SENDER: *COMPLETE THIS SECTION*

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- Print your name and address on the reverse so that we can return the card to you.
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1. Article Addressed to:

Richard Crotty, Chair
Orange County Board of
County Commissioners
Administration Building, 5th Fl
201 S. Rosalind Ave.
Orlando, FL 32801

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Acevedo - H

B. Date of Delivery

C. Signature

X

☐ Agent
☐ ~~Addressee~~

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

3. Service Type
☒ Certified Mail ☐ Express Mail
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☐ Insured Mail ☐ C.O.D.

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

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

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

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

Postmark
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Recipient's Name *(Please Print Clearly) (to be completed by mailer)*
Richard Crotty
Street, Apt. No.; or PO Box No.
201 S. Rosalind Ave.
City, State, ZIP+4
Orlando, FL 32801

PS Form 3800, February 2000 See Reverse for Instructions

7000 0600 0026 4129 8962

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

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

Postmark Here

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Robert G. Moore
Street, Apt. No.; or PO Box No.
One Energy Place
City, State, ZIP+4
Pensacola, FL 32520-0328

PS Form 3800, February 2000 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Robert G. Moore
Gulf Power Company
OUC/KUA/FMPA/Southern Co. - Florida, LLC.
One Energy Place
Pensacola, FL 32520-0328

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* J Garner
B. Date of Delivery 09/28/01
C. Signature
X J Garner
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☐ Addressee
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
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4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 0600 0026 4129 8962

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

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Robert G. Moore, VP Gulf Power Company
OUC/KUA/FMPA/Southern Company – Florida, LLC
One Energy Place
Pensacola, FL 32520-0328

DEP File 0950137-002-AC (PSD-313)
Curtis H. Stanton Energy Center
Orange County

Enclosed is the Final Permit Number PSD-FL-313. This permit authorizes the applicants to construct a natural-gas fired combined cycle unit known as Stanton Combined Cycle Unit A at the existing Curtis H. Stanton Energy Center in Orange County. This permit is issued pursuant to Chapter 403, Florida Statutes and 40CFR52.21.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

In addition to the appeal process described above, federal appeals procedures concerning this PSD permit are outlined in 40CFR 124.19, which is attached. Any person who filed comments on the draft permit may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision.

The petition must be filed with the Environmental Appeals Board within 30 days of issuance of this Notice. Petitions may be addressed to the Environmental Appeals Board, MC 1103B, U.S. Environmental Protection Agency, 401 M Street, Washington, D.C. 20460. Further details are available at www.epa.gov/eab.

Executed in Tallahassee, Florida.

CH Fancy

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 9/26/01 to the person(s) listed:

Robert G. Moore, Gulf Power *
Chair of County Commission, Orange County *
James O. Vick, Gulf Power
Rodney I. Unruh, P.E. (Black & Veatch)
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP-Central District
Marie Driscoll, Orange County EPD
Tasha O. Buford, E., Attorney
Mr. Hamilton S. Oven, DEP-Siting

Clerk Stamp

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

Victoria Gibson 9/26/01
(Clerk) (Date)

FINAL DETERMINATION

OUC/KUA/FMPA/Southern Company – Florida, LLC
Stanton Energy Center Combined Cycle Unit A
DEP File No. PA 81-14SA2, PSD-FL-313

The Department distributed a public notice package on May 17, 2001 to allow the applicant to make a combined cycle unit addition at the existing Curtis H. Stanton Energy Center located in Orlando, Orange County. The Public Notice of Intent to Issue was published in the Orlando Sentinel on May 27, 2001.

COMMENTS/CHANGES

Comments were received from the EPA dated May 17 and June 18, 2001.

Comments were received from the Fish & Wildlife Service dated February 9, 2001.

Comments on the draft permit were received from the applicant by letter dated April 25, 2001.

Comments were reviewed and incorporated into the Draft Conditions of Certification.

Pursuant to notice, the Division of Administrative Hearings, by its duly designated Administrative Law Judge, C. A. Stampelos, conducted a formal site certification hearing (Case No. 01-0416EPP) in this proceeding on June 26, 2001 in Orange County, Florida. On July 23, 2001, it was recommended that the Siting Board grant full and final certification to the Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency, and Southern-Florida, LLC, under Section 403, Part II, Florida Statutes, for the location, construction, and operation of Stanton Unit A and its associated facilities, as described in the Supplemental Site Certification Application and the evidence presented at the certification hearing.

On September 11, 2001 the Siting Board concurred with the Administrative Law Judge's recommendation and authorized issuance of related permits via its Final Order.

CONCLUSION

The final action of the Department is to issue the permit consistent with changes described above.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

OUC/KUA/FMPA/Southern Company – Florida, LLC
One Energy Place
Pensacola, FL 32520-0328

File No.	PSD-FL-313 (PA81-14SA2)
FID No.	0950137
SIC No.	4911
Expires:	December 31, 2004

Authorized Representative:

Mr. Robert G. Moore, VP of Power Generation and Transmission, Gulf Power Company

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 640 megawatt (MW) Combined Cycle unit consisting of: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment. The combined cycle unit will achieve approximately 700 megawatts during extreme winter peaking conditions. The unit is to be installed at the existing OUC Stanton Energy Center, located at 5100 South Alafaya Trail, Orlando, Orange County. UTM coordinates are: Zone 17; 483.61 km E, 3151.1 km N.

STATEMENT OF BASIS:

This PSD 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.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection.

The attached Appendices are made a part of this permit:

Appendix GC	Construction Permit General Conditions
Appendix GG	Subpart GG, Standards of Performance for Stationary Gas Turbines
Appendix XS	Semi-Annual Continuous Emission Monitor Systems Report

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

OUC Stanton Energy Center consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash. This project includes: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment.

The turbines will be equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas. During fuel oil firing, emissions will be held to 10 ppmvd at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.05% sulfur oil and good combustion practices will be employed to control all pollutants.

EMISSIONS UNITS

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
025	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
026	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
027	Water Cooling	One 10 cell Mechanical Draft Cooling Tower
028	Fuel Storage	One 1,680,000 Gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

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

This facility is within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of SO_2 and NO_X, 25/15 TPY of PM/PM_{10}, 100 TPY of CO and 40 TPY of VOC's. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting. [Chapter 403.503 (12), F.S., Definitions]

SECTION I - FACILITY INFORMATION

Based on the Title V permit, this facility is not currently a major source of hazardous air pollutants (HAPs). This facility is subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- 09/21/01 PSD Permit Issued
- 09/11/01 Site Certification Issued
- 05/27/01 Notice of Intent to Issue PSD Permit published in Orlando Sentinel
- 05/17/01 Distributed Intent to Issue Permit
- 05/01/01 Application Complete
- 01/22/01 Received PSD Application

RELEVANT DOCUMENTS:

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

- Application received on January 22, 2001.
- Letter from Fish & Wildlife Service dated February 9, 2001.
- Additional information received from applicant on May 1, 2001.
- Department's Intent to Issue and Public Notice Package dated May 17, 2001.
- Department's Draft Permit and Draft BACT determination dated May 17, 2001.
- Letters from EPA Region IV dated May 17 and June 18, 2001.
- Site Certification for the Stanton A Combined Cycle addition dated September 11, 2001.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II - ADMINISTRATIVE REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21 (j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]
8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2004 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.080, F.A.C.]

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]
10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Central District Office. [Chapter 62-213, F.A.C.]
11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Central District Office by March 1st of each year.
13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District Office.

APPLICABLE STANDARDS AND REGULATIONS

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. NSPS Requirements: Each combustion turbine (CT) shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. **Subpart A, General Provisions**, including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

   b. **Subpart GG, Standards of Performance for Stationary Gas Turbines;** see attached *Appendix GG.*

3. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

4. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

5. ARMS Emissions Units 025 and 026. Direct Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Additionally, each Emissions Unit consists of a supplementally fired heat recovery steam generator equipped with a natural gas fired 542 MMBTU/hr duct burner (HHV) and combined with a nominal 300 MW steam electrical generators. These shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.

6. ARMS Emission Unit 027. Cooling Tower, an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.

7. ARMS Emission Unit 028. Fuel Storage Tank, consisting of a 1,680,000 gallon distillate fuel storage tank. The storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.

8. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.

GENERAL OPERATION REQUIREMENTS

9. Fuels: Only pipeline natural gas or (up to) 1000 hours per year of 0.05% distillate fuel oil shall be fired in each CT emissions unit. Only natural gas shall be fired in each duct burner. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Combustion Turbine Capacity: The maximum heat input rates to each CT/HRSG shall not exceed 2,402 million Btu (HHV) per hour (MMBtu/hr) when firing natural gas with duct burner firing and power augmentation. The maximum heat input rates to each CT/HRSG shall not exceed 2,068 MMBtu/hr (HHV) when firing fuel oil. Manufacturer's curves corrected for ISO conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability} [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 533 MMBtu/hour (LHV) at any temperature or under any scenario. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

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

13. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Central District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

14. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices of pollution control equipment shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

15. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

16. Maximum allowable hours of operation for each CT/HRSG Emissions Unit are 8760 hours per year while firing natural gas. Fuel oil firing is permitted for 1000 hours during any consecutive 12-month period in each CT. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

17. Simple Cycle Operation: The plant may not be operated without the use of the SCR system except during periods of startup and shutdown.

CONTROL TECHNOLOGY

18. Dry Low NO_X (DLN) combustors and water injection capability shall be installed on each stationary combustion turbine. The permittee shall install a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Specific Condition 21. Additionally, space shall be provided for the installation of oxidation catalysts. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

19. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 21 through 25. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

20. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. A certification letter, following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002-gallons/100 gallons recirculation water flowrate.

EMISSION LIMITS AND STANDARDS

21. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on natural gas shall not exceed 3.5 ppmvd @15% O_2 on a 3-hr block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- The emissions of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil shall not exceed 10.0 ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 30 for compliance procedures). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]
- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O_2. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]

22. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on natural gas shall not exceed 17 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS; and neither 14 ppmvd @15% O_2 with the CT operating on fuel oil on a 24-hr block average to be demonstrated by CEMS. These limits shall also be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. Within 24 months of the date of completion of initial testing, the applicant shall either have installed oxidation catalyst in each CT/HRSG or forfeit its right to do so with the pre-determined (BACT) emission limits specified below. [BACT, Rule 62-212.400, F.A.C.]

- In the event that an oxidation catalyst is installed for any reason in either CT/HRSG pair within 24 months of the date of completion of initial testing, the limits for CO and VOC shall be 5 ppmvd and 3 ppmvd (respectively) to be demonstrated by stack testing during power augmentation and duct burner firing (I, A). [BACT]

23. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall exceed neither 2.7 ppmvd @15% O_2 with the CT firing fuel oil and neither 6.3 ppmvd @15% O_2 with the CT firing natural gas (with maximum duct burner firing and operating in power augmentation mode); to be demonstrated by initial stack tests using EPA Method 18, 25 or 25A. [BACT, Rule 62-212.400, F.A.C.]

24. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 1.5 grains per 100 standard cubic foot) and up to 1000 hours per consecutive 12-month period of 0.05% sulfur fuel oil. Compliance with these fuel limits in conjunction with implementation of the attached Appendix GG will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner and the combustion turbine. Note: This will effectively limit the combined SO_2 emissions for EU-025 and EU-026 to approximately 134 tons per year. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

25. PM/PM_{10} and Visible emissions (VE): VE emissions shall not exceed 10 percent opacity from the stack in use. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

26. 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 occurrences shall in no case exceed two hours in any 24-hour period except during a "cold start-up" to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 72 hours. Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [BACT, Rule 62-210.700, F.A.C.].

27. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

28. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 41 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 21 through 25. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

29. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial operation of

the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

30. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 29. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or addition of oxidation catalyst (or change of combustors, if specifically requested by the DEP on a case-by-case basis). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

   - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement) shall be conducted a) while firing natural gas with maximum duct burner heat input as well as maximum power augmentation and b) while firing fuel oil at the maximum heat input; Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO_X compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
   - EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
   - Method CTM-027 for ammonia slip (I, A) to be completed simultaneously with NO_X compliance testing.

   The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O_2) at the measured lb/hr NO_X emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 45.

31. Continuous compliance with the CO and NO_X emission limits: Continuous compliance with the CO and NO_X emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition 41 further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition 28. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

32. Compliance with the SO_2 and PM/PM_{10} emission limits: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, the applicant is responsible for ensuring that the procedures outlined in attached Appendix GG are complied with.

33. Compliance with CO emission limit: An initial and annual test for CO shall be conducted at 100% capacity with the duct burners off. The NO_X and CO test results shall be the average of three valid one-hour runs. Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75 and may substitute for the annual CO stack testing requirement.

34. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required [see Specific Condition 22 for exception].

35. Testing procedures: Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. inlet temperature). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

36. Test Notification: The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests.

37. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, odors or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

38. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

39. Records: All measurements, records, and other data required to be maintained by the applicant shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

    - The applicant will be required to maintain records indicating the daily hours of operation of each CT/HRSG unit. These records shall specify which type of fuel is being combusted and the records shall be available for review at the site. Each calendar month, a compilation of the hours of operation for each CT/HRSG unit combusting fuel oil shall be made and totalized for the most recent consecutive 12-month period. Each AOR submitted by the applicant shall include a compilation of each consecutive 12-month period during the preceding calendar year.

40. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of

this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NO_X shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly 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). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system 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 owner or operator 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). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3-hour block. However, in the event that the permittee maintains 95% or greater availability of the continuous emission monitoring systems used for determining NO_X emissions compliance for the previous quarter, then compliance with the emission limits for NO_X shall be based on 3 valid consecutive hours of data for a 3-hour block average. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. 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 semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of 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 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "cold startup." A cold startup is defined as a startup following a complete shutdown lasting a minimum of 72 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur.

Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Rules 62-4.070(3) and 62-212.400., F.A.C., and BACT]

[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].

42. <u>Continuous Monitoring System Reports</u>: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Bureau of Ambient Monitoring & Mobile Sources (BAMMS) as well as the EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

43. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

44. Subpart Da Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Da].

45. Selective Catalytic Reduction System (SCR) Compliance Procedures:

- An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner on as defined in Specific Condition 21. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during the each performance test.
- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.
- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.
- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.
- In the event of a complaint or concern by an inspector, the permittee shall be capable of making an instantaneous measurement using inlet and outlet NO_X concentrations from the SCR system and ammonia flow supplied to the SCR system to determine ammonia slip. This determination shall not be used as a compliance method but only as an indicator to determine if a special compliance test is needed to demonstrate NO_X and ammonia slip requirements of the permit. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following calculation represents one means by which the permittee may demonstrate compliance with this condition:

Ammonia slip @ 15% O_2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D, where:

A= ammonia injection rate (lb/hr)/ 17 (lb/lb.mol)

B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)

C = change in measured NO_X (ppmv@15% O_2) across catalyst

D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

[Note: exhaust gas flow rate may be back calculated using heat input and F factor]

- The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.
- Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO_X and ammonia slip related permit limits can be complied with.

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

NSPS SUBPART GG REQUIREMENTS

[Note: 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 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.]

Pursuant to 40 CFR 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:

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

where:

STD = allowable NO_X 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 = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.

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

Fuel-bound nitrogen (percent by weight)	F (NO_X percent by volume)
N≤0.015	0
0.015<N≤0.1	0.04(N)
0.1<N≤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 NO_X CEMS. The "Y" values are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards 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.

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

Pursuant to 40 CFR 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:

(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.

Pursuant to 40 CFR 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.

(1) Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NO_X CEMS shall be used to demonstrate compliance with the NO_X limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

(2) [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 § 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 § 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).

<u>Department requirement</u>: NO_X emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NO_X monitor is required to demonstrate compliance with the standards of this permit. Data from the NO_X monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

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

<u>Pursuant to 40 CFR 60.335 Test Methods and Procedures</u>:

(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 provided 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 (NO_X) shall be computed for each run using the following equation:

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

where:

NO_X	=	emission rate of NO_X at 15 percent O2 and ISO standard ambient conditions, volume percent.
NOxo	=	observed NO_X 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 H2O/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 NO_X monitor continuously correct NO_X emissions concentrations 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.

Department requirement: **The owner or operator is allowed to conduct initial performance tests at a single load because a NO_X monitor shall be used to demonstrate compliance with the BACT NO_X 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 NO_X emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: **The owner or operator is allowed to make the initial compliance demonstration for NO_X emissions using certified CEM system 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 NO_X monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(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: **The permit specifies sulfur testing methods and allows 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 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 the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

SECTION V. APPENDIX XS

SEMI-ANNUAL CONTINUOUS EMISSIONS MONITOR SYSTEMS REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NO_X) Carbon Monoxide (CO)

Reporting period dates: From ______________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ____

Date of Latest CMS Certification or Audit: ______________________________

Process Unit(s) Description: ____

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

Emission data summary [a]		**CMS performance summary** [a]	
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] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

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

[b] 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 to CMS, process or controls during last 6 months.

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

____
Name

____
Title

____ ______________________
Signature *Date*

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.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

STANTON UNIT A COMBINED CYCLE PROJECT
OUC/KUA/FMPA/Southern Co.
PSD-FL-313 and PA81-14SA2
Orange County, Florida

BACKGROUND

The applicants, Orlando Utilities Commission (OUC), the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA) and the Southern Company – Florida, LLC (SO), propose to build a 700 MW (estimated maximum gross capability) combined cycle power plant at the existing Curtis H. Stanton Energy Center. The location of the facility is 5100 South Alafaya Trail, Orlando, Orange County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). Therefore, the project is subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary units to be installed are two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system. The project includes two heat recovery steam generators (HRSGs), each with a 160 ft. stack and one steam turbine-electrical generator rated at approximately 300 MW. Duct burners will be installed in the HRSGs for supplemental firing and to achieve peak output. The project also includes one 10-cell linear mechanical draft cooling tower, and one diesel fuel storage tank (approximately 1,680,000 gallons). Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated June 30, 2001, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on January 22, 2001 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. The proposal is summarized in the table below for each combustion turbine (MW loads are assumed to be at 50% or higher).

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
PM/PM_{10}, VE	Clean Fuels Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip
SO_2 / SAM	Clean Fuels	0.5 grains / 100 scf (gas) 0.05% Sulfur distillate oil – 1000 hours / year
CO	Pipeline Natural Gas Good Combustion	17 ppmvd (all operating modes) gas – 24 hr. avg. 14 ppmvd (all operating modes) oil – 24 hr. avg.
VOC	Pipeline Natural Gas Good Combustion	3.6 ppmvd / 2.7 ppmvd (gas / oil) 6.3 ppmvd during DB plus PA
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2 (gas) – 24 hr. avg. 10 ppmvd @ 15% O_2 (oil) – 24 hr. avg.
PM - cooling tower	High efficiency drift eliminators	0.002% drift loss

Based upon the applicant's submittal, the maximum annual emissions that the facility has the potential to emit (PTE) are as follows: 134.1 TPY SO_2, 17.6 TPY SAM, 127.6 TPY PM/PM_{10}, 314.5 TPY NO_X, 372.4 TPY CO and 105.8 TPY of VOC.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the applicant is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the high efficiency units to be purchased. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

The duct burners required for supplementary gas-firing of the HRSGs are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The 0.1 lb/MW-hr NO_X emission rate proposed by the applicant is well below the revised Subpart Da output-based limit of 1.6 lb/MW-hr promulgated on September 3, 1998. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

The distillate fuel oil storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by states for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F or G Class Frame units. The applicant's proposed BACT is included for reference.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 1

RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	Power Output Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Mobile Energy, AL	~250	~3.5 - NG (CT&DB) ~11 – FO (CT&DB)	DLN & SCR	178 MW GE 7FA CT 1/99 585 mmBtu Duct Burner
KUA Cane Island 3	250	3.5 - (CT&DB)	DLN/SCR	170 MW GE 7FA. 11/99 Ammonia slip = 5 ppmvd
Calpine BHEC	1080	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 5 ppm
Calpine Delta	880	2.5 – (CT & DB) 1 hour average (LAER)	DLN/CSR	3 GE 7FA's or 3 WH 501FD's; 10 ppm max ammonia slip
Calpine Bullhead City	545	3.0 – (CT&DB)	DLN/SCR	Nearly identical to Osprey; Replace SCR catalyst after 36 mo.
Calpine Osprey	545	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 9 ppm
Stanton A (proposed)	700	3.5 - NG (CT &DB & PA) 10 – FO	DLN/SCR	Ammonia slip = 5 ppm

DB = Duct Burner DLN = Dry Low NO_X Combustion CT = Comb. Turbine PA = Power Augmentation
NG = Natural Gas SCR = Selective Catalytic Reduction DB = Duct Burner WH = Westinghouse
FO = Fuel Oil WI = Water or Steam Injection PA = Pwr. Augmentation GE = General Electric

TABLE 2

RECENT BACT LIMITS FOR CARBON MONOXIDE, VOLATILE ORGANIC COMPOUNDS, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Mobile Energy, AL	~18 – NG (CT&DB) ~26 – FO (CT&DB)	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Calpine BHEC	10 – NG (CT only) 17 – NG (off-normal)	1.2 – NG (CT) 6.6 – NG (DB & PA)	10% Opacity 26.0 lb/hr (CT & DB)	Clean Fuels Good Combustion
Calpine Delta	10 – NG (CT & DB) 10 – NG (DB & PA) 3 hr avg. – No Ox. Cat.	2 - NG	0.25 gr.S/100 scf Nat. Gas	Clean Fuels Good Combustion
Calpine Bullhead City	10 – NG (CT & DB) 33.9 – NG (DB & PA) 3 hour rolling average	1.5 - NG	18.3 lb/hr (CT) 22.8 lb/hr (DB & PA)	Clean Fuels Good Combustion
Calpine Osprey	10 – NG (CT only) 17 – NG (off-normal)	2.3 – NG (CT) 4.6 – NG (DB & PA)	10% Opacity 24.1 lb/hr (CT & DB)	Clean Fuels Good Combustion
Stanton A (proposed)	14 –FO (CT only) 17 – NG (all gas modes)	2.7 – FO 6.3 – NG (DB & PA)	10% Opacity 11.7 / 17 lb/hr (NG / FO)	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Master Overview for Alabama Power Plant Barry Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Letter from Black & Veatch to EPA Region IV dated March 10, 1999
- Letter from Black & Veatch to the Department and EPA Region IV dated March 24, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999
- Texas Natural Resource Conservation Commission Website – www.tnrcc.state.tx.us
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas, its use is minimized (1000 hours) for this project and control of NO_X emissions are proposed to be with SCR.

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 the proposed turbines. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_X control. However, 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. Standard combustor designs with wet injection can generally achieve NO_X emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NO_X emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs between 50% to 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Although the duct burners maximum heat input is 533 MMBtu/hr, it is relatively low when compared with the turbine that can accommodate a heat input greater than 2000 MMBtu/hr. The duct burners will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

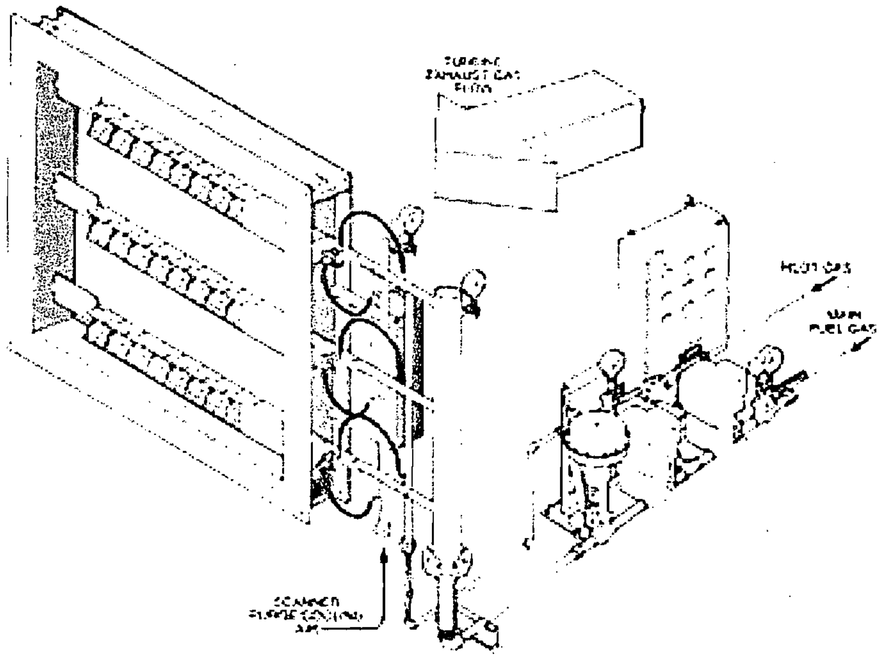


FIGURE A

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream within the HRSG. 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 but used in few applications to-date. 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 commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10 ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan. These newer catalysts (versus the older alumina-based catalysts) are resistant to sulfur fouling at temperatures below 770°F (EPRI). In fact, Mitsubishi reports that as of 1998, SCR's were installed on 61 boilers which combust residual oil (40 of which are utility boilers) and another 70 industrial boilers, which fire diesel oil. Likewise, B & W reports satisfactory results with the installation of SCR to several large Taiwan Power Company utility boilers, which fire a wide range of coals, as well as heavy fuel oil with sulfur contents up to 2.0% and 50 ppm vanadium. 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.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR.

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst 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 B

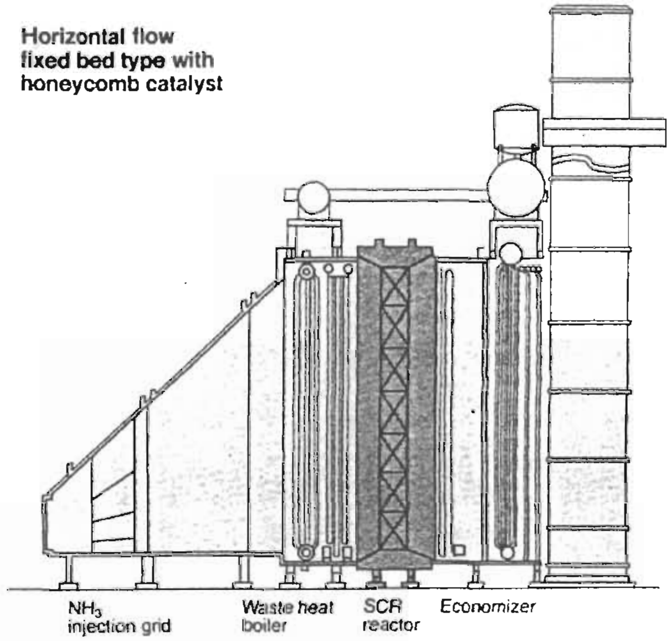


Figure C

Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits of 3.5 ppmvd NO_X are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SCNR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). However, the process also requires a low oxygen content in the exhaust stream in order to be effective. Given that a top-down review leads one to an SCR in this application, SNCR does not merit further consideration.

Emerging Technologies: SCONOx™ and XONON™

SCONOx™ is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ™[2]. The overall project includes several more 250 MW blocks with SCR for control.[3] According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two F frame units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system.

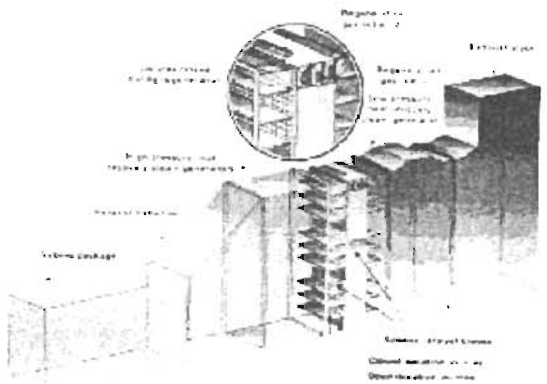


Figure D

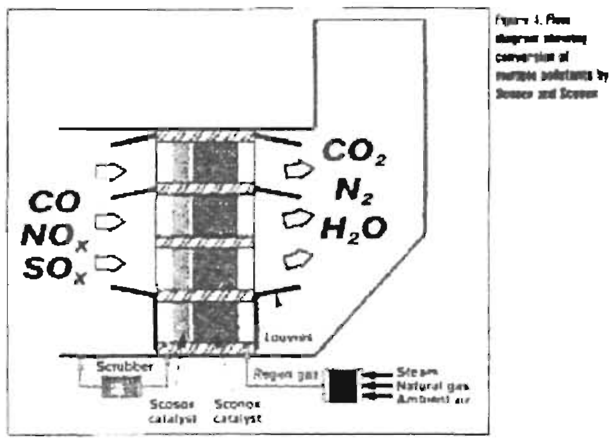


Figure E

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include (in addition to the reduction of NO_X) the elimination of ammonia and the control of VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit. The Department estimates that the application of this control technology to the Stanton A Combined Cycle Unit results in cost-effectiveness of just less than $10,000 per ton of NO_X removed. Although there are specific items within the applicant's original analysis (which estimates a cost effectiveness of $10,200 per ton of NO_X and CO removed from each CT/HRSG) that the Department cannot support (e.g. lost power revenues, contingency factors above 3%, etc.) on balance the Department concurs with the conclusion that $SCONO_X$ is not likely cost-effective for this project.

Catalytica Energy Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. 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 combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

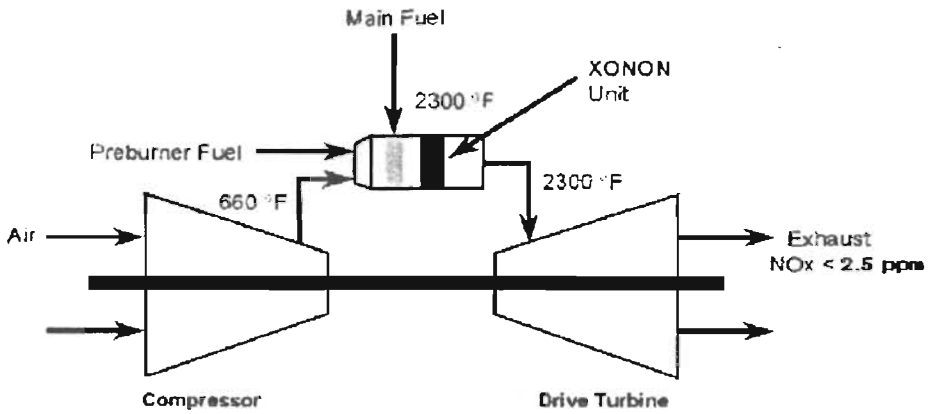
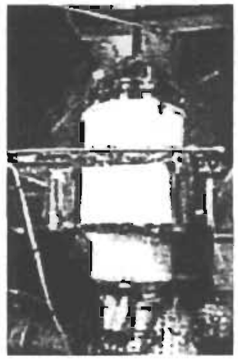


Figure F



XONON-2 installed with test instruments

Figure G

On February 8, 2001, Catalytica Energy Systems, Inc. announced that its XONON™ Cool Combustion system had successfully completed an evaluation process by the U.S. Environmental Protection Agency (EPA), which verified the ultra-low emissions performance of a XONON™-equipped gas turbine operating at Silicon Valley Power. The performance results gathered through the EPA's Environmental Technology Verification (ETV) Program provide high-quality, third party confirmation of XONON™ 's ability to deliver a near-zero emissions solution for gas turbine power production. The verification, which was conducted over a two-day period on a XONON™-equipped Kawasaki M1A-13A (1.4 MW) gas turbine operating at Silicon Valley Power, recorded nitrogen oxides (NO_X) emissions of less than 2.5 parts per million (ppm) and ultra-low emissions of carbon monoxide and unburned hydrocarbons.

The XONON™-equipped Kawasaki M1A-13A gas turbine has operated for over 7400 hours at Silicon Valley Power (SVP), a municipally owned utility, supplying near pollution-free power to the residents of the City of Santa Clara, California, with NO_X levels averaging under 2.5 ppm. Three XONON™-equipped Kawasaki M1A-13X turbines, a slightly modified commercial version of the M1A-13A, are expected to enter commercial service in late 2001 in Massachusetts at a healthcare facility of a U.S. Government agency.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to the commercialization of the XONON™ system for new and existing GE gas turbines. The agreement provides for the collaborative adaptation of XONON™ combustion technology to GE gas turbines for commercial sale. In December 1999, GE accepted the first order for XONON™ -equipped GE 7FA gas turbines as the preferred emission control system for Enron's proposed Pastoria Energy Facility. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. However, the technology cannot (at this time) be recommended for the attendant project.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) AND SO_2 CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas is an inherently clean fuel and contains no ash. Natural gas and very low sulfur fuel oil (0.05%) will be the only fuels fired at the Stanton Combined Cycle Unit and they are efficiently combusted in gas turbines making any conceivable add-on control technique for PM/PM_{10} or SO_2 either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} as well as SO_2 is a combination of good combustion practices, fuel quality, and filtration of inlet air.

The applicant has identified PM emissions over 20 TPY from the fresh-water mechanical cooling towers. Accordingly, drift eliminators shall be installed to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for these types of cooling towers.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst (excluding the SCONOx ™ process).

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Calpine Sutter in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review, which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. OUC/KUA/FMPA/SO propose to meet a limit of 14 ppmvd while firing fuel oil above 50% output. However, the applicant prefers to be permitted with higher values of 18.1 ppmvd and 27.9 ppmvd for the full output operating modes of duct burner firing, and duct burner firing with power augmentation, respectively. Duct burner firing is requested for the entire year and power augmentation is requested for up to 1000 hours per year.

The Department has reviewed actual data from similar facilities and has reasonable assurance that the General Electric PG7241FA units selected by the applicant will achieve values well below those proposed by the applicant (and guaranteed by GE), without requiring installation of an oxidation catalyst. However, should the applicant desire to obtain a sufficient operating margin above the BACT established limit identified below, the permit will authorize the installation of oxidation catalysts at an established limit of 5 ppmvd CO, providing that the applicant installs the catalyst within 24 months of commercial operation. Otherwise, the Department will require the use of a CEMS for compliance on a 24-hour block average, with two limits depending upon actual operation. The limits will be:

a) 14 ppmvd based upon a 24-hour block average for all periods of fuel oil firing; otherwise, the limit is

b) 17 ppmvd for all operating modes, based upon a 24-hour block average, which is consistent with the recently issued determination made at Blue Heron Energy Center

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by the applicant for this project are 3.6 ppmvd for gas firing with duct burners, 2.7 ppmvd while firing oil and 6.3 ppmvd during operation with duct burners plus power augmentation. According to the applicant's submittals, VOC emissions less than 2 ppm will be achieved at 100% output and duct burners off. [5]

REVIEW OF HAZARDOUS AIR POLLUTANTS (HAPS) CONTROL TECHNOLOGIES

Based upon the application, this facility will not emit HAPS above the significance thresholds, which would require the application of MACT. The formaldehyde emission factors that have been proposed by the applicant are 8.42E-5 lb/MMBtu and 1.90E-4 lb/MMBtu for gas and oil respectively. These are appropriate emission factors based upon AP-42, since the factors originated from the largest frame (7) machine within the AP-42 database. These are shown as 7EA Machines and listed in the database as ID No's 18 and 19 respectively. Annual formaldehyde emissions will therefore be approximately 2 TPY with total HAP emissions less than 18 TPY. Accordingly, the application of a MACT Determination is not required.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Stanton A Combined Cycle project assuming full load. Values for NO_X and CO are corrected to 15% O_2. The emission limits (or their equivalents) as well as the applicable averaging times are itemized within the Specific Conditions of the permit.

POLLUTANT	CONTROL TECHNOLOGY	BACT
PM/PM_{10}, VE	Clean Fuels Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip
SO_2 / SAM	Clean Fuels	0.5 grains / 100 scf (gas) 0.05% Sulfur distillate oil for 1000 hrs / year
CO	Pipeline Natural Gas Good Combustion	17 ppmvd (all operating modes) gas – 24 hr. avg. 14 ppmvd (all operating modes) oil – 24 hr. avg. 5 ppmvd (CT & DB & PA) with ox. catalyst
VOC	Pipeline Natural Gas Good Combustion	3.6 ppmvd / 2.7 ppmvd (gas / oil) 6.3 ppmvd during DB plus PA 3 ppmvd (CT & DB & PA) with ox. catalyst
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2 (gas) – 3 hr. avg. 10 ppmvd @ 15% O_2 (oil) – 3 hr. avg.
PM - cooling tower	High efficiency drift eliminators	0.002% drift loss

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using $SCONO_X$.
- EPA Region IV advised that the Department (in a draft BACT) did not present "any unusual site-specific conditions associated with the KUA Cane Island 3 project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[6] The Fish & Wildlife Service had similar comments for Calpine Osprey Energy Center.[8]
- FDEP considers a 3-hour averaging time for NO_X compliance and a 5-ppmvd ammonia slip rate to be BACT, as can be seen in other recent BACT Determinations.
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[7]
- VOC emissions of < 2 ppm from the combustion turbine by Good Combustion proposed by the applicant are acceptable values determined as BACT. However, values less than 1 ppm have already been achieved on the DLN 2.6 combustors (GE 7FA) units after tuning.
- The CO emission rate will be verified continuously with CEMS. With the duct burner on, emissions will be less than 19 ppmvd, which is within the range of recent Department BACT determinations for combustion turbines alone. However, values as high as 28 ppmvd will not be authorized, as requested by the applicant. The CO limit will be 17 ppmvd on a weighted daily (24-hour block) average, which incorporates a reasonable allowance for all daily off-normal operations. In order to accommodate the applicant's concerns over the stringency of the limit, the installation of an oxidation catalyst will be authorized, provided that it is installed in a timely fashion.
- For reference, the CO limit for the FPL Fort Myers project is 12 ppmvd. Limits for the Santa Rosa Energy Center are 9 ppmvd with the duct burner off and 24 ppmvd with the duct burner on. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
PM/Visible Emissions	Method 5 (initial test only) and Method 9 (annually)
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	CEMS plus annual method 10 during operation at capacity without use of duct burners and power augmentation
VOC and CO with Oxidation Catalyst	Annual Method 18, 25 or 25A and Method 10 with Duct Burners and Power Augmentation
NO_X 3-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 or 7E

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable standard. These excess emissions periods shall be reported as required within the Specific Conditions of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two pollutant concentrations are obtained at least 15 minutes apart. The following emission levels represent excess emission *estimates* during startup periods:

STARTUP TYPE	TIME	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)				
		NO_X	SO_2	PM_{10}	VOC	CO
Natural Gas - Cold	4 hours	160	0	48	80	500
Natural Gas - Hot / Warm	2 hours	80	0	24	40	250

STARTUP TYPE	TIME	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)				
		NO_X	SO_2	PM_{10}	VOC	CO
Distillate Oil - Cold	4 hours	360	400	70	80	500
Distillate Oil - Hot / Warm	2 hours	180	200	35	40	250

The following emissions (TPY) are shown for informational purposes only. They represent a *conservative* estimate of annualized startup emissions, which are largely controllable through best operating practices. Since each startup requires many hours of preceding shutdown time where emissions are zero, there will likely be *no annual net emission increase* from the previously estimated TPY:

STARTUP TYPE	NO. REQUIRED	NO_X	SO_2	PM_{10}	VOC	CO
Cold	48 (2 on oil)	4.1	0.4	1.2	1.9	12.0
Hot / Warm	240 (10 on oil)	10.1	1.0	0.7	4.8	30.0
Total	288 (12 on oil)	14.2	1.4	1.9	6.7	42.0

Excess emissions may occur under the following startup scenarios, subject to Rule 62-210.700, F.A.C. However, excess emissions resulting from startup, shutdown, or malfunction shall *only* be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

Hot / Warm Start: Two hours following a HRSG shutdown less than 72 hours.

Cold Start: Four hours following a HRSG shutdown greater than or equal to 72 hours.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:

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

Date: 9/25/01

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 9/25/01

REFERENCES

[1] News Release. Goaline Environmental. Genetics Institute Buys SCONOx Clean Air System. August 20, 1999.

[2] "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

[3] Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.

[4] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[5] Application for Air Permit, Attachment 2 Performance Data – GE Performance Data Natural Gas Firing Only.

[6] Letter. Neeley, R. Douglas, EPA Region IV, to Fancy, C.H., FDEP. Draft PSD Permit – KUA Project. February 2, 1999.

[7] Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

[8] Letter. Porter, Ellen to Linero, A.A., FDEP. Technical Review of Prevention of Significant Deterioration Permit Application For Osprey Energy Center. April 17, 2000.

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

THRU: Clair Fancy
Al Linero 9/21

FROM: Michael P. Halpin

DATE: September 21, 2001

SUBJECT: Stanton Energy Center Combined Cycle Unit Addition

BAH

Attached for approval and signature is a PSD permit for the subject (existing) facility. The 700 megawatt combined cycle electrical power generating unit will consist of: two nominal 170 MW "F" class combustion turbine-electrical generators; two supplementally fired heat recovery steam generators; one 300 MW steam-electrical generator; one mechanical draft cooling tower; a fuel oil storage tank and ancillary equipment. This project was subject to the Power Plant Siting Act.

The permit allows for NO_X emissions of 3.5 ppmvd on a 3-hour block average (via SCR) with ammonia slip limited to 5 ppm. Additionally, the permit will require a CEMS for the continuous measurement of CO emissions, which will be based upon a 24-hour block average.

Emissions of sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently clean fuels used.

The Siting Board met on September 11th and approved the Recommended Order of Judge Stampelos. However, according to OGC we have not received the Governor's signature yet, apparently due to the recent world developments which began on that day.

Accordingly, I recommend your approval and signature with the understanding that we will not issue the permit until we have received word that Governor Bush has signed off.

Attachments

/mph

* 9:30 AM, 9/21/01 - BUCK OVEN CALLED TO ADVISE ME THAT THE GOV, has signed the order and we CAN ISSUE the permit.

- Mike Halpin

Halpin, Mike

From: Halpin, Mike
Sent: Tuesday, October 30, 2001 7:35 AM
To: 'Waters, Glenn D.'; 'Reggie Davis'
Cc: Mulkey, Cindy; Kuberski, Garry
Subject: RE: Stanton A CEM Issues

Dwain Waters-
Here are my responses, in CAPITAL LETTERS (after the questions) to the CEMS questions Spectrum has raised (which I have left below), related to the recently issued Stanton Unit A PSD permit:

1. The permit says that CO2 will be the diluent for both NOX and CO. This is currently not the case. O2 is being used as a diluent for the CO system. Will this be allowed or do we need to see about a having a CO2 monitor for that diluent as well. I was surprised to see the diluent spelled out as usually they give you the choice of using CO2 or O2.
O2 WILL BE ALLOWED

2. The CO2 monitor is to be RATA'd using Method 3B. This is not the normal reference method for CO2, usually method 3A is
utilized. Method 3B is for determining excess air and uses an ORSAT. Method 3A is much more accurate, it uses a CO2 monitor, and is typically used for RATA testing under part60 and part75.
METHOD 3A IS ALLOWED

3. The CO monitor will be ranged 0-20ppm for the low range and 0-100 for the high range. This meets the requirements of permit as you can see from the language. The 0-20 is low end for the Siemens analyzers and the 0-100 is a permit cap.
NO RESPONSE REQUIRED, AS THIS MEETS THE PERMIT REQUIREMENTS

4. NOx will be ranged 0-10 low and 0-30 high.
NO RESPONSE REQUIRED, AS THIS MEETS THE PERMIT REQUIREMENTS

5. The language regarding conversion of the wet based numbers to dry based is somewhat confusing. This is the way we have done this to date and it appears to work well at Dahlberg. We use a set of formulas that were actually developed between Gainesville Regional Utilities and Spectrum but are right out of the CFR. Clark Mitchell is very familiar with these. Estimating moisture will not give as accurate a number I do not believe.
I CANNOT DETERMINE WHETHER THERE IS A QUESTION HERE FOR FDEP, HOWEVER FOR CLARITY THE PERMIT (SPECIFIC CONDITION 41) STATES: "If the CEM system measures concentration on a wet basis, the CEM system 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 owner or operator 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). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen."

These issues will ultimately require a revision to the PSD permit. However, you may assume that this e-mail represents FDEP's official responses to your questions, such that you can procure necessary equipment. Invariably, we find that permittee's need to make minor, incidental changes to permits as construction is commenced and continues. "OUC/KUA/FMPA/Southern Company - Florida, LLC" will need to ensure that the changes above, along with other incidental construction changes, are included within the PSD permit, prior to the completion of construction.

Michael P. Halpin
FDEP/BAR

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

JUN 18 2001

RECEIVED
JUN 21 2001
BUREAU OF AIR REGULATION

4APT-ARB

Al Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Thank you for sending to the U.S. Environmental Protection Agency (EPA) a copy of the preliminary determination and draft prevention of significant deterioration (PSD) permit for a project at the Curtis H. Stanton Energy Center in Orange County, Florida. The proposed project will consist of two combined cycle combustion turbine units. The following equipment is associated with the project: two General Electric (Model PG7241FA) combined cycle combustion turbines with heat recovery steam generators, supplemental duct firing, a 10-cell cooling tower, and a No. 2 distillate fuel oil storage tank. Natural gas will be the primary fuel for each unit, with No. 2 fuel oil as a backup. Based on the applicant's emission estimates, the pollutants subject to PSD review are nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

We have reviewed the preliminary determination and draft permit and have the following comments. These comments were discussed by telephone with Mr. Mike Halpin of the Florida Department of Environmental Protection (FDEP) on June 5, 2001.

1. Condition 30 in the draft permit (page 10 of 20) requires testing to confirm the accuracy of formaldehyde emission estimates for the combustion turbines/duct burners. Since the applicant used a formaldehyde emission factor that is far below the nominal AP-42 emission factor and thereby avoided a section 112(g) case-by-case maximum achievable control technology determination, EPA agrees that a performance test is appropriate.

2. Condition 21 in the draft permit (page 8 of 20) specifies NO_x emission limits on a 3-hour block average basis. A compliance averaging period of 3 hours for NO_x emissions has been specified in many combined cycle combustion turbine permits and is appropriate.

If you have any questions regarding these comments, please call Daphne Wilson at (404) 562-9118.

Sincerely,

for Gregg M. Worley

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

cc: M. Halpin
C. Holladay
R. Moore, Gulf Power
G. Vick, Gulf Power
R. Unruh, Black + Veatch
J. Bunyak, NPS
J. Kozlow, CD
J. Buford
B. Oven, DEP

Orlando Utilities Commission
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P.O. Box 3193
Orlando, Florida 32802
Phone: 407.423.9100
Administrative Fax: 407.236.9616
Purchasing Fax: 407.384.4141
Website: www.ouc.com

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The *Reliable* One

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May 30, 2001

Mr. Mike P. Halpin
Bureau of Air Regulations
Florida Department of
Environmental Protection
MS #5505
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Halpin:

Pursuant to Chapter 50, Florida Statutes, the Public Notice of the intent to issue PSD Permit No. PSD-FL-313 for the Curtis H. Stanton Energy Center Unit A was published in the Orlando Sentinel on May 27, 2001.

Attached is the proof of publication as received from the Orlando Sentinel on May 29, 2001.

If you have any questions, please contact me at 407/423-9133.

Very truly yours,

Robert F. Hicks
Sr. Environmental Engineer

RFH:rc
Attachment

xc: D. M. Stalls
Myron Rollins, B&V
James O. Vick, Gulf Power
Tasha O. Buford, YVAV&B
C. Holladay
T. Kozlov, CD
B. Oven, DEP
EPA
NPS

i:\secapsdpublicnotice

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Orlando Sentinel

Published Daily

State of Florida } S.S.
COUNTY OF ORANGE

Before the undersigned authority personally appeared BEVERLYC.SIMMONS, who on oath says that he/she is the Legal Advertising Representative of Orlando Sentinel, a daily newspaper published at ORLANDO in ORANGE County, Florida; that the attached copy of advertisement, being a PUBLIC NOTICE OF in the matter of PSD-FL-313 (PA 81-14SA2)

in the ORANGE Court, was published in said newspaper in the issue; of 05/27/01

Affiant further says that the said Orlando Sentinel is a newspaper published at ORLANDO, in said ORANGE County, Florida, and that the said newspaper has heretofore been continuously published in said ORANGE County, Florida, each Week Day and has been entered as second-class mail matter at the post office in ORLANDO in said ORANGE 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/she 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.

Beverly C. Simmons

The foregoing instrument was acknowledged before me this 29th day of MAY, 2001, by BEVERLY C.SIMMONS, who is personally known to me and ~~who~~ did take an oath.

(SEAL)

JULIA NICHOLS
My Comm Exp. 9/23/2001
Bonded By Service Ins
No. 683016
[ ] Personally Known [ ] Other I.D.

NOTARY PUBLIC STATE OF FLORIDA

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. PSD-FL-313 (PA 81-14SA2)
OUC Curtis H. Stanton Energy Center
Unit A Combined Cycle Addition
Orange County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to the following joint owners: OUC/KUA/FMPA/Southern Company - Florida, LLC. The permit is to install a combined cycle power-generating unit at the existing OUC Stanton Energy Center, located at 5100 South Alafaya Trail, Orlando, Orange County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR52.21 for emissions of particulate matter (PM and PM10), volatile organic compounds (VOC), sulfur dioxide (SO2), sulfuric acid mist (SAM), carbon monoxide (CO) and nitrogen oxides (NOX). The applicant's name and address is Mr. Robert G. Moore, Gulf Power Company, One Energy Place, Pensacola, FL 32520-0328.

The project consists of two nominal (existing) 170 MW GE 7FA combustion turbine-electrical generators configured for combined cycle operation, operating on natural gas with 0.05% sulfur oil backup (1000 hours per year); two supplementally-fired (natural gas) heat recovery steam generators (HRSG); one 300 MW (nominal output) steam turbine; one fresh water cooling tower; a fuel oil storage tank and ancillary equipment.

NOx emissions will be controlled by Dry Low NOx combustors and SCR to 3.5 parts per million (ppm) while firing natural gas, and by water injection and SCR to 10 ppm while firing fuel oil. Emissions of carbon monoxide (CO) will be controlled to 14 ppm while firing oil and 17 ppm while firing gas. Emissions of volatile organic compounds (VOC), sulfur dioxide (SO2), sulfuric acid mist (SAM), and particulate matter (PM/PM10) will be very low because of the inherently clean fuels and methods of combustion employed.

The following maximum potential annual emissions (in tons per year) summarize the maximum increase in regular air pollutants as a result of this project.

Pollutants	Maximum Facility Emissions (TPY)
PM/PM_{10}	128
NO_x	315
SO_2	134
SAM	18
VOC	106
CO	373

An air quality impact analysis was conducted. Emissions from the facility will not contribute to or cause a violation of any state or federal ambient air quality standards. All impacts to Class II areas are less than significant. All impacts to Class I areas are also less than significant.

The Department will issue the FINAL permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. If a petition for an administrative hearing on the Department's intent to issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

Dept of Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Central District Office
111 S. Magnolia Drive, Suite 4	3319 Maguire Boulevard, Suite 232
Tallahassee, Florida 32301	Orlando, Florida 32803-3767
Telephone: 850/488-0114	Telephone: 407/894-7555
Fax: 850/922-6979	Fax: 407/897-2966

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Technical Evaluation and Preliminary Determination as well as the Draft BACT Determination and Permit may be viewed at http://www8.myflorida.com/licensingpermitting/learn/environment/air/airpermit.html by clicking on Utilities and Other Facilities Permits Issued.

COR3912556 5/27/01

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Robert G. Moore
VP of Power Gen & Transmission
Gulf Power Company
OUC Stanton A Combined Cycle
Addition
One Energy Place
Pensacola, FL 32520-0328

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 5/21/00

C. Signature

X

☐ Agent
☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7099 3400 0000 1450 3214

PS Form **3811**, July 1999 Domestic Return Receipt 102595-00-M-0952

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

7099 3400 0000 1450 3214

Article Sent To:

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

Postmark Here

OUC Stanton

Name *(Please Print Clearly) (to be completed by mailer)*
Mr. Robert G. Moore
Street, Apt. No.; or PO Box No.
One Energy Place
City, State, ZIP+4
Pensacola, FL 32520-0328

PS Form 3800, July 1999 See Reverse for Instructions

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

1. Article Addressed to:

Mr. Richard Crotty, Chair
Orange County Board of County Commissioners
Administration Bldg., 5th Fl
201 S Rosalind Ave.
Orlando, FL 32801

A. Received by *(Please Print Clearly)* Acevedo

B. Date of Delivery

C. Signature X

☐ Agent
☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7099 3400 0000 1450 3184

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

7099 3400 0000 1450 3184

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

Article Sent To:

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

Postmark Here
Orange County

Name *(Please Print Clearly) (to be completed by mailer)*
Mr. Richard Crotty, Chair
Street, Apt. No.; or PO Box No.
201 S. Rosalind Ave
City, State, ZIP+4
Orlando, FL 32801

PS Form 3800, July 1999 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 17, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Robert G. Moore, VP of Power Gen. and Transmission
Gulf Power Company
OUC Stanton A Combined Cycle Addition
One Energy Place
Pensacola, Florida 32520-0328

Re: DEP File No. 0950137-002-AC (PSD-FL-313)
OUC/KUA/FMPA/Southern Company – Florida, LLC

Dear Mr. Moore:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the OUC Stanton A Combined Cycle addition to be located at 5100 South Alafaya Trail, Orlando, Orange County. The Department's Intent to Issue PSD Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" are also included.

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

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

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

CHF/mph/ml

Enclosures

In the Matter of an
Application for Permit by:

Mr. Robert G. Moore, VP Gulf Power Company
OUC/KUA/FMPA/Southern Company – Florida, LLC
One Energy Place
Pensacola, FL 32520-0328

DEP File No. 0950137-002-AC (PSD-313)
Curtis H. Stanton Energy Center
Orange County

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration of Air Quality (copy of Draft PSD Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, OUC/KUA/FMPA/Southern Company – Florida, LLC, applied on January 22, 2001 to the Department for a PSD permit to construct a 700 megawatt combined cycle electrical power generating unit consisting of: two nominal 170 MW "F" class combustion turbine-electrical generators; two supplementally fired heat recovery steam generators; one 300 MW steam-electrical generator; one mechanical draft cooling tower; a fuel oil storage tank and ancillary equipment. The application became complete on May 1, 2001. The project will be located at the existing Curtis H. Stanton Energy Center, 5100 South Alafaya Trail, Orlando, Orange County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit and a determination of Best Available Control Technology for the control of carbon monoxide, nitrogen oxide, sulfur dioxide, sulfuric acid mist, volatile organic compounds and particulate matter is required to conduct the work.

The Department intends to issue this PSD permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. and 40 CFR 52.21.

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

The Department will issue the final permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PSD PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT PSD permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/17/01 to the person(s) listed:

Robert G. Moore, Gulf Power *
Chair of County Commission, Orange County *
James O. Vick, Gulf Power
Rodney I Unruh, P.E. (Black & Veatch)
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP-Central District
Marie Driscoll, Orange County EPD
Tasha O. Buford, E., Attorney
Mr. Hamilton S. Oven, DEP-Siting

Clerk Stamp

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

Charlotte J. Hayes 5/17/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-313 (PA 81-14SA2)
OUC Curtis H. Stanton Energy Center
Unit A Combined Cycle Addition
Orange County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to the following joint owners: OUC/KUA/FMPA/Southern Company – Florida, LLC. The permit is to install a combined cycle power-generating unit at the existing OUC Stanton Energy Center, located at 5100 South Alafaya Trail, Orlando, Orange County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR52.21 for emissions of particulate matter (PM and PM_{10}), volatile organic compounds (VOC), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO) and nitrogen oxides (NO_X). The applicant's name and address is Mr. Robert G. Moore, Gulf Power Company, One Energy Place, Pensacola, FL 32520-0328.

The project consists of two nominal (existing) 170 MW GE 7FA combustion turbine-electrical generators configured for combined cycle operation, operating on natural gas with 0.05% sulfur oil backup (1000 hours per year); two supplementally-fired (natural gas) heat recovery steam generators (HRSG); one 300 MW (nominal output) steam turbine; one fresh water cooling tower; a fuel oil storage tank and ancillary equipment.

NO_x emissions will be controlled by Dry Low NO_x combustors and SCR to 3.5 parts per million (ppm) while firing natural gas, and by water injection and SCR to 10 ppm while firing fuel oil. Emissions of carbon monoxide (CO) will be controlled to 14 ppm while firing oil and 17 ppm while firing gas. Emissions of volatile organic compounds (VOC), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM_{10}) will be very low because of the inherently clean fuels and methods of combustion employed.

The following maximum potential annual emissions (in tons per year) summarize the maximum increase in regulated air pollutants as a result of this project.

Pollutants	Maximum Facility Emissions (TPY)
PM/PM_{10}	128
NO_x	315
SO_2	134
SAM	18
VOC	106
CO	373

An air quality impact analysis was conducted. Emissions from the facility will not contribute to or cause a violation of any state or federal ambient air quality standards. All impacts to Class II areas are less than significant. All impacts to Class I areas are also less than significant.

The Department will issue the FINAL permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

Dept. of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Technical Evaluation and Preliminary Determination as well as the Draft BACT Determination and Permit may be viewed at http://www8.myflorida.com/licensingpermitting/learn/environment/air/airpermit.html by clicking on *Utilities and Other Facilities Permits Issued.*

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

OUC/KUA/FMPA/Southern Company – Florida, LLC

Stanton Unit A Combined Cycle Project

700-Megawatt Combined Cycle Addition

Orange County

PSD-FL-313, PA81-14SA2

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

May 17, 2001

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

OUC/KUA/FMPA/Southern Company – Florida, LLC
James O. Vick, Manager Environmental Affairs – Gulf Power
One Energy Place
Pensacola, FL 32520-0328

Authorized Representative: Mr. Robert G. Moore, VP of Power Generation and Transmission

1.2 Reviewing and Process Schedule

01-22-01:	Date of Receipt of Application
03-12-01:	Request for Additional Information
05-01-01:	Application Complete
05-17-01:	Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

The OUC Curtis H. Stanton Energy Center is located at 5100 South Alafaya Trail, Orlando, Orange County. This site is approximately 140 kilometers east-southeast of the Class I Chassahowitzka National Wildlife Refuge. UTM coordinates for this facility are Zone 17; 483.61 km E; 3151.1 km N. See Figures 1 and 2 below.

FIGURE 1

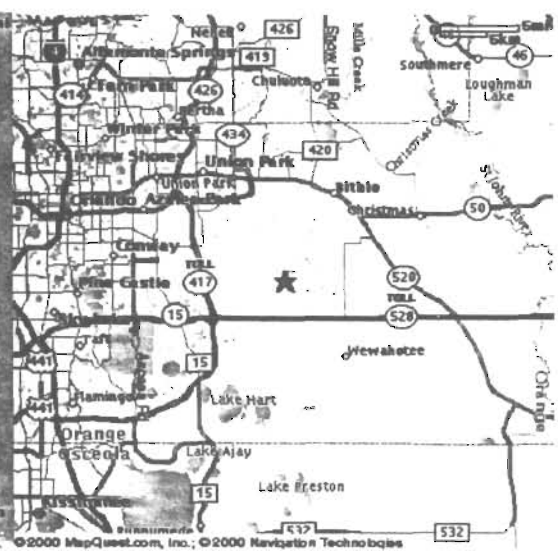


FIGURE 2

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3 Facility Category

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

The facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C

As a Major Facility, project emissions greater than the Significant Emission Rates given in Table 212.400-2 (100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC, 25/15 TPY of PM/PM_{10}) require review per the PSD rules and a determination of Best Available Control Technology (BACT). This facility is also subject to the Title IV Acid Rain Program, 40 CFR 72.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
025	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
026	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
027	Water Cooling	One 10 cell Cooling Tower
028	Fuel Storage	One 1,680,000 Gallon Distillate Fuel Oil Storage Tank

The applicant proposes to install a combined cycle unit at the existing facility. This existing facility consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash.

The project includes: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment.

The turbines will be equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas and 10 ppmvd while firing oil using SCR plus water injection. Each combustion turbine will have a maximum heat input rating of 2,402 (Natural Gas while firing duct burners) and 2,068 MMBtu/hr (oil), while the maximum duct burner heat input will be 533 MMBtu/hr (Natural Gas). The referenced CT heat inputs are specified as cases 4 and 20 (respectively) in the application.

The main fuel will be pipeline quality natural gas and the units will operate up to 8760 hours per year. Low sulfur distillate fuel oil will be fired for up to 1000 hours per year in each CT. Emission increases will occur for particulate matter (PM and PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). PSD review is required for each of these pollutants, since emissions, per the application, will increase by more than their respective significant emissions levels.

The application was prepared by Black & Veatch.

4. PROCESS DESCRIPTION

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the compressor of the 7FA where it is then directed to the combustor section, fuel is introduced, ignited, and burned. The combustion section consists of multiple separate can-annular combustors instead of a single combustion chamber.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures up to 2700 °F. Energy is recovered within the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

There are three basic operating cycles for gas turbines. These are simple cycle, regenerative, and combined cycles. In this project, the 7FA will operate in the combined cycle mode and as a continuous duty unit (versus an intermittent duty peaking unit).

In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In this case, most of the steam is fed to a separate steam turbine, which also drives an electrical generator. Typical combined cycle efficiencies are up to 55 percent. The 7FA can achieve over 50 percent efficiency in combined cycle operation, especially if the gas turbine and the HRSG/steam generator power a common shaft connected to a single electric generator. See Figures 3 and 4 below.

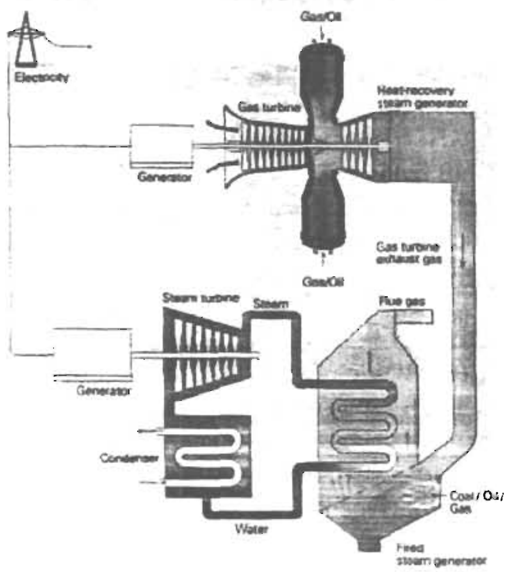


FIGURE 3

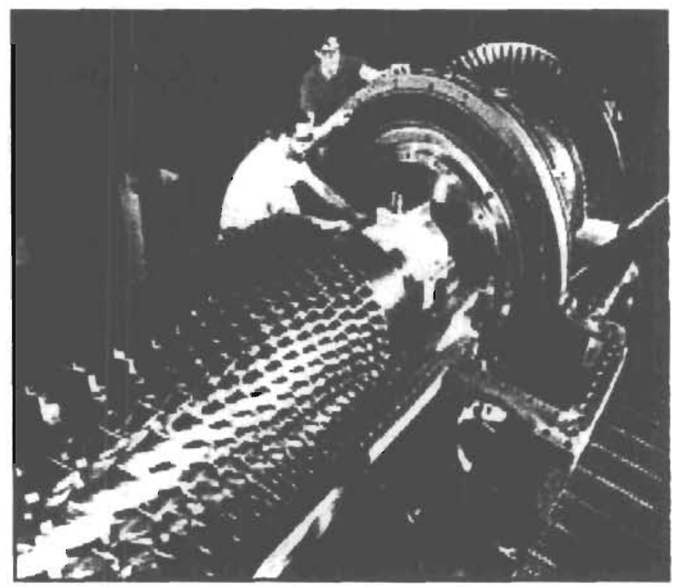


FIGURE 4

Additional process information and control measures to minimize NO_X formation are given in the draft BACT Determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 40 CFR 52.21, Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Orange County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, CO, SAM, SO_2 and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, SO_2, SAM, VOC, CO and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth.

This project will also be reviewed for Site Certification under the Power Plant Siting Act.

The emission units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

Chapter 62-17	Electrical Power Siting
Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 60	NSPS Subparts GG and Db
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide and sulfuric acid mist. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Emission Units are summarized in the Draft BACT document and Specific Conditions Nos. 21 through 25 of Draft Permit PSD-FL-313.

6.2 Emission Summary

The emissions for all PSD pollutants as a result of the construction of this facility are presented below:

FACILITY EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutants	Two CT/HRSG with Duct Burners[1]	Cooling Tower	Distillate Fuel Tank	Total	PSD Significance	PSD REVIEW?
PM/PM_{10}	107.3	20.3	0	127.6	25	Yes
SO_2	134.1	0	0	134.1	40	Yes
NO_X	314.5	0	0	314.5	40	Yes
CO	372.4	0	0	372.4	100	Yes
Ozone (VOC)	105.0	0	0.8	105.8	40	Yes
Sulfuric Acid Mist	17.6	0	0	17.6	7	Yes
Mercury	0.004	0	0	0.004	0.1	No
Lead	0.03	0	0	0.03	0.6	No
Total HAPS	8.4/18.0	0	0	8.4/18.0	10/25	No

1. Based on 6760 hours/year on natural gas at 100% output firing duct burners, 70 °F compressor inlet temperature; 1000 hours/year on oil at 100% output at 70°F compressor inlet temperature; 1000 hours/year with duct burners and power augmentation.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of clean fuels along with the use of an SCR. The gas turbine combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The SCR will control emissions of NO_X to 3.5 ppm @15% O_2 under gas-firing conditions and 10 ppmvd while oil firing. Low NO_X duct burners will be utilized between each CT and HRSG to achieve NO_X values well under the Subpart Da requirements. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Air Quality Analysis Introduction

The proposed project will increase emissions of four regulated pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, SO_2, NO_2, and CO. SO_2, PM_{10}, and NO_2 are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it.

The applicant's initial Class II NO_2, PM_{10}, SO_2, and CO analyses predicted no significant impacts in the area surrounding the proposed facility; therefore, full impact Class II AAQS and PSD Class II increment analyses were not required for these pollutants. The nearest Class I area is the Chassahowitzka National Wildlife Refuge which is located approximately 140 km west-northwest from the project site. The applicant's PSD Class I air quality analyses showed no significant impacts; therefore cumulative impact analyses were not required in these Class I areas. Also, the maximum predicted impacts for all four pollutants were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality impact analyses required by the PSD regulations for this project include:

- A Class II significant impact analysis for PM_{10}, NO_2, SO_2, and CO;
- A Class I significant impact analysis for PM_{10}, NO_2, and SO_2;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.4.2 Ambient Monitoring Requirements

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. The monitoring requirement may be satisfied by using existing representative monitoring data, if available. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis concentration. The table below shows that predicted impacts from the combustion turbines are substantially less than the respective de minimis levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant.

Maximum Project Air Quality Impacts Compared to De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max. Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Impact Greater Than De Minimis?
NO_2	Annual	0.1	14	NO
CO	8-hour	14	575	NO
PM_{10}	24-hour	1	10	NO
SO_2	Annual	2	13	NO

6.4.3 Models and Meteorological Data Used in the Air Quality Analysis

6.4.3.1 PSD Class II Area Model

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios, fuels and ambient temperatures in the vicinity of the facility. This was accomplished by representing the generating station's proposed operating load range (i.e., 50, 75 and 100 percent loads) with a representative set of stack parameters and pollutant emission rates to produce worst-case plume dispersion conditions and highest model predicted concentrations. This process is referred to as enveloping. The representative stack parameters and emission rates for each load, fuel type and operating scenario were considered in the analysis. The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3-km radius of the site was classified as rural or urban using the Auer land use classification method. Based upon a visual inspection of the USGS 7.5-minute topographic map of the generating station, it was concluded that over 50% of the area surrounding the generating station is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Orlando, FL and Tampa, FL. The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

6.4.3.2 PSD Class I Area Model

Since the entire PSD Class I Chassahowitzka National Wildlife Refuge (CNWR) area is greater than 50 km from the proposed project, long-range transport modeling was also 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 two Air Quality Related Values (AQRVs): regional haze and deposition of sulfur and nitrogen compounds. 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. For this project, the CALMET model produced a modeling domain centered over the project location that is approximately 290 km in the north-south direction by 350 km in the east-west direction. This modeling domain was produced by utilizing 1990 meteorological data from 1 sea surface, 3 upper air, 6 land surface, and 27 precipitation stations located throughout Florida and adjacent waters.

6.4.4 Significant Impact Analysis

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 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 shows significant impacts, additional modeling which includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

In order to determine the worst-case emission scenarios, the ISCST3 model in screening mode was used to assess each of the CTG/HRSG operating cases (i.e., a matrix of three CTG loads [100-, 75-, and 50-percent]; five ambient temperatures [19, 45, 60, 75 and 95°F]; and two operating modes [CTG firing natural gas and CTG firing fuel oil] for each pollutant). The worst case operating modes identified by the ISCST3 screening mode for each pollutant were then used as input for the significant impact modeling. This modeling uses ISCST3 in its regular mode. For the Class II analysis a nested rectangular grid of receptors that extends 10-km from the center of the generating station was used. The rectangular grid network consists of 100-m spacing from the center of OUC out to 3,000-m and then 500-m spacing from 3.0-km out to 10-km. Receptor spacing of 100-m intervals was used along the fenceline. The tables below show the results of the significant impact modeling for the Class II and Class I areas.

MAX PROJECT AIR QUALITY IMPACTS COMPARED TO PSD CLASS II SIGNIFICANT IMPACT LEVELS				
Pollutant	**Averaging Time**	**Max. Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**
PM_{10}	Annual	0.1	1	NO
	24-hr	1	5	NO
CO	8-hr	14	500	NO
	1-hr	60	2,000	NO
NO_2	Annual	0.1	1	NO
SO_2	Annual	0.1	1	NO
	3-hr	9	25	NO
	24-hr	2	5	NO

MAX PROJECT AIR QUALITY IMPACTS COMPARED TO PSD CLASS I SIGNIFICANT IMPACT LEVELS				
Chassahowitzka Pollutant	**Impact ($\mu g/m^3$)**	**Class I Increment ($\mu g/m^3$)**	**Class I SIL ($\mu g/m^3$)**	**Significant Impact?**
NO_X - Annual	0.002	2.5	0.10	NO
PM_{10} - Annual	0.001	4	0.16	NO
PM_{10} – 24 Hour	0.02	8	0.32	NO
SO_2 - Annual	0.01	2	0.08	NO
SO_2 – 3 Hour	0.31	25	1.00	NO
SO_2 – 24 Hour	0.12	5	0.20	NO

As shown in the tables there are no maximum predicted air quality impacts due to any emissions from the proposed project which are greater than the PSD significant impact levels. Therefore, under the PSD program, no further air quality impact analysis (PSD increment or AAQS analysis) is required for this project.

6.5 Additional Impacts

6.5.1 Impact Analysis Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from these clean fuel fired combustion turbines in comparison with a conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. An analysis of sulfur and nitrogen deposition impacts in the CNWR was done. Based on Federal Land Manager (FLM) criteria, no adverse impacts were predicted there. The maximum ground-level concentrations predicted to occur for PM_{10}, SO_2, CO and NO_X, as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS. The project impacts are less than the significant impact levels, 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.

6.5.2 Impact On Visibility

Natural gas is a clean fuel and produces little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions (as well as the very low operating hours on 0.05% sulfur oil) will minimize plume opacity. The applicant submitted visibility and regional haze analyses for the CNWR indicating impacts less than 1%. Based on FLM criteria, there will be no adverse visibility or regional haze impacts.

6.5.3 Growth-Related Air Quality Impacts

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and to assess air quality impacts that would result from that growth.

Impacts associated with the facility addition and the associated ancillary equipment will be minor. While not readily quantifiable, the temporary increase in vehicular miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The project is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the Project are anticipated. The increase in natural gas demand due to increased operation of the two affected CT's (and duct burners) will not have major impacts on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

6.5.4 Hazardous Air Pollutants

An analysis supplied by Black & Veatch indicates that the project is not a major source of hazardous air pollutants (HAPs). Although this will need to be verified through actual testing, as submitted it is not subject to any specific industry or HAP control requirements pursuant to Sections 112 of the Clean Air Act.

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations, provided the Department's BACT determination is implemented.

Michael P. Halpin, P.E., Review Engineer

Cleve Holladay, Meteorologist

PERMITTEE:

OUC/KUA/FMPA/Southern Company – Florida, LLC
One Energy Place
Pensacola, FL 32520-0328

File No.	PSD-FL-313 (PA81-14SA2)
FID No.	0950137
SIC No.	4911
Expires:	December 31, 2004

Authorized Representative:

Mr. Robert G. Moore, VP of Power Generation and Transmission, Gulf Power Company

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 640 megawatt (MW) Combined Cycle unit consisting of: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment. The combined cycle unit will achieve approximately 700 megawatts during extreme winter peaking conditions. The unit is to be installed at the existing OUC Stanton Energy Center, located at 5100 South Alafaya Trail, Orlando, Orange County. UTM coordinates are: Zone 17; 483.61 km E, 3151.1 km N.

STATEMENT OF BASIS:

This PSD 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.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection.

The attached Appendices are made a part of this permit:

Appendix GC	Construction Permit General Conditions
Appendix GG	Subpart GG, Standards of Performance for Stationary Gas Turbines
Appendix XS	Semi-Annual Continuous Emission Monitor Systems Report

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

OUC Stanton Energy Center consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash. This project includes: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment.

The turbines will be equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas. During fuel oil firing, emissions will be held to 10 ppmvd at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.05% sulfur oil and good combustion practices will be employed to control all pollutants.

EMISSIONS UNITS

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
025	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
026	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
027	Water Cooling	One 10 cell Cooling Tower
028	Fuel Storage	One 1,680,000 Gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

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

This facility is within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of SO_2 and NO_X, 25/15 TPY of PM/PM_{10}, 100 TPY of CO and 40 TPY of VOC's. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting. [Chapter 403.503 (12), F.S., Definitions]

SECTION I - FACILITY INFORMATION

Based on the Title V permit, this facility is not currently a major source of hazardous air pollutants (HAPs). This facility is subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- xx/xx/01 PSD Permit Issued
- xx/xx/01 Site Certification Issued
- xx/xx/01 Notice of Intent to Issue PSD Permit published in xxxxxxxxxxxxx
- 05/17/01 Distributed Intent to Issue Permit
- 05/01/01 Application Complete
- 01/22/01 Received PSD Application

RELEVANT DOCUMENTS:

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

- Application received on January 22, 2001.
- Letter from Fish & Wildlife Service dated February 9, 2001.
- Additional information received from applicant on May 1, 2001.
- Department's Intent to Issue and Public Notice Package dated May 17, 2001.
- Department's Draft Permit and Draft BACT determination dated May 17, 2001.
- Letter from EPA Region IV dated xx/xx/01.
- Site Certification for the Stanton A Combined Cycle addition dated xx/xx/01.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II - ADMINISTRATIVE REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21 (j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]

8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2004 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.080, F.A.C.]

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

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

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

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

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

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District Office.

APPLICABLE STANDARDS AND REGULATIONS

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. NSPS Requirements: Each combustion turbine (CT) shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. **Subpart A, General Provisions,** including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

   b. **Subpart GG, Standards of Performance for Stationary Gas Turbines;** see attached *Appendix GG.*

3. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

4. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

5. ARMS Emissions Units 025 and 026. Direct Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Additionally, each Emissions Unit consists of a supplementally fired heat recovery steam generator equipped with a natural gas fired 533 MMBTU/hr duct burner (LHV) and combined with a nominal 300 MW steam electrical generators. These shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.

6. ARMS Emission Unit 027. Cooling Tower, an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.

7. ARMS Emission Unit 028. Fuel Storage Tank, consisting of a 1,680,000 gallon distillate fuel storage tank. The storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.

8. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.

GENERAL OPERATION REQUIREMENTS

9. Fuels: Only pipeline natural gas or (up to) 1000 hours per year of 0.05% distillate fuel oil shall be fired in each CT emissions unit. Only natural gas shall be fired in each duct burner. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Combustion Turbine Capacity: The maximum heat input rates to each CT/HRSG shall not exceed 2,402 million Btu per hour (MMBtu/hr) when firing natural gas with duct burner firing and power augmentation. The maximum heat input rates to each CT/HRSG shall not exceed 2,068 million Btu per hour (MMBtu/hr) when firing fuel oil. These maximum heat input rates shall not be exceeded under any condition, regardless of ambient conditions or combustion turbine characteristics. Manufacturer's curves corrected for ISO conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 533 MMBtu/hour (LHV) at any temperature or under any scenario. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

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

13. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Central District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

14. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

15. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

16. Maximum allowable hours of operation for each CT/HRSG Emissions Unit are 8760 hours per year while firing natural gas. Fuel oil firing is permitted for 1000 hours during any consecutive 12-month period in each CT. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

17. Simple Cycle Operation: The plant may not be operated without the use of the SCR system except during periods of startup and shutdown.

CONTROL TECHNOLOGY

18. Dry Low NO_X (DLN) combustors and water injection capability shall be installed on each stationary combustion turbine. The permittee shall install a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Specific Condition 21. Additionally, space shall be provided for the installation of oxidation catalysts. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

19. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 21 through 25. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

20. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. A certification following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002-gallons/100 gallons recirculation water flowrate.

EMISSION LIMITS AND STANDARDS

21. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on natural gas shall not exceed 3.5 ppmvd @15% O_2 on a 3-hr block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- The emissions of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil shall not exceed 10.0 ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 30 for compliance procedures). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]
- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O_2. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]

22. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on natural gas shall not exceed 17 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS; and neither 14 ppmvd @15% O_2 with the CT operating on fuel oil on a 24-hr block average to be demonstrated by CEMS. These limits shall also be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. Within 24 months of the date of completion of initial testing, the applicant shall either have installed oxidation catalyst in each CT/HRSG or forfeit its right to do so with the pre-determined (BACT) emission limits specified below. [BACT, Rule 62-212.400, F.A.C.]

- In the event that an oxidation catalyst is installed for any reason in either CT/HRSG pair within 24 months of the date of completion of initial testing, the limits for CO and VOC shall be 5 ppmvd and 3 ppmvd (respectively) to be demonstrated by stack testing during power augmentation and duct burner firing (I, A). [BACT]

23. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall exceed neither 2.7 ppmvd @15% O_2 with the CT firing fuel oil and neither 6.3 ppmvd @15% O_2 with the CT firing natural gas (with maximum duct burner firing and operating in power augmentation mode); to be demonstrated by initial stack tests using EPA Method 18, 25 or 25A. [BACT, Rule 62-212.400, F.A.C.]

24. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 1.5 grains per 100 standard cubic foot) and up to 1000 hours per consecutive 12-month period of 0.05% sulfur fuel oil. Compliance with these fuel limits in conjunction with implementation of the attached Appendix GG will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner and the combustion turbine. Note: This will effectively limit the combined SO_2 emissions for EU-025 and EU-026 to approximately 134 tons per year. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

25. PM/PM_{10} and Visible emissions (VE): VE emissions shall not exceed 10 percent opacity from the stack in use. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

26. 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 occurrences shall in no case exceed two hours in any 24-hour period except during a "cold start-up" to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 72 hours. Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [BACT, Rule 62-210.700, F.A.C.].

27. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

28. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 41 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 21 through 25. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

29. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

30. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 29. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or addition of oxidation catalyst (or change of combustors, if specifically requested by the DEP on a case-by-case basis). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement) shall be conducted a) while firing natural gas with maximum duct burner heat input as well as maximum power augmentation and b) while firing fuel oil at the maximum heat input; Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO_X compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
- EPA Method 0011 or CARB Method 430 shall be utilized to evaluate the emissions of formaldehydes on each CT/Duct Burner as per the table below. A full report including all test results, analyses and applicant's MACT Determination shall be forwarded to the Bureau of Air Regulation in Tallahassee within the same time constraints identified in Specific Condition 29.

OPERATING MODE	TEST PROTOCOL	TPY CALCULATION
Maximum CT output Natural Gas; Duct Burner firing at maximum output	CARB Method 430 or EPA Method 0011	(6760/2000) times measured Lb/Hour Formaldehyde
Maximum CT output Natural Gas; Duct Burner firing and Power Augmentation implemented, both at max. output	CARB Method 430 or EPA Method 0011	(1000/2000) times measured Lb/Hour Formaldehyde
Maximum output, Fuel Oil	CARB Method 430 or EPA Method 0011	(1000/2000) times measured Lb/Hour Formaldehyde

Note: Results of the sampling method(s) identified above shall be blank corrected. For Method 0011, a minimum sample volume of 30 cubic feet shall be collected. To improve test precision, there shall be two co-located trains for each test. A minimum of 3 runs per CT/Duct Burner shall constitute a test.

- Method CTM-027 for ammonia slip (I, A) to be completed simultaneously with NO_X compliance testing.

The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O_2) at the measured lb/hr NO_X emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 45.

31. Continuous compliance with the CO and NO_X emission limits: Continuous compliance with the CO and NO_X emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition 41 further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition 28. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

32. Compliance with the SO_2 and PM/PM_{10} emission limits: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, the applicant is responsible for ensuring that the procedures outlined in attached Appendix GG are complied with.

33. Compliance with CO emission limit: An initial and annual test for CO shall be conducted at 100% capacity with the duct burners off. The NO_X and CO test results shall be the average of three valid one-hour runs. Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75.

34. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required [see Specific Condition 22 for exception].

35. Testing procedures: Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

36. Test Notification: The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests.

37. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, odors or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

38. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

39. Records: All measurements, records, and other data required to be maintained by the applicant shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

    - The applicant will be required to maintain records indicating the daily hours of operation of each CT/HRSG unit. These records shall specify which type of fuel is being combusted and the records shall be available for review at the site. Each calendar month, a compilation of the hours of operation for each CT/HRSG unit combusting fuel oil shall be made and totalized for the most recent consecutive 12-month period. Each AOR submitted by the applicant shall include a compilation of each consecutive 12-month period during the preceding calendar year.

40. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NOx shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly 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). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system 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 owner or operator 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). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.
The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.
The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. 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 semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of 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 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "cold startup." A cold startup is defined as a startup following a complete shutdown lasting a minimum of 72 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur. Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Rules 62-4.070(3) and 62-212.400., F.A.C., and BACT]

[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].

42. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Bureau of Ambient Monitoring & Mobile Sources (BAMMS) as well as the EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

43. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

44. Subpart Da Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Da].

45. Selective Catalytic Reduction System (SCR) Compliance Procedures:

- An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner on as defined in Specific Condition 21. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during the each performance test.
- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.
- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.
- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.
- Ammonia emissions shall be calculated continuously using inlet and outlet NO_X concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following

calculation represents one means by which the permittee may demonstrate compliance with this condition:

> <u>Ammonia slip @ 15% O_2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D</u>, where:
> A= ammonia injection rate (lb/hr)/ 17 (lb/lb.mol)
> B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)
> C = change in measured NO_X (ppmv@15% O_2) across catalyst
> D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

- The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.
- Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO_X and ammonia slip related permit limits can be complied with.

NSPS SUBPART GG REQUIREMENTS

[Note: 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 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.]

Pursuant to 40 CFR 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:

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

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 paragraph (a)(3) of this section.

(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 are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards 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.

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

Pursuant to 40 CFR 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:

(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.

Pursuant to 40 CFR 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.

(1) Department requirement: The requirement to monitor the nitrogen content of pipeline quality 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 shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

(2) [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 § 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 § 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 emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

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

Pursuant to 40 CFR 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 provided 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 O2 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 H2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NOx monitor continuously correct NOx emissions concentrations 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.

Department requirement: 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.

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system 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 the permit shall be used instead of that specified in paragraph (c)(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: The permit specifies sulfur testing methods and allows 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 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 the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

SECTION V. APPENDIX XS

SEMI-ANNUAL CONTINUOUS EMISSIONS MONITOR SYSTEMS REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NOx) Carbon Monoxide (CO)

Reporting period dates: From ______________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ____

Date of Latest CMS Certification or Audit: ______________________________

Process Unit(s) Description: ____

Total source operating time in reporting period [a]: ______________________________

Emission data summary [a]		**CMS performance summary** [a]	
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] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

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

[b] 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 to CMS, process or controls during last 6 months.

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

____
Name

____
Title

____ ______________________
Signature *Date*

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.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

STANTON UNIT A COMBINED CYCLE PROJECT
OUC/KUA/FMPA/Southern Co.
PSD-FL-313 and PA81-14SA2
Orange County, Florida

BACKGROUND

The applicants, Orlando Utilities Commission (OUC), the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA) and the Southern Company – Florida, LLC (SO), propose to build a 700 MW (estimated maximum gross capability) combined cycle power plant at the existing Curtis H. Stanton Energy Center. The location of the facility is 5100 South Alafaya Trail, Orlando, Orange County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). Therefore, the project is subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary units to be installed are two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system. The project includes two heat recovery steam generators (HRSGs), each with a 160 ft. stack and one steam turbine-electrical generator rated at approximately 300 MW. Duct burners will be installed in the HRSGs for supplemental firing and to achieve peak output. The project also includes one 10-cell linear mechanical draft cooling tower, and one diesel fuel storage tank (approximately 1,680,000 gallons). Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated June 30, 2001, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on January 22, 2001 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. The proposal is summarized in the table below for each combustion turbine (MW loads are assumed to be at 50% or higher).

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
PM/PM_{10}, VE	Clean Fuels Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip
SO_2 / SAM	Clean Fuels	0.5 grains / 100 scf (gas) 0.05% Sulfur distillate oil – 1000 hours / year
CO	Pipeline Natural Gas Good Combustion	17 ppmvd (all operating modes) gas – 24 hr. avg. 14 ppmvd (all operating modes) oil – 24 hr. avg.
VOC	Pipeline Natural Gas Good Combustion	3.6 ppmvd / 2.7 ppmvd (gas / oil) 6.3 ppmvd during DB plus PA
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2 (gas) 10 ppmvd @ 15% O_2 (oil)
PM - cooling tower	High efficiency drift eliminators	0.002% drift loss

Based upon the applicant's submittal, the maximum annual emissions that the facility has the potential to emit (PTE) are as follows: 134.1 TPY SO_2, 17.6 TPY SAM, 127.6 TPY PM/PM_{10}, 314.5 TPY NO_X, 372.4 TPY CO and 105.8 TPY of VOC.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the applicant is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the high efficiency units to be purchased. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

The duct burners required for supplementary gas-firing of the HRSGs are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The 0.1 lb/MW-hr NO_X emission rate proposed by the applicant is well below the revised Subpart Da output-based limit of 1.6 lb/MW-hr promulgated on September 3, 1998. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

The distillate fuel oil storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by states for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F or G Class Frame units. The applicant's proposed BACT is included for reference.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 1

RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	Power Output Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Mobile Energy, AL	~250	~3.5 - NG (CT&DB) ~11 – FO (CT&DB)	DLN & SCR	178 MW GE 7FA CT 1/99 585 mmBtu Duct Burner
KUA Cane Island 3	250	3.5 - (CT&DB)	DLN/SCR	170 MW GE 7FA. 11/99 Ammonia slip = 5 ppmvd
Calpine BHEC	1080	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 5 ppm
Calpine Delta	880	2.5 – (CT & DB) 1 hour average (LAER)	DLN/CSR	3 GE 7FA's or 3 WH 501FD's; 10 ppm max ammonia slip
Calpine Bullhead City	545	3.0 – (CT&DB)	DLN/SCR	Nearly identical to Osprey; Replace SCR catalyst after 36 mo.
Calpine Osprey	545	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 9 ppm
Stanton A (proposed)	700	3.5 - NG (CT &DB & PA) 10 – FO	DLN/SCR	Ammonia slip = 5 ppm

DB = Duct Burner DLN = Dry Low NO_X Combustion CT = Comb. Turbine PA = Power Augmentation
NG = Natural Gas SCR = Selective Catalytic Reduction DB = Duct Burner WH = Westinghouse
FO = Fuel Oil WI = Water or Steam Injection PA = Pwr. Augmentation GE = General Electric

TABLE 2

RECENT BACT LIMITS FOR CARBON MONOXIDE, VOLATILE ORGANIC COMPOUNDS, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Mobile Energy, AL	~18 – NG (CT&DB) ~26 – FO (CT&DB)	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Calpine BHEC	10 – NG (CT only) 17 – NG (off-normal)	1.2 – NG (CT) 6.6 – NG (DB & PA)	10% Opacity 26.0 lb/hr (CT & DB)	Clean Fuels Good Combustion
Calpine Delta	10 – NG (CT & DB) 10 – NG (DB & PA) 3 hr avg. – No Ox. Cat.	2 - NG	0.25 gr.S/100 scf Nat. Gas	Clean Fuels Good Combustion
Calpine Bullhead City	10 – NG (CT & DB) 33.9 – NG (DB & PA) 3 hour rolling average	1.5 - NG	18.3 lb/hr (CT) 22.8 lb/hr (DB & PA)	Clean Fuels Good Combustion
Calpine Osprey	10 – NG (CT only) 17 – NG (off-normal)	2.3 – NG (CT) 4.6 – NG (DB & PA)	10% Opacity 24.1 lb/hr (CT & DB)	Clean Fuels Good Combustion
Stanton A (proposed)	14 –FO (CT only) 17 – NG (all gas modes)	2.7 – FO 6.3 – NG (DB & PA)	10% Opacity 11.7 / 17 lb/hr (NG / FO)	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Master Overview for Alabama Power Plant Barry Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Letter from Black & Veatch to EPA Region IV dated March 10, 1999
- Letter from Black & Veatch to the Department and EPA Region IV dated March 24, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999
- Texas Natural Resource Conservation Commission Website – www.tnrcc.state.tx.us
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas, its use is minimized (1000 hours) for this project and control of NO_X emissions are proposed to be with SCR.

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 the proposed turbines. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_X control. However, 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. Standard combustor designs with wet injection can generally achieve NO_X emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NO_X emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs between 50% to 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Although the duct burners maximum heat input is 533 MMBtu/hr, it is relatively low when compared with the turbine that can accommodate a heat input greater than 2000 MMBtu/hr. The duct burners will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

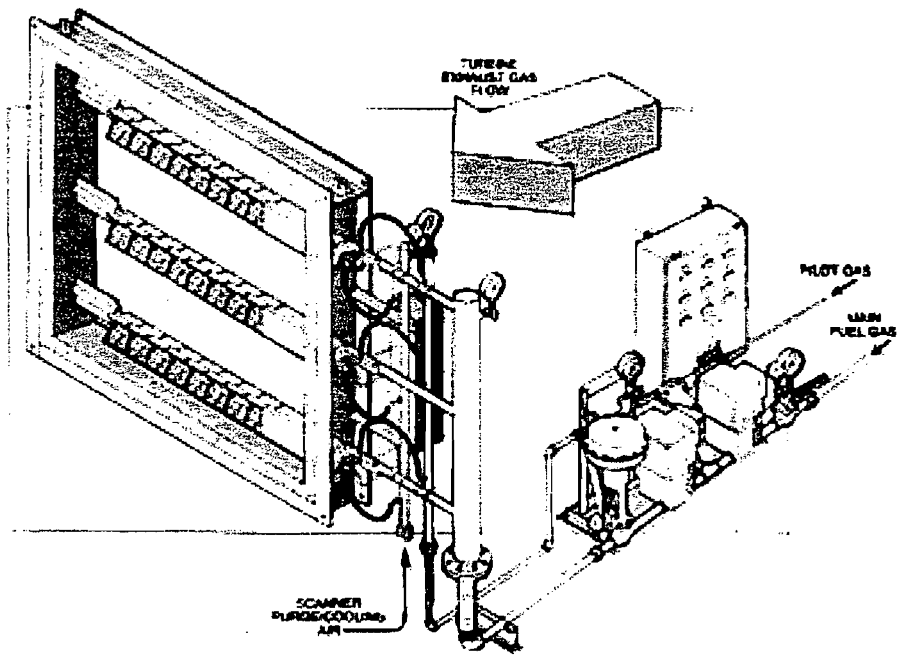


FIGURE A

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream within the HRSG. 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 but used in few applications to-date. 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 commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10 ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan. These newer catalysts (versus the older alumina-based catalysts) are resistant to sulfur fouling at temperatures below 770°F (EPRI). In fact, Mitsubishi reports that as of 1998, SCR's were installed on 61 boilers which combust residual oil (40 of which are utility boilers) and another 70 industrial boilers, which fire diesel oil. Likewise, B & W reports satisfactory results with the installation of SCR to several large Taiwan Power Company utility boilers, which fire a wide range of coals, as well as heavy fuel oil with sulfur contents up to 2.0% and 50 ppm vanadium. 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.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR.

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst 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 B

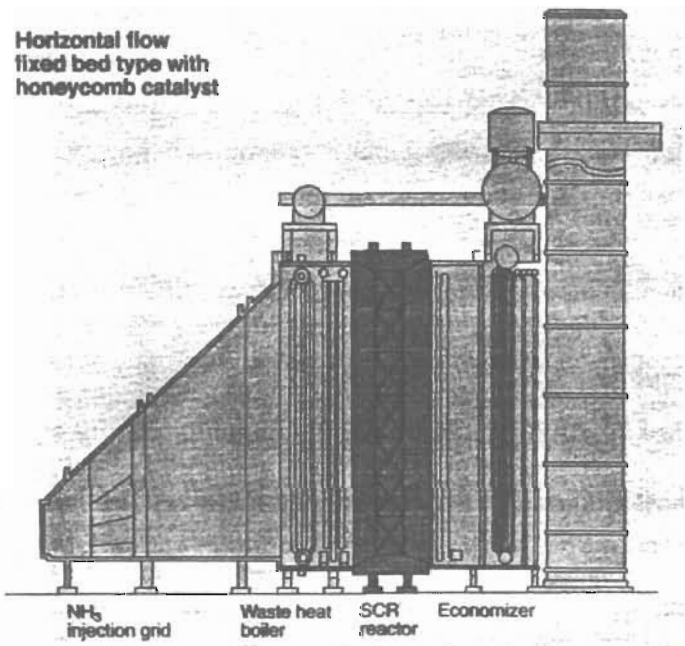


Figure C

Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits of 3.5 ppmvd NO_X are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SCNR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). However, the process also requires a low oxygen content in the exhaust stream in order to be effective. Given that a top-down review leads one to an SCR in this application, SNCR does not merit further consideration.

Emerging Technologies: SCONOx™ and XONON™

SCONOx™ is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ™[2]. The overall project includes several more 250 MW blocks with SCR for control.[3] According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two F frame units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system.

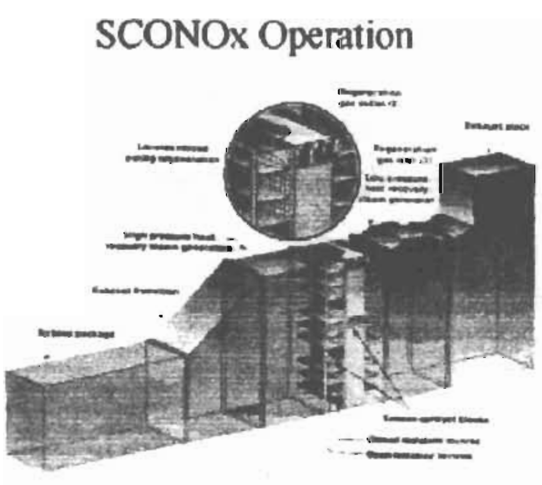


Figure D

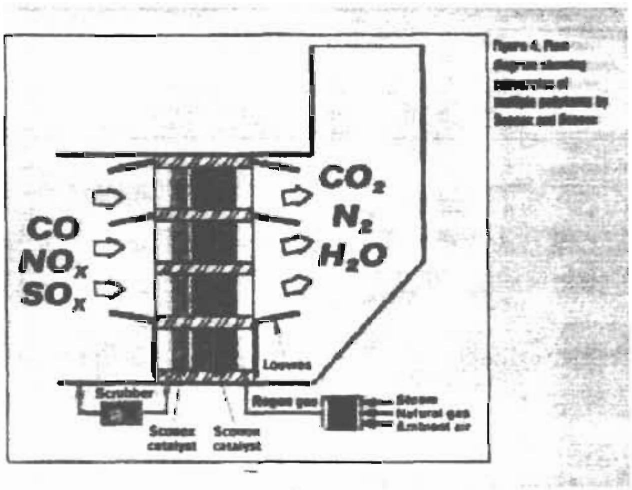


Figure E

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include (in addition to the reduction of NO_X) the elimination of ammonia and the control of VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit. The Department estimates that the application of this control technology to the Stanton A Combined Cycle Unit results in cost-effectiveness of just less than $10,000 per ton of NO_X removed. Although there are specific items within the applicant's original analysis (which estimates a cost effectiveness of $10,200 per ton of NO_X and CO removed from each CT/HRSG) that the Department cannot support (e.g. lost power revenues, contingency factors above 3%, etc.) on balance the Department concurs with the conclusion that $SCONO_X$ is not likely cost-effective for this project.

Catalytica Energy Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. 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 combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

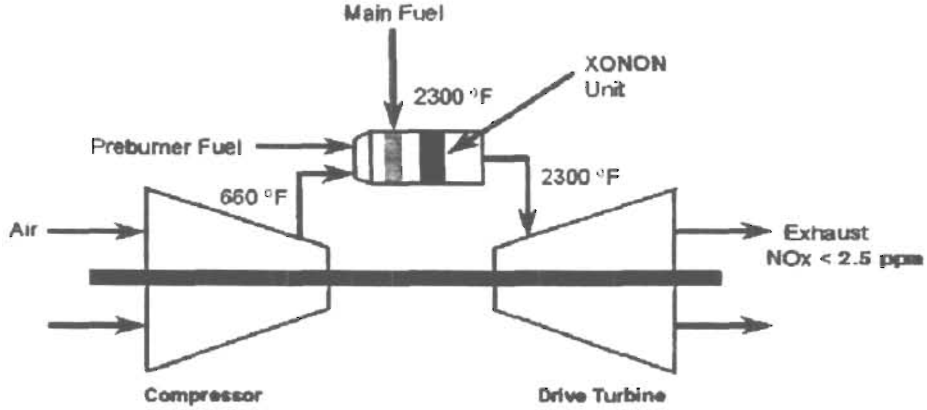
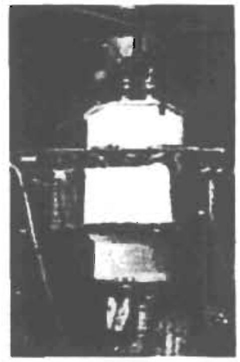


Figure F



XONON-2 installed with test instruments

Figure G

On February 8, 2001, Catalytica Energy Systems, Inc. announced that its XONON™ Cool Combustion system had successfully completed an evaluation process by the U.S. Environmental Protection Agency (EPA), which verified the ultra-low emissions performance of a XONON™-equipped gas turbine operating at Silicon Valley Power. The performance results gathered through the EPA's Environmental Technology Verification (ETV) Program provide high-quality, third party confirmation of XONON™'s ability to deliver a near-zero emissions solution for gas turbine power production. The verification, which was conducted over a two-day period on a XONON™-equipped Kawasaki M1A-13A (1.4 MW) gas turbine operating at Silicon Valley Power, recorded nitrogen oxides (NO_X) emissions of less than 2.5 parts per million (ppm) and ultra-low emissions of carbon monoxide and unburned hydrocarbons.

The XONON™-equipped Kawasaki M1A-13A gas turbine has operated for over 7400 hours at Silicon Valley Power (SVP), a municipally owned utility, supplying near pollution-free power to the residents of the City of Santa Clara, California, with NO_X levels averaging under 2.5 ppm. Three XONON™-equipped Kawasaki M1A-13X turbines, a slightly modified commercial version of the M1A-13A, are expected to enter commercial service in late 2001 in Massachusetts at a healthcare facility of a U.S. Government agency.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to the commercialization of the XONON™ system for new and existing GE gas turbines. The agreement provides for the collaborative adaptation of XONON™ combustion technology to GE gas turbines for commercial sale. In December 1999, GE accepted the first order for XONON™ -equipped GE 7FA gas turbines as the preferred emission control system for Enron's proposed Pastoria Energy Facility. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. However, the technology cannot (at this time) be recommended for the attendant project.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) AND SO_2 CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas is an inherently clean fuel and contains no ash. Natural gas and very low sulfur fuel oil (0.05%) will be the only fuels fired at the Stanton Combined Cycle Unit and they are efficiently combusted in gas turbines making any conceivable add-on control technique for PM/PM_{10} or SO_2 either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} as well as SO_2 is a combination of good combustion practices, fuel quality, and filtration of inlet air.

The applicant has identified PM emissions over 20 TPY from the fresh-water cooling towers. Accordingly, drift eliminators shall be installed to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for these types of cooling towers.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst (excluding the SCONOx ™ process).

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Calpine Sutter in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review, which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. OUC/KUA/FMPA/SO propose to meet a limit of 14 ppmvd while firing fuel oil above 50% output. However, the applicant prefers to be permitted with higher values of 18.1 ppmvd and 27.9 ppmvd for the full output operating modes of duct burner firing, and duct burner firing with power augmentation, respectively. Duct burner firing is requested for the entire year and power augmentation is requested for up to 1000 hours per year.

The Department has reviewed actual data from similar facilities and has reasonable assurance that the General Electric PG7241FA units selected by the applicant will achieve values well below those proposed by the applicant (and guaranteed by GE), without requiring installation of an oxidation catalyst. However, should the applicant desire to obtain a sufficient operating margin above the BACT established limit identified below, the permit will authorize the installation of oxidation catalysts at an established limit of 5 ppmvd CO, providing that the applicant installs the catalyst within 24 months of commercial operation. Otherwise, the Department will require the use of a CEMS for compliance on a 24-hour block average, with two limits depending upon actual operation. The limits will be:

a) 14 ppmvd based upon a 24-hour block average for all periods of fuel oil firing; otherwise, the limit is

b) 17 ppmvd for all operating modes, based upon a 24-hour block average, which is consistent with the recently issued determination made at Blue Heron Energy Center

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by the applicant for this project are 3.6 ppmvd for gas firing with duct burners, 2.7 ppmvd while firing oil and 6.3 ppmvd during operation with duct burners plus power augmentation. According to the applicant's submittals, VOC emissions less than 2 ppm will be achieved at 100% output and duct burners off. [5]

REVIEW OF HAZARDOUS AIR POLLUTANTS (HAPS) CONTROL TECHNOLOGIES

Based upon the application, this facility will not emit HAPS above the significance thresholds, which would require the application of MACT. However, some question exists concerning the accuracy of the proposed emission factors, particularly that of formaldehyde. The emission factors that have been proposed by the applicant are 8.42E-5 lb/MMBtu and 1.90E-4 lb/MMBtu for gas and oil respectively. According to EPA (Sims Roy memo dated 12-30-1999) the average formaldehyde factors for combustion turbines across all loads are 3.10E-3 lb/MMBtu and 2.81E-4 lb/MMBtu for gas and oil respectively. Although the discrepancy between the oil factors is fairly small, the applicant's gas factor is less than 3% of EPA's gas factor. FDEP must point out that the applicant's gas factor *is* within the range of factors reported by EPA (which is as low as 2.21E-6 lb/MMBtu) but the application of the EPA factor *would* subject the units to MACT. Additional EPA documentation on emission factors (from the same source as that proposed by the applicant, AP-42) suggests that the factor to be used is 7.10E-4 lb/MMBtu, which is approximately 8 times higher than that proposed by the applicant, and would also trigger a MACT review. Accordingly, the applicant's proposed emission factor may indeed be accurate for the proposed machine and configuration, and cannot be rejected outright, but must be known with a higher degree of accuracy. In order to resolve this question, each CT/HRSG will be required to undergo special testing for formaldehydes along with the other initial set of tests normally required. These tests will be structured so as to represent the PTE for formaldehydes at each of the maximum permitted operating modes. Should the results of this testing show that the emissions unit(s) will exceed 10 TPY of formaldehydes based upon maximum permitted conditions, the installation of an oxidation catalyst shall be required.

DEPARTMENT MACT DETERMINATION

Following are the MACT limits and testing protocol for formaldehyde at the Stanton A Combined Cycle project. Each CT/DB shall conduct tests and report emissions as per below and described within the permit:

OPERATING MODE	TEST PROTOCOL	TPY CALCULATION
Maximum CT output Natural Gas; Duct Burner firing at maximum output	CARB Method 430 or EPA Method 0011	(6760/2000) times measured Lb/Hour Formaldehyde
Maximum CT output Natural Gas; Duct Burner firing and Power Augmentation implemented, both at maximum output	CARB Method 430 or EPA Method 0011	(1000/2000) times measured Lb/Hour Formaldehyde
Maximum output, Fuel Oil	CARB Method 430 or EPA Method 0011	(1000/2000) times measured Lb/Hour Formaldehyde

Note: Results of the sampling method(s) shall be blank corrected.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Stanton A Combined Cycle project assuming full load. Values for NO_X and CO are corrected to 15% O_2. The emission limits (or their equivalents) as well as the applicable averaging times are itemized within the Specific Conditions of the permit.

POLLUTANT	CONTROL TECHNOLOGY	BACT
PM/PM_{10}, VE	Clean Fuels Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip
SO_2 / SAM	Clean Fuels	0.5 grains / 100 scf (gas) 0.05% Sulfur distillate oil for 1000 hrs / year
CO	Pipeline Natural Gas Good Combustion	17 ppmvd (all operating modes) gas – 24 hr. avg. 14 ppmvd (all operating modes) oil – 24 hr. avg. 5 ppmvd (CT & DB & PA) with ox. catalyst
VOC	Pipeline Natural Gas Good Combustion	3.6 ppmvd / 2.7 ppmvd (gas / oil) 6.3 ppmvd during DB plus PA 3 ppmvd (CT & DB & PA) with ox. catalyst
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2 (gas) 10 ppmvd @ 15% O_2 (oil)
PM - cooling tower	High efficiency drift eliminators	0.002% drift loss
Formaldehyde	Oxidation Catalyst	MACT requirement if > 10 TPY

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using $SCONO_X$.
- EPA Region IV advised that the Department (in a draft BACT) did not present "any unusual site-specific conditions associated with the KUA Cane Island 3 project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[6] The Fish & Wildlife Service had similar comments for Calpine Osprey Energy Center.[8]
- FDEP considers a 3-hour averaging time for NO_X compliance and a 5-ppmvd ammonia slip rate to be BACT, as can be seen in other recent BACT Determinations.
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[7]
- VOC emissions of < 2 ppm from the combustion turbine by Good Combustion proposed by the applicant are acceptable values determined as BACT. However, values less than 1 ppm have already been achieved on the DLN 2.6 combustors (GE 7FA) units after tuning.
- The CO emission rate will be verified continuously with CEMS. With the duct burner on, emissions will be less than 19 ppmvd, which is within the range of recent Department BACT determinations for combustion turbines alone. However, values as high as 28 ppmvd will not be authorized, as requested by the applicant. The CO limit will be 17 ppmvd on a weighted daily (24-hour block) average, which incorporates a reasonable allowance for all daily off-normal operations. In order to accommodate the applicant's concerns over the stringency of the limit, the installation of an oxidation catalyst will be authorized, provided that it is installed in a timely fashion.

- For reference, the CO limit for the FPL Fort Myers project is 12 ppmvd. Limits for the Santa Rosa Energy Center are 9 ppmvd with the duct burner off and 24 ppmvd with the duct burner on. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
PM/Visible Emissions	Method 5 (initial test only) and Method 9 (annually)
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	CEMS plus annual method 10 during operation at capacity without use of duct burners and power augmentation
VOC and CO with Oxidation Catalyst	Annual Method 18, 25 or 25A and Method 10 with Duct Burners and Power Augmentation
NO_X 3-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 or 7E
Formaldehyde	CARB Method 430 or EPA Method 0011

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable standard. These excess emissions periods shall be reported as required within the Specific Conditions of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two pollutant concentrations are obtained at least 15 minutes apart. The following emission levels represent excess emission *estimates* during startup periods:

STARTUP TYPE	TIME	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)				
		NO_X	SO_2	PM_{10}	VOC	CO
Natural Gas - Cold	4 hours	160	0	48	80	500
Natural Gas - Hot / Warm	2 hours	80	0	24	40	250

STARTUP TYPE	TIME	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)				
		NO_X	SO_2	PM_{10}	VOC	CO
Distillate Oil - Cold	4 hours	360	400	70	80	500
Distillate Oil - Hot / Warm	2 hours	180	200	35	40	250

The following emissions (TPY) are shown for informational purposes only. They represent a *conservative* estimate of annualized startup emissions, which are largely controllable through best operating practices.

Since each startup requires many hours of preceding shutdown time where emissions are zero, there will likely be *no annual net emission increase* from the previously estimated TPY:

STARTUP TYPE	NO. REQUIRED	NO_X	SO_2	PM_{10}	VOC	CO
Cold	48 (2 on oil)	4.1	0.4	1.2	1.9	12.0
Hot / Warm	240 (10 on oil)	10.1	1.0	0.7	4.8	30.0
Total	288 (12 on oil)	14.2	1.4	1.9	6.7	42.0

Excess emissions may occur under the following startup scenarios, subject to Rule 62-210.700, F.A.C. However, excess emissions resulting from startup, shutdown, or malfunction shall *only* be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

Hot / Warm Start: Two hours following a HRSG shutdown less than 72 hours.

Cold Start: Four hours following a HRSG shutdown greater than or equal to 72 hours.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:

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

Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

REFERENCES

[1] News Release. Goaline Environmental. Genetics Institute Buys SCONOx Clean Air System. August 20, 1999.

[2] "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

[3] Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.

[4] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[5] Application for Air Permit, Attachment 2 Performance Data – GE Performance Data Natural Gas Firing Only.

[6] Letter. Neeley, R. Douglas, EPA Region IV, to Fancy, C.H., FDEP. Draft PSD Permit – KUA Project. February 2, 1999.

[7] Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

[8] Letter. Porter, Ellen to Linero, A.A., FDEP. Technical Review of Prevention of Significant Deterioration Permit Application For Osprey Energy Center. April 17, 2000.

Memorandum

Florida Department of Environmental Protection

TO: ~~Clair Fancy~~ by AAL

THRU: Al Linero AAL

FROM: Michael P. Halpin MPH

DATE: May 17, 2001

SUBJECT: OUC Curtis H. Stanton Energy Center
Combined Cycle Addition
DEP File No. 0950137-002-AC (PSD-FL-313)

Attached is the public notice package for the addition of a combined cycle unit to be installed at OUC's Stanton Plant in Orlando. This project has been submitted as a joint application from four owners: OUC, KUA, FMPA and Southern Company – Florida, LLC, although the authorized representative is from Gulf Power. This permit will allow the installation of two General Electric 7FA CT's with flue gas routed through supplementary fired HRSGs (one for each CT), the steam from which will be sent to one steam turbine rated at approximately 300 MW. The maximum megawatt output will be approximately 700MW under specified conditions.

Nitrogen Oxides (NO_X) emissions from the gas turbines will be controlled by Dry Low NO_X (DLN-2.6) plus SCR for gas firing, and water injection plus SCR for oil firing. Emission limits for NO_X will be set at 3.5 ppmvd for gas firing and 10 ppmvd for oil firing. CO emissions will be limited to 17 ppmvd on a 24-hour average by CEMS (while firing natural gas) regardless of mode of operation. The use of 0.05% sulfur fuel oil will be allowed for up to 1000 hours per year on each CT, during which CO emissions will be limited to 14 ppmvd on a 24-hour average by CEMS.

Emissions of sulfur dioxide, SAM, volatile organic compounds and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and the design of the GE unit.

Based upon input from the EPA, the Department will require the applicant to validate the formaldehyde emission factor (which was utilized in the application) upon initial commissioning of the units. The results of that testing may require that the applicant install oxidation catalysts, and this has been provided for within the BACT and permit.

According to Buck Oven, this project is on a faster track than most projects, which are subject to the Siting Act, since it is a modification to an existing certification. In fact, Buck indicates that (barring a request for an extension of time) he needs to have the PSD work by no later than Tuesday, May 22nd. Fortunately, we were able to support the time-line and are prepared to issue as per the attached documentation.

I recommend your approval of the attached Intent to Issue.

AAL/mph

Attachments

P.E. Certification Statement

OUC/KUA/FMPA/Southern Company – Florida, LLC
Curtis H. Stanton Energy Center
Orange County

DEP File No.: 0950137-002-AC (PSD-FL-313)
Facility ID No.: 0950137

Project: PSD Permit

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).

Cleve Holladay and I conducted this review.

(Seal)

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

May 16, 2001
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

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

MAY 17 2001

RECEIVED
MAY 21 2001
BUREAU OF AIR REGULATION

4APT-ARB

Al Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Thank you for sending a copy of the prevention of significant deterioration (PSD) permit application for a project at the Curtis H. Stanton Energy Center in Orange County, Florida. The proposed project will consist of two combined cycle combustion turbine units. The following equipment is associated with the project: two 317-MW General Electric (Model PG7241FA) combined cycle combustion turbines with heat recovery steam generator (HRSG), supplemental duct firing, a 10-cell cooling tower, and a No. 2 distillate fuel oil storage tank. Natural gas will be the primary fuel for each unit, with No. 2 fuel oil as a backup. Based on the applicant's emission estimates, the pollutants subject to PSD review are nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

We have reviewed the permit application and have discussed our comments and concerns by telephone with Mr. Mike Halpin of the Florida Department of Environmental Protection (FDEP) on May 10, 2001. Our comments concerning the application are as follows:

1. We are especially interested in this project because it is subject to Florida Power Plant Siting Act requirements. The PSD permitting program for Power Plant Siting Act projects is a delegated program with FDEP acting on behalf of the U.S. Environmental Protection Agency (EPA).

2. The application states that the best available control technology (BACT) for sulfur dioxide emissions is combustion with inherently low sulfur content fuels - natural gas and fuel oil with less than 0.05 percent sulfur. Fuel oil with a sulfur content equal to 0.05 percent sulfur has been commonly cited as BACT for SO_2 emissions. Prior to issuing a draft permit, FDEP should confirm that the applicant can consistently meet a fuel oil sulfur content of less than 0.05 percent as proposed in the BACT assessment.

3. Based on the applicant's estimates, potential VOC emissions exceed 100 tons per year. The applicant should therefore provide a justification for an exemption from preconstruction ambient ozone monitoring. The applicant should also comment on whether VOC emissions of this magnitude are likely to result in an adverse ambient air quality impact with respect to ozone formation.

4. The application contains hazardous air pollutant (HAP) emission estimates for the combustion turbines. The formaldehyde emission factor stated in the application (8.42×10^{-6} lb/MMBtu) is said to be derived from AP-42. This factor, however, is approximately two orders of magnitude less than the direct AP-42 emission factor of 7.1×10^{-4} lb/MMBtu. The applicant should provide more information on the derivation of the formaldehyde emission factor for combustion turbines.

5. The permit application does not address how the applicant will minimize emissions during startups and shutdowns. EPA considers periods of startup and shutdown to be a part of normal source operation, and we encourage FDEP to regulate these emissions directly in the PSD permit. Startup and shutdown control options that could be considered include (but are not limited to) the following: limitations on the number of startups and shutdowns in any 12-month period; limitations on the number of hours allowed in any 24-hour period for excess NO_x and CO emissions due to startup and shutdown conditions; mass emission limits for NO_x and CO emissions during any 24-hour period to include emissions during startup and shutdown; and future establishment of startup and shutdown BACT emission limits for NO_x and CO derived from test results during the first few months of commercial operation. At a minimum, the permit should include a definition of the words startup and shutdown in terms of the observable operating conditions that indicate a period of startup and a period of shutdown.

6. The BACT cost analysis for catalytic oxidation contains the following questionable features: possible double counting of catalyst cost; property taxes equal to 2.75 percent of total capital investment rather than the 1 percent in the EPA *OAQPS Control Cost Manual*; and a cost for lost power generation that EPA generally considers inappropriate for electric power generation projects. Also, it is unclear how the $306,000 catalyst replacement cost was derived.

If you have any questions regarding these comments, please call Daphne Wilson at (404) 562-9118.

Sincerely,

Douglas Neeley

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

cc: M. Halpin
C. Holladay
R. Moore, Gulf Power
J. Vick, Gulf Power
R. Unruh, Black & Veatch
J. Bunyak, NPS
Z. Kozlov, CD
J. Buford
B. Oven, DEP

Memorandum

Florida Department of
Environmental Protection

RECEIVED

FEB 06 2001

BUREAU OF AIR REGULATION

TO: Al Linero
Len Kozlov
Geof Mansfield
Mary Jean Yon

FROM: Buck Oven

DATE: February 6, 2001

SUBJECT: Orlando Utilities Commission - Stanton Energy Center, Combined Cycle Unit A, Supplemental Application, PA 81-14SA2, Module 8024

OUC in conjunction with Kissimmee Utilities Authority (KUA), Florida Municipal Power Agency (FMPA) and Southern Company submitted on January 22, 2001, a supplemental application for certification of a natural gas-fired, combined cycle facility at the Stanton Energy Center. We have determined that the application is "complete" according to Siting rules. Black & Veatch are starting to distribute the application. Please have your respective staffs review the application for sufficiency and submit their comments to me by March 9, 2001.

cc: Scott Goorland

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

January 24, 2001

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Orlando Utilities Commission.
Curtis H. Stanton Energy Center
Facility ID No. 0950137-002-AC, PSD-FL-313

Dear Mr. Worley:

Enclosed for your review and comment is an application for Orlando Utilities Commission, in conjunction with Kissimmee Utility Authority, Florida Municipal Power Authority, and Southern-Florida to construct and operate a 633 MW electric generating unit at the existing Curtis H. Stanton Energy facility in Orange County, Florida

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Teresa Heron, review engineer, at 850/921-9529.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

cc: Teresa Heron

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

Black & Veatch Corporation

OUC/KUA/FMPA/Southern Co.
Stanton A Project

B&V Project 98362
B&V File 32.0500
April 25, 2001

Mr. Hamilton S. Oven
Administrator, Siting Coordination Office
Department of Environmental Protection
2800 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Re: Stanton Unit A Combined Cycle Project
Supplemental Site Certification Application
Department File No. PA 81-14SA2
DOAH Case No. 01-0416EPP
OGC Case No. 01-0176
Supplemental Information

Dear Mr. Oven:

On behalf of the Orlando Utilities Commission (OUC), the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA), and the Southern Company-Florida, LLC (Southern-Florida), Black & Veatch submits the following supplemental information in support of the Sufficiency Response filed with the Florida Department of Environmental Protection (Department) on April 23, 2001. Additional copies of this submittal have been provided to all parties controlling public review copies of the Stanton A Supplemental Site Certification Application.

The following information provides resolution of several of the air permit issues as identified in the March 12, 2001, sufficiency letter to Mr. Haddad, OUC. The issues were discussed between Mike Halpin, Department, and Dwain Waters, Southern-Florida, in a telephone conversation on April 18, 2001.

1. Request 1 concerned allotting hours for each off-normal mode of operation. Sufficiency Response 1 stated that operation using duct firing and evaporative cooling were considered normal modes, and off-normal modes (power augmentation and fuel oil firing) would be limited to 1000 hours/year. Final resolution of this issue incorporating the CO emissions limits discussed below will permit unlimited operation under normal, duct firing, and power augmentation modes. Stanton A will be permitted to operate 8760 hours/year firing natural gas, and 1000 hours/year firing fuel oil.

2. Request 2 concerned setting CO emission limits in ppm rather than lbs/hour. Sufficiency Response 1 stated that emission limits set as ppm would be acceptable, and proposed BACT

results. Final resolution of this issue will limit CO emissions to 17 ppm (@ 15% O_2) based on a 24-hour average for normal operation on natural gas, and 14 ppm (@ 15% O_2) for normal operation on fuel oil. These limits do not include startup operations.

3. There are no outstanding issues concerning Requests 3 and 4.

4. Request 5 concerned the use of an oxidation catalyst to control CO emissions. Sufficiency Response 5 stated that installation of an oxidation catalyst was not planned for the project due to costs and low annual emissions levels. Final resolution of this issue will incorporate a provision into the air permit that would require the installation of an oxidation catalyst if necessary to meet the CO emission limits listed in paragraph 2 above. The applicants have also agreed to install a continuous emissions monitoring (CEM) system for CO.

5. Request 6 concerned the level of ammonia slip (5 ppmvd) from the SCR. Sufficiency Response 6 proposed a 10 ppmvd ammonia slip. The applicants have agreed to a 5 ppmvd standard with annual testing to demonstrate compliance. No CEM or reporting other than the annual compliance demonstration will be required for ammonia slip.

6. There are no outstanding issues concerning Request 7.

7. Request 8 concerned the number of hours and emissions during startups. Sufficiency Response 8 stated that these estimates could not be provided, but that the applicants would accept standard language regarding startup limitations. The following estimates have been developed and are provided for final resolution of this issue. The estimated number of cold startups per turbine per year is 24; the estimated number of warm or hot startups per turbine per year is 120. The following estimated emissions are for informational use only and should be noted in the permit as "for informational use only".

Estimated Emissions During Start-up Operations Per Turbine Per Event

	NO_x	SO_2	PM_{10}	VOC	CO
Operational Profile on Natural Gas					
CTG cold start-up (4 hours)(lbs/event)	160	0	48	80	500
CTG warm start-up (2 hours)(lbs/event)	80	0	24	40	250
Operational Profile on Fuel Oil					
CTG cold start-up (4 hours)(lbs/event)	360	400	70	80	500
CTG warm start-up (2 hours)(lbs/event)	180	200	35	40	250

8. There are no outstanding issues concerning Request 9.

9. Request 10 concerned revision of the economic analyses. Sufficiency Response 10 either revised or justified the use of several evaluation factors. Final resolution of this issue has removed the lost power revenue criterion and revised the contingency factor to 3 percent. The revised cost analysis tables are included herein.

We appreciate the Department's cooperation and efforts during the review of the application. Please insert this letter in the Sufficiency Response volume of the Stanton A Supplemental Site Certification Application immediately behind the FDEP tab. If you have any questions concerning the project or this submittal, please do not hesitate to call me at (913) 458-7563 or Fred Haddad of OUC at (407) 236-9698.

Very truly yours,

BLACK & VEATCH CORPORATION

Michael Soltys

J. Michael Soltys
Site Certification Coordinator

JMS:slm
Enclosure[s]

cc: Mr. Frederick Haddad, OUC
Certificate of Service List
M. Halpin
C. Halladay
J. Kozlov, CD
B. Worley, EPA
G. Bunyak, NPS

bcc:

T. Buford, YVV&A
J. Vick, SOFL
L. Curtin, H&K
F. Haddad, OUC
B. Sharma, KUA
S. Miles, SOFL
R. Casey, FMPA (2)
D. Stalls, OUC
T. Tart, OUC
S. Comensky, SOFL
M. Wimberly, SOFL
R. Forry, SOFL
G. Martin, SOFL
R. Terry, SOFL
J. Franklin, SOFL
A. Nebrig, SOFL
F. Bryant, FMPA
O. Harper, SOFL
B&V CDC
B&V Law Library
B. Hinshaw, SOFL
M. French, SOFL
M. Stover, B&V
R. Young, YVV&A
M. Serafin, B&V
K. Lucas, B&V
T. Hillman, B&V
M. Stover, B&V
M. Rollins, B&V
L. Krop, B&V

OUC/KUA/FMPA/Southern Co.
Stanton A

B&V Project 98362
April 25, 2001

CERTIFICATE OF SERVICE

I Certify that a true and correct copy of this Supplemental Information was mailed to the following on this 26th day of April 2001:

Mike McGovern, SJRWMD	Tom Ballinger, PSC
Brad Hartman, FFWCC	Debra Swim, LEAF
Greg Golgowski, ECFRPC	Clair Fancy, FDEP (4)
Ajit Lalchandani, Orange County	Paul Darst, DCA
James Hollingshead, SJRWMD (3)	George Percy, DHR
Sandra Whitmire, FDOT	Pepe Menedez, DOH
Vivian Garfein, FDEP-Orlando (4)	Anthony Cotter, Orange County
Jim Golden, SFWMD	Teresa Remudo-Fries, Orange County
Marc Ady, SFWMD	Charles Lee, Audubon Society
Dorothy Field, Orlando Public Library	

Michael Soltys

J. Michael Soltys

Table 4-4
Combined NO_X and CO Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit.

	$SCONO_X$ System	SCR/ Oxidation Catalyst	LNB	Remarks
Direct Capital Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3 in BACT
SCR & Oxidation Catalyst System	N/A	1,907,000	N/A	Estimated from Engelhard Corporation.
$SCONO_x$ System (Includes catalyst)	19,800,000	N/A	N/A	Estimated from Alstom Power.
Catalyst Reactor Housing	Included	268,000	N/A	Estimated by Alstom Power & scaled from an estimate by Engelhard Corporation.
Control/Instrumentation	Included	180,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia (Storage & Handling))	N/A	200,000	N/A	Estimated from previous projects.
Purchased Equipment Costs	19,800,000	2,555,000	N/A	
Sales Tax	N/A	N/A	N/A	No sales tax on generating equipment for this project.
Freight	Included	128,000	N/A	5% of Purchased Equipment Costs
Total Purchased Equipment Costs (PEC)	19,800,000	2,683,000	N/A	
Direct Installation Costs				
Balance of Plant	Included	805,000	N/A	For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting. SCONOx bid included installation.
Total Direct Cost Less Catalyst	**19,570,000**	**1,998,000**	Base	Catalyst cost is excluded as annual O&M cost. SCR and oxidation catalyst costs are $826,000 and $664,000, respectively. SCONOx replacement cost estimate is $230,000 per year, based on a 10-year life.
Indirect Capital Costs				
Contingency	594,000	80,000	N/A	For SCR and SCONOx: 3% of Total PEC
Engineering and Supervision	Included	268,000	N/A	For SCR: 10% of Total PEC
Construction & Field Expense	198,000	134,000	N/A	For SCR: 5% of Total PEC; For SCONOx 1% of Total PEC
Construction Fee	297,000	268,000	N/A	For SCR: 10% of Total PEC; For SCONOx 1.5% of Total PEC
Start-up Assistance	Included	54,000	N/A	For SCR: 2% of Total PEC
Performance Test	40,000	27,000	N/A	For SCR: 1% of Total PEC; For SCONOx 0.2% of Total PEC
Total Indirect Capital Costs	1,129,000	831,000	Base	
Total Installed Cost (TIC)	**20,699,000**	**2,829,000**	Base	

Table 4-5 Combined NO_x and CO Control Annualized Cost Per GE 7FA CTG/HRSG Unit				
	$SCONO_X$ System	**SCR/Oxidation Catalyst**	**LNB**	**Remarks**
Direct Annual Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3 in BACT
Catalyst Replacement	40,000	686,000	N/A	Catalyst life of 3 year for SCR/Oxidation catalyst and 10 year life for SCONOx catalyst.
Operation and Maintenance	310,000	40,000	N/A	Estimated from Alstom Power & includes catalyst washing and materials. For SCR/Oxidation catalyst assumed 2 hr/day, 8,760 hr/yr at $40/hr and includes materials.
Reagent Feed	N/A	87,000	N/A	Assumes 1.4 stoichiometric ratio.
Natural Gas Consumption	218,000	N/A	N/A	Based on 340-lb/hr natural gas consumption.
Power Consumption	4,000	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR and damper actuation for $SCONO_x$.
Annual Distribution Check	N/A	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less the catalyst cost.
Total Direct Annual Cost	572,000	828,000	N/A	
Indirect Annual Costs				
Overhead	31,000	24,000	N/A	For SCR 60% of O&M Cost; For SCONOx: 10% of O&M Cost
Administrative Charges	62,000	57,000	N/A	For SCR 2% of Total Installed Cost; For SCONOx: 0.3% of TIC
Property Taxes	103,000	78,000	N/A	For SCR 2.75% of Total Installed Cost; For SCONOx: 0.5% of TIC
Insurance	41,000	28,000	N/A	For SCR 1% of Total Installed Cost; For SCONOx: 0.2% of TIC
Capital Recovery	2,273,000	311,000	N/A	Capital Recovery Factor (0.1098) times the Total Installed Cost
Total Indirect Annual Costs	2,510,000	498,000	N/A	
Total Annualized Cost	**3,082,000**	**1,326,000**	N/A	
Annual Emissions, tpy	144.1	220.1	918.5	Emissions taken from Tables 4-1, 4-2 and 4-3 in BACT
Emissions Reduction, tpy	774.3	698.3	N/A	Emissions calculated from Tables 4-1, 4-2, 4-3 in BACT
Total Cost Effectiveness, $/ton	**4,000**	**1,900**	N/A	Total Annualized Cost / Emissions Reduction
Incremental Annualized Cost	**1,756,000**	N/A	N/A	Total annualized SCR/Oxidation catalyst system cost minus the total annualized SCONOx system cost
Incremental Reduction	**23,000**	N/A	N/A	Total Incremental Annualized Cost / Incremental Emissions Reduction

Table 4-6 NO_x Control Capital Cost Per GE 7FA CTG/HRSG Unit			
Cost Item	**SCR**	**Low NO_x Burners**	**Remarks**
Direct Capital Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
SCR Catalysts System	1,161,000	N/A	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	N/A	Scaled from an estimate from Engelhard Corporation
Control/Instrumentation	140,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia Injection/Dilution Equipment	Included	N/A	Estimated from Engelhard Corporation
Ammonia Storage	200,000	N/A	Estimated from previous projects
Purchased Equipment Costs	1,769,000	N/A	
Freight	88,000	N/A	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,857,000	N/A	
Direct Installation Costs			
Balance of Plant	557,000	N/A	For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting
Total Direct Cost Less Catalyst	1,588,000	Base	Cost Catalyst cost is excluded as annual O&M cost. SCR catalyst cost is $826,000.
Indirect Capital Costs			
Contingency	56,000	N/A	3% of Total Purchased Equipment Cost
Engineering and Supervision	186,000	N/A	10% of Total Purchased Equipment Cost
Construction & Field Expense	93,000	N/A	5% of Total Purchased Equipment Cost
Construction Fee	186,000	N/A	10% of Total Purchased Equipment Cost
Start-up Assistance	37,000	N/A	2% of Total Purchased Equipment Cost
Performance Test	19,000	N/A	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	577,000	Base	
Total Installed Cost	**2,165,000**	Base	

Table 4-7
NO_x Control Annualized Cost Per GE 7FA CTG/HRSG Unit

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	380,000	N/A	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	36,000	N/A	See text for background information on this item
Reagent Feed	87,000	N/A	Assumes 1.4 stoichiometric ratio
Power Consumption	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR
Annual Distribution Check	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less catalyst cost
Total Direct Annual Cost	518,000	N/A	
Indirect Annual Costs			
Overhead	22,000	N/A	60% of O&M Cost
Administrative Charges	43,000	N/A	2% of Total Installed Cost
Property Taxes	60,000	N/A	2.75% of Total Installed Cost
Insurance	22,000	N/A	1% of Total Installed Cost
Capital Recovery	238,000	N/A	Capital Recovery Factor (0.1098) times Total Installed Cost
Total Indirect Annual Costs	385,000	N/A	
Total Annualized Cost	**903,000**	N/A	
Annual Emissions, tpy	145.4	524.1	Emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	378.7	N/A	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, $/ton	**2,400**	N/A	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 System	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	Catalyst cost is excluded as annual O&M cost. Oxidation catalyst cost is $664,000.
Indirect Capital Costs			
Contingency	33,000	NA	3% 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	343,000	Base	
Total Installed Cost	**1,118,000**	Base	

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
Total Direct Annual Cost	310,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Cost
Administrative Charges	22,000	NA	2% of Total Installed Cost
Property Taxes	31,000	NA	2.75% of Total Installed Cost
Insurance	11,000	NA	1% of Total Installed Cost
Capital Recovery	123,000	NA	Capital Recovery Factor (0.1098) times Total Installed Cost
Total Indirect Annual Costs	189,000	NA	
Total Annualized Cost	**499,000**	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	**1,600**	NA	Total Annualized Cost/Emissions Reduction

Table 6-3
VOC Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Oxidation Catalyst System	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; includes controls and monitoring equipment
Purchased Equipment Costs	1,054,000	NA	
Freight	53,000	NA	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,107,000	NA	
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	Catalyst cost is excluded as annual O&M cost. Oxidation catalyst cost is $664,000.
Indirect Capital Costs			
Contingency	33,000	NA	3% 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	343,000	Base	
Total Installed Cost	**1,118,000**	Base	

Table 6-4

VOC 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 6-1 and 6-2
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
Total Direct Annual Cost	310,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Cost
Administrative Charges	22,000	NA	2% of Total Installed Cost
Property Taxes	31,000	NA	2.75% of Total Installed Cost
Insurance	11,000	NA	1% of Total Installed Cost
Capital Recovery	123,000	NA	Capital Recovery Factor (0.1098) times Total Installed Cost
Total Indirect Annual Costs	189,000	NA	
Total Annualized Cost	**499,000**	NA	
Annual Emissions, tpy	36.9	45.8	Emissions taken from Tables 6-1 and 6-2
Emissions Reduction, tpy	8.9	NA	Emissions calculated from Tables 6-1 and 6-2
Total Cost Effectiveness, $/ton	**56,000**	NA	Total Annualized Cost/Emissions Reduction

Curtis H. Stanton Energy Center
Combined Cycle Unit A

RECEIVED
APR 23 2001
BUREAU OF AIR REGULATION

Sufficiency Report

Manual Number CHSEC- 007

Issued To C. Fancy

Location CDC Mail

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114 USA

Tel: (913) 458-2000

Black & Veatch Corporation

OUC/KUA/FMPA/Southern Co.
Stanton A Project

B&V Project 98362
B&V File 32.0500
April 20, 2001

Mr. Hamilton S. Oven
Administrator, Siting Coordination Office
Department of Environmental Protection
2800 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Stanton Unit A Combined Cycle Project
Supplemental Site Certification Application
FDEP File No. PA 81-14SA2
DOAH Case No. 01-0416EPP
OGC Case No. 01-0176
Response to Statement of Sufficiency

Dear Mr. Oven:

On behalf of the Orlando Utilities Commission, the Kissimmee Utility Authority, the Florida Municipal Power Agency, and the Southern Company-Florida, LLC, and as required by Chapter 403.5067(1)(a) of the Florida Statutes, Black & Veatch submits seven (7) copies of the response to the Statement of Sufficiency received from the Department on March 13, 2001. The seven copies correspond to your assigned Controlled Document copies 1–5 and 40-41 of the Supplemental Site Certification Application.

We appreciate the Department's cooperation and efforts during the review of the application. If you have any questions concerning the project or this submittal, please do not hesitate to call me at (913) 458-7563 or Fred Haddad of OUC at (407) 236-9698.

Very truly yours,

BLACK & VEATCH CORPORATION

Michael Soltys

J. Michael Soltys
Site Certification Coordinator

Enclosures

cc: Certificate of Service List

CERTIFICATE OF SERVICE

I Certify that a true and correct copy of the Response to Statement of Sufficiency was mailed to the following on this 20TH day of April 2001:

Mike McGovern, SJRWMD	Tom Ballinger, PSC
Brad Hartman, FFWCC	Debra Swim, LEAF
Greg Golgowski, ECFRPC	Clair Fancy, FDEP (4)
Ajit Lalchandani, Orange County	Paul Darst, DCA
James Hollingshead, SJRWMD (3)	George Percy, DHR
Sandra Whitmire, FDOT	Pepe Menedez, DOH
Vivian Garfein, FDEP-Orlando (4)	Anthony Cotter, Orange County
Jim Golden, SFWMD	Teresa Remudo-Fries, Orange County
Marc Ady, SFWMD	Charles Lee, Audubon Society
Dorothy Field, Orlando Public Library	

Michael Soltys

J. Michael Soltys

Department of Environmental Protection

AIR

1. *The emission limits proposed within the application are based upon the premise that for every hour of the year the unit will be operating with either duct burners firing, in power augmentation mode or firing fuel oil. Based upon its extensive history of permitting combustion turbines during the past two years, the Department does not find this to be reasonable for the determination of permit limits. An allotment of hours for each off-normal mode of operation will be assigned, which is consistent with prior BACT determinations.*

   Response: The Stanton Combined Cycle Unit A PSD Application requests the ability to operate at a normal combined cycle mode for up to 8,760 hours per year per CT (includes evaporative cooling and duct firing). Alternative modes of operation requested in the application include power augmentation mode at 1,000 hours per year per CT and operation using distillate fuel oil also at 1,000 hours per year per CT. Power augmentation and fuel oil operating scenarios are considered "off-normal" modes of operation.

2. *The application requests emission limits of CO to be set in lb/hr rather than concentration limits. The Department evaluates BACT for CO based upon concentration rather than mass emission rates, and assigns permit limits in the same fashion.*

   Response: The Stanton Combined Cycle Unit A PSD Application proposes BACT for CO to be good combustion control to achieve a CO emission limit of 18.1 ppmvd at 15% O_2 for normal combined cycle operation (duct burner), 26.3 ppmvd at 15% O_2 for power augmentation, and 14.3 ppmvd at 15% O_2 for fuel oil operation. The BACT analysis and conclusions are found in Section 3: Best Available Control Technology, Page 3.1, Section 4.9: Conclusions, Page 4-33 and Section 9.0: Conclusions, Page 9-1.

   Emissions limits for CO in ppm are acceptable to the applicants.

3. *Please confirm the Department's interpretation of the following CO emissions at 100 percent CT output:*

Case Pounds Per Hour	*Operating Mode*	*ppmvd @ 15%O_2*	lbs/hr
1	*CT operating at 19 degrees F*	*7.4*	*31.0*
13	*CT with cooling (EC) and duct burners (DB) at 70 degrees F*	*18.1*	*87.51*
18	*CT with EC, DB and power augmentation at 95 degrees F*	*27.9*	*142.51*
20	*CT on oil at 19 degrees F*	*14.7*	*71.0*

Response: The above reference data is correct and is based upon GE emission level guarantees.

4. *Please explain the Oxidation Catalyst economic analysis with regard to emissions reductions. According to the Air Construction application form (page 22) maximum requested annual CO emissions are up to 448.12 TPY (gas firing). Considering that the CO emissions resulting from an oxidation catalyst are 74.7 TPY, an emission reduction of 373.42 TPY should be evaluated rather than 319.7 TPY.*

Response: The difference in numbers referenced above is due to a BACT analysis based on emissions at a standardized temperature (70° F), whereas the emissions noted on Page 22 are maximum potential emissions for each worst case operating mode at various temperatures (i.e., 19°, 45°, 60°, 75°, and 95° F). The economic analysis (per ton of reduction) as outlined in the application for the BACT will be the same if based on either temperature scenario as long as the comparison remains consistent between the PTE and BACT. The economic analysis was done at a standardized temperature (70° F) to keep the analysis as simple as possible between the various BACT parameters.

5. *Based upon the requested permit levels of CO and related submittals, the application appears to support the installation of an oxidation catalyst. However, the Department wishes to point out that recent tests from TECO's Polk Power Station 7FA resulted in CO emissions of less than 1 ppmvd (gas) and less than 2 ppmvd (oil) at full load. Although contracting for CO limits between GE and its customers may not have caught up with field experience, actual results should be considered in the setting of BACT.*

Response: The BACT analysis for CO was based on base case emissions of 394.4 tons per year per CT. This annual rate assumes CT operation for 6,760 hours at 100% load with duct burner firing and 1,000 hours per year at 100% load with steam augmentation and 1000 hours per year at full load on fuel oil. The negative economic impacts, due to an oxidation catalyst, include increased production costs due to decreased efficiency, increased capital cost for the installation of the oxidation catalyst, and increased operating cost due to periodic replacement of the oxidation catalyst. The capital cost and annualized cost for installing an oxidation catalyst is $1,306,000 and $570,000. For 80 percent removal of 74.7 tons per year CO emission, the removal efficiency is $1,800 per ton removed. Annual operation will be such that CO emissions will stay under 394.4 tons per year. Therefore, installation of an oxidation catalyst is not planned for this project. Based on FDEP's internet site, the results of TECO's Polk Power Station 7FA (SCCT) are achieved by good combustion practices. Although they are able to achieve low CO emissions, there are many variables that may not be the same for the Stanton Unit A Project. The ability to tune a combustion turbine to such low loads depends on such items as: fuel quality, ambient temperature and type of combustion system. Stanton Unit A proposes more fuel oil firing (1,000 hours per year versus 750 hours per year) than the TECO Polk facility and 1,000 hours per year of power augmentation that would require the ability of the CT to consistently reduce CO emissions to approximately 96 percent. Unless GE can 100 percent guarantee they are able to achieve lower CO emissions than in their performance data, the AQCS will have concerns and would advise not setting BACT limits for emissions that the combustion turbine manufacturer will not guarantee. It should also be noted that in speaking to TECO on their performance levels, they stated that they could not guarantee these low emissions over time.

The CO exhaust concentration for the CT at 100% load, ambient temperature with duct burner firing (Case 13) is 18.1 ppmvd corrected to 15% O_2, and 27.9 for operations with power augmentation. These concentrations are consistent with recent FDEP CT BACT determinations for CO; e.g., City of Tallahassee Purdom Unit No. 8 (BACT CO concentration of 25 ppmvd), Lakeland Electric and Water Utilities Unit No. 5 (BACT CO concentration of 25 ppmvd) and Gulf Power Smith 3 (BACT CO concentration of 16 ppmvd for duct burner and 23 ppmvd for power augmentation). Furthermore, Table 1 and 2 list CCCT and SCCT facilities located in Florida, respectively, that have been recently permitted without the installation of an oxidation catalyst. The CCCT and SCCT units shown in Tables 1 and 2 use either dry low NO_x (DLN) or good combustion practice (GCP) or a combination of both to control CO emissions during natural gas (NG) and fuel oil (FO) firing.

Table 1
Summary of Recent CCCT Units Permitted Without an Oxidation Catalyst

State	Permit Date	Facility	# of CTs	Turbine Model	Fuel	Hours	CO Limit	Control Method
NH	Apr-99	Newington Energy (525 MW total)	2	GE 7FA	NG; FO	8,760; 720 FO	15 ppm	GCP
NH	Apr-99	AES Londonderry LLC (720 MW total)	2	SW 501G	NG; FO	8,760; 720 FO	15 ppm	GCP
AL	Dec-97	Alabama Power – Olin Cogeneration	1	GE 7EA (80 MW)	NG	8,760	0.07 lb/MMBtu	GCP
AL	May-98	Alabama Power – GE Plastics Cogeneration	1	GE 7EA (80 MW)	NG	8,760	0.08 lb/MMBtu (combined)	GCP
AL	Aug-98	Alabama Power, Plant Barry	3	GE 7FA (170 MW)	NG	8,760	0.057 lb/MMBtu	GCP
AL	Aug-98	Alabama Power, Plant Barry	1	GE 7FA (170 MW)	NG	8,760	0.060 lb/MMBtu	GCP
AL	Jan-99	Mobile Energy, LLC – Hog Bayou	1	GE 7FA (168 MW)	NG; FO	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/MMBtu FO	GCP
AL	Mar-99	Alabama Power – Theodore Cogeneration Facility	1	GE 7FA (170 MW)	NG	8,760	0.086 lb/MMBtu	GCP
AL	Nov-99	Tenaska Alabama Partners	3	GE 7FA (170 MW)	NG; FO	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP
AL	Apr-00	Georgia Power – Goat Rock	8	GE 7FA (170 MW)	NG	8,760	0.086 lb/MMBtu	GCP
FL	Jul-00	City of Lakeland, McIntosh Power Plant (SC, later CC)	1	SW 501G (230 MW)	NG; FO	7,008; 250 FO	25 ppm NG; 90 ppm FO	GCP
FL	Dec-98	Santa Rosa Energy Center, Sterling Fibers Mfg. Facility	1	GE 7FA (167 MW)	NG	8,760	9 ppm; 24 ppm w/ DB	GCP
FL	Nov-99	Kissimmee Utility Authority, Cane Island Power Park –Unit 3	1	GE 7FA (167 MW)	NG; FO	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP
FL	Nov-99	Lake Worth Generation	1	GE 7FA (170 MW)	NG; FO	8,760; 1,000 FO	12 ppm NG; 20 ppm FO	GCP
FL	Sep-99	Florida Power & Light – Sanford	8	GE 7FA (170 MW)	NG, FO	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP
FL	Feb-00	Gainesville Regional Utilities, Kelly Generating Station	1	GE 7EA (83 MW)	NG; FO	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP

Table 1 (Continued)
Summary of Recent CCCT Units Permitted Without an Oxidation Catalyst

State	Permit Date	Facility	# of CTs	Turbine Model	Fuel	Hours	CO Limit	Control Method
FL	Sep-98	FPL Fort Myers	6	GE 7FA (170 MW)	NG	8,760	9 ppm	GCP
FL	Draft Permit	Hines Energy (FPC)	2	SW 501F (165 MW)	NG; FO	8,760; 1,000 FO	25 ppm NG - full load; 30 ppm FO	GCP
MS	Nov-97	LS Power Limited Partnership	3	SW 501G (281 MW)	NG; FO	8,760 (up to 10% FO)	30.3 ppm NG; 36 ppm FO	GCP
MS	Dec-98	Mississippi Power Corp., Plant Daniel	4	GE 7FA (170 MW)	NG	8,760	0.057 lb/MMBtu	GCP
MS	Apr-00	Duke Energy Attala, L.L.C.	2	GE 7FA (170 MW)	NG	8,760	20 ppm	GCP
IL	Dec-01	Peoples Gas, McDonell Energy	10	250 MW	NG, ethane	8,760	0.031 lb/MMBtu	GCP
IL	Jun-99	LS Power, Kendall Energy	4	220 MW	NG	8,760	0.0626 w/DB, 0.0511no DB, >75% load	GCP
IL	Jul-99	Reliant Energy, Cardinal	3	211 MW	NG, RFG	8,760	0.0472 lb/MMBtu	GCP
IL	Sep-99	Mid America, Cordova Energy Center	2	290 MW	NG	8,760	0.0547 lb/MMBtu: loads > 75%, after 9/2001	GCP
IL	Jan-00	LS Power, Nelson Project	4	220 MW	NG; FO	8,760	0.0626 w/DB, 0.0511no DB; >75% load	GCP
IL	Feb-00	Ameren CIPS	2	600 MW	NG	8,760	0.06 lb/MMBtu	GCP

Table 2
Summary of Recent SCCT Units Permitted without an Oxidation Catalyst

State	Permit Date	Facility	Turbine Model	Fuel	Hours	CO Limit	Control Method
FL	Oct-99	Polk Power (TECO)	GE 7 FA (165 MW) x2	NG; FO	5,130; 750 FO	15 ppm NG; 33 ppm FO	GCP
FL	Nov-99	Oleander Power	GE 7FA (190 MW) x5	NG; FO	3,390; 1,000 FO	12 ppm NG; 20 ppm FO	GCP
FL	Dec-99	Reliant Energy Osceola	GE 7FA (170 MW) x3	NG; FO	3,000; 2,000 FO	10.5 ppm NG; 20 ppm FO	GCP
FL	Oct-99	Jacksonville Electric Authority – Brandy Branch	GE 7FA (170 MW) x3	NG; FO	4,000; 800 FO	15 ppm NG; 20 ppm FO	GCP
FL	Dec-99	IPS Avon Park Corp. - Vandola Power Project	GE 7FA (170 MW) x4	NG; FO	3,390; 1,000 FO	12 ppm NG; 20 ppm FO	GCP
FL	Jan-00	IPS Avon Park – Shady Hills	GE 7FA (170 MW) x3	NG; FO	3,390; 1,000 FO	12 ppm NG; 20 ppm FO	GCP
FL	Jun-00	Palmetto Power	SW 501F (180 MW) x3	NG	3,750	25 ppm (15 ppm after 1st yr.)	GCP
GA	Dec-98	Tenaska Georgia Partners, L.P.	GE 7FA (160 MW) x6	NG; FO	3,066; 720 FO	15 ppm NG; 20 ppm FO	GCP
GA	Jun-99	West Georgia Generating; Thomaston	GE 7FA (170 MW) x4	NG; FO	4,760; 1,687 FO	15 ppm NG; 20 ppm FO	GCP
GA	Oct-99	Heard County Power	SW 501FD (170 MW) x3	NG	4,000	25 ppm	GCP
GA	Aug-99	Georgia Power, Jackson County	GE 7EA (76 MW) x16	NG; FO	4,000; 1,000 FO	0.101 lb/MMBtu NG; 0.046 lb/MMBtu FO	GCP
NC	Nov-99	Carolina Power & Light, Richmond Co.	GE 7FA (170 MW) x7	NG; FO	2,000; 1,000 FO	15 ppm NG; 20 ppm FO	GCP
NC	Nov-99	Carolina Power & Light, Rowan Co.	GE 7FA (170 MW) x5	NG; FO	2,000; 1,000 FO	15 ppm NG; 20 ppm FO	GCP
NC	Jun-99	Rockingham Power (Dynegy)	SW 501F (156 MW) x5	NG; FO	3,000; 1,000 FO	25 ppm NG; 50 ppm FO	GCP
WI	Jan-99	RockGen Energy	GE 7FA (175 MW) x3	NG; FO	3,800 Total 800 FO	12 ppm NG; 15 ppm FO (load>75%) & 24 ppm FO (load<75%)	DLN, GCP
WI	Feb-99	Southern Energy	GE 7FA (180 MW) x2	NG; FO	8,760 Total, 699 FO	12 ppm NG; 15 ppm FO (load>75%) & 24 ppm FO (load<75%)	DLN, GCP

In addition, please note that the installation of a CO oxidation catalyst for Stanton Unit A will provide no air quality benefits. Instead, if the project installed an oxidation catalyst it should be noted the installation would have negative energy, environmental, and economic impacts. The oxidation catalyst would increase the back-pressure on the turbine; thereby increasing emissions per unit of electric generation due to decreased turbine efficiency and increased fuel consumption. The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions during all three possible operating cases is that a percentage of the sulfur dioxide (SO_2) in the flue gas will oxidize to sulfur trioxide (SO_3). The higher the operating temperature, the higher the SO_2 to SO_3 oxidation potential. It is estimated that approximately 30 to 60 percent of the SO_2 in the flue gas can oxidize to SO_3 as a result of the CO oxidation catalyst being installed after the combustion turbine outlet with high temperatures. The SO_3 will react with the moisture in the flue gas to form sulfuric acid (H_2SO_4) mist in the atmosphere. The increase in H_2SO_4 emissions would increase PM_{10} (matter less than 10 microns in diameter) emissions. Moreover, the use of an oxidation catalyst and SCR catalyst will increase front and back half particulate emissions during all three operating cases in the form of H_2SO_4 and ammonium bisulfate as a result of ammonia usage with the SCR and increased SO_3 production. The front half-particulate emissions will increase in the form of ammonium bisulfate assuming all SO_3 reacts to form ammonium bisulfate. Under normal conditions, there will be a mixture of front and back half increase in particulate emissions. Additionally, the CO catalyst does not remove or destroy CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2 (possible contributor to global warming). Dispersion modeling of CO emissions, under worst-case operating conditions, indicates that maximum CO air quality impacts, without the use of an oxidation catalyst system, will be insignificant. Ambient CO levels are well within established air quality standards. Because maximum CO air quality impacts without an oxidation catalyst control system are already insignificant, requiring expensive controls to further reduce CO emissions by less than 64 TPY seems to serve no environmental purpose.

6. *The applicant should be advised that ammonia slip is currently being permitted at 5 ppmvd.*

   Response: From a safety and health standpoint, a monitoring level set a 10 ppmvd appears to be a reasonable level for ammonia slip based on other sites currently operated by Southern Company. Ammonia is not a currently listed regulated pollutant. The applicants are amenable to discussion of this issue during air permit preparation.

7. *Please indicate the maximum gross MW capability of the combined cycle unit, and under what operating conditions this output is achieved. Please provide the same information for the maximum heat input of the CTs and the gas-fired duct burners under ISO conditions. Maximum combined heat input rates have been*

specified for non-ISO conditions at 2402.0 MMBtu/hr firing natural gas (Case 4 while firing duct burners) and 2067.6MMBtu/hr oil firing (Case 20).

Response: At 23° F (wet bulb at 19° F), the maximum MW capability of each combustion turbine unit is 189 MW and the steam turbine is 319 MW. Thus, the total maximum MW capability of Stanton A is 697 MW (@ 23° F). The heat input for this case is 1,898 MMBtu/hr for each combustion turbine and 533 MMBtu/hr for each duct burner. Total heat input for Stanton A (CT 1 + CT 2 + DB 1+DB 2) for this case is 4,863 MMBtu/hr.

8. *Please provide the estimated time frames required, estimated number of annual startups and the estimated emission levels of NO_X, CO and PM/PM_{10} during hot and cold startup periods. The Department intends to define these levels in the setting of BACT.*

Response: It is currently impossible to determine an estimated number of annual start-up periods and emissions during startup for the operation of Stanton Unit A. The permittee is, however, comfortable with standard FDEP language outlining start-up limitations, such as "Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed four hours in any 24-hour period for a cold startup and two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration."

9. *The Department requires as a submittal, a project specific, written cost estimate of a $SCONO_X$ control system, to be supplied by the technology provider (Alstrom Power). In addition to capital cost requirements, the submittal should include vendor estimates for use in determining any applicable annualized operating and maintenance costs.*

Response: The applicants have requested a project specific budgetary cost estimate for a SCONOx control system from Alstom Power for the Stanton Unit A CCCT Project via facsimile on March 19, 2001. A response was requested by Monday, March 26, 2001. The budgetary quote that was used in the BACT analysis was provided to Black & Veatch on April 26, 2000.

The FDEP should note that supplying project specific budgetary quotes for BACT analyses can take substantial time, since vendors realize there is no immediate financial return for their efforts. Alstom Power has recently provided a budgetary quote for another GE 7FA CCCT facility via e-mail to Black & Veatch on February 1, 2001 and it is listed below for your reference. The February 1, 2001 budgetary quote was based on firing a GE 7FA with duct burners on natural gas for 8,472 hours per year at 100 percent load and for firing fuel oil in a GE 7FA without duct firing at 100 percent load for 288 hours per year. Since the Stanton

Unit A CCCT Project has more fuel oil firing (712 hours for a total of 1,000 hours per turbine), the capital cost is expected to increase from this most recent cost estimate. Due to the time constraints Black & Veatch has recalculated the SCONOx capital and annualized costs based on this recent budgetary quote. The February 1, 2001 budgetary quote provided by Mr. Rick Oegema, of Alstom Power, had informed Black & Veatch that fuel oil fired cases would be the worst case design scenario for a project and the cost provided for that case would certainly include any necessary reductions during natural gas firing. Tables 4-4 and 4-5 in the BACT have been revised based on the Alstom Power February 1, 2001 budgetary quote and are attached in this document for your reference.

Specifically, the direct and indirect capital costs in Table 4-4 have been revised based on the February 1, 2001 Alstom Power budgetary quote. The total direct cost excluded the catalyst replacement cost for both the SCONOx and SCR/oxidation catalyst system. The estimated catalyst costs are listed in Table 4-4 under the "Remarks" column. It should be noted that the SCONOx replacement cost is based on a 10-year life for the first layer of catalyst. The SCR/oxidation catalyst indirect costs were determined based on percentages listed in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fifth Edition, 1996). The SCONOx indirect costs were adjusted based on reasonable project estimates, because if OAQPS Cost Manuel percentages were applied then the indirect costs would be misrepresented.

The direct and indirect annual costs in Table 4-5 have been revised based on the February 1, 2001 Alstom Power budgetary quote. The SCR and oxidation catalyst replacement cost was calculated based on a 3-year life, 15 percent for installation, and 5 percent for freight. The SCONOx catalyst replacement cost was based on $230,000 per year for catalyst over a 10-year life that corresponds to a capital recovery factor of 0.1424 (7.0 percent real interest rate), 15 percent for installation, and 5 percent for freight. The SCR/oxidation catalyst indirect annual costs were determined based on percentages listed in the OAQPS Control Cost Manuel. The SCONOx indirect annual costs were adjusted based on reasonable project estimates, because if OAQPS Control Cost Manuel percentages were applied then the indirect annual costs would be misrepresented.

ALSTOM POWER E-MAIL

From:gerald.r.oegema@power.alstom.com
Sent: Thursday, February 01, 2001 2:06 PM
To: Holscherga@bv.com
Cc: ronald.r.bevan@power.alstom.com
Subject: B&V Project 099262

Greg, further to your request of January 26, 2001, please note the following.

We have evaluated the performance and emission data for the cases provided, namely the NO_x emission limits of 2.0 ppmvd and 3.5 ppmvd while firing natural gas, and 15 ppmvd while firing fuel oil. The fuel oil firing case is the size controlling case, as the reduction from 42 to 15 ppmvd requires more catalyst than either of the natural gas fired cases. As a result, we are providing cost and performance data for two cases; fuel oil firing and a NO_x reduction from 42 to 15 ppmvd, and natural gas firing and a NO_x reduction from 9 to 2 ppmvd. Both cases provide a CO emission reduction of 90%.

Included in our scope is the $SCONO_x$ reactor including inlet and outlet dampers, all $SCOSO_x$ and $SCONO_x$ catalyst, inlet and outlet transitions to the reactor including expansion joints, regeneration gas production and distribution piping and valves, regeneration gas condensing and condensate collection system, catalyst installation and removal system, PLC control system and instrumentation, freight, as well as all engineering, design, and project management services to support the execution of the project.

Fuel Oil Firing
Budgetary Capital Cost Estimate - $ 19,800,000
Steam consumption for regen gas production - 20,500 #/hr
Natural gas consumption for regen gas production - 340 #/hr
Pressure drop through the $SCONO_x$ system - 5.3 in w.c.
O&M cost estimate, including catalyst washing - $310,000 per year
Catalyst replacement cost estimate - $230,000 per year

Natural Gas Firing
Budgetary Capital Cost Estimate - $ 15,600,000
Steam consumption for regen gas production - 19,700 #/hr
Natural gas consumption for regen gas production - 330 #/hr
Pressure drop through the $SCONO_x$ system - 3.8 in w.c.
O&M cost estimate, including catalyst washing - $310,000 per year
Catalyst replacement cost estimate - $230,000 per year

Costs provided are for one $SCONO_x$ system for each CCGT.

I trust that this meets with your immediate needs. Please contact me if you have
any questions.

Regards,

Rick Oegema

BACT Table 4-4 (REVISED) Combined NO_x and CO Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit.				
	$SCONO_x$ System	**SCR/ Oxidation Catalyst**	**LNB**	**Remarks**
Direct Capital Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3 in BACT
SCR & Oxidation Catalyst System	N/A	1,907,000	N/A	Estimated from Engelhard Corporation.
$SCONO_x$ System (Includes catalyst)	19,800,000	N/A	N/A	Estimated from Alstom Power.
Catalyst Reactor Housing	Included	268,000	N/A	Estimated by Alstom Power & scaled from an estimate by Engelhard Corporation.
Control/Instrumentation	Included	180,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia (Storage & Handling))	N/A	200,000	N/A	Estimated from previous projects.
Purchased Equipment Costs	19,800,000	2,555,000	N/A	
Sales Tax	N/A	N/A	N/A	No sales tax on generating equipment for this project.
Freight	Included	128,000	N/A	5% of Purchased Equipment Costs
Total Purchased Equipment Costs (PEC)	19,800,000	2,683,000	N/A	
Direct Installation Costs				
Balance of Plant	Included	805,000	N/A	For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting. $SCONO_x$ bid included installation.
Total Direct Cost Less Catalyst	**19,570,000**	**1,998,000**	Base	Catalyst cost is excluded as annual O&M cost. SCR and oxidation catalyst costs are $826,000 and $664,000, respectively. SCONOx replacement cost estimate is $230,000 per year, based on a 10-year life.
Indirect Capital Costs				
Contingency	594,000	537,000	N/A	For SCR: 20% of Total PEC; For $SCONO_x$: 3% of Total PEC
Engineering and Supervision	Included	268,000	N/A	For SCR: 10% of Total PEC
Construction & Field Expense	198,000	134,000	N/A	For SCR: 5% of Total PEC; For $SCONO_x$ 2.5% of Total PEC
Construction Fee	396,000	268,000	N/A	For SCR: 10% of Total PEC; For $SCONO_x$ 5% of Total PEC
Start-up Assistance	Included	54,000	N/A	For SCR: 2% of Total PEC
Performance Test	40,000	27,000	N/A	For SCR: 1% of Total PEC; For $SCONO_x$ 0.5% of Total PEC
Total Indirect Capital Costs	1,228,000	1,288,000	Base	
Total Installed Cost (TIC)	**20,798,000**	**3,286,000**	Base	

BACT Table 4-5 (REVISED) Combined NO_x and CO Control Annualized Cost Per GE 7FA CTG/HRSG Unit				
	$SCONO_x$ System	**SCR/Oxidation Catalyst**	**LNB**	**Remarks**
Direct Annual Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3 in BACT
Catalyst Replacement	40,000	686,000	N/A	Catalyst life of 3 year for SCR/Oxidation catalyst and 10 year life for $SCONO_x$ catalyst.
Operation and Maintenance	310,000	40,000	N/A	Estimated from Alstom Power & includes catalyst washing and materials. For SCR/Oxidation catalyst assumed 2 hr/day, 8,760 hr/yr at $40/hr and includes materials.
Reagent Feed	N/A	87,000	N/A	Assumes 1.4 stoichiometric ratio.
Natural Gas Consumption	218,000	N/A	N/A	Based on 340-lb/hr natural gas consumption.
Power Consumption	4,000	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR and damper actuation for $SCONO_x$.
Lost Power Generation				
$SCONO_x$ Washing	175,000	N/A	N/A	Down time due to $SCONO_x$ washing period.
Steam Consumption	694,000	N/A	N/A	Loss based on 20,500 lb/hr of steam required.
Backpressure	895,000	95,000	N/A	Includes back-pressure on the combustion turbine.
Annual Distribution Check	N/A	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less the catalyst cost.
Total Direct Annual Cost	2,336,000	923,000	N/A	
Indirect Annual Costs				
Overhead	31,000	20,000	N/A	For SCR 60% of O&M Labor; For $SCONO_x$: 10% of O&M Labor
Administrative Charges	63,000	66,000	N/A	For SCR 2% of Total Installed Cost; For $SCONO_x$: 0.3% of TIC
Property Taxes	104,000	90,000	N/A	For SCR 2.75% of Total Installed Cost; For $SCONO_x$: 0.5% of TIC
Insurance	42,000	33,000	N/A	For SCR 1% of Total Installed Cost; For $SCONO_x$: 0.2% of TIC
Capital Recovery	2,284,000	361,000	N/A	Capital Recovery Factor times the Total Installed Cost
Total Indirect Annual Costs	2,524,000	570,000	N/A	
Total Annualized Cost	**4,860,000**	**1,493,000**	N/A	
Annual Emissions, tpy	144.1	220.1	918.5	Emissions taken from Tables 4-1, 4-2 and 4-3 in BACT
Emissions Reduction, tpy	774.3	698.3	N/A	Emissions calculated from Tables 4-1, 4-2, 4-3 in BACT
Total Cost Effectiveness, $/ton	**6,300**	**2,100**	N/A	Total Annualized Cost / Emissions Reduction
Incremental Annualized Cost	**3,367,000**	N/A	N/A	Total annualized SCR/Oxidation catalyst system cost minus the total annualized SCONOx system cost
Incremental Reduction	**44,000**	N/A	N/A	Total Incremental Annualized Cost / Incremental Emissions Reduction

10. *Each economic analyses should be revised to incorporate the information specified above as well as the utilization of OAQPS Control Cost Method factors (e.g., contingency). Additionally, according to the application's Section 4.6.7.2, lost revenues are included in the annualized cost estimate. These should be excluded from the analyses.*

Response: The 3 percent contingency value as a function of the total purchased equipment cost suggested in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fifth Edition, 1996) is judged to be inaccurate for SCR and oxidation catalyst systems as compared to actual values typically used in the construction field for this level of estimating. There are many potential items and uncertainties that are not captured by the cost items included in the estimate including ammonia permitting cost, ammonia suppression, changes between cost quotes and contract values, changes in operating conditions, process contingency, etc. For example, the original capital cost estimate for the Kissimmee Unit 3 plant was estimated to be \$117.6 million and the current estimate to complete is \$135.7 million, a 15.4 percent increase. The increase was due to increased equipment cost, scope changes, labor/wage increases, and schedule acceleration.

The OAQPS Control Cost Manuel (Fifth Edition) states in regards to the intended users of the manual, "Moreover, the user should be able to exercise "engineering judgment" on those occasions when the procedures may need to be modified or disregarded." This was the case for the SCR/Oxidation catalyst system, but not for the SCONOx system. The 3 percent contingency factor for the $SCONO_x$ system is estimated to be appropriate based on the total purchased equipment cost. Alstom Power believes the project contingency should be about the same for a SCONOx system compared to a SCR/Oxidation catalyst system. Therefore, the contingency factor was estimated for both post combustion control systems to appropriate percentages for the project based on "engineering judgment."

In addition, the Electric Power Research Institute published the document titled, NO_x Emissions: Best Available Control Technology, A Gas Turbine Permitting Guidebook in November 1991 and list under NO_x control cost (Page 5-5) the following text:

> "Based on experience with other cost methodology sources, the contingency factor recommended by the OAQPS Manual (3% of the total equipment cost) is a lower-bound estimate. Standard EPA guidance for pollution control costing is a contingency factor of 10 to 50% of the sum of direct and indirect costs. (10) A contingency factor of 20% of the sum of direct and indirect costs was used in the economic analyses conducted by the EPA in support of the NSPS for industrial and small boilers and municipal waste combustors. (11, 12) Based on this range of values, it is recommended that individual utilities use the contingency factor that would normally be used in-house in procurement or rate estimation procedures, and document the validity of the factor for the case in

> question. The factor recommended by OAQPS should be used as a default value when more appropriate information is not available."

Furthermore, the project economic criteria used in this BACT economic analyses uses a contingency value of 20 percent as listed in the previous capital cost estimate example shown in the EPA BACT guidance document (March 15, 1990) on the use of the "top-down" approach to BACT determinations. The EPA document was published by the OAQPS, Air Quality Management Division Noncriteria Pollutants Program Source Review Section, March 15, 1990, and is titled, "Top Down" Best Available Control Technology Guidance Document. The example in Appendix B, Page B-5 shows a contingency of 20 percent.

The lost power generation is a function of the lost capacity from the combustion turbine, operating hours and the lost power generation revenue. The lost power generation revenue should be included since the owner will incur a loss of revenue that will not be recoverable. The back-pressure on the combustion turbine will decrease the total power output that the owner could have sold to generate revenue. The owner will also incur a loss in revenue from the $SCONO_x$ system by consumption of steam and natural gas for the regeneration process that could have been used to operate a steam turbine and a combustion turbine. The owner will also incur a loss in revenue when the unit is offline for annual washing of the $SCONO_x$ catalyst.

Additionally, the lost revenue calculation in the economic analysis is very minor and is included in both baselines in the $SCONO_x$ and SCR/Oxidation Catalyst comparison. Removal of these costs will have only a net $37,000 impact on a total incremental annualized cost of $6,600,000. However, the economic analysis for the SCONOx system has been updated with the most recent $SCONO_x$ budgetary quote that Black & Veatch has received from Alstom Power (see Tables 4-4 and 4-5). In addition, the annualized cost for the SCR/Oxidation Catalyst system has been recalculated. The total indirect annual cost has been recalculated for the SCR and oxidation catalyst alternative. The capital recovery cost in the original BACT was calculated by subtracting the SCR/Oxidation catalyst system cost from the total installed cost and then multiplied by the capital recovery factor. This has been recalculated to only multiply the capital recovery factor by the total installed cost of the SCR/Oxidation catalyst. The total annualized cost and cost effectiveness were then recalculated based on the revised indirect annual cost. Table 4-5 has been updated with these changes and the total annualized cost recalculated to be $1,493,000. This revised annualized cost per CTG/HRSG unit results in a cost effectiveness of approximately $2,100 per ton of NO_x and CO removed.

WATER

1. *The applicant has provided a single line diagram for the new expansion. This diagram does not show chemical feeds and all treatment systems. Some existing treatment units will be used for the treatment of the wastewater generated from the new expansion. A revised single line diagram for the entire facility (Units 1, 2, and A) showing all treatments units, chemical feeds, and disposal methods is requested. Please show average daily and maximum daily flows for all existing units and the expansion.*

   Response: The Unit 1 and 2 water mass balance shows the water uses and wastewater systems for the existing facilities and infrastructure. This drawing is based on Figure 3.5-1 submitted with the Stanton Energy Center Unit 2 Site Certification Application and shows all interfaces with new facilities. Water mass balance is attached as OUC waste water diagram, Rev. 9 and shows the chemical feeds, treatment systems, and disposal methods for Unit A as well as interconnections with the existing infrastructure. The attached water balances also include the average daily and maximum daily flows for all 3 units.

2. *On Figure 3.5-1 (single line diagram), please show final disposition of the treated water and wastewater for "OUC Tower Blowdown Treatment System" (Node 60).*

   Response: The revised water mass balances depict the final disposition of the treated water and wastewater for the cooling tower blowdown treatment system. The distillate from the new Stanton A CTBT system will be recycled to Stanton A's cooling tower under normal operating conditions; it will only be sent to the makeup pond for emergency disposal. The distillate is high quality water and should not affect the use of the makeup pond water or cause any environmental impacts.

3. *Please provide details of the SEC Recycle System. What is the make up of the basin structure?*

   Response: The existing recycle system was previously described and licensed under the Units 1 and 2 Site Certifications. A description of the recycle system taken from the Unit 1 Site Certification Application is attached.

4. *Section 3.6 (Page 3-13). Please show the new brine concentrator system on the single line diagram. Also provide details of the boiler cleaning waste neutralization system. Where does the cleaning waste disposed of?*

   Response: The new brine concentrator is illustrated on the revised water mass balance for Stanton A, which is attached. There is no boiler cleaning waste neutralization system at the site. The boiler cleaning contractor will remove the cleaning waste from the site and dispose of it by an approved method. The disposal method and location will be specified in the contractor's contract and will meet all federal and state regulations.

5. *3.6.6. Please provide details of the neutralization basin. Show all incidental waste stream and flow volumes from existing and the new units.*

Response: The neutralization system was previously licensed under the Unit 1 Site Certification. The attached description of the recycle neutralization basin system is taken from the Unit 1 Site Certification Application. The primary flow to the neutralization basin is regeneration waste from the demineralizer system. This flow is shown on the portion of the water balance representing Units 1 and 2. Acid or caustic will be added to the basin as required to control the pH within an acceptable range. Drains from chemical containment areas will also be routed to the neutralization basin. The flows associated with these drains will generally be low volume and infrequent.

6. *5.2.1. Oil and grease concentration of the water discharged from the transformer enclosure will be at 10.0 mg/L. The discharge concentration is limited at 5.0 mg/L. If the contamination is due to petroleum based oils, the Department will suggest sampling for TRPH (Total Residual Petroleum Hydrocarbons). The limit for the TRPH concentration in the effluent remains at 5.0 mg/L. The Department may require effluent monitoring for this discharged. Please provide details of the disposal area.*

Response: The large site transformers will be provided with a walled containment to hold any transformer oil leakage. A drain pipe and valve will be provided in the enclosure. The drain valve will normally be closed. Any rain water that collects within the enclosure will be checked for oil before discharge. Any oil present will be cleaned up before draining water from the enclosure. The contained water will be released as site runoff after oil removal. The transformer oil that will be used is electrical insulating oil, per ASTM D-3487 type 1 inhibited.

7. *Projected Water Use on Page 5-28. It is indicated that the proposed expansion will require up to 2.91 mgd under normal operating condition. OUC should consider using up to 3 mgd available from Orange County Landfill located adjacent to OUC site.*

Response: The applicants discussed this item with the FDEP and St. Johns River Water Management District at a meeting on March 15, 2001. Following review of further information on the Landfill runoff source, consideration can be given to its use and further discussions will be held with Orange County. It should be noted that the 2.91 mgd referred to is the cooling tower makeup water requirement that is reclaimed water provided by the Orange County Eastern

Regional Water Reclamation Facility. Please refer to the applicant's response to SJRWMD Question 1 for additional discussion of this subject.

8. *This is referred to as a zero discharge facility. Zero must refer to surface water discharge because it does not appear to be an IW definition of zero discharge – unless the makeup pond is lined. Besides groundwater and makeup well water, the makeup pond may receive any and all of the following:*

   a. *2.9 mgd DW effluent*
   b. *0.369 mgd effluent from Cooling Tower Blowdown Treatment System (effluent from crystallization system). This should probably be a good water quality, but I do not see an analysis.*
   c. *0.038 mgd from the boiler blowdown. (The text states the blowdown water will be routed to the Stanton A cooling tower for reuse. Will it be "routed" through the makeup pond?)*
   d. *? mgd from the gas desulfurization system (verbal information from GK in Air Section) that came from the Recycle Basin which receives:*

      (1) 0.015 mgd effluent from an oil/water separator which receives wastewater from floor drains.
      (2) 0.012 mgd effluent from R/O from the demineralizer
      (3) wash down water

   e. *? mgd. There is also an ash system that receives Recycle Basin water, but I am not sure if there is effluent and if it returns to this system.*

If these waste streams go to the makeup pond, I would like these to be shown on a water balance even though the wastewater streams in the pond may be so diluted by the DW effluent and the groundwater that there are no groundwater quality problems.

Response: Only the 2.9 mgd of DW from Orange County will be sent to the make-up pond. Cooling tower blowdown treatment distillate and boiler blowdown will go directly to the cooling tower under normal operations. Water for the Units 1 and 2 desulfurization and ash handling systems is taken from the recycle basin as covered in the Units 1 and 2 Site Certification Applications. All of these streams are shown on the attached water balances.

9. *Rainwater on transformers is skimmed then water goes to storm water pond. Is this tanks or IW?*

Response: The rainwater released from the transformer area after verification of no contamination is characterized as Industrial Wastewater. It will be released to the site storm water drainage system if clean or directed to the oil-water separator.

10. *The submittal said that they would complete Form 2CG for Industrial Waste application. I did not see it.*

Response: Form 2CG was not included in the SSCA. The decision not to submit this form was based upon correspondence with FDEP. Black & Veatch had sought clarification prior to filing the SSCA as to whether a form was needed for the changes being made to the industrial wastewater treatment system or whether a narrative describing the wastewater system changes would be sufficient. Black & Veatch also asked, if a form was required, which one should be used? After failing to receive a definitive response from the Department, it was assumed that a narrative would be sufficient. The system is described in detail in Section 3.6 of the SSCA. A revised water mass balance (Figure 3.5-1) was included in the SSCA First Amendment submitted on March 8, 2001, and an updated version is attached as OUC waste water diagram, rev. 9.

11. *DW goes to a septic tank.*

Response: The sanitary wastewater for Stanton A will be routed to a new septic tank and absorption field and will meet state and local requirements.

12. *The quarterly data submitted uses a lot of "BDLs." The use is inconsistent. A parameter like Mercury will have a "<" for a couple of quarters then a "BDL" in the same quarter that other parameters have "<" symbols. Will ask for the lab sheets. If these detection limits are OK, we may be able to delete some parameters.*

Response: The lab data sheets have been included in the Sufficiency Response as Attachment A.

13. *A considerable amount of waste is hauled. Who regulates the hauling?*

Response: All wastes hauled from the plant site will be coordinated with the appropriate contractors to assure that all applicable regulations are met. On-site waste disposal is coordinated through the OUC Environmental Department.

14. *Please provide copies of the chemistry laboratory bench sheets for the ground water monitoring data for the 14 monitoring wells for the years 1999 and 2000.*

Response: The chemistry laboratory bench sheets for the ground water monitoring data for the 14 monitoring wells for 1999 and 2000 are included in the Sufficiency Response as Attachment A.

15. *Some of the monitoring well information was missing for the 4th quarter of 2000. Were the wells dry? Please clarify.*

Response: The chemistry laboratory bench sheets for the ground water monitoring data for the 14 monitoring wells for 1999 and 2000 are included in the Sufficiency Response as Attachment A.

16. *The Central District does not have any record of the well completion information on the monitoring wells. Please provide copies of the Well Completion Report Forms for each monitoring well. If these forms were not included in the permit, please fill out copies of the attached forms and submit them to the Department with well construction diagrams.*

Response: The applicants are not able to provide copies of the original Well Completion Report Forms for each monitoring well at this time. Consequently, new Well Completion Report Forms are currently being completed and will be submitted to the FDEP Central District as soon as possible. Well construction diagrams will be included in the submittal.

17. *Please revise the Water Balance (Figure 3.5-1) to include all of the wastewater streams going to the reuse basin and the make-up pond. Please show the recycle basin water going to Gas Desulfurization and Ash Systems and the return effluent, if any.*

Response: The attached revised water mass balances illustrate all new facilities and all new and existing wastewater streams going to the reuse basin and the make-up pond. The Units 1 and 2 desulfurization and ash systems are included in the existing facility's mass balance.

18. *Please sample the make-up pond, and the reuse basin for the parameters required in the quarterly ground water sampling plus TRPH.*

Response: The samples have been collected and analyzed. The preliminary report is included as Attachment B.

19. *For each waste stream in the expansion, please sample the correlative waste stream in the existing system for the parameters required in the quarterly ground water sampling plus TRPH.*

Response: The samples have been collected and analyzed. The preliminary report is included as Attachment B.

20. *Please provide a copy of an analysis of brine concentrator wastewater from a similar existing system. At a minimum, the analysis shall include the primary standards for metals.*

Response: The brine concentrator system produces no wastewater stream. It is a closed loop process. The only process waste from the brine concentrator system is crystallizer salt that is encapsulated in the onsite landfill. Processed water is reused onsite.

21. *The scales for the monitoring well location maps are too small to accurately measure distances. Please show all of the monitoring wells on site plans with a scale similar to the Boring Location Map (Figure 2.3-4). Please include the locations of the Floridan Supply Wells as well.*

Response: The attached Black & Veatch drawing #8927-ISTU-S1010 shows all of the monitoring well locations and Floridan Supply wells.

22. *Please provide a scaled cross section through the reuse basin and the make-up pond.*

Response: These facilities were licensed with the Unit 1 Site Certification. Diagrams taken from the Unit 1 Site Certification Application are included and depict the recycle basin and make-up water supply storage pond.

23. *If there are historic staff guage readings for the ponds, please provide the data for 2000.*

Response: Historic staff gauge readings for the ponds for the year 2000 are attached.

24. *Please provide a data table for the monitoring wells, which includes:*
    - *a. Ground surface elevations.*
    - *b. Top of casing elevations.*
    - *c. Below top of casing depth for the years 1999 and 2000.*
    - *d. Ground water elevations for the years 1999 and 2000.*

Response 24a: See Response 16.
Response 24b: See Response 16.
Response 24c: See Response 16.
Response 24d: Ground water elevations for 1999 and 2000 are attached.

25. *Please be advised that currently the ground water is being monitored with the same parameters for both industrial waste streams and solid waste disposal sites. In reality, this is not necessary. Accordingly, based on the characterization of all industrial waste streams, please propose a separate Ground Water Monitoring Plan for addressing wastewater discharges into the reuse basin and make-up pond.*

Please also be advised that a proposal for the revised Ground Water Monitoring Plan must include a provision of incorporating additional monitoring wells especially around the make-up pond as well as the reuse basin, along with appropriate parameters to be monitored in the ground water.

It may also be noted that all new compliance monitoring wells shall be proposed not more than 100 feet from the discharge basin/ponds.

Response: A tour of the existing Stanton Energy Center facility and the proposed footprint of Stanton A was conducted on Tuesday, April 3, 2001, with representatives of FDEP Central District industrial wastewater and groundwater sections. The focus of this meeting was to clarify the design of the water and wastewater streams for the Stanton facility. The water/wastewater system infrastructure was designed and installed during the construction of Stanton Unit 1. Drawings that describe the water/wastewater system infrastructure are included as Attachment C. The drawings are described below:

Figure 5-17 is a simplified flow diagram for the makeup water supply storage pond for current and future units of this facility. The function of this pond is to store cooling tower make up and site drainage. It is a 93-acre pond. Inflows to this pond are treated sewage effluent from the Orange County easterly sub-regional plant, on site sewage treatment plant effluent, runoff from site drainage, and precipitation. Outflows from this pond are evaporation, seepage, and makeup to the plant cooling towers. Water quality analysis is provided from a recent sample of the pond and year 2000 quarterly results. The quality of this pond water analysis demonstrates that this pond does not have adverse impact to the groundwater. The applicants feel no groundwater monitoring is required.

Figure 5-20 is a simplified flow diagram of the recycle basin. The function of this pond is to store wastewater for use as makeup to the ash handling and scrubber systems. It is a 15-acre segmented lined pond. Inflows to this pond are blowdown from the cooling tower system, miscellaneous plant drains, neutralization basin, precipitation, overflow from the coal storage runoff pond, and active combustion waste area runoff pond. Outflows from this pond are makeup to the Cooling Tower Blowdown Treatment facility, ash handling, scrubber systems and evaporation. Additionally, this water is used for air heater, boiler and precipitator cleaning.

Figure 5-14 is a simplified flow diagram for the scrubber system. Water inflows to this system are from the recycle basin, service water, and service water treatment wastewater sump. Outflows from this system are evaporation and solids to solid waste disposal.

Figure 5-12 is a simplified flow diagram of the ash handling system. Water inflows to this system are from the recycle basin and service water. Outflows from this system are evaporation and solids to solid waste disposal.

Figure 3-1 is a simplified flow diagram of the chemical waste drainage. Demineralizer and condensate polisher regeneration wastes, chemical cleaning wastes and miscellaneous chemical drains are inflows to the neutralization basin. Outflow from this basin is to the recycle basin.

Figure 5-19 is a simplified flow diagram of the coal storage area runoff pond. It is a 10.4-acre segmented lined pond. The function of this pond is to store coal storage area runoff. Outflow from this pond is to the recycle basin.

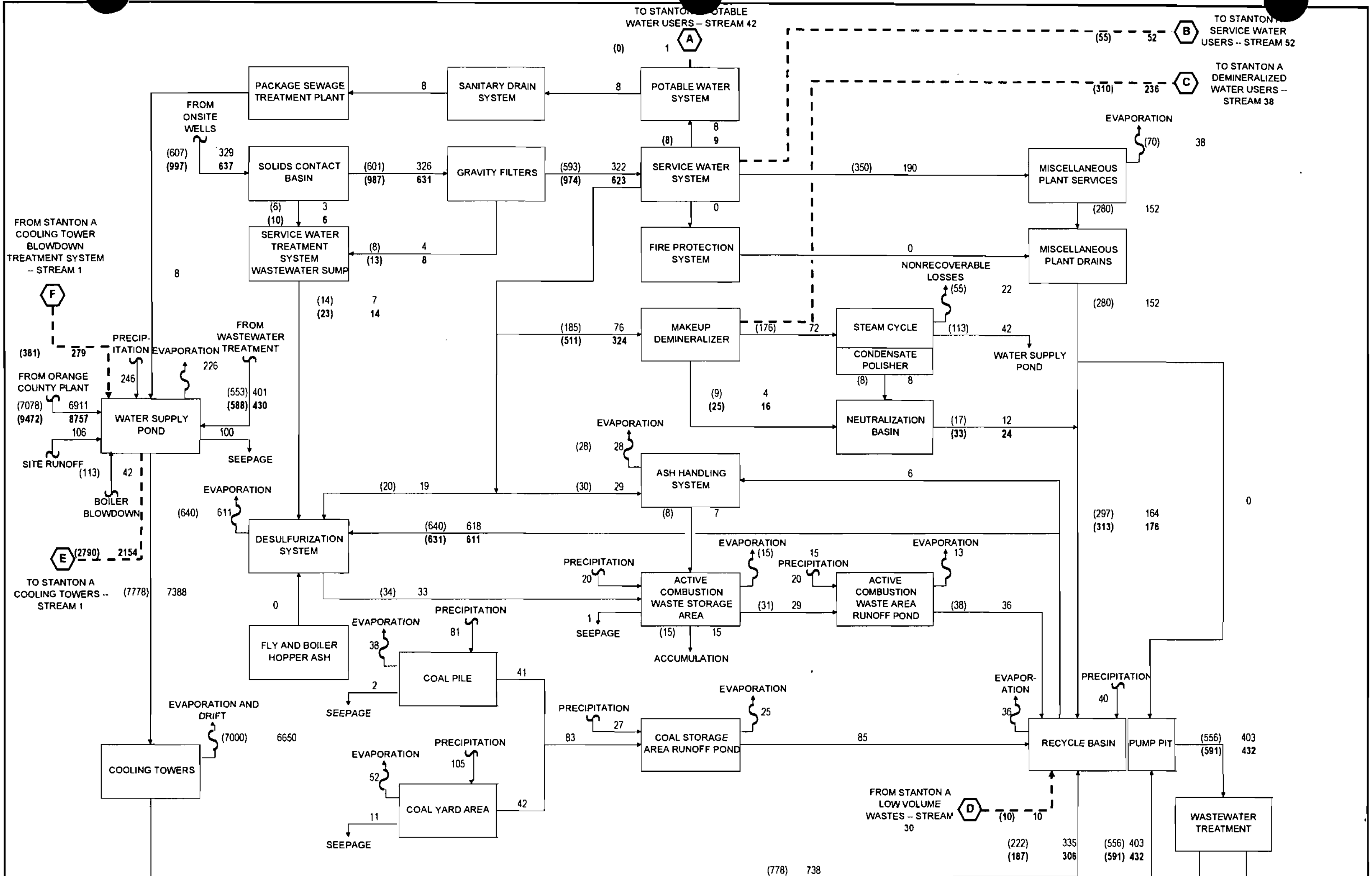
Figure 5-18 is a simplified flow diagram of the active combustion waste area runoff pond. It is a 5 acre lined pond. The function of this pond is to store active combustion waste area runoff. Outflow from this pond is to the recycle basin.

The applicants will work with the FDEP to revise groundwater sampling parameters as needed.

26. *When the Site Certification is issued for the requested modification, the Ground Water Section, Central District, Orlando must receive one copy of Ground Water Monitoring reports for industrial wastewater discharges.*

Response: OUC will add the Central District's Ground Water Section to the distribution list.

Stanton Unit 1 and 2
Stanton A
Water Mass Balances



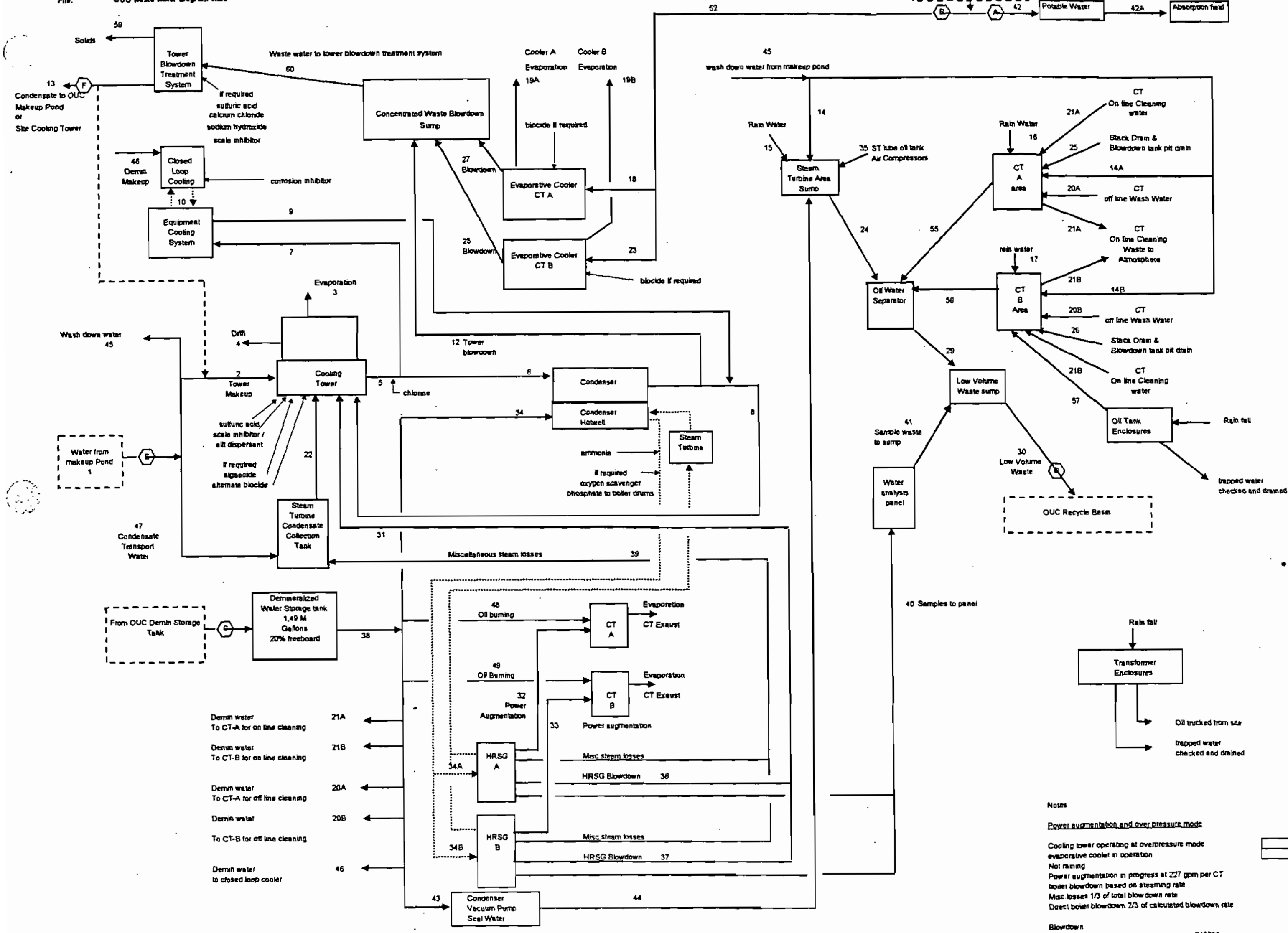
FLOWS AND FLOW PATHS FOR UNITS 1 AND 2 ARE BASED ON FIGURE 3.5-1 SUBMITTED WITH THE UNIT 2 SITE CERTIFICATION APPLICATION SUBMITTED ON 3/15/91

NOTE:
1. ALL FLOWS ARE EXPRESSED IN GALLONS PER MINUTE.
2. INTERFACES WITH STANTON A WATER MASS BALANCE INDICATED BY DASHED LINES AND ⬡ SYMBOL.
3. PEAK FLOWS ARE INDICATED BY PARENTHESES.
4. BOLD FLOWS INDICATE CHANGES ASSOCIATED WITH THE ADDITION OF UNIT A.

BLACK & VEATCH	ORLANDO UTILITIES COMMISSION STANTON ENERGY CENTER COMBINED CYCLE PROJ.	Project 049857.0030	Drawing	Rev C
Eng: Dwg: JDC	WATER MASS BALANCE		
Check: Date: 4/18/2001	INTERFACES WITH EXISTING FACILITIES		

Stanton Energy Center Unit A

By: Clausen Date: 4/16/2001
File: OUC waste water diagram 8.xls



Line No.	Stream Flows are block flows unless otherwise noted	Average Flow based on plant operation gpm	Max Flow Power Aug over press gpm
E 1	Makeup water from OUC makeup pond	2154.4	2790.0
2	Cooling tower makeup	2101.6	2735.0
3	Cooling tower evaporation	1922.9	2495.0
4	Cooling tower drift	2.6	2.7
5	Circulating water pump discharge	128250.0	135000.0
6	Condenser inlet	118750.0	125000.0
7	Cooling water to equipement cooling water system	9500.0	10000.0
8	Condenser and service water cooler discharge to tower	127977.9	134646.0
9	Equipment cooling system return hot water	9500.0	10000.0
10	Closed loop cooling flow	9025.0	9500.0
11	spare	0.0	0.0
12	Cooling tower blowdown	272.1	354.0
F 13	Waste treatment condensate to OUC makeup pond or site tower	278.6	360.9
14	Makeup pond water to steam turbine area for wash down	0.2	0.0
14A	Makeup pond water to CT-A area	0.2	0.0
14b	Makeup pond water to CT-B area	0.2	0.0
15	Rain water to steam turbine area	0.1	0.0
16	Rain water to CT-A area	0.0	0.0
17	Rain water to CT-B area	0.0	0.0
18	Makeup water to CT-A evaporative cooler	26.1	27.4
19A	CT- A evaporative cooler evaporation	22.8	24.0
19B	CT- B evaporative cooler evaporation	22.8	24.0
20A	CT-A off line cleaning wash water	0.1	0.0
20B	CT-B off line cleaning wash water	0.1	0.0
21A	CT-A on line wash water	0.5	0.0
21B	CT-B online wash water	0.5	0.0
22	Steam Turbine collection tank to cooling tower basin	66.7	75.4
23	Water to CT-B evaporative cooler	26.1	27.4
24	Steam turbine area to oil water separator	0.3	0.0
25	CT A stack drain and blowdown tank pit drain	0.0	0.0
26	CT A stack drain and blowdown tank pit drain	0.0	0.0
27	CT-A evap cooler blowdown	3.3	3.4
28	CT-B evap cooler blowdown	3.3	3.4
29	Oil water separator to low volume sump	0.8	0.0
D 30	Low volume waste to OUC recycle basin	10.3	10.0
31	Total block boiler blow down	29.3	41.4
32	Power augmentation to CT A	64.8	227.0
33	Power augmentation to CT B	64.8	227.0
34	Makeup to Condenser Hotwell	182.8	525.7
34a	Makeup for losses at HRSG A	91.4	262.9
34b	Makeup for losses at HRSG B	91.4	262.9
35	Steam turbine lube oil tank and Air Compressors	0.0	0.0
36	HRSG A Blowdown to tower	14.6	20.7
37	HRSG B Blowdown to tower	14.6	20.7
C 38	Demin. water to process	235.5	525.7
39	Total HRSG miscellaneous losses	14.4	20.4
39A	HRSG A misc. losses	7.2	10.2
39B	HRSG B misc. losses	7.2	10.2
40	Water analysis panel waste	9.5	10.0
41	Panel waste to low volume sump	9.5	10.0
A 42	Potable water to block from potable water supply	0.6	0.0
42A	Sewage to treatment from block	0.6	0.0
43	Condenser vacuum pump seal water makeup	0.0	0.0
44	Condenser vacuum pump seal water waste	0.0	0.0
45	washdown water	0.6	0.0
45A	From existing OUC potable/service water system	52.7	54.9
46	Closed loop cooling water makeup	0.0	0.0
47	Condensate transport water	52.3	55.0
48	Demin water to CT- A during fuel oil burn	25.8	0.0
49	Demin water to CT- B during fuel oil burn	25.8	0.0
50	Spare		
51	Fire Protection water to site	0.0	0.0
B 52	Evap cooler makeup from OUC site	52.1	54.5
53	spare		
54	spare		
55	CT - A area sump to oil water separator	0.3	0.0
56	CT - B area sump to oil water separator	0.3	0.0
57	Oil storage tanks to CT - B area sump	0.0	0.0
58	Spare		
59	Solids to land fill pounds per minute	7.7	10.2
60	Conc. Waste sump to blowdown treatment	278.6	360.9
	in	2442.8	3370.6
	out	2442.8	3370.6

Notes

Power augmentation and over pressure mode

Cooling tower operating at overpressure mode — 8 cycles
evaporative cooler in operation — 8 cycles
Not raining
Power augmentation in progress at 227 gpm per CT
boiler blowdown based on steaming rate — 1 %
Misc.losses 1/3 of total blowdown rate
Direct boiler blowdown 2/3 of calcutated blowdown rate

Blowdown

hot reheat	719782	
Lp admission	20469	
Main steam	803371	
	1543622	#/hr
	30.87244	gpm

Average Flow Based on plant operation

operation factor 0.95
Normal operation a function of power factor and power aug. and oil burning
power augmentation operation 2500 hours
oil burning 1000 hours
evaporative cooler in operation 12 hours per day
Assume washdown of 100 gpm for 60 minutes per week (20 minutes per area)
rain water 48.11 inches annual
steam turbine sump 1556 ft2
CT A sump 220 ft2
CTB sump 220 ft2
on line cleaning 780 gallons once per day exausted to atmosphere
off line cleaning 2430 gallons once per month trucked from site
assume 30 gallons per day per person, 30 persons/day
1% boiler blowdown based on steaming rate
Misc.losses 1/3 of total blowdown rate
Direct boiler blowdown 2/3 of calculated blowdown rate
Interconnections with Stanton Units 1 & 2 are indicated by

Figure 3.5-1

Recycle Basin Description

coal pile and yard area are assumed to have pervious surfaces and represent
24 per cent and 60 per cent of the total coal storage area, respectively, 5
which includes the coal pile, coal yard and CSA runoff pond. The CSA
runoff pond will have a surface area of approximately 10.4 acres (16 per
cent of coal storage area), with an embankment length of 4,100 feet and is
designed to retain without discharge the surface runoff and direct pond 5
precipitation from a 24-hour event having a recurrence interval of 10 years.
The 10-year, 24-hour precipitation event is considered to be 7.5 inches as
indicated in Section 2.6. The capacity of the CSA runoff pond was determined
by assuming an average of 50 per cent (3.75 inches) of the design precipi- 5
tation would occur as surface runoff. This corresponds to a runoff curve
number (U.S. Soil Conservation Service) of 67. Runoff from precipitation
exceeding the 10-year, 24-hour event will be directed to the recycle basin. 5

The maximum design water surface elevation within the CSA runoff pond
is 79.5 feet, msl. This elevation would result from surface runoff and 5
direct pond precipitation during a 10-year, 24-hour event or greater. The
pond bottom will be at Elevation 75 feet, msl and will consist of a one-foot
thick layer of compacted material providing cover for a 6-inch thick highly
impermeable liner. Soil-cement will be utilized to provide slope protection.
A section of the proposed CSA runoff pond embankment is shown on Figure 3.10-3.

Runoff and direct precipitation retained within the CSA runoff pond
will be directed to the recycle basin to be used as makeup for the flue gas
desulfurization and ash handling systems. Controlled drainage of the CSA
runoff pond to the recycle basin will be accomplished through the use of a
buried pipeline. 5

3.10.3 Recycle Basin

#3 The recycle basin, shown on Figure 3.10-1, will be lined to control seepage loss. The recycle basin is designed to provide for the temporary storage of effluents from the neutralization basin and wastewater from the miscellaneous plant drains. The recycle basin will also receive intermittent flows from the coal storage area runoff pond and the active combustion waste area runoff pond. The recycle basin will provide makeup to the desulfurization and ash handling systems. Blowdown from the cooling tower will provide makeup to the recycle basin as required to maintain proper water surface elevation.

The recycle basin will have a surface area of approximately 15 acres with an embankment length of 5,200 feet. The operating water surface elevation within the recycle basin will be 75 feet, msl corresponding to an average depth of 5 feet. The pond bottom will be at Elevation 70 feet, msl 5
and will consist of a 1-foot thick layer of compacted material providing cover for a 6-inch thick highly impermeable liner. Soil-cement will be utilized to provide slope protection. A section of the proposed recycle basin embankment is shown on Figure 3.10-4.

Compacted site fill will be placed to Elevation 80 feet, msl within the area. The site fill material will be sloped away from the perimeter of 5
the recycle basin to prevent surface runoff from entering the basin. Surface runoff from the area will be directed to the makeup water supply storage pond.

3.10.4 Active Combustion Waste Area Runoff Pond

Surface runoff from the active portion of the combustion waste storage area will be directed to the lined active combustion waste area runoff pond (ACWA runoff pond) shown on Figure 3.10-1. Runoff from both the developed and undeveloped portions of the combustion waste storage area will be directed to natural drainage systems within the area. The developed portion of the waste storage area is defined as a formerly active portion which has been reclaimed by covering with topsoil and reestablished with vegetation. The undeveloped portion is that which has not yet been utilized for combustion waste storage. The undeveloped portion of the area will be reseeded subsequent to site borrow operations.

Approximately 312 acres have been allocated for combustion waste storage. This area will be developed in active increments of approximately

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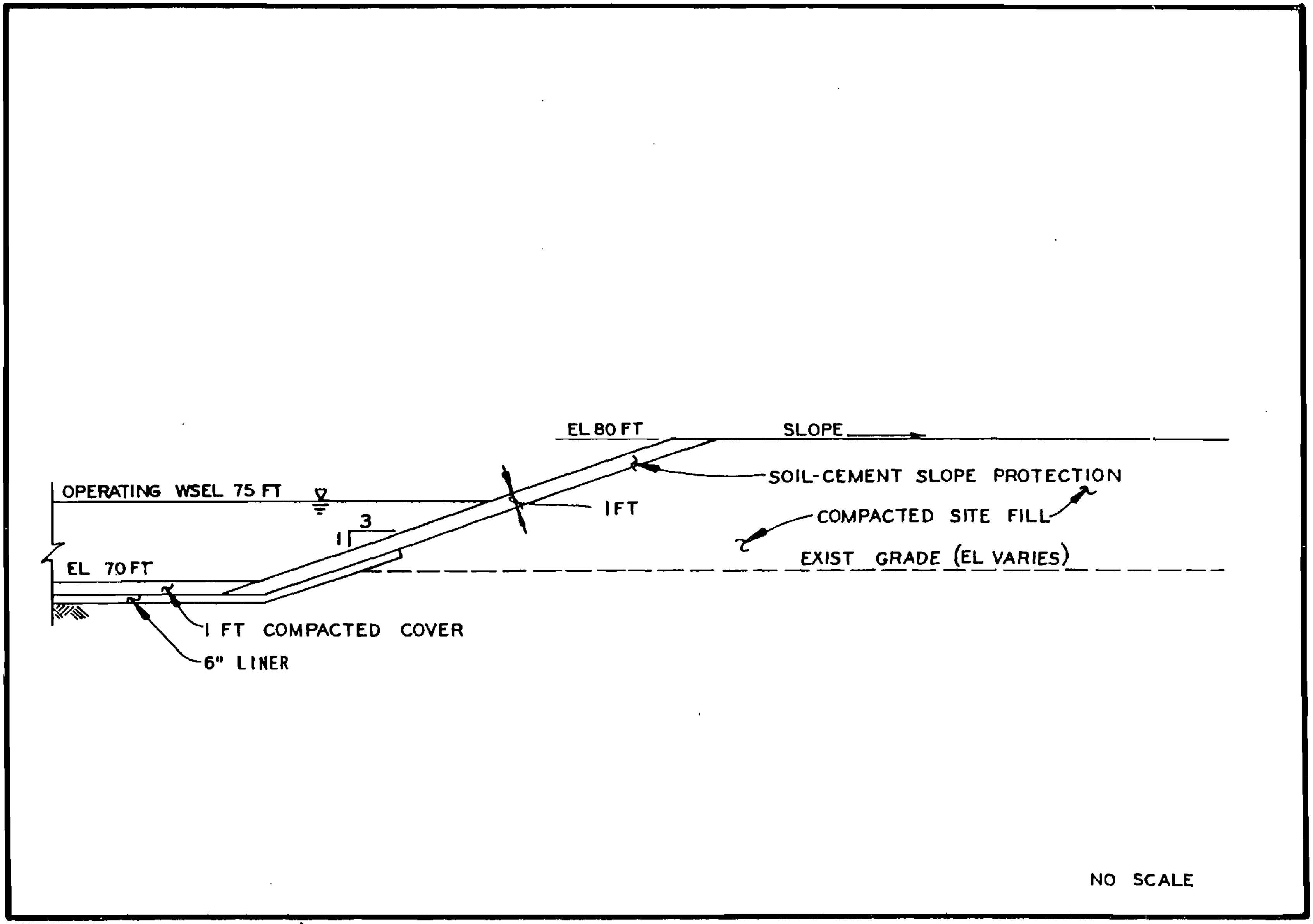

5

#3 FIGURE 3.10-4. RECYCLE BASIN EMBANKMENT SECTION

Neutralization Basin Description

3.5.8 Miscellaneous Chemical Drains

Chemical wastewaters can result from draining a chemical storage tank, overflowing a chemical tank during a filling operation, or from maintenance operations such as hosing down chemical storage areas. A separate floor drain collection system will be provided to route miscellaneous chemical wastes to the neutralization basin. Flows from the miscellaneous chemical drains will be intermittent and will not normally contribute to the wastewater flows.

3.5.9 Neutralization Basin

#5 A neutralization basin of approximately 120,000 gallons capacity will be provided for treatment of chemical wastes prior to their ultimate disposal. A basin of this capacity will be sufficient to simultaneously accommodate the wastewaters produced during regeneration of the makeup demineralizer and one condensate polisher, and will handle the largest volume of chemical cleaning solution wastes expected at one time, that being the acid cleaning solution from a steam generator. The neutralization basin will be a reinforced concrete basin lined with chemical resistant membrane, brick, and mortar. A chemical waste mixer, mounted on a walkway spanning the basin, will be provided to hasten neutralization of the chemical wastes. Sulfuric acid and sodium hydroxide, as required for neutralization, will be available from the makeup demineralizer regeneration equipment. The neutralized chemical wastewaters will be transported to the recycle basin.

Ground Water Monitoring Well Locations
Drawing 8927-ISTU-S1010

Makeup Pond and Recycle Basin Section Drawings
8927-ISTU-S3021
Figure 3.10-2
Figure 3.10-4

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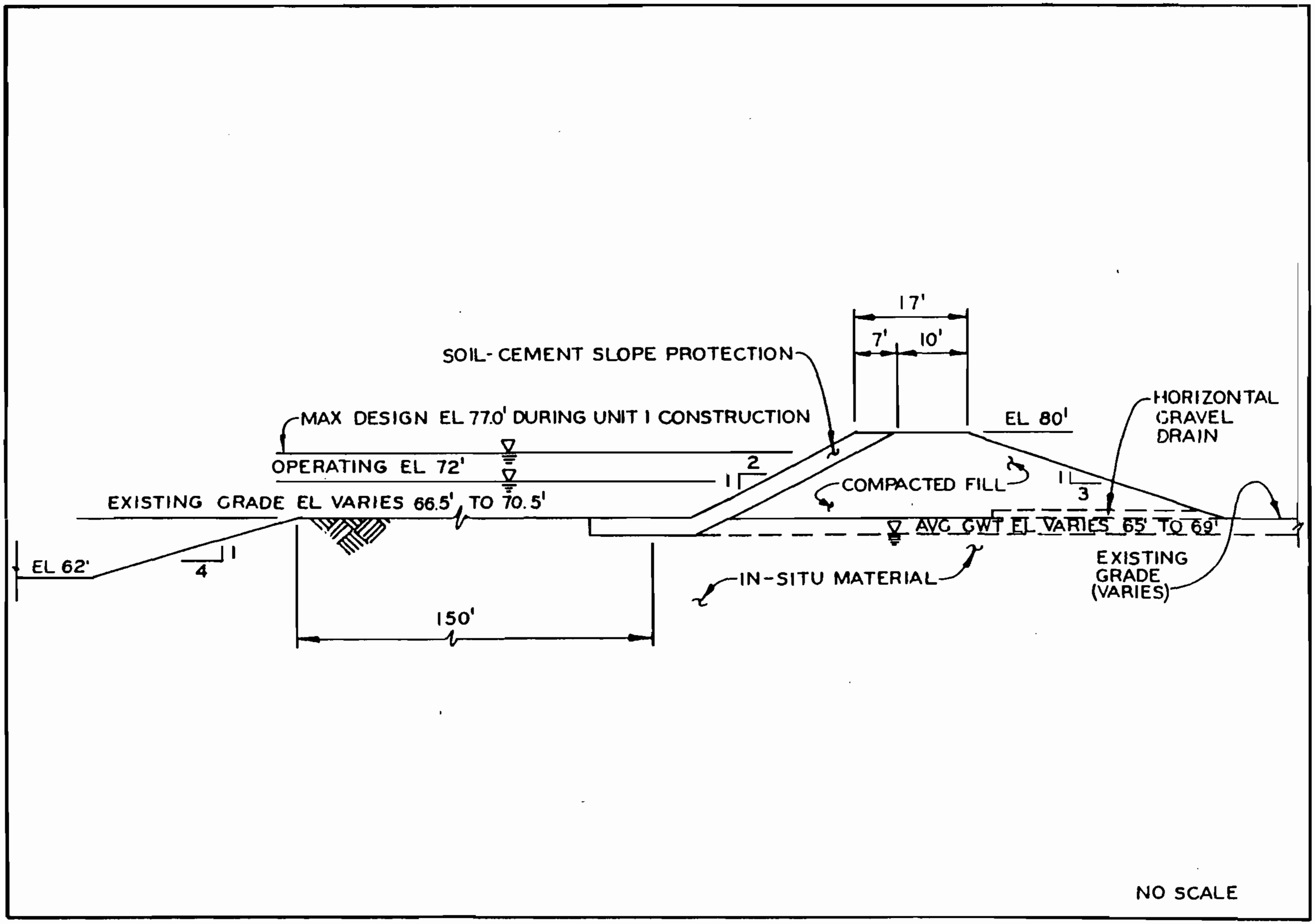

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FIGURE 3.10-2. MAKEUP WATER SUPPLY STORAGE POND EMBANKMENT SECTION

#22

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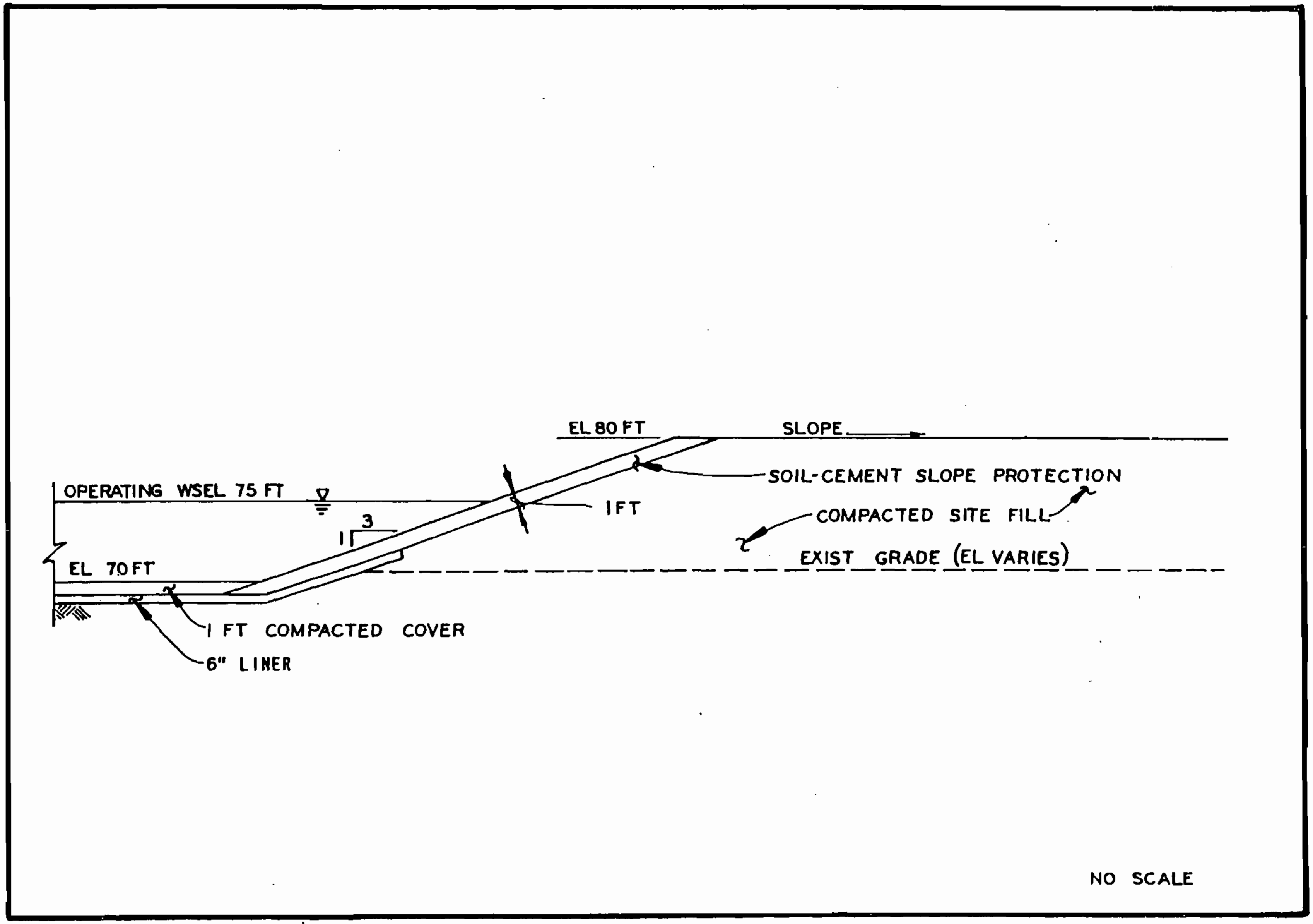

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#22 FIGURE 3.10-4. RECYCLE BASIN EMBANKMENT SECTION

Staff Gauge Readings
Year 2000

STANTON ENERGY CENTER							
MAKEUP POND AND RECYCLE BASIN STAFF GAUGE READINGS FOR 2000							
DATE	MAKEUP	RECYCLE					
	(FT)	(FT)					
1/7/00	77.3	77.8					
1/14/00	77.3	77.7					
1/21/00	77.1	77.6					
1/28/00	76.9	77.2					
2/4/00	76.8	77.3					
2/11/00	76.5	77.8					
2/18/00	76.6	78					
2/25/00	76.9	78.2					
3/2/00	76.8	78.8					
3/9/00	76.9	78.5					
3/17/00	76.7	78.1					
3/24/00	77.1	78.3					
3/31/00	77.2	78.2					
4/7/00	77	78.3					
4/14/00	76.9	78.5					
4/21/00	76.9	78.3					
4/27/00	76.7	78.1					
5/5/00	76.7	77.7					
5/12/00	76.5	77.3					
5/19/00	76.1	76.7					
5/26/00	76.7	76.6					
6/2/00	75.2	76.4					
6/9/00	74.8	75.3					
6/16/00	74.4	75.3					
6/23/00	74.5	74.9					
6/30/00	75.6	75.8					
7/7/00	75.7	75.4					
7/14/00	76.9	75.1					
7/21/00	76.1	75					
7/28/00	76.8	76.1					
8/4/00	77	76					
8/11/00	76.9	75.3					
8/18/00	76.8	74.9					
8/25/00	76.8	74.8					
9/1/00	76.7	74.4					
9/8/00	76.5	75.6					
9/14/00	76.7	76					
9/22/00	77.2	76.6					
9/29/00	77.4	76.3					
10/6/00	77.6	77					
10/13/00	77.1	76.2					
10/20/00	77.1	75.1					
10/26/00	77.3	75.2					
11/2/00	77.3	75.1					
11/10/00	76.8	76.3					
11/17/00	77	76.5					
11/22/00	77.1	75.9					
12/1/00	76.9	75.8					
12/8/00	76.9	74.9					
12/15/00	77.1	74.7					
12/22/00	76.9	75.7					
12/29/00	77.1	76.4					

Ground Water Elevations
1999-2000

Stanton Energy Center

MONITOR WELL GROUNDWATER ELEVATIONS*

MW	1999 1st QTR (FT)	1999 2nd QTR (FT)	1999 3rd QTR (FT)	1999 4th QTR (FT)	2000 1st QTR (FT)	2000 2nd QTR (FT)	2000 3rd QTR (FT)	2000 4th QTR (FT)
1	10.3	9.41	8.17	8.51	9.1	10.67	8.81	NR
2	6.84	5.41	4.39	4.21	5.4	6.08	5.08	NR
3	6.25	5.96	5.14	4.92	5.34	6.85	5.25	NR
4	6.63	6.13	4.89	4.81	5.55	6.85	5.45	NR
5	8.59	7.89	6.34	6.88	7.63	8.94	7.34	NR
6	8.58	8.45	6.06	7.03	8.13	9.58	7.36	NR
7	4.31	4.29	1.33	2.19	3.95	5.38	3.1	NR
8	7.56	7.38	6.44	6.45	6.98	8.19	11.95	NR
9	8.24	7.98	7.95	7.19	7.9	9.07	10.9	NR
10	6.42	6.67	5.82	5.68	6.4	7.7	6.7	NR
11	6.11	5.69	4.73	4.78	5.69	7.46	5.2	NR
12	10.7	10.24	8.61	8.77	10.15	11.75	9.42	NR
13	8.71	8.72	6.59	6.94	8.3	9.8	7.8	NR
14	5.58	8.47	3.44	3.98	5.05	6.2	4.8	NR
OW	6.57	6.38	4.45	5.06	4.98	7.74	5.53	NR

* - from top of casing

NR - Not Reported

ENVIRONMENTAL RESOURCE PERMITTING

1. Section 3.8.9 Storm water Management System

This section states that the system has been designed with a permanent pool residence time of 14 days. Since no littoral zone is proposed in the detention pond design a minimum 21-day residence is required per 40C42.26(4) F.A.C. Please provide supporting calculations.

This section states that the system has been designed to attenuate the peak discharge from the 100-year, 24-hour storm. Please provide a pre-post demonstration for the 25 year/24 hour and mean annual (2.3) year/24 hour design storms using the SCS II (Florida Modified) Rainfall Distribution. The 25-year storm is the design storm for projects within the SJRWMD and the mean annual storm is required for projects within the Econ Basin. Please provide inputs and output for any routing runs used in the demonstration.

a. Please provide state storage calculations with indicated levels and associated volume for permanent pool as well as pollution abatement levels.

b. Please provide a recovery demonstration indication of the orifice meets the bleed down requirements in 40C-42.026(4)(b).

Response: **Response:** The existing permanent pool volume provides residence time in excess of the 21 day requirement outlined in 40C42.26(4) F.A.C. Supplemental calculations are as follows:

Permanent Pool :

$$PPV_{rqd} = \frac{DA \times C \times R \times RT}{WS \times CF} = \frac{(52)(0.78)(31)(21)}{(153)(12)} = 14.38 \text{ acre-ft} = 626{,}461 \text{ ft}^3$$

where PPV = Permanent pool volume (acre-ft)
RT = Residence time (days)
R = Wet season rainfall (inches)
FR = Average flow rate (acre-ft/day)
CF = 12 (inches / foot)
C = runoff coefficient

$$C = \frac{(41.2 \text{ acres} \times 0.9) + (10.8 \text{ acres} \times 0.30)}{52 \text{ acres}} = 0.78$$

$PPV_{provided} = 734{,}254 \text{ ft}^3$

$PPV_{provided} > PPV_{rqd}$, therefore the existing permanent pool is adequate.

Pre-Post routing demonstrations, stage-storage calculations, and orifice design are provided in the Storm Water Management Plan immediately following Section 3.10 of the Supplemental Site Certification Application. Figure-2 has been revised to show a 90' elbow in the 5" pipe through the weir and is attached.

2. *Section 2.3.3 Vegetation*

This section describes the types of common plants found and animals observed in SEC's entire parcel (excess of 3,000 acres). However, the report does not specifically address the vegetation and animals found with the 60 acre expansion site for Stanton A, or within the proposed Substation, utilizing the Natural Gas Pipeline and for the Transmission line. In addition, the report references a botanical survey conducted from 1980 to 1981. Please provide more recent data for the site.

Response:

Expansion Site
The expansion site for Stanton A is on site property that has been prepared (filled) for future facilities, and used as a construction and equipment lay-down area for the original facility. This flat-graded area, which contains various railroad spur tracks and storm water control features, is currently maintained with regular mowing. There is no cover for wildlife species in this area, therefore, it is considered poor wildlife habitat. The mowed vegetation in the expansion area is dominated by dallis grass (*Paspalum* spp.) and witchgrass (*Dichanthelium* spp.).

Use of the 60-acre expansion site by animals is limited by the lack of habitat, the exposure to activities associated with operation and maintenance of SEC, and the 8-foot, chainlink fence that surrounds the site. However, according to a literature search and observed conditions, animals that may occasionally bypass the fence via open gates or pass through, under or over the fence include: **Mammals:** white-tailed deer (*Odocoileus virginianus*), eastern cottontail (*Syvilagus floridanus*), nine-banded armadillo (*Dasypus novemcinctus*), harvest mouse (*Reithrodontomys humulis*), old-field mouse (*Peromyscus polionotus*), Red Fox (*Vullpes vulpes*), striped skunk (*Mephitis mephitis*), raccoon (*Procyon lotor*), Virginia opossum (*Didelphis virginiana*), **Amphibians:** eastern narrow-mouth toad (*Scaphiopus holbrookii*), southern toad (*Bufo terrestris*), **Reptiles:** Florida box turtle (*Terrapene carolina bauri*), brown anole (*Anolis sagrei*), green anole (*Anolis carolinensis*), fence lizard (*Scelopaorus undulatus*), rat snake (*Elaphe obsoleta*), **Birds:** killdeer (*charadrius vociferus*), mourning dove (*Zenaida macroura*), rock dove (*Columba livia*), eastern kingbird (*Tyrannus tyrannus*), American crow (*Corvus brachyrhynchos*), American robin (*Turdus migratorius*), eastern meadowlark (*Sturnella magna*), Boat-tailed grackle (*Quiscalus major*), and common grackle (*Quiscalus quiscula*)

Substation Expansion Area

The substation expansion will occur in a 1.2-acre area immediately adjacent to and west of the existing SEC Substation No. 17 (9.2 acres). During site visits (11/7/00-11/9/00 and 12/6/00), the vegetation observed in this area included: longleaf pine (*Pinus palustris*), bushy bluestem (*Andropogon glomeratus*), lovegrass (*Eragrostis* spp.), coinwort (*Centalla asiatica*), dog fennel (*Eupatorium capilfolium*), saw palmetto (*Serenoa repens*), wax myrtle (*Myrica cerafer*), and wiregrass (*Aristida stricta*). The vegetation in this 1.2-acre area provides moderate habitat for wildlife. The proposed substation expansion area is currently not fenced and could potentially support most of the animals listed in Section 2.3.5 at some time. However, due to the proximity of the expansion area to the existing substation some of these animals will likely avoid areas immediately next to the substation because of operation and maintenance activities.

Transmission Line Corridor

The transmission line corridor passes through pine flatwoods and cypress wetland vegetative communities. However, the proposed transmission line route follows an existing maintenance trail to avoid and minimize impacts to wetlands and wildlife habitat. Plants observed in these areas during recent site visits (11/7/00-11/9/00 and 12/6/00) and identified in the most recent biological monitoring report for Stanton Energy Center mitigation areas (October 23, 1999) include: broomsedge (*Andropogon vrginicus*), bushy bluestem (*Andropogon glomeratus*), three-awn (*Aristida affinis*), bottlebrush three-awn (*Aristida spiciformis*), wiregrass (*Aristida stricta*), groundsel tree (*Baccharis halimnifolia*), blue hyssop (*Bacopa caroliniana*), partridge-pea (*Cassia chamaecrista*), coinwort (*Centella asiatica*), pineland daisy (*Chaptalia tomentosa*), Leavenworth's tickseed (*Coreopsis leavenworthii*), flatsedge (*Cyperus* spp.), coastal lovegrass (*Eragrostis refracta*), lovegrass (*Eragrostis* sp.), plumegrass (*Erianthus giganteus*), dog fennel (*Eupatorium capillifolium*), bushy goldenrod (*Euthamia minor*), marsh pennywort (*Hydrocotyle umbellata*), four-petal St. John's–wort (*Hypericum tetrapetalum*), St. John's-wort (*Hypericum* sp.), Inkberry (*Ilex glabra*), white-head bogbutton (*Lachnocaulon anceps*), redroot (*Lacnanthes caroliniana*), fetterbush (*Lyonia lucida*), wax myrtle (*Myrica cerifera*), longleaf pine (*Pinus palustris*), beakrush (*Rhynchospora* spp.), nutgrass (*Scleria baldwiniana*), nutgrass (*Scleria reticularis*), saw palmetto (*Serenoa repens*), bald cypress (*Taxodium distichum*), yellow-eyed grass (*Xyris caroliniana*), yellow-eyed grass (*Xyris* sp.).

The transmission line corridor and vicinity currently provides moderate wildlife habitat and may potentially support the following animals: **Mammals:** Virginia opossum (*Didelphis virginiana*), southeastern shrew (*Sorex longirostris*), southern short-tailed shrew (*Blarina carolinensis*), least shrew (*Cryptotis parva*), eastern pipistrelle (*Pipistrellus subflavus*), big brown bat (*Eptesicus fuscus*), hoary bat (*Lasiurus cinereus*), northern yellow bat (*Lasiurus intermedius*), seminole bat (*Lasiurus seminolus*), evening bat (*Nycticeius humeralis*), Rafinesque's big-eared bat (*Corynorhinus rafinesquii*), brazilian free-tailed bat (*Tadarida brasiliensis*), nine-banded armadillo (*Dasypus novemcinctus*), eastern cottontail (*Sylvilagus floridanus*), marsh rabbit (*Sylvilagus palustris*), marsh rice rat (*Oryzomys palustris*), harvest mouse (*Reithrodontomys humulis*), cotton mouse (*Peromyscus gossypinus*), golden mouse (*Ochrotomys nuttalli*), hispid cotton rat (*Sigmodon hispidus*), round-tailed muskrat (*Neofiber alleni*), coyote (*Canis latrans*), Red Fox (*Vulpes vulpes*), gray fox (*Urocyon cinereoargenteus*), raccoon (*Procyon lotor*), long-tailed weasel (*Mustela frenata*), striped skunk (*Mephitis mephitis*), bobcat (*Lynx rufus*), feral pig (*Sus scrofa*), white-tailed deer (*Odocoileus virginianus*), **Amphibians:** eastern narrow-mouth toad (*Scaphiopus holbrooki*), crawfish frog (*Rana areolata*), pig frog (*Rana grylio*), southern leopard frog (*Rana utricularia*), eastern narrow-mouth toad (*Gastrophryne carolinensis*), oak toad (*Bufo querecius*), southern toad (*Bufo terrestris*), Florida cricket frog (*Hyla cinerea cinerea*), Pine woods treefrog (*Hyla femoralis*), barking treefrog (*Hyla gratiosa*), squirrel treefrog (*Hyla squirella*), chorus frog (*Pseudacris nigrita*), little grass frog (*Limnaoedus ocularis*), **Reptiles:** Florida box turtle (*Terrapene carolina bauri*), brown snake (*Storeria dekayi*), mud snake (*Farancia abacura*), pine snake (*Pituouphis melanoleucus*), Florida cottonmouth (*Agkistrodon piscivorus conanti*), rat snake (*Elaphe obsoleta*), **Birds:** cattle egret (*Bubulcus ibis*), turkey vulture (*Cathartes aura*), black vulture (*Coragyps atratus*), red-tailed hawk (*Buteo lineatus*), marsh hawk (*Circus cyaneus*); American kestrel (*Falco sparverius*), bobwhite (*Colinus virginianus*), killdeer (*Charadrius vociferus*), mourning dove (*Zenaida macroura*), eastern kingbird (*Tyrannus tyrannus*), great crested flycatcher (*Myiarchus crinitus*), American crow (*Corvus brachyrhynchos*), American robin (*Turdus migratorius*), Carolina chickadee (*Parus carolinensis*), house wren (*Troglodytes aedon*), mockingbird (*Mimus plyglottos*), eastern bluebird (*Sialia sialis*), loggerhead shrike (*Lanius ludovicianus*), yellow-rumped warbler (*Dendroica coronata*), pine warbler (*Dendroica pinus*), eastern meadowlark (*Sturnella magna*), Boat-tailed grackle (*Quiscalus major*), common grackle (*Quiscalus quiscula*), northern cardinal (*Cardinalis cardinalis*), and savannah sparrow (*Passerculus sandvicensis*).

Natural Gas Pipeline Corridor

The natural gas pipeline route is located entirely within the OUC utility corridor extending south from the main SEC property, and more specifically, adjacent to the maintenance trail within the corridor. The vegetation in these areas is mostly maintained as lawn for maintenance and operation of the transmission line and railroad tracks. Common plants observed in these areas during recent site visits (11/7/00-11/9/00 and 12/6/00) and identified in the most recent biological monitoring report for Stanton Energy Center mitigation areas (October 23, 1999) include: bahiagrass (*Paspalum notatum*), bushy bluestem (*Andropogon glomeratus*), little bluestem (*Schizachrium scoparium*), witch grasses (*Dichanthelium* spp.), groundsel tree (*Baccharis halimnifolia*), dog fennel (*Eupatorium capillifolium*), and bushy goldenrod (*Euthamia minor*). Common animals occurring in this area are similar to those found in the SEC Stanton A expansion area.

3. *Section 3.3.3.2 mentions that the existing rail line will be upgraded northwest of the coal units. What does the upgrade entail to the rail line? Addition impacts to wetlands, additional impervious storm water concerns, etc?*

   Response: Potential upgrades include new ballast, track/tie replacement, reconnections. No additional impacts to wetlands or additional impervious storm water concerns are anticipated.

4. *Please provide the Central District with a copy of the Orlando Utilities Commission Joint Agency Mitigation Monitoring Plan (1992).*

   Response: A copy of the Joint Agency Mitigation Monitoring Plan is included as Attachment D.

5. *Section 4.1.1 identifies general construction impacts. The 60 acre Stanton A is described as "generally maintained grassland." This is not sufficient information/description to conclude that the area is an upland. Please clarify and revise accordingly.*

   a. *Please provide a copy of the wetland determination for this parcel.*

   b. *Was a formal binding determination permitted by the Department? If yes, please provide a copy.*

   c. *Specifically identify all wetland areas proposed for impact (including temporary and permanent and for the conversion of a forested system to herbaceous wetland).*

   Response: The 60 acre Stanton A expansion area was graded, filled, and prepared during construction for Units 1 and 2. The area was used for equipment laydown during construction of Units 1 and 2 and included within the previously certified area for potential future development. The vegetation is dominated by dallisgrass (*Paspalum dilatatum*) and Bermuda grass (*Cynodon dactylon*), which is currently maintained with regular mowing. When the expansion area was prepared, a storm water management system was also constructed. These storm water structures include drainage swales, culverts, and a detention pond. The detention pond will be regraded to meet detention requirements associated with Stanton A. The altered vegetation, hydrology, and soils of this parcel do not exhibit wetland attributes.

   a. No wetland determination was prepared for this parcel. Grading and storm water activities and environmental impacts associated with the expansion area were included in the Site Certification for Units 1 and 2.

   b. No evidence of a formal binding determination was found.

   c. **Substation Expansion Area (W1 on Figure 6.1-1 in SSCA)**

The wetland impact area within the substation expansion area is identified as W1 and is a herbaceous wetland. This wetland will be filled with crushed rock and converted to upland. This impact will be permanent and encompass an area of 0.13 acre.

Transmission Line Corridor (W2, W3, W4, and W6 on Figure 6.1-1 in SSCA)

Impact area W2 is a herbaceous wetland area within the proposed transmission line corridor. This wetland area will be filled with native soil and converted to upland. This impact will be permanent and will encompass an area of 0.23 acre. This impact area is a proposed site for one of the transmission structures and supporting keyhole pad.

Impact area W3 is a cypress strand area within the proposed transmission line corridor. The trees within the 125-foot wide transmission corridor will be cleared and permanently maintained as an emergent wetland. The impact area is 0.40 acre.

Impact area W4 is a herbaceous wetland within the proposed transmission line corridor. This wetland area will be filled with native soil and converted to upland. This impact will be permanent and will encompass an area of 0.11 acre. This impact area is a proposed site for one of the transmission structures and supporting keyhole pad.

Impact area W6 is a borrow ditch from which soil was removed and used to construct the existing field access road. This surface water will be filled with native soil and converted to upland. This impact will be permanent and will encompass an area of 0.23 acre. This impact includes proposed sites for two transmission structures and supporting keyhole pads.

Natural Gas Pipeline Corridor (W5 on Drawing 98362-ERP-4A in Section 10.4.4 in the SSCA)

Impact area W5 is a herbaceous wetland within the proposed gas pipeline corridor. This wetland was mistakenly labeled "forested mixed wetlands" wetland type in Table 6.2-2 of the SSCA. This wetland area was cleared for utility corridor use (railroad, maintenance road, transmission line) and is maintained in a herbaceous state. The existing vegetation is dominated by (*Juncus effusus*), arrowhead (*Sagittaria* sp.), and cattails (*Typha latifolia*). Only a few saplings of red maple (*Acer rubrum*), sweet gum (*Liquidambar styraciflua*), and bald cypress (*Taxodium distichum*) remain in this area. This wetland area will be trenched, the pipeline will be installed, and then the soils will be replaced to original grade. This impact will be temporary and will encompass an area of 0.06 acre. This impact is temporary because the herbaceous vegetation and wetland conditions will be allowed to return.

6. *Drawing Figure 6.1-1 is not legible.*

Response: Large scale drawings of the proposed and alternate transmission line routes are attached as Figure 6.1-1. The drawings have been signed and sealed.

7. *Please provide clear detailed plan and cross section drawings to the proposed transmission line. Specifically include:*

   a. *road names*
   b. *location of existing line (with dimensions)*
   c. *location of proposed line (with dimensions)*
   d. *location of wetlands, ditches, surface waters, etc. (in numerical order)*
   e. *length and width of the line that will impact wetlands*
   f. *legend for wetlands including type and acreage*
   g. *cross section location*
   h. *location of the proposed road*
   i. *substation location and dimensions*
   j. *concrete pad locations with dimensions*
   k. *turbidity barrier type and location*
   l. *other pertinent information*

Response:

a) There are no named roads in the near vicinity of the transmission line, which is entirely on SEC property. The closest road is Alafaya Trail. This road is now marked on Drawing TLINE3, Figure 6.1-1, revised on March 21, 2001.

b) The existing transmission lines going south out of the SEC Substation are now shown on Drawing TLINE 3, Figure 6.1-1.

c) The location of the transmission centerline is shown on Figure 6.1-1.

d) Revised Drawing TLINE3, Figure 6.1-1 illustrates the location of the wetlands, ditches, surface waters in numerical order (W-1 through W-6).

e) Revised Drawing TLINE3, Figure 6.1-1 illustrates the size and width of the transmission line impacts.

f) A legend providing wetland type and acreage can be found on Drawing 98362-ERP-4.

g) The cross section location is shown on Figure 6.1-1.

h) The applicants are not proposing to construct any roads for the proposed transmission line route.

i) The Substation location and impact area are shown on Figure 6.1-1.

j) There will be no large concrete pads. Structures will be either concrete or steel poles. Concrete poles will be directly embedded. Steel poles will either be direct embedded or supported by concrete pier foundations.

k) Turbidity barriers are shown on Drawing 98362 ERP-1A in Section 10.4 of the SSCA.
l) There is no other pertinent information.

8. *Revise the cross section drawings to provide:*

a. width of the line/corridor
b. cross hatch fill in wetlands, surface waters, ditches, etc.
c. legend to the cross hatched areas
d. acreage to the impact areas
e. all dimensions to toe of slope
f. dimension to slope to the keypad.

Response:

a) The width and length of line is shown on Figure 6.1-1.
b) TLINE3, Figure 6.1-1 provides a plan view of the transmission line and includes cross hatched wetlands, surface waters, ditches. Figure 6.1-1 also includes a cross section of the transmission line indicating the impact area within the adjacent borrow ditch.
c) Figure 6.1-1 provides a legend to cross hatched areas.
d) Figure 6.1-1 provides acreages to the impact areas.
e) The toe of slope has a 3:1 ratio using a unitless measure.
f) The distance between the transmission pole and the toe of slope of the keyhole pad is 56' with 2' of fill or 59' with 3' of fill.

9. *Demonstrate why a new 125 feet wide corridor is necessary for the proposed transmission line. Please provide avoidance/minimization and alternatives considered for the new line.*

Response: Under high wind conditions such as those generated by hurricane winds, the transmission structures deflect and the conductors (wires) blow out (swing) significantly. The right-of-way width selected is the minimum width to keep the conductors contained on the right-of-way under these conditions, as required by electric codes. In addition, Florida has established limits for electric and magnetic fields within and at the edge of rights-of-way. Again the right-of-way width selected is the minimum width to satisfy the Florida Statute regarding EMF.

The proposed route was selected over the alternate route due to environmental impacts, cost, and the need to construct access roads. Although the alternate route would have paralleled the existing transmission lines, this route had additional wetlands impacts from construction of both access roads and key hole pads.

10. *Section 6.1.8.1.*

a. *Are culverts required to maintain hydrologic flow? If yes, please reflect on the plan and cross section drawings.*

b. *Where are the concrete foundations being installed? (Identify on the drawings any that will be in wetlands, ditches, surface waters, etc. and provide dimensions).*

Response:

a. No access roads or flow constraints are being constructed for the transmission line. As such, no culverts are being installed. Storm water will flow naturally around the key hole pads.

b. The concrete pier foundations for the transmission line structures will be located directly under the transmission structures. The locations and dimensions of these structures are shown on revised Figures 6.1-1 and 6.1-2, which are attached.

11. *Section 6.1.8.4*

Identifies 0.4 acres of forested cypress strand to be cleared. Table 6.1-3 indicates clearing will be permanent. Please identify whether the entire area will be converted from a forested wetland to herbaceous wetland or from a forested wetland to upland filled area. Please revise the drawing and tables/exhibits accordingly.

Response: The forested cypress strand (0.4 acre) referenced in Table 6.1-3 will be converted to and maintained as herbaceous wetland; no fill is required or proposed to this area. A revised Figure 98362-ERP-4 identifies the wetland impact types (*i.e.*, fill or clear) for the permanent wetland impact areas.

12. *6.2 Natural Gas Pipeline*

Where is the 4.5 mile 16 inch FGT transmission line located?

a. *Demonstrate why a 16-inch pipeline requires a 50 feet wide permanent corridor.*

b. *Drawing Figure 6.2-1 may serve as an overall location map for the proposed natural gas pipeline provided road names and section, townships and ranges were added to the drawing and the drawing is legible.*

c. *Detailed plan and cross section drawing are required for the entire pipeline. Include in the plan view drawing:*
   - a) *wetland locations*
   - b) *wetland types*

c) *cross hatch proposed wetland impacts*
d) *location of the proposed pipeline*
e) *temporary work area with dimension*
f) *cross hatch wetland impacts*
g) *legend to the proposed wetland impacts*
h) *dimensions (length and width) to the impacts*
i) *road names*
j) *north arrow*
k) *cross section*

Response:

6.2 Natural Gas Pipeline

The 26" FGT supply line is located approximately 1.5 miles south of the Bee-Line, as shown on Figure 2.1-1 in the SSCA.

a. Except where the gas pipeline crosses Bee Line Expressway right-of-way, the entire route is on OUC property. The 35-foot corridor is entirely within the larger OUC corridor (which was disturbed with the installation of the railroad and southern access road) and is required for pipeline access and maintenance. The 35-foot area would support trucks, repair equipment, temporary spoil area, and pipe laydown area.

b. Revised Figure 6.2-1 is included herein and provides the requested legal description for the location of the project and the natural gas pipeline. Refer to Drawing 098362-DS-S3300 for road names and locations.

c.
  a) See Drawings S3306, Rev. 1 and S3308, Rev. 1, which are included in Attachment E.
  b) See Drawings S3306, Rev. 1 and S3308, Rev. 1 in Attachment E.
  c) See Drawings S3306, Rev. 1 and S3308, Rev. 1 in Attachment E.
  d) See Drawings S3300-S3309 in Attachment E as well as Figure 6.2-1, Figure 6.2-2 (revised, dated 04-17-2001), and Figure 6.2-2A (new, dated 04-17-2001).
  e) The temporary work area is the area within the silt fencing as shown on Drawings S3300-S3309 in Attachment E.
  f) See the response in 12(c).
  g) See Drawing 98362-ERP-4A.
  h) See Drawing 98362-ERP-4A.
  i) See Drawing S3300, Rev. 1, in Attachment E.
  j) North arrows are on all drawings that require one.
  k) See Figures 6.2-2 and 6.2-2A.

13. Cross section drawings are necessary for the wetland, surface water and ditch crossings. Include the following:

a. identify cross section

b. *width of cross section*
c. *cross hatch impacts*
d. *location of the existing railway, unimproved roadway, etc.*
e. *location of the transmission line*
f. *culvert type, size, dimensions, invert*
g. *stabilization type*
h. *turbidity type and location*

Response: Figure 6.2-2A has been created to show these details. Drawings S3300-S3309 in Attachment E provide location information and silt fence installations. No culverts are required.

14. *Please indicate avoidance/minimization considerations for the transmission line installation. Include documentation regarding the construction of this line by directional bore.*

Response: The applicants believe the question was meant to refer to the natural gas pipeline and have addressed the pipeline considerations in this response. No alternatives to the proposed gas pipeline route were considered between the FGT pipeline and Stanton A. During the selection of potential routing options, the primary objectives were to minimize impacts to wetlands, wildlife, protected species, such as the red-cockaded woodpeckers, and to follow existing linear facilities in the project area. The proposed route was the obvious choice. It is the shortest possible route and will have a minimal impact on the environment. The choice to place the gas pipeline adjacent to existing roadways and within existing utility corridors appears to be a logical routing option.

Regarding the construction of this line by directional bore, trenching was chosen over directional boring based on the high cost of directional boring and the minimal impact to the small, poor quality wetland to be crossed.

15. *Provide a copy of the permit file number, type of permit, date authorized for the existing 26 inch FGT gas line.*

Response: The FGT 26 inch mainline was authorized pursuant to FERC Docket No. CP65-393.

16. *Will the pipeline cross any surface waters? If yes, please identify all surface waters in your drawings. Please note that if the surface waters are determined to be sovereign submerged lands than a public easement will be necessary for all sovereign impacts.*

Response: The proposed pipeline will cross two surface waters. Following the pipeline route from the north to south, the first surface water is located on SEC property (Drawing S3306, rev. 1). At this point, the pipeline will be attached to the existing access road bridge for an aerial crossing. The second surface water crossing is illustrated on Drawing S3308, rev. 1, included in Attachment E. The gas pipeline will be installed within the existing dirt access trail for the second surface water crossing. Drawings S3306, rev. 1 and S3308, rev. 1 illustrating surface water locations are enclosed in Attachment E in response to sufficiency questions 12 and 22.

These areas do not include sovereign submerged lands, as indicated by letter dated March 13, 2001, from FDEP's Bureau of Public Land Administration and attached herein.

17. *Section 6.3.7.2 states that the Green Branch and Turkey Creek will be crossed by the 16-inch natural gas transmission line. Has a title determination been conducted for these locations? Please note as indicated above that if these areas are sovereign submerged lands then a public easement with detailed survey drawings will be required for the impacts crossing any that is sovereign.*

Response: These areas do not include sovereign submerged lands, as indicated by letter dated March 13, 2001, from FDEP's Bureau of Public Land Administration and attached herein.

18. *Table 6.2.2 states fill in forested wetlands as a temporary impact. Please clarify. (Typically, the owner of the transmission line does not desire forested systems to recruit within their pipeline and corridor.)*

Therefore, it appears that the fill in the forested system is permanent impact. Please clarify and revise all documentation.

Response: The wetlands identified in Table 6.2.2 were initially surveyed by review of US Geological Survey maps and National Wetlands Inventory maps. Field surveys were conducted in November and December of 2000. Table 6.2.2 does not reflect field reconnaissance information. Field surveys indicated that the forested mixed wetlands and cypress strands were mistakenly labeled. While these wetlands were forested prior to development of the utility corridor, the impact areas are no longer forested and are maintained in herbaceous or emergent vegetation. The new gas pipeline will not require clearing of forested wetlands, only trenching through emergent wetlands in one area. The trenching impacts will be temporary and herbaceous wetland conditions will be maintained. The revised wetland impacts are given below.

Table 6.2-2 Wetland Areas and Impacts Within the SEC Natural Gas Pipeline Corridor		
Wetland Type	**ft²/acres**	**Impact Type**
Emergent wetland (Forested mixed wetlands)	2,760/0.06	Trench/Backfill - Temporary
Upland (Cypress strand)	8,110/0.17	No Impact - Previously converted
Emergent wetland (Cypress strand)	8,750/0.20	No Impact - Pipeline will be attached to access road bridge

19. Section 6.2.7.3.1 references a survey conducted in 1981. These are outdated.

Response:

Natural Gas Pipeline Corridor

The natural gas pipeline route is located immediately next to the SEC access road and within the OUC utility corridor south of the SEC property. The vegetation in these areas is mostly maintained as lawn for maintenance and operation of the transmission line and railroad tracks. Common plants observed in the gas pipeline corridor during recent site visits (11/7/00-11/9/00 and 12/6/00) and identified in the most recent biological monitoring report for Stanton Energy Center mitigation areas (October 23, 1999) include bahiagrass (*Paspalum notatum*), bushy bluestem (*Andropogon glomeratus*), little bluestem (*Schizachrium scoparium*), witch grasses (*Dichanthelium* spp.), groundsel tree (*Baccharis halmnifolia*), dog fennel (*Eupatorium capillifolium*), and bushy goldenrod (*Euthamia minor*). Common animals occurring in the pipeline corridor include: **Mammals:** white-tailed deer (*Odocoileus virginianus*), eastern cottontail (*Syvilagus floridanus*), nine-banded armadillo (*Dasypus novemcinctus*), harvest mouse (*Reithrodontomys humulis*), old-field mouse (*Peromyscus polionotus*), Red Fox (*Vullpes vulpes*), striped skunk (*Mephitis mephitis*), raccoon (*Procyon lotor*), Virginia opossum (*Didelphis virginiana*), **Amphibians:** eastern narrow-mouth toad (*Scaphiopus holbrookii*), southern toad (*Bufo terrestris*), **Reptiles:** Florida box turtle (*Terrapene carolina bauri*), brown anole (*Anolis sagrei*), green anole (*Anolis carolinensis*), fence lizard (*Scelopaorus undulatus*), rat snake (*Elaphe obsoleta*), **Birds:** killdeer (*charadrius vociferus*), mourning dove (*Zenaida macroura*), rock dove (*Columba livia*), eastern kingbird (*Tyrannus tyrannus*), American crow (*Corvus brachyrhynchos*), American robin (*Turdus migratorius*), eastern meadowlark (*Sturnella magna*), Boat-tailed grackle (*Quiscalus major*), and common grackle (*Quiscalus quiscula*).

20. *Section 6.2.8.4 states that the pipeline will have minimal impact on vegetation and is temporary in nature. Please refer to statement regarding permanent impacts above.*

Response: Please refer to the response given for Question 18.

21. *Figure 6.2-2 please revise to include the following to this exhibit:*

    a. *total width in wetlands*
    b. *statement that all disturbed area will be returned to pre-existing elevations.*

Response: See updated Figures 6.2-2 and 6.2-2A.

22. *No detail plan view drawings were provided for the proposed pipeline.*

    a. *Please note that it appears that mitigation will be required for the conversion of forested wetlands to a herbaceous wetland and for all permanent impacts.*
    b. *What considerations were made for the Substation expansion which in the application reflects 0.13 acres of fill? Please demonstrate avoidance/minimization.*

    Response: See Drawings S3300-S3309 in Attachment E.

    a. Due to the minimal wetlands impacts resulting from the development of Unit A, the applicants propose to purchase mitigation banking credits as compensation.

    b. The substation expansion is an unavoidable impact. The new bay for the Unit A connection was placed on the west side of the substation to leave the existing bays for future units open and available using the existing transmission line corridor.

23. *Please note that the drawings provided in the Joint Application for an Environmental Resource Permit application are not legible. (Refer to the questions/statements regarding the plan and cross section drawings above.)*

Response: Refer to revised Figure 2, Figure 8, and Drawings 98362-ERP-4, 98362-TLINE2, and 98362-TLINE3.

24. *ERP Drawing 98-362-ERP-4A reflects 2,760 square feet of wetland impacts to Wetland 5 (W5). Please explain why W5 impact (east of the existing roadway) is necessary.*

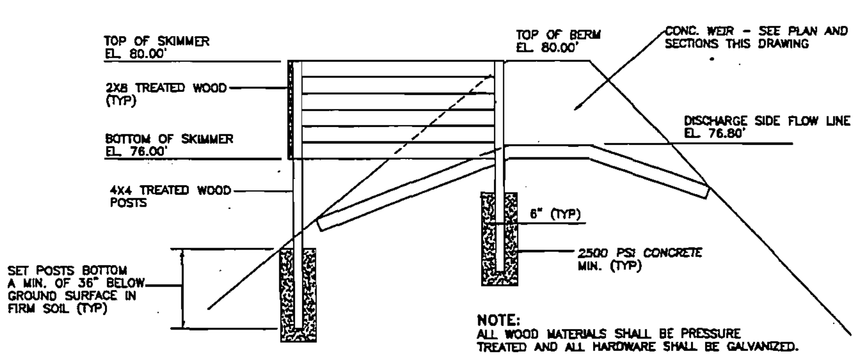
Response: Wetland impact area W5 would be a temporary impact to a previously disturbed, low quality herbaceous wetland and is required to install the natural gas pipeline. The wetland area spans the width of the corridor and cannot be reasonably avoided. Alternative installation techniques (i.e. directional bore) would not be cost effective for this small area. The temporary trench would be backfilled with the original excavated material, returned to original contours, and allowed to revegetate to an herbaceous or emergent cover.

25. *The section, Township and Ranges in the maps/drawings are not legible.*

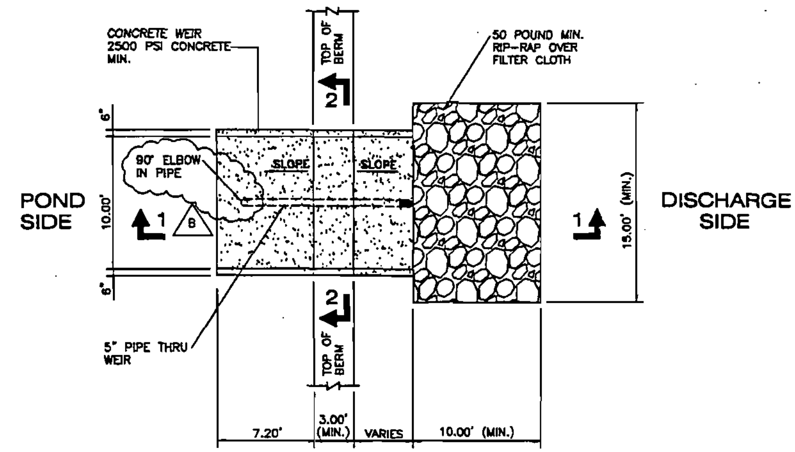
Response: A revised Figure 2, Property Location, is included herein and provides the requested Sections, Townships and Ranges for the project.

Storm Water Pond Section and Details
Figure 2, Rev. B

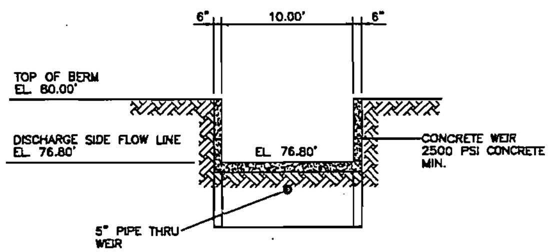
FIGURE-2



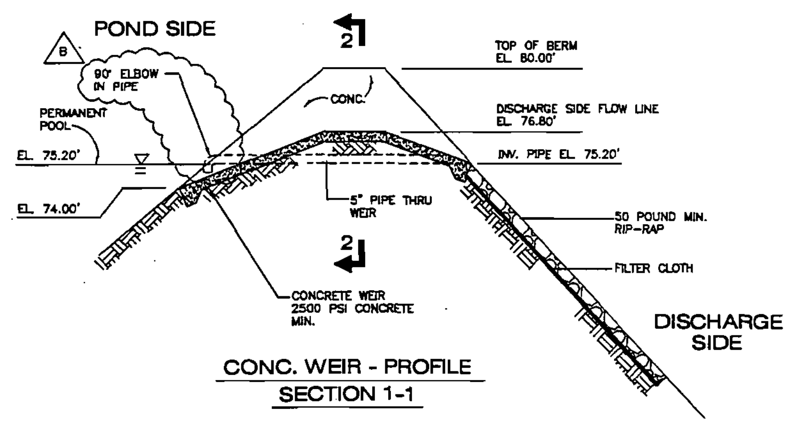
SECTION THRU OIL SKIMMER



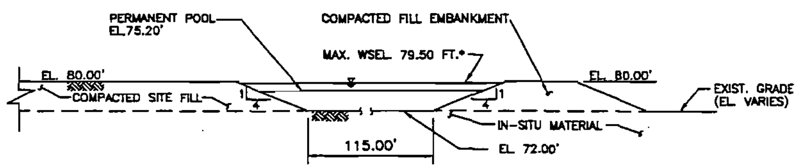
PLAN VIEW AT CONCRETE WEIR



CONC. WEIR
SECTION 2-2



CONC. WEIR - PROFILE
SECTION 1-1



*RESULTING FROM RUNOFF AND DIRECT PRECIPITATION FROM 100-YEAR, ANNUAL RAINFALL

SECTION 3-3
LOOKING WEST

SECTION TAKEN ON FIGURE-1

CAD FIGURE-2.DWG
AutoCad | CMF-20001

Southern Company Services, Inc.
FOR
SOUTHERN COMPANY GENERATION

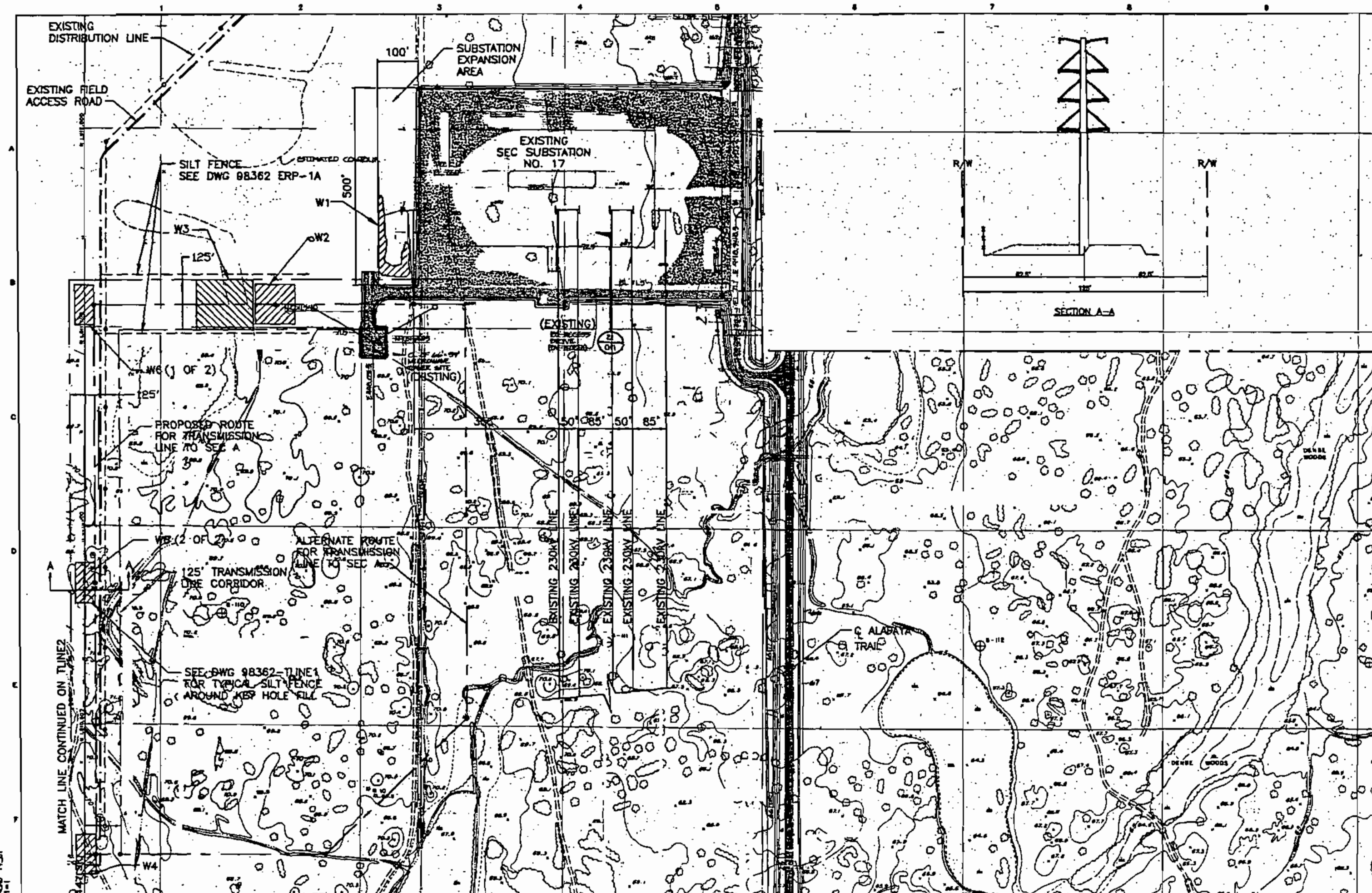
STANTON ENERGY CENTER - UNIT A
1-2x1 COMBINED CYCLE BLOCK
SECTIONS AND DETAILS

REVISION	DATE	DESCRIPTION	BY	CHK'D
B	4/04/01	ADDED 90° ELBOW IN 5" PIPE THRU WEIR	CMF	RCB
A	01/12/01	ISSUED FOR REVIEW	CMF	

DESIGNED	DRAWN	CHECKED	SCALE	PROJECT I.D.	DRAWING NUMBER	REV.
RCB	CMF		NONE		FIGURE-2	B

Figure 6.1-1:
TLINE2
TLINE3

Wetland Impact Areas
Drawing 98362-ERP-4



LEGEND

FILL IMPACTS

CLEARING IMPACTS

IMPACT AREA	DESCRIPTION
W1	HERBACEOUS WETLAND (0.13 ACRE)
W2	HERBACEOUS WETLAND (0.23 ACRE)
W3	CYPRESS WETLAND (0.40 ACRE)
W4	HERBACEOUS WETLAND (0.11 ACRE)
*W5	HERBACEOUS WETLAND (0.06 ACRE)
W6	SURFACE WATER (TOTAL = 0.23 ACRE)

* IMPACT AREA W5 IS SHOWN ON DRAWING 98362-ERP-4A.

STANTON ENERGY CENTER
COMBINED CYCLE PROJECT

WETLAND IMPACT AREAS

DRAWING 98362-ERP-4

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP
0		INITIAL ISSUE			

DRAWING STATUS – PROJECT:
NOT TO BE USED FOR CONSTRUCTION
RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION
RELEASED FOR CONSTRUCTION
CONFORMED TO CONSTRUCTION RECORDS

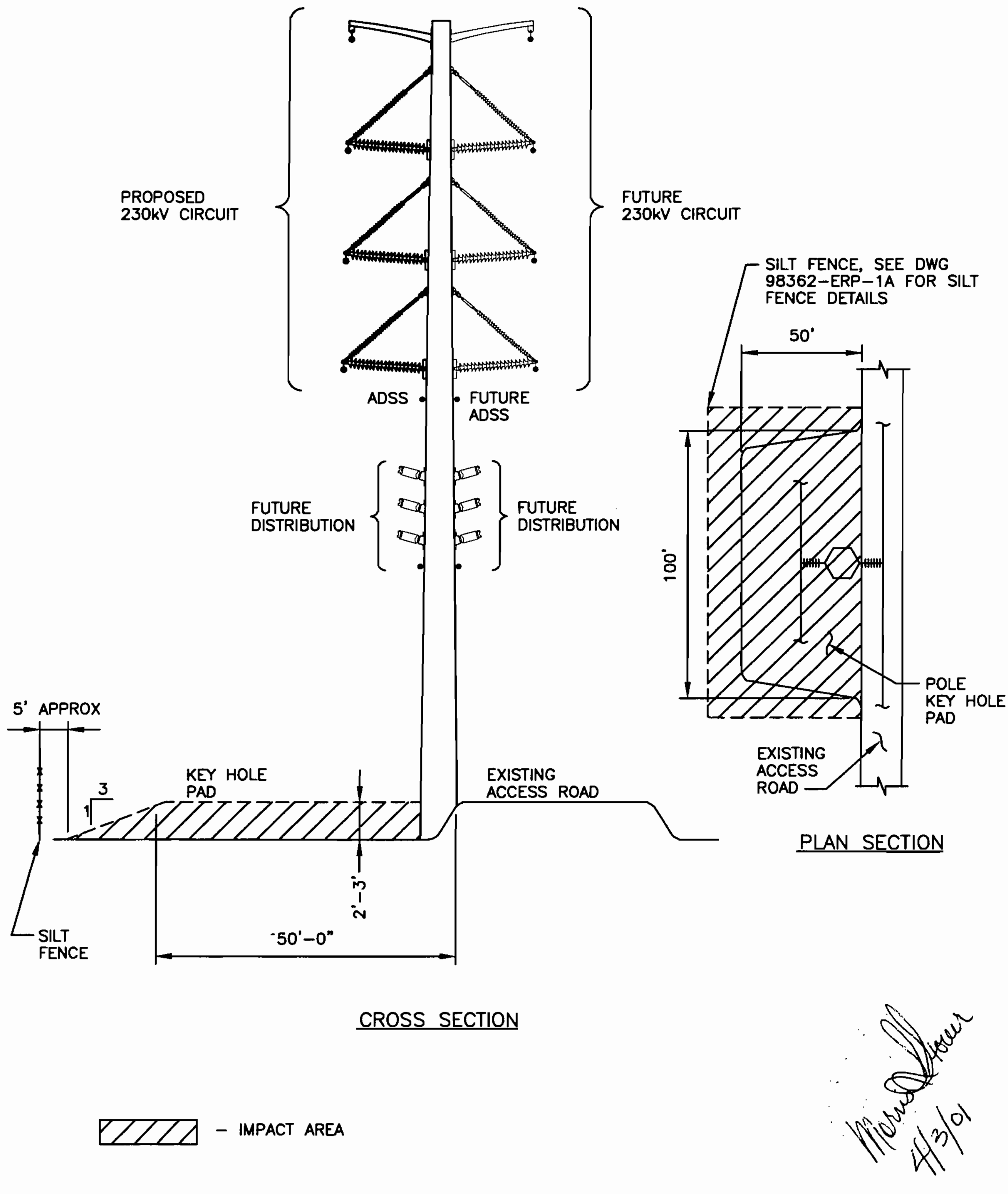
BLACK & VEATCH

ORLANDO UTILITIES COMMISSION
ORLANDO, FLORIDA

STANTON ENERGY CENTER COMBINED CYCLE PROJECT
T-LINE SILT FENCE PLAN

PROJECT 98362
DRAWING NUMBER TLINE3
TLINE3

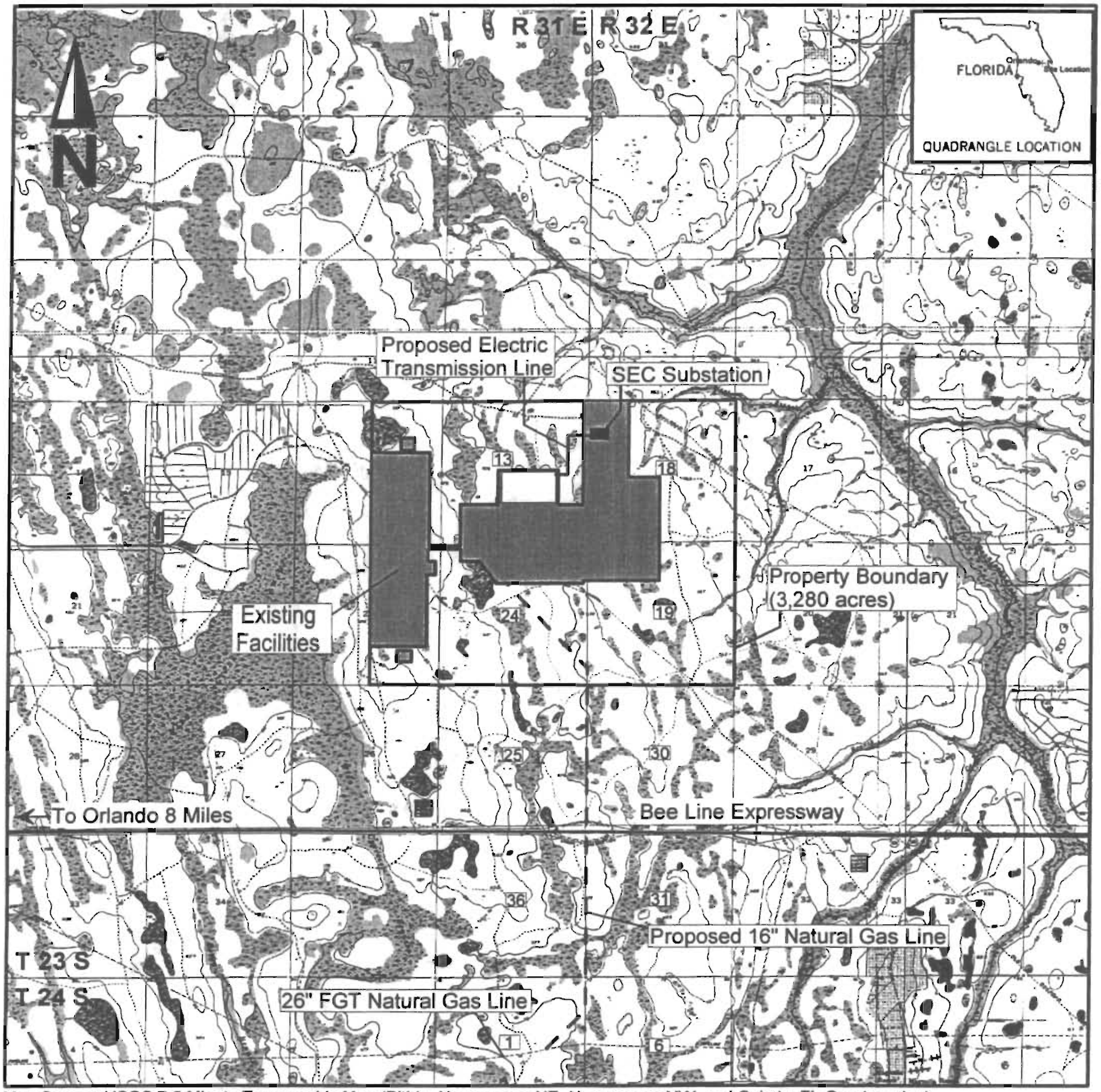
Typical Transmission Tower Structures
Figure 6.1-2



TYPICAL TRANSMISSION
TOWER STRUCTURES

FIGURE 6.1-2

Location Map
Figure 6.2-1



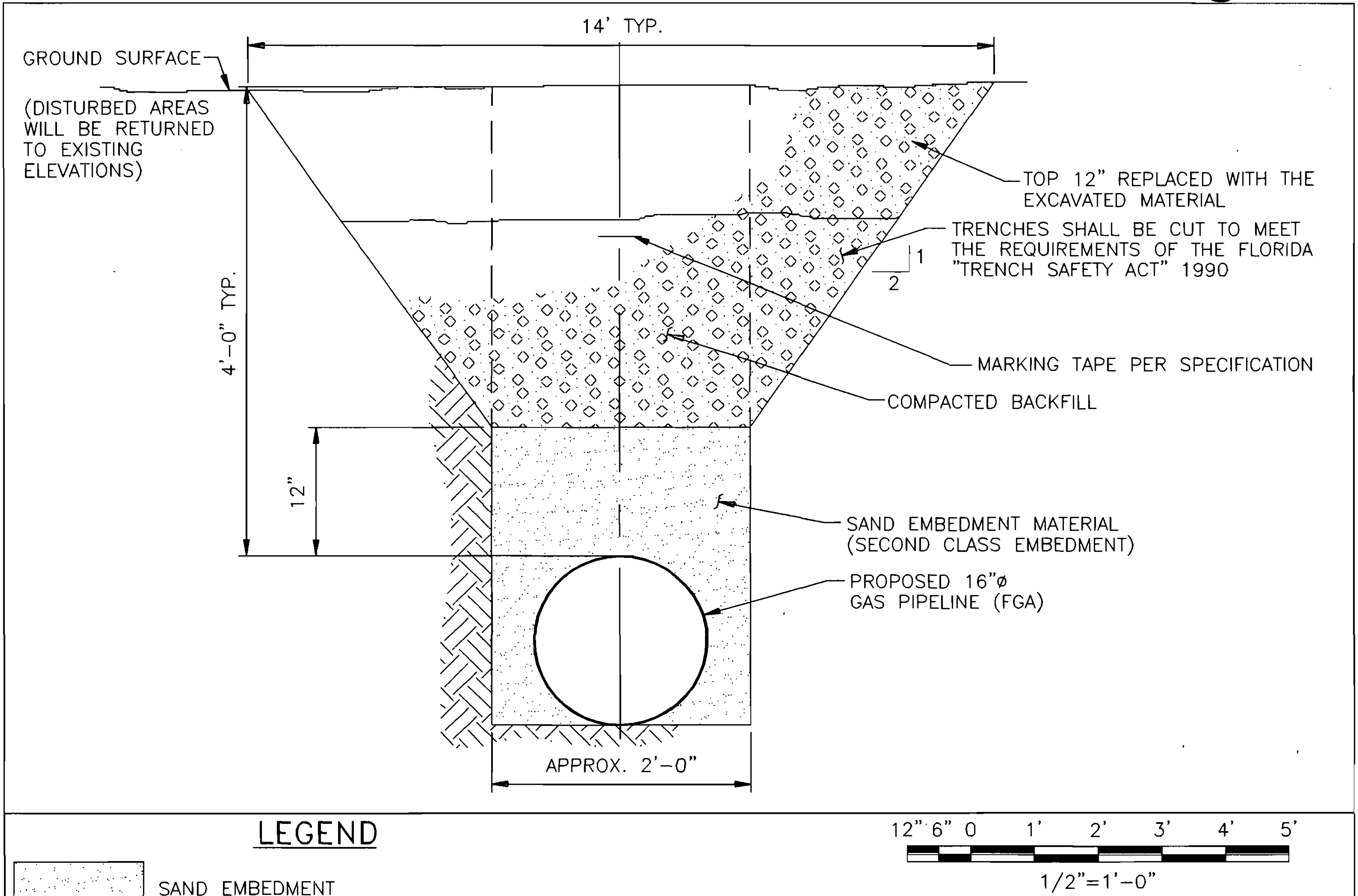
Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

Miles
0 1 2 3

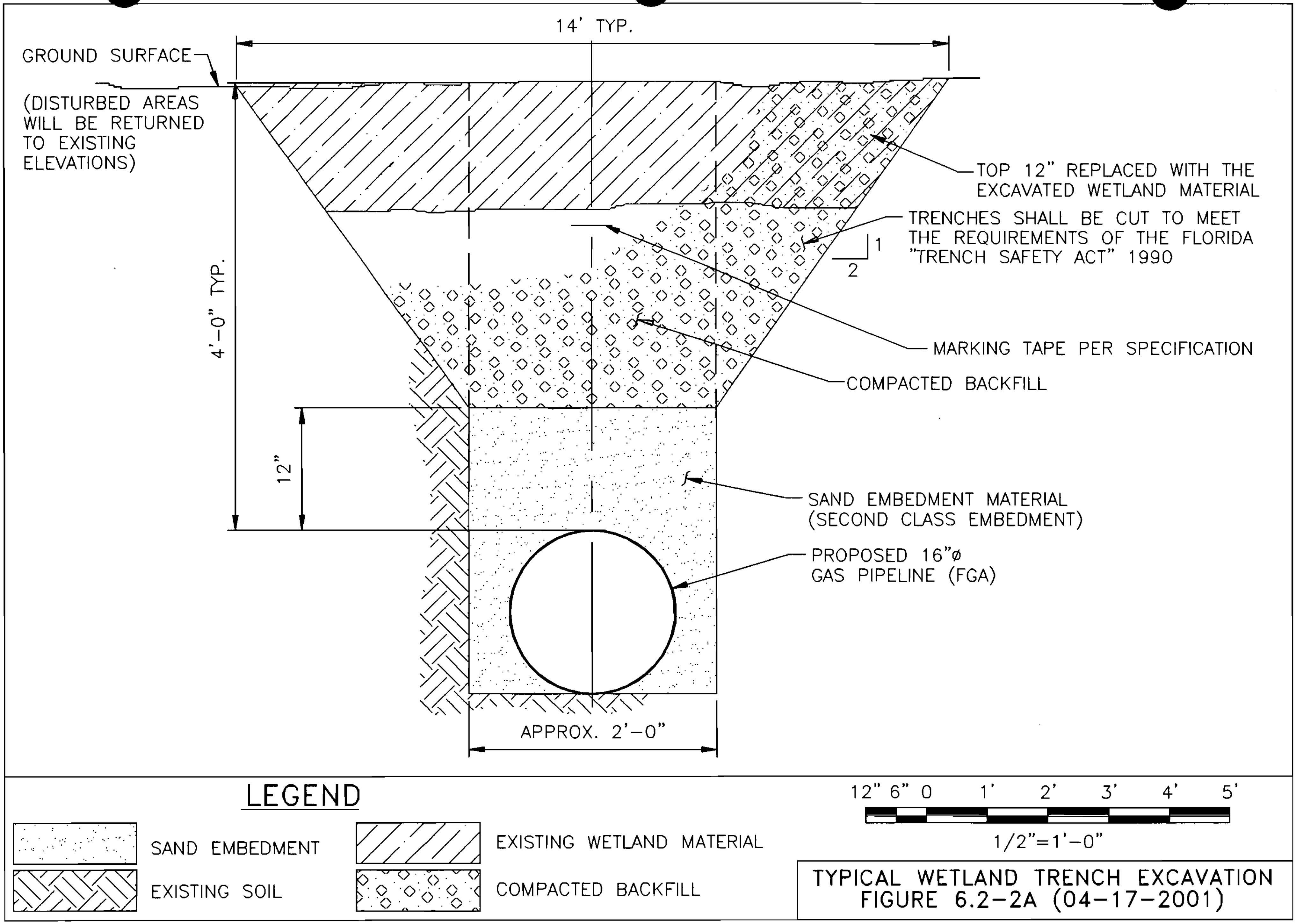
Stanton Energy Center
Property Location
Figure 6.2-1

Site Location.srf

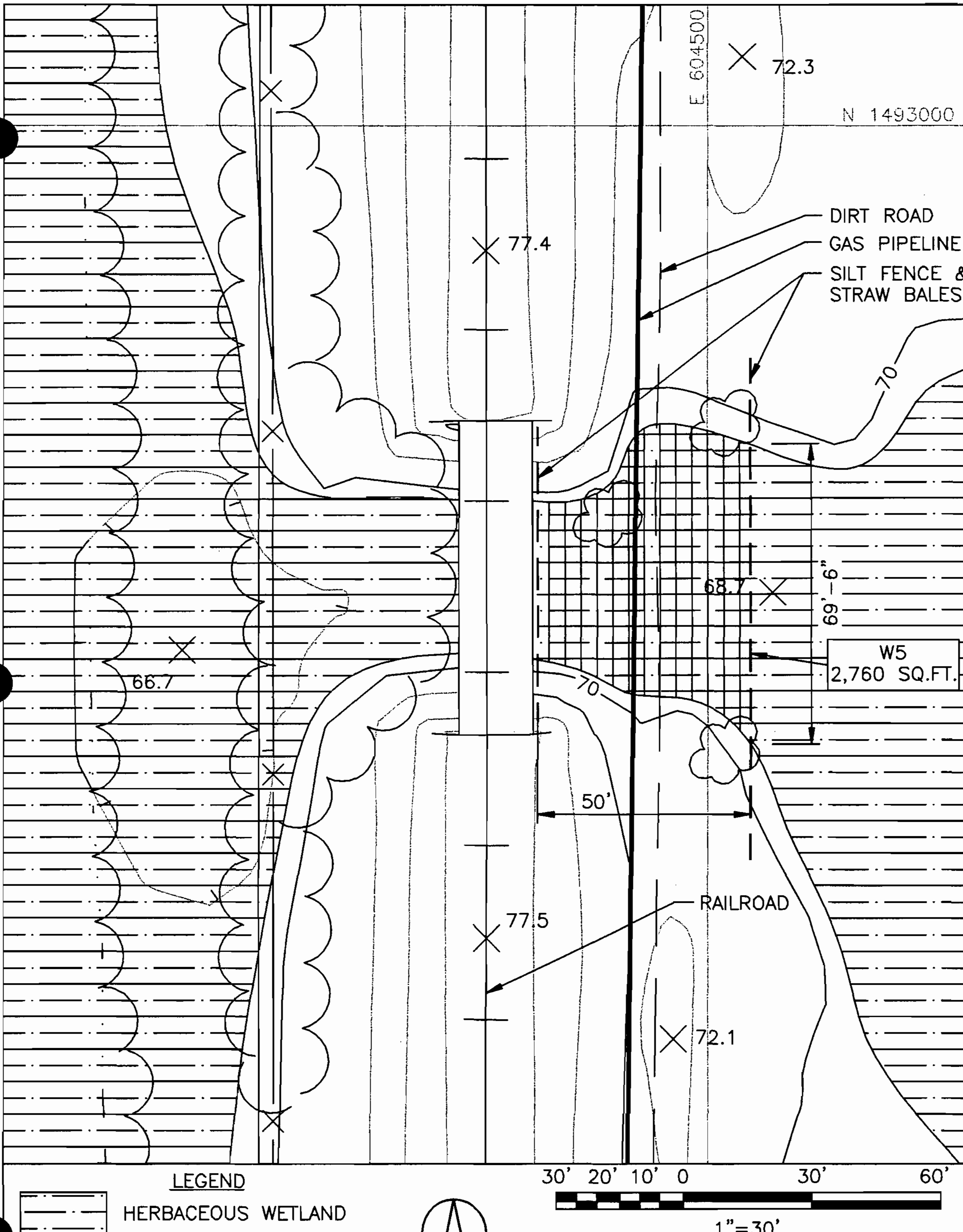
Gas Line Excavation Drawings:
Figure 6.2-2
Figure 6.2-2A
98362-ERP-4A



TYPICAL GAS LINE TRENCH EXCAVATION
FIGURE 6.2-2 (04-17-2001)



TYPICAL WETLAND TRENCH EXCAVATION
FIGURE 6.2-2A (04-17-2001)



SEC COMBINED CYCLE PROJECT
WETLAND IMPACT AREA W5
DRAWING 98362-ERP-4A (04-17-2001)

FDEP Bureau of Public Land Administration Letter

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

Lainie Krop
Black & Veatch
11401 Lamar Avenue
Overland Park, Kansas
66211

March 13, 2001

RE: Stanton Energy Pipeline

Dear Ms. Krop:

After reviewing the report from our Title and Land Records Section, The Bureau of Public Land Administration formed an opinion that, in the absence of any unknown information to the contrary, The State of Florida has no claim to lands on which The Stanton Energy Center proposes to lay a pipeline. Those lands include: sections 13, 23, 24, 25, and 36 of township 23 south, range 31 east; sections 18, 19, 30, and 31 of township 23 south, range 32 east; section 1 of township 24 south, range 31 east; and section 6 of township 24 south, range 32 east. However, The State of Florida holds the deed on a parcel of land in section 30/township 23 south/range 32 east. The deed does not include the west 300 feet of section 30, so our opinion is that the proposed pipeline will not encroach on state lands, assuming the pipeline will cover only 150 feet on each side of the section line. Additionally, our Title Department recommended that the proprietary requirements normally applied to state owned lands not be applied to two branches of the Econlockhatchee Creek. If these waters are deemed navigable in the future, then the proprietary requirements regarding state owned water bodies would apply to the proposed activity.

I hope this is all the information you needed. Please let me know if I can help you in any other ways with this project or with future projects. Thanks for your patience.

Respectfully Yours,

M. Wayne Patton
Bureau of Public Land Administration
Division of State Lands

mwp
enclosure (1)

COMMENTS: THE STATE HAS NO CLAIM TO ANY UPLANDS LOCATED AT THE AREA IN QUESTION. RECORDS ON FILE WITHIN THE TITLE & LAND RECORDS SECTION INDICATE THAT ALL OF SECTIONS 13, 14, 23 & 24 OF T23S/31E WERE CONVEYED TO A PRIVATE PARTY BY VIRTUE OF DEED # 10411, AND ALL OF SECTIONS 18 & 19 OF T23S/32E WERE CONVEYED TO A PRIVATE PARTY BY VIRTUE OF DEED # 12017. FOR THE HART BRANCH AND THE COWPENS BRANCH OF THE ECONLOCKHATCHEE CREEK IN THE AREAS OF THE PROPOSED ACTIVITY, WE RECOMMEND THAT THE PROPRIETARY REQUIREMENTS THAT WOULD NORMALLY APPLY TO STATE OWNED LANDS NOT BE APPLIED TO THESE WATERBODIES. IF, IN THE FUTURE, THE SUBJECT WATERBODIES ARE DETERMINED TO BE NAVIGABLE AND THEREFORE STATE OWNED, THEN THE PROPRIETARY REQUIREMENTS ESTABLISHED BY THE BOARD REGARDING STATE OWNED WATERBODIES WILL APPLY TO THE PROPOSED ACTIVITY. THE SITE IS NOT LOCATED WITHIN AN AQUATIC PRESERVE. COPIES ATTACHED. JCJ 01/29/01 TO: STEVE REMKE, PLA

JCJ 02/22/01
AN ADDITIONAL REQUEST WAS MADE FOR A TITLE REVIEW OF A PROPOSED GAS LINE IN THE AREAS COVERED IN THE INITIAL REQUEST, AS WELL AS IN THE FOLLOWING AREAS: T23S/R31E/25 & 36, T23S/R32E/30 & 31, T24S/31E/1, & T24S/32E/6. THE ADDITIONAL REMARKS IN THIS REVIEW ARE BASED ON AN APPROXIMATE LOCATION OF THE PROPOSED GAS CORRIDOR, BECAUSE THE REQUESTOR DID NOT PROVIDE AN ACTUAL DESCRIPTION FOR THE PROPOSED CORRIDOR. RECORDS ON FILE WITHIN THE TITLE & LAND RECORDS SECTION INDICATE THAT ALL OF T23S/R31E/25 & 36 AND T24S/31E/1 WERE CONVEYED TO A PRIVATE PARTY BY VIRTUE OF DEED # 10411. ALL OF T23S/R32E/30 & 31 AND T24S/32E/6 WERE CONVEYED TO A PRIVATE PARTY BY VIRTUE OF DEED # 12017. THE STATE HAS NO CLAIM TO THE UPLANDS IN THESE SECTIONS EXCEPT FOR A PORTION OF SECTION 30 IN T23S/R32E AS DESCRIBED IN A DEED TO THE TIITF (OR BK 3427/PG 1809) DATED OCTOBER 6, 1983. THIS DEED DOES NOT INCLUDE THE WEST 300 FEET OF SECTION 30. HOWEVER, THE PARCEL OF UPLANDS COVERED IN THE DEED IS ALSO SUBJECT TO LEASE # 3339 TO THE DEPT. OF CORRECTIONS. COPIES ATTACHED.

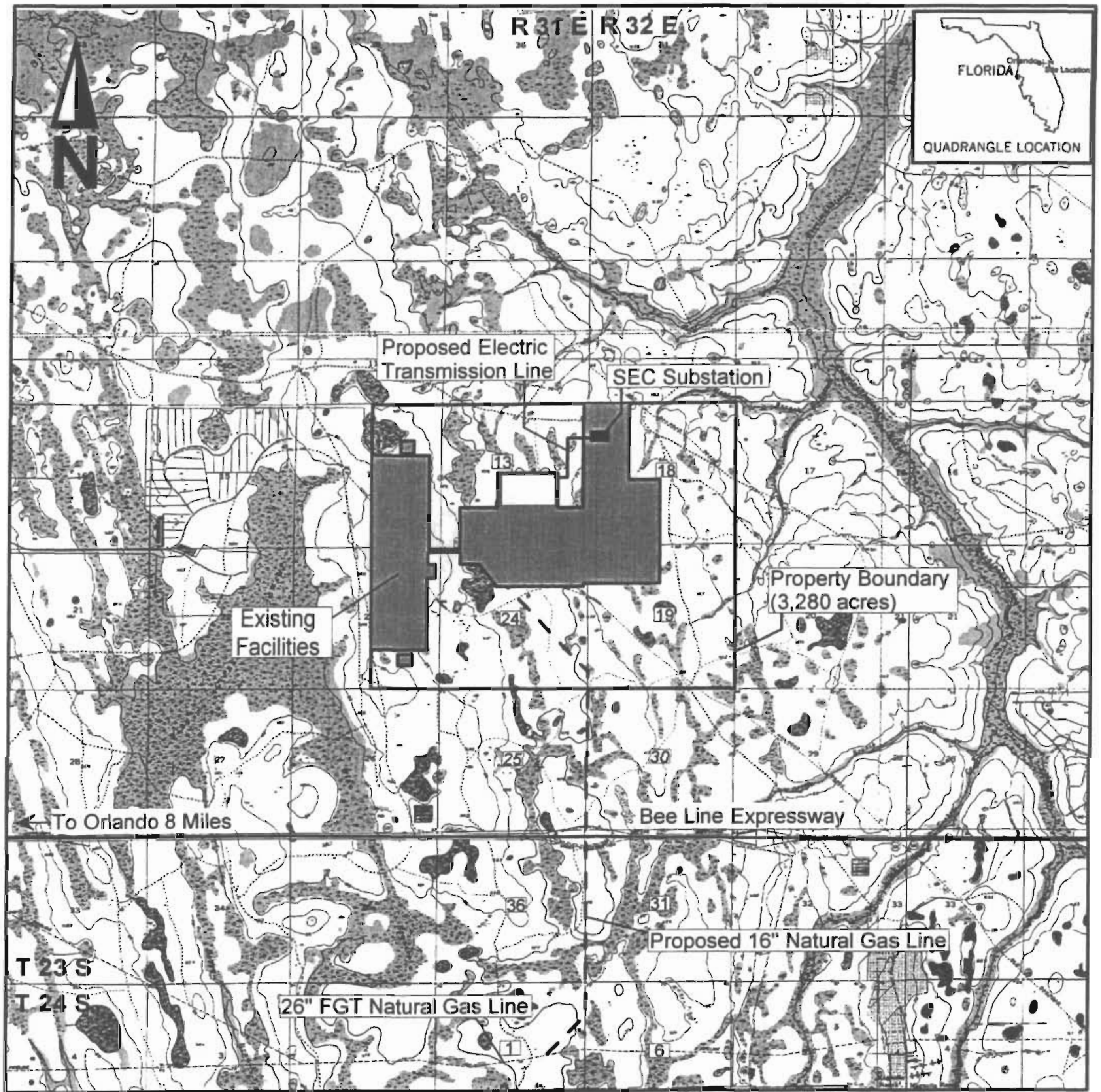
PREPARER: JAMES C. JENKINS
DATE PREPARED: 02 / 06 / 2001

****

NOTICE: THE CONCLUSIONS AND DETERMINATIONS SET FORTH IN THIS TITLE WORKSHEET ARE BASED ON A REVIEW OF THE RECORDS CURRENTLY AVAILABLE WITHIN THE DEPARTMENT OF ENVIRONMENTAL PROTECTION AS SUPPLEMENTED, IN SOME CASES, BY INFORMATION FURNISHED BY THE REQUESTING PARTY. SINCE THE ACCURACY AND COMPLETENESS OF THE TITLE INFORMATION REVIEWED MAY VARY, THE CONCLUSIONS AND DETERMINATIONS SET FORTH HEREIN DO NOT CONSTITUTE A LEGAL OPINION OF TITLE AND SHOULD NOT BE RELIED ON AS SUCH.

****

Location Maps:
Figure 2
Figure 8



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

Miles

0 1 2 3

Stanton Energy Center
Property Location
Figure 2

Site Location.srf

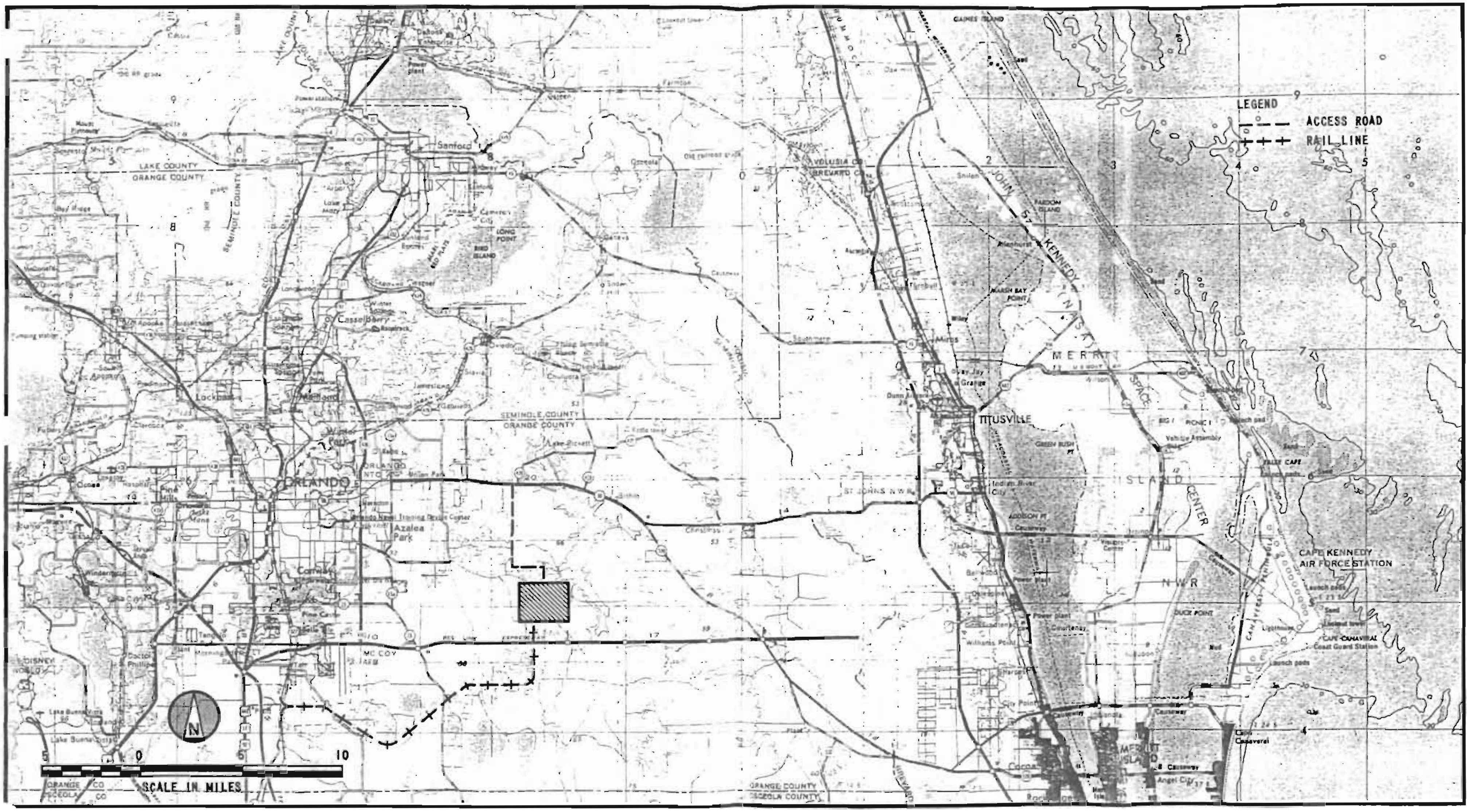


FIGURE 8
REGIONAL AREA MAP

St. Johns River Water Management District

1. *District water use rules require that the lowest acceptable quality water source, including reclaimed water or surface water (which includes storm water), must be utilized for each consumptive use. To use a higher quality water source an applicant must demonstrate that the use of all lower quality water sources will not be economically, environmentally or technologically feasible.*

   a) *A source of reclaimed water is readily available from the Orange County Easterly Waste Water Treatment System. Information submitted with the application indicates that this water is intended to be used for cooling uses, but not for all uses. Please demonstrate why it is not feasible to use reclaimed water for all uses except for potable water. In order to demonstrate that the use of a lower quality source is not economically feasible, the applicant must demonstrate in detail that the use would render the entire project economically unfeasible. [Section 10.3 (e)(f)(g), Applicant's Handbook, Consumptive Uses of Water (February 8, 1999) (A.H.)]*

   b) *A source of storm water is available from the adjacent Orange County Landfill to meet some of the power plant's water needs. Please evaluate the feasibility of using this source. In order to demonstrate that the use of a lower quality source is not economically feasible, the applicant must demonstrate in detail that the use would render the entire project economically unfeasible. [Section 10.3(e)(f)(g), A.H.]*

   c) *The applicant includes a request for 2.13 million gallons per day of groundwater from the Floridan aquifer for cooling water use during emergency conditions. The existing power plant facility includes an approximately 90-acre storage pond with approximately 146 million gallons of storage capacity. The Orange County Easterly Waste Water Facility has an emergency groundwater backup allocation of 100 million gallon per year. Orange County applied for renewal of this permit with the same allocation. That permit application is complete and will be recommended for approval. Please demonstrate why it is not feasible to use either the water in the existing storage pond or the emergency groundwater backup allocation for the Orange County Waste Water Facility for the requested emergency backup use. [Section 10.3(e)(f)(g), A.H.]*

Response 1a: The existing Stanton water treatment system was originally designed to treat groundwater, and is not currently capable of treating the Orange County effluent. An entirely new pretreatment and demineralizer system would be required to remove organics and other foulants and render the effluent usable for Stanton A demineralized water makeup supply. A new demineralized water treatment system is estimated to cost approximately $5 million and is not required because the existing demineralizer system has adequate capacity for Stanton A.

However, the applicants are amenable to accepting no increase in the current site allocation of groundwater as long as Orange County landfill stormwater of adequate quality is delivered to an appropriate location at the Stanton site. OUC will evaluate reuse and treatment on a site-wide basis to determine the best alternatives to avoid increase in groundwater consumption.

Response 1b: The applicants are committed to evaluating the potential use of stormwater from the Orange County Landfill for power plant operations. As described above, the existing Stanton water treatment system is not currently capable of treating waters significantly different from the design groundwater. However, OUC will accept the stormwater as a supplemental makeup source for power plant operations if the stormwater meets certain quality standards and Orange County delivers the stormwater to an appropriate location at the Stanton site, as determined by OUC, at no burden to the applicants.

Response 1c: The applicants will withdraw the request for emergency use of groundwater pending approval of the Orange County Easterly Waste Water Facility emergency allocation and agreement for the delivery/use of Orange County Landfill stormwater of adequate quality. The availability of this water provides adequate assurance of cooling water supply in the event of an effluent shortage.

2. *The applicant has completed an initial evaluation that includes simulations of the drawdown in the Floridan aquifer due to the average daily withdrawal from all three units and of the drawdown due to the maximum combined capacity of the onsite wells pumping continuously for 30 days. Please provide copies of the input and output files for these model simulations. Additional impact analyses are necessary as follows:*

- *An analysis to evaluate the cumulative drawdown impacts of the proposed withdrawals in combination with withdrawals from all existing legal uses.*

- *An analysis to evaluate the cumulative impacts of the proposed withdrawals in combination with withdrawals from all existing legal uses and all withdrawals requested by applicants whose applications are complete. This analysis is necessary to determine whether there are competing applications.*

- *An analysis to evaluate the cumulative impacts due to all existing and reasonably anticipated uses at some future year or years, including the proposed withdrawals. This can be in multiple evaluations such as for years 2005, 2010, and 2020. The purpose of this evaluation is to address the sustainability of the resource.*

Response: As part of the Curtis Stanton Energy Center Combined Cycle Unit Power Plant Siting Supplemental Application No. PA 81-14SA2, Black & Veatch developed a site-specific groundwater model, performed model simulations, and submitted model results to Florida DEP. Black & Veatch's model simulation was based on estimated transmissivity of 72,000 ft^2/day for the Upper Foridan Aquifer. Site borehole data indicate the presence of a confining unit (Hawthorn Formation) between the unconfined aquifer and the Upper Foridan Aquifer. A detailed discussion of the geology and hydrogeology is presented in the Siting Supplemental Application, and will not be repeated herein.

The primary concern that St. Johns River Water Management District raised was the model did not take into account other pumping wells that may impact the boundary conditions of the local model. Black & Veatch initiated discussions with James Hollingshead, Doug Munch, and Brian McGurk, to get clarification regarding Comment No. 2. James Hollingshead further discussed the issue with Dwight Jenkins and Doug Munch (both with St Johns River Water Management District) and instructed Black & Veatch to complete the following additional tasks:

- Simulate the 1995 steady state condition of St. John River Water Management District's East Central Florida (ECF) Regional Model and document results near the Curtis H. Stanton Power Plant area. The 1995 steady state simulations of the ECF Regional model are based on average annual pumping rates for the plant.

- Simulate the 2020 steady state condition of St. Johns River Water Management District's East Central Florida (ECF) Regional Model and document results near the Curtis H. Stanton Power Plant area. The 2020 steady state simulations of the ECF Regional model are based on average annual pumping rates for the plant.

- Compare the average condition results of the 1995 and 2020 simulations in the unconfined aquifer to see if the 2020 conditions would cause impacts on wetlands over the area surrounding the plant site.

After the remaining modeling tasks were identified, Black & Veatch performed the following tasks:

- Acquired the ECF Regional Model files and simulated 1995 and 2020 boundary conditions.

- Created local models using the 1995 and 2020 ECF Regional Model conditions in the vicinity of the plant, and the 1995 and 2020 ECF Regional Model boundary conditions.

- Simulated the 1995 and 2020 conditions and documented results as requested.

- Simulated and documented plant increased well pumping conditions.
- Prepared model input and output files for submittal as requested.

The tasks were completed to fully address the modeling comments. The completed modeling tasks and the results are discussed in the following text.

Data Collection
Black & Veatch contacted the Regional Modeling Group of St. Johns River Water Management District and acquired free format files of the ECF MODFLOW model. The ECF model files included steady state simulated heads for 1995 and 2020 conditions.

Formulation of a Local Model
The local model was created to simulate and evaluate results in the vicinity of the plant. The approximate plant area within the regional model is shown on Figure 1. The ECF Regional Model contains 174 rows, 194 columns, and 4 layers. The dimensions of each grid cell of the ECF model are 2,500 by 2,500 feet. The Stanton Plant wells are located at row 94, column 109, and layer 2 of the ECF Regional Model.

Using the configuration and results of the ECF model created by St. John River Water Management District, Black & Veatch created a local model. The local model was created using GMS-MODFLOW Version 3.1. Groundwater Modeling Software (GMS) is a pre-, post processing software that is widely used with MODFLOW and other modeling packages.

Model Area
The local model consists of an 11 by 11 grid model of the ECF Regional Model, which covers an area of approximately 5 by 5 miles. The grid spacing in the X and Y directions is 2,500 feet, similar to the ECF Regional Model. The local model grid, with the row, column, and layer indices is shown on Figure 2. The grid cell containing the two plant wells is at the center of the local model (Row 6, Column 6, and Layer 2).

Model Layers
The simulated aquifers include the Surficial Aquifer System (SAS) and the Floridan Aquifer System (FAS). The SAS is referred to as the unconfined aquifer in the Site Supplemental Application. The local model layers are similar to the ECF Regional Model, with the SAS modeled as Layer 1, the Upper Floridan Aquifer modeled as Layers 2 and 3, and the Lower Floridan Aquifer modeled as Layer 4.

Model Boundaries
The perimeter boundary heads of the local model were specified and are equal to the ECF Regional Model simulated heads at the local model boundaries. The ECF

Regional Model simulation results indicated that layer 1 heads over the local model area are essentially the same for 1995 and 2020 conditions while the potentiometric levels in the Upper Florican Aquifer dropped approximately 6 feet. The stability of the SAS groundwater elevations during significant changes in the Upper Floridan Aquifer levels, indicates that the SAS is basically independent of the Upper Floridan Aquifer over the local model area. This is supported by the following:

- The presence of the Hawthorn formation between the SAS and the Upper Floridan Aquifer, as identified during subsurface investigations performed by Black & Veatch.
- Prior pump testing performed by Black & Veatch.
- Prior groundwater modeling performed by Black & Veatch.

Consequently, heads in layer 1 of the local model were imported from the ECF Regional Model and specified.

Because the 1995 and the 2020 simulations of the regional model result in two separate boundary conditions for the local model, two separate local models were created to evaluate and compare the local conditions for the two time periods. The only difference between the two local models was that, one used the 1995 boundary conditions, while the other used the 2020 boundary conditions.

Hydraulic Parameters

The ECF Regional Model properties were assigned to each corresponding grid cell of the local model in layers one through four. This was accomplished by importing the appropriate cell regional model layer configurations, and properties. The imported configurations and properties included layer top/bottom elevations, hydraulic conductivities, and leakances between layers. The model parameters for layers one through four of the grid cell containing the plant wells are shown in Table 1.

Table 1
Local Model Parameters and Layer Elevations at the Plant Wells Grid Cell

Model Layer	Layer	Top Elevation	Bottom Elevation	Horizontal Hydraulic	Leakance
Number	Designation	(NGVD, Feet)	(NGVD, Feet)	Conductivity (ft/day)	(VCONT)
1	SAS	80	5	60	5.00E-06
2	Upper FAS	5	-339	250	1.17E-02
3	Upper FAS	-339	-467	1,750	1.55E-04
4	Lower FAS	-467	-1,663	75	NU

NU = Not Used in Model

The model developed based on the ECF Regional Model agrees well with the model previously developed by Black & Veatch. Using the ECF Regional Model, the transmissivity of the Upper Floridan Aquifer at the plant wells location is 86,250 ft^2/day. This is in good agreement with the previous Black & Veatch estimated transmissivity of 72,000 ft^2/day. The 5.00E-06 leakance value between the SAS and the Upper Floridan Aquifer at the plant wells location is also in good agreement with Black & Veatch's documented presence of the Hawthorn Formation located between the SAS (unconfined aquifer) and the Upper Floridan Aquifer.

Simulation of 1995 Conditions with a Local Model

For all four layers, the 1995 local model perimeter boundary heads were specified, and were equal to the ECF model simulated heads for 1995. Heads in layer 1 of the local model were imported from the ECF Regional Model and specified. The layer 1 specified heads allow comparison of the 1995 and 2020 ECF Regional Model results over the local model area. The perimeter boundary heads from the ECF Regional Model establish conditions that take into account the impact of pumping wells located outside the local model area.

Pumping of wells within the area of the local model was set to match the locations and pumping rates in the 1995 ECF Regional Model. This resulted in pumping water from two grid cells from layer 2. The first pumping location is found at ECF Regional Model Row 94, Column 109, and includes the two Stanton plant wells pumping at the present average day total rate of 49,501 ft^3/day (257 gpm). The other location is a well approximately 1.25 miles southeast of the plant wells at ECF Regional Model Row 95, Column 111, and includes pumping at a rate of 13,934 ft^3/day (72.4 gpm).

The SAS (unconfined aquifer) water level contours over the local model area for 1995 are shown in Figure 3. The water table above the cell containing the plant wells is at approximately elevation 75 feet. Over the 5 by 5-mile local model area, the water table elevations range from 40 feet to 80 feet. The simulated water table is higher than elevation 80 feet over an area of approximately 1 by 2.5 miles west of the plant. This may be the location of a local water table divide. East of this divide, flow is generally from southwest to northeast with an approximate hydraulic gradient of 0.001.

Simulated 1995 potentiometric contours for the Upper Floridan Aquifer (local model layer 2) are presented in Figure 4. These local model simulated potentiometric elevations for the Upper Floridan Aquifer are in agreement with the potentiometric elevations of the ECF Regional Model. Simulated potentiometric elevations range from 38 feet on the northeast portion of the modeled area to 44 feet on the southwest portion of the modeled area; therefore, groundwater flow is from southwest to northeast. Pumping from the wells at the

Stanton Energy Center has very little local influence on the general groundwater flow, as can be observed in Figure 4.

Simulation of 2020 Conditions with a Local Model

The local model to simulate the 2020 condition was created using the ECF Regional Model simulated heads for the year 2020. Similar to the 1995 local model, the perimeter boundary heads for all layers and the water table heads in layer 1 were specified based on the ECF Regional Model. The 2020 local model was simulated using the 2020 pumping conditions established in the ECF Regional Model, which was the same for the two grid cells where pumping occurred for the 1995 local model. No additional pumping locations were required for the local 2020 model, because none were added to the 2020 ECF Regional Model within the area of the local model. Therefore, pumping within the 1995 and 2020 local models was the same, but the perimeter boundary conditions differed due to pumping differences outside the boundaries of the local model areas.

The 2020 SAS (unconfined aquifer) water level contours over the local model area which were simulated by the ECF Regional Model are shown in Figure 5. The simulated water table elevations are almost identical to the 1995 water table elevations shown on Figure 3. The water table above the cell containing the plant wells is at approximately elevation 75 feet. Over the 5 by 5 mile local model area, the water table elevations range from 40 to 80 feet. As for 1995, over an area of approximately 1 by 2.5 miles west of the plant, the simulated water table is high and appears to create a divide. East of this divide, flow is generally from southwest to northeast with an approximate hydraulic gradient of 0.001.

The simulated 2020 potentiometric elevations in the Upper Floridan Aquifer are lower than the 1995 potentiometric elevations. Simulated potentiometric contours for 2020 for the Upper Floridan Aquifer are presented on Figure 6. These local model simulated potentiometric elevations for the Upper Floridan Aquifer are in agreement with the potentiometric elevations of the ECF Regional Model. Simulated potentiometric elevations range from approximately 33 feet on the northeast portion of the modeled area to 37 feet on the southwest portion of the modeled area. The 2020 potentiometric elevations in the Upper Floridan Aquifer are lower than in 1995 by approximately 6 feet. However, the 2020 groundwater flow direction, from southwest to northeast, is similar to that in 1995. Review of the contours in Figure 6 shows present plant pumping has very little impact on the potentiometric level and hydraulic gradient of the Upper Floridan Aquifer.

Comparison of Local Area 1995 and 2020 Simulation Results for the SAS

The ECF Regional Model generated groundwater elevation contours for 2020 and 1995 for the SAS (unconfined aquifer) are almost identical. Figure 7 presents differences in water table elevations between 1995 (Figure 3) and 2020 (Figure 5). Absolute differences in water table elevations between the two conditions within the 5 by 5-mile local area range from 0.05 foot to 0.08 feet.

These results indicate that the elevation of the groundwater in the SAS (unconfined aquifer) is not impacted over the local area by the increase in pumping from the Upper Floridan Aquifer that is anticipated from 1995 to 2020. This is shown by the consistent level of the SAS groundwater elevations, even though the potentiometric level of the Upper Floridan Aquifer drops 6 feet between 1995 and 2020. Since the elevation of the groundwater in the SAS is constant for 1995 and 2020, this also demonstrates that wetlands in the plant vicinity will not be impacted by the additional 2020 aquifer stresses. No impact on the SAS was also predicted by the earlier Black & Veatch model, which showed no lowering of the SAS water levels due to pumping from the Upper Floridan Aquifer. Additionally, well monitoring within the SAS during a pump test at the Stanton Energy Center showed no lowering of the SAS water level during the pump test.

The presence of the Hawthorn Formation in the plant site vicinity is the reason for the limited hydraulic interaction between the SAS (unconfined aquifer) and the Upper Floridan Aquifer.

Simulation of Additional Plant Pumping

The projected additional pumping associated with the third unit at the Stanton Energy Center was superimposed on the 2020 local model and evaluated. To evaluate this scenario, the average pumping rate at the plant wells was increased from 251 gpm (used in the ECF Regional Model) to 551 gpm projected in the Supplemental Site Certification Application. Figure 8 shows the potentiometric contours for the Upper Floridan Aquifer when pumping is increased to the projected average rate. Closer contour spacing is shown in the vicinity of the plant to better show the impact of the additional pumping. The contours clearly indicate that the additional pumping has a minor, very local impact on the potentiometric levels in the Upper Floridan Aquifer.

Figure 9 shows potentiometric level differences for the Upper Floridan Aquifer between potentiometric elevations for the present plant pumping rate and potentiometric elevations for the projected increased plant pumping rate. The additional drawdown in the Upper Floridan Aquifer due to the increased pumping rate is only 0.30 feet at the grid containing the plant wells and 0.15 feet at approximately 2,500 feet from the plant wells. At 1.5 miles from the plant pumping wells there is essentially no additional drawdown due to the increased pumping rate. Based on the lack of impact due to lowering of the Upper Floridan Aquifer 6 feet, the additional 0.3 feet drawdown in the Upper Floridan Aquifer will not have any impact on the SAS (unconfined aquifer).

Summary and Conclusion
Black & Veatch has completed and documented hydraulic modeling results to address the comments on its first submitted model.

- The 1995 and 2020 water table elevations in the SAS (unconfined aquifer) have been presented from the ECF Regional Model simulated results.

- Appropriate boundary conditions from the ECF Regional Model were used to create the local 1995 and the 2020 models. Simulations were completed using these boundary conditions.

- Comparison of the 1995 and 2020 ECF Regional Model results indicate no change in SAS (unconfined aquifer) water table elevations between 1995 and 2020 within the 5 by 5 mile area of the local model, even though the potentiometric level of the Upper Floridan Aquifer is projected to drop 6 feet. Consequently, wetlands in the vicinity of the plant will not be impacted as a result of increased pumping from the Upper Floridan Aquifer from 1995 to 2020.

- The proposed increase in water use for Stanton A at the Stanton Energy Center will not affect groundwater elevations in the SAS (unconfined aquifer); therefore, wetlands, and environmental features that have direct or indirect relationship to wetland habitats for rare, endangered, or threatened species will not be impacted.

- The increase in groundwater pumping to support Stanton A will have very minimal impact in the Upper Floridan Aquifer. Increased pumping drawdown diminishes within approximately 1.5 miles from the plant pumping wells.

Black & Veatch's modeling results submitted with the Supplemental Site Certification Application are in agreement with the ECF Regional Model.

3. *Is any dewatering of the site anticipated to be required during construction? If so, please confirm that any site dewatering will be below the thresholds in Section 40C-22.030 of the Florida Administrative Code [Sections 10.2(e)(f)(g)(i); 10.3(d)(i), A.H.]*

Response: Black & Veatch talked to Charles A. Lobdell, III, Assistant General Counsel of the SJRWMD, to obtain clarification and found that this request is focused on Florida Administrative Code 40C-22.030 (3) (b), which states:

Maximum daily withdrawals for any dewatering activity shall not exceed four million gallons per day (MGD), except during the first 120 hours of dewatering when the daily and instantaneous pumpage rates shall not exceed six MGD. Average daily withdrawal shall not exceed two MGD for the first 60 days of the dewatering activity and shall not exceed one MGD over a 180 day duration.

To respond to the comment, preliminary dewatering estimates for construction of Stanton A were developed.

It is anticipated that dewatering of specific structures will be required during construction of Stanton A. Previous investigations have indicated that the groundwater level of the unconfined aquifer within the site vicinity is approximately at elevation 72.0 feet. Based on an estimated site grade of 79.5 feet, construction dewatering will be required for the following:

- Two oil/water separators placed 15 feet below grade.
- An estimated 12 electrical manholes placed 10 to 12 feet below grade.
- 200 linear feet of circulation water piping placed 10 to 12 feet below grade.

Dewatering for the circulation water piping will be performed for 100 feet of the pipe at a time.

Dewatering for each individual separator, manhole, or individual section of the circulation water piping is considered an individual dewatering activity.

The preliminary dewatering estimates were performed using gravity well drainage equation from NAVFAC Design Manual P-418. It is anticipated that a conventional wellpoint system will be used to accomplish the dewatering tasks. The estimated dewatering rates for each individual dewatering activity are shown on Table 1.

Table 1
Individual Dewatering Activity Pumping Rates and Durations

Dewatering Activity	Estimated Flow Rate		Estimated Dewatering Duration (month)	Quantity
	(gpm)	(MGD)		
Oil / Water Separator	290	0.42	1	2
Electrical Manholes	190	0.27	1	12
Circ. Water Pipes (100' section)	225	0.32	2	2

The estimated flow rates in Table 1 for each dewatering activity are below the lowest allowable dewatering discharge rate of 1 MGD for a 180 day duration and are well within compliance with the requirements of Section 40C-22.030 (3) (b).

4. *The information requested for all wells and pumps/surface water sources located on the property must be included in the SOURCES OF WATER Summary Data Sheet. Please also provide information regarding any and all offsite sources (connection points) and surface water pumps associated with the onsite storage pond. [Form 40C-2-1082-1, A.H.]*

Response: A revised SOURCES OF WATER Summary Data Sheet is attached, which includes any and all offsite sources and surface water pumps associated with the onsite storage pond.

Best Available Copy

Figure 1: Stanton Plant Area Location in the ECF Regional Model

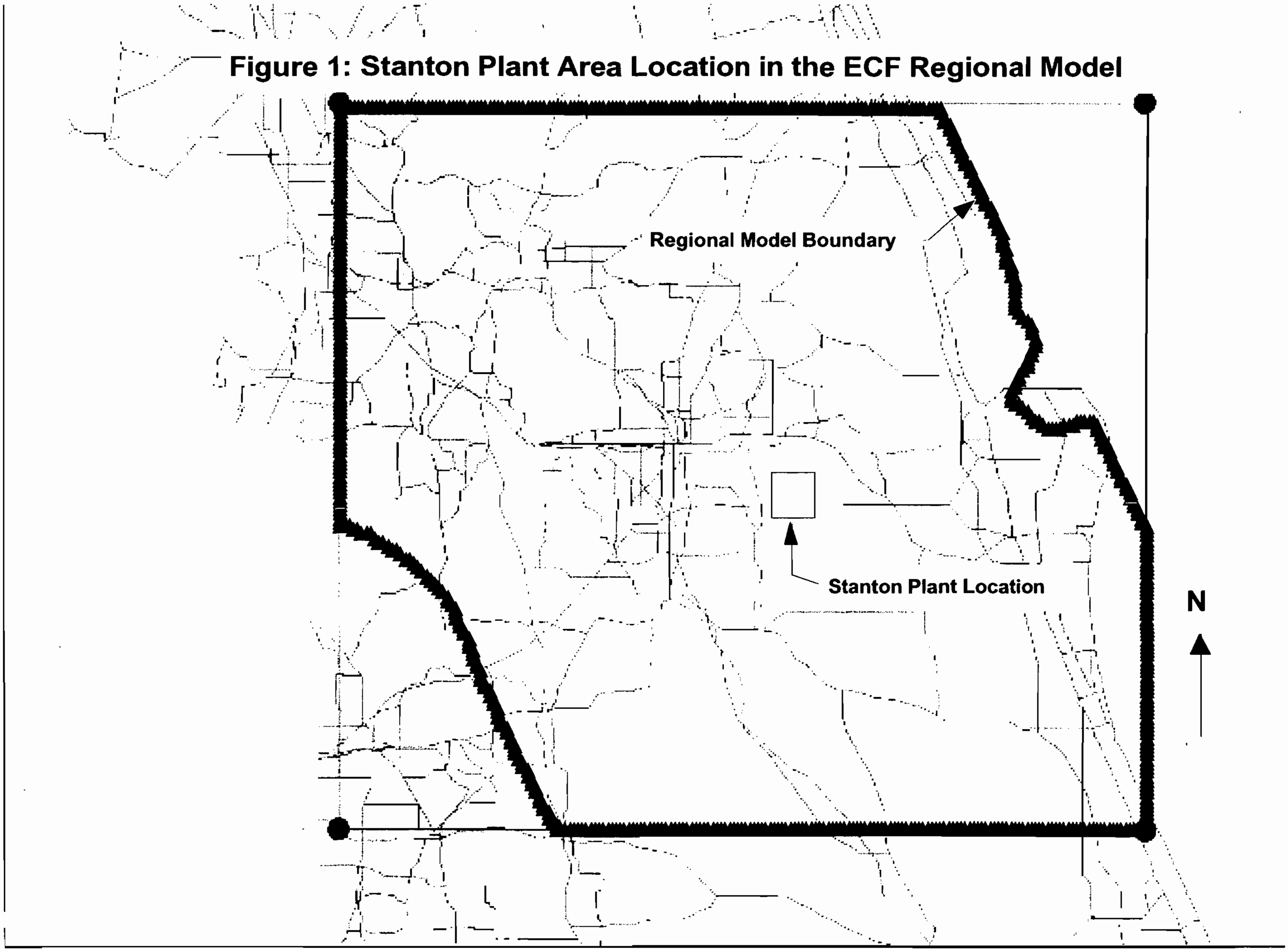


Figure 2: Local Model Grid, Layer 2, With Row, Column, and Layer Numbers

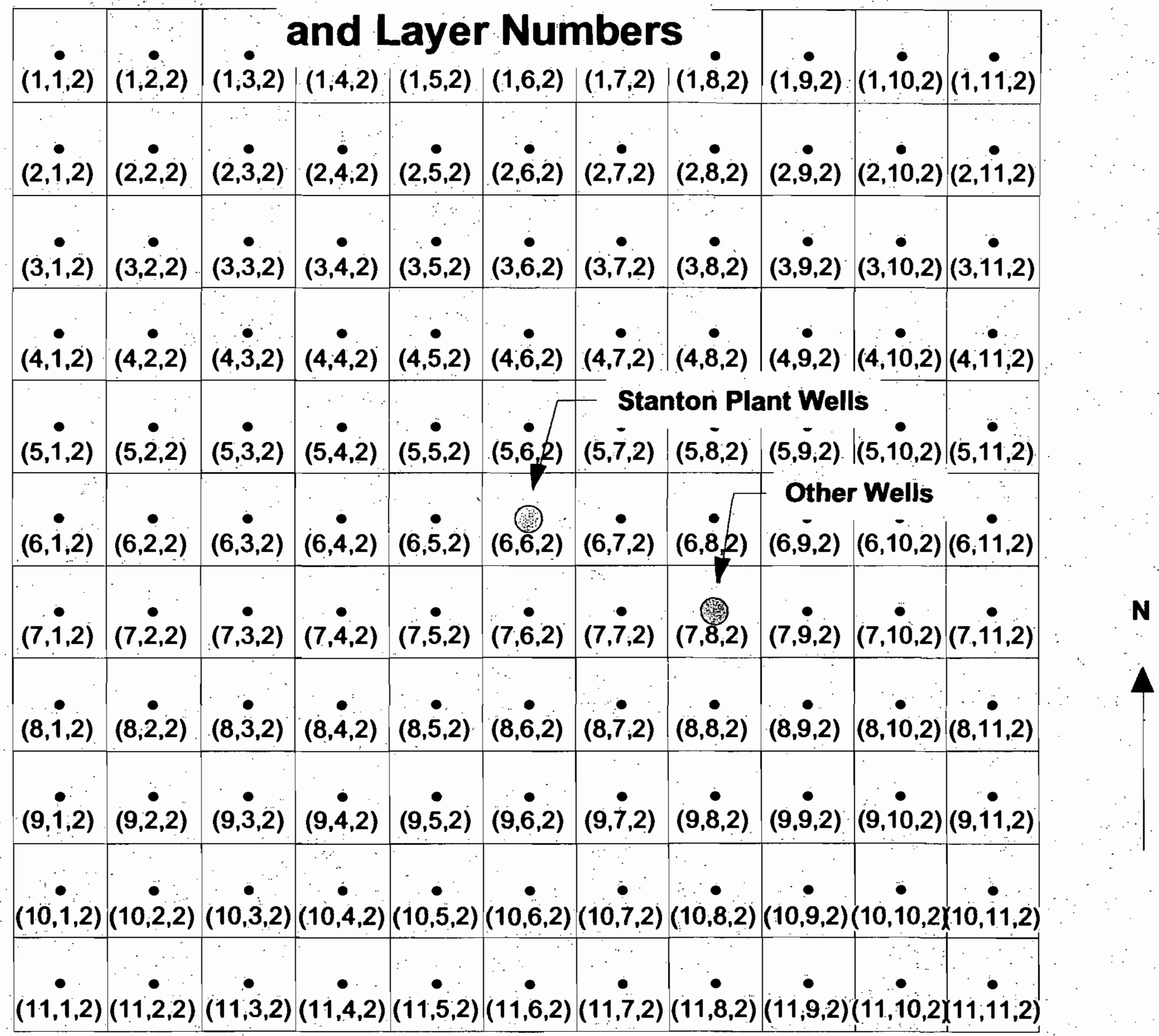


Figure 3: Water Table Elevation Contours for the SAS (Unconfined Aquifer) for 1995

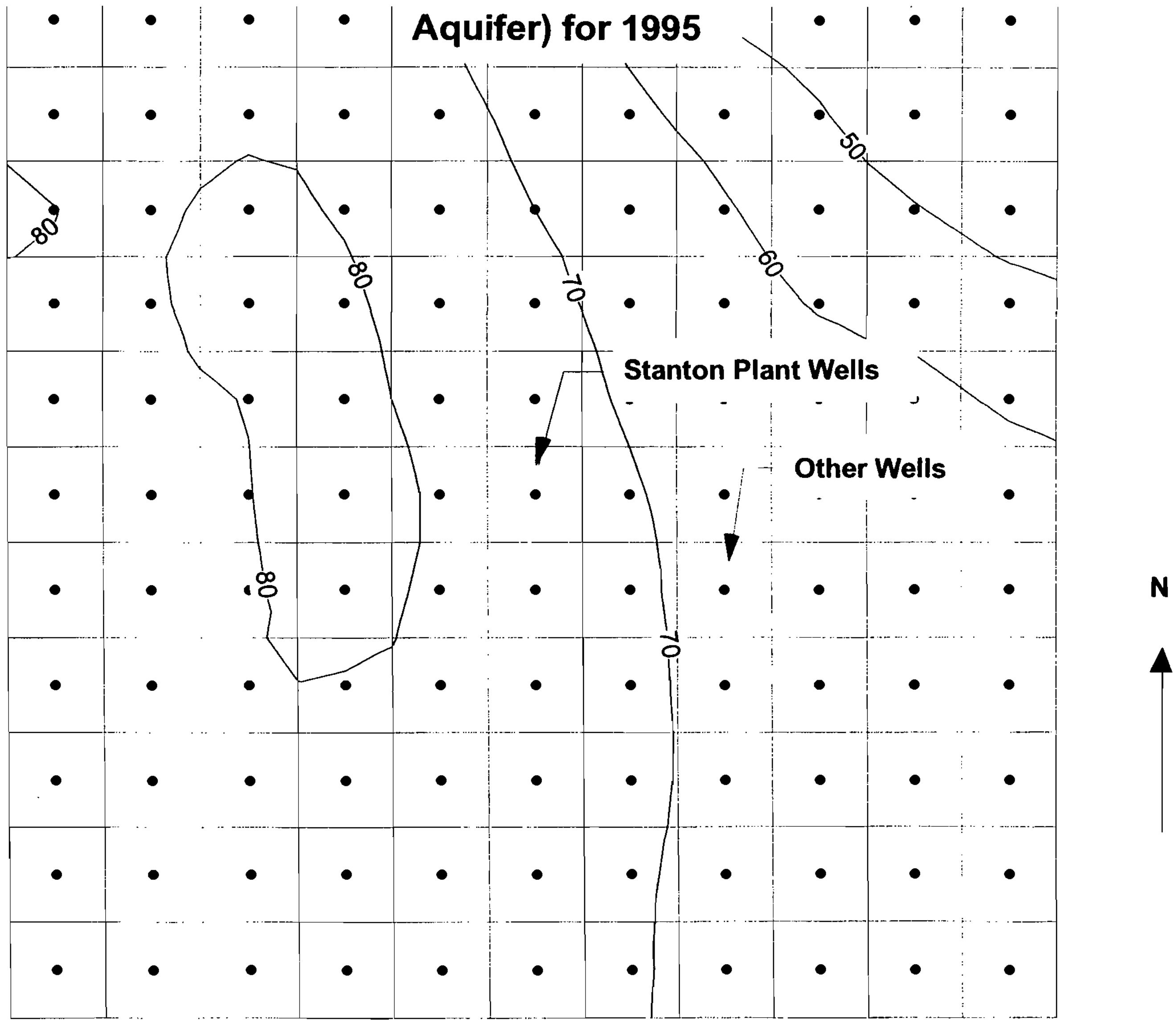


Figure 4: Potentiometric Contours for the Upper Floridan Aquifer for 1995

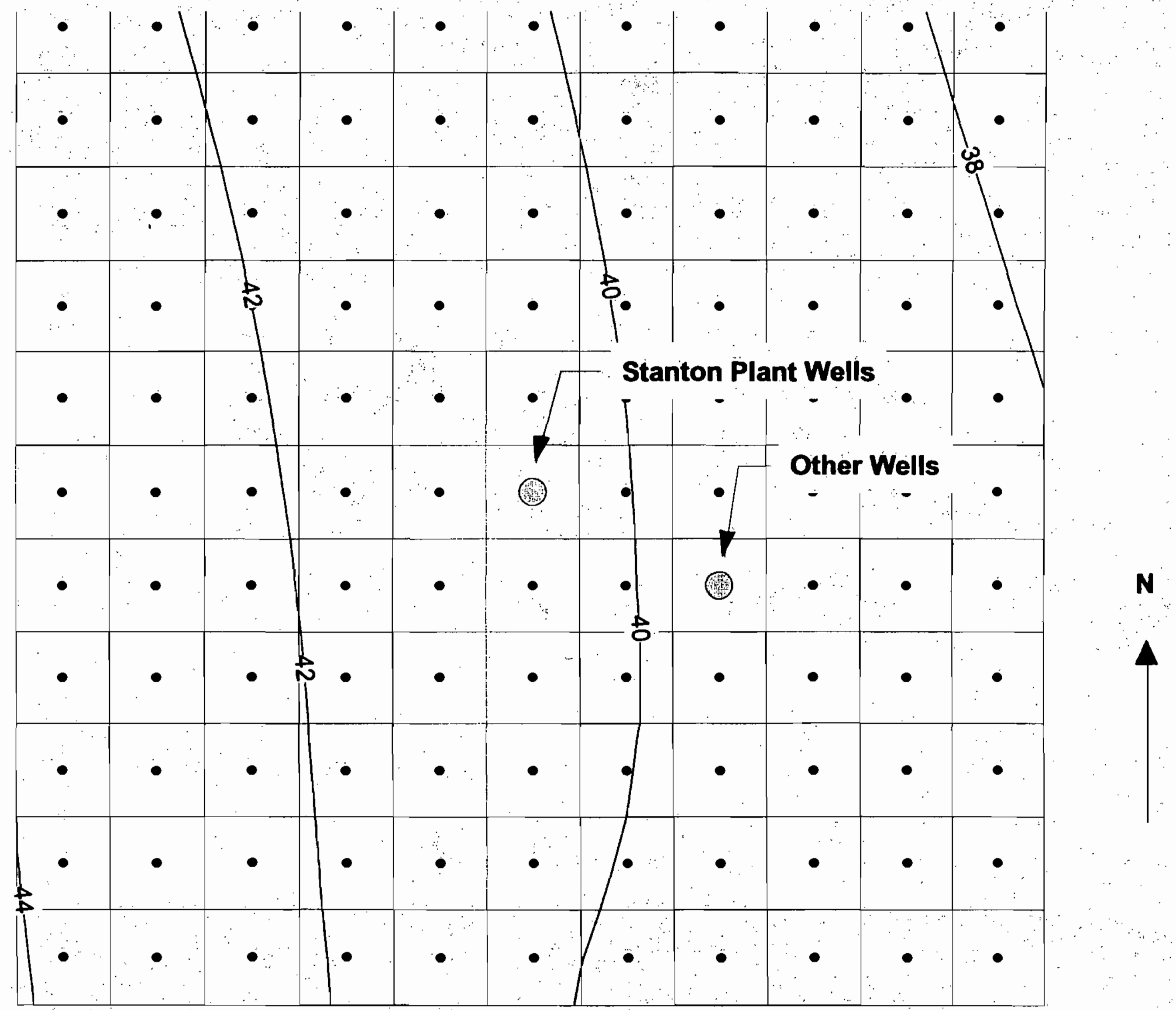


Figure 5: Water Table Elevation Contours for the SAS (Unconfined Aquifer) for 2020

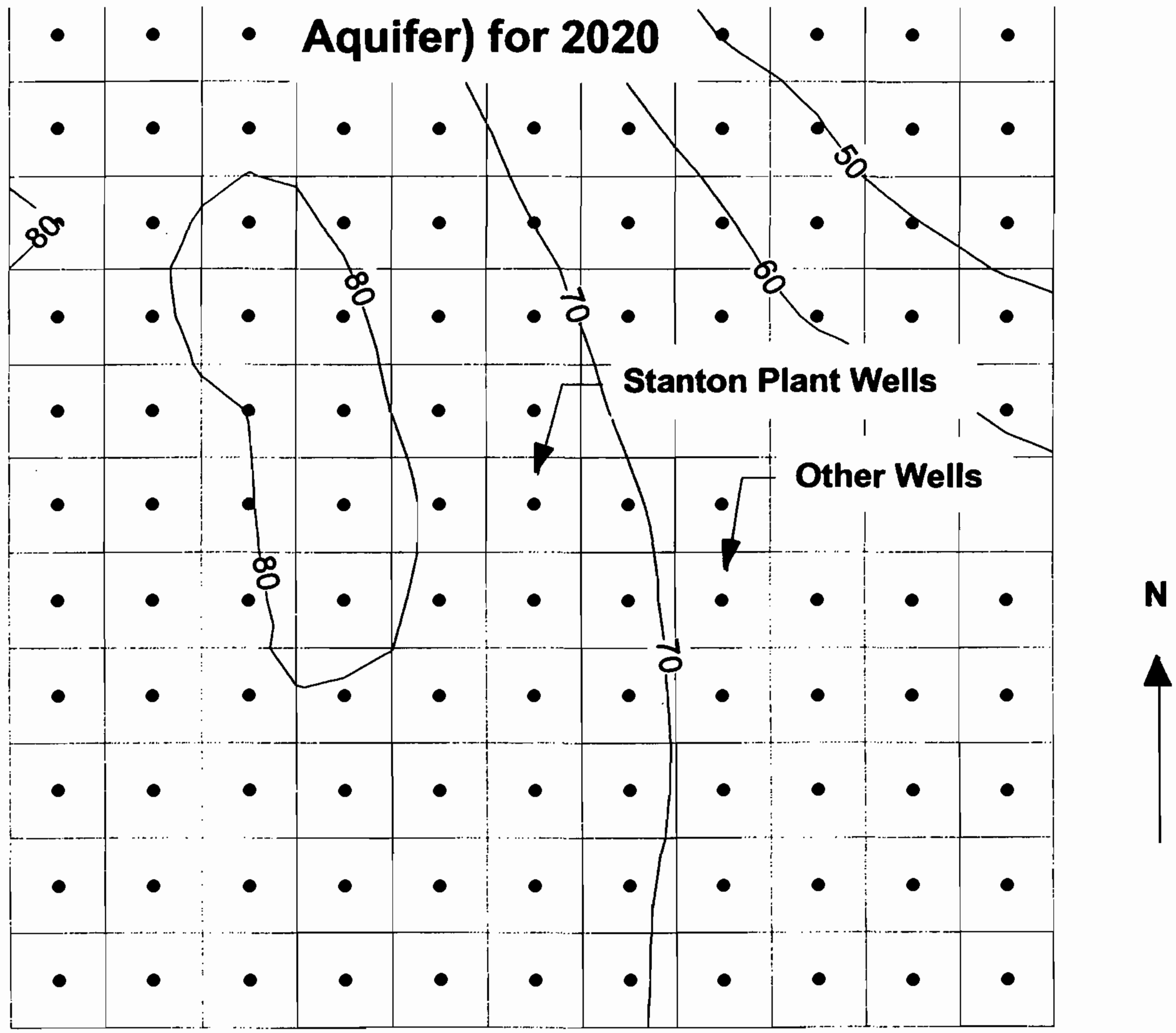


Figure 6: Potentiometric Contours for the Upper Floridan Aquifer for 2020

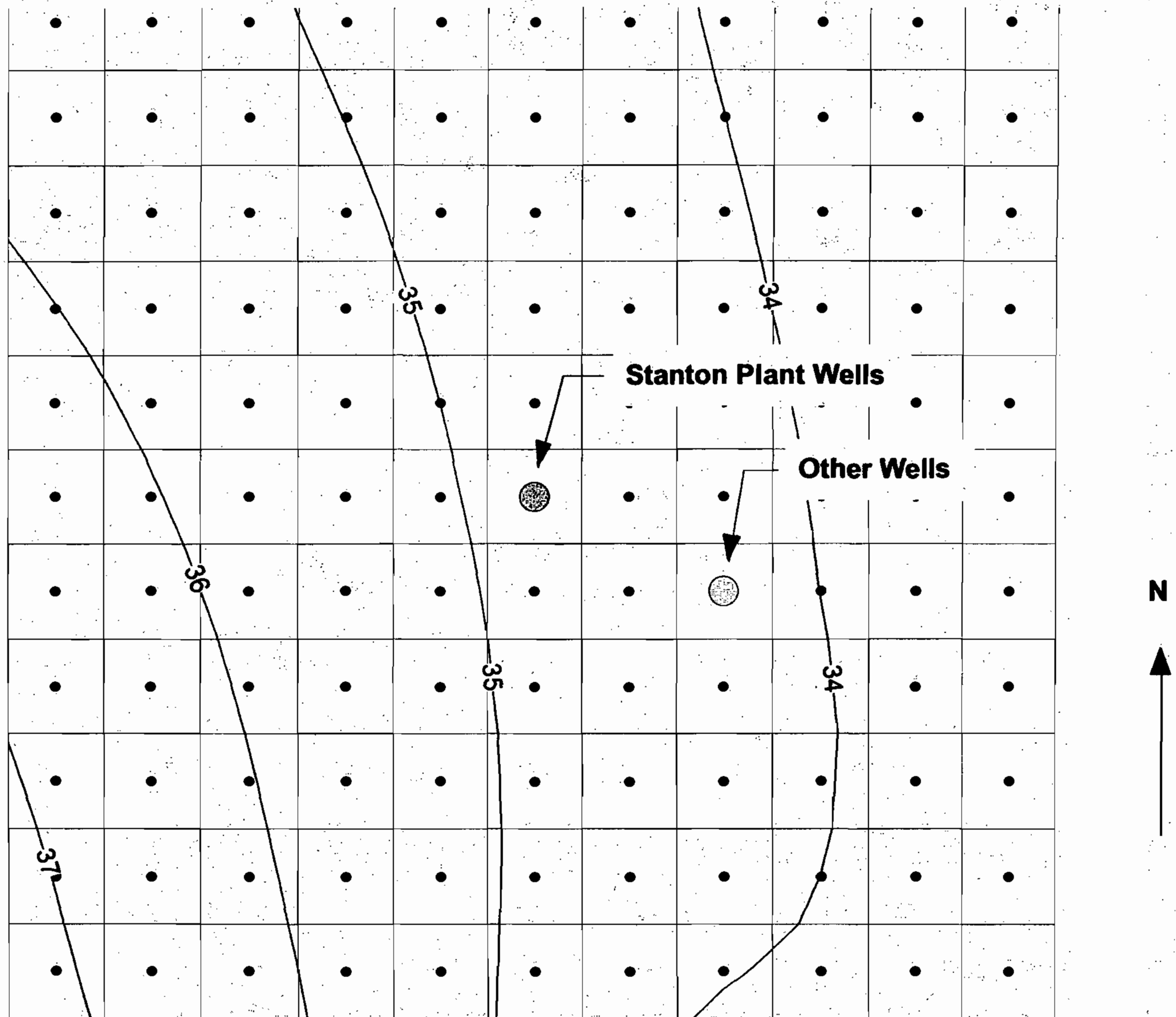


Figure 7: 2020 and 1995 SAS (Unconfined Aquifer) Water Table Elevation Differences

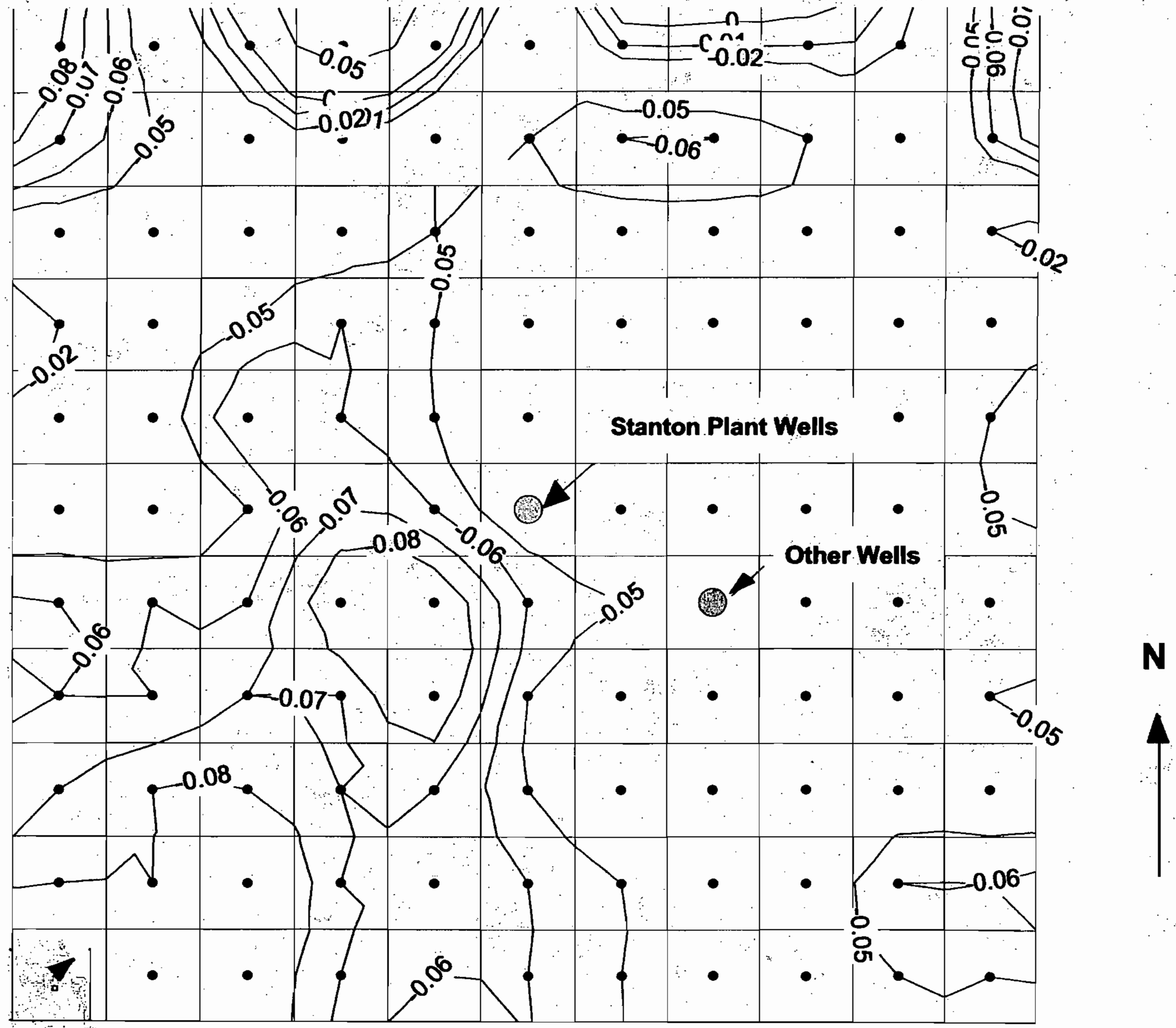


Figure 8: Potentiometric Contours for the Upper Floridan Aquifer with Increased Plant Pumping

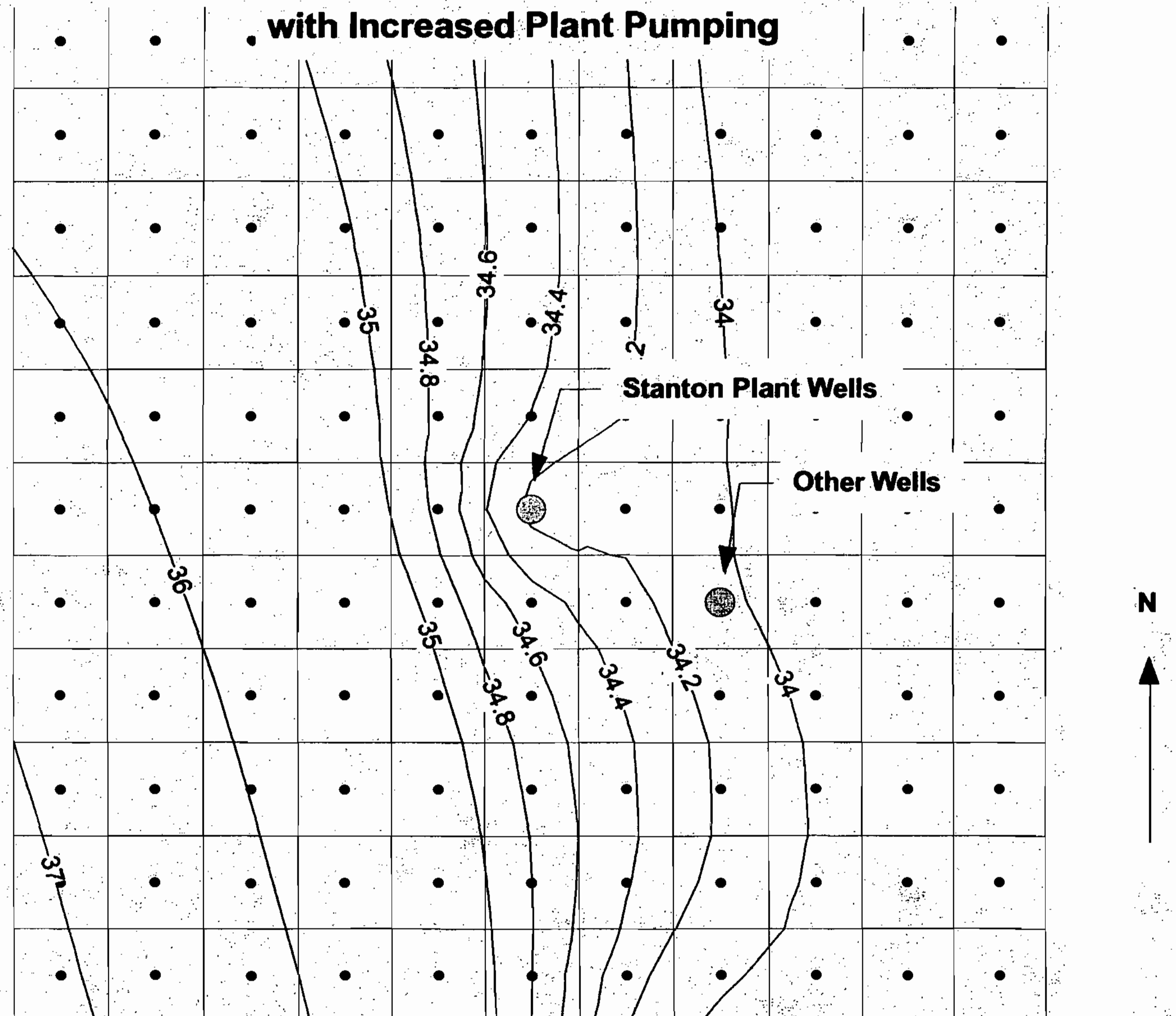
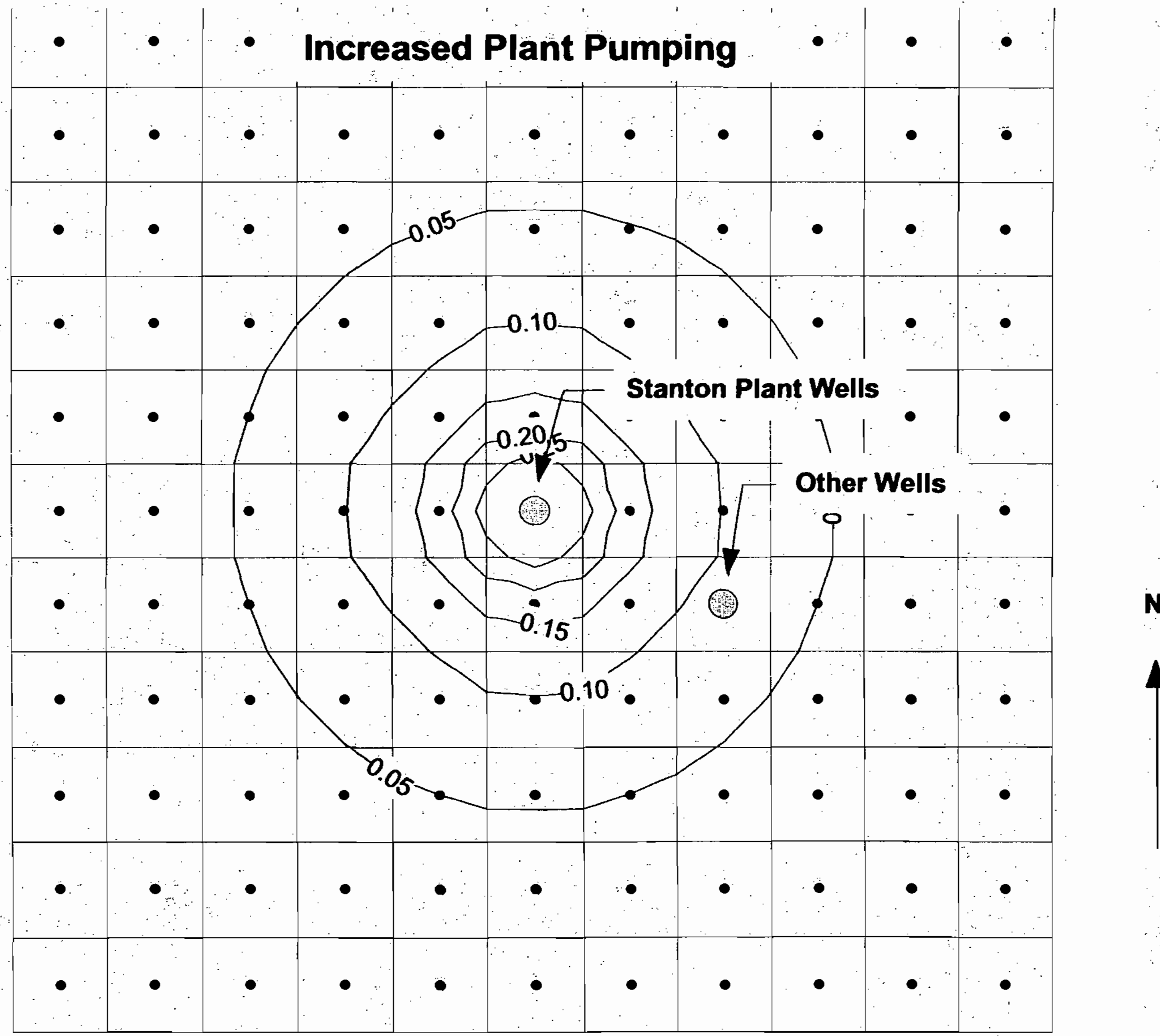


Figure 9: Increase in Drawdown in the Upper Floridan Aquifer Due to Increased Plant Pumping



SOURCES OF WATER
(Summary Data Sheet)

Please supply information regarding the source(s) of water for your activities. Include information regarding **all** wells/pumps on the property.

Table 1.
SUMMARY OF GROUND WATER SOURCES

Well or Pump Number	Wellfield or Facility Name	Casing Dia. (in)	Casing Depth (ft)	Total Depth (ft)	Operation Hrs/wk	Pump Capacity (in gpm)	Date Drilled	Existing or proposed (date)	Type of Use*
1	Stanton				84 [1]	850		Existing	(d)
2	Stanton				84 [1]	850		Existing	(d)

1 One continuous, one spare

* - See use descriptions on page 4. If more than one use type, show predominate use

Table 2
SUMMARY OF SURFACE WATER SOURCES

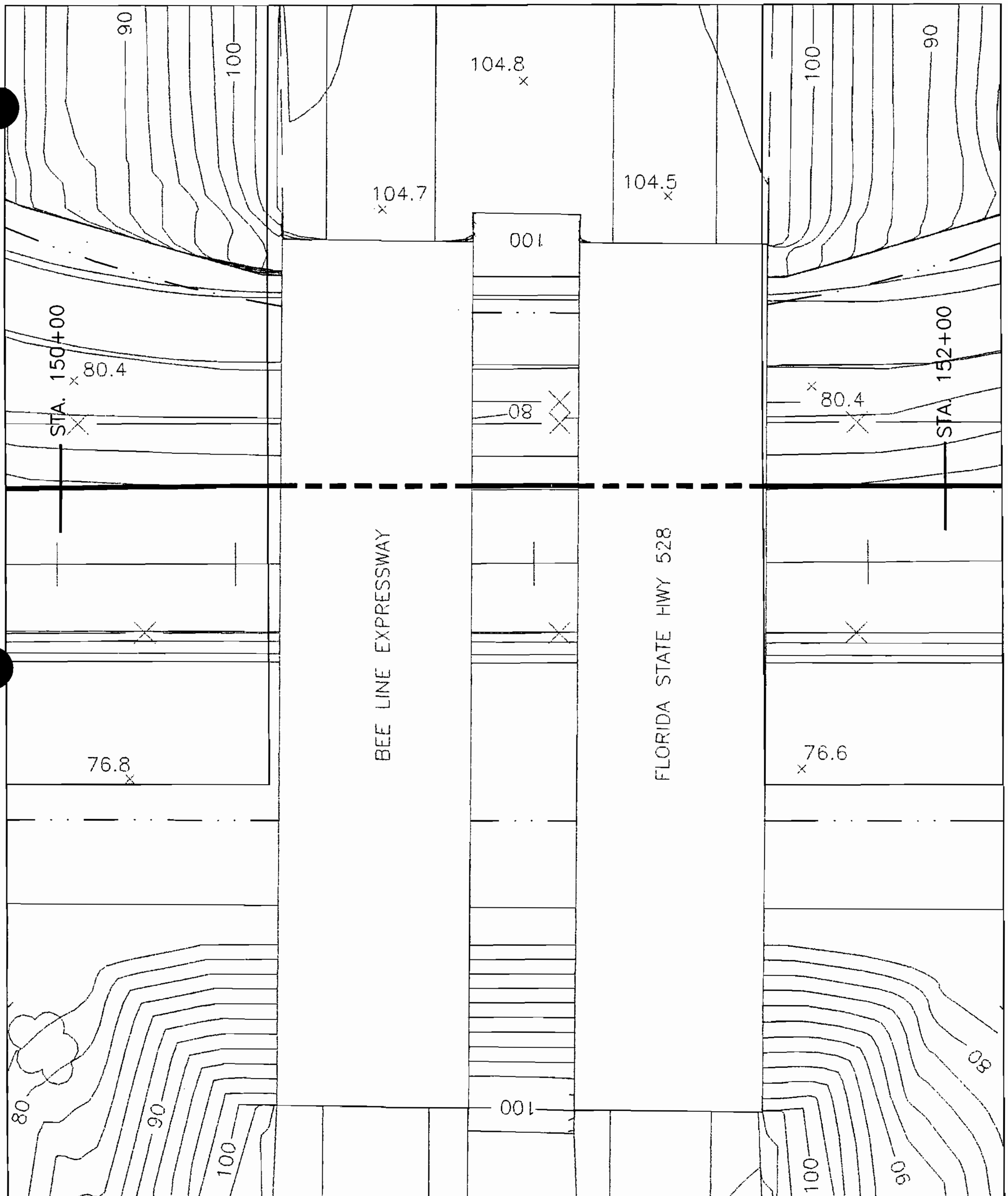
Pump Number	Pump Capacity (gpm)	Operation Hrs/wk	Acreage of Surface Water Body	Name of Source	Status (date if proposed)	Type of Use
1HRD-P-1A	4500	84 [1]	93 acres	Makeup Wtr Supply Storage Pond	Existing	(d)
1HRD-P-1B	4500	84 [1]	93 acres	Makeup Wtr Supply Storage Pond	Existing	(d)
1WSG-P-1A	1150	84 [1]	15 acres	Recycle Basin	Existing	(d)
1WSG-P-1B	1150	84 [1]	15 acres	Recycle Basin	Existing	(d)

1 One continuous, one spare

Florida Department of Transportation

The Florida Department of Transportation (Department) has reviewed the subject application for the site certification and found that additional information will be needed for the Department to adequately evaluate the application for certification. The Department will need detailed construction plans for the natural gas pipeline's crossing of State Road 528 and its right of way.

Response: Preliminary construction plans for the natural gas pipeline's crossing of State Road 528 and its right of way are attached. The plans comply with the Department's Utility Accommodation Manual. The plans have been provided to Mr. George Marek of the DOT's District 5 Maintenance Office.



LEGEND

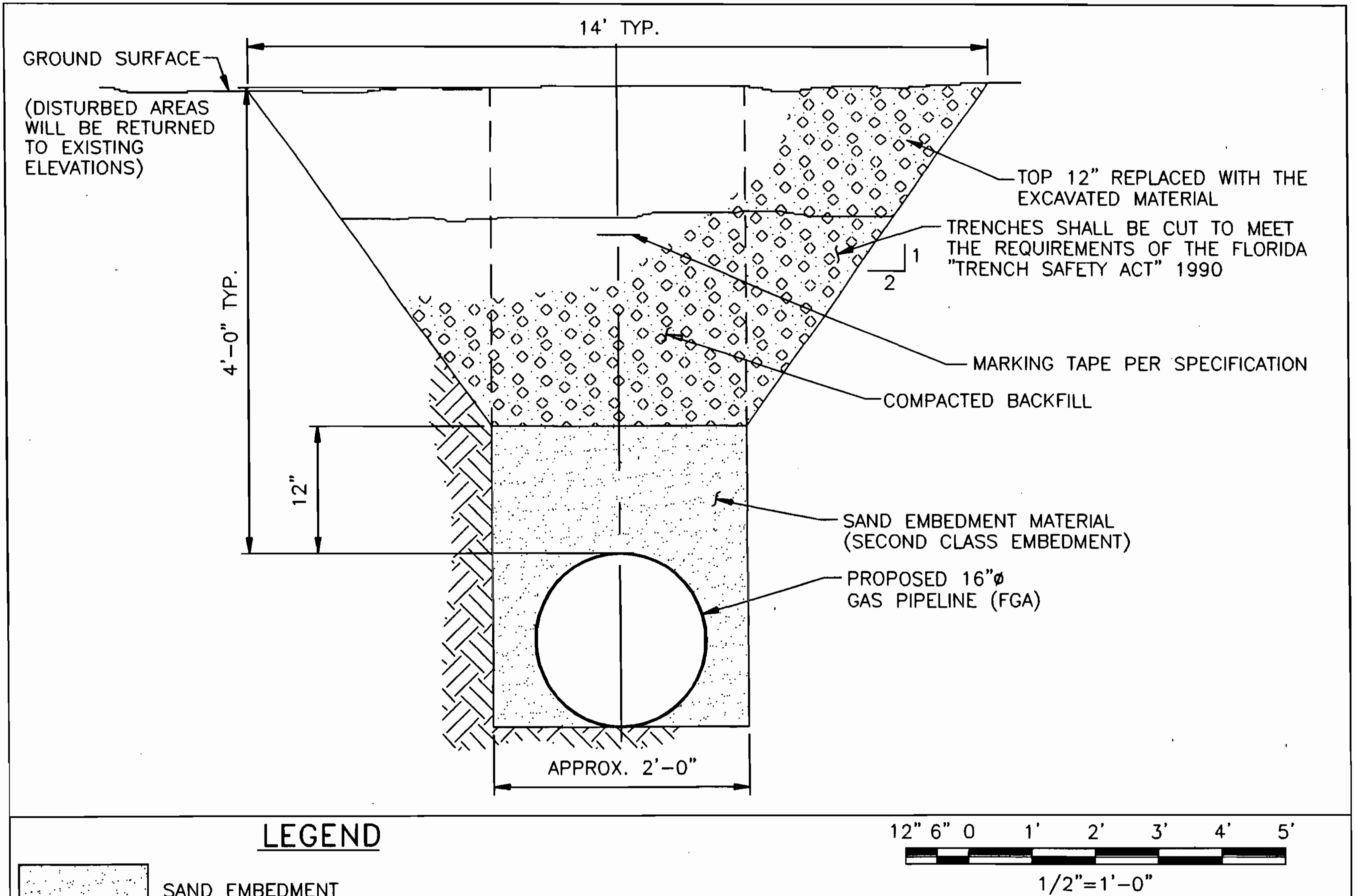
16" GAS PIPELINE

SILT FENCE
(TEMPORARY WORK AREA)

30' 20' 10' 0 30' 60'

1"=30'

SEC COMBINED CYCLE UNIT A
PIPING UNDER BEE-LINE EXPRESSWAY



TYPICAL GAS LINE TRENCH EXCAVATION
FIGURE 6.2-2 (04-17-2001)

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

March 12, 2001

Mr. Fredrick F. Haddad, Jr., P.E.
Vice President, Power Resources
Orlando Utilities Commission
Post Office Box 3193
Orlando, Florida 32802

Re: Stanton Energy Center combined Cycle Unit A, PA 81-14SA2

Dear Mr. Haddad:

The Department of Environmental Protection and other affected agencies have reviewed the Supplemental Site Certification Application submitted on January 22, 2001. The Department finds the application to be not sufficient. Please provide information requested in the following comments:

AIR

1. The emission limits proposed within the application are based upon the premise that for every hour of the year the unit will be operating with either duct burners firing, in power augmentation mode or firing fuel oil. Based upon its extensive history of permitting combustion turbines during the past 2-years, the Department does not find this to be reasonable for the determination of permit limits. An allotment of hours for each off-normal mode of operation will be assigned, which is consistent with prior BACT determinations.
2. The application requests emission limits of CO to be set in lb/hr rather than concentration limits. The Department evaluates BACT for CO based upon concentration rather than mass emission rates, and assigns permit limits in the same fashion.
3. Please confirm the Department's interpretation of the following CO emissions at 100% CT output:

Case	**Operating Mode**	**ppmvd @ 15%O_2**	**pounds per hour**
1	CT operating at 19 degrees F	7.4	31.0
13	CT with cooling (EC) and duct burners (DB) at 70 degrees F	18.1	87.51
18	CT with EC, DB and power augmentation at 95 degrees F	27.9	142.51

20	CT on oil at 19 degrees F	14.7	71.0

4. Please explain the Oxidation Catalyst economic analysis with regard to emissions reductions. According to the Air Construction application form (page 22) maximum requested annual CO emissions are up to 448.12 TPY (gas firing). Considering that the CO emissions resulting from an oxidation catalyst are 74.7 TPY, an emission reduction of 373.42 TPY should be evaluated rather than 319.7 TPY.

5. Based upon the requested permit levels of CO and related submittals, the application appears to support the installation of an oxidation catalyst. However, the Department wishes to point out that recent tests from TECO's Polk Power Station 7FA resulted in CO emissions of less than 1 ppmvd (gas) and less than 2 ppmvd (oil) at full load. Although contracting for CO limits between GE and its customers may not have caught up with field experience, actual results should be considered in the setting of BACT.

6. The applicant should be advised that ammonia slip is currently being permitted at 5 ppmvd.

7. Please indicate the maximum gross MW capability of the combined cycle unit, and under what operating conditions this output is achieved. Please provide the same information for the maximum heat input of the CT's and the gas-fired duct burners under ISO conditions. Maximum combined heat input rates have been specified for non-ISO conditions at 2402.0 MMBtu/hr firing natural gas (Case 4 while firing duct burners) and 2067.6 MMBtu/hr oil firing (Case 20).

8. Please provide the estimated time frames required, estimated number of annual start-ups and the estimated emission levels of NO_X, CO and PM/PM_{10} during hot and cold start-up periods. The Department intends to define these levels in the setting of BACT.

9. The Department requires as a submittal, a project specific, written cost estimate of a $SCONO_X$ control system, to be supplied by the technology provider (Alstom Power). In addition to capital cost requirements, the submittal should include vendor estimates for use in determining any applicable annualized operating and maintenance costs.

10. Each economic analyses should be revised to incorporate the information specified above as well as the utilization of OAQPS Control Cost Method factors (e.g. contingency). Additionally, according to the application's Section 4.6.7.2, lost revenues are included in the annualized cost estimate. These should be excluded from the analyses.

WATER

The following are Industrial Wastewater Review Comments:

1. The applicant has provided a single line diagram for the new expansion. This diagram does not show chemical feeds and all treatment systems. Some existing treatment units will be used for the treatment of the wastewater generated from the new expansion. A revised single

line diagram for the entire facility (Units 1, 2 and A) showing all treatments units, chemical feeds, and disposal methods is requested. Please show average daily and maximum daily flows for all existing units and the expansion.

2. On figure 3-5-1(single line diagram), please show final disposition of the treated water and wastewater for "OUC Tower Blowdown Treatment System" (node 60)

3. Please provide details of the SEC Recycle System. What is the make up of the basin structure?

4. Section 3-6 (page 3-13) – Please show the new brine concentrator system on the single line diagram. Also provide details of the boiler cleaning waste neutralization system. Where doe the cleaning waste disposed of.

5. 3-6-6 – Please provide details of the neutralization basin. Show all incidental waste stream and flow volumes from existing and the new units.

6. 5-2-1 Oil and Grease concentration of the water discharged from the transformer enclosure will be at 10.0mg/L. The discharge concentration is limited at 5.0mg/L. If the contamination is due to petroleum based oils, the Department will suggest sampling for TRPH (Total Residual Petroleum Hydrocarbons). The limit for the TRPH concentration in the effluent remains at 5.0 mg/L. The Department may require effluent monitoring for this discharge. Please provide details of the disposal area.

7. Projected Water Use on Page 5-28. It is indicated that the proposed expansion will require up to 2.91 mgd under normal operating condition. OUC should consider using up to 3 mgd available from Orange County Landfill located adjacent to OUC site.

8. This is referred to as a zero discharge facility. Zero must refer to surface water discharge because it does not appear to be an IW definition of zero discharge—unless the make-up pond is lined. Besides ground water and make-up well water, the make-up pond <u>may</u> receive any and all of the following:

    a. 2.9 MGD DW Effluent

    b. 0.369 MGD Effluent from Cooling Tower Blowdown Treatment System (effluent from crystallization system). This should probably be a good water quality but I do not see an analysis.

    c. 0.038 MGD From the boiler blowdown (The text states the blowdown water will be routed to the Stanton A cooling tower for reuse. Will it be "routed" though the make-up pond?)

    d. ? MGD From the gas desulfurization system (verbal information from GK in Air Section) that came from the Recycle Basin which receives:

    (1) 0.015 MGD effluent from an oil/water separator which receives wastewater from floor drains.

(2) 0.012 MGD effluent from R/O from the demineralizer

(3) wash down water

e. ? MGD There is also an ash system that receives Recycle Basin water but I am not sure if there is effluent and if it returns to this system.

If these waste streams go to the make-up pond, I would like these to be shown on a water balance even though the wastewater streams in the pond may be so diluted by the DW effluent and the ground water that there are no ground water quality problems.

9. Rainwater on Transformers is skimmed then water goes to stormwater pond. Is this tanks or IW?
10. The submittal said that they would complete Form 2CG for Industrial Waste application. I did not see it.
11. DW goes to a septic tank.
12. The quarterly data submitted uses a lot of "BDLs". The use is inconsistent. A parameter like Mercury will have a "<" for a couple of quarters then a "BDL" in the same quarter that other parameters have "<" symbols. Will ask for the lab sheets. If these detection limits are OK, we may be able to delete some parameters.
13. A considerable amount of waste is hauled. Who regulates the hauling?
14. Please provide copies of the chemistry laboratory bench sheets for the ground water monitoring data for the 14 monitoring wells for the years 1999 and 2000.
15. Some of the monitoring well information was missing for the 4th quarter of 2000. Were the wells dry? Please clarify.
16. The Central District does not have any record of the well completion information on the monitoring wells. Please provide copies of the Well Completion Report Forms for each monitoring well. If these forms were not included in the permit, please fill out copies of the attached forms and submit them to the Department with well construction diagrams.
17. Please revise the Water Balance (Figure 3.5-1) to include all of the wastewater streams going to the reuse basin and the make-up pond. Please show the recycle basin water going to Gas Desulfurization and Ash Systems and the return effluent if any.
18. Please sample the make-up pond, and the reuse basin for the parameters required in the quarterly ground water sampling plus TRPH.
19. For each wastestream in the expansion, please sample the correlative wastestream in the existing system for the parameters required in the quarterly ground water sampling plus TRPH.
20. Please provide a copy of an analysis of brine concentrator wastewater from a similar existing system. At a minimum the analysis shall include the primary standards for metals.

21. The scales for the monitoring well location maps are too small to accurately measure distances. Please show all of the monitoring wells on site plans with a scale similar to the Boring Location Map (Figure 2.3-4). Please include the locations of the Floridan Supply wells as well.

22. Please provide a scaled cross section through the reuse basin and the make-up pond.

23. If there are historic staff gauge readings for the ponds, please provide the data for 2000.

24. Please provide a data table for the monitoring wells which includes:

    a. Ground surface elevations.

    b. Top of casing elevations.

    c. Below top of casing depth for the years 1999 and 2000.

    d. Ground water elevations for the years 1999 and 2000.

25. Please be advised that currently the ground water is being monitored with the same parameters for both industrial waste streams and solid waste disposal sites. In reality, this is not necessary. Accordingly, based on the characterization of all industrial waste streams, please propose a separate Ground Water Monitoring Plan for addressing wastewater discharges into the reuse basin and the make-up pond.

    Please also be advised that a proposal for the revised Ground Water Monitoring Plan must include a provision of incorporating additional monitoring wells especially around the make-up pond as well as the reuse basin, along with appropriate parameters to be monitored in the ground water.

    It may also be noted that all new compliance monitoring wells shall be proposed not more than 100' form the discharge basin/ponds.

26. When the Site Certification is issued for the requested modification, the Ground Water Section, Central District, Orlando must receive one copy of Ground Water Monitoring reports for industrial wastewater discharges.

Environmental Resource Permitting

1. Section 3.8.9 Stormwater Management System

This section states that the system has been designed with a permanent pool residence time of 14 days. Since no littoral zone is proposed in the detention pond design a minimum 21-day residence is required per 40C42.026(4) F.A.C. Please provide supporting calculations

This section states that the system has been designed to attenuate the peak discharge from the 100-year - 24 hour storm. Please provide a pre-post demonstration for the 25 year/ 24 hour and Mean annual (2.3) year / 24 hour design storms using the SCS II (Florida Modified) Rainfall Distribution. The 25-year storm is the design storm for projects within the SJRWMD and the Mean annual storm is required for projects within the Econ Basin. Please provide inputs and output for any routing runs used in the demonstration.

a. Please provide stage storage calculations with indicated levels and associated volume for permanent pool as well as pollution abatement levels.

b. Please provide a recovery demonstration indication the orifice meets the bleed down requirements in 40C-42.026(4)(b).

2. Section 2.3.3 Vegetation

This section describes the types of common plants found and animals observed in SEC's entire parcel (excess of 3, 000 acres). However the report does not specifically address the vegetation and animals found with the 60 acre expansion site for Stanton A, or within the proposed Substation, utilizing the Natural Gas Pipeline and for the Transmission line. In addition, the report references a botanical survey conducted from 1980 to 1981. Please provide more recent data for the site.

3. Section 3.3.3.2 mentions that the existing rail line will be upgraded northwest of the coal units. What does the upgrade entail to the rail line? Addition impacts to wetlands, additional impervious stormwater concerns, etc?

4. Please provide the Central District with a copy of the Orlando Utilities Commission Joint Agency Mitigation Monitoring Plan (1992).

5. Section 4.1.1 identifies General Construction Impacts

The 60 acre Stanton A is described as "generally maintained grassland". This is not sufficient information/description to conclude that the area is an upland. Please clarify and revise accordingly.

a. Please provide a copy of the wetland determination for this parcel.

b. Was a formal binding determination permitted by the Department? If yes, please provide a copy.

c. Specifically identify all wetland areas proposed for impact, (including temporary and permanent and for the conversion of a forested system to a herbaceous wetland).

6. Drawing Figure 6.1-1 is not legible.

7. Please provide clear detailed plan and cross section drawings to the proposed transmission line. Specifically include:
   a) road names
   b) location of existing line (with dimensions)
   c) location of proposed line (with dimensions)
   d) location of wetlands, ditches, surface waters, etc (in numerical order)
   e) length and width of the line that will impact wetlands
   f) legend for wetlands including type and acreage
   g) cross section location
   h) location of the proposed road
   i) substation location and dimensions
   j) concrete pad locations with dimensions
   k) turbidity barrier type and location
   l) Other pertinent information.

8. Revise the cross section drawings to provide:
   a) width of the line/corridor

b) Cross hatch fill in wetlands, surface waters, ditches, etc.
c) legend to the cross hatched areas
d) acreage to the impact areas
e) all dimensions to toe of slope
f) Dimension to slope to the keypad.

9. Demonstrate why a new 125 feet wide corridor is necessary for the proposed transmission line. Please provide avoidance/minimization and alternatives considered for the new line.

10. Section 6.1.8.1

a. Are culverts required to maintain hydrologic flow? If yes, please reflect on the plan and cross section drawings.

b. Where are the concrete foundations being installed? (Identify on the drawings any that will be in wetlands, ditches, surface waters, etc. and provide dimensions).

11. Section 6.1.8.4

Identifies 0.4 acres of forested cypress strand to be cleared. Table 6.1-3 indicates clearing will be permanent. Please identify whether the entire area will be converted from a forested wetland to a herbaceous wetland or from a forested wetland to upland filled area. Please revise the drawing and tables/exhibits accordingly.

12. 6.2 Natural Gas Pipeline

Where is the 4.5 mile 16 inch FGT transmission line located?

a. Demonstrate why a 16-inch pipeline requires a 50 feet wide permanent corridor.

b. Drawing Figure 6.2-1 may serve as an overall location map for the proposed natural gas pipeline provided road names and section, townships and ranges were added to the drawing and the drawing is legible.

c. Detailed plan and cross section drawings are required for the entire pipeline. Include in the plan view drawing:

a) wetland locations
b) wetland types
c) cross hatch proposed wetland impacts
d) location of the proposed pipeline
e) temporary work area with dimension
f) cross hatch wetland impacts
g) legend to the proposed wetland impacts
h) dimensions (length and width) to the impacts
i) road names
j) north arrow
k) Cross-section.

13. Cross-section drawing are necessary for the wetland, surface water and ditch crossings. Include the following:
    a) Identify cross section
    b) Width of cross section
    c) Cross hatch impacts
    d) Location of the existing railway, unimproved roadway, etc.
    e) Location of the transmission line
    f) Culvert type, size, dimensions, invert
    g) Stabilization type
    h) Turbidity type and location.

14. Please indicate avoidance/minimization considerations for the transmission line installation. Include documentation regarding the construction of this line by directional bore.

15. Provide a copy of the Permit file number, type of permit, date authorized for the existing 26 inch FGT gas line.

16. Will the pipeline cross any surface waters? If yes, please identify all surface waters in your drawings. Please note that if the surface waters are determined to be sovereign submerged lands than a public easement will be necessary for all sovereign impacts.

17. Section 6.3.7.2 states that the Green Branch and Turkey Creek will be crossed by the 16-inch natural gas transmission line. Has a title determination been conducted for these locations? Please note as indicated above that if these areas are sovereign submerged lands then a public easement with detailed survey drawings will be required for the impacts crossing any area that is sovereign.

18. Table 6.2.2 states fill in forested wetlands as a temporary impact. Please clarify. (Typically, the owner of the transmission line does not desire forested systems to recruit within their pipeline and corridor.)

Therefore, it appears that the fill in the forested system is a permanent impact. Please clarify and revise all documentation.

19. Section 6.2.7.3.1 references a survey conducted in 1981. These are outdated.

20. Section 6.2.8.4 states that the pipeline will have minimal impact on vegetation and is temporary in nature. Please refer to statement regarding permanent impacts above.

21. Figure 6.2-2 please revise to include the following to this exhibit:
    a) total width in wetlands
    b) Statement that all disturbed area will be returned to pre-existing elevations.

22. No detail plan view drawings were provided for the proposed pipeline.

a. Please note that it appears that mitigation will be required for the conversion of forested wetlands to a herbaceous wetland and for all permanent impacts.

b. What considerations were made for the Substation expansion which in the application reflects 0.13 acres of fill? Please demonstrate avoidance/minimization.

23. Please note that the drawings provided in the Joint Application for an Environmental Resource Permit application are not legible. (Refer to the questions/statements regarding the plan and cross section drawings above.)

24. ERP Drawing 98-362-ERP-4A reflects 2,760 square feet of wetland impacts to Wetland 5 (W5). Please explain why W5 impact (east of the existing roadway) is necessary.

25. The Section, Township and Ranges in the maps/drawings are not legible.

Also attached are requests for additional information from the St. Johns River Water Management District and the Florida Department of Transportation.

Sincerely,

Hamilton S. Oven

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

St. Johns River
Water Management District
Henry Dean, Executive Director • John R. Wehle, Assistant Executive Director

Post Office Box 1429 • Palatka, FL 32178-1429 • (904) 329-4500

March 2, 2001

DEPARTMENT OF
ENVIRONMENTAL PROTECTION

MAR 07 2001

SITING COORDINATION

Hamilton S. Oven, Administrator
DEP Siting Coordination Office
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, FL 32399-2400

Via Facsimile Transmission (850) 921-7250

Re: Curtis H. Stanton Energy Center Combined Cycle Unit A Power Plant Siting Supplemental Application No. PA 81-14SA2; DOAH Case No. 01-0416EPP; DEP Case No.01-0176; SJRWMD F.O.R. #2001-08

Dear Mr. Oven:

Pursuant to Section 403.5067, Florida Statutes, and Rule 62-17.081(2)(a)1, Florida Administrative Code, the St. Johns River Water Management District transmits to you its request for additional information which must be provided in order to render this application sufficient to enable the District to carry out its statutory responsibilities. The request below reflects the information the District's technical staff believes is needed to complete the District's review and to thereafter prepare a report to the Department:

1. District water use rules require that the lowest acceptable quality water source, including reclaimed water or surface water (which includes stormwater), must be utilized for each consumptive use. To use a higher quality water source an applicant must demonstrate that the use of all lower quality water sources will not be economically, environmentally or technologically feasible.

    a) A source of reclaimed water is readily available from the Orange County Easterly Waste Water Treatment System. Information submitted with the application indicates that this water is intended to be used for cooling uses, but not for all uses. Please demonstrate why it is not feasible to use reclaimed water for all uses except for potable water. In order to demonstrate that the use of a lower quality source is not economically feasible, the applicant must demonstrate in detail that the use would render the entire project economically unfeasible. [Section 10.3(e)(f)(g), Applicant's Handbook, Consumptive Uses of Water (February 8, 1999) (A.H.)]

b) A source of stormwater is available from the adjacent Orange County Landfill to meet some of the power plant's water needs. Please evaluate the feasibility of using this source. In order to demonstrate that the use of a lower quality source is not economically feasible, the applicant must demonstrate in detail that the use would render the entire project economically unfeasible. [Section 10.3(e)(f)(g), A.H.]

c) The application includes a request for 2.13 million gallons per day of groundwater from the Floridan aquifer for cooling water use during emergency conditions. The existing power plant facility includes an approximately 90-acre storage pond with approximately 146 million gallons of storage capacity. The Orange County Easterly Waste Water Facility has an emergency groundwater backup allocation of 100 million gallons per year. Orange County applied for renewal of this permit with the same allocation. That permit application is complete and will be recommended for approval. Please demonstrate why it is not feasible to use either the water in the existing storage pond or the emergency groundwater backup allocation for the Orange County Waster Water Facility for the requested emergency backup use. [Section 10.3(e)(f)(g), A.H.]

2. The applicant has completed an initial evaluation that includes simulations of the drawdown in the Floridan aquifer due to the average daily withdrawal from all three units and of the drawdown due to the maximum combined capacity of the onsite wells pumping continuously for 30 days. Please provide copies of the input and output files for these model simulations. Additional impact analyses are necessary as follows:

   - An analysis to evaluate the cumulative drawdown impacts of the proposed withdrawals in combination with withdrawals from all existing legal uses.

   - An analysis to evaluate the cumulative impacts of the proposed withdrawals in combination with withdrawals from all existing legal uses and all withdrawals requested by applicants whose applications are complete. This analysis is necessary to determine whether there are competing applications.

   - An analysis to evaluate the cumulative impacts due to all existing and reasonably anticipated uses at some future year or years, including the proposed withdrawals. This can be in multiple evaluations such as for years 2005, 2010 and 2020. The purpose of this evaluation is to address the sustainability of the resource.

   District staff can assist the applicant with the completion of these analyses. Doug Munch with the District's Division of Groundwater Programs may be contacted for further assistance at (386) 329-4173. [Sections 6.5.1; 9.4.1(b)(e)(f), 10.2(e)(f)(g)(k)(l)(p); 10.3(c)(d), A.H.]

3. Is any dewatering of the site anticipated to be required during construction? If so, please confirm that any site dewatering will be below the thresholds in section 40C-

22.030 of the Florida Administrative Code. [Sections 10.2 (e) (f) (g) (i); 10.3 (d) (i), A.H.]

4. The information requested for **all** wells and pumps/surface water sources located on the property must be included in the SOURCES OF WATER Summary Data Sheet. Please also provide information regarding any and all offsite sources (connection points) and surface water pumps associated with the onsite storage pond. [Form 40C-2-1082-1, A.H.]

The District appreciates the Department's assistance in obtaining the above-requested information. If further clarification is needed regarding the District's requests, please contact me at (386) 312-2347. Thank you in advance for your cooperation.

Sincerely,

Charles A. Lobdell, III
Assistant General Counsel

cc: James Hollingshead
Dwight Jenkins
Doug Munch

Florida Department of Transportation

JEB BUSH
GOVERNOR

605 Suwannee Street
Tallahassee, Florida 32399-0450

THOMAS F. BARRY, JR.
SECRETARY

February 28, 2001

Mr. Hamilton S. Oven, P.E., Administrator
Siting Coordination Office
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Re: Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency and Southern Company – Florida, LLC Curtis H. Stanton Energy Center Combine Cycle Unit A Power Plant Siting Supplemental Application
No. PA 81-14SA2
DOAH Case No. 01-0416 EPP
DEP OGC Case No. 01-0176

Dear Mr. Oven:

The Florida Department of Transportation (Department) has reviewed the subject application for site certification and found that additional information will be needed for the Department to adequately evaluate the application for certification. The Department will need detailed construction plans for the natural gas pipeline's crossing of State Road 528 and its right of way. Mr. George Marek of the Department's District 5 Maintenance Office will be pleased to work with the applicant to identify the details to be included in the plans. Mr. Marek can be reached by phone at (904) 943-5281.

If you have any questions, please call me at 414-5386 or Sandra Whitmire, Siting Coordinator, at 414-4812. Thank you.

Sincerely,

Sheauching Yu
Assistant General Counsel

cc: Roy Young and Tasha Buford, Esquires
David Bruce May, Jr. and Lawrence N. Curtin, Esquires
Brian Hutt, District 5
George Marek, District 5
Sandra Whitmire

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

January 24, 2001

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Orlando Utilities Commission.
Curtis H. Stanton Energy Center
Facility ID No. 0950137-002-AC, PSD-FL-313

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for Orlando Utilities Commission, in conjunction with Kissimmee Utility Authority, Florida Municipal Power Authority, and Southern-Florida to construct and operate a 633 MW electric generating unit at the existing Curtis H. Stanton Energy facility in Orange County, Florida

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Teresa Heron, review engineer, at 850/921-9529.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

cc: Teresa Heron

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1. Article Addressed to:

Richard Crotty, Chair
Orange County Board of
County Commissioners
Administration Building, 5th Flr.
201 S. Rosalind Ave.
Orlando, FL 32801

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Orlando, FL 32801

PS Form 3800, February 2000 See Reverse for Instructions

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Recipient's Name *(Please Print Clearly) (to be completed by mailer)*
Robert G. Moore
Street, Apt. No.; or PO Box No.
One Energy Place
City, State, ZIP+4
Pensacola, FL 32520-0328

PS Form 3800, February 2000 — See Reverse for Instructions

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1. Article Addressed to:

Mr. Robert G. Moore
Gulf Power Company
OUC/KUA/FMPA/Southern Co. - Florida, LLC.
One Energy Place
Pensacola, FL 32520-0328

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* J GARNER
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Orlando Sentinel

Published Daily

State of Florida } S.S.
COUNTY OF ORANGE

Before the undersigned authority personally appeared BEVERLYC.SIMMONS, who on oath says that he/she is the Legal Advertising Representative of Orlando Sentinel, a daily newspaper published at ORLANDO in ORANGE County, Florida; that the attached copy of advertisement, being a PUBLIC NOTICE OF in the matter of PSD-FL-313 (PA 81-14SA2) in the ORANGE Court, was published in said newspaper in the issue; of 05/27/01

Affiant further says that the said Orlando Sentinel is a newspaper published at ORLANDO, in said ORANGE County, Florida, and that the said newspaper has heretofore been continuously published in said ORANGE County, Florida, each Week Day and has been entered as second-class mail matter at the post office in ORLANDO in said ORANGE 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/she 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.

Beverly C. Simmons

The foregoing instrument was acknowledged before me this 29th day of MAY, 2001, by BEVERLY C.SIMMONS, who is personally known to me and who did take an oath.

(SEAL)

STATE OF FLORIDA NOTARY PUBLIC
JULIA NICHOLS
My Comm Exp. 9/23/2001
Bonded By Service Ins
No. 683016
[ ] Personally Known [ ] Other I.D.

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. PSD-FL-313 (PA 81-14SA2)
OUC Curtis H. Stanton Energy Center
Unit A Combined Cycle Addition
Orange County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to the following joint owners: OUC/KUA/FMPA/Southern Company - Florida, LLC. The permit is to install a combined cycle power-generating unit at the existing OUC Stanton Energy Center, located at 5100 South Alafaya Trail, Orlando, Orange County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR52.21 for emissions of particulate matter (PM and PM10), volatile organic compounds (VOC), sulfur dioxide (SO2), sulfuric acid mist (SAM), carbon monoxide (CO) and nitrogen oxides (NOX). The applicant's name and address is **Mr. Robert G. Moore, Gulf Power Company, One Energy Place, Pensacola, FL 32520-0328.**

The project consists of two nominal (existing) 170 MW GE 7FA combustion turbine-electrical generators configured for combined cycle operation, operating on natural gas with 0.05% sulfur oil backup (1000 hours per year); two supplementally-fired (natural gas) heat recovery steam generators (HRSG); one 300 MW (nominal output) steam turbine; one fresh water cooling tower; a fuel oil storage tank and ancillary equipment.

NOx emissions will be controlled by Dry Low NOx combustors and SCR to 3.5 parts per million (ppm) while firing natural gas, and by water injection and SCR to 10 ppm while firing fuel oil. Emissions of carbon monoxide (CO) will be controlled to 14 ppm while firing oil and 17 ppm while firing gas. Emissions of volatile organic compounds (VOC), sulfur dioxide (SO2), sulfuric acid mist (SAM), and particulate matter (PM/PM10) will be very low because of the inherently clean fuels and methods of combustion employed.

The following maximum potential annual emissions (in tons per year) summarize the maximum increase in regular air pollutants as a result of this project.

Pollutants	Maximum Facility Emissions (TPY)
PM/PM_{10}	128
NO_x	315
SO_2	134
SAM	18
VOC	106
CO	373

An air quality impact analysis was conducted. Emissions from the facility will not contribute to or cause a violation of any state or federal ambient air quality standards. All impacts to Class II areas are less than significant. All impacts to Class I areas are also less than significant.

The Department will issue the FINAL permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

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

Dept. of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Technical Evaluation and Preliminary Determination as well as the Draft BACT Determination and Permit may be viewed at http://www8.myflorida.com/licensingpermitting/learn/environment/air/airpermit.html by clicking on Utilities and Other Facilities Permits Issued.

COR3912556 5/27/01

0950137-002
①

							DRAWING STATUS – PROJECT:	DATE	APPROVED
							NOT TO BE USED FOR CONSTRUCTION		
							RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION		
0		INITIAL ISSUE					RELEASED FOR CONSTRUCTION		
NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLM	CONFORMED TO CONSTRUCTION RECORDS		

100' 50' 0 100' 200'
1"=100'

BLACK & VEATCH
ENGINEER MSS DRAWN TRA
CHECKED DATE

ORLANDO UTILITIES COMMISSION
ORLANDO, FLORIDA
STANTON ENERGY CENTER COMBINED CYCLE PROJECT
T-LINE SILT FENCE PLAN

PROJECT 98362
CAD NO. TLINE3
DRAWING NUMBER TLINE3
FIGURE 6.1-1

PTBORD 1-17-01
1=1

3/27/01

0950137-002 (2)

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLM
0		INITIAL ISSUE				

DRAWING STATUS – PROJECT:	DATE	APPROVED
NOT TO BE USED FOR CONSTRUCTION		
RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION		
RELEASED FOR CONSTRUCTION		
CONFORMED TO CONSTRUCTION RECORDS		

100' 50' 0 100' 200'
1"=100'

BLACK & VEATCH
ENGINEER MSS DRAWN TRA
CHECKED DATE

ORLANDO UTILITIES COMMISSION
ORLANDO, FLORIDA

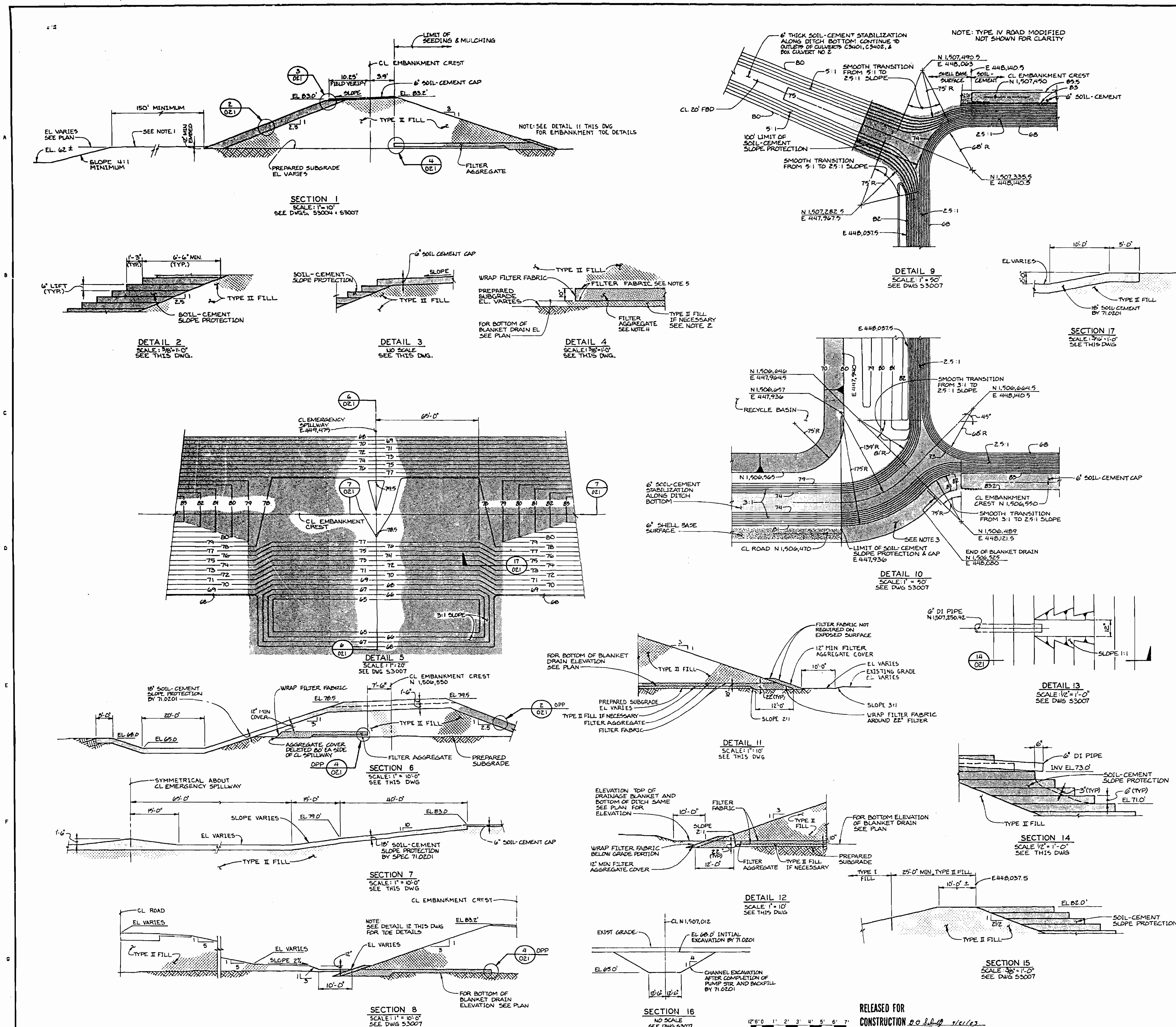
STANTON ENERGY CENTER COMBINED CYCLE PROJECT
T-LINE SILT FENCE PLAN

PROJECT 98362
CAD NO. TLINE2
DRAWING NUMBER TLINE2
FIGURE 6.1-1

PTBORD 1-17-01
1=1

0950137-002

(3)



NOTES

1. THE POND BOTTOM PERIMETER SHALL BE GRADED SMOOTH AND COMPACTED TO 95 PERCENT OF MAX DENSITY AT THE SURFACE.
2. AFTER PREPARATION OF SUBGRADE. TYPE II FILL MAY BE REQUIRED AT SOME LOCATIONS TO CONSTRUCT BLANKET AT ELEVATIONS INDICATED ON THE DRAWINGS.
3. GRADUAL TRANSITION FROM TYPE IV ROAD MODIFIED AS SHOWN IN SECTION 19 DWG S3203 (E447,936) TO TYPICAL EMBANKMENT CREST (E448,121.5).
4. THE AGGEGATE FILTER MATERIAL SHALL BE BACK DUMPED AND SPREAD IN ONE UNIFORM LIFT MAINTAINING THE DESIGN FILTER THICKNESS. DUMP TRUCKS AND SPREADING EQUIPMENT SHALL WORK FROM THE TOP OF THE AGGREGATE FILTER AND SHALL NOT COME IN DIRECT CONTACT WITH THE ENGINEERING FILTER FABRIC. OVERSTRESSING THE AGGREGATE MATERIAL SHALL BE AVOIDED BY USING EQUIPMENT THAT EXERTS ONLY MODERATE PRESSURES. THE AGGREGATE FILTER SHALL BE COMPACTED BY TRACKING CRAWLER TYPE EQUIPMENT OR PASSING VIBRATORY COMPACTORS HAVING MODERATE WEIGHT OVER THE MATERIAL UNTIL ACHEIVING A DENSITY OF NO LESS THAN 70 PERCENT OF RELATIVE DENSITY AS DETERMINED BY ASTM D2049.
5. THE ENGINEERING FILTER FABRIC SHALL BE OVERLAPPED A MINIMUM OF 12 INCHES AT FABRIC SPLICES WHEN BEING PLACED IN A HORIZONTAL POSITION. AN OVERLAP OF 24 INCHES SHALL BE USED AT FABRIC SPLICES WHEN THE FABRIC IS IN A SLOPED OR VERTICAL POSITION. SECURING PINS SHALL BE USED WHEN NECESSARY TO ENSURE PROPER ANCHORING OF THE. FABRIC. THE FABRIC SHALL BE PROTECTED BY COVERING WITH AT LEAST 12 INCHES OF MATERIAL PRIOR TO COMPACTION. CAUTION SHALL BE USED WHEN PLACING MATERIAL OVER THE FILTER FABRIC TO PREVENT DAMAGE TO OR PUNCTURE OF THE FABRIC

RELEASED FOR CONSTRUCTION D.O. [signature] 9/21/83

NO.	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP
8	12-16-88	CONFORMED TO CONSTRUCTION RECORDS	BD		
7	2-6-85	REVISED SPILLWAY DETAILS, SECT 1, ADD SECT 17	TPP		
6	12-14-84	DETAIL 5 ON HOLD. REVISED EMBANKMENT DETAILS	TPP		
5	8-9-84	REVISED COORDINATE ON DETAIL 13	TPP		
4	6-7-84	REVISED SECTION 1, 11, & 12 DETAIL 13	CTF		
3	4-4-84	REVISED DETAILS AND ADDED NOTES	CTF		
2	9-21-83	GENERAL REVISIONS	TPP	SRI	
1	8-16-83	GENERAL REVISIONS	CTF	TPP	
0	7-19-83	INITIAL ISSUE	CTF	TPP	

SCALE: 1" = 10' ; 1" = 20' ; 3/8" = 1'-0"

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED [signature]
DATE 7-19-83 REG NO. 32245

BLACK & VEATCH CONSULTING ENGINEERS
ENGINEER T.P. PINTCKE DRAWN MRJ
CHECKED S.R. IHNOW DATE 9-21-83

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 1
SITEWORK - MAKEUP WATER POND
PLANS, SECTIONS, & DETAILS

PROJECT 8927 - DRAWING NUMBER 1STF-S3021 REV 8

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Robert G. Moore
VP of Power Gen & Transmission
Gulf Power Company
OUC Stanton A Combined Cycle
 Addition
One Energy Place
Pensacola, FL 32520-0328

2. Article Number *(Copy from service label)*
7099 3400 0000 1450 3214

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 5/21/00

C. Signature
X [signature]
☐ Agent
☐ Addressee

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

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

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

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

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

7099 3400 0000 1450 3214

Article Sent To:

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

OUC Stanton

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Robert G. Moore
Street, Apt. No.; or PO Box No.
One Energy Place
City, State, ZIP+4
Pensacola, FL 32520-0328

PS Form 3800, July 1999 See Reverse for Instructions

Submit **only** your source code file -- `picture.cpp`

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Richard Crotty, Chair
Orange County Board of County
Commissioners
Administration Bldg., 5th Fl
201 S Rosalind Ave.
Orlando, FL 32801

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Acevedo

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

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

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

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

2. Article Number (Copy from service label)
7099 3400 0000 1450 3184

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

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

7099 3400 0000 1450 3184

Article Sent To:

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

Postmark Here

Orange County

Name (Please Print Clearly) (to be completed by mailer)
Mr. Richard Crotty, Chair
Street, Apt. No.; or PO Box No.
201 S. Rosalind Ave
City, State, ZIP+4
Orlando, FL 32801

PS Form 3800, July 1999 See Reverse for Instructions

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

RECEIVED
MAY 01 2001
BUREAU OF AIR REGULATION

Black & Veatch Corporation

OUC/KUA/FMPA/Southern Co.
Stanton A Project

B&V Project 98362
B&V File 32.0500
April 25, 2001

Mr. Hamilton S. Oven
Administrator, Siting Coordination Office
Department of Environmental Protection
2800 Blair Stone Road
Tallahassee, FL 32399-2400

~~AL~~ 5/2
FYI - Please return for file
Thanks
Patty

Subject: Re: Stanton Unit A Combined Cycle Project
Supplemental Site Certification Application
Department File No. PA 81-14SA2
DOAH Case No. 01-0416EPP
OGC Case No. 01-0176
Supplemental Information

Dear Mr. Oven:

On behalf of the Orlando Utilities Commission (OUC), the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA), and the Southern Company-Florida, LLC (Southern-Florida), Black & Veatch submits the following supplemental information in support of the Sufficiency Response filed with the Florida Department of Environmental Protection (Department) on April 23, 2001. Additional copies of this submittal have been provided to all parties controlling public review copies of the Stanton A Supplemental Site Certification Application.

The following information provides resolution of several of the air permit issues as identified in the March 12, 2001, sufficiency letter to Mr. Haddad, OUC. The issues were discussed between Mike Halpin, Department, and Dwain Waters, Southern-Florida, in a telephone conversation on April 18, 2001.

1. Request 1 concerned allotting hours for each off-normal mode of operation. Sufficiency Response 1 stated that operation using duct firing and evaporative cooling were considered normal modes, and off-normal modes (power augmentation and fuel oil firing) would be limited to 1000 hours/year. Final resolution of this issue incorporating the CO emissions limits discussed below will permit unlimited operation under normal, duct firing, and power augmentation modes. Stanton A will be permitted to operate 8760 hours/year firing natural gas, and 1000 hours/year firing fuel oil.

2. Request 2 concerned setting CO emission limits in ppm rather than lbs/hour. Sufficiency Response 1 stated that emission limits set as ppm would be acceptable, and proposed BACT

results. Final resolution of this issue will limit CO emissions to 17 ppm (@ 15% O_2) based on a 24-hour average for normal operation on natural gas, and 14 ppm (@ 15% O_2) for normal operation on fuel oil. These limits do not include startup operations.

3. There are no outstanding issues concerning Requests 3 and 4.

4. Request 5 concerned the use of an oxidation catalyst to control CO emissions. Sufficiency Response 5 stated that installation of an oxidation catalyst was not planned for the project due to costs and low annual emissions levels. Final resolution of this issue will incorporate a provision into the air permit that would require the installation of an oxidation catalyst if necessary to meet the CO emission limits listed in paragraph 2 above. The applicants have also agreed to install a continuous emissions monitoring (CEM) system for CO.

5. Request 6 concerned the level of ammonia slip (5 ppmvd) from the SCR. Sufficiency Response 6 proposed a 10 ppmvd ammonia slip. The applicants have agreed to a 5 ppmvd standard with annual testing to demonstrate compliance. No CEM or reporting other than the annual compliance demonstration will be required for ammonia slip.

6. There are no outstanding issues concerning Request 7.

7. Request 8 concerned the number of hours and emissions during startups. Sufficiency Response 8 stated that these estimates could not be provided, but that the applicants would accept standard language regarding startup limitations. The following estimates have been developed and are provided for final resolution of this issue. The estimated number of cold startups per turbine per year is 24; the estimated number of warm or hot startups per turbine per year is 120. The following estimated emissions are for informational use only and should be noted in the permit as "for informational use only".

Estimated Emissions During Start-up Operations Per Turbine Per Event

	NO_x	SO_2	PM_{10}	VOC	CO
Operational Profile on Natural Gas					
CTG cold start-up (4 hours)(lbs/event)	160	0	48	80	500
CTG warm start-up (2 hours)(lbs/event)	80	0	24	40	250
Operational Profile on Fuel Oil					
CTG cold start-up (4 hours)(lbs/event)	360	400	70	80	500
CTG warm start-up (2 hours)(lbs/event)	180	200	35	40	250

8. There are no outstanding issues concerning Request 9.

9. Request 10 concerned revision of the economic analyses. Sufficiency Response 10 either revised or justified the use of several evaluation factors. Final resolution of this issue has removed the lost power revenue criterion and revised the contingency factor to 3 percent. The revised cost analysis tables are included herein.

We appreciate the Department's cooperation and efforts during the review of the application. Please insert this letter in the Sufficiency Response volume of the Stanton A Supplemental Site Certification Application immediately behind the FDEP tab. If you have any questions concerning the project or this submittal, please do not hesitate to call me at (913) 458-7563 or Fred Haddad of OUC at (407) 236-9698.

Very truly yours,

BLACK & VEATCH CORPORATION

Michael Soltys

J. Michael Soltys
Site Certification Coordinator

JMS:slm
Enclosure[s]

cc: Mr. Frederick Haddad, OUC
Certificate of Service List
M. Halpin
C. Holladay
J. Kahn, CD
B. Worley, EPA
J. Bunyak, NPS

bcc:

T. Buford, YVV&A
J. Vick, SOFL
L. Curtin, H&K
F. Haddad, OUC
B. Sharma, KUA
S. Miles, SOFL
R. Casey, FMPA (2)
D. Stalls, OUC
T. Tart, OUC
S. Comensky, SOFL
M. Wimberly, SOFL
R. Forry, SOFL
G. Martin, SOFL
R. Terry, SOFL
J. Franklin, SOFL
A. Nebrig, SOFL
F. Bryant, FMPA
O. Harper, SOFL
B&V CDC
B&V Law Library
B. Hinshaw, SOFL
M. French, SOFL
M. Stover, B&V
R. Young, YVV&A
M. Serafin, B&V
K. Lucas, B&V
T. Hillman, B&V
M. Stover, B&V
M. Rollins, B&V
L. Krop, B&V

OUC/KUA/FMPA/Southern Co.
Stanton A

B&V Project 98362
April 25, 2001

CERTIFICATE OF SERVICE

I Certify that a true and correct copy of this Supplemental Information was mailed to the following on this 26th day of April 2001:

Mike McGovern, SJRWMD	Tom Ballinger, PSC
Brad Hartman, FFWCC	Debra Swim, LEAF
Greg Golgowski, ECFRPC	Clair Fancy, FDEP (4)
Ajit Lalchandani, Orange County	Paul Darst, DCA
James Hollingshead, SJRWMD (3)	George Percy, DHR
Sandra Whitmire, FDOT	Pepe Menedez, DOH
Vivian Garfein, FDEP-Orlando (4)	Anthony Cotter, Orange County
Jim Golden, SFWMD	Teresa Remudo-Fries, Orange County
Marc Ady, SFWMD	Charles Lee, Audubon Society
Dorothy Field, Orlando Public Library	

Michael Soltys

J. Michael Soltys

Table 4-4
Combined NO_X and CO Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit.

	$SCONO_X$ System	SCR/ Oxidation Catalyst	LNB	Remarks
Direct Capital Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3 in BACT
SCR & Oxidation Catalyst System	N/A	1,907,000	N/A	Estimated from Engelhard Corporation.
$SCONO_x$ System (Includes catalyst)	19,800,000	N/A	N/A	Estimated from Alstom Power.
Catalyst Reactor Housing	Included	268,000	N/A	Estimated by Alstom Power & scaled from an estimate by Engelhard Corporation.
Control/Instrumentation	Included	180,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia (Storage & Handling))	N/A	200,000	N/A	Estimated from previous projects.
Purchased Equipment Costs	19,800,000	2,555,000	N/A	
Sales Tax	N/A	N/A	N/A	No sales tax on generating equipment for this project.
Freight	Included	128,000	N/A	5% of Purchased Equipment Costs
Total Purchased Equipment Costs (PEC)	19,800,000	2,683,000	N/A	
Direct Installation Costs				
Balance of Plant	Included	805,000	N/A	For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting. SCONOx bid included installation.
Total Direct Cost Less Catalyst	**19,570,000**	**1,998,000**	Base	Catalyst cost is excluded as annual O&M cost. SCR and oxidation catalyst costs are $826,000 and $664,000, respectively. SCONOx replacement cost estimate is $230,000 per year, based on a 10-year life.
Indirect Capital Costs				
Contingency	594,000	80,000	N/A	For SCR and SCONOx: 3% of Total PEC
Engineering and Supervision	Included	268,000	N/A	For SCR: 10% of Total PEC
Construction & Field Expense	198,000	134,000	N/A	For SCR: 5% of Total PEC; For SCONOx 1% of Total PEC
Construction Fee	297,000	268,000	N/A	For SCR: 10% of Total PEC; For SCONOx 1.5% of Total PEC
Start-up Assistance	Included	54,000	N/A	For SCR: 2% of Total PEC
Performance Test	40,000	27,000	N/A	For SCR: 1% of Total PEC; For SCONOx 0.2% of Total PEC
Total Indirect Capital Costs	1,129,000	831,000	Base	
Total Installed Cost (TIC)	**20,699,000**	**2,829,000**	Base	

Table 4-5 Combined NO_x and CO Control Annualized Cost Per GE 7FA CTG/HRSG Unit				
	$SCONO_x$ System	**SCR/Oxidation Catalyst**	**LNB**	**Remarks**
Direct Annual Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3 in BACT
Catalyst Replacement	40,000	686,000	N/A	Catalyst life of 3 year for SCR/Oxidation catalyst and 10 year life for SCONOx catalyst.
Operation and Maintenance	310,000	40,000	N/A	Estimated from Alstom Power & includes catalyst washing and materials. For SCR/Oxidation catalyst assumed 2 hr/day, 8,760 hr/yr at $40/hr and includes materials.
Reagent Feed	N/A	87,000	N/A	Assumes 1.4 stoichiometric ratio.
Natural Gas Consumption	218,000	N/A	N/A	Based on 340-lb/hr natural gas consumption.
Power Consumption	4,000	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR and damper actuation for $SCONO_x$.
Annual Distribution Check	N/A	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less the catalyst cost.
Total Direct Annual Cost	572,000	828,000	N/A	
Indirect Annual Costs				
Overhead	31,000	24,000	N/A	For SCR 60% of O&M Cost; For SCONOx: 10% of O&M Cost
Administrative Charges	62,000	57,000	N/A	For SCR 2% of Total Installed Cost; For SCONOx: 0.3% of TIC
Property Taxes	103,000	78,000	N/A	For SCR 2.75% of Total Installed Cost; For SCONOx: 0.5% of TIC
Insurance	41,000	28,000	N/A	For SCR 1% of Total Installed Cost; For SCONOx: 0.2% of TIC
Capital Recovery	2,273,000	311,000	N/A	Capital Recovery Factor (0.1098) times the Total Installed Cost
Total Indirect Annual Costs	2,510,000	498,000	N/A	
Total Annualized Cost	**3,082,000**	**1,326,000**	N/A	
Annual Emissions, tpy	144.1	220.1	918.5	Emissions taken from Tables 4-1, 4-2 and 4-3 in BACT
Emissions Reduction, tpy	774.3	698.3	N/A	Emissions calculated from Tables 4-1, 4-2, 4-3 in BACT
Total Cost Effectiveness, $/ton	**4,000**	**1,900**	N/A	Total Annualized Cost / Emissions Reduction
Incremental Annualized Cost	**1,756,000**	N/A	N/A	Total annualized SCR/Oxidation catalyst system cost minus the total annualized SCONOx system cost
Incremental Reduction	**23,000**	N/A	N/A	Total Incremental Annualized Cost / Incremental Emissions Reduction

Table 4-6 NO_x Control Capital Cost Per GE 7FA CTG/HRSG Unit			
Cost Item	**SCR**	**Low NO_x Burners**	**Remarks**
Direct Capital Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
SCR Catalysts System	1,161,000	N/A	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	N/A	Scaled from an estimate from Engelhard Corporation
Control/Instrumentation	140,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia Injection/Dilution Equipment	Included	N/A	Estimated from Engelhard Corporation
Ammonia Storage	200,000	N/A	Estimated from previous projects
Purchased Equipment Costs	1,769,000	N/A	
Freight	88,000	N/A	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,857,000	N/A	
Direct Installation Costs			
Balance of Plant	557,000	N/A	For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting
Total Direct Cost Less Catalyst	1,588,000	Base	Cost Catalyst cost is excluded as annual O&M cost. SCR catalyst cost is $826,000.
Indirect Capital Costs			
Contingency	56,000	N/A	3% of Total Purchased Equipment Cost
Engineering and Supervision	186,000	N/A	10% of Total Purchased Equipment Cost
Construction & Field Expense	93,000	N/A	5% of Total Purchased Equipment Cost
Construction Fee	186,000	N/A	10% of Total Purchased Equipment Cost
Start-up Assistance	37,000	N/A	2% of Total Purchased Equipment Cost
Performance Test	19,000	N/A	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	577,000	Base	
Total Installed Cost	**2,165,000**	Base	

Table 4-7 NO_x Control Annualized Cost Per GE 7FA CTG/HRSG Unit			
	SCR	**Low NO_x Burners**	**Remarks**
Direct Annual Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	380,000	N/A	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	36,000	N/A	See text for background information on this item
Reagent Feed	87,000	N/A	Assumes 1.4 stoichiometric ratio
Power Consumption	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR
Annual Distribution Check	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less catalyst cost
Total Direct Annual Cost	518,000	N/A	
Indirect Annual Costs			
Overhead	22,000	N/A	60% of O&M Cost
Administrative Charges	43,000	N/A	2% of Total Installed Cost
Property Taxes	60,000	N/A	2.75% of Total Installed Cost
Insurance	22,000	N/A	1% of Total Installed Cost
Capital Recovery	238,000	N/A	Capital Recovery Factor (0.1098) times Total Installed Cost
Total Indirect Annual Costs	385,000	N/A	
Total Annualized Cost	**903,000**	N/A	
Annual Emissions, tpy	145.4	524.1	Emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	378.7	N/A	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, $/ton	**2,400**	N/A	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 System	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	Catalyst cost is excluded as annual O&M cost. Oxidation catalyst cost is $664,000.
Indirect Capital Costs			
Contingency	33,000	NA	3% 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	343,000	Base	
Total Installed Cost	**1,118,000**	Base	

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
Total Direct Annual Cost	310,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Cost
Administrative Charges	22,000	NA	2% of Total Installed Cost
Property Taxes	31,000	NA	2.75% of Total Installed Cost
Insurance	11,000	NA	1% of Total Installed Cost
Capital Recovery	123,000	NA	Capital Recovery Factor (0.1098) times Total Installed Cost
Total Indirect Annual Costs	189,000	NA	
Total Annualized Cost	**499,000**	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	**1,600**	NA	Total Annualized Cost/Emissions Reduction

Table 6-3
VOC Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Oxidation Catalyst System	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; includes controls and monitoring equipment
Purchased Equipment Costs	1,054,000	NA	
Freight	53,000	NA	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,107,000	NA	
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	Catalyst cost is excluded as annual O&M cost. Oxidation catalyst cost is $664,000.
Indirect Capital Costs			
Contingency	33,000	NA	3% 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	343,000	Base	
Total Installed Cost	**1,118,000**	Base	

Table 6-4

VOC 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 6-1 and 6-2
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
Total Direct Annual Cost	310,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Cost
Administrative Charges	22,000	NA	2% of Total Installed Cost
Property Taxes	31,000	NA	2.75% of Total Installed Cost
Insurance	11,000	NA	1% of Total Installed Cost
Capital Recovery	123,000	NA	Capital Recovery Factor (0.1098) times Total Installed Cost
Total Indirect Annual Costs	189,000	NA	
Total Annualized Cost	**499,000**	NA	
Annual Emissions, tpy	36.9	45.8	Emissions taken from Tables 6-1 and 6-2
Emissions Reduction, tpy	8.9	NA	Emissions calculated from Tables 6-1 and 6-2
Total Cost Effectiveness, $/ton	**56,000**	NA	Total Annualized Cost/Emissions Reduction

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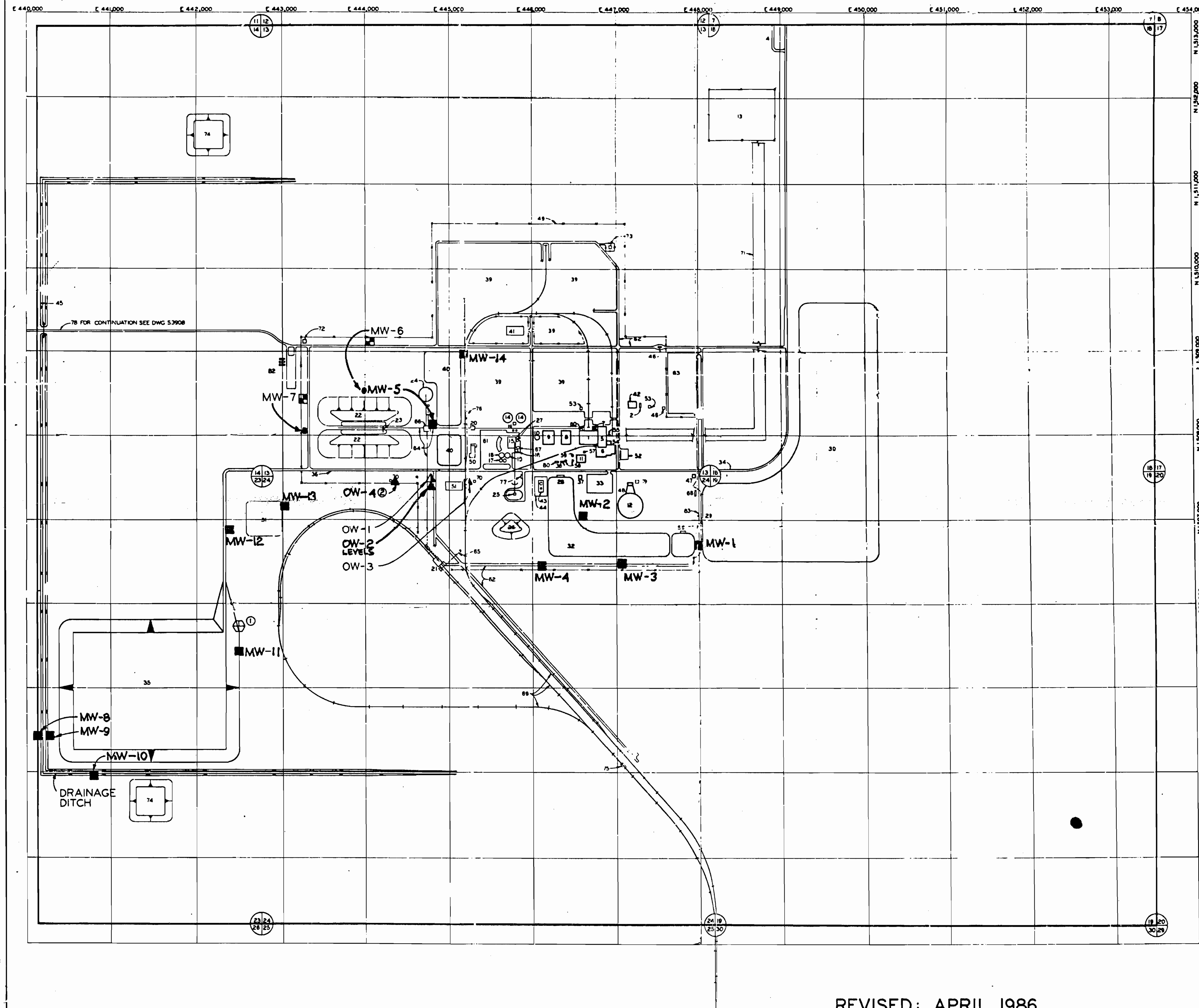


REVISED: APRIL 1986

FACILITIES LEGEND

1 UNIT 1 STEAM GENERATOR
2 FIRST AID TRAILER
3
4 ALTERNATE ACCESS ROAD
5 TURBINE ROOM
6 ADMINISTRATION AND PLANT SERVICES BUILDING
7 CONTROL CENTER BUILDING
8 PRECIPITATOR
9 AIR QUALITY CONTROL BUILDING
10 CHIMNEY
11 WATER MANAGEMENT BUILDING
12 COOLING TOWER
13 SUBSTATION
14 THICKENER
15 SLUDGE CONDITIONING BUILDING
16 FLY ASH SILO
17 ASH DEWATERING TANK
18 ASH SETTLING TANK
19 ASH WATER STORAGE TANK
20 COAL CRUSHER BUILDING
21 COAL CAR UNLOADING BUILDING
22 COAL STORAGE AREA
23 STACKER RECLAIMER
24 EMERGENCY STOCKOUT AND RECLAIM
25 SCRUBBER ADDITIVE RECLAIM
26 SCRUBBER ADDITIVE STORAGE
27 SCRUBBER ADDITIVE STORAGE TANK
28 SCRUBBER MAKEUP WATER PUMP STRUCTURE
29 CIRCULATING WATER MAKEUP PUMP STRUCTURE
30 MAKEUP WATER SUPPLY STORAGE POND
31 ACTIVE COMBUSTION WASTE AREA RUNOFF POND
32 RECYCLE BASIN
33 ADMINISTRATION AND PLANT SERVICES PARKING LOT
34 MAIN PLANT ACCESS ROAD
35 COMBUSTION WASTE STORAGE AREA
36 COMBUSTION WASTE HAUL ROAD
37 COMPRESSED GAS STORAGE BUILDING
38 WATER STORAGE PUMP BUILDING
39 CONSTRUCTION LAYDOWN AREA
40 COAL STORAGE AREA RUNOFF POND
41 CONSTRUCTION WAREHOUSE
42 CONSTRUCTION OFFICE BUILDING
43 FUEL OIL STORAGE
44 OIL SPILL CONTAINMENT BERM
45 CONCRETE BATCH PLANT (OFFSITE)
46 GUARD STATION
47 SECURITY BUILDING
48 CIRCULATING WATER PUMP STRUCTURE
49 SECURITY FENCE
50 YARD SERVICES BUILDING
51 PERMANENT WAREHOUSE
52 VISITORS PARKING LOT
53 CONSTRUCTION TOILET BUILDING
54 LUBE OIL STORAGE ROOM
55 GENERATOR TRANSFORMER AREA
56 WASTEWATER RETURN PUMP STRUCTURE
57 [illegible]
58 SERVICE WATER STORAGE TANKS
59 DEMINERALIZED WATER STORAGE TANK
60 CONDENSATE STORAGE TANKS
61 COMBUSTION WASTE LOADING AREA
62 PLANT SERVICE ROADS
63 CONSTRUCTION PARKING
64 YARD COAL CONVEYOR
65 FUTURE YARD SCRUBBER ADDITIVE CONVEYOR
66 COAL TRANSFER STRUCTURE
67 LIME STORAGE SILO
68 SEWAGE TREATMENT PLANT
69 RAILROAD
70 WELL WATER PUMP HOUSE
71 SITE TRANSMISSION CORRIDOR
72 TEMPORARY ACCESS ROAD GUARDHOUSE
73 CONSTRUCTION POWER SUBSTATION
74 TOPSOIL COVER STOCKPILE
75 TRACK SCALE
76 FUTURE LIME UNLOADING BUILDING
77 TRUCK SCALE
78 TEMPORARY ACCESS ROAD
79 CIRCULATING WATER CHEMICAL FEED BUILDING
80 EMERGENCY GENERATOR BUILDING
81 THICKENER PUMP BUILDING
82 TEMPORARY CONSTRUCTION PARKING AND CONTRACTOR TRAILER AREA
83 SUS BUILDING

LEGEND

▲ EXISTING OBSERVATION WELLS

■ NEW GROUND WATER MONITORING WELL

⊕ FUTURE GROUND WATER MONITORING WELL

NOTES

1. TYPICAL PLACEMENT OF FUTURE ADDITIONAL MONITORING WELLS, ONE PER CELL, 300 FOOT SPACING
2. OBSERVATION WELL OW-4 WILL BE USED AS A MONITORING WELL
3. PIEZOMETER REMOVED DURING CONSTRUCTION
4. MW-5 AND MW-6 WILL BE LOCATED WITHIN 100 FEET OF COAL STORAGE AREA
5. MW-11 AND MW-12 WILL BE LOCATED WITHIN 100 FEET OF THE COMBUSTION WASTE STORAGE AREA
6. MW-13 AND MW-14 WILL BE LOCATED WITHIN 100 FEET OF THEIR [illegible]

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP

... STATE OF FLORIDA
SIGNED
DATE ____ REG NO. ____

BLACK & VEATCH CONSULTING ENGINEERS

ENGINEER | DRAWN | CHECKED | DATE

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 1

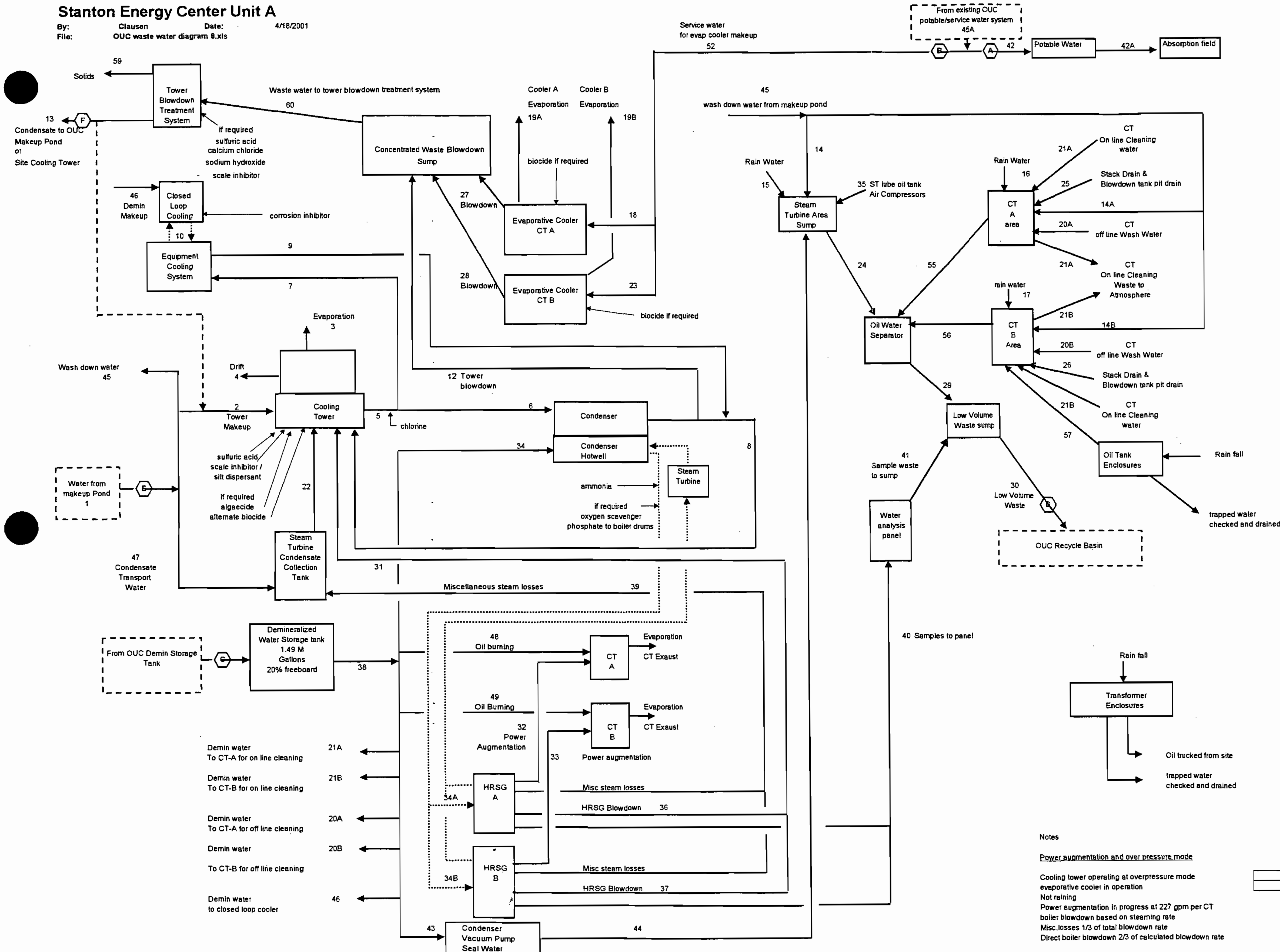
GROUND WATER MONITORING WELLS

PROJECT / DRAWING NUMBER: 8927 - ISTU-S1010

CODE
AREA

Stanton Energy Center Unit A

By: Clausen Date: 4/18/2001
File: OUC waste water diagram 8.xls



Line No.	Stream Flows are block flows unless otherwise noted	Average Flow based on plant operation gpm	Max Flow Power Aug over press gpm
E 1	Makeup water from OUC makeup pond	2154.4	2790.0
2	Cooling tower makeup	2101.6	2735.0
3	Cooling tower evaporation	1922.9	2495.0
4	Cooling tower drift	2.6	2.7
5	Circulating water pump discharge	128250.0	135000.0
6	Condenser inlet	118750.0	125000.0
7	Cooling water to equipement cooling water system	9500.0	10000.0
8	Condenser and service water cooler discharge to tower	127977.9	134646.0
9	Equipment cooling system return hot water	9500.0	10000.0
10	Closed loop cooling flow	9025.0	9500.0
11	spare	0.0	0.0
12	Cooling tower blowdown	272.1	354.0
F 13	Waste treatment condensate to OUC makeup pond or site tower	278.6	360.9
14	Makeup pond water to steam turbine area for wash down	0.2	0.0
14A	Makeup pond water to CT-A area	0.2	0.0
14b	Makeup pond water to CT-B area	0.2	0.0
15	Rain water to steam turbine area	0.1	0.0
16	Rain water to CT-A area	0.0	0.0
17	Rain water to CT-B area	0.0	0.0
18	Makeup water to CT-A evaporative cooler	26.1	27.4
19A	CT- A evaporative cooler evaporation	22.8	24.0
19B	CT- B evaporative cooler evaporation	22.8	24.0
20A	CT-A off line cleaning wash water	0.1	0.0
20B	CT-B off line cleaning wash water	0.1	0.0
21A	CT-A on line wash water	0.5	0.0
21B	CT-B online wash water	0.5	0.0
22	Steam Turbine collection tank to cooling tower basin	66.7	75.4
23	Water to CT-B evaporative cooler	26.1	27.4
24	Steam turbine area to oil water separator	0.3	0.0
25	CT A stack drain and blowdown tank pit drain	0.0	0.0
26	CT A stack drain and blowdown tank pit drain	0.0	0.0
27	CT-A evap cooler blowdown	3.3	3.4
28	CT-B evap cooler blowdown	3.3	3.4
29	Oil water separator to low volume sump	0.8	0.0
D 30	Low volume waste to OUC recycle basin	10.3	10.0
31	Total block boiler blow down	29.3	41.4
32	Power augmentation to CT A	64.8	227.0
33	Power augmentation to CT B	64.8	227.0
34	Makeup to Condenser Hotwell	182.8	525.7
34a	Makeup for losses at HRSG A	91.4	262.9
34b	Makeup for losses at HRSG B	91.4	262.9
35	Steam turbine lube oil tank and Air Compressors	0.0	0.0
36	HRSG A Blowdown to tower	14.6	20.7
37	HRSG B Blowdown to tower	14.6	20.7
C 38	Demin. water to process	235.5	525.7
39	Total HRSG miscellaneous losses	14.4	20.4
39A	HRSG A misc. losses	7.2	10.2
39B	HRSG B misc. losses	7.2	10.2
40	Water analysis panel waste	9.5	10.0
41	Panel waste to low volume sump	9.5	10.0
A 42	Potable water to block from potable water supply	0.6	0.0
42A	Sewage to treatment from block	0.6	0.0
43	Condenser vacuum pump seal water makeup	0.0	0.0
44	Condenser vacuum pump seal water waste	0.0	0.0
45	washdown water	0.6	0.0
45A	From existing OUC potable/service water system	52.7	54.9
46	Closed loop cooling water makeup	0.0	0.0
47	Condensate transport water	52.3	55.0
48	Demin water to CT- A during fuel oil burn	25.8	0.0
49	Demin water to CT- B during fuel oil burn	25.8	0.0
50	Spare		
51	Fire Protection water to site	0.0	0.0
B 52	Evap cooler makeup from OUC site	52.1	54.9
53	spare		
54	spare		
55	CT - A area sump to oil water separator	0.3	0.0
56	CT - B area sump to oil water separator	0.3	0.0
57	Oil storage tanks to CT - B area sump	0.0	0.0
58	Spare		
59	Solids to land fill pounds per minute	7.7	10.2
60	Conc. Waste sump to blowdown treatment	278.6	360.9
	in	2442.8	3370.6
	out	2442.8	3370.6

Notes

Power augmentation and over pressure mode

Cooling tower operating at overpressure mode	8	cycles
evaporative cooler in operation	8	cycles
Not raining		
Power augmentation in progress at 227 gpm per CT		
boiler blowdown based on steaming rate	1	%
Misc.losses 1/3 of total blowdown rate		
Direct boiler blowdown 2/3 of calculated blowdown rate		

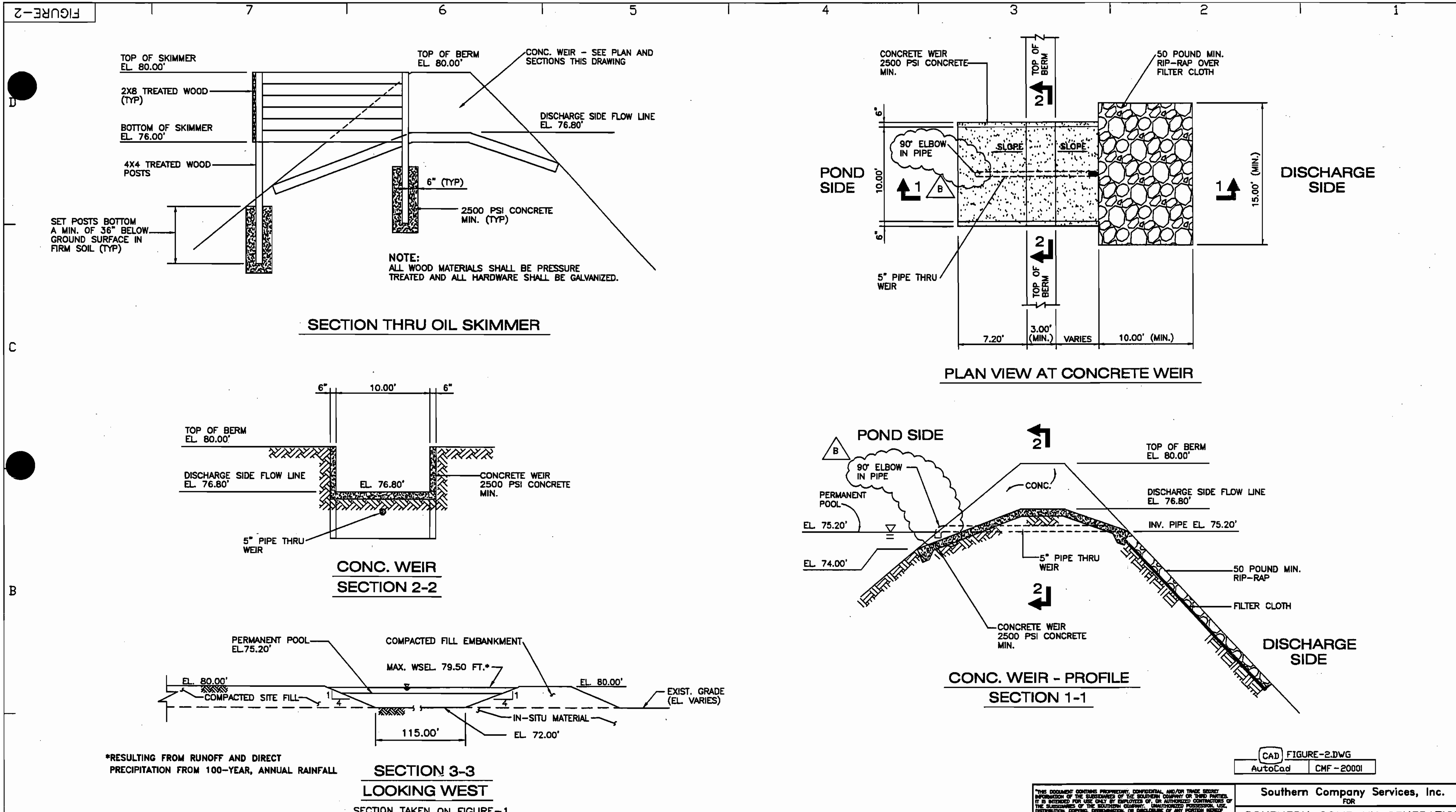
Blowdown

hot reheat	719782	
Lp admission	20469	
Main steam	803371	
	1543622	#/hr
	30.87244	gpm

Average Flow Based on plant operation

operation factor 0.95
Normal operation a function of power factor and power aug. and oil burning
power augmentation operation 2500 hours
oil burning 1000 hours
evaporative cooler in operation 12 hours per day
Assume washdown of 100 gpm for 60 minutes per week (20 minutes per area)
rain water 48.11 inches annual
steam turbine sump 1556 ft2
CT A sump 220 ft2
CTB sump 220 ft2
on line cleaning 780 gallons once per day exausted to atmosphere
off line cleaning 2430 gallons once per month trucked from site
assume 30 gallons per day per person, 30 persons/day
1% boiler blowdown based on steaming rate
Misc.losses 1/3 of total blowdown rate
Direct boiler blowdown 2/3 of calculated blowdown rate
Interconnections with Stanton Units 1 & 2 are indicated by

Figure 3.5-1



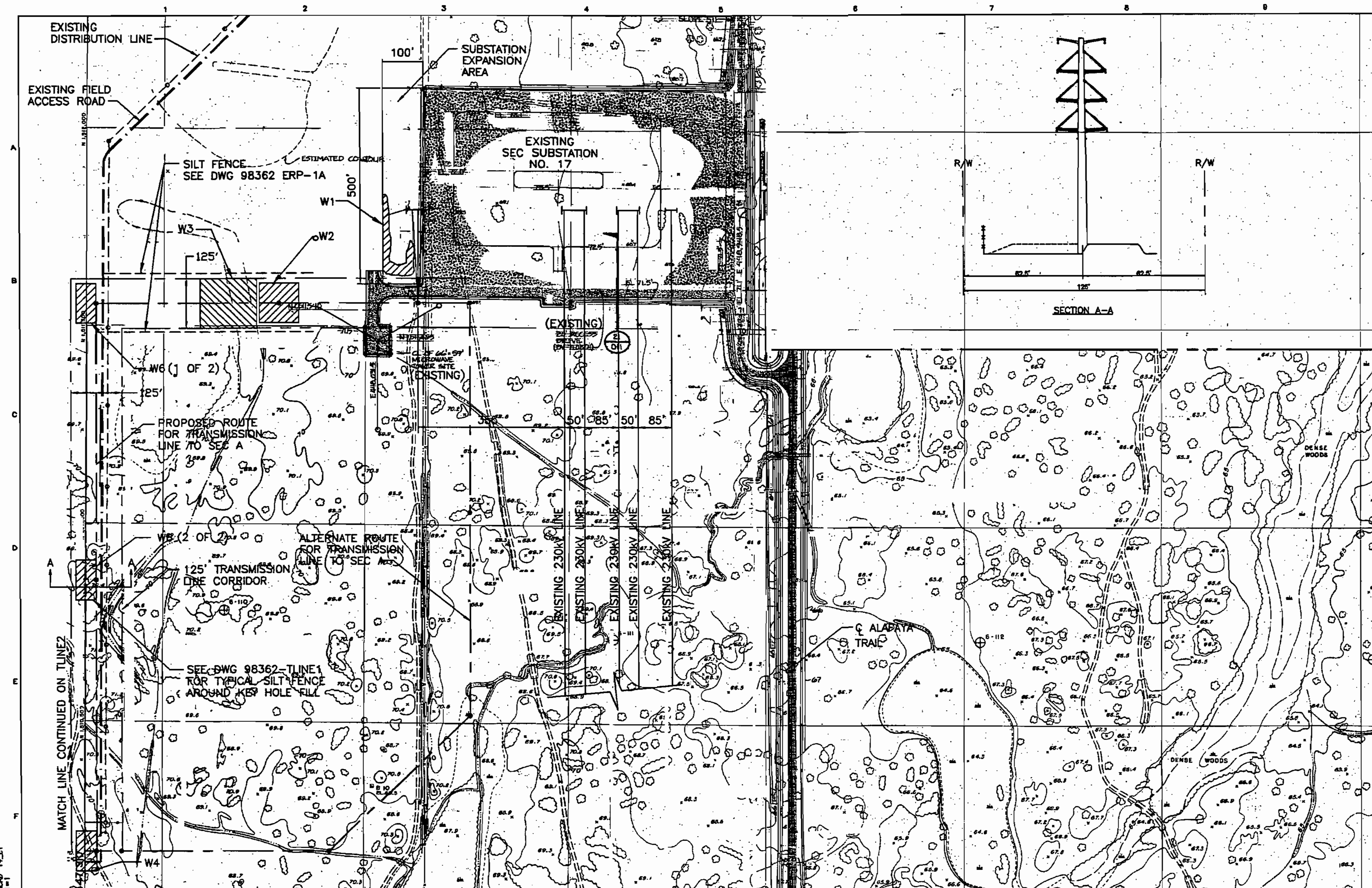
CAD FIGURE-2.DWG
AutoCad | CMF - 20001

Southern Company Services, Inc.
FOR
SOUTHERN COMPANY GENERATION

STANTON ENERGY CENTER – UNIT A
1–2x1 COMBINED CYCLE BLOCK
SECTIONS AND DETAILS

REVISION	DATE	DESCRIPTION	BY	CHK'D
B	4/04/01	ADDED 90° ELBOW IN 5" PIPE THRU WEIR	CMF	RCB
A	01/12/01	ISSUED FOR REVIEW	CMF	

DESIGNED	DRAWN	CHECKED	SCALE	PROJECT I.D.	DRAWING NUMBER	REV.
RCB	CMF		NONE		FIGURE-2	B



LEGEND

FILL IMPACTS

CLEARING IMPACTS

IMPACT AREA	DESCRIPTION
W1	HERBACEOUS WETLAND (0.13 ACRE)
W2	HERBACEOUS WETLAND (0.23 ACRE)
W3	CYPRESS WETLAND (0.40 ACRE)
W4	HERBACEOUS WETLAND (0.11 ACRE)
*W5	HERBACEOUS WETLAND (0.06 ACRE)
W6	SURFACE WATER (TOTAL = 0.23 ACRE)

* IMPACT AREA W5 IS SHOWN ON DRAWING 98362-ERP-4A.

STANTON ENERGY CENTER COMBINED CYCLE PROJECT

WETLAND IMPACT AREAS

DRAWING 98362-ERP-4

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLM
0		INITIAL ISSUE				

DRAWING STATUS – PROJECT:
NOT TO BE USED FOR CONSTRUCTION
RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION
RELEASED FOR CONSTRUCTION
CONFORMED TO CONSTRUCTION RECORDS

BLACK & VEATCH

ORLANDO UTILITIES COMMISSION
ORLANDO, FLORIDA

STANTON ENERGY CENTER COMBINED CYCLE PROJECT
T-LINE SILT FENCE PLAN

PROJECT 98362

DRAWING NUMBER TLINE3

CAD NO. TLINE3

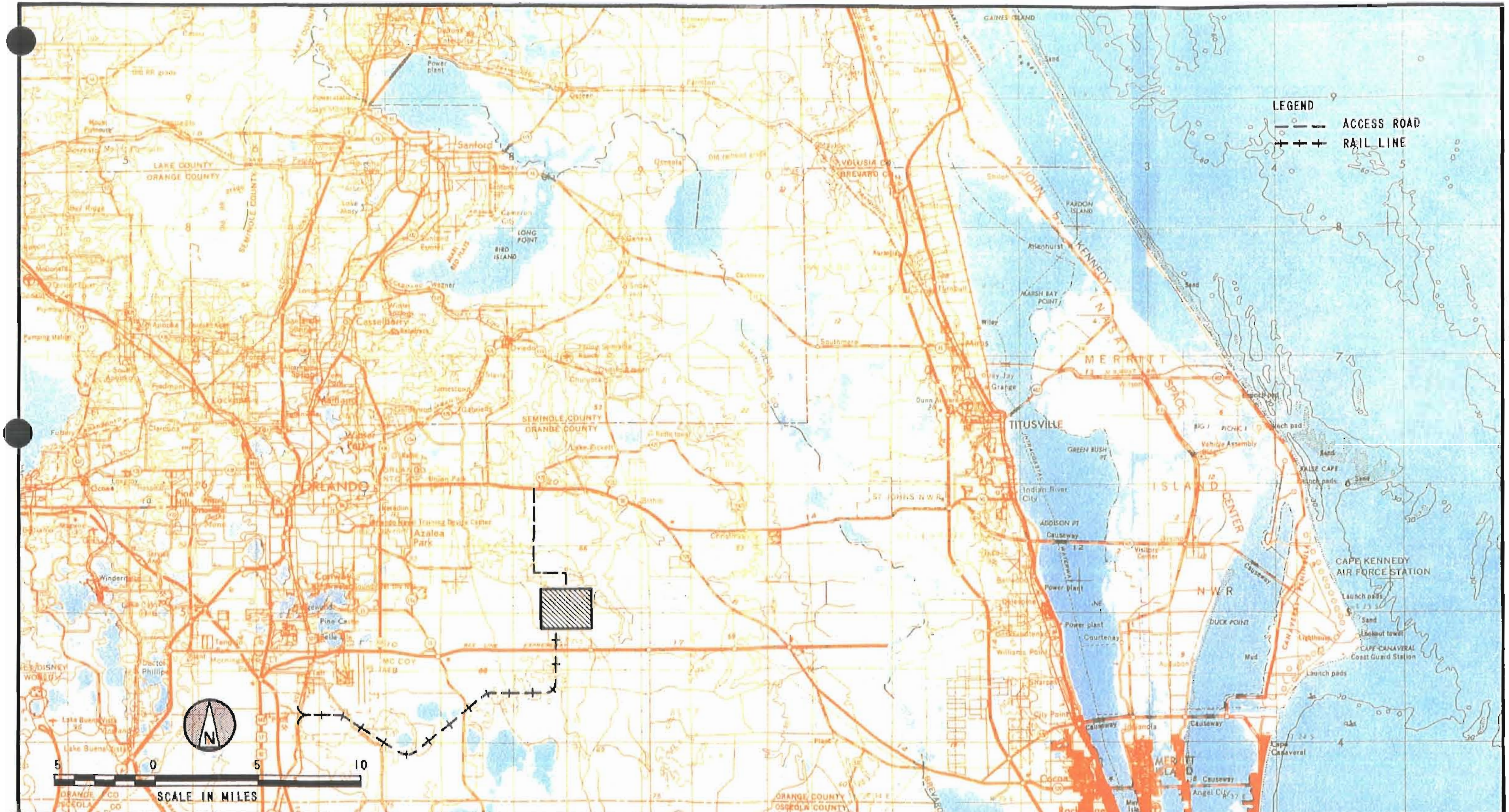


FIGURE 8
REGIONAL AREA MAP