67 ft. H x 32 ft. W;
- Assumed 19% aqueous ammonia to ammonia skid;
- Scope as noted: Typical to HRSG supplier

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

ECT 000105-0300-1100
Calpine Blue Heron
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00928
September 8, 2000

CAMET® CO CATALYST SYSTEM
NOxCAT™ VNX™ SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **Camet®** metal substrate CO System and **NOxCAT™ VNX™** ceramic substrate SCR systems summarized per the technical data and site conditions provided.

Scope of Supply: The equipment supplied is installed by others in accordance with Engelhard design and installation instructions.
Engelhard **Camet®** CO and **NOxCAT™ VNX™** SCR catalyst in modules;
Internal support frames for catalyst modules - installed inside internally insulated casing (casing by others);
Ammonia Delivery System Components: Aqueous (19% Sol.) Ammonia to skid
- Ammonia Injection Grid (AIG);
- 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:
    - Blowers (on/off/flow indicators)
    - Air/ammonia flow indicator and controller
    - System pressure indicators
    - Main power disconnect switch

BUDGET PRICES: Per Turbine See Performance data

Excluded from Scope of Supply:
Ammonia storage and pumping
Any transitions to and from reactor
Electrical grounding equipment
Foundations
All other items not specifically listed in Scope of Supply
Internally insulated reactor Housing (HRSG Casing)
Any interconnecting field piping or wiring
Utilities
All Monitors

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	• Three (3) Years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life.
Expected Life	5 - 7 years

CO / SCR SYSTEM DESIGN BASIS:

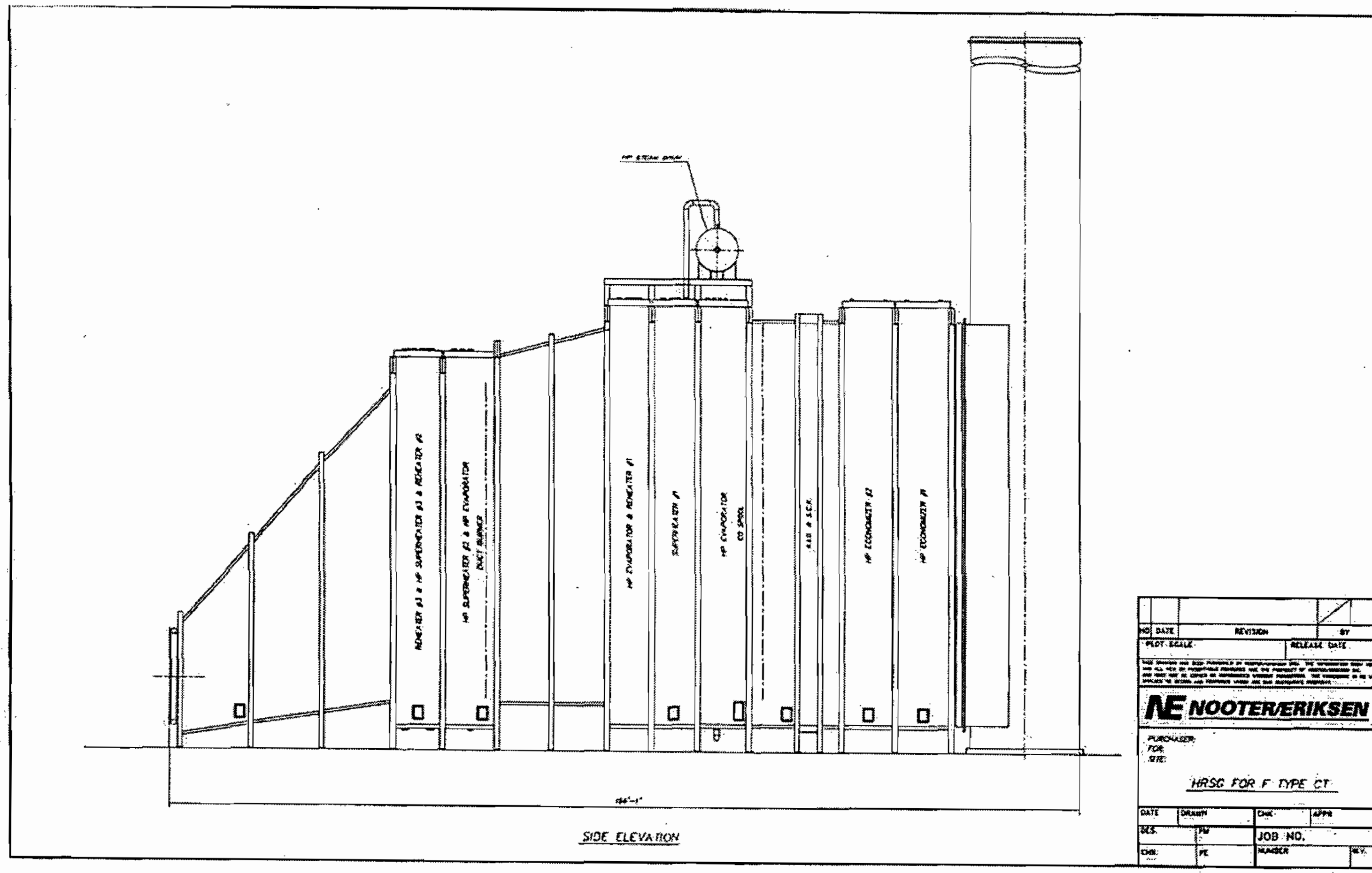
Gas Flow from:	Combustion Turbine + Duct Burner
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data - Designed for Gas Velocities within $\pm$15% at the reactor inlet
Temperature (At catalyst face):	Designed for Gas Temperature with maximum range $\pm 20^{O}$F at the reactor inlet
CO Inlet (At catalyst face):	See Performance Data
CO Reduction	90% Reduction
NOx Inlet (At catalyst face):	See Performance Data
NOx Reduction :	To 3.5 ppmvd @ 15% O_2 (NG)
NH_3 Slip:	9 ppmvd @ 15%O_2
HRSG Cross Section	67 ft. H x 32 ft. W

ENGELHARD

ECT 000105-0300-1100
Calpine Blue Heron
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00928
September 8, 2000

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	
TURBINE EXHAUST FLOW, lb/hr	3,980,503
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	71.51
O2	10.50
CO2	4.36
H2O	12.73
Ar	0.90
GIVEN: TURBINE CO, ppmvd @ 15% O2	37
CALC.: TURBINE CO, lb/hr	193.2
GIVEN: TURBINE NOx, ppmvd @ 15%O2	25
CALC.: TURBINE NOx, lb/hr	212.5
CALC. GAS MOL. WT.	27.97
GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650
DESIGN REQUIREMENTS	
CO CATALYST CO OUT, ppmvd @ 15% O2	3.7
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5
NH3 SLIP, ppmvd @ 15% O2	9
GUARANTEED PERFORMANCE DATA	
CO CATALYST CO CONVERSION, % - Min.	90.0%
CO OUT, lb/hr - Max.	19.3
CO OUT, ppmvd @ 15% O2 - Max.	3.7
CO PRESSURE DROP, "WG - Max.	1.0
SCR CATALYST NOx CONVERSION, % - Min.	85.9%
NOx OUT, lb/hr - Max.	30.1
NOx OUT, ppmvd @ 15% O2 - Max.	3.5
EXPECTED AQUEOUS NH3 (19% SOL.) FLOW, lb/hr	505.2
NH3 SLIP, ppmvd @ 15% O2 - Max.	9
SCR PRESSURE DROP, "WG - Max.	2.0
CO SYSTEM	**$880,000**
REPLACEMENT CO CATALYST MODULES	**$770,000**
SCR SYSTEM	**$1,678,000**
REPLACEMENT SCR CATALYST MODULES	**$1,178,000**


HP STEAM DRUM
REHEATER #3 & HP SUPERHEATER #3 & REHEATER #2
HP SUPERHEATER #2 & HP EVAPORATOR
DUCT BURNER
HP EVAPORATOR & REHEATER #1
SUPERHEATER #1
HP EVAPORATOR
CO SPOOL
HP ECONOMIZER #2
HP ECONOMIZER #1
SIDE ELEVATION
NO
DATE
REVISION
BY
PLOT SCALE
RELEASE DATE
NOOTER/ERIKSEN
PURCHASER:
FOR:
SITE:
HRSG FOR F TYPE CT
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DES.
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Figure 4

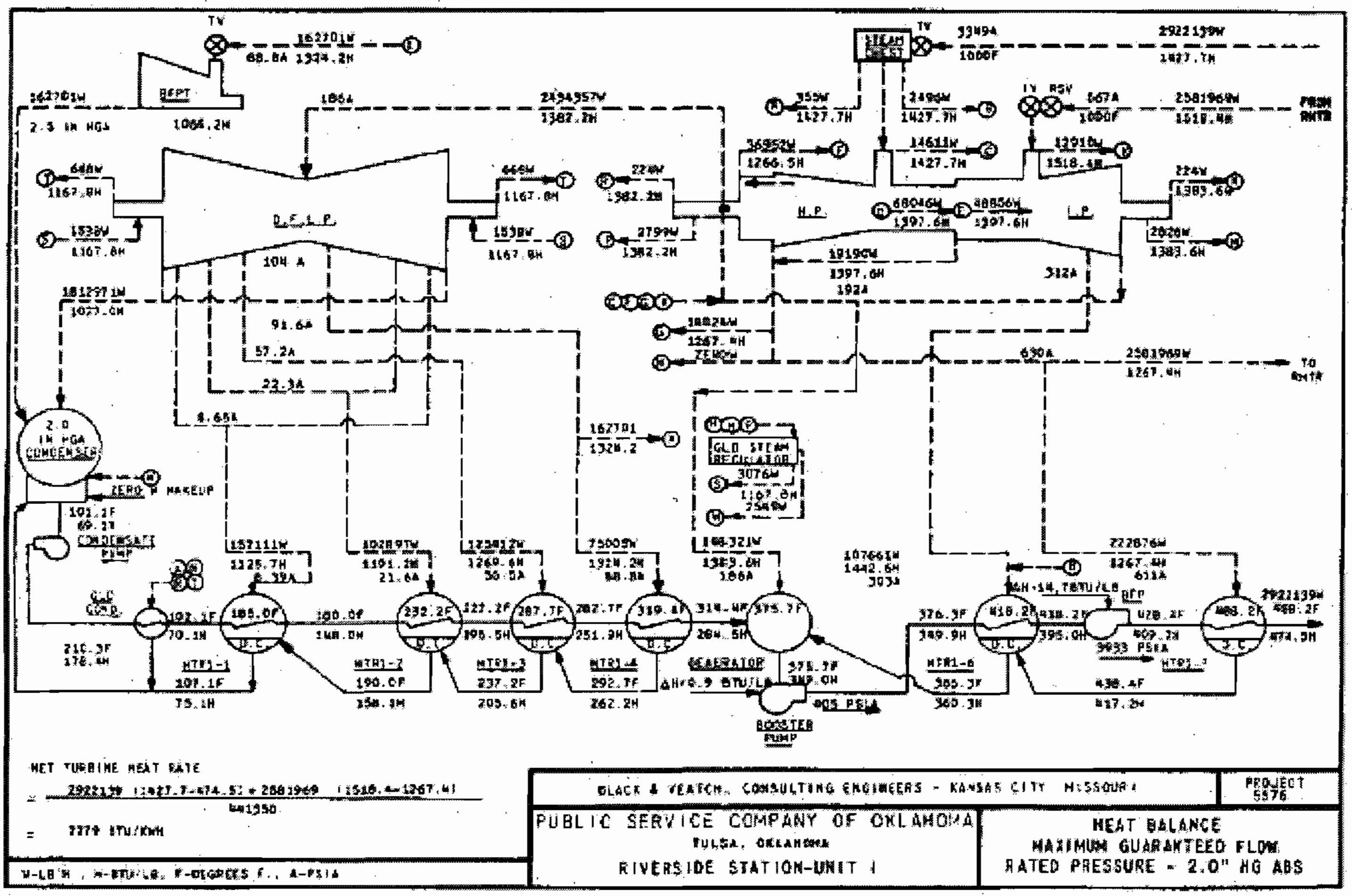


FIGURE 2.13 Thermodynamic properties and flow rates in a modern natural-gas-burning steam power plant—PSO Riverside Station Unit #1. (Courtesy of Public Service Company of Oklahoma.)

Chapter 3

Table 2.10: Annual Costs for Thermal and Catalytic Incinerators
Example Problem

Cost Item	Suggested Factor	Unit Cost[a]	Thermal	Fluid-Bed Catalyst
Direct Annual Costs[b], DC				
Operating Labor				
Operator	0.5 hr/shift	$12.95/hr.	6,480	6,480
Supervisor	15% of operator	-	972	972
Operating Materials	-			
Maintenance				
Labor	0.5 hr/shift	$14.95/hr.	7,130	7,130
Materials	100% of maintenance labor	-	7,130	7,130
Catalyst replacement	100% of catalyst replaced	$650/ft³ for metal oxide	0	15,100
Utilities				
Natural Gas	-	$3.30/kft³	264,500	63,400
Electricity	-	$0059/kWh	36,500	44,200
Total DC			**$321,200**	**$144,400**
Indirect Annual Cost, IC				
Overhead	60% of sum of operating, supervisor, & maintenance labor & maintenance materials	-	13,000	17,800
Administrative Charges	2% TCI	-	9,650	17,800
Property Taxes	1% TCI	-	4,830	8,900
Insurance	1% TCI	-	4,830	122,700
Capital recovery[c]	CRF [TCI - 1.08 (cat. Cost)]	-	68,800	122,700
			$101,100	**$171,300**
Total Direct Cost (rounded)			**$422,000**	**$316,000**

[a] 1998 dollars
[b] Assumes 8,000 hr/yr
[c] The capital recovery cost factor, CRF, is a function of the catalyst or equipment life (typically, 2 and 10 years, respectively) and the opportunity cost of the capital (i.e., interest rate). For example, for a 10-year equipment life and a 7% interest rate, CRF = 0.1424

Table 2.9: Capital Cost Factors for Thermal and Catalytic Incinerator [10] Example Problems

Cost Item	Thermal-Recuperative	Fluid-Bed
	Cost, $	
Catalytic		
Direct Costs		
Purchased equipment costs		
Incinerator (EC)	$254,200	$468,000
Auxiliary equipment	-	-
Sum = A	254,000	468,000
Instrumentation, 0.1 A[a]	25,400	46,800
Sales taxes, 0.30 A	7,630	14,000
Freight. 0.05 A	12,700	13,400
Purchased equipment cost, B	$300,000	$552,400
Direct installation costs		
Foundations & supports, 0.08 B	24,000	44,200
Handling & erection, 0.14 B	42,000	77,300
Electrical, 0.04 B	12,000	22,100
Piping, .002 B	6,000	11,000
Insulation for ductwork, 0.01B	3,000	5,520
Painting, 0.01 B	3,000	5,520
Direct installation costs	$90,000	$165,000
Site preparation[a]	-	-
Buildings[a]	-	-
Total Direct	**$390,000**	**$718,000**
Indirect Costs (installation)		
Engineering, .010 B	30,000	55,200
Construction and field expenses, 0.05 B	15,000	27,600
Contractor fees, 0.10 B	30,000	55,200
Start-up, 0.02 B	6,000	11,000
Performance test, 0.01 B	3,000	5,520
Contingencies, 0.03 B	9,000	16,600
Total Indirect Costs	$93,000	$171,100
Total Capital Investment (rounded)	**$483,000**	**$889,000**

[a] None of these items is required.

Table 2.8: Capital Cost Factors for Thermal and Catalytic Incinerators [10]

Cost Item	Factor
Direct Costs	
Purchased equipment costs	
Incinerator (EC) + auxiliary equipment[a]	As estimated, A
Instrumentation[b]	0.10 A
Sales taxes	0.03 A
Freight	0.05 A
Purchased equipment cost, PEC	B = 1.18 A
Direct installation costs	
Foundations & supports	0.08 B
Handling & erection	0.14 B
Electrical	0.04 B
Piping	0.02 B
Insulation for ductwork[c]	0.01 B
Painting	0.01 B
Direct installatoin costs	0.03 B
Site preparation	As required, SP
Buildings	As required, Bldg.
Total Direct Costs, DC	**1.30 B + SP + Bldg.**
Indirect Costs (installation)	
Engineering	0.10 B
Construction and field expenses	0.05 B
Contractor fees	0.10 B
Start-up	0.02 B
Performance test	0.01 B
Contingencies	0.03 B
Total Indirect Costs, IC	0.31 B
Total Capital Investment = DC + IC	**1.61 B + SP + Bldg.**

[a] Ductwork and any other equipment normally not included with unit furnished by incinerator vendor.
[b] Instrumentation and controls often furnished with the incinerator, and those often included in the EC.
[c] If ductwork dimensions have been established, cost may be estimated based on \$10 to \$12/ft² of surface for fluid application. (Alternatively, refer to Section 1.2 of this Manual. Fan housing and stacks may also be insulated.

Table 3.10. Annual Costs for Thermal and Catalytic Incinerators Example Problem

Cost Item	Suggested Factor	Unit Cost[a]	Thermal	Fluid-Bed Catalyst
Direct Annual Costs[b], DC				
Operating Labor				
Operator	0.5 h/shift	$12.95/h	6,480	6,480
Supervisor	15% of operator	—	972	972
Operating Materials	—			
Maintenance				
Labor	0.5 h/shift	$14.25/h	7,130	7,130
Material	100% of maint. labor	—	7,130	7,130
Catalyst replacement	100% of catalyst replaced ea. 2 yr.	$650/ft^3 for metal oxide	0	15,100
Utilities				
Natural Gas	—	$3.30/kft^3	264,500	63,400
Electricity	—	$0.059/kWh	36,500	44,200
Total DC			$321,200	$144,400
Indirect Annual Costs, IC				
Overhead	60% of sum of operating, supr., & maint. labor & maint. materials.	—	13,000	13,000
Administrative charges	2% TCI	—	9,650	17,800
Property taxes	1% TCI	—	4,830	8,900
Insurance	1% TCI	—	4,830	8,900
Capital recovery[c]	CRF [TCI- 1.08 (Cat. Cost)]	—	68,800	122,700
			$101,100	$171,300
Total Annual Cost (rounded)			$422,000	$316,000

[a]1988 dollars

[b]Assumes 8.000 h/yr

[c]The capital recovery cost factor, CRF, is a function of the catalyst or equipment life (typically, 2 and 10 years, respectively) and the opportunity cost of the capital (i.e., interest rate). For example, for a 10-year equipment life and a 7% interest rate, CRF = 0.1424.

Table 3.8. Capital Cost Factors for Thermal and Catalytic Incinerators[a]

Cost Item	Factor
Direct Costs	
Purchased equipment costs	
Incinerator (EC) + auxiliary equipment[b]	As estimated, A
Instrumentation[c]	0.10 A
Sales taxes	0.03 A
Freight	0.05 A
Purchased equipment cost, PEC	B = 1.18 A
Direct installation costs	
Foundations & supports	0.08 B
Handling & erection	0.14 B
Electrical	0.04 B
Piping	0.02 B
Insulation for ductwork[d]	0.01 B
Painting	0.01 B
Direct installation cost	0.30 B
Site preparation	As required, SP
Buildings	As required, Bldg
Total Direct Cost, DC	1.30 B + SP + Bldg.
Indirect Costs (installation)	
Engineering	0.10 B
Construction and field expenses	0.05 B
Contractor fees	0.10 B
Start-up	0.02 B
Performance test	0.01 B
Contingencies	0.03 B
Total Indirect Cost, IC	0.31 B
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.

[a]Reference [25]

[b]Ductwork and any other equipment normally not included with unit furnished by incinerator vendor.

[c]Instrumentation and controls often furnished with the incinerator, and those often included in the EC.

[d]If ductwork dimensions have been established, cost may be estimated based on \$10 to \$12/ft^2 of surface for fluid application. (Alternatively, refer to Chapter 10 of this Manual.
Fan housings and stacks may also be insulated.

Table 3.9. Capital Costs for Thermal and Catalytic Incinerators Example Problem

Cost Item	Cost, $ Thermal-Recuperative	Cost, $ Fluid-Bed Catalytic
Direct Costs		
Purchased equipment costs		
Incinerator (EC)	$254,200	$468,200
Auxiliary equipment[a]	—	—
Sum = A	$254,200	$468,200
Instrumentation, 0.1A	25,400	46,800
Sales taxes, 0.03A	7,630	14,000
Freight, 0.05A	12,700	23,400
Purchased equipment cost, B	$300,000	$552,400
Direct installation costs		
Foundation and supports, 0.08B	24,000	44,200
Handling and erection, 0.14B	42,000	77,300
Electrical, 0.04B	12,000	22,100
Piping, 0.02B	6,000	11,000
Insulation (for ductwork), 0.01B	3,000	5,520
Painting, 0.01B	3,000	5,520
Direct installation cost	$90,000	$165,500
Site preparation[a]	—	—
Buildings[a]	—	—
Total Direct Cost	$390,000	$718,000
Indirect Costs (installation)		
Engineering, 0.10B	30,000	55,200
Construction and field expenses, 0.05B	15,000	27,600
Contractor fees, 0.10B	30.000	55.200
Start-up, 0.02B	6.000	11,000
Performance test, 0.01B	3.000	5,520
Contingencies, 0.03B	9.000	16.600
Total Indirect Cost	$93,000	$171,100
Total Capital Investment (rounded)	$483,000	$889.000

United States
Environmental Protection
Agency

Office of
Research and Development
Washington, DC 20460

EPA/625/6-91/014
June 1991

Jeff

Technology Transfer

Handbook

Control Technologies for Hazardous Air Pollutants

Example Case

Using Equation 4.3-7:

$Q_{fg} = Q_{com} = 20{,}200$ scfm
$T_{co} = 1{,}000°F$
$Q_{fg,a} = 20{,}200\,[(1{,}000 + 460)/537]$
$Q_{fg,a} = 54{,}900$ acfm

4.3.5 Catalyst Bed Requirement

The total volume of catalyst required for a given destruction efficiency is determined from the design space velocity as follows:

$$V_{bed} = 60\ Q_{com}/SV \tag{4.3-8}$$

where:

V_{bed} = volume of catalyst bed required, ft^3

Example Case

Using Equation 4.3-8:

$Q_{com} = 20{,}200$ scfm
$SV = 30{,}000\ hr^{-1}$ (Table 4.3-1)
$V_{bed} = 60 \times 20{,}200/30{,}000$
$V_{bed} = 40\ ft^3$

4.3.6 Evaluation of Permit Application

Compare the results from the calculations and the values supplied by the permit applicant using Table 4.3-2. The calculated values in the table are based on the example case.

If the calculated values agree with the reported values, then the design and operation of the proposed catalytic incinerator system may be considered appropriate based on the assumptions used in this handbook.

Table 4.3-2. Comparison of Calculated Values and Values Supplied by the Permit Applicant for Catalytic Incineration[a]

	Calculated Value (Example Case)[a]	Reported Value
Continuous monitoring of temperature rise and pressure drop across catalyst bed	yes	...
Supplementary fuel flow rate, Q_f	179 scfm	...
Dilution air flow rate, Q_d	0	...
Combined gas steam flow rate, Q_{com}	20,200 scfm	...
Catalyst bed volume, V_{bed}	40 ft^3	...

[a]Based on Emission Stream 2.

The equations given in Table 4.3-3 are to be used for flow rates from 2,000 scfm to 50,000 scfm, and will yield costs in April 1988 dollars. These costs include instrumentation. These equations should not be extrapolated outside their range.

After obtaining equipment costs, the next step in the cost algorithm is to obtain the purchased equipment cost, PEC. The PEC is calculated as the sum of the equipment cost EC (incinerator and auxiliary equipment) and the cost of instrumentation, freight and taxes. Table 4.3-4 provides appropriate factors to estimate these costs. After obtaining the purchased equipment cost, PEC, the total capital cost (TCC) is estimated using the factors presented in Table 4.3-4.

4.3.7 Capital and Annual Costs of Catalytic Incinerators

This section presents procedures for estimating the capital and annual costs of a fixed bed catalytic incinerator.

4.3.7.1 Catalytic Incinerator Capital Costs

The capital cost of a catalytic incinerator is estimated as the sum of the equipment cost (EC) and the installation cost. The equipment cost is primarily a function of the total emission stream flow rate and the heat exchanger efficiency as well as the cost of auxiliary equipment. Table 4.3-3 provides equations to estimate the equipment cost of fixed bed catalytic incinerators based on Q_{com} and HR. Refer to Section 4.12 to obtain the auxiliary costs.

Table 4.3-3. Equipment Costs for Fixed Bed Catalytic Incinerators[a]

Catalytic Incinerator Cost, CC (April 1988 $)	Heat Exchanger Efficiency, HR
$CC = 1{,}105\ Q_{com}^{0.5471}$	HR = 0%
$CC = 3{,}623\ Q_{com}^{0.4189}$	HR = 35%
$CC = 1{,}215\ Q_{com}^{0.5575}$	HR = 50%
$CC = 1{,}443\ Q_{com}^{0.5527}$	HR = 70%

[a]Reference 5.

Example Case

$Q_{fg,a}$ = 20,200 scfm
η = 50 percent

Table 4.3-3:

CC = $1,215 (20,200)$^{0.5575}$
CC = $305,000

The auxiliary equipment costs (i.e., ductwork and fans) obtained from Section 4.12 are $10,000. Instrumentation is included with CC. Use Table 4.3-4 to obtain the purchased equipment cost, PEC.

CC + auxiliary equipment	=	$315,000
Sales tax = (315,000)(0.03)	=	$ 9,500
Freight = (315,000)(0.05)	=	$ 15,800

PEC = $315,000 + $9,500 + $15,800
PEC = $340,000

After obtaining the PEC, simply use the factors provided in Table 4.3-4 to obtain the total capital cost. The example case costs are presented in Table

4.3.7.2 Catalytic Incinerator Annual Costs

The total annual cost (TAC) of a catalytic incinerator consists of direct and indirect annual costs. Table 4.3-6 contains appropriate factors used to estimate total annual costs, while the discussion below details the information necessary to correctly use these factors.

Direct Annual Cost. These costs include fuel, electricity, catalyst replacement operating and supervisory labor, and maintenance labor and materials.

Fuel usage is calculated in Section 4.3.4.2. Once this value is calculated, multiply it by 60 to obtain scfh and multiply this by the annual operating hours to obtain the annual fuel usage. Then simply multiply the annual fuel usage by the cost of fuel to obtain this annual cost.

Electricity costs are primarily associated with the fan needed to move the gas through the incinerator. Use Equation 4.3-9 to estimate the power requirements for a fan assuming a combined motor-fan efficiency of 65 percent and a fluid specific gravity of 1.0.

$$F_p = 1.81 \times 10^{-4} (Q_{fg,a}) (P) (HRS) \qquad (4.3\text{-}9)$$

Table 4.3-4. Capital Cost Factors for Catalytic Incinerators[a]

Cost Item	Factor
Direct Costs	
Purchased equipment costs	
Incinerator (CC) + auxiliary equipment, EC	As estimated, EC
Instrumentation[b]	0.10 EC
Sales taxes	0.03 EC
Freight	0.05 EC
Purchased Equipment Cost, PEC	PEC = 1.18 EC
Direct installation costs	
Foundations & supports	0.08 PEC
Handling & erection	0.14 PEC
Electrical	0.04 PEC
Piping	0.02 PEC
Insulation for ductwork[c]	0.01 PEC
Painting	0.01 PEC
Direct Installation Cost, DC	0.30 PEC
Site preparation	As required, SP
Buildings	As required, Bldg.
Total Direct Cost, DC	1.30 PEC + SP + Bldg.
Indirect Costs (installation)	
Engineering	0.10 PEC
Construction and field expenses	0.05 PEC
Contractor fees	0.10 PEC
Start-up	0.02 PEC
Performance test	0.01 PEC
Contingencies	0.03 PEC
Total Indirect Cost, IC	0.31 PEC
Total Capital Cost (TCC) = DC + IC	1.61 PEC + SP + Bldg.

[a] Reference 5.
[b] Instrumentation and controls often furnished with the incinerator, and thus often included in the EC.
[c] If ductwork dimensions have been established, cost may be estimated based on $10 to $12/ft² of surface for field application. Fan housings and stacks may also be insulated.

Table 4.3-5. Example Case Capital Costs

Cost Item	Factor	Cost ($)
Direct Costs		
Purchased Equipment Costs, PEC		
Incinerator (EC) + auxiliary equipment		$315,000
Instrumentation	Included	0
Sales Tax	0.03	9,500
Freight	0.05	15,800
Purchased Equipment Cost, PEC		$340,000
Direct Installation costs		
Foundation and supports	0.08 PEC	$ 27,200
Handling and erection	0.14 PEC	47,700
Electrical	0.04 PEC	13,600
Piping	0.02 PEC	6,800
Insulation for ductwork	0.01 PEC	3,400
Painting	0.01 PEC	3,400
Direct Installation Cost	0.30 PEC	$102,000
Site preparation		As required, SP
Building		As required, Bldg.
Total Direct Cost, DC		$340,000 + $102,000 + SP + Bldg.
Indirect Costs		
Engineering	0.10 PEC	$ 34,000
Construction and field expense	0.05 PEC	17,000
Contractor fees	0.10 PEC	34,000
Start-up	0.02 PEC	6,800
Performance test	0.01 PEC	3,400
Contingencies	0.03 PEC	10,200
Total Indirect Cost, IC	0.31 PEC	$105,000

Total Capital Cost = DC + IC
= $340,000 + $102,000 + $105,000 + SP + Bldg.

Total Capital Cost = $547,000 + SP + Bldg.

where:

F_p = power needed for fan, kWh/yr

$Q_{fg,a}$ = total emission stream flowrate, acfm

P = system pressure drop, in. H_2O (from Table 4.3-7)

HRS = operating hours per year, hr/yr

In general, catalyst replacement costs are highly variable and depend on the nature of the catalyst, the amount of poisons and particulates in the emission stream, the temperature history of the catalyst, and the design of the unit. Given that these costs are so variable it is not possible to accurately predict the costs for a given application. However, for purposes of this report, it is assumed the catalyst has a life of two years. To estimate this cost, multiply the catalyst volume from section 4.3.5 by the appropriate capital recovery factor assuming a two year life and 10 percent interest rate (i.e, CRF = 0.5762). The catalyst replacement cost can be estimated as $650/ft^3 for base metal oxide catalysts, and $3,000/ft^3 for noble metal catalysts.[5] The initial catalyst cost used in estimating the capital recovery cost, can be obtained by multiplying the catalyst requirement by the catalyst cost.

Operating labor requirements are estimated as 0.5 hours per 8-hour shift. The operator labor wage rate is provided in Table 4.3-6. Supervisory costs are estimated as 15 percent of operator labor costs.

Maintenance labor requirements are estimated as 0.5 hours per 8-hour shift with a slightly higher labor rate (see Table 4.3-6) to reflect increased skill levels. Maintenance materials are estimated as 100 percent of maintenance labor.

Indirect annual costs: These costs include the capital recovery cost, overhead, property taxes, insurance, and administrative charges. The capital recovery cost is based on an estimated 10-year equipment life and subtracts out the initial catalyst cost, while overhead, property taxes, insurance, and administrative costs are percentages of the total capital cost. Table 4.3-6 contains the appropriate factors for these costs.

Example Case

ect Annual Costs

nual fuel usage = 179 (60 min/hr)(6000 hr/yr)
= 64.4×10^6

nual fuel cost = $3.30(64.4x10⁶/1,000)
= $213,000

:ctricity:

F_p = 1.81×10^{-4} (20,200)(6+8)
(6000 hr/yr)
= 3.07×10^5 kWh/yr

nual electricity cost, AEC:

AEC = $0.059 ($3.07 \times 10^5$)
= $18,100

talyst Replacement Cost, CRCT

V_{bed} = 40 ft^3

)recious metal catalyst is used, thus

CRCT = (40)($3,000)(0.5762)
= $69,100

)erating labor costs are estimated as:

(0.5 hr/shift)/(8 hr/shift) x 6000 hr/yr = 375 hr/yr
375 hr/yr ($12.96/hr) = $4,900/yr

pervisory costs are estimated as 15 percent of this
;t, or $700.

intenance labor costs are estimated as:

(0.5 hr/shift)/(8 hr/shift) x 6,000 hr/yr = 375 hr/yr
375 hr/yr ($14.26/hr) = $5,300/yr

intenance materials are estimated as 100 percent
this cost, or $5,300.

tal Direct Costs: $213,000 + $18,100 + $69,100
+ $4,900 + $700 + $5,300 +
$5,300 = $316,000

lirect Annual Costs

'erhead = 0.60 ($4,900 + $700 + $5,300
+ $5,300) = $9,700
ministrative = 0.02 ($547,000) = $10,900
operty taxes = 0.01 ($547,000) = $5,500
urance = 0.01 ($547,000) = $5,500
ipital recovery = 0.1628 ($547,000 - 1.08
($120,000)) = $69,500

tal Indirect Costs: $9,700 + $10,900 + $5,500 +
$5,500 + $69,100 = $101,000

tal Annual Costs: $316,000 + $101,000 =
$417,000

Table 4.3-6. Annual Cost Factors for Catalytic Incinerators[a]

Cost Item	Factor
Direct Annual Cost (DAC)[b]	
Utilities	
Fuel (natural gas)[c]	$3.30/1,000 ft^3
Electricity	$0.059/kwh
Catalyst replacement	$650/$ft^3$ base metal oxide $3,000/$ft^3$ precious metal
Operating Labor	
Operator	$12.96/hr
Supervisor	15% of operator labor
Maintenance	
Labor	$14.26/hr
Material	100% of maintenance labor
Indirect Annual Cost (IAC)	
Overhead	0.60 (Operating labor and maintenance costs)
Administrative	2% of TCC
Property taxes	1% of TCC
Insurance	1% of TCC
Capital recovery[d]	0.1628 [TCC - 1.08 (Cat. cost)]

[a]Reference 5.
[b]1988 dollars.
[c]The fuel cost may vary. When possible, obtain a value more appropriate for the situation.
[d]The capital recovery factor is calculated as: $i(1+i)^n/(1+i)^n - 1$
where: i = interest rate, 10 percent
n = equipment life, 10 yrs

Table 4.3-7. Typical Pressure Drops for Catalytic Incinerators[a]

Equipment Type	Heat Recovery HR (%)	Pressure Drop P (in. H_2O)
Catalytic Incinerator (Fixed-Bed)	0	6
Heat Exchanger	35	4
Heat Exchanger	50	8
Heat Exchanger	70	15

[a]The pressure drop is calculated as the sum of the incinerator and heat exchanger pressure drops.

Table 8.1F-11b

Oxidation Catalyst Costs (per gas turbine/HRSG)

Description of Cost				Cost Factor		Cost ($)	Notes
Direct Capital Costs (DC):							
Purchased Equip. Cost (PE):							
Basic Equipment:							
Auxiliary Equipment: HRSG tube/fin modifications							
Instrumentation: oxidation cat. Controls							
Taxes and freight:							
PE Total:						$725,000	1
Direct Install. Costs (DI):							
Foundation & supports:				0.08 PE		$58,000	2
Handling and erection (included in PE cost):						$0	1
Electrical (included in PE cost):						$0	1
Piping (included in PE cost):						$0	1
Insulation (included in PE cost):						$0	1
Painting (included in PE cost):						$0	1
DI Total:						$58,000	
DC Total (PE+DI):						$783,000	
Indirect Costs (IC):							
Engineering:				0.10 PE		$72,500	2
Construction and field expenses:				0.05 PE		$36,250	2
Contractor fees:				0.10 PE		$72,500	2
Start-up:				0.02 PE		$14,500	2
Performance testing:				0.01 PE		$7,250	2
Contingencies:				0.05 PE		$36,250	1
IC Total:						$239,250	
Less: Capital cost of initial catalyst charge						-$350,000	
Total Capital Investment (TCI = DC + IC):						$672,250	
Direct Annual Costs (DAC):				hr/yr:	4,380		
Operating Costs (O):	sched. (hr/day24		day/week: 7		wk/yr: 52		
Operator:	hr/shift:	0.0	operator pay ($/hr):	39.20		$0	2
Supervisor:	15% of operator					$0	2
Maintenance Costs (M): 0.5 hr/oxidation cat. per shift							
Labor:	hr/shift:	0.0	labor pay ($/hr):	39.2		$0	2
Material:	% of labor cost100%					$0	2
Utility Costs:							
Perf. loss:	(kwh/unit):	172.5					1
Electricity cost	($/kwh):	0.0336	Performance loss cost penalty:			$50,773	5
Catalyst replace:	based on 3 yr. Life					$116,667	1
Catalyst dispose:	based on 240 ft^3 catalyst, $15/$ft^3$, 3 yr. Life					$1,200	1
Total DAC:						$168,640	
Indirect Annual Costs (IAC):							
Overhead:	60% of O&M					$0	2
Administrative:				0.02 TCI		$13,445	2
Insurance:				0.01 TCI		$6,723	2
Property tax:				0.01 TCI		$6,723	2
Total IAC:						$26,890	
Total Annual Cost (DAC + IAC):						$195,530	
Capital Recovery (CR):							
Capital recovery factor (CRF):	interest rate (%):	10					
	period (years):	15		0.1315		$88,383	2
Total Annualized Costs						$283,913	

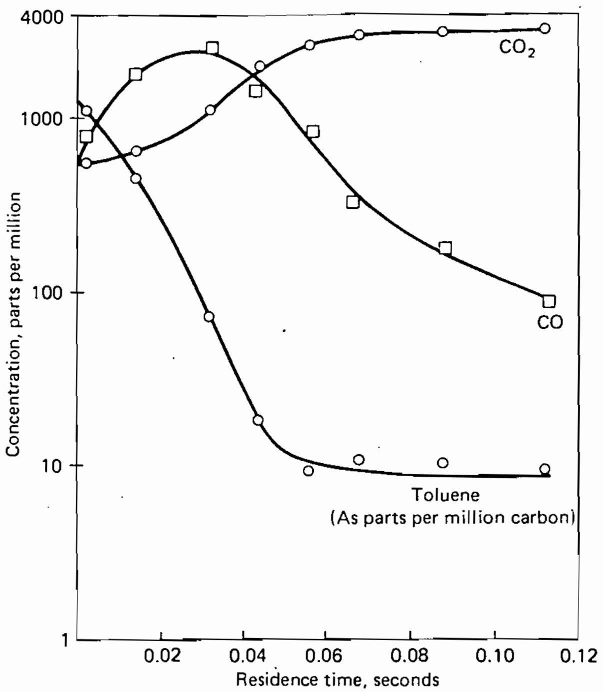


Figure 6-28 Toluene–CO–CO_2 concentrations during incineration at 1525°F. (SOURCE: K. H. Hemsath and P. E. Susey. *Am. Inst. Chem. Engineers Symposium Series No. 137* **70**, 1974.)

(1030°K). An interesting result of these experiments was the difficulty in oxidizing CO compared with the hydrocarbons. Figure 6-28 shows the concentration-time profile for toluene at a temperature of 1525°F (1100°K). Also shown are the profiles of CO and CO_2, which indicate the appearance and subsequent oxidation of CO during the toluene oxidation period. Apparently CO is more difficult to oxidize than hydrocarbons under the same temperature-time conditions, since the other three hydrocarbons showed behavior similar to that indicated in Figure 6-28. Higher temperatures and longer residence time may be required to incinerate CO, compared to hydrocarbons. Hence a situation involving only hydrocarbons may call for an incinerator design different from the design needed when CO is also present.

6-14-B Some Basic Theory on Catalytic Afterburners

Although basic theory on catalytic process pertaining to afterburner design is still under development, several worthwhile points can be considered here. In general, the overall process may be divided into two distinct steps which govern catalytic oxidation: (1) the heat and mass transport processes between the catalytic surface and the gas stream; and (2) the elementary chemical reaction processes at the catalytic sites on the solid surface. At the present

stage of development, the theory indicates that for normal design rates for afterburner catalysts, the reaction rate is controlled or impeded by mass diffusion of reactants through the porous substrate of the catalyst. Hence only a fraction of the effective catalyst surface is used to catalyze the oxidation reactions [27]. Generally speaking, the overall rate constant k is related to rate constants for the mass transfer (k_{mt}) and the chemical reaction (k_{chem}) processes by

$$\frac{1}{k} = \frac{1}{k_{mt}} + \frac{1}{k_{chem}}$$

As noted earlier in this section, the rate of oxidation of a hydrocarbon is proportional to the concentration of that hydrocarbon in the gas stream, provided at least 2 percent oxygen by volume is present in excess of that required for complete oxidation.

It is found that at reasonably low temperatures, for example, 300° to 500°F (425° to 525°K), the quantity k_{chem} controls. However, as the temperature is increased in order to increase the chemical rate, the quantity k_{mt} controls. This occurs in the temperature range of 600° to 900°F (600° to 750°K). The role of chemical reaction rates versus mass transfer processes and the selectivity of a catalyst is shown by Figure 6-29 [27]. The conversion-temperature curves are shown for various molecular species and solvent hydrocarbons in general for oxidation over a Pt/Al_2O_3 catalyst. This type of catalyst has a high selectivity for hydrogen, with reasonable conversion even below 200°F. High conversions occurs in the 300° to 500°F range. The

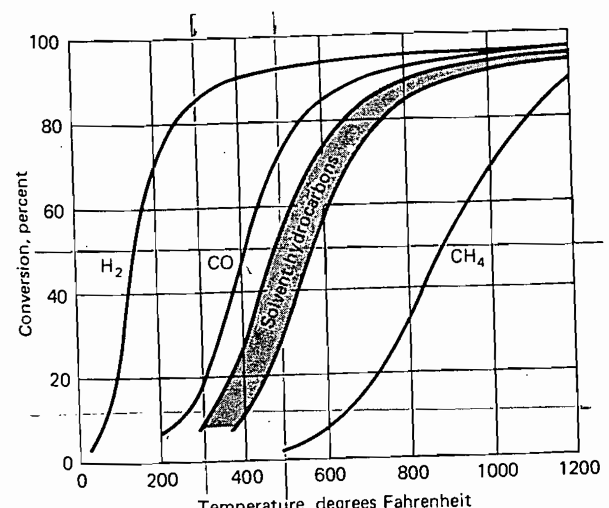
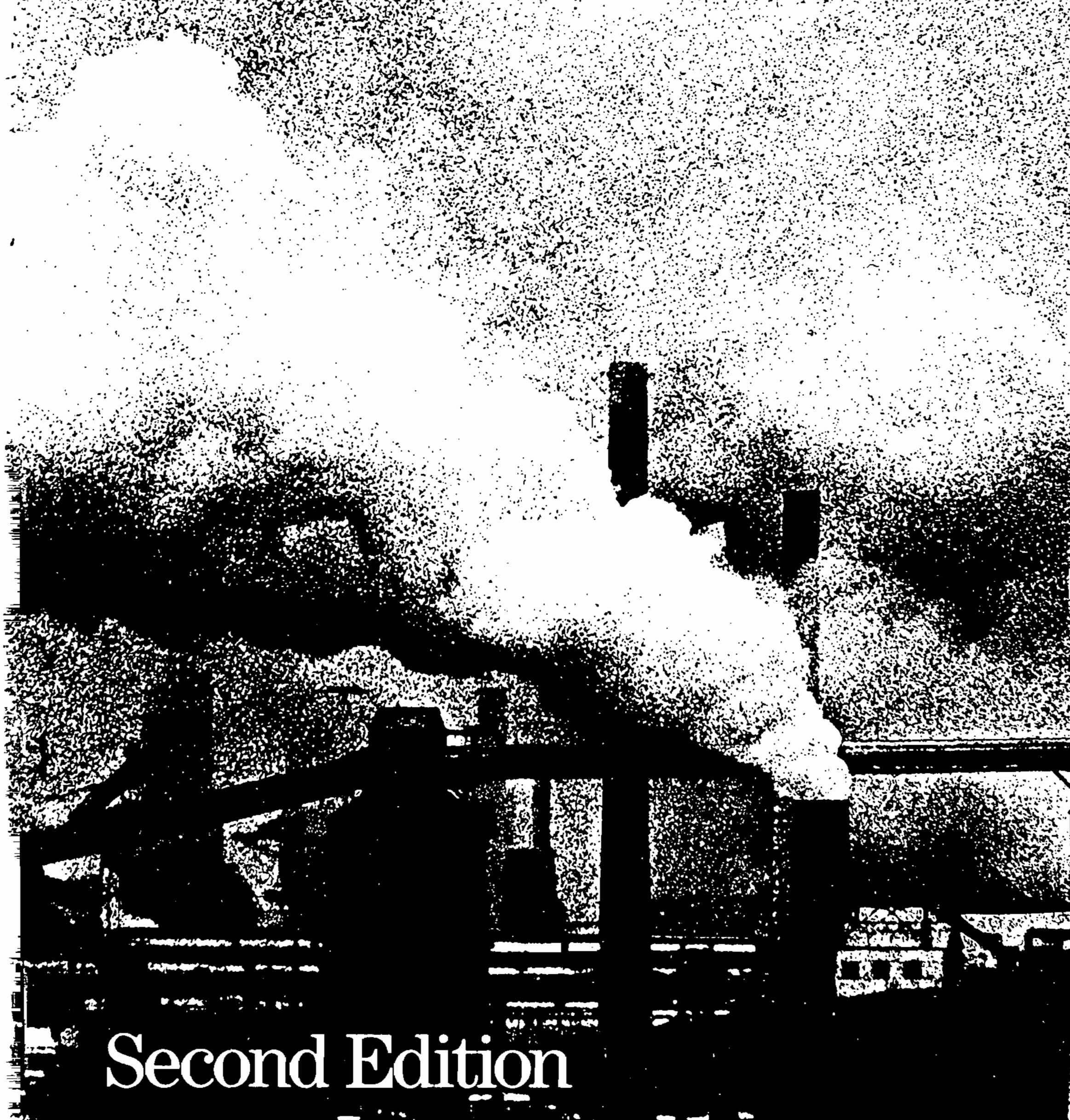


Figure 6-29 Typical temperature-conversion performance curves for various molecular species being oxidized over Pt/Al_2O_3 catalysts. (SOURCE: R. D. Hawthron. *Am. Inst. Chem. Engineers Symposium Series No. 137* **70**, 1974.)

AIR POLLUTION

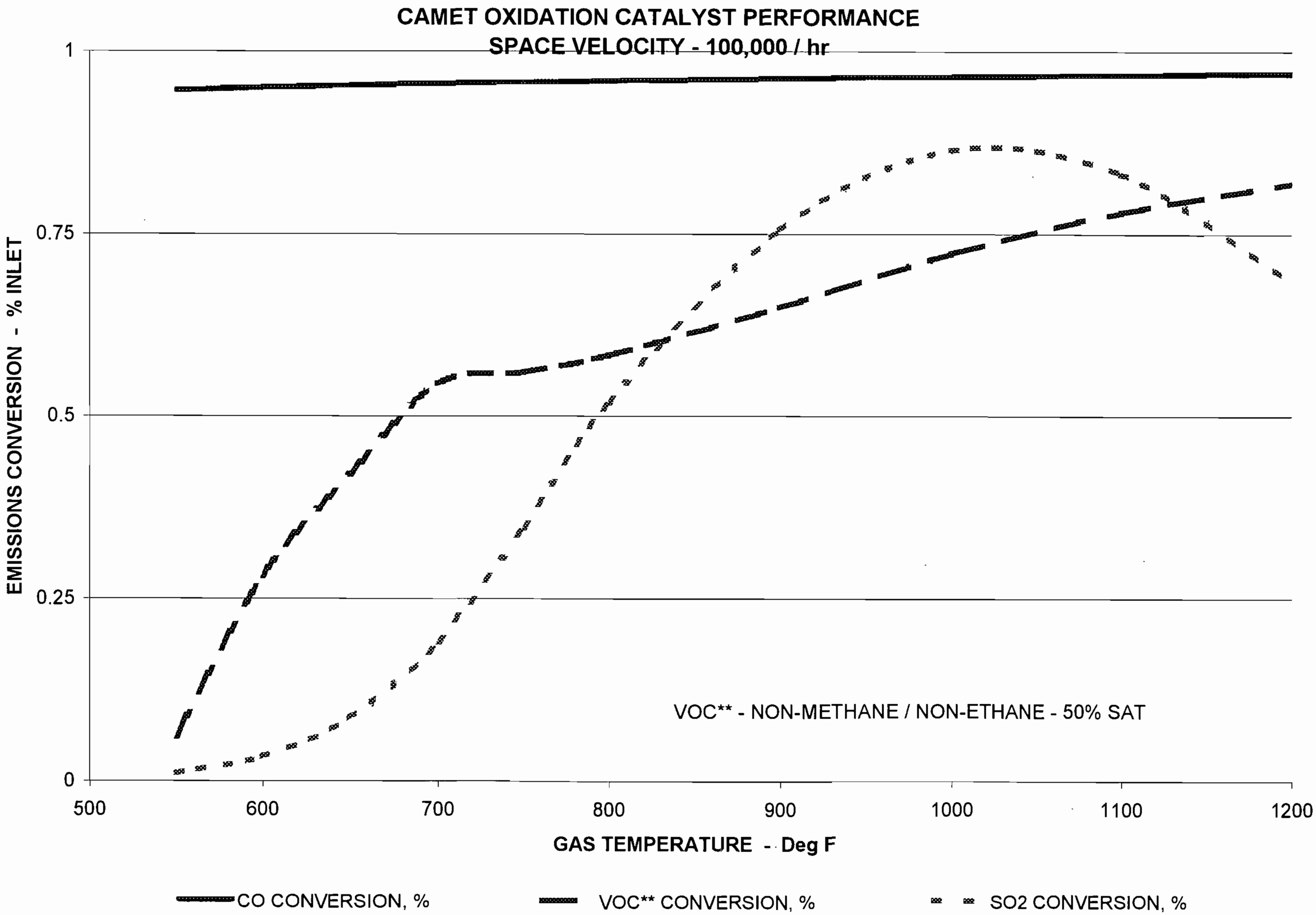
Its Origin and Control

Kenneth Wark
and Cecil F. Warner



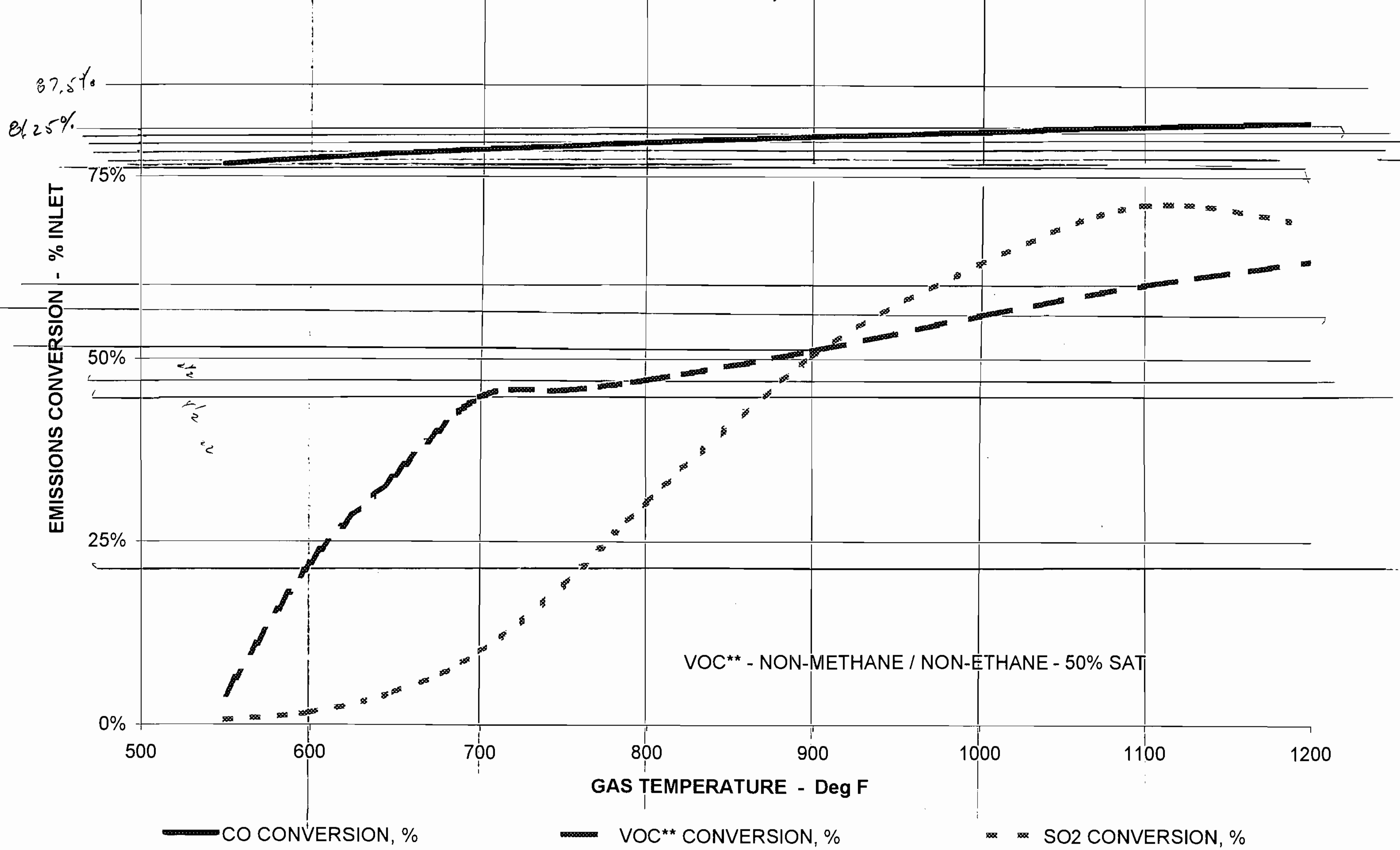
Second Edition

ENGELHARD


CAMET OXIDATION CATALYST PERFORMANCE
SPACE VELOCITY - 100,000 / hr
EMISSIONS CONVERSION - % INLET
1
0.75
0.5
0.25
0
500
600
700
800
900
1000
1100
1200
GAS TEMPERATURE - Deg F
VOC** - NON-METHANE / NON-ETHANE - 50% SAT
CO CONVERSION, %
VOC** CONVERSION, %
SO2 CONVERSION, %

ENGELHARD

CAMET OXIDATION CATALYST PERFORMANCE
SPACE VELOCITY - 200,000 / hr



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Catalytic Converters

Results and Discussion

The strong dependence of the oxidation of individual hydrocarbons on oxygen concentration indicates the oxidation is restricted to the amount of oxygen available on a surface that is largely covered by hydrocarbons. Figure 4 shows how the conversion versus temperature oxidations for three hydrocarbons when reacted alone over the platinum catalyst. Part A has a higher oxygen concentration with no CO and the removal of each hydrocarbon is below 200°C. Part B has the same parameters but with temperature requirements 40-50°C higher than Part A. In the presence of CO (Part C), the required temperature for each reaction is over 300°C. The significance of Part C is the great inhibition of CO. CO adsorbs more strongly than the hydrocarbons and therefore covers most of the Pt surface.[3]

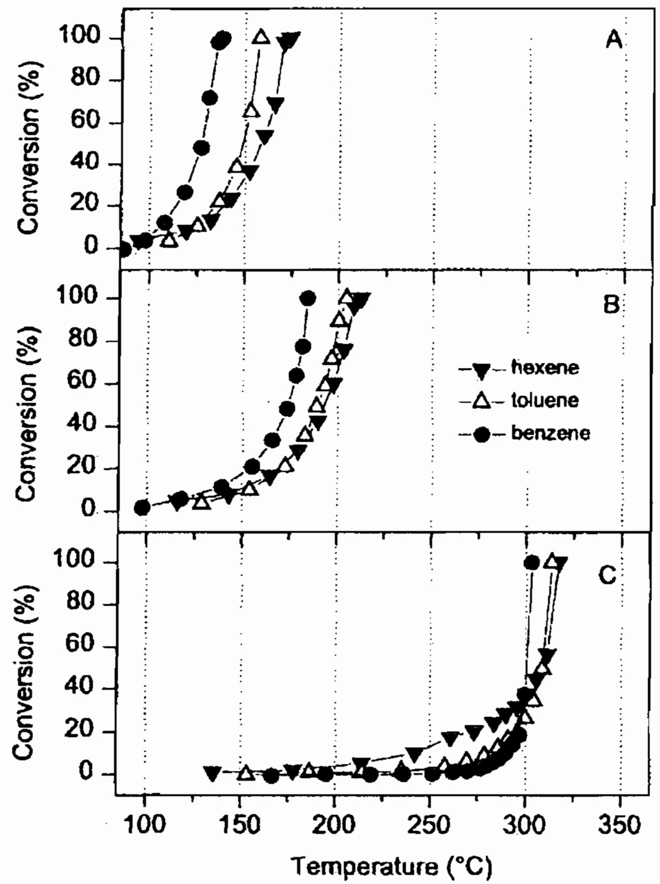


Figure 4: Conversion vs. temperature curves for the separate reactions of hexane, benzene, and toluene over 200mg Pt/Al_2O_3/M. (A) in ~0.6% O_2/He; (B) in ~0.1% O_2/He; (C) in 1.0% CO/~0.6% O_2/He. (click to enlarge) 3

The order of adsoption strength is hexene > toluene > benzene can be expected. the adsorption strength of unsaturated hydrocarbons occurs through donation of π

electrons to the vacant d orbitals of the metal catalyst (Pt).[3] Weaker adsorption strength is due to more delocalized π electrons of the absorbate/metal interaction.[3] The aromatic structures of toluene and benzene therefore have weaker adsorption strength to that of hexene. Toluene is stronger than benzene because the alkyl groups increase the adsorption of substituted aromatics.[3]

The relative adsorption strengths of the individual hydrocarbons effects the relative activities as well. Stronger hydrocarbon adsorption (hexene versus benzene) reduces oxygen coverage on the surface and leads to a lower rate. Figure 5 further shows that different adsorption strengths of the hydrocarbons relative to CO are reflected in the required temperatures to remove the them in the mixtures. Each hydrocarbon increases the temperature required to remove CO, but effects the magnitude by only 10-40°C, while the reverse effect of CO on hydrocarbon oxidation is effected by more the 100°C.[3]

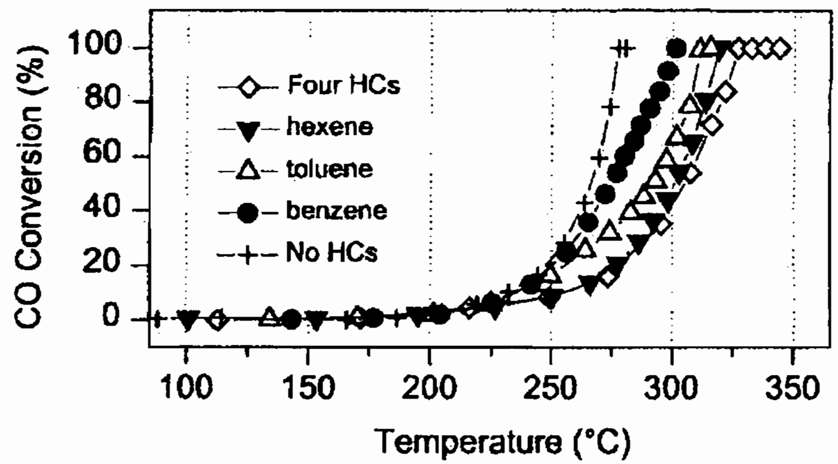


Figure 5: Conversion vs. temperature for the reaction of CO over $Pt/Al_2O_3/M$ in the presence of hexene, benzene, toluene and of the four hydrocarbon mixture. (click to enlarge)[3]

Next Section

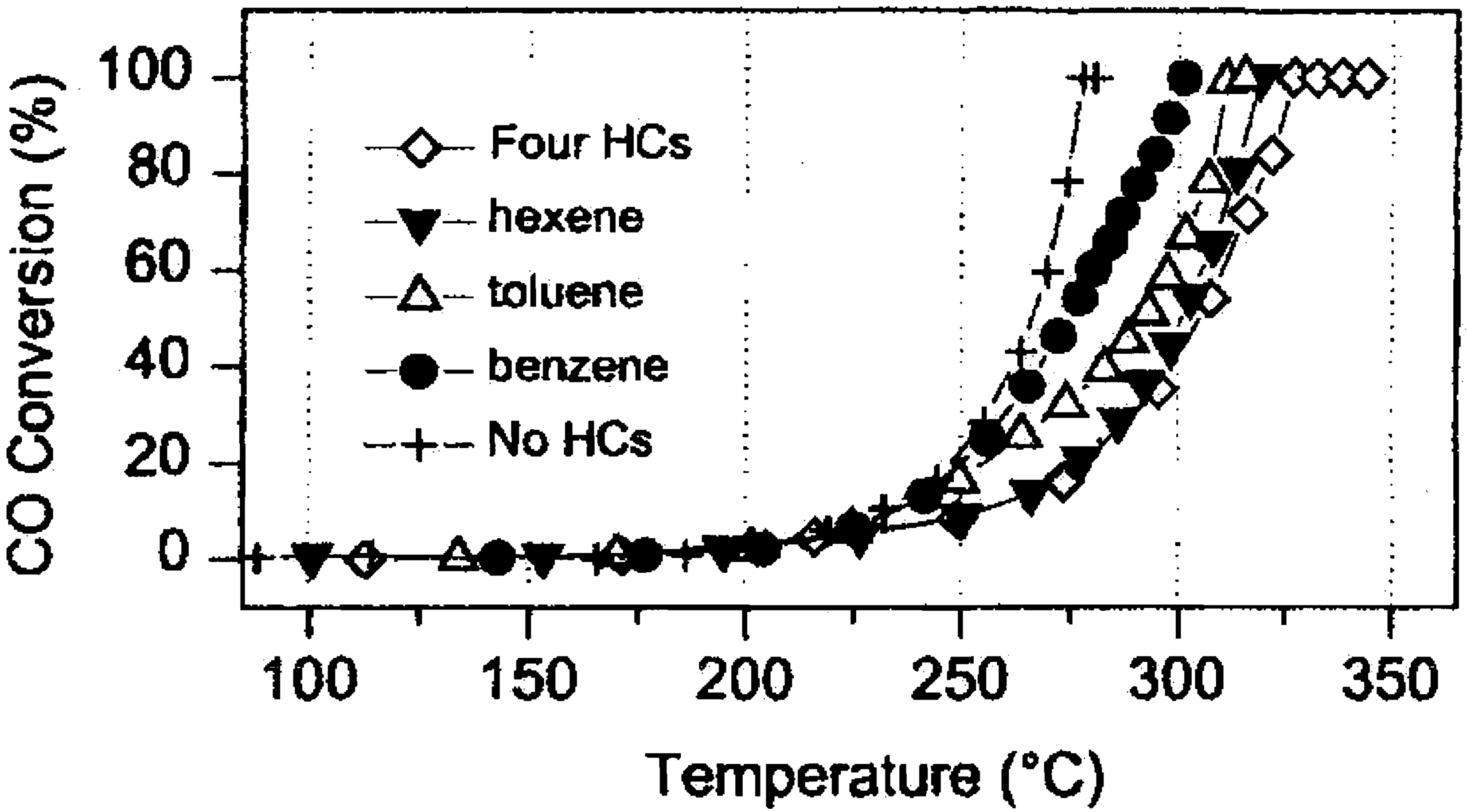
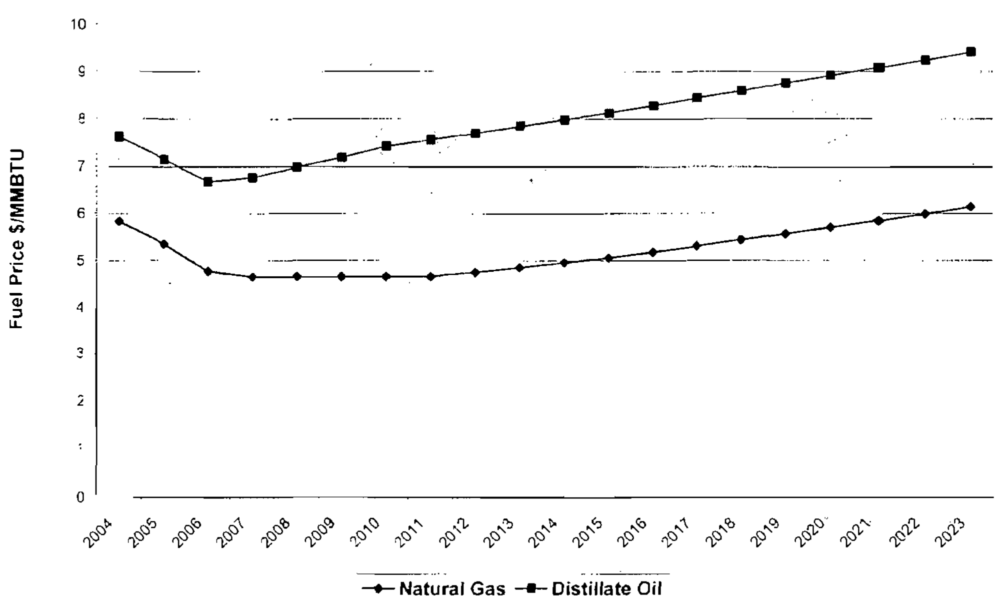

CO Conversion (%)
0
20
40
60
80
100
100
150
200
250
300
350
Temperature (°C)
Four HCs
hexene
toluene
benzene
No HCs

Exhibit___ (PRM-3)

Fuel Price Forecast for Hines



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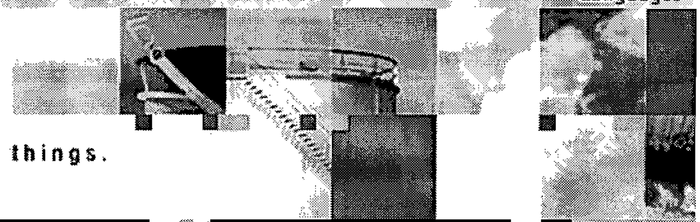

ENGELHARD

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Camet® catalytic systems Overview | Environmental Technologies | Camet® catalytic systems Market Applications

Camet® catalytic systems

Engelhard's **Camet®** catalytic systems destroy carbon monoxide (CO) and volatile organic compounds (VOCs) produced by power generation equipment.

As power plant emissions have received increased attention by regulators, power generators have been required to meet ever more stringent environmental regulations. **Camet** technology offers an efficient, cost-effective program for gas or oil fired turbines and boilers to meet these regulations.

The technology has been proven effective by millions of hours of trouble-free performance in the field. **Camet**-based catalytic converters have a superior conversion efficiency and low-pressure drop.

The effectiveness of **Camet** catalysts is a direct result of Engelhard's innovative catalytic core over which the exhaust gases are passed. The core consists of a continuous metal foil that is corrugated, coated with a uniform washcoat containing the catalyst, folded and encased in a steel container. The folded foil's unique herringbone and skew patterns produce the needed turbulence to ensure excellent fluid-to-wall contact, leading to superior conversion efficiency per unit volume.

The system provides superior conversion efficiency and enables generators to treat large flow rates of exhaust gas with smaller volumes of highly active catalysts.

The metal foil substrate provides enhanced catalyst durability with reduced weight. It is rugged and washable. The system also performs effectively in a broad range of operating temperatures: from 500°F to 1250°F (260°C to 675°C).

Camet catalytic systems can be customized to meet the needs of new or retrofit installations, even where space is limited. Engelhard can tailor catalyst composition, cell density and catalyst module shape and dimensions to meet specific requirements.

Camet catalysts can be configured in individual modules for manual handling or, to reduce service downtime, in complete panels for mechanical loading. Test cores in each unit enable accurate and simple monitoring of the catalyst's efficiency through the life of the product.

For more information, contact Nancy Ellison

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IDAHO DEPARTMENT OF
ENVIRONMENTAL QUALITY
1410 NORTH HILTON, BOISE, ID 83706-1255
(208) 373-0502

TRANSMITTAL COVER SHEET

FAX NUMBER (208) 373-0154
2ND FLOOR

DATE:

TO: Mike Halpin, Florida DEP
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DOCUMENT DESCRIPTION:

Westinghouse 501F Emission Data

TOTAL NUMBER OF PAGES (INCLUDING THIS COVER SHEET): 14

COMMENTS:

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✓

SIEMENS Westinghouse

IDA - West
Expected 501F Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
AEROPAC 2-95x200 / 0.90 Power Factor

Vendor Data

CTT-1988
03/13/00

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7
FUEL TYPE	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
LOAD LEVEL	BASE	BASE	60%	BASE	60%	BASE	60%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,981	20,981	20,981	20,981	20,981	20.981	20,981
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,299	23,299	23,299	23,299	23,299	23,299	23,299
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	OFF	OFF	OFF	OFF	OFF	OFF
AMBIENT DRY BULB TEMPERATURE, °F	95.0	95.0	95.0	51.0	51.0	5.0	5.0
AMBIENT WET BULB TEMPERATURE, °F	82.5	82.5	82.5	44.2	44.2	3.1	3.1
AMBIENT RELATIVE HUMIDITY, %	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
BAROMETRIC PRESSURE, psia	13.430	13.430	13.430	13.430	13.430	13.430	13.430
COMPRESSOR INLET TEMPERATURE, °F	84.3	95.0	95.0	51.0	51.0	5.0	5.0
INJECTION FLUID	-	-	-	-	-	-	-
INJECTION RATIO	-	-	-	-	-	-	-
INLET PRESSURE LOSS, inches of water (Total)	3.4	3.3	2.0	3.8	2.1	3.9	2.1
EXHAUST PRESSURE LOSS, inches of water (Total)	10.4	10.0	5.8	12.3	6.7	13.8	7.3
EXHAUST PRESSURE LOSS, inches of water (Static)	8.0	7.7	4.4	9.5	5.2	10.7	5.6
COMBUSTION TURBINE PERFORMANCE:							
GROSS POWER OUTPUT, kW	152,490	146,240	87,190	170,320	101,700	189,610	113,320
GROSS HEAT RATE, Btu/kWh (LHV)	9,435	9,520	11,020	9,180	10,580	9,005	10,055
GROSS HEAT RATE, Btu/kWh (HHV)	10,470	10,565	12,230	10,190	11,745	9,995	11,165
FUEL FLOW, lbm/hr	68,540	66,330	45,820	74,510	51,320	81,360	54,360
INJECTION RATE, lbm/hr	-	-	-	-	-	-	-
HEAT INPUT, mmBtu/hr (LHV)	1,438	1,392	961	1,563	1,077	1,707	1,140
HEAT INPUT, mmBtu/hr (HHV)	1,597	1,545	1,068	1,738	1,198	1,896	1,266
EXHAUST TEMPERATURE, °F	1,127	1,133	1,094	1,096	1,104	1,077	1,046
EXHAUST FLOW, lbm/hr	3,083,910	3,012,087	2,330,169	3,372,556	2,462,745	3,595,899	2,625,916
EXHAUST GAS COMPOSITION (BY % VOL):							
OXYGEN	11.92	12.08	12.92	12.52	13.05	12.45	13.16
CARBON DIOXIDE	3.73	3.71	3.31	3.76	3.52	3.85	3.53
WATER	11.33	10.91	10.15	8.29	7.81	7.80	7.16
NITROGEN	72.11	72.41	72.70	74.50	74.68	74.95	75.21
ARGON	0.90	0.91	0.91	0.93	0.94	0.94	0.94
MOLECULAR WEIGHT	28.06	28.10	28.15	28.39	28.42	28.48	28.50
NET EMISSIONS: Based on Westinghouse 21T5620 test methods							
NOx, ppmvd @ 15% O2	25	25	30	25	30	25	30
NOx, lbm/hr as NO2	150	145	120	162	134	177	142
CO, ppmvd @ 15% O2	10	10	30	10	30	10	30
CO, lbm/hr	37	36	73	[illegible]	82	43	87
SO2, lbm/hr – See detailed Calculations	~~0.93~~ 4.65	~~0.90~~	~~0.82~~	[illegible]	[illegible]	[illegible]	~~0.74~~
VOC, ppmvd @ 15% O2 as CH4	2.0	2.0	3.0				
VOC, lbm/hr as CH4	4.16	4.03	4.17				
PARTICULATES, lbm/hr	13.18	12.92	10.06				
OPACITY	<= 10%	<= 10%	<= 10%				

Mike Halpin
Florida DEP
Fax 850-921-9533
Office 850 921-9519

NOTES:

- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Gross power output is at the generator terminals minus static excitation loss.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 93208.
- VOC's are non methane, non ethane.
- Gas fuel composition is 98% CH4, 0.6% C2H6, 1.4% N2, 0.2 grains of sulfur per 100 SCF. → Actual Sulfur in gas = 1.0 grain/100SCF
- Gas fuel must be in compliance with the Siemens Westinghouse Gas Fuel Spec (21T0306, Rev 7).
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per US EPA Method 5/202 (front and back half).
- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.

5 times higher

Pg 4.3

SIEMENS
Westinghouse

IDA - West

Expected 501F Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
AEROPAC 2-95x200 / 0.90 Power Factor

Vendor Data

CTT-1988
03/13/00

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7
FUEL TYPE	No. 2 Dist	No. 2 Dist	No. 2 Dist	No. 2 Dist	No. 2 Dist	No. 2 Dist	No. 2 Dist
LOAD LEVEL	BASE	BASE	60%	BASE	60%	BASE	60%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	18,450	18,450	18,450	18,450	18,450	18,450	18,450
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	19,680	19,680	19,680	19,680	19,680	19,680	19,680
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	OFF	OFF	OFF	OFF	OFF	OFF
AMBIENT DRY BULB TEMPERATURE, °F	95.0	95.0	95.0	51.0	51.0	5.0	5.0
AMBIENT WET BULB TEMPERATURE, °F	82.5	82.5	82.5	44.2	44.2	3.1	3.1
AMBIENT RELATIVE HUMIDITY, %	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
BAROMETRIC PRESSURE, psia	13.430	13.430	13.430	13.430	13.430	13.430	13.430
COMPRESSOR INLET TEMPERATURE, °F	84.3	95.0	95.0	51.0	51.0	5.0	5.0
INJECTION FLUID	Water	Water	Water	Water	Water	Water	Water
INJECTION RATIO	0.40	0.40	0.20	0.40	0.20	0.40	0.20
INLET PRESSURE LOSS, inches of water (Total)	3.4	3.3	2.8	3.8	2.9	3.9	3.0
EXHAUST PRESSURE LOSS, inches of water (Total)	10.2	9.8	7.1	12.0	8.0	13.6	8.8
EXHAUST PRESSURE LOSS, inches of water (Static)	7.8	7.5	5.6	9.3	6.2	10.5	6.8
COMBUSTION TURBINE PERFORMANCE:							
GROSS POWER OUTPUT, kW	146,630	140,470	83,670	164,090	97,880	183,090	109,330
GROSS HEAT RATE, Btu/kWh (LHV)	9,740	9,835	11,265	9,470	10,430	9,280	9,950
GROSS HEAT RATE, Btu/kWh (HHV)	10,385	10,490	12,010	10,100	11,120	9,895	10,610
FUEL FLOW, lbm/hr	77,470	74,950	51,220	84,290	55,490	92,160	59,120
INJECTION RATE, lbm/hr	30,990	29,980	10,250	33,720	11,100	36,870	11,820
HEAT INPUT, mmBtu/hr (LHV)	1,429	1,383	945	1,555	1,024	1,700	1,091
HEAT INPUT, mmBtu/hr (HHV)	1,525	1,475	1,008	1,659	1,092	1,814	1,163
EXHAUST TEMPERATURE, °F	1,089	1,096	934	1,060	886	1,040	833
EXHAUST FLOW, lbm/hr	3,123,013	3,049,918	2,756,985	3,415,120	2,963,119	3,642,535	3,151,828
EXHAUST GAS COMPOSITION (BY % VOL):							
OXYGEN	12.07	12.21	14.26	12.66	14.74	12.58	14.85
CARBON DIOXIDE	4.98	4.94	3.74	5.01	3.81	5.15	3.83
WATER	10.06	9.64	7.64	7.01	4.94	6.50	4.27
NITROGEN	72.00	72.30	73.43	74.39	75.56	74.83	76.09
ARGON	0.90	0.91	0.92	0.93	0.95	0.94	0.96
MOLECULAR WEIGHT	28.39	28.43	28.53	28.73	28.83	28.80	28.90
NET EMISSIONS: Based on Westinghouse 21T5620 test methods							
NOx, ppmvd @ 15% O2	42	42	42	42	42	42	42
NOx, lbm/hr as NO2	256	248	168	278	182	305	194
CO, ppmvd @ 15% O2	30	30	950	30	950	30	950
CO, lbm/hr	112	108	2,319	121	2,510	133	2,674
SO2, lbm/hr	77.5	75.0	51.2	84.3	55.5	92.2	59.1
VOC, ppmvd @ 15% O2 as CH4	10.0	10.0	100.0	10.0	100.0	10.0	100.0
VOC, lbm/hr as CH4	21.2	20.5	139.5	23.1	151.0	25.2	160.8
PARTICULATES, lbm/hr	43.8	43.0	63.8	49.0	69.9	52.4	74.6
OPACITY	<= 20%	<= 20%	<= 40%	<= 20%	<= 40%	<= 20%	<= 40%

NOTES:
- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Gross power output is at the generator terminals minus static excitation loss.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 83208.
- VOC's are non methane, non ethane.
- Particulates are per US EPA Method 5/202 (front and back half).
- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Fuel oil composition is 86.434% C, 13.5% H, 0.05% S, 0.015% FBN and 0.001% ash.
- Liquid fuel must be in compliance with the latest revision of the Siemens Westinghouse Liquid Fuel Spec (21T4424, Rev 6).
- Particulates for oil fuel are based on specific gravity and may vary depending on fuel.

From: Anita Lindell <alindell@uswest.net>
To: Ken Hanna <khanna@deq.state.id.us>
Date: Tue, Aug 29, 2000 6:34 PM
Subject: Garnet Energy PSD application - toxic emissions

The toxic emissions using the EPA and CARB emission factors are calculated as follows using the
GE 7FA turbine numbers as an example:

Natural gas fuel, VOC toxics: Ex. Acetaldehyde

Weight fraction acetaldehyde = 0.0003, this is adjusted to non-methane, non-ethane basis by
dividing by 0.0931 (1.00-0.7669-0.1400). The non-methane, non-ethane weight fraction is
0.00322.
The wt.fraction is then multiplied by the non-methane, non-ethane VOC emission rate =
0.00322*10.6 = 0.0342 lb/hr

Fuel oil, VOC toxics: Same method except that since the VOC profile is different the correction
factor is different for non-methane, non-ethane basis. For fuel oil it is 0.7343.

PM emissions: there is no need to adjust the wt. fractions so they are used as is and multiplied by the
PM emission rate.

Since there are no speciation tables for duct burners we have usually used (and did in this application) the total VOC emissions
for gas turbine plus duct burners and then used the gas turbine weight fractions. There are emission
factors for boilers in AP-42 that are new as of April 2000 that I used for another project and that
appear appropriate for duct burners. Using these numbers actually produce lower emissions for the
combination of gas turbines and duct burners. Both methods have been accepted by regulatory
agencies so I will not change our method for this application since we have presented what we
believe are worst-case toxic emissions and they passed the modeling analysis.

In going though the toxic emission calculations I discovered that I had used natural gas emission
factors for the diesel fired emergency generator and the fire pump. I went back and used the correct CARB speciation table for PM emissions and used AP-42 Section 3.3 for diesel engines for VOC toxics since AP-42 has more toxic compounds included than CARB. Since the engines only operate 26 hours per year, the emissions are still on the order of 1/1000 of one lb/hr. Therefore, the
contribution does not change the total emission rates that were used in modeling and the modeling
results should be the same for all pollutants (Walt used a source group

Table 4-9

Summary of Toxic Emissions for the S-W 501 F Turbine

Toxic Compound	Turbine on NG (lb/hr)[b]	Turbine on Oil (lb/hr)[b]	Heater (lb/hr)[a]	Diesel Generator (lb/hr)[a]	Fire Pump (lb/hr)[a]	Worst-Case Total Hourly Emissions (lb/hr)	Idaho DEQ Screening Emissions Level (lb/hr)	Modeling Required (Yes/No)	Annual Total Facility Emissions (tons/yr)[c]
Ammonia	43.0	43.8	0.0	0.0	0.0	43.8	1.2	Yes	188.7
Sulfuric Acid [d]	.862	14.217	0.0	0.0	0.0	14.217	0.067	Yes	6.180
VOC									
Acetaldehyde	.0821	0.0	0.0	0.00065	0.00021	0.083	0.003	Yes	0.345
Acrolein	0.0	0.0	0.0	0.000079	0.000026	0.000105	0.017	No	0.0000014
Benzene	.301	4.40	.00082	0.00079	0.00026	4.401	0.0008	Yes	2.060
1,3-Butadiene	0.0	4.05	0.0	0.000033	0.000011	4.050	0.000024	Yes	0.729
Cyclohexane	.0274	0.0	.000219	0.0000	0.0000	0.028	70	No	0.116
Cyclopentane	.0547	0.0	0.0	0.0000	0.0000	0.055	115	No	0.230
Ethylbenzene	.0274	0.0	0.0	0.0000	0.0000	0.027	29	No	0.115
Formaldehyde	2.22	0.0	.00194	0.0010	0.00033	2.220	0.00051	Yes	9.319
Hexane (isomers)	.0547	0.0	.000227	0.0000	0.0000	0.055	12	No	0.231
Heptane	.109	0.0	0.0	0.0000	0.0000	0.109	109	No	0.460
Nonane	.0274	0.0	0.0	0.0000	0.0000	0.027	70	No	0.115
Octane	.0547	0.0	0.0	0.0000	0.0000	0.055	93	No	0.230
Pentane (isomers)	.356	0.0	.003.40	0.0000	0.0000	0.359	118	No	1.509
Toluene	.109	0.0	.000414	0.00035	0.00011	0.110	25	No	0.462
Trimethylbenzene (isomers)	.109	0.0	0.0	0.0000	0.0000	0.109	8.2	No	0.460
Xylene (isomers)	.0547	0.0	0.0	0.00024	0.00008	0.055	29	No	0.230
PM									
Arsenic	0.0	.555	0.0	0.0045	0.0015	0.561	0.0000015	Yes	0.100
Cadmium	0.0	.0524	0.0	0.0043	0.0014	0.058	0.0000037	Yes	0.010
Chromium	.0197	.0524	0.0	0.0045	0.0015	0.058	0.033	Yes	0.092
Cobalt	.0197	0.0	0.0	0.0000	0.0000	0.020	0.007	Yes	0.083
Copper	.0197	0.0	0.0	0.0000	0.0000	0.020	0.067	No	0.083
Lead [e]	0.0	.576	0.0	0.0000	0.0000	0.576	0.6 tpy	No	0.104
Manganese	.0197E	.0524	0.0	0.0000	0.0000	0.052	0.333	No	0.092
Mercury	.00000730	.00000730	4.00E-08	0.0000	0.0000	0.000007	0.007	No	0.000
Nickel	.0197	.0524	0.0	0.0004	0.0001	0.053	0.000027	Yes	0.092
Selenium	0.0	.0524	0.0	0.0004	0.0001	0.053	0.013	Yes	0.009
Tin	0.0	.0524	0.0	0.0000	0.0000	0.052	0.133	No	0.009
Zinc	.097	.576	0.0	0.0047	0.0015	0.583	0.333	Yes	0.187

NA = Not Applicable
Note: The emissions for the gas turbines are presented for the coldest temperature of 5 deg. F and at full load with duct firing. These conditions represent the worst case emissions from the S-W 501F turbine.
a - The gas preheater is firing natural gas and the emergency generator and fire pump are firing low-sulfur distillate oil.
b - Two turbines.
c - The total annual emissions are based on 8,760 hours of operation on natural gas for the two gas turbines and the gas preheater, and 26 hours of operation for the generator and fire pump.
d – Sulfuric acid is also a PSD pollutant with a threshold of 7 tpy. No modeling required for PSD.
e - Lead is a PSD pollutant with a threshold of 0.6 tpy. No modeling required for PSD.

Total Organic Carbon Compound Speciation of Exhaust Gases from Natural Gas-Fired Internal Combustion Source gas turbine

Compound	Weight Percent
1,2,3-Trimethylbenzene	0.01%
1,2,4-Trimethylbenzene	0.01%
1,3,5-Trimethylbenzene	0.02%
1-Nonene	0.01%
2,2-Dimethylbutane	0.01%
2,4-Dimethylpentane	0.01%
2-Methyl-1-Pentene	0.02%
2-Methyl-2-Butene	0.01%
3-Methyl Pentane	0.02%
3-Methylheptane	0.02%
3-Methylhexane	0.01%
Acetaldehyde	0.03%
Acetylene	0.32%
Alkylbenzenes (C3/C4/C5)	0.01%
Aromatic - C10	0.01%
Benzene	0.11%
Butane (isomers)	0.26%
Cis-2-Butene	0.02%
Cyclohexane	0.01%
Cyclopentane	0.02%
Decane (isomers)	0.02%
Ethane	14.00%
Ethylbenzene	0.01%
Ethylene	0.63%
Formaldehyde	0.81%
Heptane	0.02%
Heptane (isomers)	0.04%
Heptene	0.01%
Hexane	0.02%
Hexane (isomers)	0.02%
Iso-Butane	0.43%
Isobutylene	0.02%
Isobutyraldehyde	0.02%
Iso-Pentene	0.01%
Methane	76.69%
Methylcyclohexane	0.02%
Methylcyclopentane	0.04%
M-Ethyltoluene	0.01%
M-Xylene	0.01%
N-Butane	1.00%
N-Decane	0.01%
Nonane	0.01%
Nonane (isomers)	0.01%
N-Pentane	0.13%
N-Undecane	0.01%
Octane	0.02%
Octane (isomers)	0.02%
Octene	0.01%
O-Ethyltoluene	0.01%
Olefins - C10	0.02%
Olefins - C9	0.04%
O-Xylene	0.01%
Pentane (isomers)	0.13%
Propane	2.91%
Propene	1.69%
Toluene	0.04%
Trans-2-Butene	0.13%
Trans-2-Pentene	0.01%
Xylene (isomers)	0.02%
Total	*100.00%*

Reference: USEPA, January 1990. Air Emission Species Manual, Vol. I: VOC Species Profiles, OAQPS, EPA-450/2-90-001a

State of California
Air Resources Board

Identification of Volatile Organic Compound Species Profiles

ARB Speciation Manual
Second Edition
Volume 1 of 2

August 1991

TABLE II
VOC SPECIES PROFILE

3 EXTERNAL COMBUSTION BOILER- NATURAL GAS

PROFILE NUMBER	SPECIES	WEIGHT FRACTION
3	BENZENE	.0325
	CYCLOHEXANE	.0087
	FORMALDEHYDE	.0768
	ISOMERS OF HEXANE	.0090
	ISOMERS OF PENTANE	.0810
	METHANE	.5600
	N-BUTANE	.0815
	N-PENTANE	.0540
	PROPANE	.0366
	TOLUENE	.0164
*TOTAL	3	.9565

heater

4 BOILERS- REFINERY GAS

PROFILE NUMBER	SPECIES	WEIGHT FRACTION
4	ETHANE	.1959
	FORMALDEHYDE	.0702
	ISOBUTANE	.0399
	METHANE	.0760
	N-BUTANE	.2093
	PROPANE	.1732
	PROPYLENE	.1530
*TOTAL	4	.9174

5 BOILERS- COKE OVEN GAS

PROFILE NUMBER	SPECIES	WEIGHT FRACTION
5	ACETYLENE	.0065
	BENZENE	.0154
	ETHANE	.0234
	ETHYLENE	.1023
	METHANE	.8280
	PROPYLENE	.0026
*TOTAL	5	.9783

TABLE II
VOC SPECIES PROFILE

9 INDUSTRIAL ICE- DISTILLATE OIL

turbine

PROFILE NUMBER	SPECIES	WEIGHT FRACTION
9	ACETYLENE	.0917
	BENZENE	.0641
	BUTENE	.1172
	ETHANE	.0262
	ETHYLENE	.2509
	METHANE	.1160
	PROPYLENE	.1513
	1,3-BUTADIENE	.0590
*TOTAL	9	.8765

11 COKE OVEN STACK GAS- PRIMARY METALS

PROFILE NUMBER	SPECIES	WEIGHT FRACTION
11	ACETYLENE	.0097
	BENZENE	.1144
	BUTENE	.0009
	ETHANE	.0750
	ETHYLENE	.2422
	METHANE	.4530
	PROPANE	.0046
	PROPYLENE	.0166
	TOLUENE	.0057
	1,3-BUTADIENE	.0042
*TOTAL	11	.9264

13 IRON SINTERING- PRIMARY METALS

PROFILE NUMBER	SPECIES	WEIGHT FRACTION
13	ACETYLENE	.1201
	ETHANE	.0281
	ETHYLENE	.0516
	METHANE	.7330
	PROPYLENE	.0262
*TOTAL	13	.9591

State of California
Air Resources Board

Identification of Particulate Matter Species Profiles

ARB Speciation Manual
Second Edition
Volume 2 of 2

August 1991

TABLE II
PARTICULATE MATTER CATEGORIES AND SPECIES PROFILES

114 STAT. I.C. ENGINE-LIQUID FUEL

PM CODE	SPECIES	WEIGHT FRACTION
114	ARSENIC	.005300
	CADMIUM	.000500
	CHROMIUM	.005300
	ELEM CARBON	.150000
	LEAD	.005500
	NICKEL	.000500
	SELENIUM	.000500
	TIN	.000500
	TITANIUM	.000500
	ZINC	.005500
	NITRATES	.038620
	SULFATES	.250000
	OTHER	.537280
*TOTAL 114		1.000000

turbine
generator
fire pump

115 STAT. I.C. ENGINE-GASOLINE

PM CODE	SPECIES	WEIGHT FRACTION
115	BROMINE	.000500
	CALCIUM	.005500
	CHROMIUM	.000500
	COBALT	.000500
	COPPER	.000500
	CHLORINE	.070000
	ELEM CARBON	.200000
	IRON	.000500
	MANGANESE	.000500
	NICKEL	.000500
	ZINC	.000500
	POTASSIUM	.005500
	NITRATES	.005500
	SULFATES	.450000
	OTHER	.259500
*TOTAL 115		1.000000

TABLE II
PARTICULATE MATTER CATEGORIES AND SPECIES PROFILES

123 STAT. I.C.ENGINE-GAS

PM CODE	SPECIES	WEIGHT FRACTION
123	BROMINE	.000500
	CALCIUM	.005500
	CHROMIUM	.000500
	COBALT	.000500
	COPPER	.000500
	CHLORINE	.070000
	ELEM CARBON	.200000
	IRON	.000500
	MANGANESE	.000500
	NICKEL	.000500
	ZINC	.000500
	POTASSIUM	.005500
	NITRATES	.005500
	SULFATES	.450000
	OTHER	.259500
*TOTAL 123		1.000000

turbine

125 PETROLEUM HEATERS-GAS

PM CODE	SPECIES	WEIGHT FRACTION
125	BROMINE	.000500
	CADMIUM	.000500
	CALCIUM	.050000
	CHROMIUM	.005500
	COBALT	.020000
	COPPER	.000500
	ELEM CARBON	.070000
	IRON	.005500
	LEAD	.000500
	MANGANESE	.000500
	MOLYBDENUM	.000500
	NICKEL	.005500
	SELENIUM	.005500
	ZINC	.005500
	STRONTIUM	.000500
	ZIRCONIUM	.000500
	NITRATES	.005500
	SULFATES	.470000
	OTHER	.353000
*TOTAL 125		1.000000

Summary of Hourly and Annual Toxic Emissions Used in Modeling
S-W 501F Turbines plus Auxiliary Equipment

Toxic Compound	Modeling Required (Yes/No)	Averaging Period	Turbine on NG (lb/hr) [a]	Turbine on Oil (lb/hr) [a]	Modeled 1-Hour Emission Rate (lb/hr) [b]	Heater (lb/hr) [c]	Diesel Generator (lb/hr) [d]	Fire Pump (lb/hr) [d]
Ammonia	Yes	24-Hour	21.52	21.9	21.9	0.0	0.0	0.0
Sulfuric Acid	Yes	24-Hour	0.431	7.1	7.108	0.0	0.0	0.0
VOC								
Acetaldehyde	Yes	Annual	0.0411	0.0	0.0411	0.0	0.0000019	0.00000064
Benzene	Yes	Annual	0.1505	2.1998	0.2348	0.00082	0.0000024	0.00000078
1,3-Butadiene	Yes	Annual	0.0	2.0248	0.0833	0.0	0.00000010	0.000000032
Formaldehyde	Yes	Annual	1.1084	0.0	1.1085	0.0019	0.0000030	0.00000098
PM								
Arsenic	Yes	Annual	0.0	0.2777	0.0115	0.0	0.000013	0.0000044
Cadmium	Yes	Annual	0.0	0.026	0.0011	0.0	0.000013	0.0000042
Chromium	Yes	Annual	0.010	0.026	0.0106	0.0	0.000013	0.0000044
Cobalt	Yes	24-Hour	0.010	0.000	0.010	0.0	0.000000	0.000000
Nickel	Yes	Annual	0.010	0.026	0.0106	0.0	0.0000013	0.00000042
Selenium	Yes	24-Hour	0.0	0.026	0.026	0.0	0.0000013	0.00000042
Zinc	Yes	24-Hour	0.010	0.288	0.288	0.0	0.000014	0.0000046

NA = Not Applicable

Note: The emissions for the gas turbines are presented for the coldest temperature of 5 deg. F and at full load with duct firing. These conditions represent the worst case emissions from the S-W 501F turbine.

a - Per turbine.

b - For 24-hour average, highest of gas or oil firing. For annual average, combination of gas (8,400 hours and oil firing (360 hours).

c - Natural-gas-fired only. 8,760 hours.

d - Fuel oil-fired only. 30 minutes each week for testing.

Summary of Hourly and Annual Toxic Emissions
S-W 501F Turbines plus Auxiliary Equipment

Toxic Compound	2 Turbines on NG (lb/hr) [b]	2 Turbines on Oil (lb/hr) [b]	Heater (lb/hr) [a]	Diesel Generator (lb/hr) [a]	Fire Pump (lb/hr) [a]	Worst-Case Total Hourly Emissions (lb/hr)	Idaho DEQ Screening Emissions Level (lb/hr)	Modeling Required (Yes/No)	Annual Total Facility Emissions (tons/yr) [c]
Ammonia	43.0436	43.7693	0.0000	0.0000	0.0000	43.8	1.2	Yes	188.7
Sulfuric Acid [d]	0.8622	14.2170	0.0000	0.0000	0.0000	14.217	0.067	Yes	6.180
VOC									
Acetaldehyde	0.0821	0.0000	0.0000	0.00065	0.00021	0.083	0.003	Yes	0.345
Acrolein	0.0000	0.0000	0.0000	0.000079	0.000026	0.000105	0.017	No	0.0000014
Benzene	0.3011	4.3996	0.00082	0.00079	0.00026	4.401	0.0008	Yes	2.060
1,3-Butadiene	0.0000	4.0496	0.0000	0.000033	0.000011	4.050	0.000024	Yes	0.729
Cyclohexane	0.0274	0.0000	0.00022	0.0000	0.0000	0.028	70	No	0.116
Cyclopentane	0.0547	0.0000	0.0000	0.0000	0.0000	0.055	115	No	0.230
Ethylbenzene	0.0274	0.0000	0.0000	0.0000	0.0000	0.027	29	No	0.115
Formaldehyde	2.2168	0.0000	0.00194	0.0010	0.00033	2.220	0.00051	Yes	9.319
Hexane (isomers)	0.0547	0.0000	0.00023	0.0000	0.0000	0.055	12	No	0.231
Heptane	0.1095	0.0000	0.0000	0.0000	0.0000	0.109	109	No	0.460
Nonane	0.0274	0.0000	0.0000	0.0000	0.0000	0.027	70	No	0.115
Octane	0.0547	0.0000	0.0000	0.0000	0.0000	0.055	93	No	0.230
Pentane (isomers)	0.3558	0.0000	0.0034	0.0000	0.0000	0.359	118	No	1.509
Toluene	0.1095	0.0000	0.00041	0.00035	0.00011	0.110	25	No	0.462
Trimethylbenzene (isomers)	0.1095	0.0000	0.0000	0.0000	0.0000	0.109	8.2	No	0.460
Xylene (isomers)	0.0547	0.0000	0.0000	0.00024	0.00008	0.055	29	No	0.230
PM									
Arsenic	0.0000	0.5554	0.0000	0.0045	0.0015	0.561	0.0000015	Yes	0.100
Cadmium	0.0000	0.0524	0.0000	0.0043	0.0014	0.058	0.0000037	Yes	0.010
Chromium	0.0197	0.0524	0.0000	0.0045	0.0015	0.058	0.033	Yes	0.092
Cobalt	0.0197	0.0000	0.0000	0.0000	0.0000	0.020	0.007	Yes	0.083
Copper	0.0197	0.0000	0.0000	0.0000	0.0000	0.020	0.067	No	0.083
Lead [e]	0.0000	0.5764	0.0000	0.0000	0.0000	0.576	0.6 tpy	No	0.104
Manganese	0.0197	0.0524	0.0000	0.0000	0.0000	0.052	0.333	No	0.092
Mercury	0.0000	0.0000	0.0000	0.0000	0.0000	0.000007	0.007	No	0.000
Nickel	0.0197	0.0524	0.0000	0.0004	0.0001	0.053	0.000027	Yes	0.092
Selenium	0.0000	0.0524	0.0000	0.0004	0.0001	0.053	0.013	Yes	0.009
Tin	0.0000	0.0524	0.0000	0.0000	0.0000	0.052	0.133	No	0.009
Zinc	0.0197	0.5764	0.0000	0.0047	0.0015	0.583	0.333	Yes	0.187

NA = Not Applicable

Note: The emissions for the gas turbines are presented for the coldest temperature of 5 deg. F and at full load with duct firing. These conditions represent the worst case emissions from the S-W 501F turbine.

a - The gas preheater is firing natural gas and the emergency generator and fire pump are firing No. 2 fuel oil.

b - Two turbines.

c- The total annual emissions are based on 8760 hours (8,400 on gas and 360 on oil) of operation for the two gas turbines and the gas preheater, and 26 hours of operation for the generator and fire pump.

IDAHO DEPARTMENT OF
ENVIRONMENTAL QUALITY
1410 NORTH HILTON, BOISE, ID 83706-1255
(208) 373-0502

TRANSMITTAL COVER SHEET

FAX NUMBER (208) 373-0154
2ND FLOOR

DATE:

TO: Mike Halpin, Florida DEP
FAX: (850) 921-9533
PHONE: (850) 921-9519

FROM: Ken Hanna
1410 N. HILTON
BOISE, IDAHO 83706-1255
PHONE: (208) 373-0283

DOCUMENT DESCRIPTION:

Westinghouse 501F Emission Data

TOTAL NUMBER OF PAGES (INCLUDING THIS COVER SHEET): 15

COMMENTS: I retransmitted the SW Data Page that had your name on it blocking the VOC data!

If you do not receive entire fax, please call 208-373-0283.

✓

SIEMENS Westinghouse

IDA - West

Expected 501F Combustion Turbine Performance Vendor Data
Combined Cycle / Dry Low NOx Combustor
AEROPAC 2-95x200 / 0.90 Power Factor

CTT-1998
03/13/00

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7
FUEL TYPE	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
LOAD LEVEL	BASE	BASE	60%	BASE	60%	BASE	60%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,981	20,981	20,981	20,981	20,981	20,981	20,981
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,299	23,299	23,299	23,299	23,299	23,299	23,299
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	OFF	OFF	OFF	OFF	OFF	OFF
AMBIENT DRY BULB TEMPERATURE, °F	95.0	95.0	95.0	51.0	51.0	5.0	5.0
AMBIENT WET BULB TEMPERATURE, °F	82.5	82.5	82.5	44.2	44.2	3.1	3.1
AMBIENT RELATIVE HUMIDITY, %	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
BAROMETRIC PRESSURE, psia	13.430	13.430	13.430	13.430	13.430	13.430	13.430
COMPRESSOR INLET TEMPERATURE, °F	84.3	95.0	95.0	51.0	51.0	5.0	5.0
INJECTION FLUID	-	-	-	-	-	-	-
INJECTION RATIO	-	-	-	-	-	-	-
INLET PRESSURE LOSS, inches of water (Total)	3.4	3.3	2.0	3.8	2.1	3.9	2.1
EXHAUST PRESSURE LOSS, inches of water (Total)	10.4	10.0	5.8	12.3	6.7	13.8	7.3
EXHAUST PRESSURE LOSS, inches of water (Static)	8.0	7.7	4.4	9.5	5.2	10.7	5.6
COMBUSTION TURBINE PERFORMANCE:							
GROSS POWER OUTPUT, kW	152,490	146,240	87,190	170,320	101,700	189,610	113,320
GROSS HEAT RATE, Btu/kWh (LHV)	9,435	9,520	11,020	9,180	10,580	9,005	10,055
GROSS HEAT RATE, Btu/kWh (HHV)	10,470	10,565	12,230	10,190	11,745	9,995	11,165
FUEL FLOW, lbm/hr	68,540	66,330	45,820	74,510	51,320	81,360	54,360
INJECTION RATE, lbm/hr	-	-	-	-	-	-	-
HEAT INPUT, mmBtu/hr (LHV)	1,438	1,392	961	1,563	1,077	1,707	1,140
HEAT INPUT, mmBtu/hr (HHV)	1,597	1,545	1,068	1,736	1,196	1,896	1,266
EXHAUST TEMPERATURE, °F	1,127	1,133	1,094	1,096	1,104	1,077	1,046
EXHAUST FLOW, lbm/hr	3,083,910	3,012,087	2,330,169	3,372,556	2,482,745	3,595,899	2,625,918
EXHAUST GAS COMPOSITION (BY % VOL):							
OXYGEN	11.92	12.06	12.92	12.52	13.05	12.45	13.16
CARBON DIOXIDE	3.73	3.71	3.31	3.76	3.52	3.85	3.53
WATER	11.33	10.91	10.15	8.29	7.81	7.80	7.16
NITROGEN	72.11	72.41	72.70	74.50	74.68	74.95	75.21
ARGON	0.90	0.91	0.91	0.93	0.94	0.94	0.94
MOLECULAR WEIGHT	28.06	28.10	28.15	28.39	28.42	28.48	28.50
NET EMISSIONS: Based on Westinghouse 21T5620 test methods							
NOx, ppmvd @ 15% O2	25	25	30	25	30	25	30
NOx, lbm/hr as NO2	150	145	120	162	134	177	142
CO, ppmvd @ 15% O2	10	10	30	10	30	10	30
CO, lbm/hr	37	36	73	40	82	43	87
SO2, lbm/hr – See detailed Calculations	~~0.99~~ 4.65	~~0.80~~	~~0.82~~	~~1.01~~	~~0.70~~	~~1.11~~	~~0.74~~
VOC, ppmvd @ 15% O2 as CH4	2.0	2.0	3.0	2.0	3.0	2.0	3.0
VOC, lbm/hr as CH4	4.16	4.03	4.17	4.52	4.67	4.94	4.94
PARTICULATES, lbm/hr	13.18	12.92	10.06	14.74	10.89	15.76	11.57
OPACITY	<= 10%	<= 10%	<= 10%	<= 10%	<= 10%	<= 10%	<= 10%

NOTES:

- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Gross power output is at the generator terminals minus static excitation loss.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 93208.
- VOC's are non methane, non ethane.
- Gas fuel composition is 98% CH_4, 0.6% C_2H_6, 1.4% N_2, 0.2 grains of sulfur per 100 SCF. → Actual Sulfur in gas = 1.0 $\frac{\text{grain}}{100\text{SCF}}$ 5 times higher Pg 4.3
- Gas fuel must be in compliance with the Siemens Westinghouse Gas Fuel Spec (21T0306, Rev 7).
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per US EPA Method 5/202 (front and back half).
- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.

- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.

Table 4-6 NOx controlled VOC/CO uncontrolled

Criteria Pollutant Potential Annual Emissions Rates – S-W 501 F BASE LOAD

	Pollutant (tons/year)				
	NO_X	CO	VOC	PM-10	SO_2
Two Gas Turbine Sets w/ Duct Firing (natural gas fuel 350 days per year)	243.43 ✓	598.08 ✓ 689 at 60% Load, no Duct Firing	103.49 ✓	156.24 ✓	~~43.48~~ ✓ 51.8 with Duct Burner Correction - Table B-4
Two Gas Turbine Sets w/o Duct Firing (low-sulfur distillate oil 15 days per year)	15.01 ✓	43.56 ✓ 904 at 60% Load, no duct Firing	8.32 ✓ 54.4 at 60% Load, no duct firing	17.64 ✓ 25.2 at 60% Load, no duct Firing	30.57 ✓
Gas Preheater 8760 hr/yr	1.8 ✓	1.8 ✓	0.04 ✓	0.16 ✓	0.013 ✓
Emergency Generator	0.05 ✓	0.01 ✓	0.004 ✓	0.003 ✓	0.003 ✓
Fire Pump	0.02 ✓	0.01 ✓	0.001 ✓	0.001 ✓	0.001 ✓
Total Facility	260.3	643.4	111.9	174.1	~~74.1~~ 82.4

26 hr/yr

NOTE:
The gas turbines emissions are for base load with power augmentation on natural gas and at the annual average temperature. 51°F

NOx $\left(\frac{162+31.2 \text{ lb}}{hr}\right)(1-0.85)\left(\frac{24 \text{ Hr}}{day}\right)\left(\frac{350 \text{ days}}{yr}\right)\left(\frac{ton}{2000 \text{ lb}}\right) = 122 \frac{tons}{yr} \rightarrow 122(2) = 243 \frac{tons}{yr}$

NOx $\left(\frac{278 \text{ lb}}{hr}\right)(1-0.85)\left(\frac{24 \text{ hr}}{day}\right)\left(\frac{15 \text{ days}}{yr}\right)\left(\frac{ton}{2000 \text{ lb}}\right) = 7.5 \frac{tons}{yr} \rightarrow (7.5)(2) = 15 \frac{tons}{yr}$

Also see calculations in tech memo attachments.

Data from Table 4-3 is used to determine values in this table.

See calculations in tech memo attachment. At 60% load, 51°F CO emissions increase considerably over what is emitted at Base load, 51°F, on oil.

Data from these mfgr info pages are entered onto Table 4.3 & 6.3

TABLE B-4

Gas Turbine: **Siemens-Westinghouse 501 F**
Exhaust Gas Information at Base Load with Duct Firing
Natural Gas

	M_W	5 F	51 F	95 F evap.coolers on
		Exhaust gas analysis (vol %)		
Ar	32	0.94	0.93	0.90
N_2	28	74.95	74.50	72.11
O_2	44	12.45	12.52	11.92
CO_2	40	3.85	3.76	3.73
H_2O	18	7.80	8.29	11.33

	5 F	51 F	95 F
M_W of exhaust gas (lb/mole)	29.71	29.66	29.26
Mass Flow (1000 lb/hr)	3,596	3,373	3,084
Temperature (°F)	1,077	1,096	1,127
Pressure (psia)	13.43	13.43	13.43
Volumetric Flow (ft^3/s)	41,284	39,268	37,125
Volumetric Flow (at turbine outlet) (aft^3/min)	2,477,065	2,356,075	2,227,513
Volumetric Flow (at stack outlet) (aft^3/min)	1,063,672	999,364	926,376
Stack Velocity (ft/s)	69.7	65.5	60.7
Gross kW	189,610	170,320	152,490
Heat Rate (Btu/kWh, LHV)	9,005	9,180	9,435
Gas Turbine Heat Input (MMBtu/hr, LHV)	1,707	1,564	1,439
Duct Burner Heat Input (MMBtu/hr, LHV)	390	390	390

Examples

Exhaust gas emission rates (manufacturer data)

$(177)(1-0.85) = 26.6$

$(31.2)(1-0.85) = 4.7$

	5 F	51 F	95 F		
NO_X					
1 Gas Turbine - Uncontrolled	177	162	150	lb/hr	✓ mfgr rating
1 Gas Turbine - Controlled	26.6	24.3	22.5	lb/hr	✓
1 Duct Burner - Uncontrolled	31.2	31.2	31.2	lb/hr	✓
1 Duct Burner - Controlled	4.7	4.7	4.7	lb/hr	✓
Total - Uncontrolled	208.2	193.2	181.2	lb/hr	✓
Total - Controlled (85% w/SCR)	31.2	29.0	27.2	lb/hr	✓
with duct firing — 4.5 ppm ✓					
3.0 ppmvd × 0.15 = 4.5					

$(74.2)(1-0.77) = 17.1$

	5 F	51 F	95 F		
CO					
1 Gas Turbine	43.0	40.0	37.0	lb/hr	Mfgr data ✓
1 Duct Burner	31.2	31.2	31.2	lb/hr	✓
Total for one set	74.2	71.2	68.2	lb/hr	✓
Total-Controlled 77%	17.1	16.4	15.7		

$(12.74)(1-0.20) = 10.19$

VOC control as per 3-13-01 e-mail correction

	5 F	51 F	95 F		
VOC as CH_4 nonmethane, nonethane					
1 Gas Turbine	4.94	4.52	4.16	lb/hr	✓ mfgr data
1 Duct Burner	7.80	7.80	7.80	lb/hr	✓
Total for one set	12.74	12.32	11.96	lb/hr	
Total-Controlled 20%	10.19	9.86	9.57		
PM-10					
1 Gas Turbine (Filerable + Condensible)	15.8	14.7	13.2	lb/hr	✓
1 Duct Burner	3.9	3.9	3.9	lb/hr	✓
Total for one set	19.7	18.6	17.1	lb/hr	

		5 F	51 F	95 F		
SO_2						
	S	1	1	1	gr/100scf	
	SO_2	0.00316	0.00316	0.00316	lb/MMBtu	✓
1 Gas Turbine		5.40 ✓	4.94	4.55	lb/hr	✓
1 Duct Burner		1.23 ~~0.23~~	1.23 ~~0.23~~	1.23 ~~0.23~~	lb/hr	
Total for one set		~~5.63~~ 6.63	~~5.18~~ 6.17	~~4.78~~ 5.78	lb/hr	

Duct Burner $SO_2 = \left(0.00316 \frac{lb}{mmBtu}\right)\left(390 \frac{mmBtu}{hr}\right) = 1.23$ lb/hr

TABLE B-7

Gas Turbine: Siemens-Westinghouse 501 F
Exhaust Gas Information at Base Load without Duct Firing
Fuel Oil

	M_W	5 F	51 F	95 F evap.coolers on
		Exhaust gas analysis (vol %)		
Ar	32	0.94	0.93	0.90
N_2	28	74.83	74.39	72.00
O_2	44	12.58	12.66	12.07
CO_2	40	5.15	5.01	4.98
H_2O	18	6.50	7.01	10.06
M_W of exhaust gas (lb/mole)		30.02	29.96	29.56
Mass Flow (1000 lb/hr)		3,643	3,415	3,123
Temperature (°F)		1,040	1,060	1,089
Pressure (psia)		13.43	13.43	13.43
Volumetric Flow (ft^3/s)		40,400	38,448	36,321
Volumetric Flow (at turbine outlet) (aft^3/min)		2,424,015	2,306,861	2,179,272
Volumetric Flow (at stack outlet) (aft^3/min)		1,066,567	1,001,663	928,547
Stack Velocity (ft/s)		69.9	65.6	60.8
Gross kW		183,090	164,090	146,630
Heat Rate (Btu/kWh, LHV)		9,280	9,470	9,740
Heat Input (MMBtu/hr)		1,699	1,554	1,428

Exhaust gas emission rates

		5 F	51 F	95 F	
NO_X					
1 Gas Turbine		305	278	256	lb/hr ✓
1 Gas Turbine - Controlled		**45.8**	**41.7**	**38.4**	**lb/hr** ✓
85% w/SCR		**6.3 ppm** ✓			
CO					
1 Gas Turbine		133.0	121.0	112.0	lb/hr ✓
Total-Controlled (77%)		30.6	27.8	25.8	
VOC as CH_4	nonmethane, nonethane				
1 Gas Turbine		25.20	23.10	21.20	lb/hr ✓
Total-Controlled (20%)		20.2	18.5	17.0	
PM-10					
1 Gas Turbine		52.4	49.0	43.8	lb/hr ✓
SO_2					
	S	0.05	0.05	0.05	wt%
	SO_2	0.05464	0.05464	0.05464	lb/MMBtu ✓
1 Gas Turbine		92.85	84.91	78.04	lb/hr ✓

$(42\ ppmvd)(1-0.85) = 6.3\ ppmvd\ @\ 15\%\ O_2$

$(133.0)(1-0.77) = 30.6$

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TABLE B-2
(6-5-01 Revision)

Source Garnet Energy 027-00081

Annual Emissions Summary for Natural Gas and Fuel Oil for the S-W 501F Turbine (tons/yr)

Equipment	NO_X	CO	VOC	PM-10	SO_2
Two Gas Turbine Sets w/ Duct Firing (natural gas 8,400 hours per year)	68.7 each 137.94	79.2 each 158.42	41.4 each 82.79	78.1 each 156.24	21.8 each 43.51
Two Gas Turbine Sets w/o Duct Firing (No.2 fuel oil 360 hours per year)	4.1 each 8.10	18.7 each 37.49	5.9 each 11.77	9.3 each 18.69	14.6 each 29.11
Total for Two Turbine Sets	**146.04**	**195.92**	**94.56**	**174.93**	**72.62**
Natural Gas Preheater	1.75	1.75	0.044	0.16	0.013
Emergency Generator	0.05	0.01	0.004	0.003	0.003
Fire Pump	0.02	0.01	0.001	0.001	0.001
Total Plant	**147.86**	**197.69**	**94.61**	**175.09**	**72.64**
Significant Emission Rates	40.0	100.0	40.0	15.0	40.0

Natural Gas Firing in the Turbines:

The emissions are presented for 51 F and 100% load with duct firing. The only exception is CO, which is presented at 51 F and 60% load since emissions are higher at this load. There is no duct firing at 60% load.

Distillate Oil Firing in the Turbines:

The emissions are presented for 51 F. The duct burners are not operating during oil firing. The emissions at 100% load are added to the emissions at 60% load to account for the total emissions during oil firing.

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example for 1 gas Turbine: $NO_x = \frac{137.94}{2} = 68.7 \frac{tons}{yr}$

Note: At turbine operations of up to 8760 hr/yr (8400+360) on natural gas only (i.e., no oil firing), then emissions would be less than the totals shown above for combined oil and gas firing. Therefore, annual hours of operation are not limited in the permit for when only natural gas is fired.

Annual Emission limit example:

NO_x Annual total for one turbine $= 68.7 + 4.1 = 72.8 \frac{tons}{yr}$

Also, see attached spreadsheets for hourly & annual data.

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One SW 501F Combustion Turbine with Duct Firing
Fuel: Natural Gas

Hourly Emissions

Turbine Inlet Temperature	Load	NO_X	CO	VOC	PM-10	SO_2
F	%	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
5	100 w/duct	17.72	17.07	10.19	19.70	5.63
5	60	12.07	20.01	3.95	11.60	3.60
51	100 w/duct	16.42	16.38	9.86	18.60	5.18
51	60	11.39	18.86	3.74	10.90	3.40
95	100 w/duct	15.40	15.69	9.57	17.10	4.78
95	60	10.20	16.79	3.34	10.10	3.04
Removal at 100% load (%) =		91.5	77	20		
Removal at 60% load (%) =		91.5	77	20		

Annual Emissions

Turbine Inlet Temperature	Load	NO_X	CO	VOC	PM-10	SO_2
F	%	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
5	100 w/duct	74.43	71.68	42.81	82.74	23.65
5	60	50.69	84.04	16.60	48.72	15.12
51	100 w/duct	68.97	68.78	41.40	78.12	21.76
51	60	47.84	79.21	15.69	45.78	14.28
95	100 w/duct	64.69	65.88	40.19	71.82	20.08
95	60	42.84	70.52	14.01	42.42	12.77
Hours on NG at 60 - 100% load(hrs/yr) =			8,400			

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One SW 501F Combustion Turbine without Duct Firing
Fuel: Distillate Fuel Oil

Hourly Emissions

Turbine Inlet Temperature	Load	NO_X	CO	VOC	PM-10	SO_2
F	%	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
5	100	25.93	30.59	20.16	52.40	92.85
5	60	16.49	615.02	128.64	74.60	59.44
51	100	23.63	27.83	18.48	49.00	84.91
51	60	15.47	577.30	120.80	69.90	55.79
95	100	21.76	25.76	16.96	43.80	78.04
95	60	14.28	533.37	111.60	63.80	51.51
Removal at 100% load (%) =		91.5	77	20		
Removal at 60% load (%) =		91.5	77	20		

Annual Emissions

Turbine Inlet Temperature	Load	NO_X	CO	VOC	PM-10	SO_2
F	%	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
5	100	4.02	4.74	3.12	8.12	14.39
5	60	0.41	15.38	3.22	1.87	1.49
51	100	3.66	4.31	2.86	7.60	13.16
51	60	0.39	14.43	3.02	1.75	1.39
95	100	3.37	3.99	2.63	6.79	12.10
95	60	0.36	13.33	2.79	1.60	1.29
Hours on FO at 100% load(hrs/yr) =			310			
Hours on FO at 60% load (hrs/yr) =			50			

GARNET ENERGY LLC

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March 20, 2001

Mr. Stephen E. West
Regional Administrator
Idaho Department of Environmental Quality
1410 North Hilton
Boise, ID 83706

Re: *Garnet Energy PSD Application – Proposal to Include an Oxidation Catalyst for Removal of Carbon Monoxide*

Dear: Mr. West:

Garnet Energy LLC (Garnet) has a Prevention of Significant Deterioration (PSD) application currently being reviewed by the Idaho Department of Environmental Quality (IDEQ) air quality staff. Early in the process of preparing all of the documentation for the PSD application, Garnet representatives met with IDEQ staff regarding the issues that would need to be considered in the air permit application submittal. All of the concerns raised by the IDEQ staff have been addressed in the PSD application, the application declared complete by IDEQ staff, and the draft air permit currently being prepared.

One of the concerns raised by the IDEQ staff at the initial project meetings was the facility's projected carbon monoxide (CO) emissions and the potential impacts on nearby Ada County and the Treasure Valley in general. Garnet addressed the emissions of CO in the PSD application regarding the use of the best available emission control technology (BACT) and the projected ground-level impacts. The studies performed in support of the PSD application indicated that BACT for the CO emissions would be good combustion controls. Add-on control, such as catalytic oxidation, was deemed to be more expensive than what is considered reasonable by the USEPA. In addition, the dispersion modeling analysis demonstrated that the maximum projected ground-level CO concentrations would be below the USEPA significant impact levels (SILs). Emissions below the SILs are interpreted by the USEPA to be inconsequential with regard to the maintenance of the national ambient air quality standards, which are based on the maintenance of the public health and welfare.

Garnet recognizes the importance of the IDEQ concerns regarding the sensitivity of the CO air quality in the Treasure Valley. Therefore, while not required by PSD regulation or by the IDEQ, Garnet will voluntarily install a CO oxidation catalyst system to reduce projected CO emissions by about 77 percent over those presented in the PSD application.

Based on catalyst-manufacturer's information, installation and operation of the CO catalyst system will simultaneously reduce emissions of volatile organic compounds (VOC), some which are ozone precursors, by about 15 to 24 percent, including some toxic air pollutants (TAPs). Formaldehyde emissions will be reduced by approximately the same amount as CO (i.e., 77 percent). Application of the CO catalyst will result in the total VOC emissions from the proposed facility being below 100 tons per year.

In summary, by volunteering to install a CO oxidation catalyst, the amount of CO emissions that would be emitted will be reduced as well as the amount of ozone precursors and emissions of formaldehyde.

Garnet is committed to working in a pro-active manner with IDEQ to assure the air quality of southwestern Idaho. We believe that the voluntary installation of a CO oxidation catalyst system demonstrates our commitment.

Should you have any questions, please do not hesitate to call me at (208) 395-8952.

Sincerely,

Michael R. Elliott, P.E.
Project Manager

cc: Kenneth L. Hanna, IDEQ
Walter J. Russell, AirPermits.com
Anita K. Lindell, AirPermits.com
Krista K. McIntyre, Stoel Rives

Attachment

File: Garnet - IDEQ

Table 8. Annual average					
Pollutant	**Averaging Period**	**Modeled Emission Rates (lb/hr)**			
		Turbine[a]	**Heater**[b]	**Generator**[b]	**Fire Pump**[b]
NO_x	Annual	29.5	0.2	0.01113	0.00366
SO_2	Annual	8.45	0.0015	0.00073	0.00024
	3-hour				
	24-hour				
PM_{10}	Annual	19.85	0.02	0.00078	0.00026
	24-hour				
CO	1-hour				
	8-hour				
Acetaldehyde	Annual	0.0411		1.90E-06	6.40E-07
Ammonia	24-hour				
Arsenic	Annual	0.0115		1.30E-05	4.40E-06
Benzene	Annual	0.2348	0.00041	2.40E-06	7.80E-07
1,3-Butadiene	Annual	0.0833		1.00E-07	3.20E-08
Cadmium	Annual	0.0011		1.30E-05	4.20E-06
Chromium	24-hour				
Cobalt	24-hour				
Formaldehyde	Annual	1.1085	0.00097	3.00E-06	1.00E-06
Nickel	Annual	0.0106		1.30E-06	4.20E-07
Selenium	24-hour				
Sulfuric Acid	24-hour				
Zinc	24-hour				
a. Assumes 8400 hr/yr operation using Natural gas and 360 hrs/yr using oil.					
b. Assumes operation of: Heater 4380 hr/yr; generator and fire pump 26 hrs/yr.					

Table 9. Maximum predicted concentration (ug/m^3)

Pollutant	Averaging Period	Regulatory Limit (ug/m^3)[a]	Annual	Base Load			60% Load			Exceeds Threshold?	Impact on Limit (%)
				5°F	51°F	95°F	5°F	51°F	95°F		
NO_2	Annual	1	0.938[b]							No	93.80%
SO_2	Annual	1	0.0419							No	4.19%
	3-hour	25		12.23	20.29	21.87	9.68	18.10	18.44	No	87.48%
	24-hour	5		3.18	3.74	3.83	2.60	3.04	3.06	No	76.52%
PM_{10}	Annual	1	0.099							No	9.94%
	24-hour	5		1.90	2.16	2.15	3.26	3.65	3.80	No	75.99%
CO	1-hour	2000		124.40	154.82	121.72	1147.85	1524.97	1510.96	No	76.25%
	8-hour	500		40.91	40.91	25.06	221.71	372.48	383.10	No	76.62%
Acetaldehyde	Annual	0.45	0.0002							No	0.04%
Ammonia	24-hour	900		0.75	0.97	1.07	0.96	1.19	1.30	No	0.14%
Arsenic	Annual	0.00023	0.0001							No	43.48%
Benzene	Annual	0.12	0.00189							No	1.58%
1,3-Butadiene	Annual	0.0036								No	0.00%
Cadmium	Annual	0.00056	0.0001							No	17.86%
Chromium	24-hour	25		0.00393	0.00353	0.00286	0.00353	0.00393	0.00393	No	0.02%
Cobalt	24-hour	5		0.00033	0.00037	0.00049	0.00044	0.00055	0.00059	No	0.01%
Formaldehyde	Annual	0.077	0.0054							No	7.01%
Nickel	Annual	0.0042	0.00005							No	1.19%
Selenium	24-hour	10		0.00086	0.00097	0.00112	0.00107	0.00130	0.00155	No	0.02%
Sulfuric Acid	24-hour	50		0.24	0.26	0.31	0.29	0.35	0.42	No	0.85%
Zinc	24-hour	50		0.00953	0.01070	0.01243	0.01180	0.01438	0.01713	No	0.03%

a. Significant contribution for criteria pollutants (58.01.01.006.93), AAC or AACC for the toxics (58.01.01.585 (AAC) and 586 (AACC)).

b. The concentration for NO_2 assumes total conversion of NO to NO_2. This is the Tier I (initial screening) approach recommended by 40 CFR 51 App. W "Guideline on Air Quality Models". If this ambient concentration exceeded the significant contribution level then AirPermits.com would have proceeded to the Tier 2 by multiplying the Tier I estimate by an empirically derived NO_2/NO_x value of 0.75.

Modeled Impacts

working copy

From: Anita Lindell <alindell@uswest.net>
To: Ken Hanna <khanna@deq.state.id.us>, Mike Elliott <...
Date: Mon, Mar 5, 2001 10:03 PM
Subject: Revised emissions for Garnet Energy

Ken,

As I was preparing the letter to IDEQ for Mike Elliott, I slightly revised the criteria emission calculations. I assumed a 15% VOC removal just to be safe if the CO catalyst isn't as good at removing VOC as the manufactuer thinks. Then I reduced the hours at 100% load during oil firing by the amount of hours that I assumed for 60% load during oil firing. Lastly, I added the hours on 100% load and 60% load on oil to get more accurate total emissions during oil firing. This allows 50 hours on oil and still comfortably being less than 100 tpy of VOC. Please see the formulas and it should be pretty self explanatory. Otherwise, don't hesitate to call me tomorrow afternoon. Thanks,

Anita

working copy

From:	Anita Lindell <alindell@uswest.net>
To:	Mike Elliott <melliott@ida-west.com>
Date:	Thu, Mar 1, 2001 6:58 PM
Subject:	Garnet Energy-Response to comments from EPA

These estimates were superseded by 3-5-01 info from Anita!

Mike,

I have received a response from Engelhard, the catalyst manufacturer, and based on this prepared new emissions estimates for criteria pollutants for the SW 501 F turbines. The emissions estimates are attached in an excel file.

According to Engelhard, less catalyst could be used to get to 5 ppm CO instead of the approximately 3.8 ppm that they had originally estimated. However, it only reduced the control efficiency to about 77%. In other words, you need to put on a catalyst that can achieve 77% CO removal to get to 5 ppm on natural gas. On oil the same removal would give you 7 ppm CO, except for the 60% load where the CO would be 219 ppm. You can only run on oil at 60% load for 17 hours.

Action:
☒ Double check emission estimates
☒ revise PTC perm to include new limits.

Engelhard also indicated that to get to 5 ppm CO we would get approximately 24% VOC removal. I have included this in the emission calculations. VOC is now below 100 tpy for all the cases I have described. Therefore, no modeling or ambient monitoring is required.

In addition, the formaldehyde removal is about the same as the CO removal, i.e. for our case about 77%. So instead of 9.3 tpy of total formaldehyde we would have about 2.2 tpy of formaldehyde. This should calm EPA. Note that formaldehyde is not estimated by CARB to be emitted during oil firing of the turbines.

This is a summary of what I propose should go into the permit:

Fuel	Hours per year	Load (%)	NOx
(ppm)	CO (ppm)		
NG	Up to ~~8,350~~ 7990	100	
4.5	5		
NG	Up to ~~8,350~~ 7990	60	
4.5	5		
FO	Up to ~~360~~ 310	100	
6.3	7		
FO	Up to ~~17~~ 50	60	
6.3	219		

Per 3-5-01 changes. KH.

Note: Modeling is not necessary since no emissions will increase.

Superseded!

And the formaldehyde emissions estimated at 2.2 tpy instead of 9.3 tpy.

Please let me know if you have questions. Thanks,

Anita

CC: Ken Hanna <khanna@deq.state.id.us>, Walt Russell <...

Working copy only
- not for source file
Since the March 20, 200
addresses this issue.

From: Anita Lindell <alindell@uswest.net>
To: Ken Hanna <khanna@deq.state.id.us>
Date: Tue, Mar 13, 2001 4:46 PM
Subject: Revised emissions for Garnet

Ken,

Per your e-mail of 3/12/01 I checked to see if we could stay under 100 tpy VOC at 8760 hours per year of natural gas operation. This is possible if we increase VOC removal. I have assumed 20% removal as average since the manufacturer said we could get up to 24%. With 20% removal of VOC and 8760 hours of operation on natural gas only we get 91.7 tpy VOC for two turbines so that is ok.

The spreadsheet that I am attaching includes the 20% VOC removal, up to 360 hours per year of oil firing (of those 50 hours can be on the 60% load case) so the natural gas hours here would be 8400. As before, we would like the hour restrictions to read:

Up to 8760 hours on natural gas
Up to 360 hours on distillate oil, if oil is used you would then subtract those hours from the natural gas hours.
Up to 50 hours of the 360 oil hours could occur on the 60% load case.

I hope that this makes everyone happy! Let me know if you have any other questions. Thanks,

Anita

CC: Mike Elliott <melliott@ida-west.com>, Walt Russell...

Table 4-9
CO Reduction System Annualized Cost Per GE 7FA CTG/HRSG Unit

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	306,000	NA	Catalyst life of 3 yr. Of equivalent operating hours
Operation and Maintenance	4,000	NA	See text for background information on this item
Lost Power Generation	40,000	NA	Back Pressure on Combustion Turbine
Total Direct Annual Cost	350,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Labor
Administrative Charges	26,000	NA	2% of Total Installed Cost
Property Taxes	36,000	NA	2.75% of Total Installed Cost
Insurance	13,000	NA	1% of Total Installed Cost
Capital Recovery	143,000	NA	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	220,000	NA	
Total Annualized Cost	**570,000**	NA	
Annual Emissions, tpy	74.7	394.4	Emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	319.7	NA	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, $/ton	**1,800**	NA	Total Annualized Cost/Emissions Reduction

Table 4-8
CO Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Oxidation Catalyst	746,000	NA	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	NA	Scaled from an estimate from Engelhard Corporation based on catalyst size
Control/Instrumentation	40,000	NA	Estimated
Purchased Equipment Costs	1,054,000		
Freight	53,000		5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,107,000		
Direct Installation Costs			
Balance of Plant	332,000	NA	8% For Foundations & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting.
Total Direct Capital Cost Less Catalyst	775,000	Base	
Indirect Capital Costs			
Contingency	221,000	NA	20% of Total Purchased Equipment Cost
Engineering and Supervision	111,000	NA	10% of Total Purchased Equipment Cost
Construction & Field Expense	55,000	NA	5% of Total Purchased Equipment Cost
Construction Fee	111,000	NA	10% of Total Purchased Equipment Cost
Start-up Assistance	22,000	NA	2% of Total Purchased Equipment Cost
Performance Test	11,000	NA	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	531,000	Base	
Total Installed Cost	**1,306,000**	Base	

GE ENERGY SERVICES

May - 2004

Natural Gas		CT #1 Natural Gas Firing			
Operating Load (MW)	**Heat Input 10^6 Btu/hr**	**Parameter**	**Units**	**Measured Emissions**	**Permitted Emission Limit**
112.1	1336.7	NOx	ppm @ 15% O_2	19.0	20
112.1	1336.7	NOx	lb/hr[1]	80.5	136.0
112.1	1336.7	CO	ppm @ 15% O_2	3.4	15
112.1	1336.7	CO	lb/hr[1]	1.3	63.0
112.1	1336.7	SO_2	lb/hr[2]	<0.12	-
135.3	1536.9	NOx	ppm @ 15% O_2	16.4	20
135.3	1536.9	NOx	lb/hr[1]	92.6	136.0
135.3	1536.9	CO	ppm @ 15% O_2	0.4	15
135.3	1536.9	CO	lb/hr[1]	1.4	63.0
135.3	1536.9	SO_2	lb/hr[2]	<0.14	-
157.2	1734.8	NOx	ppm @ 15% O_2	15.9	20
157.2	1734.8	NOx	lb/hr[1]	101.0	136.0
157.2	1734.8	CO	ppm @ 15% O_2	0.3	15
157.2	1734.8	CO	lb/hr[1]	1.0	63.0
157.2	1734.8	SO_2	lb/hr[2]	<0.15	-
175.1	1918.8	NOx	ppm @ 15% O_2	16.3	20
175.1	1918.8	NOx	lb/hr[1]	114.9	136.0
175.1	1918.8	CO	ppm @ 15% O_2	0.0	15
175.1	1918.8	CO	lb/hr[1]	0.7	63.0
175.1	1918.8	SO_2	lb/hr[2]	0.31	-
Base	1919.0	PM	lb/hr[3]	3.9	15.3
Base	1919.0	Opacity	%	0.0	20

1 – Calculated based on measured heat input and measured EPA F_d Factor.
2 – Calculated based on measured heat input and fuel sulfur analysis.
3 – Calculated based on measured exhaust gas volumetric flow rate.

GE ENERGY SERVICES

May - 2004

Natural Gas	CT #2 Natural Gas Firing				
Operating Load (MW)	Heat Input 10^6 Btu/hr	Parameter	Units	Measured Emissions	Permitted Emission Limit
120.0	1396.5	NOx	ppm @ 15% O_2	17.4	20
120.0	1396.5	NOx	lb/hr[1]	89.0	136.0
120.0	1396.5	CO	ppm @ 15% O_2	13.1	15
120.0	1396.5	CO	lb/hr[1]	41.0	63.0
120.0	1396.5	SO_2	lb/hr[2]	0.24	-
139.9	1571.0	NOx	ppm @ 15% O_2	15.0	20
139.9	1571.0	NOx	lb/hr[1]	86.5	136.0
139.9	1571.0	CO	ppm @ 15% O_2	0.3	15
139.9	1571.0	CO	lb/hr[1]	1.2	63.0
139.9	1571.0	SO_2	lb/hr[2]	0.27	-
159.0	1746.1	NOx	ppm @ 15% O_2	14.9	20
159.0	1746.1	NOx	lb/hr[1]	95.5	136.0
159.0	1746.1	CO	ppm @ 15% O_2	0.2	15
159.0	1746.1	CO	lb/hr[1]	0.8	63.0
159.0	1746.1	SO_2	lb/hr[2]	0.30	-
176.6	1923.6	NOx	ppm @ 15% O_2	13.9	20
176.6	1923.6	NOx	lb/hr[1]	119.4	136.0
176.6	1923.6	CO	ppm @ 15% O_2	0.2	15
176.6	1923.6	CO	lb/hr[1]	0.9	63.0
176.6	1923.6	SO_2	lb/hr[2]	0.31	-
Base	1841.7	PM	lb/hr[3]	5.2	15.3
Base	1841.7	Opacity	%	0.0	20

1 – Calculated based on measured heat input and measured EPA F_d Factor.
2 – Calculated based on measured heat input and fuel sulfur analysis.
3 – Calculated based on measured exhaust gas volumetric flow rate.

Complete test results summaries are tabulated and can be found on pages 9 through 12.

To: Mike Halpin
805-921-9533
Date: 8-18-04

Mike, we have checked our files, and I have attached the stack testing information for the siemens turbines you requested. The source was limited to natural gas so there is not information on fuel oil. We also checked another source and although it was a siemens, it was not the model you were looking for. Good luck and let us know if you need anything else.

Todd Ellis
State of Nebraska
402-471-4561
todd.ellis@ndeq.state.ne.us

Low Load

TEST REPORT
ON
COMPLIANCE AIR EMISSION TESTING

OF THREE
WESTINGHOUSE 501FD
TURBINE GENERATORS

AT THE
MORGAN ENERGY CENTER, LLC
DECATUR ENERGY CENTER

LOCATED IN
DECATUR, MORGAN COUNTY, ALABAMA

PREPARED FOR

MORGAN ENERGY CENTER, LLC
AND
CALPINE CORPORATION

JUNE, 2004

CUBIX JOB NO. 7464

Table 2
CT3 Reduced Load Summary of Results

Company:	Calpine Corporation				
Location:	Morgan Energy Center, Decatur, Morgan County, AL				
Source:	Westinghouse 501 D Combustion Turbine				
Designation:	Unit 3/CT3				
Technicians	JNT, WMS				
Test Run No.	**8611-CT3-C1**	**8611-CT3-C2**	**8611-CT3-C3**		
Load Condition	**TO, Reduced**	**TO, Reduced**	**TO, Reduced**		
Date	**6/10/04**	**6/10/04**	**6/10/04**		
Start Time	09:01	10:20	11:39		
Stop Time	10:01	11:20	12:39		
Turbine/Compressor Operation					
Turbine Active Power (MW)	59.95	59.98	59.99		
Steam Turbine Generator Active Power (MW)	126.01	131.27	151.91		
Internal Guide Vane Position (%)	42.88	42.89	42.91		
Compressor Exhaust Temperature (°F)	1116.8	1123.7	1123.6		
Fuel Data					
Fuel Heating Value (Btu/lb, GHV)	23283	23283	23283		
Volatile fraction (non-methane,non-ethane % from fuel analysis)	2.33%	2.33%	2.33%		
CO2 F-Factor (DSCF/MMBtu)	1024	1024	1024		
O2 F-Factor (DSCF/MMBtu)	8636	8636	8636		
Total Fuel Sulfur (ppm/wt. from fuel analyses)[reported as<1]	1.0	1.0	1.0		
Fuel Flow Rate (klb/hr)	37.5	37.5	37.5		
Fuel Flow (Btu/hr)	8.73E+08	8.73E+08	8.73E+08		
Calc. Moisture Content (vol % at stack)	8.28	8.07	7.96		
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.38	29.36	29.36		
Temperature (°F) : Dry bulb	82	85	88		
(°F) Wet bulb	76	75	75		
Humidity (lb/lb air)	0.0178	0.0163	0.0156		
Measured Exhaust Emissions ***(corrected using Equation 6c-1)***				**Average**	
NOx (ppmv)	1.7	2.2	2.1	**2.0**	
CO (ppmv)	27.7	22.9	19.6	**23.4**	
O2 (vol %)	14.89	14.84	14.84	**14.85**	
CO2 (vol %)	3.44	3.42	3.42	**3.43**	
THC as C3H8 (ppmv)(wet)	0.16	0.21	0.24	**0.2**	
THC AS C3H8 (ppmv)(dry)	0.17	0.23	0.26	**0.22**	
Fo Factor	1.75	1.77	1.77	**1.76**	
Exhaust Flow Rate					
via EPA Method 19's O2 F-factor (SCFH, dry)	2.62E+07	2.60E+07	2.60E+07	**2.61E+07**	
Calculated Mass Emission Rates (via EPA Method19)					**Permit Limit**
NOx (lbs/hr)	5.43	6.72	6.63	**6.3**	**31.2**
CO (lbs/hr)	52.82	43.24	37.10	**44.4**	**156.0**
SO2 (lbs/hr)	0.08	0.08	0.08	**0.1**	
THC (lbs/hr)	0.51	0.67	0.78	**0.66**	**30.0**
NOx (lbs/MMBtu)	0.006	0.008	0.008	**0.007**	**0.013**
CO (lbs/MMBtu)	0.060	0.050	0.042	**0.051**	**0.117**
THC (lbs/MMBtu)	0.001	0.001	0.001	**0.001**	**0.0131**

Table 3
CT2 Reduced Load Summary of Results

Company:	Calpine Corporation				
Location:	Morgan Energy Center, Decatur, Morgan County, AL				
Source:	Westinghouse 501 D Combustion Turbine				
Designation:	Unit 2/CT2				
Technicians	JNT, WMS				
Test Run No.	**8611-CT2-C1**	**8611-CT2-C2**	**8611-CT2-C3**		
Load Condition	**TO, Reduced**	**TO, Reduced**	**TO, Reduced**		
Date	**6/11/04**	**6/11/04**	**6/11/04**		
Start Time	08:30	09:48	11:05		
Stop Time	09:30	10:48	12:05		
Turbine/Compressor Operation					
Turbine Active Power (MW)	60.00	59.99	60.86		
Steam Turbine Generator Active Power (MW)	180.6	200.3	216.5		
Internal Guide Vane Position (%)	42.90	42.90	42.74		
Compressor Exhaust Temperature (°F)	1117.1	1117.9	1117.9		
Fuel Data					
Fuel Heating Value (Btu/lb, GHV)	23283	23283	23283		
Volatile fraction (non-methane,non-ethane % from fuel analysis)	2.33%	2.33%	2.33%		
CO2 F-Factor (DSCF/MMBtu)	1024	1024	1024		
O2 F-Factor (DSCF/MMBtu)	8636	8636	8636		
Total Fuel Sulfur (ppm/wt. from fuel analyses)[reported as<1]	1.0	1.0	1.0		
Fuel Flow Rate (klb/hr)	37.35	37.26	37.57		
Fuel Flow (Btu/hr)	8.70E+08	8.68E+08	8.75E+08		
Calc. Moisture Content (vol % at stack)	8.23	8.09	7.95		
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.30	29.30	29.30		
Temperature (°F) : Dry bulb	83	87	90		
(°F) Wet bulb	76	76	76		
Humidity (lb/lb air)	0.0177	0.0167	0.0160		
Measured Exhaust Emissions *(corrected using Equation 6c-1)*				**Average**	
NOx (ppmv)	2.1	2.0	2.0	**2.0**	
CO (ppmv)	24.8	17.6	18.1	**20.2**	
O2 (vol %)	14.91	14.90	14.93	**14.91**	
CO2 (vol %)	3.43	3.40	3.36	**3.40**	
THC as C3H8 (ppmv)(wet)	0.1	0.1	0.2	**0.2**	
THC as C3H8 (ppmv)(dry)	0.12	0.16	0.25	**0.18**	
Fo Factor	1.75	1.77	1.78	**1.76**	
Exhaust Flow Rate					
via EPA Method 19's O2 F-factor (SCFH, dry)	2.62E+07	2.61E+07	2.64E+07	**2.62E+07**	
Calculated Mass Emission Rates (via EPA Method19)					**Permit Limit**
NOx (lbs/hr)	6.69	6.24	6.31	**6.4**	**31.2**
CO (lbs/hr)	47.15	33.39	34.85	**38.5**	**156.0**
SO2 (lbs/hr)	0.07	0.07	0.08	**0.1**	
THC (lbs/hr)	0.37	0.46	0.75	**0.53**	**30.0**
NOx (lbs/MMBtu)	0.008	0.007	0.007	**0.007**	**0.013**
CO (lbs/MMBtu)	0.054	0.038	0.040	**0.044**	**0.117**
THC (lbs/MMBtu)	0.000	0.000	0.001	**0.001**	**0.0131**

INITIAL COMPLIANCE TEST REPORT

For

ADEM AIR PERMIT AND FEDERAL NSPS TESTING

Per ADEM Air Permit No. 712-0080-X001 and 40 CFR 60, Subparts GG and Da

From

UNIT 1, A COMBINED-CYCLE WESTINGHOUSE MODEL 501F-D COMBUSTION GAS TURBINE GENERATOR SET WITH A SUPPLEMENTARY FIRED HEAT RECOVERY STEAM GENERATOR

At the

MORGAN ENERGY CENTER

Located in

DECATUR, MORGAN COUNTY, ALABAMA

Prepared for the

MORGAN ENERGY CENTER, LLC

And

CALPINE CORPORATION

Test Completion Date: January 11th, 2004
Report Preparation Date: February 5nd, 2004

Cubix Project Number: 8274-FL1

Prepared by

methodology requirements per 40 CFR 60, Subpart Da. Visible emissions test runs were 60 minutes in duration. PM and VE testing was conducted with Test Runs U1-C-7 through U1-C-9 while operating at base load with PAG on and DB firing.

Table 2, the executive summary, shows the performance for the unit during the testing. These performance results are an average of the three test runs at each test condition. These emissions are compared to the permit limits set forth in ADEM Air Permit No. 712-0080-X001. NO_X, CO, VOC, and PM mass emission rates are reported in terms of pounds per hour (lbs/hr) and pounds per Million British thermal unit of natural gas fuel burned (lb/MMBtu). Visible emissions are reported in terms of percent opacity.

TABLE 2
Executive Summary

Unit 1, a Siemens Westinghouse Model 501F-D Combustion Turbine Parameter	PAG Off DB Off Low Load	PAG Off DB Off Base Load	PAG On DB On Base Load	†ADEM Permit Limits
Generator Output (MW)	115.0	188.2	194.1	-
Turbine Heat Input (HHV)	1388.8	2065.6	2103.3	-
Duct Burner Heat Input (HHV)	0.0	0.2	487.3	-
NO_x (lbs/hr)	11.3	12.5	16.8	**31.2**
NO_x (lbs/MMBtu)	0.00811	0.00606	0.00650	**0.013**
CO (lbs/hr)	25.4	3.20	6.11	**156/232**
CO (lbs/MMBtu)	0.0183	0.00155	0.00236	**0.117/0.100**
VOC (lbs/hr as propane)	4.55	0.08	0.41	**30.0**
VOC (lbs/MMBtu as propane)	0.00328	0.00004	0.00016	**0.0131**
VE (% opacity)			0%	**10%**
PM (lbs/hr)			10.4	**11.0**
PM (lbs/MMBtu)			0.00402	**0.005**

† Where column lists multiple ADEM permit limits, the limits are for operation from (1) 60% to base load with the turbine only and (2) from 60% to base load with power augmentation (PAG) and with duct burners on or off, respectively.

Tables 3 through 5 represent the test results from the three test conditions for initial compliance testing. These tabular summaries contain all pertinent operational parameters, ambient conditions, measured emissions, corrected concentrations, and calculated emission rates. NO_X and CO emissions are reported in units of parts per million by volume (ppmv) on a dry basis and ppmv corrected to 15% excess O_2. Volatile organic compound (VOC) concentrations were determined from THC measurements and are reported in units of ppmv as methane on a wet basis, ppmv as propane on a wet basis, and ppmv as methane on a dry basis, corrected to 15% excess O_2. Concentrations of PM were determined in units of grams per dry standard cubic feet (grams PM/DSCF) of exhaust gas. Mass emission rates for NO_X, CO, VOC, and PM, are reported in terms of lbs/hr and lb/MMBtu.

TABLE 3: Summary of Results
Low Load Testing

Company: Morgan Energy Center LLC
Plant: Morgan Energy Center
Location: Decatur, Morgan County, Alabama
Technicians: LJB, RPO, JTH, TAR, NS
Source: Unit 1, a Siemens Westinghouse 501FD Combustion Turbine

Test Number	U1-C-1	U1-C-2	U1-C-3		
Date	1/8/04	1/8/04	1/9/04		
Start Time (CEMS Time)	20:36	23:19	10:20		ADEM
Stop Time (CEMS Time)	22:53	24:19	11:20		Permit
Power Turbine Operation		Low Load		*Averages*	Limits
Generator Output (MW)	115.0	115.0	115.0	***115.0***	
Net Plant Output (MW, includes steam turbine)	152.4	152.5	152.6	***152.5***	
Barometric Pressure (psia)	14.43	14.42	14.44	***14.43***	
Inlet Guide Position Rotary (degrees)	31.84	31.85	31.79	***31.83***	
Compressor Inlet Temperature (°F, CTIM)	34.6	34.3	36.4	***35.1***	
Compressor Discharge Temperature (°F)	674.8	674.8	677.6	***675.7***	
Compressor Discharge Pressure (psia)	171.51	171.41	171.59	***171.50***	
Mean Turbine Exhaust Temperature (°F)	1084.8	1085.5	1087.4	***1085.9***	
NH_3 Injection Rate (SCFH)	738	1046	1024	***936***	
SCR Inlet Temperature (°F)	617.4	617.3	617.2	***617.3***	
PAG Steam Flow (KPPH)	3.90	3.90	3.88	***3.89***	
PAG Fuel/Steam Ratio	0.07	0.07	0.06	***0.06***	
Turbine Fuel Data (Natural Gas)					
Fuel Heating Value (Btu/SCF, Gross)	1033.6	1033.6	1033.6	***1033.6***	
Fuel Specific Gravity	0.5841	0.5841	0.5841	***0.5841***	
Sulfur in Fuel (% Weight)	< 0.0001	< 0.0001	< 0.0001	***< 0.0001***	**0.8**
O_2 "F_d Factor" (DSCFex/MMBtu @ 0% excess air)	8642	8642	8642	***8642***	
CO_2 "F_c Factor" (DSCFex/MMBtu @ 0% excess air)	1025	1025	1025	***1025***	
Turbine Gas Fuel Flow (kSCFH, CEMS data)	1343.7	1343.4	1343.9	***1343.7***	
Duct Burner Gas Fuel Flow (kSCFH, CEMS data)	0.0	0.0	0.0	***0.0***	
Heat Input (MMBtu/hr, Higher Heating Value)	1388.8	1388.6	1389.1	***1388.8***	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.47	29.46	29.51	***29.48***	
Temperature (°F): Dry Bulb	35.9	36.1	38.0	***36.7***	
(°F): Wet Bulb	35.5	35.5	36.7	***35.9***	
Humidity (lbs moisture/lb of air)	0.0043	0.0043	0.0043	***0.0043***	
Measured Emissions					
NO_X (ppmv, dry basis)	2.65	2.28	2.62	***2.52***	
NO_X (ppmv, dry @ 15% excess O_2)	**2.34**	**1.99**	**2.33**	***2.22***	
CO (ppmv, dry basis)	11.20	10.39	6.44	***9.34***	
CO (ppmv, dry @15% excess O_2)	**9.87**	**9.09**	**5.72**	***8.23***	
THC as VOC (ppmv, wet as Methane)	3.38	4.15	0.20	***2.58***	
THC as VOC (ppmv, dry @ 15% excess O_2)	3.19	3.90	0.19	***2.42***	
THC as VOC (ppmv, wet as Propane)	**1.30**	**1.60**	**0.08**	***0.99***	
O_2 (% volume, dry basis)	14.21	14.16	14.26	***14.21***	
CO_2 (% volume, dry basis)	3.92	3.92	3.93	***3.92***	
F_o (fuel factor, range = 1.600-1.836 for NG)	1.71	1.72	1.69	***1.71***	
H_2O (% volume, stoichiometric)	6.70	6.74	6.65	***6.70***	
Stack Volumetric Flow Rates (via EPA Method 19)					
via O_2 "F_d Factor" (SCFH, dry basis)	3.75E+07	3.72E+07	3.78E+07	***3.75E+07***	
via CO_2 "F_c Factor" (SCFH, dry basis)	3.63E+07	3.63E+07	3.62E+07	***3.63E+07***	
Calculated Emission Rates (via M-19 O_2 or CO_2 "F-factor")					
NO_X (lbs/hr)	**11.9**	**10.1**	**11.8**	*11.3*	**31.2**
CO (lbs/hr)	**30.5**	**28.1**	**17.7**	*25.4*	**156**
THC as VOC (lbs/hr)	**5.98**	**7.31**	**0.357**	*4.55*	**30.0**
NO_X (lbs/MMBtu)	**0.00854**	**0.00728**	**0.00851**	*0.00811*	**0.013**
CO (lbs/MMBtu)	**0.0220**	**0.0202**	**0.0127**	*0.0183*	**0.117**
THC as VOC (lbs/MMBtu)	**0.00431**	**0.00526**	**0.000257**	*0.00328*	**0.0131**

TABLE 4: Summary of Results
Base Load Testing

Company: Morgan Energy Center LLC
Plant: Morgan Energy Center
Location: Decatur, Morgan County, Alabama
Technicians: LJB, RPO, JTH, TAR, NS
Source: Unit 1, a Siemens Westinghouse 501FD Combustion Turbine

Test Number	U1-C-4	U1-C-5	U1-C-6		
Date	1/9/04	1/9/04	1/9/04		
Start Time (CEMS Time)	14:08	15:31	17:03		ADEM Permit Limits
Stop Time (CEMS Time)	15:13	16:36	18:08		
Power Turbine Operation		Base Load		*Averages*	
Generator Output (MW)	187.7	188.0	188.8	***188.2***	
Net Plant Output (MW, includes steam turbine)	253.2	253.9	254.8	***254.0***	
Barometric Pressure (psia)	14.45	14.46	14.47	***14.46***	
Inlet Guide Position Rotary (degrees)	-0.15	-0.16	-0.15	***-0.15***	
Compressor Inlet Temperature (°F, CTIM)	36.7	36.3	35.0	***36.0***	
Compressor Discharge Temperature (°F)	752.0	751.5	750.0	***751.1***	
Compressor Discharge Pressure (psia)	247.38	247.70	248.48	***247.86***	
Mean Turbine Exhaust Temperature (°F)	1080.2	1079.8	1078.9	***1079.6***	
NH_3 Injection Rate (SCFH)	900	816	950	***889***	
SCR Inlet Temperature (°F)	632.3	632.2	632.3	***632.2***	
PAG Steam Flow (KPPH)	3.87	3.87	3.87	***3.87***	
PAG Fuel/Steam Ratio	0.05	0.05	0.05	***0.05***	
Turbine Fuel Data (Natural Gas)					
Fuel Heating Value (Btu/SCF, Gross)	1033.6	1033.6	1033.6	***1033.6***	
Fuel Specific Gravity	0.5841	0.5841	0.5841	***0.5841***	
Sulfur in Fuel (% Weight)	< 0.0001	< 0.0001	< 0.0001	***< 0.0001***	**0.8**
O_2 "F_d Factor" (DSCFex/MMBtu @ 0% excess air)	8642	8642	8642	***8642***	
CO_2 "F_c Factor" (DSCFex/MMBtu @ 0% excess air)	1025	1025	1025	***1025***	
Turbine Gas Fuel Flow (kSCFH, CEMS data)	1994.4	1996.6	2004.5	***1998.5***	
Duct Burner Gas Fuel Flow (kSCFH, CEMS data)	0.0	0.5	0.0	***0.2***	
Heat Input (MMBtu/hr, Higher Heating Value)	2061.4	2064.3	2071.8	***2065.8***	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.50	29.53	29.56	***29.53***	
Temperature (°F): Dry Bulb	37.8	36.9	35.4	***36.7***	
(°F): Wet Bulb	35.4	34.4	32.9	***34.2***	
Humidity (lbs moisture/lb of air)	0.0038	0.0036	0.0034	***0.0036***	
Measured Emissions					
NO_X (ppmv, dry basis)	1.98	2.00	1.87	***1.95***	
NO_X (ppmv, dry @ 15% excess O_2)	**1.68**	**1.70**	**1.59**	***1.66***	
CO (ppmv, dry basis)	0.80	0.85	0.81	***0.82***	
CO (ppmv, dry @15% excess O_2)	**0.68**	**0.72**	**0.69**	***0.70***	
THC as VOC (ppmv, wet as Methane)	0.02	0.05	0.02	*0.03*	
THC as VOC (ppmv, dry @ 15% excess O_2)	0.02	0.05	0.02	***0.03***	
THC as VOC (ppmv, wet as Propane)	**0.01**	**0.02**	**0.01**	***0.01***	
O_2 (% volume, dry basis)	13.94	13.96	13.96	***13.96***	
CO_2 (% volume, dry basis)	4.10	4.11	4.10	***4.10***	
F_o (fuel factor, range = 1.600-1.836 for NG)	1.70	1.69	1.69	***1.69***	
H_2O (% volume, stoichiometric)	6.86	6.81	6.77	***6.81***	
Stack Volumetric Flow Rates (via EPA Method 19)					
via O_2 "F_d Factor" (SCFH, dry basis)	5.35E+07	5.37E+07	5.39E+07	***5.37E+07***	
via CO_2 "F_c Factor" (SCFH, dry basis)	5.16E+07	5.15E+07	5.18E+07	***5.16E+07***	
Calculated Emission Rates (via M-19 O_2 or CO_2 "F-factor")					
NO_X (lbs/hr)	**12.6**	**12.8**	**12.1**	*12.5*	**31.2**
CO (lbs/hr)	**3.11**	**3.32**	**3.16**	*3.20*	**156**
THC as VOC (lbs/hr)	**0.05**	**0.13**	**0.06**	*0.08*	**30.0**
NO_X (lbs/MMBtu)	**0.00614**	**0.00622**	**0.00582**	***0.00606***	**0.013**
CO (lbs/MMBtu)	**0.00151**	**0.00161**	**0.00153**	***0.00155***	**0.117**
THC as VOC (lbs/MMBtu)	**0.00002**	**0.00006**	**0.00003**	***0.00004***	**0.0131**

TABLE 5: Summary of Results
Base Load Testing
with PAG + DB On

Company: Morgan Energy Center LLC
Plant: Morgan Energy Center
Location: Decatur, Morgan County, Alabama
Technicians: LJB, RPO, JTH, TAR, NS
Source: Unit 1, a Siemens Westinghouse 501F Combustion Turbine

Test Number	U1-C-7	U1-C-8	U1-C-9		
Date	1/10/04	1/10/04	1/11/04		
Start Time (CEMS Time)	15:05	17:58	8:51		ADEM Permit Limits
Stop Time (CEMS Time)	16:05	18:58	9:51		
Power Turbine Operation	Base Load - with PAG and DB			*Averages*	
Generator Output (MW)	192.6	193.5	196.1	***194.1***	
Net Plant Output (MW, includes steam turbine)	296.9	298.7	292.0	***295.9***	
Barometric Pressure (psia)	14.55	14.56	14.60	***14.57***	
Inlet Guide Position Rotary (degrees)	-0.19	-0.19	-0.15	***-0.17***	
Compressor Inlet Temperature (°F, CTIM)	37.2	36.0	33.4	***35.52***	
Compressor Discharge Temperature (°F)	752.7	750.9	748.1	***750.6***	
Compressor Discharge Pressure (psia)	252.07	252.84	254.70	***253.21***	
Mean Turbine Exhaust Temperature (°F)	1070.8	1070.0	1069.3	***1070.0***	
NH_3 Injection Rate (SCFH)	1177	1160	960	***1099***	
SCR Inlet Temperature (°F)	658.7	659.1	657.7	***658.5***	
PAG Steam Flow (KPPH)	45.01	45.00	49.84	***46.61***	
PAG Fuel/Steam Ratio	0.53	0.32	0.43	***0.43***	
Turbine Fuel Data (Natural Gas)					
Fuel Heating Value (Btu/SCF, Gross)	1033.6	1033.6	1033.6	***1033.6***	
Fuel Specific Gravity	0.5841	0.5841	0.5841	***0.5841***	
Sulfur in Fuel (% Weight)	< 0.0001	< 0.0001	< 0.0001	***< 0.0001***	**0.8**
O_2 "F_d Factor" (DSCFex/MMBtu @ 0% excess air)	8642	8642	8642	***8642***	
CO_2 "F_c Factor" (DSCFex/MMBtu @ 0% excess air)	1025	1025	1025	***1025***	
Turbine Gas Fuel Flow (kSCFH, CEMS data)	2024.6	2031.3	2048.9	***2034.9***	
Duct Burner Gas Fuel Flow (kSCFH, CEMS data)	471.2	471.4	471.7	***471.4***	
Heat Input (MMBtu/hr, Higher Heating Value)	2579.7	2586.8	2605.3	***2590.6***	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.72	29.74	29.81	***29.76***	
Temperature (°F): Dry Bulb	37.0	35.0	38.0	***36.7***	
(°F): Wet Bulb	33.0	31.0	34.0	***32.7***	
Humidity (lbs moisture/lb of air)	0.0030	0.0027	0.0032	***0.0030***	
Measured Emissions					
NO_X (ppmv, dry basis)	2.63	2.27	2.80	***2.57***	
NO_X (ppmv, dry @ 15% excess O_2)	**1.84**	**1.57**	**1.92**	***1.78***	
CO (ppmv, dry basis)	1.43	1.54	1.62	***1.53***	
CO (ppmv, dry @15% excess O_2)	**0.99**	**1.05**	**1.12**	***1.06***	
THC as VOC (ppmv, wet as Methane)	0.09	0.15	0.21	*0.15*	
THC as VOC (ppmv, dry @ 15% excess O_2)	0.070	0.12	0.16	***0.12***	
THC as VOC (ppmv, wet as Propane)	**0.035**	**0.058**	**0.081**	***0.058***	
VE (% opacity)	**0**	**0**	**0**	***0***	**10**
O_2 (% volume, dry basis)	12.47	12.39	12.28	***12.38***	
CO_2 (% volume, dry basis)	4.90	4.90	4.92	***4.91***	
F_o (fuel factor, range = 1.600-1.836 for NG)	1.72	1.74	1.75	***1.74***	
H_2O (% volume, per EPA Method 4)	10.14	10.26	10.85	***10.42***	
Stack Volumetric Flow Rates (via EPA Method 19)					
via O_2 "F_d Factor" (SCFH, dry basis)	5.53E+07	5.49E+07	5.46E+07	***5.49E+07***	
via CO_2 "F_c Factor" (SCFH, dry basis)	5.40E+07	5.41E+07	5.43E+07	***5.41E+07***	
Calculated Emission Rates (via M-19 O_2 or CO_2 "F-factor")					
NO_X (lbs/hr)	**17.4**	**14.9**	**18.3**	***16.8***	**31.2**
CO (lbs/hr)	**5.75**	**6.15**	**6.43**	***6.11***	**156**
THC as VOC (lbs/hr)	**0.24**	**0.40**	**0.57**	***0.41***	**30.0**
PM (lbs/hr)	**17.5**	**10.2**	**3.41**	***10.4***	**11.0**
NO_X (lbs/MMBtu)	**0.00673**	**0.00575**	**0.00701**	***0.00650***	**0.013**
CO (lbs/MMBtu)	**0.00223**	**0.00238**	**0.00247**	***0.00236***	**0.117**
THC as VOC (lbs/MMBtu)	**0.00009**	**0.00016**	**0.00022**	***0.00016***	**0.0131**
PM (lbs/MMBtu)	**0.00679**	**0.00396**	**0.00131**	***0.00402***	**0.005**

DeAngelo, Gregory

From: Halpin, Mike
Sent: Thursday, February 19, 2004 11:35 AM
To: DeAngelo, Gregory
Cc: Kahn, Joseph; Koerner, Jeff
Subject: FPC Hines

Greg -
Can you tell me what you ultimately did with respect to start-up times for Hines Power Block 3? They've sent in a PSD Mod for Hines PB-2 which (Jeff thinks) might be close to what you gave them on PB-3, and he says that he remembers you negotiating something like this with them. I'm not inclined to allow what they are asking for, but if you've given them this for PB-3 I'll not fight it. Here's what they're asking for:

1. CEMS Data Exclusion: As provided in this paragraph, NOx and CO emissions data recorded during periods of startup, shutdown, oil-to-gas fuel switches, and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of Condition No. 9 of this section. a. Periods of data excluded for startup shall not exceed two hours in any 24-hour block except for cold startups. A "cold startup" is defined as a startup following a complete shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed ~~6~~ hours in any 24-hour block period. A "warm startup" is defined as a startup following a complete shutdown lasting 8 to 48 hours. Periods of data excluded for warm startup shall not exceed 3 hours in any 24-hour block period.
b. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block. c. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block. d. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that meets the notification requirements specified in Condition No. 26 of this section. e. All periods of data excluded for any startup, shutdown, oil-to-gas fuel switch, or documented malfunction shall be consecutive for each episode. Periods of data excluded for all startups, shutdowns, oil-to-gas fuel switches, or documented malfunctions shall not exceed ~~8~~ hours in any 24-hour block period during which a cold startup occurred. ~~Periods of data excluded for all startups, shutdowns, oil-to-gas switches, or documented malfunctions shall not exceed 5 hours in any 24-hour block period during which a warm startup occurred.~~ For all other 24-hour block periods, periods of data excluded for all startups, shutdowns, oil-to-gas fuel switches, or documented malfunctions shall not exceed 4 hours. f. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the startup, shutdown, or documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, oil-to-gas fuel switching, or documented malfunction.

I'm copying Joe on this because I think he did the PSD permit. I'm copying Jeff because Al told him to be a spy, I mean "buddy".

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