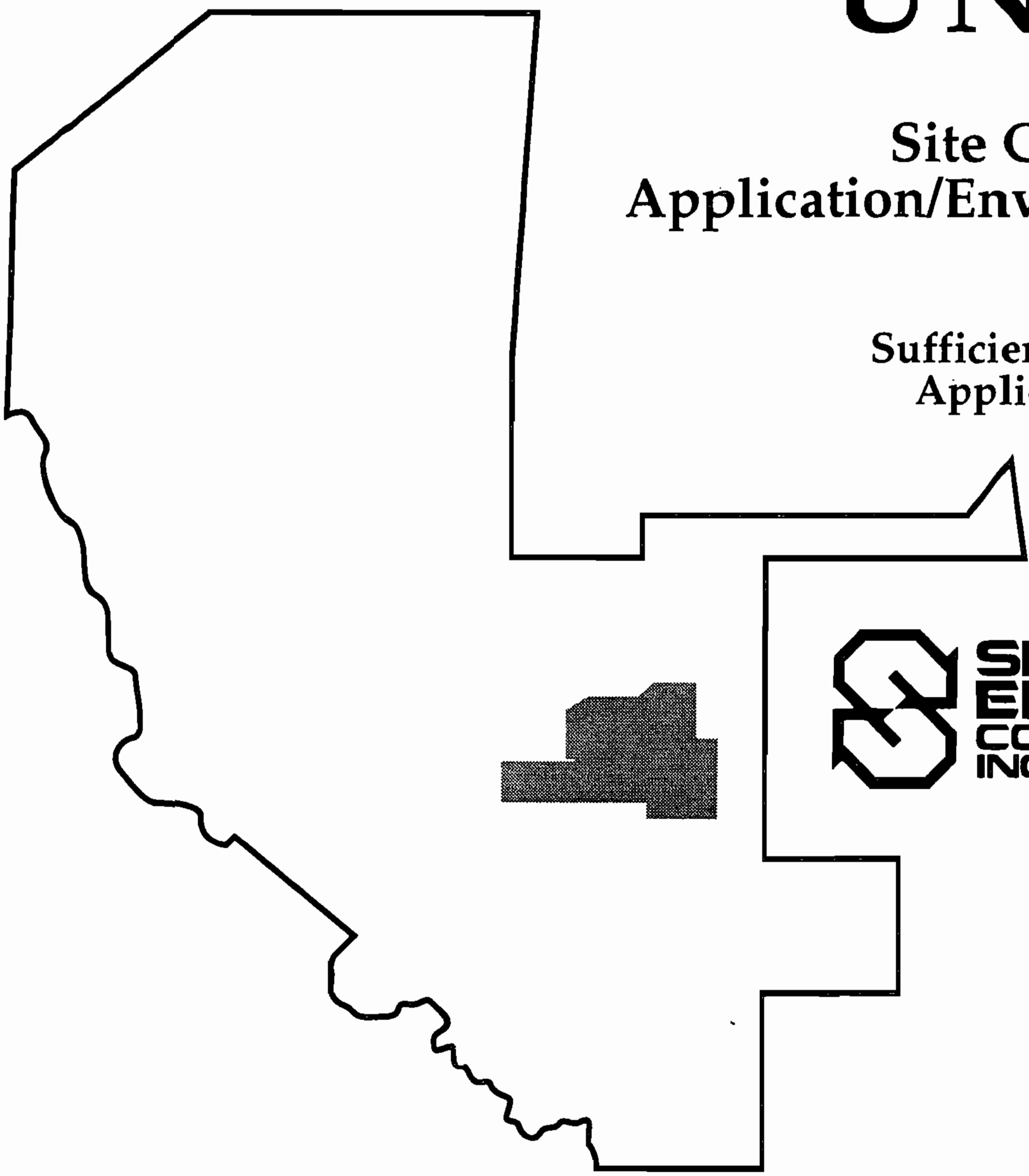
HARDEE UNIT 3



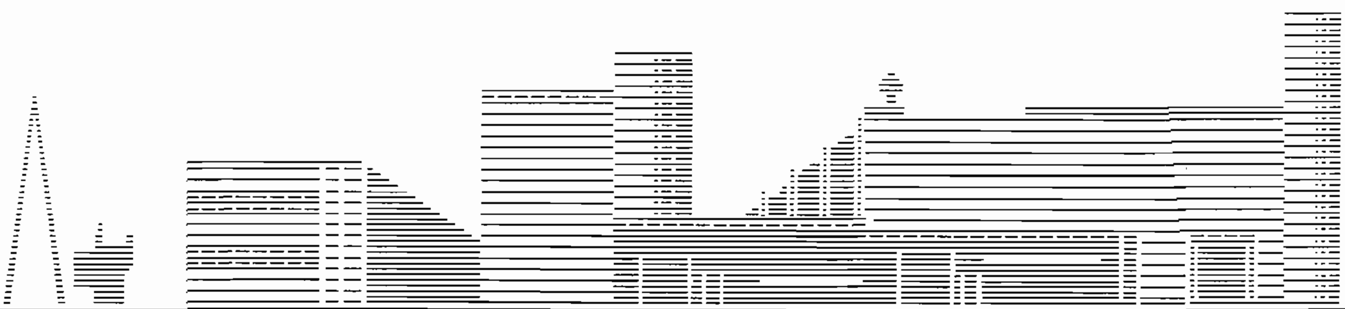
Site Certification Application/Environmental Analysis

Sufficiency Comments/ Applicant Responses

SUBMITTED BY

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

August 1994



Florida Department of
Environmental Protection

Memorandum

8/26

TO: Richard Donelan
John Brown
Al Rushanan
Trudie Bell
Raoul Clark
Cheri Albin
Mike Hickey

From: Steve Palmer SP
Siting Coordination Office

Date: August 29, 1994

SUBJECT: Seminole Electric Cooperative Incorporated Hardee Unit 3 (PA89-25SA)

Attached is the Seminole Electric Cooperative Incorporated, (SECI), Site Certification Application insufficiency response for the Hardee Unit 3 electric power generation facility. Review of the response for sufficiency should begin as of this date with comments due to the Siting Coordination Office on September ~~15~~ 22, 1994.

If you have any questions, please call me or Buck Oven at 904/ 487-0472.

attachment--

cc: Buck Oven

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

DEPARTMENT OF ENVIRONMENTAL PROTECTION

AUG 26 1994

SITING COORDINATION

August 26, 1994

Mr. Steve Palmer
Office of Siting Coordination
Florida Department of Environmental Protection
3900 Commonwealth Blvd., Suite 953
Tallahassee, FL 32399

**RE: SEMINOLE ELECTRIC COOPERATIVE, INC.
APPLICATION FOR SITE CERTIFICATION PA89-25SA
RESPONSES TO SUFFICIENCY COMMENTS**

Dear Mr. Palmer:

Seminole Electric Cooperative, Inc. hereby submits its responses to the comments on the sufficiency of the application for site certification for the Hardee Unit 3. Seminole has provided responses to the comments sent by you on July 19 and July 22, 1994 on behalf of the several agencies which submitted such comments. Copies of these responses are being provided directly to recipients of the Site Certification Application and to counsel or representatives of the several parties to this proceeding.

Should you have any questions concerning these responses, please contact me.

Sincerely,

Kenneth L. Bachor

Kenneth L. Bachor, PE
Manager, Environmental Licensing

kls

cc: Richard T. Donelan, Jr.
Recipients of Site Certification Application, PA 89-25SA

CONTENTS

Department of Environmental Protection

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

July 19, 1993

Mr. Ken Bachor
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33614

Dear Mr. Bachor:

After review of the Site Certification Application (SCA) submitted by Seminole Electric Cooperative for construction of an electric power generation facility at Hardee County, the Department of Environmental Protection finds the SCA to be insufficient. Enclosed are comments from the Department of Environmental Protection staff and from the other reviewing agencies regarding the SCA.

If you have any questions, please call me at 904/487-0472.

Sincerely,

Steven L. Palmer
Siting Coordination Office

enclosures--

cc: Doug Roberts

Florida Department of
Environmental Protection

Memorandum

TO: Buck Oven, P.E. Administrator

FROM: For John Brown, P.E. Administrator
Preston Lewis

DATE: June 27, 1994

SUBJECT: Seminole Electric Cooperative Incorporated (SECI)
Hardee Unit 3 - PA 89-25SA, Mod 8035
PSD-FL-214

The Bureau of Air Regulation finds the above referenced application package insufficient. Based on our initial review of their proposal, we have determined that the following additional information is needed in order to process the application:

1. The application states that the Hardee Power Station was certified for 660 megawatts (MW) in 1990, of which 220 MW was certified for SECI. The application also states that the Hardee Unit 3 Project represents an expansion of the Hardee Power Station site from 220 MW to 440 MW, and the overall site expansion from 660 MW to 880 MW. Please explain why the applicant is seeking approval for 440 MW when 220 MW was already granted to SECI in 1990?

2. Please submit a detailed process flow diagram for the combined cycle unit showing the volumetric air flow rates for each stream when burning natural gas and fuel oil. Also, submit the same for simple cycle operation.

3. Please submit the manufacturer's design specification for the proposed Westinghouse Model 501F combustion turbine. This should include but not be limited to, submitting brochures describing the turbine, associated testing (pilot plant or field) and test methods utilized in determining preliminary laboratory data.

4. Please submit manufacturer's name, model number and maximum steam production rate for the Heat Recovery Steam Generator (HRSG).

5. What is the efficiency of the combustion turbine? Calculate Y (refer to 40 CFR 60, Subpart GG) in kilojoules per watt hour, showing all the calculations.

6. Please provide more information on "steam for power augmentation". This should include but not be limited to, providing bench scale test results by Westinghouse, technical articles on the subject and actual field test results obtained on any combustion turbine worldwide. Also, provide names, addresses and telephone numbers of any owners or states that have either installed or permitted combustion turbines with power augmentation. Also, provide a comparative cost analysis if nitrogen injection is utilized to increase turbine power output rather than steam injection, and what effect will nitrogen injection have on exhaust emissions? Additionally, why can the generator capacity needed in the power augmentation mode not be included in the base load capacity of the combustion turbine?

7. Please describe the circumstances including the number of hours under which the turbine will be operated in simple cycle mode?

8. Please provide the names and addresses of all the manufacturers and suppliers that were contacted for budgetary quotations and engineering estimates in developing capital and annualized cost estimates for this project. Also, list other vendors that were contacted for quotations of the combustion turbine, and if any vendor was willing to provide a turbine in 1999 with a NO_x emissions limit guarantee of less than 15 ppmvd, corrected to ISO conditions and 15% O_2.

9. Please recalculate the cost effectiveness ($/ton NO_x removed) by using 6 ppmvd as the emission limit for a natural gas-fired dry low NO_x combustor equipped with a selective catalytic reduction (SCR) system, and 12 ppmvd as the emission limit for distillate fuel oil. These emission limits are technologically feasible and have been attained by different facilities with SCR.

10. Does the applicant propose to do co-firing of natural gas and fuel oil in the combustion turbine? If so, how long will the co-firing last and provide details on how co-firing will be accomplished.

11. Please submit a detailed listing of all the continuous emission monitoring systems (CEMs) required for this project. This should include the type of the CEM (in-situ or extractive), the pollutant it will monitor, and any associated data acquisition system.

12. What kind of control and monitoring equipment do you propose to use for continuously recording power generation, fuel injection and the steam injection rates?

13. What is the estimated annual throughput and type of air pollution control for the fuel oil storage tank? What are the estimated emissions?

14. In Table 7-6 the value for the 3-Hour HSH is incorrectly given as 30.5 for the period 83040212. Based on the modeling output accompanying the application, the value should be 144 for the period 83032418. Please do a refined analysis for this period and update Table 7-7 with a 1983 value for the 3-Hour HSH.

If there are any questions on the above, please call Syed Arif (Engineering) or Cleve Holladay (Modeling) at 488-1344.

JB/SA/bjb

Memorandum

Florida Department of
Environmental Protection

RECEIVED
JUN 17 1994
D. E. R.
SITING COORDINATION

June 15, 1994

TO: Steve Palmer
Siting Coordination Office
M.S. #48

FROM: J. Doug Oliver Doug Oliver
Biological Scientist
Bureau of Mine Reclamation
M.S. #715

RE: Seminole Electric Cooperative Inc. Hardee Unit 3

Thank you for the opportunity to provide feedback on the Site Certification Application for the above referenced facility. Our concerns were adequately addressed in the May 1994 version of the two-volume application, and in yesterday's informational meeting with other DEP and SECI representatives. Do not hesitate to contact me at 488-8217, if I can be of assistance or can provide further information.

/jdo

TO: Richard D. Drew, Chief
Bureau of Water Facilities Planning and Regulation

THROUGH: Al Bishop, P.E. Administrator
Point Source Evaluation Section

FROM: Greg Knecht
Point Source Evaluation Section

DATE: June 24, 1994

SUBJECT: Seminole Electric Cooperation, Inc. - Hardee Unit 3
Site Certification Application

We have reviewed the Site Certification Application and Environmental Analysis. We have the following comments:

1. The mixing zone lengths were calculated using the dispersion model presented by Fischer et al. (1979). Please provide information on how the various model parameters and coefficients were estimated.

2. Please provide the historical data for Payne Creek as referenced in 5.1.1-8. Is there a reason why the United States Geological Survey (USGS) site 02295420 data were not used for the thermal mixing zone analysis?

3. We suggest that the temperature in the cooling reservoir be monitored monthly.

4. In response to the Department of Environmental Protection's comments on the Plan of Study (FDEP-16), the applicant states "The CORMIX3 model is a nearfield model used to estimate thermal and/or chemical impacts in the receiving water (i.e., Payne Creek) resulting from the infrequent reservoir discharges. Was this model used in the determination of the mixing zone lengths? If so, please provide the input and output sets used.

5. Section 5.2.1-2 states that plant wastewaters will receive an overall 30:1 dilution based on inflows to the reservoir. Does this predicted dilution take into account the concentrations associated with these inflows?

6. Section 5.2.1-2 states that the long term reservoir water quality was estimated based on the mass balances of all reservoir inflows and outflows. Please characterize these inflows and outflows separately.

7. If the model used to calculate the mixing zone lengths assumed a base flow of 22 cubic feet per second, the permit should also contain this stipulation.

8. Section 5.2.1-3 states that mixing zone lengths and widths were based on predicted discharge and streamflow rates for the 25-year, 24-hour storm. Are these the same streamflow rates used to predict the thermal mixing zone length?

9. Section 5.2.1-4 describes the mixing zone calculations for the parameters listed in Table 5.2.1-2. The analytical detection limits established by the applicant need to be justified.

10. Section 5.2.1-4 states that the total dilution available in Payne Creek if 67:1. How was this determined?

12. Section 5.2.1-5 states that the ambient concentrations for lead and mercury vary with flow. Please provide the ambient flows associated with the ambient concentrations used in the calculations.

11. As stated in 17-302.500 Florida Administrative Code "all surface waters of the State shall at all places and at all times be free from: (1) domestic, industrial, agricultural, or other man-induced non-thermal components of discharges which, alone or in combination with other substances or in combination with other components of discharges (d) are acutely toxic". We request that acute bioassays be performed yearly on the cooling reservoir.

If you have any questions or comments, please contact Greg Knecht or Kevin Petrus.

GK

TO: Steve Palmer

FROM: Trudie D. Bell

DATE: June 7, 1994

SUBJECT: PA89-25SA, Seminole Electric Cooperative, Inc.
Hardee Unit 3

The Bureau of Wetland Resource Management staff has reviewed the site certification application for the above referenced project. The Bureau has determined that the application is insufficient. Please provide the following information to allow the Bureau to fully evaluate the impacts of the proposed project.

1. Please provide a full-size recent aerial photograph of 1":200' scale with a north arrow, jurisdictional lines and the impact and mitigation areas delineated in such a fashion as to not obscure the photographic image.

2. The narrative states that the forested segment of the unnamed tributary is being encroached upon by weedy species. Please provide a list of the encroaching species.

3. Please specify what material will be placed on the geotextile fabric to create the temporary work pads in the wetlands.

4. Please provide a vegetation species list for the drainage ditch to be impacted. The narrative states that the ditch is maintained, please clarify the type of maintenance and the maintenance schedule.

5. Please clarify to where the dewatering effluent will be pumped if it becomes necessary to dewater during the construction of the pipeline supports.

6. Please provide a vegetation species list for the wetland area to be impacted by the retainment berm.

7. Please clarify the purpose of the ditch at the base of the retainment berm.

8. The drawings for the wetland impacts are illegible, with the exception of the pipeline. Please provide plan view and cross-section drawings similar to the pipeline drawings for the other wetland impacts.

9. Please clarify the exact number of trees to be removed for the pipeline construction.

10. Please provide a vegetation species list for the plants currently found at the mitigation site and at what elevation each species is found.

11. Please revise the mitigation cross-sections to show the vertical elevation related to NGVD and seasonal high and low water.

Florida Department of
Environmental Protection

Memorandum

To Al Rushmar,

RECEIVED

JUN 2? 1994

BUREAU OF WATER FACILITIES PLANNING AND REGULATION

TO: Richard Drew

THROUGH: Phil Coram

Craig Diltz

FROM: Bala Nori BKN

DATE: June 22, 1994

SUBJECT: Seminole Electric Cooperative Hardee Power Station Unit 3 PA 89-25SA

The Industrial Wastewater Section has reviewed the referenced submittal. Our comments are as follows:

The cooling reservoir discharges to Payne creek, which is projected to occur only for storm events in excess of the 10-year 24-hour storm. The cooling reservoir will be operated by TECO Power Services and SECI, with two separate NPDES permits proposed.

SECI needs to explain which of the existing facilities will be shared with TECO as indicated in section 1.3.1 of the SCA.

The site certification application indicates synthetic gas may be used as an alternative fuel. If synthetic gas is used as a fuel, the SCA will require modification. Under this arrangement it will be necessary to have more extensive internal wastestream monitoring and possibly discharge limits at both facilities.

Please contact Craig Diltz if you have any questions.

CD/bn/ss

Memorandum

Florida Department of
Environmental Protection

TO: Richard D. Garrity
Hamilton Oven

FROM: Michael S. Hickey MSH

DATE: June 24, 1994

SUBJECT: SECI - Hardee Unit #3 (PA89-25SA)
Review of the SCA for Sufficiency

The following are the Southwest District's comments on the above subject:

WATER FACILITIES COMMENTS:

DOMESTIC WASTEWATER COMMENTS by Bill Washburn:

I have again reviewed the SCA submitted by SECI for their Hardee Unit #3 (PA89-25SA). The information provided is skimpy. Since the WWTP is a small ancillary part of the large power generating facility, they obviously have not designed it yet, or at least have not provided us with that design information. It would be nice to review and approve the WWTP design at this time and address it in the sufficiency review. But that cannot be done.

Lacking that, what they have given us is sufficient at this time with the proviso that we have incorporated in the final Site Certification much of the same information and requirements that are contained thoughout the Florida Power Corp Site Cert (PA92-33), and especially in Section XV of that document. Using the FPC SC as a starting point, I will draft similar portions to be included in the Hardee Power submittal and will provide them to Mike to forward on to Tallahassee.

INDUSTRIAL WASTEWATER COMMENTS by Al McLaurin:

The below listed comments pertain to my review of the site certification package:

1. The consultant's analysis and choice of a 10 year, 24 hour worst case storm event based on an analysis of the last 37 years of weather data was not provided within the report. Please have the consultant provide the analysis used to determine this worst case storm event.

2. The consultant indicates on page 5.1.1-5 of volume 1 of the submitted certification report that the 10 year, 24 hour storm event would yield 7.5" of rain and the 25 year, 24 hour storm event would yield 9.0" of rain. However, no other storm events were analyzed during the modelling process. In addition, it appears that the modelling routines employed by the consultant allowed for the smaller rainfall event to be considered as the worst case because of frequency of occurrence. However, operating level was considered as 123 feet in the pond and would rise to 123.86 feet, during the 7.5" storm event. No pond elevation analysis was done for the higher rainfall event. There appears to be a flaw in the consultant's analysis of not looking at all rainfall events and deciding on a more conservative event. It appears that consultant is limited to a very narrow pond operating elevation bandwidth and must opt for the more aggressive pond design.

3. There appears to only be a two foot elevation between the cooling water reservoir operating elevation and a potential pond discharge. What will happen should the utility need additional cooling capacity, as projected in the analysis, and raise the pond elevation allowing for less storage during a period of wet weather, which may result in a discharge during periods other than the 10 year, 24 hour storm event. It should be noted that most power plant and equipment designs allow for a 10 to 25% operating output above design conditions for short periods. Most gas turbine power plants have this peaking factor built into them during their design phase. Therefore, it is possible that the utility may opt to raise the pond elevation for better heat rejection and increase the power plant output during high demand periods which may coincide with a high rainfall events leading to more frequent discharges than anticipated.

4. The consultant should submit for a separate construction permit for the domestic wastewater treatment plant, prior to construction or submit the necessary documentation to demonstrate the capability of the system to operate properly as part of this certification. The permittee should consider removing the nitrate monitoring requirement from the domestic wastewater operating permit and monitor for it in the existing groundwater monitoring wells for the cooling water reservoir. The requirement to monitor for nitrate (as nitrogen) should be added to the GWMP list of monitored parameters.

5. The permittee should be required to monitor the discharges from the oily water separator, domestic wastewater treatment plant and neutralization pond prior to their discharging into the cooling pond reservoir.

TECHNICAL SERVICES COMMENTS:

GEOLOGICAL COMMENTS by Joe May:

I have reviewed the SCA with regard to ground water quality protection and have the opinion that the SCA is largely sufficient. However, I have the following insufficiency comments:

2.3.2.2 KARST HYDROGEOLOGY

As part of the sinkhole potential and fracture analysis investigations several surface depressions were identified, with some located within the cooling water reservoir area. It is also my understanding that these depressions were ground-truthed. The methods of ground-truthing should be specified as well as the location of the identified depressions, unless this information is located in the referenced document (TPS/SECI, 1989 of the SCA).

I agree that the findings of the AT&E, 1993 report (Appendix 10.7 of the SCA) do not indicate lost circulation zones, voids or cavities shallower than approximately 90 feet below ground surface. However, examination of the boring logs for B-14 and B-15 (along the east-west trending access corridor to the proposed site) indicate a possible anomaly. Specifically, the SPT blow counts recorded in the logs indicate loose sands to depths significantly greater than the borings located within the proposed site. This apparent anomaly should be interpreted and explained.

Table 2.3.2-3 indicates that ground water monitoring well HPS-1 had consistently and substantially higher concentrations of arsenic, chromium, lead and gross alpha yet had consistently lower values for TDS (with the exception of HPS-6 for the TDS parameter). This apparent anomalous location should also be interpreted and explained.

3.5 PLANT WATER USE

Table 3.5.0-3 indicates that a wastewater sump will receive wastewater streams from several sources (≈93,000 gpd). This wastewater sump as well as the following wastewater stream routes should also be placed and identified on the Hardee Unit 3 Plot Plan (Figure 3.2.0-4 of the SCA): sewage treatment plant effluent, equipment and floor drain effluent, neutralization effluent, and the evaporative cooling water.

Wastestream water quality analyses should also be required such that:

Within six months of startup for new facilities the SECI shall provide a wastestream characterization for: ion exchange reject water, the plant sanitary effluent, boiler blowdown effluent, floor drain effluent, plant island stormwater effluent. Thereafter, a wastestream characterization shall be performed from a surface water sample collected from the Cooling Pond condenser intake structure within six months of the completion of construction but in no event with less frequency than every 5 years. Samples for characterization shall be analyzed for the Primary and Secondary Drinking Water Standards (Chapter 17-550, F.A.C)., Fecal Coliform and the EPA Priority Pollutants. The components identified in the wastestream characterizations shall be collectively designated as ground water indicator parameters that may be used to modify the Ground Water Monitoring Plan.

5.2.1.2 GROUND WATER DISCHARGES

The TDS contour map included in the SCA (Figure 5.2.1-1) was derived from an unspecified 2-D finite element model. The SECI should provide the input and output files (preferably on an IBM formatted 3½" floppy disk) and reference the finite element software program as well as the version. Any calibration and verification procedures which may have been used should also be described.

APPENDIX 10.5.2 GROUND WATER MONITORING PROGRAM

The existing and proposed monitoring well locations are acceptable as is the well construction design. The field measurement of pH, specific conductivity and temperature is acceptable. However, water level measurements prior to purging is also required. The field measurement of sulfite is also acceptable since this would actually be more stringent then the minimum required field parameters.

The collection of grab samples for the purposes of monitor well sampling is not acceptable. Ground water sampling and analyses shall be performed in accordance with Chapter 17-160, F.A.C. The SECI should reference the approved FDEP CompQAP number and ground water sampling protocol. Recently the State has certified the FPC Polk Power Station which requires the following parameters to be sampled and analyzed on a quarterly basis:

PRIMARY STANDARDS

PARAMETERS	UNITS
Nitrate (as N)	mg/L
Nitrite (as N)	mg/L
Sodium	mg/L
Turbidity	NTU
Cyanide (as CN)	mg/L
Antimony	mg/L
Arsenic	mg/L
Barium	mg/L
Beryllium	mg/L
Cadmium	mg/L
Chromium	mg/L
Lead	mg/L
Mercury	mg/L
Nickel	mg/L
Selenium	mg/L
Thallium	mg/L
Benzene	mg/L
Fecal Coliform	cts/100 ml
Carbon tetrachloride	mg/L
1,2-Dichloroethane	mg/L
Trichloroethylene	mg/L
para-Dichlorobenzene	mg/L
1,1-Dichloroethylene	mg/L
cis-1,2-Dichloroethylene	mg/L
1,2-Dichlorpropane	mg/L
Ethylbenzene	mg/L
Monochlorobenzene	mg/L
o-Dichlorobenzene	mg/L
Styrene	mg/L
Toluene	mg/l
trans-1,2-Dichloroethylene	mg/L
Xylenes (total)	mg/L
Dichloromethane	mg/L
1,2,4-Trichlorobenzene	mg/L
1,1,2-Trichlorethane	mg/L
Polychlorinated biphenyl (PCB)	mg/L
Tetrachloroethylene	mg/L
1,1,1-Trichloroethane	mg/L
Vinylchloride	mg/L

SECONDARY STANDARDS

Foaming Agents	mg/L
Chloride	mg/L
Total Dissolved Solids (TDS)	mg/L
pH*	std. units
Color*	color units
Fluoride (as F)	mg/L
Aluminum	mg/L
Copper	mg/L
Iron	mg/L
Manganese	mg/L
Silver	mg/L
Zinc	mg/L
Sulfate	mg/L

OTHERS

Temperature*	°C
Total Organic Carbon (TOC)	mg/L
Specific Conductance*	µmhos/cm
Water Level (NGVD)*	feet
Dissolved Oxygen (minimum)	mg/L
Ammonia (as N)	mg/L
Ammonium (as NH4)	mg/L
Vanadium (as valence of +5)	mg/L
Calcium	mg/L
Magnesium	mg/L
Potassium	mg/L
Bicarbonate	mg/L
EPA 601/602 analytes	mg/L

ACID EXTRACTABLES

Phenols	mg/L

BASE EXTRACTABLES

Butyl benzyl phthalate	mg/L
Di-n-butylphthalate	mg/L
Diethylphythalate	mg/L
Dimethylphythalate	mg/L
Dioctylphythalate	mg/L

* field measurement

Please note that after four consecutive quarters of data after start of commercial operation the SECI may request a reduction in sampling frequency or specific parameters of the ground water monitoring program. The request shall be considered reasonable when a trend analysis of the parameter indicates no significant or substantial change in the parameter. Specific parameters that are key indicators of the domestic or industrial processes or field measured parameters may not be reduced or eliminated from the ground water monitoring plan.

Since this list is more comprehensive than that proposed in the SCA, and in consideration that the facility has an operational data base, I recommend (in the interest of expediency) that a technical teleconference or meeting be arranged in order to discuss ground water monitoring parameters as well as wastestream analyses.

Should you have any questions, please contact me at extension 433.

BIOLOGICAL COMMENTS by Stefan Schulze:

I have reviewed the Site Certification Application (SCA) submitted by the above referenced facility with regard to surface water concerns. I have the following questions and comments:

3.5.1.3 Cooling Reservoir Releases

Seminole Electric's calculations predict that the cooling water reservoir will discharge water into Payne Creek only after extreme storm events (i.e., greater than the 10-year, 24-hour storm). Below what level will the pond water have to be maintained in order to ensure this retention capacity? How much fluctuation in pond level occurs between moderate and peak production? The Department must be assured that discharges from the cooling pond will occur infrequently.

3.8.1 Stormwater Detention Pond

Non-contact surface water runoff from the facility will be routed to a stormwater detention pond with the ability to retain a 25-year, 24-hour storm event. The stormwater pond is designed to retain the first 2.5 cm. of runoff. The treated stormwater will then be discharged to the adjacent unnamed tributary to Payne Creek.

It is my understanding that the facility has applied for a stormwater discharge permit from SWFWMD. Should a permit application also be filed with FDEP? The potential for stormwater contamination is quite high at a large industrial facility such as this and a surface water quality monitoring plan should be developed for this discharge.

DRINKING WATER COMMENTS by Ed Coppock:

The Drinking Water Program have the following comments on this submittal:

There is no information in the sitting application that address the drinking water review other than a statement that potable water will be provided in accordance with FAC 17-550 and 555 and that all necessary information will be provided as part of the conditions of certification. Therefore, all necessary information providing reasonable assurance that the potable water portion of this project will meet the requirements of FAC 17-550, 17-551, 17-555 and 17-560 will be required on the conditions of certification.

AIR QUALITY PROGRAM COMMENTS by David Zell:

After review of the air resources portion of the Site Certification Application (SCA) and attendance at the June 24 project briefing meeting, the SW District Office Air Program finds the SCA sufficient and has no comments. The key elements of the air portion of the application are the PSD BACT determination and the air quality source impact evaluation which are reviewed by the Bureau of Air Regulation staff in Tallahassee.

WASTE MANAGEMENT COMMENTS by Allison Amram:

The proposed Hardee Unit #3 for Seminole Electric will be taking their solid waste away from the site, and disposing of the wastes at permitted solid waste management facilities. The Solid Waste Section does not have any sufficiency comments.

WATER MANAGEMENT COMMENTS by Greg Colianni:

In general, the wetland mitigation plan provided is consistent with recommendations discussed with (KBN) representatives. If successful, the proposed forested wetland creation and herbaceous restoration and enhancement will adequately compensate for wetland encroachment. Specific details which are absent from the proposal and should be provided to the Department for sufficiency include:

1. Normal pool, seasonal high water and low water elevations for the tributary wetland and how these elevations relate to the planting elevations for tree species to be installed.

2. Coinciding with proposed monitoring events, nuisance species eradication events should be performed to assist establishment of desirable wetland species. Also, installed trees having died from shock or stress should be replaced during each monitoring event.

3. It should be acknowledged by SECI they will be responsible for the ultimate success of the wetland mitigation which may entail implementing an alternative, remedial mitigation plan.

/sgl

cc: Al Rushanan
SWD PPSA Reviewers

DEPARTMENT OF
ENVIRONMENTAL PROTECTION
JUN 2 0 1994
SITING COORDINATION

STATE OF FLORIDA
DEPARTMENT OF COMMUNITY AFFAIRS

EMERGENCY MANAGEMENT • HOUSING AND COMMUNITY DEVELOPMENT • RESOURCE PLANNING AND MANAGEMENT

LAWTON CHILES
Governor

LINDA LOOMIS SHELLEY
Secretary

27 June 1994

Mr. Hamilton S. Oven
Siting Coordination Office
3900 Commonwealth Boulevard
Mail Station 48
Suite 953A
Tallahassee, Florida 32399-3000

Dear Mr. Oven:

We have completed an initial screening review for the purpose of determining the sufficiency of the site certification application for Seminole Electric Cooperative's proposed Hardee Unit No. 3 power plan. The application is insufficient in the following area:

Section 5.7 of the application, "Noise Impacts," describes the expected noise during operation of Hardee Unit 3. The Department suggests, however, that the description of the expected noise levels to be produced by the site during operation at full buildout (880 megawatts) should also be included in the application, to assist reviewing agencies in determining the suitability of the site for the proposed expansion.

If you have any questions or comments concerning these comments please call Paul Darst at (904) 488-4925.

Sincerely,

Bob Dennis

Bob Dennis
Community Program Administrator

BD/rpd

CC: Ken Bachor, Seminole Electric Cooperative, Inc.

DEPARTMENT OF
ENVIRONMENTAL PROTEC

JUN 28 1994

SITING COORDINATION

Southwest Florida Water Management District

2379 Broad Street • Brooksville, Florida 34609-6899 • 1-800-423-1476 (Florida Only) or (904) 796-7211 • SUNCOM 628-4150 • T.D.D. Number Only (Florida Only): 1-800-231-6103

7601 Highway 301 North Tampa, Florida 33637-6759 (813) 985-7481 SUNCOM 578-2070

170 Century Boulevard Bartow, Florida 33830-7700 (813) 534-1448 SUNCOM 572-6200

111 Corporation Way Venice, Florida 34292-3524 (813) 483-5970 SUNCOM 549-5970

2303 Highway 44 West Inverness, Florida 34453-3809 (904) 637-1360

June 24, 1994

VIA FACSIMILE
AND U.S. MAIL

Mr. Hamilton S. Oven
Siting Coordination Office
Department of Environmental Protection
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Ms. Martha L. Nebelsiek
Assistant General Counsel
Department of Environmental Protection
2600 Blair Stone Road, Suite 654
Tallahassee, Florida 32399-2400

Subject: Sufficiency Comments
Seminole Electric Cooperative, Inc.
Application No. 89-25SA
DOAH Case No. 94-2765EPP

Dear Mr. Oven and Ms. Nebelsiek:

What follows are the District's sufficiency comments on the above-referenced application. Next to each subject area is the individual who would best be able to discuss specifics of the concerns identified.

A. Engineering/Surface Water Management (Jan R. Burke, Jr.)

1) The storm water management plan (calculations and construction drawings) was not signed, dated, and sealed by a Florida registered engineer as required by Chapter 471, Florida Statutes. Please provide a certified copy of the storm water management plan.

B. Wetlands (Mark K. Hurst)

1) Please provide a certified survey of the approved wetland limits in the vicinity of those areas adjacent to proposed construction.

2) Please provide a numbering system for all on-site wetlands (including those less than 0.5 acre) and for each wetland clearly indicate the index number on

the construction drawings. In tabular form, please indicate for each wetland the index number, on-site acreage, impact acreage, and indicate whether the wetland has been claimed by the District, the Army Corps of Engineers, and/or the Department of Environmental Protection (DEP).

3) Please provide construction drawings (plan view and cross-sections) signed, dated, and sealed by a Florida registered engineer for the mitigation area and all proposed construction in wetlands.

4) Please provide a complete description of measures to be implemented during construction activities in wetlands to prevent adverse quantity and quality impacts off site. Show all erosion and sediment control measures to be utilized on the construction drawings for the project. Clearly label all turbidity curtains, silt screens, hay bale fences and other turbidity control measures placed.

5) A mitigation plan was submitted along with the DEP application information. Please provide a compensation/ mitigation plan as part of the Management and Storage of Surface Waters (MSSW) application or at least a statement that the DEP mitigation plan is also submitted as compensation for impacts under District jurisdiction.

6) Please delineate which portion of the larger mitigation area is proposed for compensation under the MSSW application.

7) Please provide herbaceous ground cover (mulching and/or planting) within the forested mitigation area.

8) Please include all design details of the mitigation area on the construction drawings. Details should include plan and cross-sectional views showing limits of each distinct zone in reference to proposed control elevations, proposed plantings (species, sizes, densities and relative composition) within each zone, mulching details, proposed water elevations (seasonal high water level and normal pool), bottom elevations, and slopes.

C. <u>Water Use</u> (P. Scott Laidlaw)

1) Please provide a map, not necessarily an aerial, indicating the specific location of the three existing wells, District ID Nos. 1, 2, & 3. Indicate the distances in feet to the nearest north/south and east/west property boundaries. Also, please indicate any numbering/identification system you have placed on these points for referencing.

2) The Water Balance Diagram submitted in support of your SCA, Figure 3.5.0.1, Cooling Reservoir Water Balance - Annual Average Conditions for 880-MW Buildout, indicates an Annual Average Daily quantity of 3.174 MGD from the deep wells, however, your application indicates the current allocation under the Site Certification is 3.8 MGD. Please provide revised water balance diagrams (i.e., diagrams for the proposed 440-MW Hardee Unit 3 and the build-out of 880-MW) consistent with the quantities currently allocated for the Site Certification.

3) The Water Balance Diagram submitted in support of your SCA, Figure 3.5.0.2, Cooling Reservoir Water Balance - Worst Case Monthly Conditions for 880-MW Buildout, indicates a Peak Month Daily quantity of 7.17 MGD from the deep wells, however, your application indicates the current allocation under the Site Certification is 8.64 MGD. Please provide revised water balance diagrams (i.e., diagrams for the proposed 440-MW Hardee Unit 3 and the build-out of 880-MW) consistent with the quantities currently allocated for the Site Certification.

4) A Log-Pearson Type III distribution was provided in support of the Annual Average Daily water requirements for the HPS. Please provide this same type of analysis for the Peak Month Daily water use requirements to support the permitted 8.64 MGD.

5) Please provide a comparison of the water conservation processes and equipment of the proposed plant with other plants of comparable generating capacity and ambient conditions (i.e., HPS existing equipment), including plants using cooling towers and other forms of heat exchangers. Demonstrate that the configuration of the proposed plant optimizes water conservation and that the most water-efficient processes and equipment practicable will be employed.

6) Please provide a comparison of actual groundwater use to KWH of power produced on an Annual Average Daily and Peak Month Daily basis from the existing HPS units for the years 1992 and 1993.

7) According to the SCA, the existing cooling reservoir can handle the additional heat dissipation requirements for the additional generating capacity (i.e., increase from 660-MW to 880-MW ultimate site capacity). The SCA states that the "engineering rule of thumb" for cooling area per megawatt of generating capacity is 2.0 acres/MW of steam. Based on the ultimate site capacity of 880-MW, the area-to-capacity ratio is

2.04 acres/MW. How much of a "safety factory" is incorporated into the ratio of 2.0 acres/MW?

Originally, the cooling pond had a ratio for area-to-capacity of 2.7 acres/MW (i.e., 570 acres and 210-MW steam cycle), however, only 2.0 acres/MW is currently required. Please provide a detailed explanation addressing the change in this "engineering rule of thumb". Was the cooling reservoir originally designed with an anticipated power generating capacity beyond the initial site capacity of 660-MW? If there is a safety factor designed into the sizing of the cooling pond, what is this site's ultimate power generating capacity?

8) Water cropping from adjacent phosphate lands to the north is addressed as a possible source of cooling reservoir makeup water. According to the SCA, a pond of 25 acres is considered feasible. Will this concept of water cropping be utilized by SECI, or are these scenarios just conceptual and considered impracticable at this time? If this idea is considered impracticable, what factors would have to be addressed in order for this idea of water cropping to be utilized by SECI to reduce its groundwater pumpage by as much as 18 to 20% with a 25 acre holding reservoir? Solutions to many of the potential problems associated with water cropping have been addressed in the SCA. Are the possible solutions considered economically infeasible? Based on reducing groundwater withdrawals by approximately 20 percent and at an annual average daily withdrawal rate of 3.8 MGD of water from the Floridan aquifer, an approximate cost of $3.2 million is indicated to water crop. Is this cost considered economically infeasible to produce 0.76 MGD of cooling reservoir makeup water?

Each of the above-named individuals can be reached at the District's Bartow office. If you have any general or procedural questions, I can be reached at the District's Brooksville office.

Sincerely,

Mark F. Lapp

Mark F. Lapp
Assistant General Counsel

MFL:jlk
cc: Jan R. Burke, Jr.
P. Scott Laidlaw
Mark K. Hurst
Dawn G. Turner
File of Record

SEMINOLE\OvenNebe.Ltr

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

RECEIVED

JUL 11 1994

Bureau of
Air Regulation

July 1, 1994

Mr. Clair H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399

Dear Mr. Fancy:

We have reviewed the Prevention of Significant Deterioration (PSD) permit application and the Site Certification Application for Seminole Electric Cooperative Incorporated's (SECI) proposed 440 MW combined cycle gas-fired power plant. The proposed project, Hardee Unit 3, would be located on the existing Hardee Power Station site, in Hardee and Polk Counties, 130 km southeast of Chassahowitzka Wilderness Area (WA), a Class I air quality area, administered by the Fish and Wildlife Service (Service). The proposed project would be a significant emitter of nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and sulfuric acid mist (H_2SO_4). The facility is also subject to PSD regulations for beryllium and inorganic arsenic.

__Best Available Control Technology Analysis__

We have reviewed the Best Available Control Technology (BACT) analysis and are satisfied that the analysis is complete. We believe either low NO_x combustors or selective catalytic reduction (SCR) represents BACT for gas-fired cogeneration turbines. We support industry and manufacturer efforts to develop technology which approaches control levels achieved by add-on controls. Such pollution control efforts are advantageous provided similar reductions in pollution can be achieved. We agree that 15 ppm represents a BACT limit which manufacturers are currently comfortable guaranteeing to their customers. We understand that some manufacturers are hoping to design combustors which will achieve even lower rates to further approach the rates achieved by SCR. Earlier this year, we reviewed an application for turbines at Tampa Electric Company's (TECO) Mulberry facility. BACT for TECO's turbines was the use of dry-low NO_x combustors to achieve 9 ppm. Therefore, while we do not object to a BACT emission level of 15 ppm NO_x, we suggest

SECI be required to meet the lowest emission rate that is demonstrated as being achievable over a reasonable amount of time. This will help to verify a true BACT limit and may encourage manufacturers to guarantee emission rates lower than 15 ppm.

Since fuel oil will only be used as a backup fuel, we agree that water injection represents BACT for control of NO_x during fuel oil use; however, the Hartwell Energy Limited Partnership in Georgia is required to meet a 25 ppm NO_x emission limit when firing oil, using water injection. Therefore, we believe SECI should also be required to meet a 25 ppm NO_x emission limit.

We agree that low sulfur fuel (.05 percent sulfur content) represents BACT to minimize sulfur dioxide emissions. Likewise, we agree combustion control represents BACT for carbon monoxide. Note that Florida required the Auburndale Power Partners, LP, to meet 15 ppm for carbon monoxide emissions, using combustion control. Again, the lowest demonstrated emission limit should be set as BACT.

Air Quality Modeling Analysis

The air quality dispersion modeling analysis was performed correctly--ISCST2 modeling predicted violations of the Class I SO_2 increment; however, MESOPUFF II modeling predicted that SECI would not contribute significantly to the violations.

The visibility analysis performed with the EPA VISCREEN model indicates that there should be no impact of a coherent visible plume at Chassahowitzka WA.

Air Quality Related Values Analysis

SECI adequately addressed potential effects to Class I Air Quality Related Values, including vegetation, wildlife, and soils. However, in the discussion of effects to wildlife, SECI mentions that the concentrations of metals in plants are predicted to be much lower than Service recommended safety levels for wildlife; therefore, adverse effects to fish and wildlife are not expected. We would like to note that accumulation of some metals, particularly mercury, occurs primarily through the aquatic food chain, not through ingestion of terrestrial vegetation. Fish are known to accumulate mercury and pass on toxic amounts to fish-eating birds, mammals, and reptiles.

When we receive new information on air quality-sensitive receptors at Chassahowitzka WA, we will forward it to you for use by future PSD applicants.

Thank you for providing us the opportunity to comment on the proposed project. If you have questions, please call Ms. Ellen Porter of our Air Quality Branch in Denver at telephone number 303/969-2071.

Sincerely yours,

James W. Pulliam, Jr.
Regional Director

cc: J. Crif
C. Halladay
B. Owen
J. [illegible], [illegible]
D. Harper, EPA
M. [illegible] [illegible] Electric
CHF/JB/PL

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR REGULATION

(FDEP.BAR)

FDEP.BAR-1

Comment: The application states that the Hardee Power Station was certified for 660 megawatts (MW) in 1990, of which 220 MW was certified for SECI. The application also states that the Hardee Unit 3 Project represents an expansion of the Hardee Power Station site from 220 MW to 440 MW, and the overall site expansion from 660 MW to 880 MW. Please explain why the applicant is seeking approval for 440 MW when 220 MW was already granted to SECI in 1990?

Response: SECI is seeking approval at this time for 440 MW of generating capacity for the Hardee Unit 3 project. The initial 1990 site certification did address overall impacts for 660 MW of generation at the HPS site, however, the power plant site certification and PSD permit granted in 1990 for the original Hardee Power Station did not address SECI's 220 MW portion of the project. Those approvals authorize construction and operation of the existing 295-MW facility owned by TECO Power Services (TPS).

SECI has determined, and the Florida PSC has approved in a need determination order dated June 21, 1994 that to continue to provide the most reliable, cost-effective service to its customers, SECI must replace 440 MW of power currently purchased on a partial requirements (PR) basis from Florida Power & Light Company (FPL) with power from another source. Through a competitive bidding and negotiation process, SECI has determined that the best alternative for displacing that 440 MW of PR purchases is construction and operation of the proposed 440-MW Hardee Unit 3 combined cycle generating facility. An analysis was performed which is detailed in the need for power document filed with the PSC on December 17, 1993. The analysis showed that using Hardee Unit 3 to replace 440 MW of PR purchases from FPL beginning in 1999 provides a 30-year savings of $299 million present worth revenue requirements (PWRR) compared to a "no replacement" scenario under SECI's current base case planning assumptions.

The remaining 145 MW of planned capacity is to be constructed by TPS at a later date, bringing total capacity to 880 MW.

FDEP.BAR-2

Comment: Please submit a detailed process flow diagram for the combined cycle unit showing the volumetric air flow rates for each stream when burning natural gas and fuel oil. Also, submit the same for simple cycle operation.

Response: Detailed flow diagrams for combined cycle operation on natural gas and fuel oil are attached. If the units are operated in simple cycle, the exhaust flow going to the HRSG is diverted to the bypass damper to atmosphere. Flows through the CT remain the same during simple cycle operation

FDEP.BAR-3

Comment: Please submit the manufacturer's design specification for the proposed Westinghouse Model 501F combustion turbine. This should include but not be limited to, submitting brochures describing the turbine, associated testing (pilot plant or field) and test methods utilized in determining preliminary laboratory data.

Response: Attached are the Hardee contract technical specifications for the combustion turbine, copies of Westinghouse's most recent development papers and copies of ASME paper 94-GT-474 titled "Uprated 501F Gas Turbine, 501FA."

FDEP.BAR-4

Comment: Please submit manufacturer's name, model number and maximum steam production rate for the Heat Recovery Steam Generator (HRSG).

Response: The HRSG vendor has not been selected at this time. Although the final steam rate of the HRSG has not yet been determined, the HRSG will be designed to support the approximate steam turbine flow requirement of 976,000 lb/hr.

FDEP.BAR-5

Comment: What is the efficiency of the combustion turbine? Calculate Y (refer to 40 CFR 60, Subpart GG) in kilojoules per watt hour, showing all the calculations.

Response: In accordance with the New Source Performance Requirements for Stationary Combustion Turbines, 40 CFR 60, Subpart GG, the calculation of parameter Y (kJ/watt-hour) for Section 60.332 is as follows for Seminole's Hardee Unit 3:

501F Gas Fuel, ISO Conditions:

Heat Input = 1,512 x 10^6 Btu/hr (LHV)
Load = 156.3 x 10^6 watts

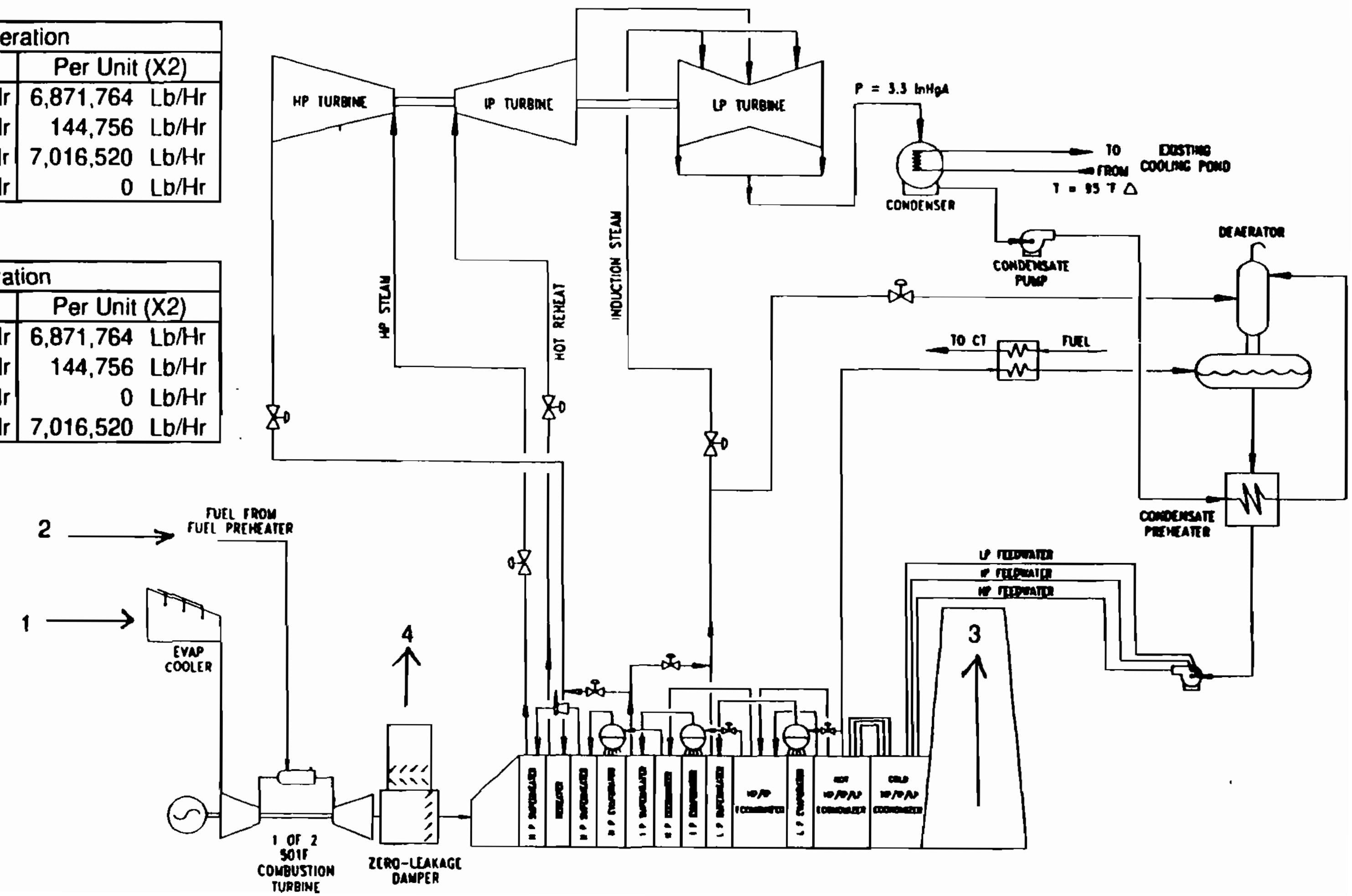
Y = kJ/watt-hour = 1,512 x 10^6 Btu/hr x 1.05485 kJ/Btu/(156.3 x 10^6 watts)
= **10.2**

SEMINOLE ELECTRIC PROJECT

NATURAL GAS AT 59 °F AMBIENT, 100% LOAD

Combined Cycle Operation		
Flow	Per Engine	Per Unit (X2)
1 Inlet Air	3,435,882 Lb/Hr	6,871,764 Lb/Hr
2 Fuel	72,378 Lb/Hr	144,756 Lb/Hr
3 HRSG Stack	3,508,260 Lb/Hr	7,016,520 Lb/Hr
4 Bypass Stack	0 Lb/Hr	0 Lb/Hr

Simple Cycle Operation		
Flow	Per Engine	Per Unit (X2)
1 Inlet Air	3,435,882 Lb/Hr	6,871,764 Lb/Hr
2 Fuel	72,378 Lb/Hr	144,756 Lb/Hr
3 HRSG Stack	0 Lb/Hr	0 Lb/Hr
4 Bypass Stack	3,508,260 Lb/Hr	7,016,520 Lb/Hr



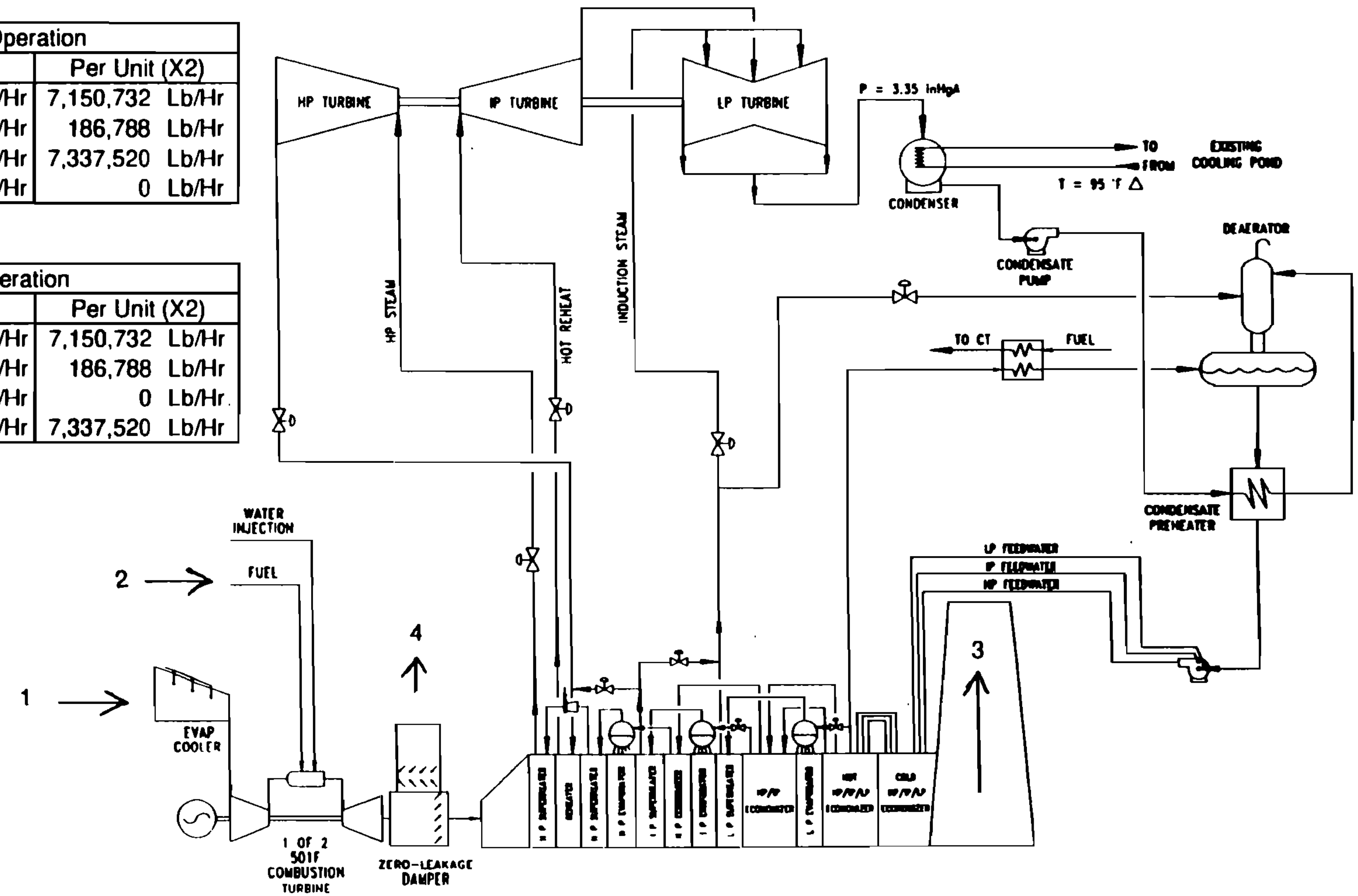
FDEP.BAR-3

SEMINOLE ELECTRIC PROJECT

#2 DISTILLATE OIL AT 59 °F AMBIENT, 100% LOAD

Combined Cycle Operation		
Flow	Per Engine	Per Unit (X2)
1 Inlet Air	3,575,366 Lb/Hr	7,150,732 Lb/Hr
2 Fuel	93,394 Lb/Hr	186,788 Lb/Hr
3 HRSG Stack	3,668,760 Lb/Hr	7,337,520 Lb/Hr
4 Bypass Stack	0 Lb/Hr	0 Lb/Hr

Simple Cycle Operation		
Flow	Per Engine	Per Unit (X2)
1 Inlet Air	3,575,366 Lb/Hr	7,150,732 Lb/Hr
2 Fuel	93,394 Lb/Hr	186,788 Lb/Hr
3 HRSG Stack	0 Lb/Hr	0 Lb/Hr
4 Bypass Stack	3,668,760 Lb/Hr	7,337,520 Lb/Hr



FDEP.BAR-4

<u>501F Oil Fuel, ISO Conditions</u>:

Heat Input = 1,726 x 10^6 Btu/hr (LHV)
Load = 166.6 x 10^6 watts

Y = kJ/watt-hour = 1,726 x 10^6 Btu/hr x 1.05485 kJ/Btu/(166.6 x 10^6 watts)
= **10.93**

FDEP.BAR-6

<u>Comment</u>: Please provide more information on "steam for power augmentation". This should include but not be limited to, providing bench scale test results by Westinghouse, technical articles on the subject and actual field test results obtained on any combustion turbine worldwide. Also, provide names, addresses and telephone numbers of any owners or states that have either installed or permitted combustion turbines with power augmentation. Also, provide a comparative cost analysis if nitrogen injection is utilized to increase turbine power output rather than steam injection, and what effect will nitrogen injection have on exhaust emissions? Additionally, why can the generator capacity needed in the power augmentation mode not be included in the base load capacity of the combustion turbine?

<u>Response</u>: Hardee Unit 3 is required to generate 440 MW of capacity during Seminole's peak load demands of the summer months. In order to meet this requirement, the combustion turbines utilize both evaporative coolers and steam augmentation. Steam augmentation will be required to supplement the generation capacity only when the combined cycle unit demand is above 420 MW, the unit is burning natural gas, and the ambient temperature exceeds 80°F.

Unlike steam generating facilities which can be custom designed for each application, combustion turbines are manufactured in standard sizes. These sizes are established by each combustion turbine manufacturer's design and by customer demand. When a utility or customer orders a combustion turbine, they must select from the available sizes offered by the manufacturer. Consequently, there is not always a direct correlation between the customer's generation needs and the combustion turbine sizing offered by the manufacturer. In order to accommodate these possible differences, there are some alternative designs that the manufacturer can provide to allow a better match between the combustion turbine output capability and the customer's needs. Examples of these alternatives are evaporative inlet coolers and steam augmentation which allow the combustion turbine capacity to be increased when ambient conditions exceed ISO conditions (14.7 psi, 59°F and 60 percent R.H.).

In addition, the 150 MW combustion turbines which are being supplied by Westinghouse for the Hardee Unit 3 Project are rated at this capacity only at ISO conditions. As the ambient temperature increases, the generation capacity of the combustion turbine decreases due to the decrease in the air density entering the combustion chamber. The installation of evaporative coolers allows the air entering the combustion turbines to be cooled by having the inlet air come in contact with water. An alternative approach to increasing combustion turbine capacity is to utilize steam augmentation. By injecting steam after the fuel combustor the volumetric gas flow through the combustion turbine is increased. The result is that the net generation capacity of the combustion turbine is increased during periods of high ambient temperature.

Steam for power augmentation is injected into the turbine combustor casing. The benefit of this process is that steam injection increases the mass flow through the turbine section of the combustion turbine and thereby increases the CTs megawatt output. Steam power augmentation can increase dynamic pressure activity in the overall combustion process. It is desirable to minimize this dynamic pressure to minimize the maintenance and repair required for the CT. Thus, to minimize this activity in CTs with dry low combustors, it is necessary to increase the percentage of fuel to the pilot combustion zone from its normal "low NO_x" level to a slightly higher percentage. As fuel to the pilot combustion zone increases, there is a slight increase in NO_x and CO levels. Water in steam or liquid form is NOT used to reduce NO_x levels with this process. Note that the Hardee Unit 3 CTs will only require steam for power augmentation to meet plant output requirements when ambient temperatures exceed 80°F, and the unit demand exceeds 420 MWs and the units are burning gas.

Steam for power augmentation has been implemented in combustion turbines with conventional fuel combustion systems for many years. There are no combustion turbines which combine dry low NO_x combustion technology with steam power augmentation in operation at this date. Therefore, we are unable to provide plant reference information.

There are no known operating combustion turbines using nitrogen injection with natural gas or fuel oil. We have no basis to provide economic or environmental analysis of nitrogen injection.

Current combustion turbine technology has advanced to allow manufacturers to produce combustion turbines capable of producing 150 MW at ISO condition. This is the largest combustion turbine available today. Manufacturers are currently developing combustion turbines of higher capacity, however, there are currently no larger combustion turbines in commercial operation. The proposed Hardee Unit 3 configuration is the most economical design to meet SECI's generation requirements as determined by the Florida Public Services Commission.

FDEP.BAR-7

Comment: Please describe the circumstances including the number of hours under which the turbine will be operated in simple cycle mode?

Response: Simple cycle operation of the combustion turbines will be done when it is economical due to unit load demand being below the minimum controllable operating load for the steam turbine or when the steam turbine is not available (such as during maintenance procedures). Simple cycle operation, however, will have no effect on the plant emissions since the emission control is achieved by the type of fuel burned and the combustion turbine's burner configuration and not by post combustion controls. This will result in the same emissions for the facility whether it operates in simple or combined cycle mode of operation.

FDEP.BAR-8

Comment: Please provide the names and addresses of all the manufacturers and suppliers that were contacted for budgetary quotations and engineering estimates in developing capital and annualized cost estimates for this project. Also, list other vendors that were contacted for quotations of the combustion turbine, and if any vendor was willing to provide a turbine in 1999 with a NO_x emissions limit guarantee of less than 15 ppmvd, corrected to ISO conditions and 15% O_2.

Response: Owner cost estimates which were prepared for the Hardee Unit 3, were developed from the proposal pricing for Hardee Units 1 and 2. Hardee Units 1 and 2 were placed in service in 1993, and at the time the owner's estimate for Hardee Unit 3 was developed they provided representative pricing for a similar combined cycle facility. These prices, in conjunction with contacting the major turbine generator equipment supplier, water treatment suppliers and updating the engineer's estimate created for the Hardee Units 1 and 2, provided the majority of the information used to develop the owner's cost estimate for the facility.

Because SECI accepted bid proposals for both independent power projects and for turnkey construction of Hardee Unit 3, the owner's cost estimate was only used to compare capital equipment cost with the turnkey and other bidders. All of these proposals were compared by performing a life-cycle analysis which compared both the facility's fixed charges and the energy cost over the entire life of the facility.

Four turnkey bids were received in response to the request for proposals. These proposals were provided by:

Black and Veatch 913-339-2043
Contact: Mr. Jim Templin
8400 Ward Parkway
P.O. Box 8405
Kansas City, MO 64114

Ebasco Constructors, Inc. (Now Raytheon) 404-242-6029
Contact: Mr. James Lambert
145 Technology Park
Norcross, GA 30090-2979

NRG Energy, Inc. 612-373-5400
Contact: Mr. Dan Dentloff
1221 Nicolet Mall, Suite 731
Minneapolis, MN 55403

Gibbs and Hill, Inc. 212-216-7280
Contact: Mr. Richard LeFebvre
11 Penn Plaza
New York, NY 10001

All of these turnkey proposals offered combustion turbines of either the Westinghouse or General Electric designs with NO_x emission guarantee limits of 9 ppm (ISO) for the January 1999 in-service date. The 9 ppm (ISO) guarantees which were offered by the manufacturers have never been demonstrated in commercial operation and had only been demonstrated on development burner design. These guarantees were offered as a one-time demonstration at steady state conditions with the combustion turbines in new condition. Due to varying load conditions, and equipment aging which occurs over the equipment operating life, SECI and Westinghouse believe that 15 ppm (ISO) NO_x limitation is an emission limitation representative of what the equipment can achieve over the life of the facility.

SECI does not believe a one-time contractual guarantee demonstrated under controlled conditions should be the basis for lifetime plant NO_x emission limitations.

FDEP.BAR-9

Comment: Please recalculate the cost effectiveness ($/ton removed) by using 6 ppmvd as the emission limit for a natural gas-fired dry low NO_x combustor equipped with a selective catalytic reduction (SCR) system, and 12 ppmvd as the emission limit for distillate fuel oil. These emission limits are technologically feasible and have been attained by different facilities with SCR.

Response: The cost effectiveness of reducing NO_x to 6 ppmvd corrected to 15 percent oxygen when firing natural gas and to 12 ppmvd corrected to 15 percent oxygen when firing oil was calculated using the same approach identified in Section 4.0 of the Prevention of Significant Deterioration Permit Application. The cost effectiveness is estimated to be greater than $5,500 per ton of NO_x removed assuming 100 percent capacity factor and maximum requested use of oil firing (1,500 hours per year) and steam augmentation (2,000 hours/year). It should be noted that more realistic cost effectiveness estimates, as presented in Subsection 4.3.1.2 of the PSD Application, would exceed $7,000 per ton of NO_x removed. If consideration is given to other pollutants that would occur as a result of SCR (e.g., ammonia and secondary emissions) the cost effectiveness would exceed $10,000 per ton of NO_x removed.

Cost Effectiveness Calculation Basis:

Tons removed: Gas at 15 ppmvd to 9 ppmvd = 195 TPY (see Table B-5 in PSD application)

Gas at 15 ppmvd to 6 ppmvd = 293 TPY (additional 98 TPY)

Oil at 42 ppmvd to 15 ppmvd = 300 TPY (see Table B-5 in PSD application)

Oil at 42 ppmvd to 12 ppmvd = 333 TPY (additional 33 TPY)

GAS w/PA at 25 ppmvd to 9 ppmvd = 161 TPY (see Table B-5 in PSD application)

Gas w/ PA at 25 ppmvd to 6 ppmvd = 191 TPY

Previous total = 656 TPY (see Table B-5 in PSD application)

New total = 817 TPY

Annualized Cost: $4,498,950 (same basis as Table B-5; increase in ammonia costs only)

Cost Effectiveness: $4,498,950 ÷ 817 TPY = $5,506/tons NO_x removed

Adjusted Cost Effectiveness Calculation Basis:

Primary Emission Increase with SCR:	244 TPY
(Particulate and Ammonia; see Table 4-3 in PSD application)	
Secondary Emission Increase with SCR:	135 TPY
(see Table 4-3 in PSD application)	
Total Emissions with SCR:	379 TPY

Adjusted Cost Effectiveness: $4,498,950 ÷ (817 - 379 TPY) = $10,272/tons NO_x removed

The above calculations assume that SCR is technically feasible for the lower NO_x concentrations for the Hardee Unit 3 Project. This assumption is incorrect for two reasons. First, SCR has only achieved or required these levels for much smaller combustion turbines (generally less than 50 MW). The largest machine with similar limits is about 80 MW which is about half the size as that proposed for the Hardee Unit 3 Project. As noted in the PSD Application, the advanced combustion turbine is not similar to a conventional turbine since firing temperatures are much higher; thus, an advanced turbine with dry-low NO_x combustors inherently incorporates greater NO_x removal than conventional machines. On the same generation basis or the conventional CT at 6 ppmvd, an advanced machine would be equivalent at about 7 ppmvd. Second, SCR has not been demonstrated at 12 ppmvd for the amount of oil firing proposed for the project. The projects with SCR either do not use oil or have very limited use of oil. Indeed, most of the SCR projects are cogenerators that do not have to incorporate the redundancy required by a utility required to assure reliable service.

There are also additional environmental consequences that occur by attempting to achieve lower NO_x concentrations with SCR, i.e., additional ammonia slip. Ammonia injection is the primary control mechanism in an SCR system. As the catalyst becomes less active, more ammonia is required to achieve permitted emission limits, resulting in an increase in ammonia slip.

FDEP.BAR-10

<u>Comment</u>: Does the applicant propose to do co-firing of natural gas and fuel oil in the combustion turbine? If so, how long will the co-firing last and provide details on how co-firing will be accomplished.

<u>Response</u>: There is no intent for the combustion turbines to be co-fired on natural gas and fuel oil simultaneously on a single machine on a continuous basis. However, during fuel switchovers natural gas and fuel oil will be co-fired for a period of about 15 minutes.

Continuous co-firing of both natural gas and fuel oil for the combined cycle facility can only be accomplished by operating one combustion turbine on natural gas and the other combustion turbine on fuel oil.

FDEP.BAR-11

<u>Comment</u>: Please submit a detailed listing of all the continuous emission monitoring systems (CEMs) required for this project. This should include the type of the CEM (in-situ or extractive), the pollutant it will monitor, and any associated data acquisition system.

<u>Response</u>: NO_x and a diluent will be measured via the continuous emission monitoring system (CEMS) in the HRSG stack since the combined cycle mode of operation will be utilized whenever possible. SO_2 will be monitored through the use of fuel analysis. Opacity may be monitored, depending on the actual number of hours of operation firing fuel oil.

While the CEMS has not been selected, the requirements the CEMS would have to meet were identified in Section 5.6.2.2 of the PSD Application. Compliance with the NSPS reporting requirements for NO_x (Section 60.334, 40 CFR Part 60, Subpart GG) will be accomplished through the installation of a CEMS meeting the requirements of Appendix B of 40 CFR Part 60 and 40 CFR Part 75 regulations. The CEMS will likely be an extractive system. SECI will provide the Department the required monitoring plans and testing protocols when this equipment is selected.

FDEP.BAR-12

Comment: What kind of control and monitoring equipment do you propose to use for continuously recording power generation, fuel injection and the steam injection rates?

Response: The Westinghouse Distributed Processing Family (WDPF) control system will control and record power generation, fuel injection and steam injection rates. The WDPF of equipment is a distributed control system that provides integrated modulating control, sequential control, and data acquisition for the control of power generation equipment (and/or other equipment). One of the functions that the WDPF equipment will accomplish is data logging. Data logging is used to collect, format, and print process data, i.e. for Power Generation, Steam Injection, and Fuel Injection. Logs can be printed periodically; hourly, daily, monthly, etc. Logs can be printed with summary information as follows: averages, totals, maximums, time of maximums, minimums, time of minimums,... This WDPF equipment would be used to control, monitor, and record plant power generation, fuel injection, and steam injection rates along with a voluminous amount of other information that is required to run the plant.

FDEP.BAR-13

Comment: What is the estimated annual throughput and type of air pollution control for the fuel oil storage tank? What are the estimated emissions?

Response: The annual throughput of fuel oil will be a maximum of approximately 37,644,000 gallons per year. The estimated fuel usage is based on each of the two combustion turbines operating at maximum capacity for 1,500 hours per year and assuming an annual average temperature of 72°F (based on the annual average temperature from the National Weather Service station in Tampa).

The fuel oil storage tank will have a maximum storage capacity of 4.4 million gallons of distillate fuel oil. The applicable New Source Performance Standard (NSPS) for the fuel tanks is 40 CFR Part 60, Subpart Kb since the storage tank has a capacity greater than 40 cubic meters (m^3)[approximately 10,568 gallons]. The storage tank will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb, with a true vapor pressure of 0.22 pound per square inch (psi) at 100°F. Because the fuel oil is expected to have a maximum true vapor pressure of less than 3.5 kilopascals (kPa), or approximately 0.51 psi, only the minor monitoring of operating requirements specified in 40 CFR 60 116b(a) and (b) will apply. As a result, no pollution control is required for this storage tank.

The volatile organic compound (VOC) emissions were estimated for the proposed storage tank using the EPA TANKS program, Version 2.0. The program is available through EPA using the electronic bulletin board service of the Technology Transfer Network (TTN). The emission calculations are based on the procedures and assumptions found in the EPA publication *Compilation of Air Pollution Emission Factors (AP-42)*, which is used to generate emissions for sources such as the storage tank. The assumptions used to estimate VOC emissions and the emission estimates for the storage tank are presented in Attachment FDEP.BAR-13. Using this approach, the maximum VOC emissions are estimated to be approximately 1 ton per year.

FDEP.BAR-14

Comment: In Table 7-6 the value for the 3-Hour HSH is incorrectly given as 30.5 for the period 83040212. Based on the modeling output accompanying the application, the value should be 144 for the period 83032418. Please do a refined analysis for this period and update Table 7-7 with a 1983 value for the 3-Hour HSH.

Response: In Table 7-6 from the PSD permit application (see Appendix 10.1.5), the 3-hour highest, second-highest (HSH) value for 1983 should be 144 $\mu g/m^3$ instead of 30.5 $\mu g/m^3$. The revised concentration was predicted to occur at a direction and distance of 120 degrees and 196 meters (m), respectively, from the proposed CTs for the period ending March 24, 1983, hour 18 (83032418) (see revised Table 7-6). Based on this result, a refined analysis was performed for 1983 with the results presented in revised Table 7-7. As shown in Table 7-7, the maximum total concentration due to all modeled sources added to a background concentration is 434 $\mu g/m^3$. This maximum concentration, which is

Table 7-6. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Revised 7/20/94

Averaging Time	Modeled Sources' Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual				
	15	70	1,000	82——
	17	20	1,000	83——
	18	90	1,000	84——
	18	80	1,000	85——
	18	90	1,000	86——
24-Hour HSH	35.7	130	200	82011424
	74.3	120	196	83020324
	85.4	130	200	84032924
	88.3	120	196	85021224
	NS	--	--	86——
3-Hour HSH	97.5	130	152	82011418
	144	120	196	83032418
	137	140	128	84032915
	142	20	221	85083121
	48.6	10	212	86031412

Note: YY = year.
MM = month.
DD = day.
HH = hour.
HSH = highest,second-highest.
NS = not significant, Hardee Unit 3.

[a] Relative to the midpoint between the locations of the two proposed HRSG stacks.

Table 7-7. Maximum Predicted SO_2 Concentrations Compared With AAQS--Refined Analysis, Revised 7/20/94

Averaging Time	Year	Concentration ($\mu g/m^3$) Total	Concentration ($\mu g/m^3$) Modeled Sources	Concentration ($\mu g/m^3$) Background	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)	Florida AAQS ($\mu g/m^3$)
Annual	1984	29	18	11	90	1,000	84--------	60
24-Hour HSH	1983	125	75.1	50	124	175	83020324	260
	1984	138	87.9	50	136	136	84032924	
	1985	138	88.3	50	120	196	85021224	
3-Hour HSH	1982	356	99.6	256	132	146	82011418	1,300
	1983	434	178	256	128	159	83020312	
	1984	397	141	256	138	132	84032915	
	1985	406	150	256	16	217	85083121	

Note: YY = year.
MM = month.
DD = day.
HH = hour.
HSH = highest, second-highest.

[a] Relative to the midpoint between the locations of the two proposed HRSG stacks.

Source: KBN, 1994.

approximately 33 percent of the applicable ambient air quality standard (AAQS), is similar to the refined concentration of 406 $\mu g/m^3$ reported for 1985. Based on these results, the maximum concentrations predicted for the proposed project and other emission sources will be well below and in compliance with AAQS, with an adequate margin of safety.

ATTACHMENT FDEP.BAR-3

Combustion Turbine/Generator Sets
Section D-1.1

Contents

Contents (Continued)

Contents (Continued)

1.1.1 Scope

1.1.1.1 General

A. This specification defines the minimum technical requirements for the furnishing, installation, test, and startup, of two (2) 150 MW nominal (ISO, baseload) packaged, simple cycle gas turbine-generator assemblies and associated equipment. The combustion turbines shall incorporate mature technology and proven designs, or engines which are currently advanced technology.

These units should be available for commercial operation to meet the schedule presented in the commercial sections.

The turbine shall be of the stationary type, simple cycle, suitable for continuous or peaking operation, with a direct driven generator.

The Contractor shall determine the precautions necessary to protect the compressor and turbine from corrosion when the plant is shut down or operating. Any necessary heaters or other devices to prevent damage causing condensation shall be supplied.

The combustion turbine generators and auxiliaries supplied under this Contract shall be supplied per Contractor's standard design.

1.1.1.2 Project Description

The equipment will be installed in standard enclosures for outdoor service in a moisture-laden environment. The power block is intended to provide capacity for Owners system. The units are expected to start 50 to 100 times per year, operating 16 to 24 hours per day on Natural Gas Fuel or No. 2 Oil.

Each combustion turbine unit will be capable of continuous operation at a 50% baseload in accordance with Article B.9.2.1 and will be capable of increasing or decreasing load on load control between base load and 50% base load or less at a minimum rate of 10 MW/Minute.

Each combustion turbine unit shall be capable of automatic starting and loading to base load within thirty minutes from receipt of a start signal when operating in the simple cycle mode. This should be capable with a 230 kV bus voltage at or greater than 207 kV.

All materials and components for the complete design, assembly, and testing of all equipment shall be the responsibility of the Contractor. Any omission from this specification does not relieve the Contractor of his responsibility to provide soundly engineered and reliably operational equipment. The combustion turbines shall be designed for natural gas and No. 2 distillate fuel oil operation.

1.1.1.3 Summary Scope of Supply

The following list of equipment, services and documentation is the minimum scope of supply which the Contractor shall provide. Further definition of each item is to be found in later sections of this specification.

Quantity	Description
2	Combustion Turbine units with water injection for emissions control.

The packages will be complete in all respects including exhaust bypass stacks configured for operation in either simple or combined cycle modes.

The Contractor shall provide its "standard" combustion turbine-generator package to the maximum extent possible, including the following typical items.

Item	Description	Remarks
I.	Combustion Turbine Package	Dual fuel with steam injection for power augmentation
	Engine Assembly	With Compressor Water Wash Piping
	Inlet Manifold	
	Evaporative Cooler	
	Exhaust Manifold	
	Insulation Blankets	
	Conduit & Wiring Turbine	
	Piping & Valving Turbine	
	Compressor Bleed	
	Cooling Air	
	Lube Oil Supply Drains & Vents	
	Fuel Gas Manifold	Stainless Steel Dual Fuel Capability
	Water Injection Manifold	
	Steam Injection Manifold	
	Off-Line and On-Line Compressor H_2O Wash	
	Turbine-Generator Coupling Cover	
	Fuel Oil Piping	Stainless Steel

Item	Description	Remarks
	Atomizing Air Piping	
	Multiple Blade Path Thermocouples	
II.	Generator Package	60 Hz, 13.8 kV. 0.85 PF
	Hydrogen Cooled	A generator with sufficient kVA rating @ 0.85 PF to absorb Combustion Turbine base load generated shaft power to provide 150 MW net.
	Liquid Detectors	
	Static Exciter Assembly	
	Lube Oil Piping	Stainless Steel
	Current Transformers (13)	
	Neutral Grounding Transformer & Resistor	
	Generator Instrumentation	Actual equipment quantities are to be verified by the Contractor
	Stator Winding RTD's (12)	
	Hydrogen Gas RTD's (4)	
	Bearing Thermocouples and Vibration Pickups	
	Exciter Air RTD's (4)	
	All Instrumentation to be Wired to a Terminal Box.	
III.	Mechanical Package	
	Bedplates	
	Enclosures	Panels in high temperature shall be stainless 409. Roofs shall be removable and weather proof. Entire Turbine compartment shall be made of painted Carbon Steel.
	Pressure Switch & Gage Cabinet (PS&G)	

Item	Description	Remarks
	Lube Oil System	
	Main Lube/Seal Oil Pump (AC)	
	Emergency Lube Oil Pump (DC) with Starter	
	Auxiliary Lube/Seal Oil Pump (AC)	
	AC Motor Driven Vapor Extractor & Demister	
	Lube Oil Immersion Heater	
	Lube Oil Filter	Duplex type, 5 Micron Synthetic Media With Transfer Valve (100% capacity)
	Two 100% Lube Oil Coolers	
	Lube Oil Cooler Temperature control valve	
	Accumulator	
	Lube Oil Piping - Supply Vent & Drains	Stainless Steel
	Lube Oil Reservoir	
	Oil Level Alarm	
	Duplex Thermocouples--Exhaust and Bearing Metal	
	Internal Lube/Seal Oil System	
	Seal Oil System - Generator	
	Emergency Seal Oil Pump - DC	
	Drain Regulator	
	Seal Oil Supply Piping and Vapor Extractor	Stainless Steel

Item	Description	Remarks
	Fuel Oil System	
	Fuel Pump & Motor	Pump should have stainless steel internals
	Suction Filter	
	Fuel Control Valve(s)	
	Flow Divider	Stainless Steel internals
	Fuel Stop Valves	
	Fuel Oil Filter	Dual, 100% with pressure drop indication, capable of transfer during operation.
	Carbon Dioxide Fire Protection	
	Emergency Lighting	12V DC
	Air Compressors for CT Service and Instrument Air	
IV.	Electrical Package	
	Bedplate	
	Floorplate Assembly	
	Enclosure (to include) Motor Control Center, AC Motor Control Center, DC	
	Automatic and Manual Synchronizer	(Voltage and frequency matching)
	Voltage Regulator with Volts per Hz Limiter	
	Protective Relay Panel and Relays	
	Batteries (Refer to Section D-2.9)	(125 VDC)

Item	Description	Remarks
	Battery Charger	Remote from battery
	Microprocessor Based Digital Control System:	Designed to interface with Owner's system-wide supervisory control system.
	Control Function	
	Sequence Function	
	Annunciating Function	
	Temperature Monitoring & Recording	
	Vibration Monitoring & Recording	
	Power Supply	Incl. Redundant System
	Operator Interface	
	Isochronous and Droop Control Governor	
	Air Conditioner	2 Per Electrical Package
	Carbon Dioxide Fire Protection	
	Generator Circuit Breaker	1 Per Unit
	Central Carbon Dioxide Prot. Panel	
	Conduit and Wiring	
	Cable Assemblies	
	Emergency Lighting	12V DC
	Internal Compartment Lighting	120 Volt A.C (Fluorescent in Electrical & Control Compartment, Incandescent elsewhere)
V.	Starting Package	
	Bedplates	
	Enclosure	
	Turning Gear & Clutch Assembly	
	Starting Clutch	

Item	Description	Remarks
	Starting Motor (AC Electric Motor)	4160 Volts (HP verified by the Contractor).
	Controls	
	Torque Converter	
	Charging Pump (Shaft Driven)	
	Magnetic Pick-up	
	Leveling Devices	
	Conduit & Wiring Assembly	
	Piping & H.P. Flex Hoses	
	Atomizing Air Blower	
	Motor Starter	
VI.	Pipe Packages	
	Generator End	
	Lube Oil	Stainless Steel
	Seal Oil	Stainless Steel
	Turbine End	
	Lube Oil	Stainless Steel
	Turbine Cooling Air	
	PS&G	
	Atomizing Air	Stainless Steel
	Fuel Oil	
	Flow Divider Internals	Stainless Steel
	Gas Fuel	Stainless Steel
VII.	Package Interconnecting Material	
	Atomizing Air Piping	Stainless Steel
	Cooling Air Piping	
	Lube Oil Piping	Stainless Steel
	Pipe Insulation & Lagging	
	Compressor Bleed Piping	

Item	Description	Remarks
	Fire Protection Piping	
	Cable Trays	
	Cables	
	Conduit & Wiring	
	Liquid Fuel and Gas Piping Within Enclosures	Carbon Steel
	PS&G Piping	
	Water Injection Piping within Turbine Enclosure(s)	Stainless Steel
	Steam Injection Piping within Turbine Enclosure(s)	Stainless Steel
	Liquid Fuel Piping to Turbine Enclosure	
	Water Injection Piping to Turbine Enclosure	Water supplied from Demineralized Water Tank.
	Natural Gas Piping (including metering station)	From Owner defined pickup point to units
	Piping and Tubing Fittings	Swagelock fittings only.
VIII.	Turbine & Generator Accessory Equipment	
	Turbine and Generator Enclosures	Turbine enclosure of carbon steel, with painted perforated carbon steel Liner. Turbine enclosure shall have removable weatherproof roof.
	Turbine Lube Oil Cooler (Oil to Water)	2 x 100% - Shell and Tube 90/10 Cu/Ni
	Waste Drain Piping	
	Air Inlet System with Silencing and Mist Eliminator, Rain Louvers & Filtration	
	Exhaust Transition Duct	409 stainless steel
	Exhaust Stack (Bypass)	Self standing, 75 ft. high

Item	Description	Remarks
	Foundation Leveling Wedges and Clamps	
	Turbine Seating Plate	
	Anchor Bolt Design & Anchor Bolts	
	Carbon Dioxide Fire Protection for Turbine Enclosure	
	Fuel Gas System	Refer to Section C-9.10
	Fuel Gas Throttle Valve	
	Fuel Gas Isolation Shutoff Valve	
	Fuel Gas Overspeed Trip Valve	
	Fuel Gas Vent Valve	
	Fuel Gas Strainer	
	Turbine Inlet Filter	Self cleaning; reverse airflow, pulse type.
	Water Injection System	
	Steam Injection System	
	Off-Line and On-line Compressor Water Wash System	
	Water Wash Pump (AC)	
	Detergent Storage Tank	
	Control and Trip Valves	

1.1.2 Applicable Documents

1.1.2.1 General

A. Intentionally Omitted.

B. Design, fabrication, and testing shall meet the intent of the requirements of the applicable and specified codes, standards, and specifications.

1.1.2.2 Codes and Standards

The following codes and standards shall apply:

A. American Society of Mechanical Engineers (ASME)--ASME Boiler and Pressure Vessel Code, Sections VIII and IX.

B. American National Standards Institute (ANSI).

- -- ANSI B133.3--Gas Turbine Auxiliary Equipment.
- -- ANSI B133.4--Gas Turbine Control and Protection Systems.
- -- ANSI B133.5--Gas Turbine Electrical Equipment.
- -- ANSI B133.6--Gas Turbine Ratings and Performance.
- -- ANSI B133.7--Gas Turbine Fuels.
- -- ANSI B133.8--Gas Turbine Installation Sound Emissions.
- -- ANSI B133.9--Gas Turbine Environmental Requirements and Responsibilities.
- -- ANSI B133.10--Gas Turbines-Information to be supplied by User and Manufacturer.
- -- ANSI B133.11--Gas Turbines-Shipping and Installation.
- -- ANSI B133.12--Gas Turbines-Maintenance and Safety.
- -- ANSI B1.1--Unified Inch Screw Threads.
- -- ANSI B2.1--Pipe Threads.
- -- ANSI B16.5--Steel Pipe Flanges and Flanged Fittings.
- -- ANSI B16.9--Wrought Steel Butt Weld Fittings.
- -- ANSI B16.11--Forged Steel Fittings - Socket Weld and Threaded.
- -- ANSI B17.1--Keys and Key Seats.
- -- ANSI B31.1--Power Piping (Piping External to Enclosures).
- -- ANSI C50.13--Telephone Influence Factor.
- -- ANSI S1.13--Method for measurement of Sound Pressure levels.
- -- ANSI Y14.17--American Drafting Standards.

C. Instrumentation Society of America (ISA) (except Contractor may use his standard nomenclature on P&ID's and his standard instrument tagging system).

D. National Electric Manufacturer's Association (NEMA).

- -- NEMA MG1--Motors and Generators.
- -- NEMA SM33--Gas Turbine Sound and its Reduction.

E. Institute of Electrical and Electronics Engineers (IEEE).

- -- IEEE 37.20--Switchgear Assemblies.
- -- IEEE 43--Recommended Practice for Testing Insulation Resistance.

- -- IEEE 95--Insulation Testing of Large AC Rotating Machinery.
- -- IEEE 115--Standard Test Procedures for Synchronous Machines.

F. National Fire Protection Association (NFPA).

- -- NFPA 70--National Electrical Code.

G. Occupational Safety and Health Act--49 CFR Part 1910.

H. Tubular Exchanger Manufacturer's Association (TEMA)--TEMA Standards of Tubular Exchanger Manufacturer's Association.

I. American Institute of Steel Construction Inc. (AISC)--Specification for the design, fabrication, and erection of structural steel for buildings, including supplementary revisions as applicable.

J. American Welding Society (AWS).

- -- AWS A2.4--Symbols for Welding and Nondestructive Testing.
- -- AWS A5.1--Specification for Carbon Steel Covered Arc Welding Electrodes.
- -- AWS A5.5--Specification for Low-Alloy Steel Covered Arc Welding Electrodes.
- -- AWS A5.17--Specification for Bare Carbon Steel Electrodes and Fluxes for Submerged Arc Welding.
- -- AWS A5.18--Specification for Carbon Steel Filler Metals for Gas Shielded Arc Welding.
- -- AWS A5.20--Specification for Carbon Steel Electrodes for Flux-Cored Arc Welding.
- -- AWS D1.1--Structural Welding Code - Steel.

1.1.3 Performance Requirements

1.1.3.1 General

This equipment will be a part of a combined cycle facility providing electric power. The prime design criteria are reliability and availability, followed by maintainability and the maximization of operational efficiency. The Contractor shall provide equipment which will operate at base load as peaking capacity for the Owner's system. The units must be capable of operating at a continuous controlled partial load down to 50% of base load in accordance with Article B.9.2.1 at the ramp rate of 10 MW/minute (simple cycle operation).

The combustion turbine-generator shall have the capability to drop from 100% load to idle without tripping.

1.1.3.2 Environmental Conditions

A. The equipment installation Site is located in Florida. The Combustion Turbines will be installed outdoors in the standard manufacturer's enclosure except as otherwise specified.

B. Outdoor Environmental Conditions at the Site.
   - (a) Site Elevation--125 Ft. Above Sea Level.
   - (b) Maximum Ambient Temperature--100°F.
   - (c) Minimum Ambient Temperature--20°F.
   - (d) Humidity Range--40-100%.
   - (e) Atmospheric Conditions.
     - Wind Velocity--100 mph sustained.
     - Dust filters are required.
     - Seacoast atmosphere - may contain soot, oil, and corrosive contaminants.

1.1.3.3 Facility Utilities

1.1.3.3.1 Power Sources. Contractor furnished equipment shall have voltage, current, frequency, and short circuit ratings for use with the following power sources:

Power System	System Ground	Symmetrical Short Circuit Current (Amps) RMS
4160V, 3 Phase + 10% - 15%	High Resistance	20,000

4160 Volt power for unit auxiliaries and startup will be provided by the Contractor.

Contractor shall provide transformers for all 480 VAC and 120 VAC power required by each unit.

Notes:

1. Voltage may decrease (-) 15% during starting of vendor supplied large motors.
2. Harmonic content - all AC sources:

Total RMS:	5% of fundamental
Single Frequency:	3% of fundamental

1.1.3.4 Wiring

All wiring for external connection by the Contractor shall be wired out to terminal blocks. All cables shall be tagged on both ends.

1.1.3.5 Motors

All AC motors shall be squirrel-cage induction type suitable for full voltage starting. The rated horsepower of the motors shall exceed, by a minimum of five percent, the maximum brake horsepower required by the driven equipment under any conditions of operation, without overloading, or exceeding the specified temperatures.

1.1.3.6 Enclosures

Omitted Intentionally.

1.1.3.7 Water Injection

Water injection will be used for NO_x control while operating on #2 fuel oil without reducing the life of the combustion components as compared to dry operation.

1.1.3.7.1 Water Injection Curve. Contractor will provide a curve showing water to fuel ratio for loads from 25% of base load to base load for ambients of 20, 59, and 90F. Data will be provided per Schedule established under Article B.10.

1.1.3.7.2 Operational Parameters.

A. Contractor shall provide description of the required operational parameters for running the turbine with water injection for NO_x control while operating on # 2 fuel oil. These parameters must include the permissible ranges of water temperature, pressure, and flow during:

- Start-up Sequence
- Normal Operation
- Normal Shutdown
- Trip

Data will be provided per Schedule established under Article B.10.

1.1.3.8 Omitted Intentionally

1.1.3.9 Omitted Intentionally

1.1.3.10 Performance Characteristics

A. Estimated Performance--Contractor shall submit estimated performance curves for each NO_x emissions limit which shall include the following as a minimum for Natural Gas and No. 2 distillate fuel oil, with and without IGV modulation. Data will be submitted per Schedule established under Article B.10.

1. Expected output power of turbine/generator as a function of compressor inlet air temperature. (Base load)
2. Heat rate as a function of compressor inlet air temperature and power (kW) from 25% of base load to base load.
3. Exhaust flow rate as a function of compressor inlet air temperature and power (kW) from 25% of base load to base load.
4. Exhaust temperature as a function of compressor inlet air temperature and power (kW) from 25% of base load to base load.
5. Water requirements (flow, pressure, and temperature) as a function of compressor inlet air temperature and power (kw) from 25% base load to peak.
6. The effects of barometric pressure on Items 1-5 above.

B-H. Intentionally Omitted.

I. Generator Performance Data to be submitted per Schedule established under Article B.10.

- Saturation and synchronous impedance curves.
- Reactive capability curves.
- Excitation V curves.
- Three-phase short circuit decrement curve.
- Line-to-line short circuit decrement curve.
- Line to neutral short circuit decrement curve.
- Voltage vs. frequency curves.
- Generator output vs. cold liquid temperature curve.
- Efficiency vs. load curve.
- Permissible I2 vs. time curves
- C.T. excitation and ratio correction factor curves.
- Certified Generator Performance Specification Form per ANSI Standard C50.13.

J. Exhaust Characteristics to be submitted per Schedule established under Article B.10.

Contractor shall also submit per Schedule established under Article B.10 a listing of the typical exhaust characteristics expected during normal operation and a normal start-up sequence. This listing should include the expected exhaust flow rate, temperature profile, emissions and duration for each activity involved in a start-up.

K. Instrumentation and Control Data to be submitted per Schedule established under Article B.10.

1. Control System Architecture diagram delineating control equipment supply, interfaces and data communication network(s).
2. Experience with the control system to be provided.
3. Operator interface description including arrangement, CRT displays/controls and accessing displays/control for:
   - Local unit operator interface.
   - Local back-up operator interface.
4. Description of Coax data communication interface.
5. Description of redundancy for:
   - Control and protection processors.
   - Critical control and protection sensors (provide a listing).
6. Description of "first out" annunciation system (sequence of events).
7. Description of printer and logging capability.
8. Description of control/electrical module arrangement and size.
9. Size and access to all control panels.

1.1.3.11 Frequency Control

A. During operation the governor control shall maintain output and frequency within the following limits:

- Frequency Drift--With any constant load between, no load and rated load, the change in regulated frequency shall be within plus or minus 3.23 percent from rated frequency.
- Steady-State--Frequency control shall be within plus or minus 3.23 percent from rated when the load is varied from no load to rated load and all transients have decayed.
- Frequency Variations--During steady-state conditions shall show a random nature (as opposed to cyclic variations).

1.1.4 Design and Construction Requirements

Combustion Turbine

The combustion turbine shall be operated on Natural Gas or No. 2 Oil with water injection for emissions control, including:

Multi-stage axial flow air compressor with:

- Horizontally split casing giving access to internal parts.
- Individually removable stainless steel blading.
- Accessible pressure-lubricated, tilt-pad journal bearing.
- Double acting Kingsbury type thrust bearing.

Combustion system including:

- Can-type combustors in a circular array.
- Combustors removable with insulated cylinder cover in place.
- Low emissions design.
- Ignition system including retractable igniters.

Multistage type turbine featuring:

- Horizontally split casing giving access to internal parts.
- Alloy turbine blades individually removable.
- Individual first stage vanes removable with cylinder cover in place.
- Insulated high temperature shell areas.
- Accessible pressure-lubricated, tilt-pad journal bearing.

Necessary fuel, lube, and cooling air piping.

1.1.4.1 Electrical Design Requirements

1.1.4.1.1 Generator

- General--Shall be designed in accordance with all requirements of ANSI C50.10 and ANSI C50.15.
- Rating--A generator with sufficient kVA rating @ 0.85 PF to absorb Combustion Turbine base load generated shaft power to provide 150 MW net.
- Voltage--13.8 kV.
- PF--0.85.
- Frequency--60 Hz.
- Cooling Medium--Hydrogen Cooled.
- Insulation--Class F.

- Temperature Rises--Temperatures of various parts of the machine shall not exceed the values given in ANSI C50.15 for Class F insulation.
- Terminals.
  - -- Phase Winding--Suitable for Isolated Phase Bus Connections.
  - -- Neutral Windings--Neutral shall be made up by Contractor and connected to Contractor supplied neutral grounding transformer.

1.1.4.1.2 Exciter

- General--Static exciter.
- Response Rate--0.5 or better at generator rated load conditions.

1.1.4.1.3 Generator Neutral Grounding Equipment

- Rating--Sized to limit ground fault current to approximately 10 amperes.

1.1.4.1.4 Current Transformers

- Rating--12000/5A (Depends on unit size proposed).
- Accuracy.
  - -- Metering: 0.3 B 2.0.
  - -- Relay: C400.

1.1.4.1.5 Wiring

All electrical and control wiring for external connection by others shall be wired out to terminal blocks.

All cable shall be tagged at both ends.

1.1.4.1.6 Omitted Intentionally.

1.1.4.1.7 Transformers

The 4.16 kV to 480 volt transformers shall be rated for 55°C. Insulating liquid shall be non-flammable "Wecasal" or Silicon.

The 480 volt to 120 volt transformers shall be rated for 55°C and shall be dry type. Where power is to be utilized at additional voltage level, the Contractor shall supply the transformers in his Control Panel.

Contractor shall provide all electrical distribution equipment required for all levels of transformers from Contractor furnished 4160 volts.

1.1.4.1.8 One (1) generator main circuit breaker - nominally rated 13.8 kV, three-phase, 60 hertz, vacuum type rated 1000 MVA with stored energy closing and trip mechanical, one close and trip coil for 125 VDC operation and stationery auxiliary switch.

1.1.4.2 General Construction Requirements

1.1.4.2.1 Turbine Casings and Rotors.

A. The design and construction of the turbine casings shall be such that there is no growth or distortion of any part under the operating conditions such as to affect the efficiency and reliability of the unit.

B. The design of the casings shall permit access to the blading without undue difficulty. Suitable guides shall be provided where necessary to prevent damage to the blading while raising or lowering the upper portion of the casings. Alternatively, the casings shall be designed to permit removal of complete units for periodic overhauls. Approved lifting gear, such as lifting beams, sli: , jacks, etc., required for removing complete units, rotor, or the upper portion of casings shall be provided.

C. Any internal thermal insulation shall be arranged to accommodate differential thermal expansion and shall satisfactorily withstand high sound pressure levels inside the machine.

D. Contractor shall provide arrangement to accommodate thermal expansion of the casings.

E. Ports shall be provided in the combustion turbine to permit inspection of the interior by means of a boroscope for all stages of the compressor and turbine.

F. Cylinder flange bolt heaters to facilitate tightening of the cylinder bolts shall be provided with the combustion turbine generator.

G. In no circumstances shall the casings be subjected to high temperatures either at the factory or Site, without the protection of adequate lagging.

1.1.4.2.2 Shafts.

A. In the design of the shafts, all sudden variations in diameter shall be avoided and the parts of the shaft that run in bearings shall be finished in an approved manner and polished.

1.1.4.2.3 Seals. Arrangements shall be made where possible to enable the turbine seals to be examined and replaced without the necessity of dismantling the casings. Arrangements shall be made to preclude any leakage of gas thru the seals in the combustion turbine enclosures.

1.1.4.2.4 Bearings.

A. The main bearings shall be of rugged design consistent with the requirements of continuous service. The bearing housing shall prevent oil or oil vapors from leaking out and air from leaking in. Sight glasses shall be located on all bearing drains and shall be easily read and accessible. All bearings shall have temperature monitoring instrumentation compatible with the control system to include measurement of bearing lube oil temperatures and bearing metal temperatures as a minimum. Guards and shields shall be provided to protect personnel from rotating shafts.

B. The bearings should be accessible for inspection and repair without removing major components, i.e., inlet duct, silencer.

1.1.4.2.5 Intentionally Omitted.

1.1.4.2.6 Blading.

A. The blading and discs of the compressor and turbine shall be designed to be free from resonant vibrations in the normal speed range and shall withstand thermal transients without distortion, creep, or incremental damage.

B. The blading shall also be able to resist deterioration by pitting, blunting, corrosion, erosion, crystallization, creep or otherwise. Blading shall be coated or treated as appropriate for the fuels specified herein. Coating or treating of blades shall be as follows:

- Compressor Blades & Vanes - Chromalloy SA-12 or PWA 77, or Sermatel 5380 DP or Owner approved acceptable equal.
- Turbine Blades & Vanes Row 1 and 2 - NiCoCrAlY overlay coating.

C. Blading materials and the method of securing the blades in the rotor and casings will be provided.

1.1.4.2.7 Combustion Chamber(s), Burners, and Igniters.

A. The combustion turbine shall be capable of firing Natural Gas and No. 2 distillate fuel oil with water injection.

B. The combustion chamber(s) shall be designed to accommodate thermal expansion without imposing loads on adjacent parts. Combustion chamber(s) and transition pieces(s) shall be designed for water injection operation with no detriment on service life compared to dry operation.

C. The combustion chamber(s) shall be mounted so that they can be easily inspected when necessary.

D. The gas temperatures of all combustion chambers shall be closely matched.

E. The burners shall be of the "smokeless" design capable of efficient atomization and stable combustion at all loads.

F. If an air atomizing system is required for proper operation, the necessary air compressors and equipment shall be furnished under the scope of this Contract.

G. Exhaust emissions shall comply with the requirements herein.

H. Automatically operated igniters shall be provided for the burners. Arrangements shall be made for purging, if necessary, to prevent accumulation of carbon deposits on the burner tips.

I. The igniters shall be designed for maximum reliability and their operation shall be automatic.

J. Adequate detection equipment shall be provided to detect failure of the flame and to automatically cut off the fuel supply. In the event of fuel failing to ignite or start-up, means shall be provided for automatically purging unburned fuel from the combustion chambers and turbine.

1.1.4.2.8 Cooling Systems.

A. Each combustion turbine-generator unit shall be provided with individual external cooling systems for cooling lubricating oil, and other systems. Shell and tube heat exchanger shall use the closed cooling water for temperature control. The heat exchangers shall be provided with temperature control valves and interconnect piping between the skids and the heat exchanger.

1.1.4.2.9 Turning Gear.

A. A rotor turning gear will be furnished if required for the unit to minimize distortion of the rotor after operation and to permit reloading of the unit after a shutdown.

B. The turning gear shall be motor operated and shall engage and start automatically. The turning speed(s) and recommended time period for which rotors must be turned for various starting and stopping conditions shall be provided. A mechanical interlock or overrun between the engine starting and engine turning mechanism shall be provided to prevent simultaneous operation.

C. A jacking pump and turning gear oil pump shall be provided, if necessary.

D. Necessary oil piping and appurtenances shall be included. Turning gear oil piping systems shall be complete with all necessary pressure switches or other interlocks to prevent turning gear operation if lubricating oil pressure drops below that required for effective bearing lubrication. Suitable housings and safety guards shall be provided for all moving parts of the turning gears. Limit switches shall be provided on turning gear clutches for remote indication. The turning gears shall have automatic engaging and disengaging mechanism. The turning gear oil system shall be a separate completely sealed system with its own reservoir using synthetic oil.

1.1.4.3 Air Intake System

The air intake system shall consist, as a minimum, of the following equipment:

1.1.4.3.1 Filter system with the following features:

A. The air filter system is to utilize a rainhood followed by a mist eliminator stage to prevent the ingress of water mist, followed by a self cleaning (reverse flow, pulse type) filter design having an efficiency exceeding 95% per ASHRAE Test Procedure 52-76 "Method of Testing Air Cleaning Devices Used in General Ventilation for Removing Particulate Matter."

B. Capacity--The inlet air filter shall be sized for an average face velocity not to exceed 500 ft/min (inlet air) at maximum air flow conditions.

C. Intentionally Omitted.

D. Filters are to effectively clean intake air with a maximum air pressure drop of one to two inch water gage.

E. A pressure switch is to be provided for alarm and shutdown. Contractor will provide alarm & shutdown pressure drops. Shutdown will not exceed 5.0" H_2O.

F. Blow in doors shall be furnished.

G. A mist eliminator shall be furnished to remove high moisture content and water mist from the incoming air.

H. The inlet duct and filter house will be fabricated from galvanized carbon steel or factory painted carbon steel with zinc rich primer. Bare carbon steel or corten is unacceptable.

1.1.4.3.2 Filter House Construction

A. Filter compartment to be completely weatherproof and suitable for outdoor installation at site conditions.

B. A service door is to be provided to each level. Exterior mounted stairs and platforms are to be provided for access to the service doors.

C. Internal walkways are to be provided within the filter house to simplify operator changeout of filter elements.

D. Filter compartment is to be designed to allow maintenance on the filters while turbine/generator is in operation.

E. The filter house is to be equipped with internal lighting capable of withstanding operation vibration.

F. Intentionally Omitted.

G. All materials in the air flow path downstream of the filter elements are to be painted or hotdipped galvanized.

H. All fasteners shall be tack welded.

I. Acoustic materials are to be compatible with intake air environment.

J. If Perforated material is used for sound insulation containment it shall be hotdipped galvanized steel.

1.1.4.3.3 Inlet Silencer

An inlet silencer shall be furnished to meet the required sound levels. It shall be fabricated from hotdipped galvanized steel. Bare carbon steel or corten is unacceptable.

1.1.4.3.4 Structural Supports for filter compartment, silencer assembly, transition and ducting shall be provided by the Contractor.

1.1.4.3.5 Evaporative Cooler

An evaporative cooler shall be provided in the inlet air system of each combustion turbine to cool the ambient air at the turbine inlet.

The evaporative coolers shall be furnished with cellulose cross fluted configuration media, designed to provide maximum air-to-water contact and minimum water droplet carry-over. Stainless steel vane type moisture separators shall be furnished. The design will address biofouling control of the media and related effects on combustion turbine components.

The design cooler saturation efficiency shall be 85 percent. The air velocity at the cooler media shall not exceed 650 fpm.

Each evaporative cooler shall have a recirculation pump assembly, reservoir, and blowdown bleedoff valves and associated controls.

The evaporative cooler design shall be capable of draining all water from the enclosure with easily accessible drain valves.

The evaporative cooler enclosure from the wetted surfaces up to the moisture separator shall be stainless steel.

1.1.4.4 Exhaust System

A. The exhaust system shall consist of an exhaust collector expansion joint, transition piece, exhaust bypass stack and silencer. The bypass stack will be configured for simple cycle operation.

B. The exhaust system shall be thermally and acoustically treated. No cast refractory may be used to internally line ducting. Exterior surface temperature of the ductwork and stack shall not exceed 140°F with an ambient temperature of 80°F.

C. The exhaust stack and ductwork shall include two (2) two (2) foot by five (5) foot removable panels or doors (each) for man & equipment access to the duct/stack internals.

D. The bypass stacks provided must be suitable for simple cycle operation and shall meet the requirements of the environmental permit to be obtained by the Owner. (See Exhibit M, Optional Pricing.)

   The height of the bypass stack shall be 75 ft. Exhibit M provides incremental unit prices for increased stack height.

E. The bypass stack will have a carbon steel plate exterior with six inches of insulation and a 409 stainless steel liner. The silencer will be made of 409 stainless steel or Owner approved equal.

1.1.4.5 Rainwater Drainage

All enclosures, and ductwork have peaked or pitched roofs to prevent the accumulation of rainwater. Internal air flow passages (i.e. the filter house) will be fitted with low point drains to prevent the accumulation of rainwater. Drains shall be of sufficient size so that they will not plug.

In addition any and all external or internal structural members will be configured to prevent the accumulation of rainwater, or be provided with drainage holes/passages.

1.1.4.6 Water Injection System

The water injection system shall contain the following components and features as a minimum:

A. Equipment necessary for injecting a variable water flow into the combustion turbine.
B. Set of nozzles or equivalent for injecting a controlled rate of water into the combustor region of the engine.
C. Manifold which connects all combustor section nozzles.
D. All necessary controls and metering equipment mounted on a separate skid.
E. Interconnecting piping to connect engine manifolds to water injection metering skid.
F. Interface connections are to be flanges at the edge of the skid for water supply.
G. All manifolds and piping shall be stainless steel (304 SS).
H. All valves shall have stainless steel trim.
I. Design of manifolding and piping shall provide compensation for thermal growth.
J. Water injection controls shall respond to an operator initiated 4-20 mA override control signal within allowable turbine operating limits.
K. The water injection system shall be provided with a system of freeze protection to 10°F.

1.1.4.7 Lubrication System

1.1.4.7.1 Combustion Turbine and Generator Lubrication System. The lubrication of the turbine, generator, and exciter shall be accomplished by a continuous flow of oil supplied by a common lubrication system. The lubrication system shall be designed with warning annunciation to indicate abnormal conditions and immediately shut down the combustion turbine if operation is dangerous or potentially damaging.

The oil cooling system shall utilize a closed loop oil to water heat exchanger. Oil coolers for oil to water cooling systems shall be shell and tube type with materials as follows. Alternate materials may be used provided they equal or exceed the strength and corrosion-erosion characteristics of the materials specified.

- Tube Material--90-10-Cu-Ni - ASTM B111, UNS No. C70600.
- Tubesheet Material--Aluminum bronze - ASTM B171, UNS No. C61400.
- Channel and Cover--Steel - ASTM A285 Gr C.

Each oil cooler shall have sufficient capacity to cool the entire oil supply to the machine over the complete operating range at site conditions. The oil piping to and from the oil coolers shall include an automatic double three-way valve to switch the oil from one cooler to the other or to operate both coolers simultaneously in the event of high ambient or cooling water temperature. For manual override, a single handwheel shall position both valves simultaneously to prevent simultaneous shutdown of both coolers.

The combustion turbine and generator lubrication oil system shall, as a minimum, contain the following features:

A. Main lube oil pump (shaft or AC driven).

B. Auxiliary AC lube oil pump (100% capacity).

C. Emergency DC lube oil pump and emergency seal oil pump.

D. The steel oil reservoir shall be furnished complete with level indicator, high and low level alarm switches, drain, vent, manhole, valves, and piping. The oil reservoir vent shall be equipped with a demister to prevent the escape of oil vapors. The demister shall be designed to have an efficiency of 99.9% for particles 0.3 microns and larger. Electrostatic precipitators are not allowed. All openings to the oil reservoir shall be gasketed and raised at least 1 inch above the reservoir surface. The top shall be sufficiently rigid to support the equipment mounted on it without vibration or deflection. The bottom of the reservoir shall be sloped to a low point drain connection. The reservoir shall be designed for a minimum 5 minute retention time. The interior of the reservoir shall be lined or coated with a suitable rust preventive compatible with the lubricating oil.

E. Three separate lube oil pumps and drive systems shall be furnished and all oil pumps shall have mechanical seals and removable metallic suction strainers.

F. Ball valves are required for lubricating oil duties. The ball valves shall be designed and manufactured to meet the requirements of API-607 for fire safe valves.

G. Omitted Intentionally.

H. Dual full capacity lube oil filter (98.5 percent of 40 micron and above) shall be provided to protect all bearings form metallic particles and foreign matter.

Each filter shall be equipped with a differential pressure gauge across the filter to monitor the filter condition. A full flow transfer valve station shall be furnished to allow isolation of each filter independently, and to allow the filters to be placed in service simultaneously. The Contractor shall provide the initial filters and a full set of spares.

I. Pressure switches shall be provided as required to permit automatic sequential starting of the main auxiliary oil pump and emergency DC oil pump on dropping oil pressure. Auxiliary contacts as required for indication shall be furnished and wired to the control system.

J. The system shall include bearing metal temperature, and oil pressure and temperature, alarm, and trip mechanism. Each bearing shall be provided with thermocouple well and thermocouple in each bearing and each oil drain.

K. Thermal calculations for the cooling system radiators shall be submitted to the Owner prior to fabrication of the radiators.

L. Lubricating oil supply piping downstream of the filters shall be stainless steel. The balance of the lubricating oil piping shall be carbon steel.

M. The lubricating oil system shall be designed to minimize the possibility of fire due to the leakage of vapors or fluids from the systems onto normally high temperature parts as a result of physical damage or piping failure. At a minimum, this shall include the following:

   1. Intentionally omitted.
   2. Suitable drains shall be provided from the housings.
   3. Lube oil lines shall be located below cable trays.

N. The Contractor shall furnish lubricating oil required for flushing and initial operation including anti-foam and other additives.

O. Lube oil vapor recovery will be provided by the Contractor.

P. One lube oil purification system shall be provided for each combustion turbine. Oil shall be drawn from the lube oil reservoir into the oil purifier by chamber vacuum. Either centrifugal action or vacuum dehydration will remove 100% of the free water in the oil. The dehydrated oil will then pass through a 3 micron filter prior to being returned to the lube oil reservoir.

The purification system, including the pump, shall be capable of cycling a minimum of 10 percent of the lube oil reservoir capacity per hour. The purification system shall be designed for continuous operation. Local control shall be provided.

1.1.4.8 Fuel System

1.1.4.8.1 General.

A. The combustion turbine will be capable of dual fuel operation on No. 2 oil and natural gas. Transfer between gas and oil will be on line without shutdown and automatic. Transfer between oil and gas will be manually initiated automatic on line without shutdown.

1.1.4.8.2 Dual Fuel System. The dual fuel system shall contain as a minimum the following features:

A. Gas strainer, pressure switches, and local gages.
B. Pressure regulating and primary shut-off valve.
C. Fuel metering valve.
D. Secondary shut-off valve.
E. Main liquid fuel pump configured for a 10 to 30 psig inlet pressure.
F. Flow divider.
G. Fuel heat tracing for viscosity control will be provided by Contractor.
H. Dual fuel filters (5 micron) with differential pressure alarm, and manual transfer. Fuel filters to be changeable during operation.
I. Fuel flow meters for both oil and gas fuel (instantaneous reading, and totalizing using WDPF).
J. Contractor will install manual fuel shut-off valves and pressure relief valves to be mounted external to the turbine package.
K. Piping connection to the fuel supply is to be flange mounted at the perimeter of the engine skid.
L. All piping, manifolds, and nozzles are to be steel.
M. Gas fuel system is to be sized for normal operation.
N. Gas fuel system is to be designed to function with pipeline quality natural gas.
O. Fuel control valve is to be designed to be electrically controlled and to provide a smooth, nonpulsating flow to the engine under all operating conditions.
P. All of the above items are to be contained within an enclosure.

Q. Contractor shall supply a schematic of the dual fuel No. 2 distillate oil and natural gas system.

R. Omitted Intentionally.

S. Contractor shall provide a schedule of required Natural Gas Fuel Pressure vs. Ambient Temperature and load for operation of the CT Units.

1.1.4.9 Silencing Systems

A. All equipment provided by Contractor shall have silencing systems as required to meet specified sound level limits. This shall apply to all ducting and off-base equipment as well as the major enclosed compartments.

B. All sound attenuating enclosures provided by the Contractor shall be suitable for their installed environment. Enclosures must present a good outward appearance and not hamper the function, performance, or accessibility of the enclosed equipment.

C. Turbine enclosure vent ducts are to be fitted with exhaust silencers, if required to meet noise levels.

1.1.4.10 Fire Detection and Protection

Fire detection and suppression system shall be an automatic discharge system to provide a discharge of carbon dioxide into the gas turbine enclosure and a directed discharge onto the compressor end bearing of the CT. This system shall contain, as a minimum, the following features:

A. Actuation shall be by means of rate compensated thermal detectors, and by remote actuation.

B. Detectors are to be located inside the equipment enclosures. Thermal detectors are to be positioned to accurately monitor actual compartment temperature.

C. Thermal fire detectors are to be Fenwall Model 27121 or equal.

D. Detectors shall be rated for hazardous locations for Class I, Div 2, Group D Hazard (CT only).

E. A minimum of two (2) Products of Combustion (POC) detectors in electrical package and two (2) thermal detectors in other various enclosures shall be provided, all of which are to interface with the control system.

F. Remote electric and remote manual actuation of the system shall be provided.

G. System shall maintain a minimum extinguishant gas concentration to conform to NFPA 12 for duration of turbine coast down (CT only).

H. All ventilation ducts shall close and all forced draft ventilation systems shall shut down upon initial actuation of system.

I. One CO_2 central storage tank common for both combustion turbine generators and the steam turbine generator shall be provided.

J. All necessary valves, piping, and internal wiring for the fire suppression system shall be provided.

K. Signals shall be monitored and provide basis for shutdown and discharge if a single element detects a fire.

L. Any fire detection system shutdown signal shall trip the turbine.

M. System shall provide remote annunciation of activation or of a system fault.

N. In addition, an automatic dry chemical type system shall be furnished for the exhaust bearing area of the combustion turbine.

O. Intentionally omitted.

1.1.4.11 Compressor Water Wash System

Water wash system is to be a self-contained system to allow off-line and on-line compressor section cleaning as required. The water wash system is to include the following features:

A. Stainless steel or fiberglass detergent reservoir of adequate capacity.

B. Intentionally omitted.

C. Piping to connect to engine water wash manifold.

D. Connection points for:

- Demineralized Water Supply.
- Air Supply.
- Soap Fill Vent.

E. Compressor waterwash skid will not be located in the turbine enclosure.

F. "Off-Line" and "On-Line" water wash system shall be provided.

1.1.4.12 Starting System

The starting system shall be an electric motor or frequency converter.

A. 4160V 3ϕ 1800 rpm electric motor or frequency converter system of adequate rating to provide five consecutive start attempts without cooldown. Owner to follow Contractor's recommended start-up procedures.

B. All 4160 controls and starters shall be mounted on an external skid which is separate from the gas turbine skid.
C. Contractor shall furnish a schematic of the starting system.
D. Contractor shall furnish inrush current vs time curves.
E. Instrumentation for motor control system shall be mounted internal to control cabs.

1.1.4.13 Control System

A combustion turbine control system shall be designed to safely and reliably control, monitor, and sequence each combustion turbine unit applying state-of-the-art microprocessor based control technology. This system shall be furnished in a self-contained modular unit with HVAC. Each combustion turbine shall be capable of operation from the unit control module, the site control room and an off-site control center.

Each control system shall include:

1. Redundant control and protection processors.
2. Redundant power supplies.
3. Input and output signal conditioning and power conditioning.
4. Sequence of events processor ("first out" annunciator) at unit control module.
5. Alarm/utility printer(s) at control room.
6. Operator video display terminal as a "back-up" operator control station at the unit control module.
7. Redundant control and protection processor data communications.
8. Communication processors with external ports to meet site requirements located in the control room.
9. Capability for two-way communication over a coax data link between unit control module and site control room.
10. Hardwired signals between an Owner supplied RTU and the control processor, located in the control room.
11. Redundant critical primary sensors.
12. Electric, pneumatic and/or hydraulic control valves as applicable.
13. Pressure switches and gauges.
14. Vibration monitoring system.
15. Auto synchronization.
16. Voltage regulation.

17. Switchgear, protective relaying.
18. Motor control centers.
19. Battery and Battery charger system.

1.1.4.13.1 Electrical/Control Module. An electrical/control module shall be supplied to house the electrical and control equipment for an individual gas turbine unit. The module shall include, as a minimum, the following features:

A. Size of module is to be adequate to accommodate all required equipment with sufficient space for operator functions and accessibility to equipment for maintenance.

B. The module will be fully insulated and will include redundant HVAC systems. Redundant HVAC units will be mounted external of the module. Connecting ductwork if necessary to be supplied and installed by Contractor, HVAC shall be capable of both heating and cooling.

C. The module will be installed outdoors where air temperatures will range from 20°F to 100°F. The module temperature shall be controlled to a nominal 72°F, relative humidity of 50%, year round.

D. Omitted Intentionally.

E. The module will be constructed as a single lift assembly with a rigid welded baseplate constructed of 8" wide flange beams as a minimum. Flooring is to be minimum 3/16" steel plate. Walls are to be of steel sandwich construction with insulation between inner and outer panels.

F. The module is to have a minimum of two entry/exit doors. At least two (2) doors shall be of sufficient width to pass all internal electrical equipment. Door locations shall not enter/exit into or toward the turbo-machine compartments.

G. The Contractor shall install the following equipment into each module:

   1. Gas turbine-generator unit local control panel with operator interface.
   2. Protective relays for generator.
   3. Generator metering automatic synchronizer and voltage regulator.
   4. Turbine-generator unit motor control center.
   5. Auxiliary power transformer 480 Vac to 120 Vac for control loads and lighting.
   6. Batteries shall be located in a separate enclosure(s) unless batteries are sealed.
   7. Telephone jack and intercom jack.
   8. Intentionally Omitted.

9. Protective relays for auxiliary transformer.
10. Battery chargers.
11. Generator Circuit Breaker.

H. The module shall be wired to electrically interconnect equipment and electrical services supplied.

I. All terminal strips shall be clearly labeled.

J. Terminal blocks shall be used at Purchaser/Contractor interconnect wiring connections.

1.1.4.13.2 Combustion Turbine Control System. The combustion turbine control system shall include, as a minimum, the following features:

A. Microprocessor based control and monitoring system to be used in fuel management and control, automatic sequencing and protection.

B. Governor function to control speed and load of turbine by varying fuel flow and other variables.

C. Automatic sequencing of events for turbine start up with optional manual control capability to allow Owner's control of duration of non-synchronous speed idle time and synchronized speed idle time.

D. Automatic sequencing of events for turbine start, normal stop, and emergency stop function.

E. Measure, monitor, and display critical turbine operating temperatures and modulate control of variables to keep temperatures within limits.

F. Monitor potentially dangerous conditions and provide alarm and trip functions if limits are exceeded.

G. Provide annunciation of system alarms and trip. Provide "First Out" feature for annunciation of multiple alarm conditions.

H. Back-up display and control for use in the event of a CRT failure.

I. Interface with active control components and MCC.

J. Provide permissive circuits when limit conditions are satisfied.

K. Fuel management and control to include:

- Light off control.
- Engine acceleration control.
- Engine speed governing.
- Engine temperature governing.

L. Water injection rate as a function of fuel flow.

M. Vibration monitoring:
   - Bently Nevada system.
   - A minimum of two (2) velocity pickups on engine.
   - X-Y proximity probes at each bearing.
   - Continuous monitoring of each channel.
   - Continuous display of each channel.
   - Vibration display meters to be easily readable by operator.
   - Non-Latching alarm relays.
   - Latching trip relays.

N. Continuous display of the following:
   - Combustion Turbine Generator speed.
   - Water injection rate.

O. Audible "tone" alarm is to be provided inside module and a horn blast mounted outside the module.

P. A module operator's interface (CRT or equal) shall be mounted in each unit control panel and directly connect to the microprocessor control processors and be used to display or control the following parameters:
   1. Turbine:
      - Speed.
      - Exhaust temperature.
      - Dedicated Start-up sequence display.
      - Control modes (Load control, fuel selection, operation selection).
      - Compressor discharge pressure.
      - Fuel control signal.
   2. Annunciator display for alarms (software).
   3. Thermocouple and generator RTD readouts.
   4. Control system diagnostic information
   5. Trips.

Q. All operator interface controls shall be logically arranged and clearly marked.

R. Redundancy and automatic failure shall be included to prevent single point failure and provide a high level of reliability and availability. Redundancy shall be applied to:
   1. Control and protection microprocessors.
   2. Control system power supplies.

3. Control and protection microprocessor data communication.
4. Control system memory.

S. Alarm and trip conditions to be time tagged, displayed, and logged. Data transmitted via communications link shall not lose time tag.

T. Capability for data transmission over a 1000 foot coax data communications cable between the unit microprocessor based control system and the supervisory and data acquisition system in the site control room.

U. Printers shall be supplied for each unit and be located in the control room. A printer shall have the capability of copying any display shown on the CRT, automatically logging alarms, logging of reports, or process parameters.

V. The Owner will provide an RTU to link his off-site control facility with the unit. The RTU will be "hardwire" connected to the unit microprocessor based turbine control system through screw termination blocks.

Commands to Turbine Control System include:

- Turbine Start/Stop.
- Governor Raise/lower.
- Vars Raise/lower.
- Load Control Remote:
  - Base load.
  - Peak load (steam injection for power augmentation).

Feedback from Turbine Control System include:

- Ready to be started.
- Generator Breaker open/close.
- Fire Alarm.
- Major Alarm (a grouping of Owner/Contractor agreed alarm).
- Minor Alarm (a grouping of Owner/Contractor agreed alarm).
- Watts, Vars, Volts.

W. A manual emergency trip push-button shall be included.

X. There shall be a non-resetable measurement of total fired hours and a non-resetable measurement of "total starts" and of "emergency stops".

Y. Annunciated alarm shall include as a minimum:

- Alarm and Fast Shutdown on Generator - 86G lockout relay.
- Alarm and Open Breaker on Generator - 86-1 lockout.
- Alarm on Gas Analyzer Failure (H_2).
- Alarm on gas Change Operation (H_2).
- Alarm on Hydrogen Supply Pressure Low.

- Alarm on Purge Supply Pressure High.
- Alarm on Purge Supply Pressure Low.
- Alarm on Hydrogen Purity Low.
- Alarm on Hydrogen Pressure High.
- Alarm on Hydrogen Pressure Low.
- Alarm on Hydrogen Pressure Extra Low.
- Alarm on Exciter Maximum Cold Air Temperature.
- Alarm on Min. Cold Gas Temperature.
- Alarm on Max. Cold Gas Temperature.
- Alarm on Liquid Detector Level High.
- Alarm on Defoaming Tank Level High.
- Alarm on Drain Regulator Level Low.
- Alarm and Unload on Generator Load High.
- Alarm and Trip on Lube Oil Pressure Low.
- Alarm on Lube Temperature High/Low.
- Alarm on Lube Level Low.
- Alarm on DC Lube Pump Trouble.
- Alarm on Lube System Trouble.
- Alarm on Seal Oil Pressure Low.
- Alarm on Seal Oil Differential Pressure Low.
- Alarm, Trip, and Vent Generator on Seal Oil Differential Pressure Extra Low.
- Alarm, Trip, and Vent Generator on Emergency Seal Oil Pump Trouble.
- Alarm on Instrument Air Pressure Low.
- Alarm on Vibration System Trouble.
- Alarm on Controller Subsystem Trouble.
- Alarm on Control System Power Supply Trouble.
- Alarm on Blade Path Temperature Spread Monitor Failure.
- Alarm on Battery Charger Trouble.
- Alarm on Turbine Enclosure Products of Combustion.
- Alarm and Trip on Fuel Pump Suction Pressure Low.
- Alarm and Trip on Ignition Oil Flow High.
- Alarm on Fuel Flow Limit Hold.
- Alarm on Turning Gear Not On.
- Alarm on Bleed Valves Not Open.

- Alarm and Trip on Bleed Valves Not Closed.
- Alarm and Trip on Starting Device Sequence Check.
- Alarm and Trip on Start Device Failure.
- Alarm on Turbine Acceleration Low.
- Alarm and Trip on Turbine Acceleration Extra Low.
- Alarm on C.T. Compressor Inlet Pressure Low.
- Alarm on Flame Detector Failure during start-up.
- Alarm and Trip on Turbine Flame Out during start-up.
- Alarm on Cooling Air Temperature High/Low.
- Alarm on Blade Path Thermocouple Circuit Open.
- Alarm on Blade Path Thermocouple Circuit Open for 12 Hours.
- Alarm and Unload on Blade Path Temperature Spread High.
- Alarm and Dump Load on Blade Path Temperature Spread Extra High.
- Alarm and Unload on Turbine Exhaust Temperature High.
- Alarm and Trip on Turbine Exhaust Temperature Extra High.
- Alarm and Trip on Fire Protection System.
- Alarm on Generator/Turbine Vibration High.
- Alarm and Trip on Generator/Turbine Vibration Extra High.
- Alarm, Dump Load, or Trip on Turbine Speed Low.
- Alarm and Trip on Turbine Speed Extra Low.
- Alarm and Trip on Turbine Overspeed.
- Alarm on Disc Cavity (DC-2) Temperature High.
- Alarm and Inhibit Fuel Transfer Sequence.
- Alarm on Water Injection Pressure High/Low.
- Alarm on Water Injection Control Trouble.
- Alarm on High/Low Fuel Supply Pressure.
- Alarm and Trip on Control System Failure.

1.1.4.13.3 Generator Control Panel. The generator control and display panel shall include, as a minimum, the following items:

- One (1) AC Volts, line side.
- One (1) AC Volts, generator side.
- One (1) AC generator current, generator side.
- One (1) AC generator current, line side.
- One (1) AC Watt.
- One (1) Watt-hour.
- One (1) power factor.

- One (1) VAR.
- One (1) DC volt, generator exciter.
- One (1) DC current, general exciter.
- Two (2) AC frequency.
- Synchroscope.
- One (1) generator breaker control switch.
- One (1) synchronizing mode switch (Auto-Manual-Off).
- One (1) voltage adjust switch - (Raise-Lower) (active when breaker is open).
- One (1) VAR/PF adjust switch (active when interconnected with utility; breaker closed).
- Two (2) breaker status push to test indicating lights (open-green) (one) (closed-red) (one).
- One (1) set of synchronizing lights.
- One (1) voltage regulator with VAR control (or separate VAR control if not part of voltage regulator).
- One (1) generator watt transducer WTR.
- One (1) generator VAR transducer VARTR.
- One (1) generator amp transducer.
- One (1) generator voltage transducer.
- Provisions for remote starting and synchronization.

1.1.4.13.4 Generator Protective Relays and Devices. The following relays and devices or equivalent shall be provided, as a minimum, for generator and line side protection. Contractor shall supply his "Standard" package to the maximum extent possible, but must include as a minimum protective scheme as per ANSI/IEEE Standard C37.102.

Quantity	Device #	Description
Three (3)	87G	Generator differential relays
One (1)	59G	Generator ground fault voltage relay
One (1)	46	Negative sequence relay
One (1)	40	Loss of excitation relay
One (1)	32	Reverse power relay
One (1)	27G	Generator undervoltage relay

Quantity	Device #	Description
One (1)	25X	Synchronizing check relay (May be part of autosync control equipment, provided it is active during manual sync operation.)
One (1)	86G	Generator lockout relay
One (1)	81G	Generator over/under frequency relay
One (1)	59G	Overvoltage
One (1)	60	Voltage balance relay
One (1)	21	Distance relay
One (1)	62	Time delay relay

1.1.4.13.5 Batteries and Battery Chargers. Batteries are to be installed in a vented remote exterior module. These assemblies are to be of sufficient size to provide the following:

- Safe shutdown of Contractor supplied equipment.
- Control power for combustion turbine unit control with a capacity of at least 3 hours.

1.1.4.13.6 Control System Power Conditions.

A. Control System AC and DC power shall be conditioned to protect the system from fast rise-time transients and high frequency common mode noise and normal mode noise. Voltage and frequency regulation shall be applied to maintain a constant output despite variation of the AC input.

B. Special handling procedures shall be followed to avoid damage to printed circuit boards by Electrostatic Discharge. Personnel handling the printed boards should be properly grounded, test equipment shall be grounded and anti-static bags shall be used to store sensitive equipment.

1.1.4.14 Local Instrumentation

In addition to the instrumentation located in the electrical/control module there shall be, as a minimum, the following equipment or panel mounted instruments which are to be easily readable by operator.

A. Gas Turbine Compressor Discharge Pressure.

B. Gas Turbine Fuel Supply Pressure.

C. Gas Turbine Fuel Control Valve Inlet Pressure.

D. Gas Turbine Lube Oil Filter Differential Pressure.

E. Gas Turbine Oil Reservoir Temperature.

F. Gas Turbine Cooler Inlet Temperature.

G. Gas Turbine Cooler Outlet Temperature.

1.1.4.15 Structures and Enclosures

1.1.4.15.1 Structures.

A. Omitted Intentionally.

B. There shall be separate packages provided. Typical packages are to be for:

- Turbine.
- Air Filter/Inlet System.
- Exhaust Duct and Stack.
- Modular Electric/Control Package.
- Starting Package.
- Water Injection Control.
- Mechanical Package.
- Generator.
- Exciter.
- Turbine Pipe Package.
- Generator Pipe Package.
- Contractor will supply a complete list of packages including sizes and weights.
- Battery and battery charger if unsealed.

C. Each base shall be sufficiently rigid to allow lifting and installation of the skids with the major equipment in place.

D. Bases shall be sufficiently rigid to maintain alignment of components during operation.

E. All on-base piping and package interconnect and wiring shall be done by the Contractor.

F. Lifting lugs shall be provided on each base structure.

G. Foundation mounting holes and jacking screws shall be provided on each base.

H. All interface connections shall be brought out to common connection points at the perimeter of each base.

1.1.4.15.2 Enclosures and Ventilation. The gas turbine and the majority of the auxiliary equipment shall be housed in fully enclosed, sound attenuated enclosures. These enclosures shall have, as a minimum, the following features:

A. The enclosure walls shall consist of a painted carbon steel outer surface over a sound insulation material with a perforated, painted carbon steel inner surface.
B. All surfaces are to be painted per Section 1.1.4.18.
C. Omitted Intentionally.
D. Walls are to be supported sufficiently to withstand the internal pressure developed by the carbon dioxide fire extinguishing system.
E. Fire retardant R13 or better insulation is to be used.
F. Two access doors are to be installed on all enclosures to provide easy access for inspection and maintenance of equipment.
G. Stainless steel hinges and chrome plated latches are to be used on all doors.
H. Interior lighting shall be provided in each compartment. Electrical package shall have enclosed fluorescent lighting. Fixtures designed so as not to cause interference with electronic equipment. All other compartments shall have enclosed incandescent lighting fixtures. Lighting levels shall be per ANSI C2 & IES Standards.
I. Ventilation systems with automatic control shall be provided for each compartment.
J. Redundant exhaust fans shall be provided for the turbine compartment.
K. Omitted Intentionally.
L. Turbine compartment shall be equipped with fire detection and suppression system per Section 1.1.4.10.

1.1.4.16 Piping and Tubing

A. The Contractor shall furnish and install all piping systems, piping, valves, and fittings for connecting the various components within each skid and interconnecting each skid.
B. Owner will supply and install, as required, all piping external to the equipment skids.
C. All interface connections shall be made at the edge of the equipment skids.
D. No interface piping connections shall be smaller than 3/4" IPS. Smaller interface connections shall be stainless steel tubing.
E. All piping shall be steel unless otherwise specified.

F. All tubing shall be stainless steel and Swagelok fittings shall be applied to tubing.

G. Flanged connections are mandatory for fuel piping.

H. Interface connections of pipe sizes 1-1/4", 2-1/2", 3-1/2", and 5", shall not be used.

I. All interface connections larger than 2" shall be flanged.

J. Piping provided by the Contractor shall be securely fastened to minimize vibration and prevent breakage. Piping shall be designed to provide adequate flexibility and for the accessibility necessary for proper operation and maintenance.

K. Piping shall be installed with adequate clearance between piping and adjacent structures.

L. All package interconnect piping shall be completely visible for leak inspection purposes and shall not interfere with normal maintenance. Pipe trenches are acceptable, buried pipe is unacceptable.

1.1.4.17 Drains & Drain Tanks

All equipment drains will be above grade.

1.1.4.18 Painting

1.1.4.18.1 General and Indoor Equipment. All equipment and structures supplied by the Contractor shall be finish painted. Paint systems shall meet the following requirements or approved specification submitted by the Contractor:

A. All paint shall be applied per the paint manufacturer's instructions.

B. All surface preparation shall be per paint manufacturer's instructions.

C. Finish coats, primer coats, and substrates shall be compatible per paint manufacturer's instructions.

D. Where possible the primer and finish coats shall be paint from the same manufacturer.

E. All visible metal surfaces of indoor equipment and structures shall be painted except for stainless steel and/or plated surfaces which may be left unpainted at Contractor's option.

F. Indoor components may be painted with alkyd primer and alkyd enamel topcoat systems or polyamide epoxy paint systems.

G. Manufacturer's standard paint may be used as a base coat on purchased components if it is compatible with topcoat system.

H. Exterior of all fabricated structures and enclosures shall be painted with matching or harmonizing colors of the Owner's choice.

I. Color of individual purchased components may be manufacturer's standard color if other paint system requirements are met.

J. Interior color of all compartments and enclosures shall be white.

1.1.4.18.2 Outdoor Equipment - General Requirements.

A. All equipment and structures to be mounted outdoors shall be painted on all surfaces exposed to air.

B. Outdoor equipment and structures shall be painted with an exterior rated paint system which includes a corrosion inhibitive polyamide epoxy primer and a two-part polyurethane top coat.

C. Combined film thickness of primer and topcoat for outdoor equipment and structures shall not be less than 4 mil.

1.1.4.19 Vibration and Critical Speeds

1.1.4.19.1 Critical Speed and Balance.

A. The turbine, compressor, and generator shall be so designed as to leave a wide margin of safety between the critical speeds and the normal running and tripping speeds.

B. Special attention shall be given to the accurate static and dynamic balance of the rotating portions of the turbine, compressor, generator, and exciter. Means shall be provided for making adjustment to the balance. The machine shall not exhibit more vibration or make more noise than Contractor's normal acceptance criteria (alarm at 4.6 mils; trip at 6.0 mils).

C. Vibration shall be measured by proximity type vibration detectors located on the shaft and/or bearing housing.

D. The combustion turbine generator unit shall be designed to have an adequate margin of safety when run up to 15 percent above design speed.

E. The maximum overspeed test to which any part of the machine may be subjected at the factory or on the site shall be 13 percent unless otherwise agreed.

1.1.4.19.2 Lateral Critical Speeds. Contractor shall provide to Owner the results of a lateral critical speed analysis for gas turbine/generator. The turbine generator shall have no critical speeds within a 10% separation margin below the synchronous speed nor any critical speeds within the range between synchronous speed and trip speed.

1.1.4.19.3 Radial Vibration. The maximum allowable steady state measured vibration during acceptance test for the generator or combustion turbine shaft shall be 3.0 mils peak to peak which includes the electrical and mechanical run out of the shaft. The maximum combined value of the electrical and mechanical run out of the generator shaft shall be .5 mil.

1.1.4.20 Preparation for Shipment and Storage

The Contractor shall be responsible for properly preparing all equipment for shipment and for up to twenty-six weeks of outdoor storage prior to installation. Preparation steps to be taken shall include the following:

A. All loose parts are to be properly packaged and tagged for identification.

B. All moving parts in any assembly shall be adequately braced to prevent vibration damage during transit.

C. All open connection flanges shall be covered with blind flanges.

D. All base openings shall be sealed with plugs or by covers and waterproof tape.

E. All open tubing connections shall be capped.

F. All unpainted machined surfaces shall be coated with a removable protective coating.

G. Compartment doors shall be locked or bolted shut.

H. Fluid systems shall be blown dry and all openings sealed to prevent entry of objects and damage to flange.

I. All piping, valves, and tubing shall be adequately supported for shipment. Temporary supports may be required.

1.1.5 Inspections and Tests

1.1.5.1 General

A. Tests shall be performed by the Contractor to verify that all equipment has been properly manufactured and assembled. These tests shall be performed on individual components or completed assemblies as applicable. Instruments used to measure data which is used to determine guaranteed performance must be calibrated.

B. Contractor shall provide to Owner, prior to conducting tests, a description of intended factory tests.

C. Tests shall be certified as having been properly performed and that all components have successfully passed these tests.

D. Certified test results shall be provided to the Owner.

E. Owner or his designated agent shall have the right to inspect all components and equipment for supply under this specification.

F. All factory tests shall be successfully completed before equipment is shipped to Owner.

G. Contractor shall furnish to Owner two (2) certified copies of the results of mutually agreed to factory tests and two (2) copies of all performance curves or tabulated data which has been determined by these tests.

H. Except as noted when agreed upon by Contractor and Owner, factory retests shall be performed to verify acceptability of equipment in the event of questionable test data, or in the event of adjustments and/or corrections and/or parts replacement during acceptance tests.

1.1.5.2 Factory Tests

1.1.5.2.1 Gas Turbine Tests. Each combustion gas turbine rotor is to be spin tested at the factory to 110% of operating speed. This test is to demonstrate the conformance of the rotor to design requirements. This test is to be in accordance with the Manufacturer's standard factory testing procedures.

1.1.5.2.2 Generator Tests.

Generator. The following factory tests will be performed on the generator.

- Mechanical.
  - -- Rotor Overspeed.
  - -- Rotor Mechanical Balance.
  - -- Mechanical Inspection.
  - -- Air Leakage Test.
  - -- Seasoning and balancing in heated rotor box.
- Electrical.
  - -- Measurement of Cold Resistance of Armature and Field Windings.
  - -- Insulation Resistance Measurements.
  - -- Dielectric Tests.
    - (1) Armature--The standard test voltage shall be an alternating voltage whose effective value is twice the rated voltage of the machine, plus 1,000 volts, applied for 60 seconds.

(2) Field--The standard test voltage for field voltages up to and including 500 volts is an alternating voltage of ten times the rated voltage, but not less than 1,500 volts. The standard test voltage for field voltages rated greater than 500 volts is 4,000 volts plus twice the rated voltage. This test is applied for 60 seconds.

-- Resistance Temperature Detector Tests Consisting OF:

(1) Resistance measurement.

(2) Insulation resistance measurement.

(3) One minute dielectric test at 1500 volts AC, with a continuity check of the device afterwards.

Excitation System. The Excitation System shall be tested in accordance with IEEE 421.1, 421A and 421B.

1.1.5.2.3 Lubrication and Fuel Oil System Tests. Operational tests shall be run on each lubrication and fuel oil system or component. Tests shall be run with full system design pressure. The items which shall be checked, verified, and recorded are as follows:

- Pump(s) Operation.
- Filter pressure drop.
- Relief valve settings.
- Pressure switch settings.
- Temperature switch settings.
- Level switch settings.
- Leaks.
- Automatic temperature valve operation.
- Cooler fan operation.
- Transfer valves switchover.

1.1.5.2.4 Control System Tests. All control systems which are supplied by the Contractor shall be tested prior to shipment. The items which are to be checked, verified, and recorded shall include the following:

- Check each circuit for continuity and conformity to wiring diagrams and check all final assembly wiring.
- Point to point wiring checks, including power distribution and supply systems.
- Checkout of start system logic using simulator.
- Checkout of protective devices using simulator.
- Checkout of protective systems logic using simulator.

- Calibration of speed, temperature, pressure and vibration monitoring equipment.
- Test and startup of starting systems.
- Test of protective systems.
- Functional test and setup of turbine governing system.
- Test and setup of generator control systems.
- Automatic (PC based) hardware loop back checks.
- Functional tests of water injection system.
- Checkout and test of all interfaces with Owner supplied control signals including all inputs and outputs.
- Various simulation tests such as: Loss of power; voltage spikes; transfer between redundant processors, power supplies; effects of changes in ambient temperature.

1.1.5.2.5 Miscellaneous Subsystems Tests. Each subsystem in the Contractor's scope of supply shall be tested prior to shipment. Results of these tests shall be documented. Subsystems shall be tested for the following items:

- Conformity to applicable specification.
- Proper calibration of each adjustable component.
- Proper operation of the assembled subsystem either at the Factory or at the Site.

1.1.5.3 Intentionally Omitted

1.1.6 Documentation

1.1.6.1 Omitted Intentionally

1.1.6.2 Submittals and Review

All submittal documents shall be furnished per the documentation schedule. All drawing submittals shall consist of two (2) prints and one (1) reproducible of each drawing. The reproducible for all drawings of sizes larger than standard "B" size (11" x 17") shall be mylar poly sepias. Submittals of other documents shall consist of two (2) copies unless otherwise specified. Each document or drawing shall be dated and stamped as being "Certified". A copy of each drawing or document will be returned to the Contractor marked with either required changes or Approval by Owner within two (2) weeks of receipt.

Contractor prepared drawings shall also be furnished on disk or tape compatible with an Autocad 10.0 system.

1.1.6.3 Omitted Intentionally

1.1.6.4 Remainder of Documentation

Certified documents shall be furnished by the Contractor to the Owner in accordance with Article B.10:

Document
General Arrangement, Main Units
Project Schedule
Utilities List
Turbine Operational Parameters
Foundation Loading Diagram, Main Unit
Installation Foot Print, Main Unit
Anchor Bolt & Jack Screw Detail, Main Unit
Lift Plan
Torsional Analysis Report
Process & Equipment Symbols Legend
Process & Instrument Diagram for the following Systems:
a. Fuel System
b. Lube/Seal Oil System
c. Water Injection System
d. Turbine Cooling & Bleed Air System
e. Instrument Air System
f. Water Wash System
g. Atomizing Air System
h. Fire Protection System
i. Starting Package Oil System
j. Ventilation System
Instrumentation Diagram, Auxiliary Systems
Foundation Loading Diagram, Start Skid
Foundation Loading Diagram, Ladder & Platform
General Arrangement, Start Skid
General Arrangement, Ladder & Platform
Abbr., Symbols & Ref. Data, Electrical

Document
One Line Diagram
Three Line Diagram, Generator Metering Protection Relaying
Schematic, Generator Excitation System
One Line Diagram, Motor Control Center 480V
Schematic, Motor Control Center AC/DC
Equipment Drains
Starting Motor Schematic
Motor Schedule
Interconnection Wiring Diagram
Control System, Detail Tech. Spec.
Arrangement Drawing, Control Panel
Logic Diagram, Turbine Control (Multi-Sheet)
Plan and Evaluation, Electrical Package
Installation Drawing, Electrical Package
Foundation Loading, Electrical Package
Logic Diagram, Fire & Halon Protection
Final Spare Parts List
Operation & Maintenance Manuals
System Wiring Diagram, Generator Excitation
Conduit/Wiring Diagram, Mechanical Package
Wiring Diagram, Auxiliary Motors
Conduit/Wiring Diagram, Turbine Enclosure
Wiring Diagram, Turbine Dual Fuel System
Wiring Diagram, Turbine Vibration System
Conduit/Wiring Diagram, Turbine Pipe Packages
Wiring Diagram, Turbine Controls (Multi-sheet)
Wiring Diagram, Turbine Fire & Gas Protection
Arrangement, Lineside Cubicle
Wiring Diagram, Neutral Cubicle
Wiring Diagram, Turbine Control Room
Conduit & Wiring Diagram, Main Turbine/Generator Terminals Box
Wiring Diagram, Lighting & Low Voltage Dist.
Wiring Diagram/Switch Development, Generator Control Panel
Test Reports

1.1.6.5 Intentionally Omitted

1.1.6.6 Operation and Maintenance Manuals

1.1.6.6.1 Twelve (12) sets of Operation and Maintenance Manuals shall be provided to the Owner. These manuals shall contain explicit explanatory information and instructions for the proper installation, operation and maintenance of all equipment provided by the Contractor.

1.1.6.6.2 The Operation and Maintenance Manuals shall contain, as a minimum, the following material for all equipment:

- Installation Instructions.
- Operating Instructions including Safety Precautions.
- Preventative Maintenance Schedule.
- Inspection Procedures.
- Trouble Shooting Guide.
- Compressor Cleaning Instructions.
- Cross Section Drawings of Major Components.
- All Fluid Systems Schematics.
- Control Logic Diagram.
- Electrical Wiring Diagrams.
- Vendor Operating and Maintenance Manuals.
- Parts Lists.
- Illustrated Parts Breakdown.

1.1.6.7 Detail Drawing Requirements

1.1.6.7.1 Unit One-Line Diagram. The one-line diagram shall contain a simplified electrical schematic of the power system from generator ground to the Owner's high voltage bus including protective relaying, excitation system and synchronizing system. Also shown on this drawing shall be auxiliary power systems with schematic display of distribution panels. Device nomenclature shall follow the IEEE Standard for electrical switchgear. The purpose of this drawing shall be to define for system coordination protection functions, operational functions (synchronization, breaker closure, load control), short circuit limitations and auxiliary power requirements.

1.1.6.7.2 Electrical Connection Drawing. The electrical connection drawing shall contain dimensional data concerning location of gas turbine power plant equipment junction boxes, receptacles, cutouts, electrical devices requiring field interconnections and ground stud locations. Cable routing through conduit embedments shown on the foundation interface drawing shall also be shown on this drawing. The purpose of this drawing shall be to provide all necessary information to allow the Owner to determine cable trench and conduit needs for Contractor supplied cables/wiring. The drawing shall identify all routing of Contractor supplied cable through the foundation conduit embedments.

1.1.6.7.3 Cable Block Diagram. The cable block diagram shall contain information for interconnecting cables and wires connected to the Contractor's supplied equipment. It shall indicate "from/to" information, cable size for Contractor supplied cables and voltage level requirements, information for the Owner to supply interconnecting cable/wire not furnished by the Contractor.

The purpose is to define requirements for the Contractor supplied cables/wires and necessary information for installation bids.

1.1.7 Maintenance Schedule and Spare Parts

1.1.7.1 Maintenance Schedule

The Contractor shall furnish his recommended schedule of routine maintenance to maintain maximum equipment reliability. He shall also include a schedule of periodic or anticipated maintenance steps during the first six years of ownership and operation.

1.1.7.2 Intentionally Omitted

1.1.7.3 Special Tools

A. Special tools required for operation and maintenance of the units shall be furnished with the units. This shall include all necessary tools for performing routine maintenance, hot section inspection, fuel manifold nozzle and combustor replacement, generator rotor removal, and first row vane replacement.

B. Contractor will furnish any special tools required for erection of the units. These tools will remain the property of the Contractor.

1.1.7.4 Intentionally Omitted

1.1.8 Field Support

1.1.8.1 Installation and Start-Up

1.1.8.1.1 Contractor shall provide the services of a qualified field service technician at the installation site for the duration of installation/check-out to assist in the installation, check-out, and start-up of the turbine/generator, the switchgear, and all auxiliary equipment.

1.1.9 Intentionally Omitted

THE 501F
ADVANCED COMBUSTION TURBINE
DEVELOPMENT/TESTING/IMPLEMENTATION

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ABSTRACT

The 501F engine is a high temperature industrial grade advanced combustion turbine jointly developed by Westinghouse Electric Corporation and Mitsubishi Heavy Industries, LTD. Initial offering of the engine is in the 150 MW size range. Full load shop tests of the new engine were successfully completed at MHI'S Takasago Machinery Works in the summer of 1989 and again, due to an opportunity provided by the delivery schedule of the prototype engine, in August of 1991. Design enhancements were incorporated into the engine through continuous development efforts since the first full load shop test. This paper includes a description of the engine, including pre-501F and unique 501F features, a discussion of the design enhancements incorporated since the first shop test, and a description of the second full load shop test along with a discussion of the results of the testing. The current status of the first 501F project, commissioned in the spring of 1993, is presented which includes a discussion of the prototype start-up activities and operating experience to date. The paper concludes with a discussion about future development plans for the 501F engine.

INTRODUCTION

Detailed design, component testing, prototype manufacturing, and two full load shop tests for the 501F advanced combustion turbine were completed between January 1987 and July 1991. The engine incorporates advances in aerodynamic design, turbine cooling technology, and mechanical design concepts. After the first shop test, design enhancements were implemented to further improve engine performance and reliability. The second shop test verified the new design enhancements and provided valuable information for future engine development. The engine is a 150 MW class high temperature engine with exhaust temperatures that are amenable to combined cycle applications. The engine will operate on all conventional combustion turbine fuels, incorporating dual fuel nozzles and technology when requested, and will also operate with coal derived low BTU gas produced in an integrated gasification combined cycle power plant.

Testing, an integral part of any engine development program, included advanced technology component verification tests, full load shop tests, and prototype field tests.

The first four engines manufactured, including the prototype engine, were installed as part of a repowering project for a domestic US utility. The engines were installed, completed field testing, and were declared commercial in May and June of 1993.

This paper gives a description of the engine, discusses results of each of the two full load shop tests and component verification testing, and provides a summary of commissioning activities and commercial operation status of the prototype plant.

501F DESCRIPTION

The 501F engine, as shown in Figure 1, is the most recent in a series of single shaft heavy duty industrial gas turbines designed and manufactured by Westinghouse and its alliance partner. The engine incorporates many proven design concepts included in the 501 series since the first 501A engine started in 1968. These include features such as cold end drive, horizontally split casings for ease of maintenance, two bearing rotor, and axial exhaust. Additional features of the 501 series engines have previously been described by Entenmann et al (1991). The engine has additional unique features which will improve the reliability, availability, and maintainability of the engine as well as allow a significant increase in rotor inlet temperature (RIT). Some of the more significant features include:

- COMPRESSOR BLADE LOCKING FEATURE THAT IS VISIBLY INSPECTABLE.

- BLADE RINGS IN THE COMPRESSOR SECTION FOR EASE OF MAINTENANCE AND TO OPTIMIZE CYLINDER TO ROTOR ALIGNMENT.

- ADVANCED COMBUSTOR SYSTEM INCORPORATING LOW NOx FEATURES.

- COMBUSTOR TRANSITION COOLING SCHEME WHICH INCORPORATES THE BENEFITS OF ASYMMETRIC EXTERNAL COOLING CHARACTERISTICS OF COMBUSTOR SHELL AIR FLOW.

- A BOLTED COMPRESSOR ROTOR DESIGN TO INCREASE ROTOR DYNAMIC STABILITY MARGIN AS WELL AS FACILITATE FABRICATION AND MAINTENANCE OF THE ROTOR.

- COOLED STAGE 3 STATOR VANE SEGMENT AND ROTATING TURBINE BLADE TO IMPROVE RELIABILITY.

- A NEW 16 STAGE HIGHLY EFFICIENT AXIAL COMPRESSOR INCORPORATING LARGER DIAMETER REAR STAGES TO ADDRESS SPINDLE THRUST BALANCE AND TWO EXIT GUIDE VANES TO STRAIGHTEN THE FLOW EXITING THE COMPRESSOR.

- A TURBINE FLOW PATH THAT WAS DESIGNED UTILIZING A FULLY THREE DIMENSIONAL FLOW ANALYSIS.

- A REVISED JOURNAL BEARING DESIGN CONSISTING OF A TWO-ELEMENT TILTING PAD FOR LOAD CARRYING AND AN UPPER HALF FIXED BEARING TO ADDRESS TOP PAD FLUTTER AND RELATED LOCAL BABBIT SPRAGGING.

- LEADING EDGE GROOVE (LEG) DIRECT LUBRICATED THRUST BEARING TO REDUCE THE REQUIRED OIL FLOW AND ASSOCIATED

MECHANICAL LOSS.

- INTEGRAL "Z" TIP SHROUDS ON THE 3rd AND 4th STAGE TURBINE BLADES TO REDUCE THE POTENTIAL FOR FLOW INDUCED NON-SYNCHRONOUS VIBRATION.

- STATE-OF-THE-ART TURBINE COMPONENT COOLING SCHEMES TO INCREASE RELIABILITY AND OVERALL ENGINE EFFICIENCY.

COMPONENT VERIFICATION TEST PROGRAM

Critical components unique to the 501F engine were tested independently prior to design finalization to verify performance and reliability. Special test rigs and facilities were used. Testing included rotating blade vibration tests, turbine aerodynamic tests, combustion system testing, and turbine cooled parts heat transfer tests.

Rotating Blade Vibration Test

Natural frequencies and vibratory stresses of compressor and turbine blading for selected stages were recorded during high speed rotor balancing testing to determine if the blades were tuned properly. An optical fiber measuring system was used for compressor blading and a telemetry system was used for turbine blades. Analysis of all the recorded data confirmed that the blades were well tuned.

Turbine Aerodynamic Testing

The aerodynamic performance of each stage was verified via a series of tests, including a two dimensional cascade test to measure stage averaged loss coefficient, an annular cascade test using a scale model of the stage 1 vane segment to determine the flow coefficient of that component, and a scale model rotor of the fourth stage blade to determine the effects of the fully three dimensional analysis techniques used in the turbine design. The data confirmed that the original design objectives were satisfied. Figure 2 shows the model test rotor.

Combustion System Testing

Prior to the shop tests, basic characteristics of the combustion system, such as flame propagation, exhaust emissions, pattern factor, combustor wall temperature, and dynamic pressure oscillation, were investigated in both atmospheric and high pressure tests. Figure 3 shows the high pressure combustor test facility.

Turbine Cooled Parts Heat Transfer Test

Many advanced cooling techniques are incorporated into the 501F hot parts in order to maintain metal temperatures within the appropriate design criteria. Figure 4 shows the cooling design for the first stage vane and blade. In order to verify the pin fin array and shower head cooling effectiveness prior to finalizing the design, scale model tests were conducted. In order to verify the cooling effectiveness of the final design for the stage 1 vane and blade, hot cascade tests were performed. The results of the tests confirmed design calculations.

SHOP TEST PROGRAM

The objective of the first full load shop test, conducted in the summer of 1989, was to verify the following engine operating characteristics and develop the optimum control setting schedules for system components. The engine characteristics studied were: starting characteristics, including light-off, acceleration, vibration, and surge margin; performance, including individual compressor, turbine, and overall CT performance; exhaust emissions; hot parts metal temperatures; mechanical characteristics, including blading vibratory stresses, casing temperatures, axial and radial growths.

The engine was coupled to a 162MVA generator and all the auxiliaries associated with the test were shop facilities. Distillate oil was used as the fuel. The compressor air supply inlet system included a bell-mouth inlet to accurately measure air flow and the electrical power generated during the test was absorbed by a water rheostat with cooling towers. Figure 5 is a sketch of the general arrangement of the facility.

Between the first and second shop tests, design enhancements were incorporated into the engine, most of which were based on data reduction from the first test results. Static cooling circuits were optimized resulting in a net reduction in cooling air usage, which would result in a more efficient turbine. The airfoil surfaces of coated blades and vanes were polished to reduce flow losses and hence improve turbine efficiency. In addition, a new combustion system was available for use in the 501F, the FDF-42 combustion system. The system incorporates low NOx features, was developed for dual fuel applications, and incorporates advanced cooling schemes in the combustor basket and the transition, called "PLATEFIN" and MTFIN". Figure 6 shows the new combustion system.

The objectives of the second shop test were to verify the design enhancements incorporated since the first test , including an assessment of the impact on engine performance, emissions, and noise levels, and verify the new combustion system.

Shop Test Data Acquisition System

In addition to the normal supervisory instrumentation, more than 1500 pieces of instrumentation were installed on the engine for first shop test and more than 1000 for the second. Included were advanced instrumentation systems such as an accufiber probe for monitoring turbine inlet temperature, an optical pyrometer for monitoring stage 1 turbine blade metal temperature, and an optical fiber compressor blade vibration monitoring system. A summary of the special instrumentation is presented in Figure 7 and Table 1 presents the purpose for and type of measurements taken during the second shop test.

Full Load Shop Test Results

Figure 8 presents FDF-42 combustor system metal temperatures measured during full load operation and Figure 9 presents the outlet gas path profile for the second test. All the combustor system metal temperatures measured satisfy design criteria and the shape of the profile will result in increased combustor transition and downstream hot parts durability.

Figure 10 presents NOx emissions levels for the new FDF-42 combustion system on oil fuel with steam or water injection. All emissions characteristics, including Oxides of Nitrogen (NOx), Carbon Monoxide (CO), Unburned Hydro-Carbons(UHC), Volatile Organic Compounds (VOC), and Backrack Smoke Number (BSN), met their respective design targets with injection ratios less than or equal to design targets.

Power and heat rate improved significantly from the first test. Cooling circuit enhancements described earlier were verified via performance and metal temperature measurements during testing. Figure 11 presents stage 3 vane metal temperatures for both the first and second shop tests. During the second shop test, the cooling flows to the third and fourth stage vane segments were less than those used during the first test yet metal temperatures satisfied design criteria.

Figure 12 summarizes rotor dynamics response during start-up. Vibration levels were very low during acceleration to running speed, less than .05 MM (.002 IN.), and were lower during rated speed operation as expected.

Vibration characteristics of the 1st and 2nd stage turbine blades were verified via telemetry instrumentation. Figure 13 shows the measured stress levels in comparison with allowable stresses for all stages of the turbine, including the first shop test data. Measured stress levels are well below allowable stress levels. Blade frequency and damping factors were also verified during the test.

510F OPERATING PLANT STATUS

A total of twenty five 501F/701F technology engines are on order with seven in commercial operation (9/93), the first of which was a 701F engine (50 Hz) and was started in June of 1992. The same engine is the first application of a new dry low NOx combustion system with "F" technology and has demonstrated capabilities to achieve 25 ppm NOx dry in commercial operation. This system is currently being adapted to other "F" technology machines as well as 501D5 engines.

The prototype 501F plus three other engines were installed as part of a repowering project. The engines first rolled and supported steam blows in December of 1992 and, after preoperational testing, went commercial in the spring of 1993. Some engine related issues occurred during the commissioning activities and were addressed and resolved prior to commercial operation. Air separator and combustion system modifications were developed and implemented on all four engines during the commissioning process. Table 2 presents reliability and availability statistics for the engines, auxiliaries, steam turbines, and overall site for the time between commercial operation and the first scheduled inspection outage. The engines were extremely reliable during this first commercial run and bettered all RAM (Reliability, Availability, Maintainability) analysis predictions for the project.

FUTURE DEVELOPMENT PLANS

We are continuing to evaluate design modifications to increase the performance capabilities of the 501F engine, considering such areas as material technologies, cooling design technology, compressor and turbine performance technologies, and mechanical design technology. For example, the 501F currently has equiaxed materials throughout the turbine hot section. There are ongoing programs between Westinghouse and Mitsubishi to develop advanced alloys and material processing techniques, such as directionally solidified (DS) and single crystal (SC) technologies, which will result in increased performance for the 501F via either reduced cooling requirements or increased firing temperatures. With respect to cooling technologies, we are jointly developing cooling schemes even more advanced than those incorporated into the current 501F design.

Along with advances in design technology, we are also continually advancing manufacturing technology used in producing the 501F. The improvement in design and manufacturing technologies will result in higher performing, more reliable, cost effective engines.

SUMMARY

The 501F engine design, including a new combustion system, was verified via two full load shop tests. The overall objectives of the tests were satisfied in that the performance and emissions characteristics of the engine were verified, the new combustion system was evaluated and performed well, and the design enhancements incorporated before the second test were verified. Both power and heat rate performance improved since the first test and the dynamic response of the rotor was demonstrated to be excellent. Current operating statistics for the 501F prototype indicate a very reliable engine. Future plans for 501F development include additional material, cooling, and combustor system capabilities which will enhance engine performance and reliability. We will continue to develop 501F technology and incorporate associated design enhancements into future engines.

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Entenmann, D.T., Hultgren, K.G., Smed, J.P., Aoyama, K., Tsukagoshi, K., and Umemura, S., "501F Development Update", ASME Paper 92-GT-237, June 1, 1992.

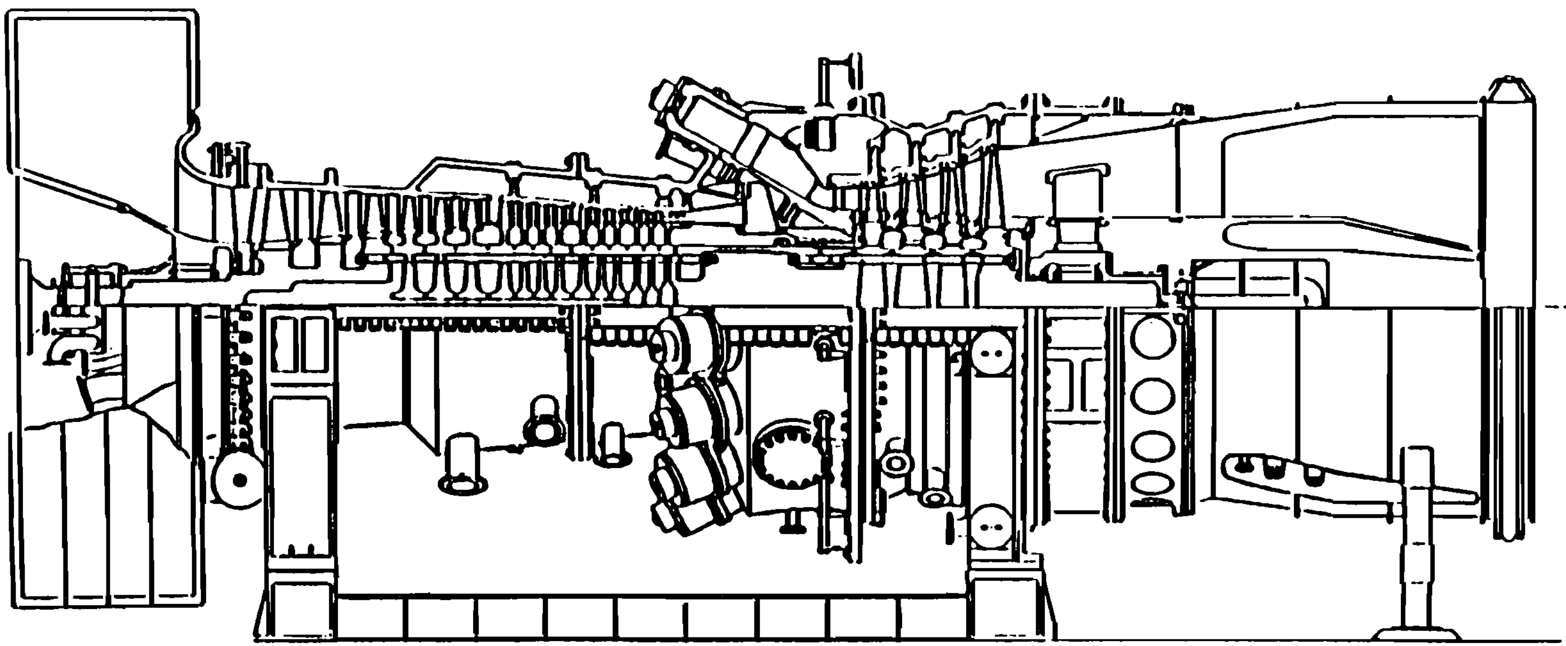


Figure 1. 501F Longitudinal Section

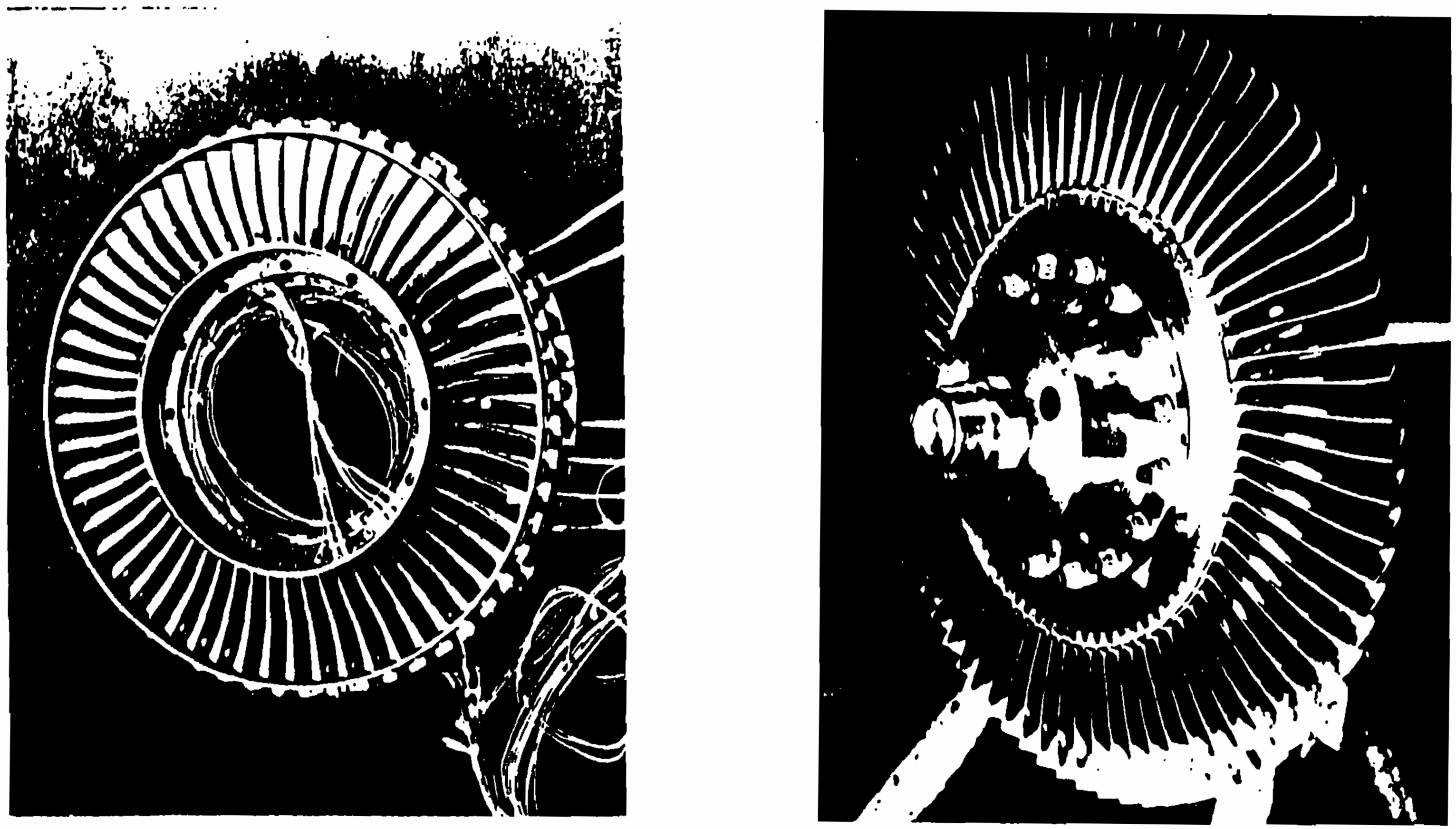


Figure 2. Model Test Rotor

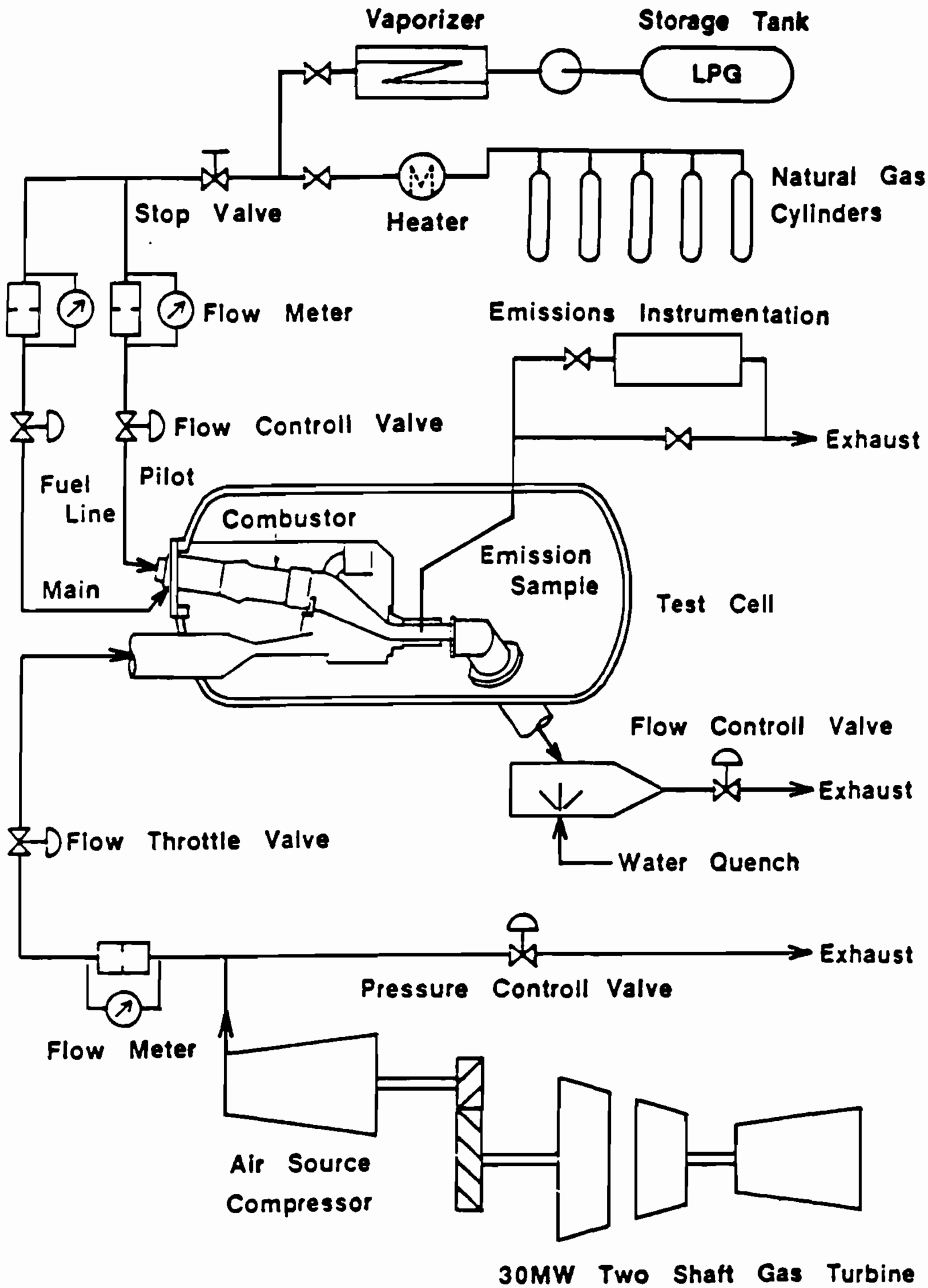


Figure 3. Schematic of Combustion Test Facility

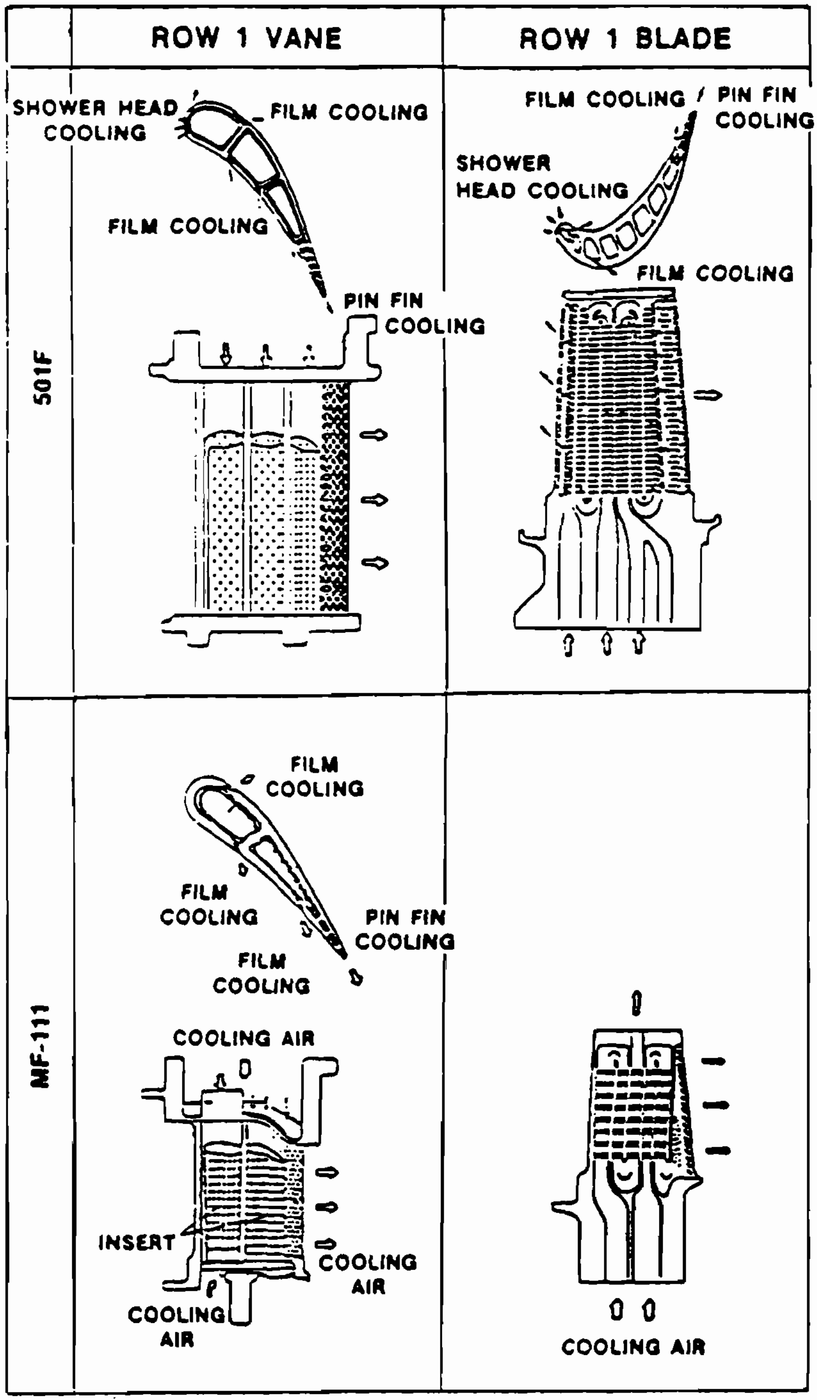
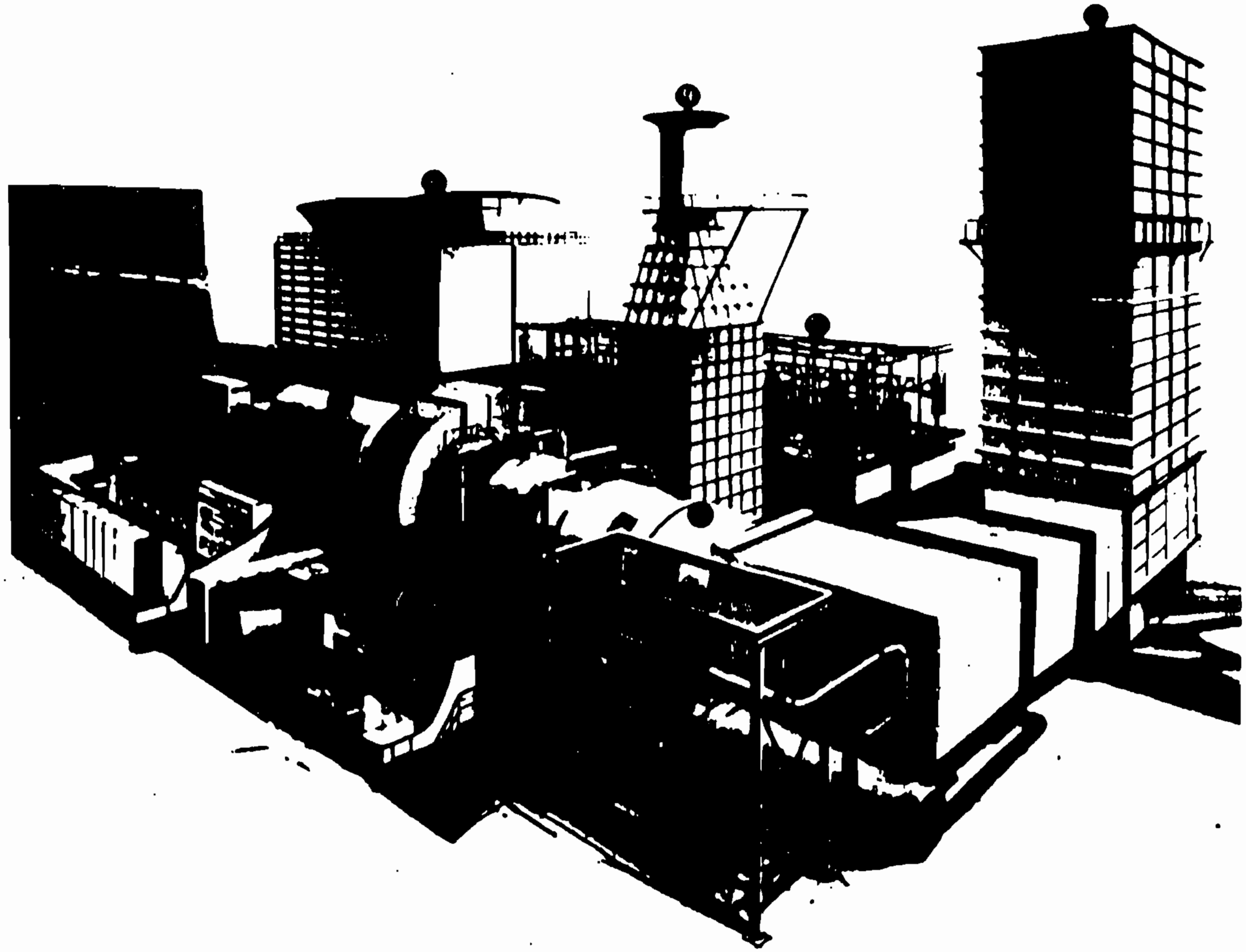


Figure 4. Cooling Scheme for 501F and MF-111



GENERAL ARRANGEMENT

1. GAS TURBINE
2. GENERATOR
3. EXCITER
4. STARTER
5. G/T CONTROL ROOM
6. SPECIAL INSTRUMENTATION ROOM
7. COOLING AIR COOLER
8. COOLING TOWER
9. AIR INTAKE TOWER
10. WATER RHEOSTERT
11. EXHAUST TOWER

Figure 5. General Arrangement of the 501F Test Facility

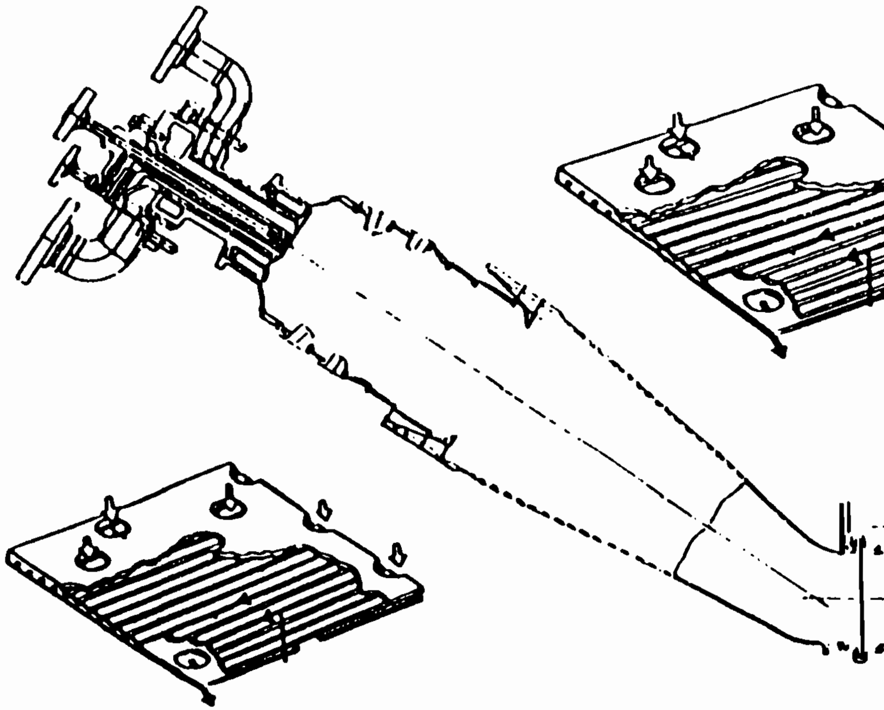


Figure 6. Combustion System Configuration

(A) PERFORMANCE

1 AIR FLOW
2 INLET TEMP. & PRESS
3 EXHAUST TEMP. & PRESS
4 FUEL FLOW
5 GENERATOR OUTPUT
6 COMPRESSOR
  (SURGE MARGIN
  (STAGE EFF.
7 TURBINE
  (STAGE EFF.
  (DIFFUSER EFF.

(B) METAL TEMP.

8 COMBUSTOR BASKET
9 TRANSITION PIECE
10 TURB. ROW 1 BLADE
11 TURB. ROW 1-4 VANE
12 BEARING METAL
13 OUTER CASING
14 INNER CASING
15 EXHAUST CYLINDER

(C) STRESS/VIBRATION

16 COMPRESSOR BLADE
17 COMPRESSOR VANE
18 COMBUSTOR BASKET
19 TRANSITION PIECE
20 TURBINE BLADE
21 ROTOR VIB.
22 CASING VIB.
23 ROTOR TORSIONAL VIB.

(D) OTHERS

24 COOLING AIR NETWORK
- FLOW
- TEMPERATURE
- PRESSURE

25 TRUST LOAD
26 EXHAUST EMISSION
27 ROTOR/CASING EXPANS
28 NOISE
29 LUBE OIL TEMP.

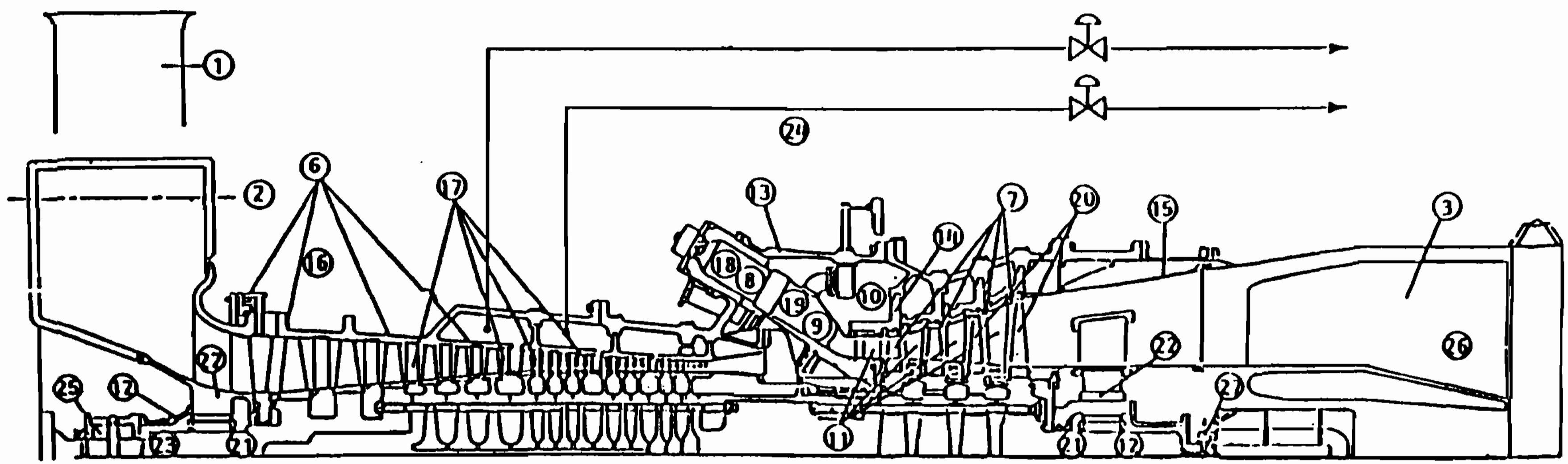


Figure 7. 501F Prototype Special Measurements

MEASUREMENT PURPOSE	NUMBER OF MEASUREMENTS						
	TEMP.	PRESS	HUMID	D PRESS	STRESS	CLEAR	OTHER
OVERALL PERFORMANCE	26	28	2				
COMPRESSOR PERFORMANCE	38	39		5		6	
TURBINE PERFORMANCE	52	42				10	
COMBUSTOR RELIABILITY	113			4	13		
TURBINE RELIABILITY	172				15		
ROTOR RELIABILITY						3	
COOLING AIR CIRC + BLEED LINES	138	102					
EXHAUST GAS INGREDIENTS	1						2
NOISE							16
BEARING RELIABILITY	20						
CASING RELIABILITY	180					2	
LUBE OIL LINES							
CONTROL							
SHAFT VIBRATION							
TOTALS	740	211	2	9	28	21	18
TOTAL MEASURES 1029							

Table 1. 2nd 501F Shop Test Measurements

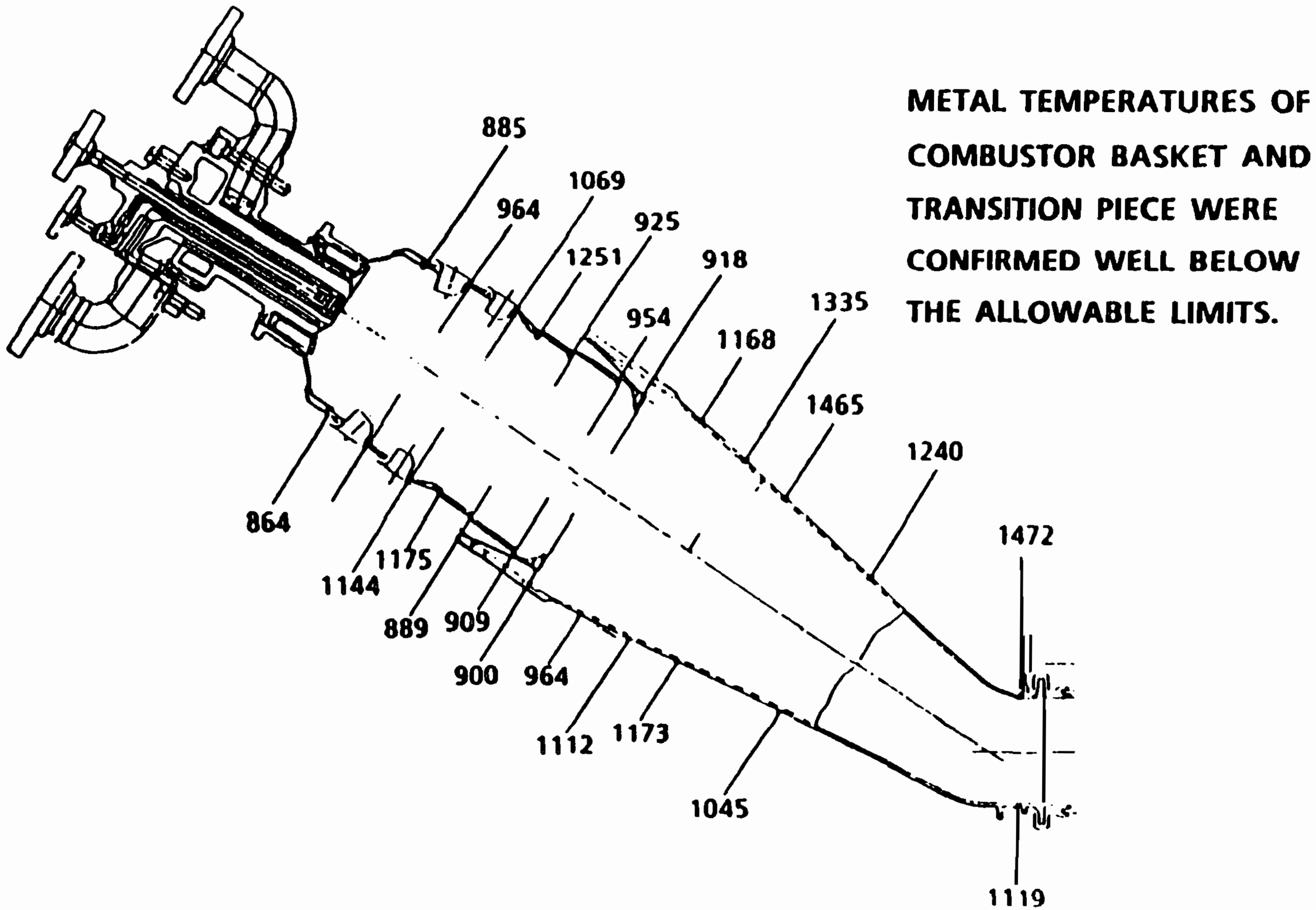


Figure 8. Combustor Metal Temperatures

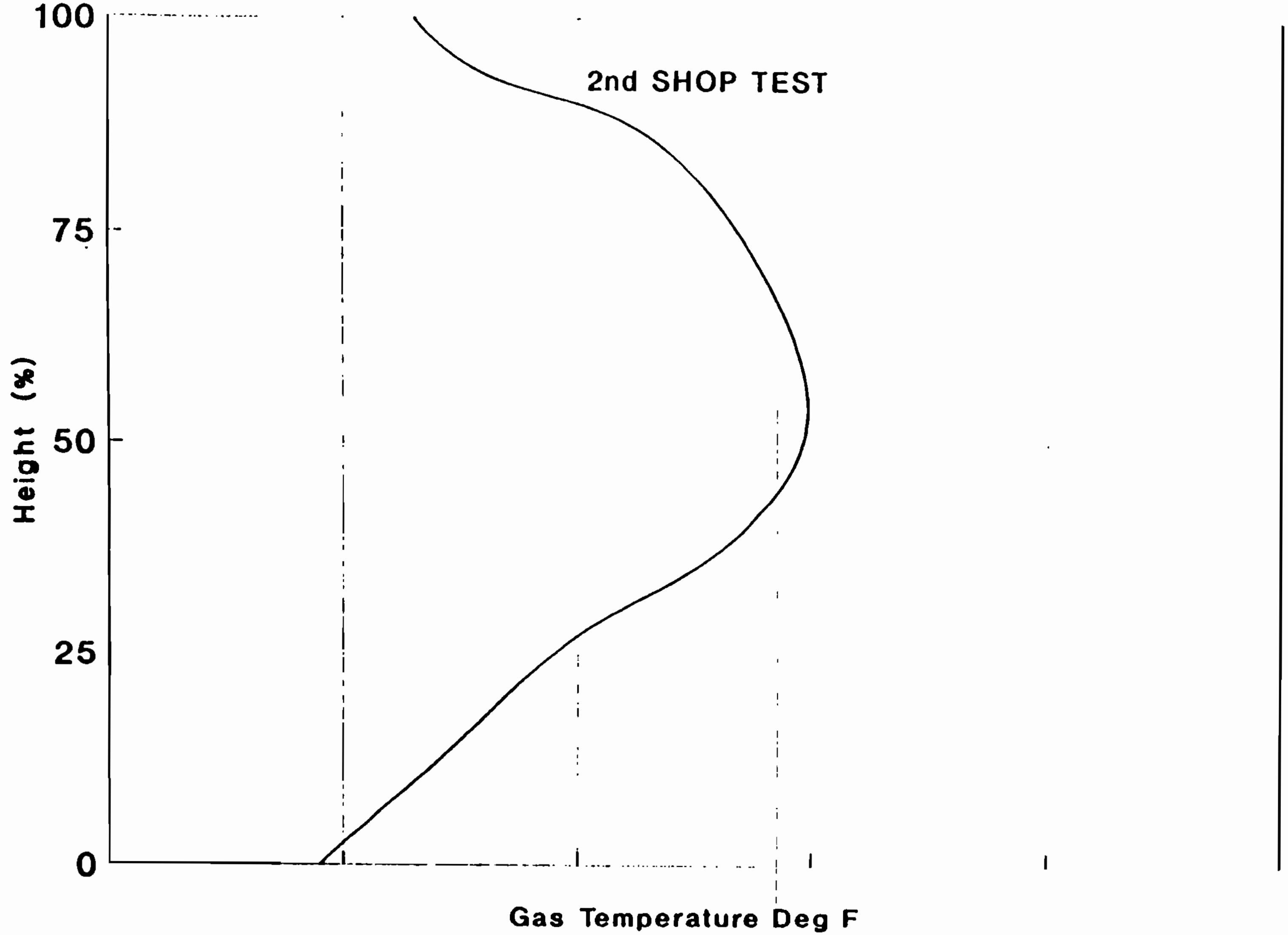


Figure 9. Gas Path Temperature Profile.

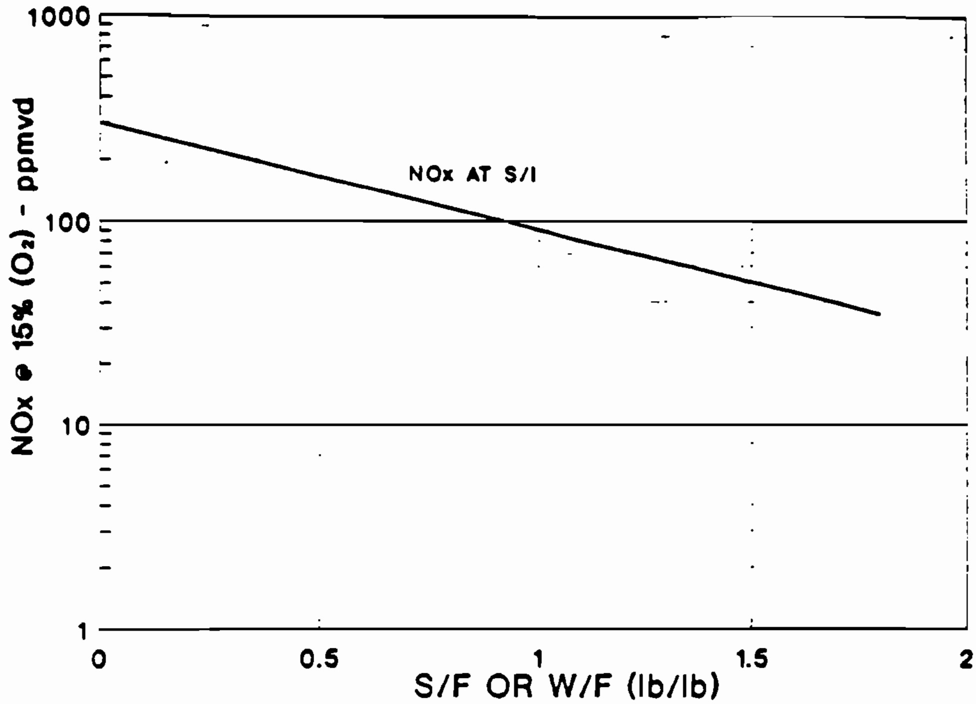


Figure 10. Emissions Characteristics

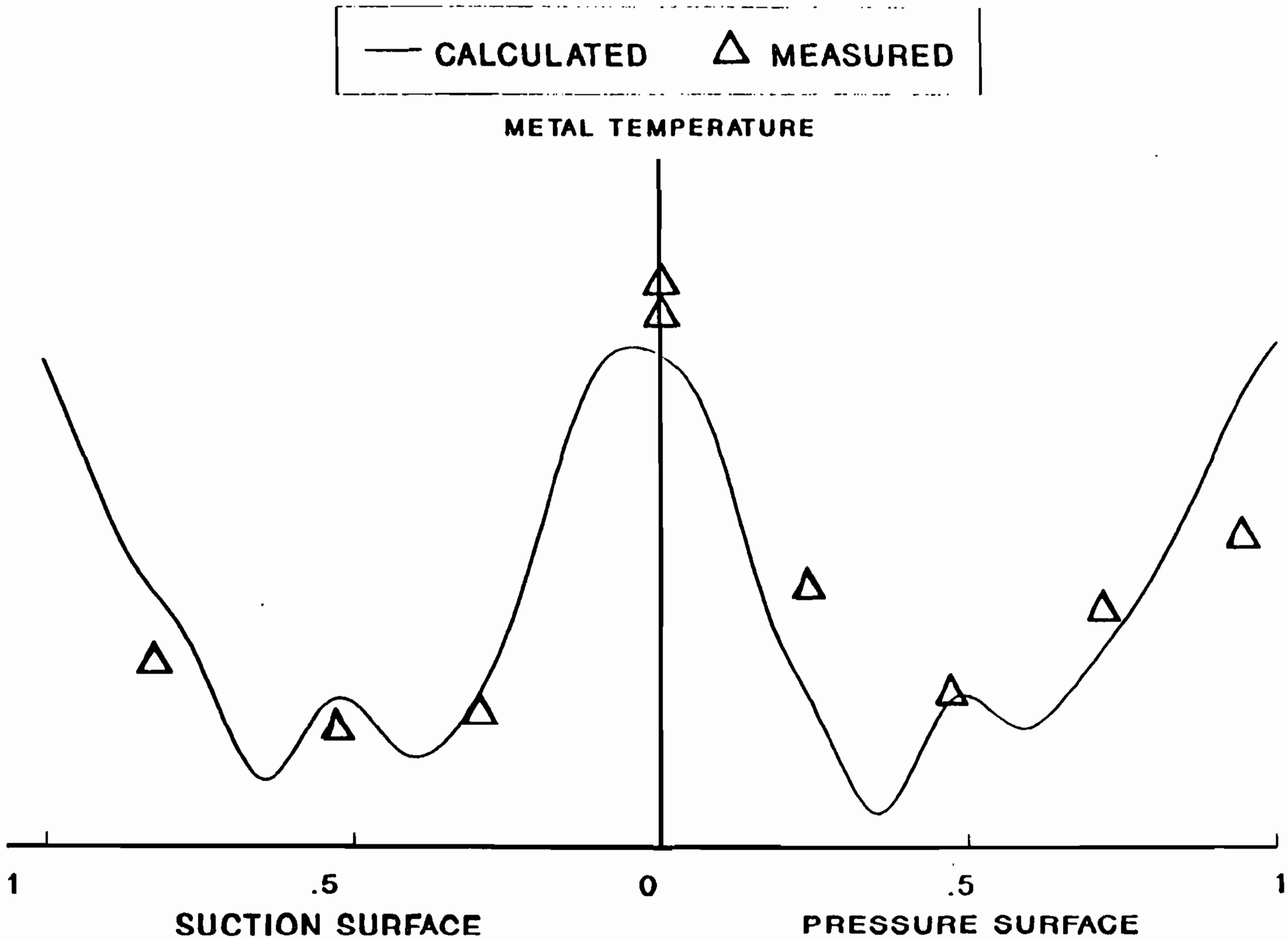


Figure 11. Row 3 Vane Metal Temperature

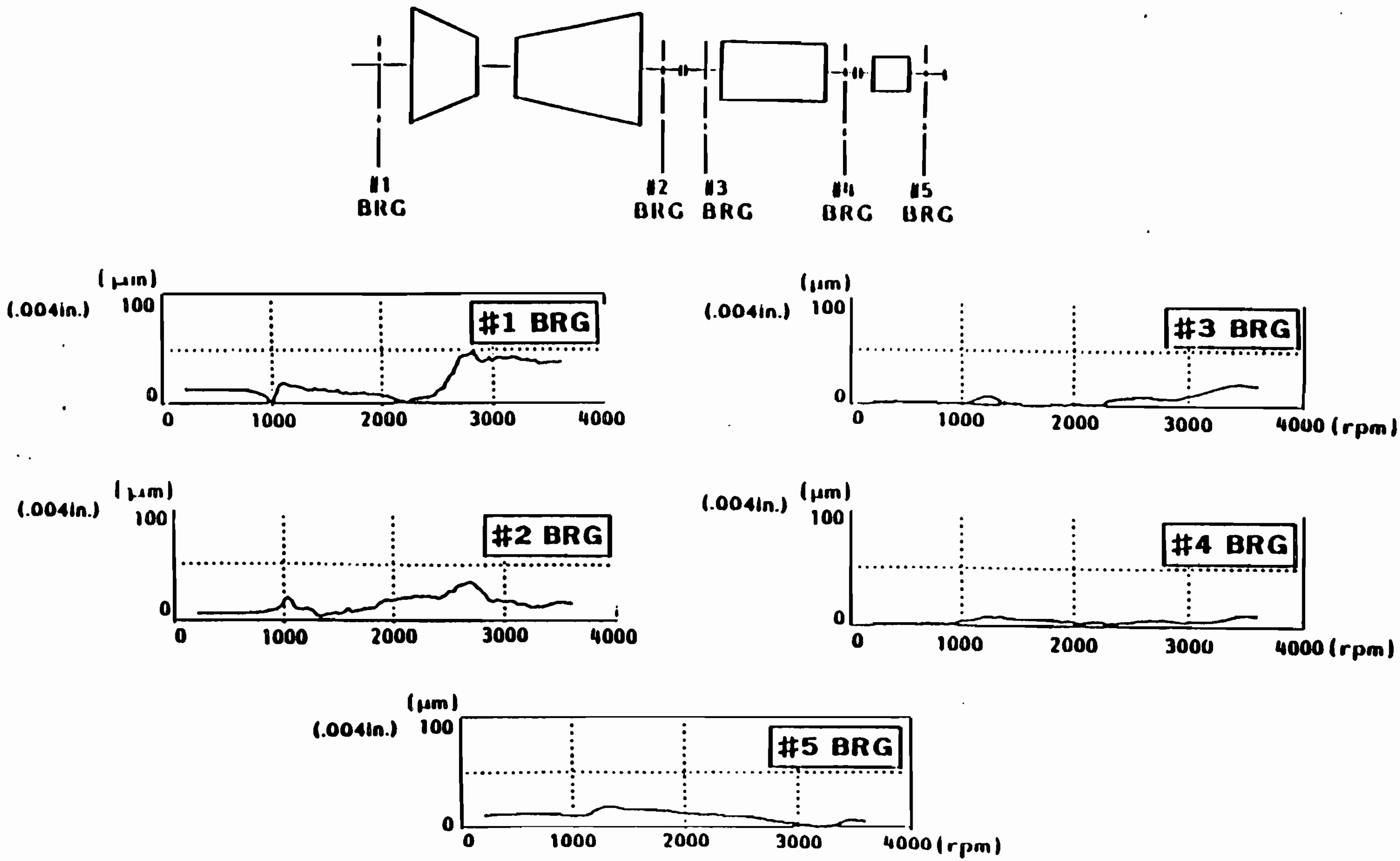


Figure 12. Rotor Vibrations (Relative, Peak to Peak)

94-GT-474

UPRATED 501F GAS TURBINE, 501FA

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Abstract

This paper introduces the engineering approach taken in developing the 501FA gas turbine, which is an uprated version of the existing 501F 150MW class gas turbine. The concepts and procedures which were utilized to uprate this gas turbine are also presented. To achieve better performance, new techniques were incorporated which reflected test results and operating experience. No advanced technologies were introduced. Instead, well experienced techniques are adopted so as not to deteriorate reliability. Improvement of the performance was mainly achieved mainly due to the reduction of cooling air. Tip clearances were also optimized based on shop test and field results.

1. Introduction

When adopting new features, the most important consideration is whether these features have been verified thoroughly in actual engine application, shop tests or component testing. The 501FA gas turbine is an uprated version of the 501F gas turbine designed for 60Hz applications. The first shop test was performed in 1989, after which the first four units were shipped to Florida, USA where they have been providing operating experience since December of 1992. Another two units started operation in May of 1993 at Kyushu Electric, Japan. In 1992, the 701F gas turbine, which is a scaled engine of the 501F for 50 Hz applications, started commercial operation at the Mitsubishi Kanazawa Power Station and verified the concepts of new dry low NOx combustion system at a rated turbine inlet temperature of 1350°C. The technologies developed in the process of designing the 701F can also be introduced into the 501FA. Based on the experiences above, the 501FA's targeted higher performance will be achieved by improving the basic design and by the implementation of new techniques.

Improvement in performance of the 501FA is achieved mainly by reducing the total cooling air usage flow and reduced tip clearances in the turbine and compressor. For compatibility of hot parts between the 501FA and 501F, the flow path was not changed and provides the users of existing 501F engine with an opportunity to upgrade their engines and incorporate the 501FA improvements.

The first 501FA engine will start commercial operation in February of 1997 in the United States. In addition to performance tests planned for the first engine, a series of laboratory tests will be carried out on selected components to verify and further support the design changes incorporated in the 501FA.

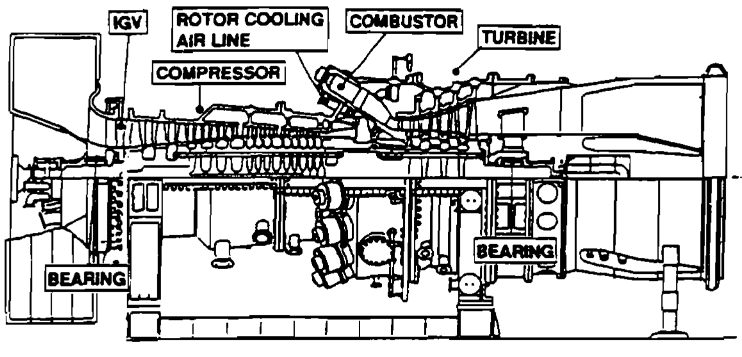

Figure 1 501F/501FA Longitudinal section

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The Hague, Netherlands – June 13–16, 1994

2. Design Review of the 501F

The first part of the paper is a brief review of the current 501F design so that the new features of the 501FA can be clearly understood. The 501F is a 15O MW class 60 Hz engine jointly developed by Mitsubishi Heavy Industries, Ltd. and Westinghouse Electric Corporation. Basic rotor construction entails a sixteen stage compressor that is spigotted and bolted together by 12 thru bolts, plus a four stage turbine section whose disks are aligned using CURVIC' couplings and also held together by 12 thru bolts. The CURVIC coupling consists of toothed connection arms that extend from adjacent discs and interlock providing precise alignment and torque carrying features. The compressor has three interstage bleeds for starting and cooling and variable inlet guide vanes for surge control and improved part-load performance. In the turbine, the forward three stages of vanes and blades are cooled. Shrouded interlocked turbine blades are used in the third and four stages. Rotor cooling is accomplished by the use of an external cooler. the basic longitudinal section is shown in Figure 1.

The first shop test was conducted in 1989 to verify that the turbine met the design target(Ref.1). Commercial operation started in December of 1992 in Florida, USA. Prior to shipping the first shipping the first units, a second full load test was conducted(Ref.2).

Supplementing these design tests on the 501F was data from the 701F, a 50 Hz engine, started operation in 1992 at the Mitsubishi Kanazawa Power Station near Tokyo, Japan. At this site, a new dry low Nox combustion system with multi nozzles was installed and verified. The resulting NOx level was 25ppm at a firing temperature of 1350°C(Ref.3). Since the 501F and 701F use the same basic hardware, the technology of low NOx combustion system developed for the 701F will be applied to the 501FA.

1.Trademark of Gleason Works

Table 1 Summary of 501FA'S modifications from 501F

PARTS			MODIFICATIONS	REQUIRED ENGINEERING ITEMS
TURBINE	VANE	ROW 1	· Reduced Cooling Air · Thermal Barrier Coating	· Thermal Analyses
		ROW 2	· Reduced Cooling Air · Auto Flow Modulation	· Thermal Analyses · Flow Network Analyses
		ROW 3	· Auto Flow Modulation	· Flow Network Analyses
	BLADE	ROW 1	· Reduced Cooling Air · Thermal Barrier Coating · Cascading System	· Thermal Analyses · Estimation of Creep Rupture · Flow Network Analyses
		ROW 2	· Reduced Cooling Air	· Thermal Analyses · Estimation of Creep Rupture
		ROW 3	· Reduced Cooling Air	· Thermal Analyses · Estimation of Creep Rupture
	#1 RING SEGMENT		· Optimized Cooling Scheme · Reduced Tip Clearance	· Thermal Analyses · Estimation of Transient Tip Clearance
	#2 RING SEGMENT		· Abradable Coating for Tip Clearance Reduction	· Estimation of Transient Tip Clearance
	#3, #4 RING SEGMENT		· Thick Honeycomb Seals for Tip Clearance Reduction	· Estimation of Transient Tip Clearances
COMPRESSOR	#7 – #16 STAGE		· Abradable Coating for Tip Clearance Reduction	· Estimation of Transient Tip Clearances
	IGV SETTING		· Increased Air Flow	· Flutter Analyses for Turbine Stage 4

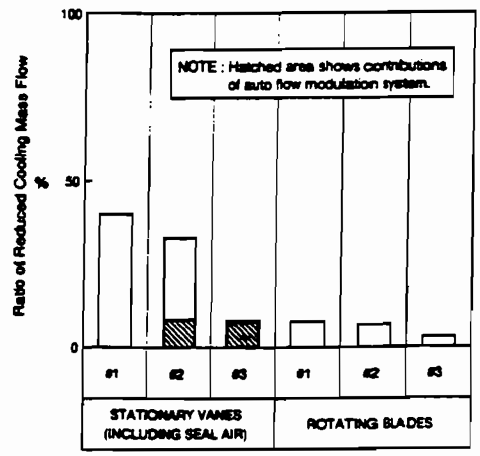

Figure 2 Contributions to performance of reduced cooling air

3. New features of the 501FA

The improvement of performance is achieved by reduction of the cooling air flow rate. Performance improvement due to reduced tip clearances are not included in the uprated performance estimates. The improvement due to reduced tip clearances is considered to be a margin. Table 1 summarizes the design changes made to the 501FA. The following discussion describes the design changes in more detail.

3-1 Reduction of cooling air

In this paper, cooling air is usually categorized into seal air and cooling air for blades and vanes. Thus, the explanation has been divided into two portions. Contributions of reduced cooling air to incremental gains in performance are shown in Figure 2 on a percentage basis. Overall, cooling has been reduced by approximately 10 percent.

(A) Reduction of seal air

The function of the seal air is to protect the rotor and the stationary hot parts from hot gas ingestion by pressurizing internal cavities. The amount of cooling air has significant effects on the cooling effectiveness of cooled vanes and blades. Therefore, any reduction should be done based on measured data from shop tests such as temperature readings for metal temperature and cavity temperature. The most important data for reducing the required seal air was acquired during the flow modulation test in the actual engine. The test was carried out in 1991 at full load condition. In this test, cooling air which was bled from intermediate stages of the compressor was modulated by valves installed in the cooling air circuits. Cavity temperatures were monitored versus cooling flow rate. The data showed that once hot gas ingestion occurs

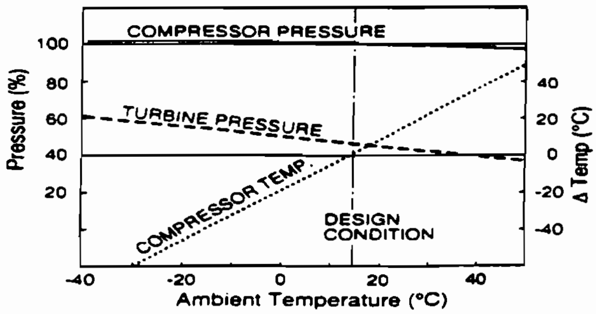

Figure 3 Effect of ambient temperatute on bleed circuit available pressure drop (STAGE 3)

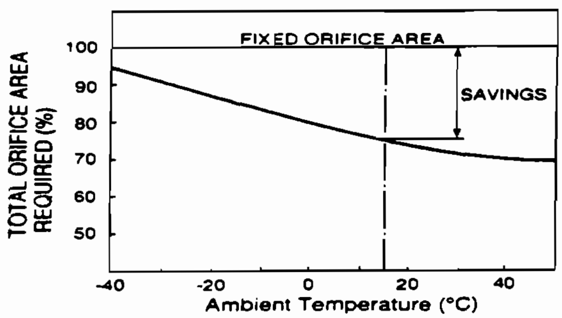

Figure 4 Potential flow savings with modulated bleed flow (STAGE 3)

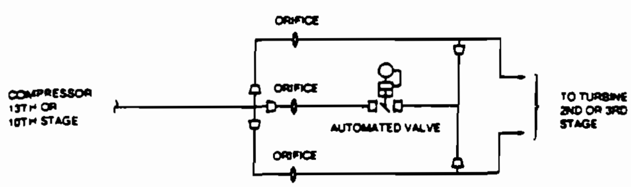

Figure 5 Piping schematics for 501FA second and third stage bleeds

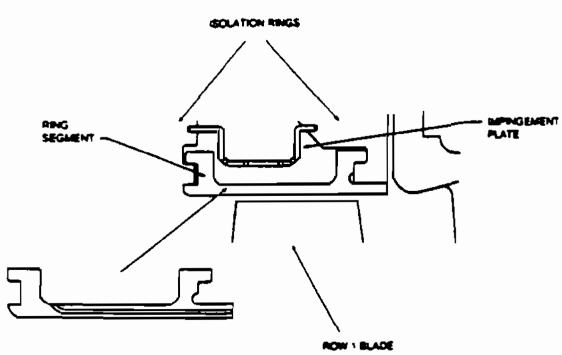

Figure 6 Sketch of ring segment

while modulating flow rate, cavity temperature suddenly increases. Cavity seal air flow requirements are affected by ambient temperature. In general, low ambient temperature requires large amounts of seal flow because of the small pressure difference between the compressor bleed stage and the turbine flow path as shown in Figure 3. On the contrary, high ambient temperature requires smaller amount of seal air. If cooling air is controlled by fixed orifices in the cooling air circuits, excess cooling air is consumed on hot days. This is the concept of auto flow modulation system. The data of the flow modulation test was used to estimate the minimum required seal air flow rate. Potential flow savings are conceptually shown in Figure 4. The figure shows the total orifice area required versus ambient temperature. The system is featured in the 501FA's stage 2 and 3 cooling air circuits. The conceptual system drawing is shown in Figure 5. By monitoring disc cavity temperature, automated valves can continuously adjust amount of cooling air so as to maintain the disc cavity temperature to be below a maximum allowable level. For emergencies such as electrical errors, valve position is set to fail in the open position. The minimum required flow is assured through the valve bypassing lines.

In addition to this, the number of parts were reduced to cut leak air. For example, the turbine of the 501F has isolation rings which support

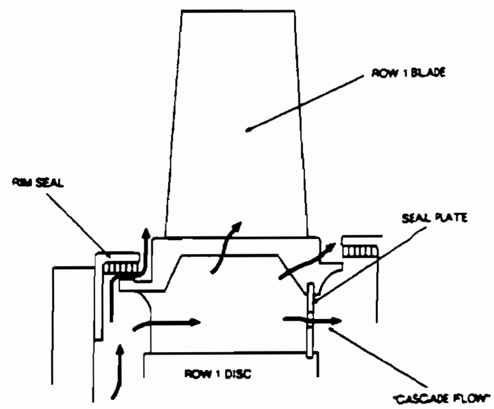

Figure 8 Concept of cascading cooling air system

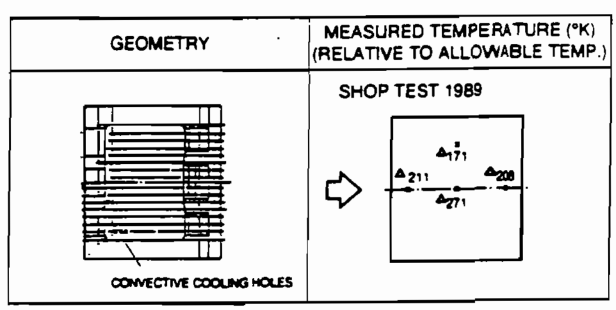

Figure 7 Measurement results of ring segment temperature

vane segments, that are installed between the blade ring and the vane segments as shown in Figure 6. The main function is literally to isolate the blade rings from the hot vane segment. Halving the number of isolation rings can be an effective method in reducing the cooling air leakage.

Some improvements were made to adjust cooling flow distribution in a more effective way. An example is the #1 ring segment. This is a stationary part facing the stage 1 rotating blade's tip, as shown in Figure 6. This is cooled by a multi-hole type convection cooling scheme. At the initial stage of the development, a very conservative cooling design was used due to lack of the information on heat transfer around this region and the uncertainty of the gas temperature distribution. However, it was found that cooling air could be reduced according to the results of the full load shop test. Metal temperature measured for the initial geometry, which has many cooling holes, showed relatively low temperature. Figure 7 shows the results of the measurement. As a result, some holes were intentionally plugged after the test, which resulted in unequally spaced cooling holes. For this uprating, the unequally spaced cooling holes were replaced by a small number of equally spaced ones in order to reduce cooling flow. At the same time, impingement cooling plates were also optimized to meet new geometry.

A cascading system is one method to use seal air effectively. The concept of the system is shown in Figure 8. The principle of the system is as follows. By introducing a certain amount of rim seal air upstream of the first disc through the holes on the exhaust seal plates, the down stream cavity is pressurized by "cascade flow" to minimize the supply air required from the stage 2 vane cooling air circuit. With the cascading system, supply pressure for the second stage can be reduced and seal air can be saved. The advantage is that cooling air can be saved with low risk. Westinghouse has installed this system on the W501's and W251's,where it has operated successfully for many thousands of hours.

(B) Reduction of cooling air for airfoils

Metal temperature of stationary vanes were measured at many locations during the full load shop test and the cascade test. These tests revealed that not only did surface metal temperature have a large margin against oxidation, but also that the average metal temperature also provide a large margin for creep rupture due to the gas bending force. The conclusion was that saving cooling air is possible for stage 1 and 2. In addition, thermal barrier coating was applied over the airfoil for stage 1 to further reduce the metal temperature. For stage 3, no change was made. To achieve the cooling air flow design target, not only was the thermal analysis carried out, but also the total cooling air circuit system was optimized to meet the requirements due to the modifications of vane cooling.

The amount of cooling air was reduced for the stages 1 through 3 rotating blades. In general, creep rupture lives of the cooled blades have relatively large margins. Therefore, it is possible to increase average metal temperature. Also, the row 1 blade surface metal temperature measured by pyrometer testing was much lower than the allowable limit, as shown in Figure 9(also see Ref.(1)). Although it is difficult to measure the metal temperature of rotating blades directly, combination of measured data and thermal analysis can give complete metal temperature distribution all over the blade. The procedure is summarized in Figure 10. The first thing to be done is to simulate the stationary cascade test by computer. On the next step, the difference between stationary cascade test and actual rotating cascade can be deduced by

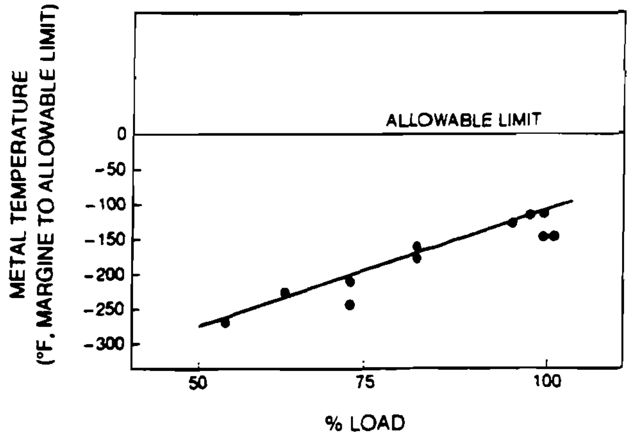

Figure 9 Turbine row 1 blade metal temperature

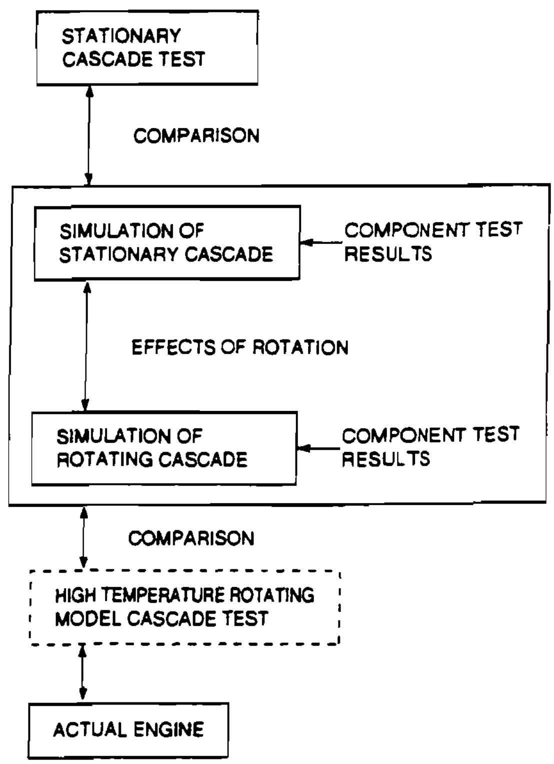

Figure 10 Procedure of thermal analysis

computer. This computer system includes thermo-flow network program and finite element solver with sophisticated pre/post-processor. Figure 11 shows one example of cooling flow network model of the stage 1 blade. The results of component tests were used to estimate heat and flow characteristics. To complete the design, comparisons were made between the test and the analysis. In order to get higher accuracy, extra efforts are necessary; although it is expensive, the high temperature rotating model cascade test appears to be the next step required. For other stages, like stage 2, 3 and 4, new blade material with higher creep rupture strength is needed in order to reduce the cooling air any further. MGA1400[2], which was developed by Mitsubishi Heavy Industries, Ltd. and Mitsubishi Material is one of the candidate materials.

Modifications of cooled rotor blades was also implemented. For the stage 1 blade, resizing of film cooling holes and optimization of tip cooling was done. The aim of the first modification was to reduce air flow. The second modification was done to solve a minor problem that could be expected if any countermeasures were not taken in the uprated engine. These cooling air changes are expected to improve resistance to local high temperature oxidation during long periods of operation. Improvement of tip cooling was achieved by bypassing holes between two air passages inside the blade. These additional holes are able to supply cooler air into the hotter portion of cooling flow network model of the stage 1 blade as shown in Figure 11.

The modifications of the stage 1 and 2 vanes include resizing of cooling holes. The flow network was also optimized to meet the requirement. Thermal barrier coating was applied on the stage 1 airfoil. For the stage 2 and 3 blades, cooling flow was adjusted at the entry of the cooling air passage.

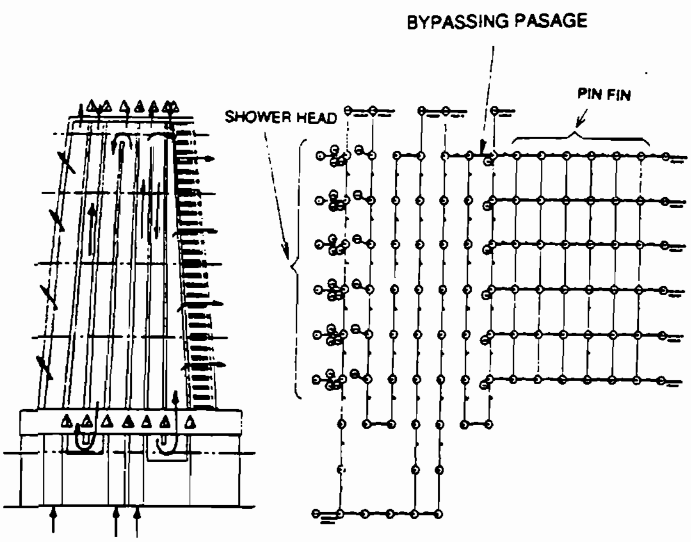

Figure 11 Flow network model of row 1 blade

2 Trademark of Mitsubishi Material and MHI

3-2 Reduction of tip clearances

Tip clearance has a large impact on performance. Effects of reduced tip clearances are conceptually shown in Figure 13 and 14. Smaller clearances are preferable in terms of performance, but increase the probability of tip rubbing. Therefore, it is necessary to establish complete confidence and a safety factor when reducing tip clearances. Tip clearance reduction of the compressor and turbine were done based on the measured transient tip clearances at the shop test for both cold and hot start. At the shop test, turbine row 2 blade clearance was measured by a clearance meter. Measurements showed that the minimum transient clearance for stage 2 blades appeared at cold start, as shown in Figure 12. For other turbine stages, clearances were monitored by three touch sensors with different lengths, as well as from information obtained from finite elemental analyses. For some of the compressor stages, tip clearances were also monitored by touch sensors. Again, for other stages not monitored, finite element analysis provided additional information as to how much tip clearance can be reduced. To avoid serious damage due to rubbing, abradable coating was applied. Nickel-graphite is the coating material selected for the compressor. This material has been used for the MF-61, 6 MW class gas turbine.

Compressor front stage tip clearances are maintained the same as those of the 501F since only small increase of the efficiency will be gained. In addition, cost of abradable coating is rather high. Tip clearances were reduced only for stage 7 through 16. All turbine stages will have smaller tip clearances compared to the 501F. No serious damage is expected ,because stage 2 will adopt the LCO22[3] abradable coating and stage 3 and 4 use honeycomb seals. The LCO22 coating has been used successfully on W251B9/10. For the first stage, tip clearances were chosen prudently to maintain an adequate margin of safety based on the shop test results.

3.Trademark of Praxair

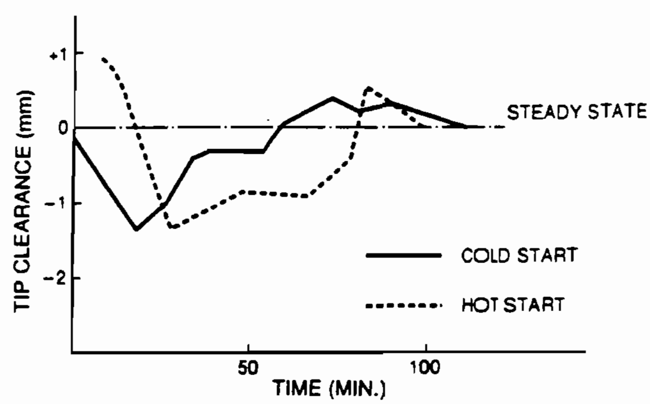

Figure 12 Measured transient tip clearance of turbine row 2 blade

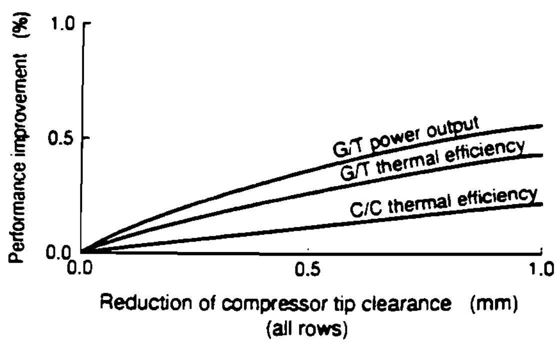

Figure 13 Effects of reduced tip clearances on performance (compressor)

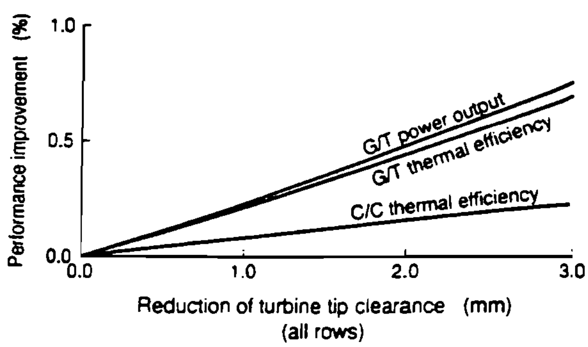

Figure 14 Effects of reduced tip crearances on performance (turbine)

4. Performance

The performance of the 501FA is summarized in Table 2. Power output is increased by 5.7% relative to the 501F's power with adjustment of the inlet guide vane angle. In order to confirm feasibility of power increase unstalled flutter analysis was conducted for the last stage of turbine blade. Efficiency is expected to be increased by 1.7%. Turbine inlet temperature is unchanged. Exhaust gas temperature increases by about 8 °F(3.9°C). This results in higher combined cycle efficiency together with larger flow.

Table 2 Performance of 501F/501FA

	① 501F	② 501FA	①/②
POWER, KW *	153,200	161,900	+5.7%
HEAT RATE, BTU/KW-HR	9,670	9,505	△1.7%
AIR FLOW, LBS./SEC	943	965	+2.3%
PRESSURE RATIO	14.0	14.6	+4.3%
EXHAUST TEMPERATURE, °F	1073	1080	+7°F

* ISO Base Rating, Natural Gas Firing, Generator End

5. Summary

The 501FA inherits its basic configuration from the 501F. Bot shop and field experiences were utilized to develop the potential of th 501FA. In order to save cooling air, results of full load shop testin were carefully investigated to determine how much margin was in th current design. For optimizing tip clearances, investigations wer made to accurately measure transient tip clearances. To back up th modifications, some new techniques were introduced. These includ TBC, abradable coating, and auto flow modulation all of which can b considered minimum risk. Also, the orthodox technique of reducin the number of parts was used to reduce leakage flow. The performanc of the 501FA is better than the 501F without reducing reliability.

6. Acknowledgments

The authors wish to express acknowledgment to many engineers o both Westinghouse Electric Corporation and Mitsubishi Heavy Industries, Ltd. who have devoted themselves to this project.

The authors which to express their thanks for manuscript editing t Mr. D. Mark Sefcik who is a representative of Westinghouse Electric Corporation stationed in Mitsubishi Heavy Industries, Ltd. facility in Takasago, Japan.

7. References

(1) D.T. Entenmann et al, "Shop Test of the 501F, A 150 MW Combustion Turbine", ASME 90-GT-362.

(2) D.T. Entenmann et al, "501F Development Update", ASME 92-GT-237

(3) I. Fukue et al, "A New High-Efficiency Heavy Duty Combustion Turbine 701F", ASME 93-GT-146

WESTINGHOUSE COMBUSTION TURBINE LOW NOx TECHNOLOGY UPDATE

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Dallas, Texas
November 17-19, 1993

WESTINGHOUSE COMBUSTION TURBINE LOW NOx TECHNOLOGY UPDATE

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and
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Orlando, FL.

Introduction

Westinghouse has aggressively continued developing, testing, and implementing lower NOx combustion technology. The primary goal in this process is to meet the increasingly stringent regulatory requirements for all emissions while continuing to maintain a world class operating reliability. The efforts include design for conventional (wet), lean premixed dry low NOx, and advanced concepts such as catalytic combustion. The program is designed to provide multiple options for long-term development of the various combustion systems utilizing the expertise of Westinghouse and its worldwide alliances. A description of the program organization and results from operating units, full engine field tests, and combustor rig tests are presented.

The flow chart in Figure 1 summarizes the organization and products of the combustion technology program from combustors currently available to development combustors. The conventional systems include the standard combustors supplied by Westinghouse for over 20 years and the recently developed DF-42 combustor for improved NOx performance at lower water and steam injection rates. The dry low NOx systems are organized into two parallel paths. The Dry Low NOx program addresses the near term implementation of combustors with a NOx requirement of 15 ppm or greater, while the Ultra Low NOx program is focused on the development of combustors for 9 ppm NOx and less.

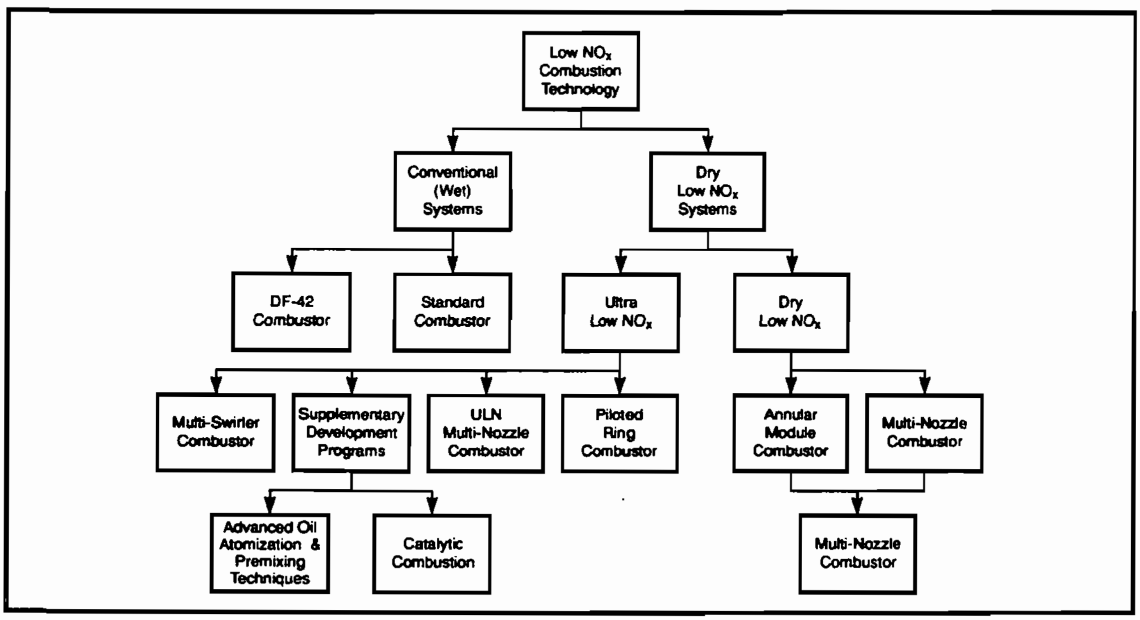


Figure 1. Organization and Products of the Combustion Technology Program.

Conventional (Wet) Combustors

Westinghouse has supplied numerous conventional combustion systems which utilize steam or water injection to control NOx with operation on natural gas and distillate oil fuels. The original designs for the 501 (60 Hz, 100 MW nominal rating) and 251 (50/60 Hz, 50 MW nominal rating) combustion systems have proven to be reliable through years of operation demonstrating lower than 42 ppmvd (@ 15% O_2) on natural gas and 65 ppmvd (@15% O_2) on distillate fuels with minimal secondary emissions (CO, UHC, and smoke).

Development has continued resulting in further reductions in NOx levels with conventional combustors without increasing the steam or water injection rates. To accomplish this, the dual fuel DF-42 combustion system was introduced into commercial operation in 1991 on 501D5 turbines. Since its introduction, the DF-42 combustor has been installed in ten combustion turbines in the United States, four of these are operating with steam injection and six operating with water injection. Emission testing on these units indicates better than expected NOx levels which are summarized in Figure 2.

DF-42 NO_X Emission Levels
(ppmvd @ 15% O_2)

	Natural Gas		No. 2 Fuel Oil	
	NOx	Inj. Rate*	NOx	Inj. Rate*
Steam Injection	15	(S/F=1.85)		
	25	(S/F=1.30)	42	(S/F=1.60)
Water Injection	25	(W/F=1.15)	42	(W/F=0.95)

* Injection Rate is Ratio of Steam or Water to Fuel Flow Rate

Figure 2. NOx Emission for DF-42 Combustor with Steam and Water Injection.

Dry Low NOx Design Philosophy

NOx emissions are governed by two mechanisms in combustion turbine combustors, primarily by converting atmospheric nitrogen at high temperatures (thermal and prompt NOx), and by the conversion of nitrogen in the fuel (called fuel bound nitrogen, FBN) [1]. Fuel bound nitrogen is typically limited to heavy fuel oils, therefore the primary challenge in designing low NOx combustors for conventional fuels arises in lowering the flame temperature to limit the thermal NOx reactions. Conventional combustors burn with a diffusion flame having a characteristically high flame temperature which is reduced by injecting water or steam into the combustion zone. Water and steam injection increases the net power output of the gas turbine, but decreases the overall plant cycle efficiency and consumes water which must be of high quality.

As an alternate to conventional combustors, dry low NOx combustors reduce the flame temperature through the combustion mechanism of premixing the fuel and air before ignition. Figure 3 demonstrates that NOx production (i.e. flame temperature) is governed by the fuel/air ratio and can be limited by operating in a fuel lean condition. Premixed combustion takes advantage of the lower flame temperature by creating a homogeneous lean fuel/air ratio whereas diffusion flames have localized zones which burn at the stoichiometric fuel/air ratio producing the maximum flame temperature. Currently, all of the dry low NOx combustors offered by Westinghouse utilize the lean premixed combustion approach.

The primary focus on new combustor development has been on NOx emissions, but the dry low NOx systems presented are also designed to maintain low secondary emissions of carbon monoxide (CO), unburned hydrocarbons (UHC), and for reliability and operability consistent with current regulatory and customer requirements.

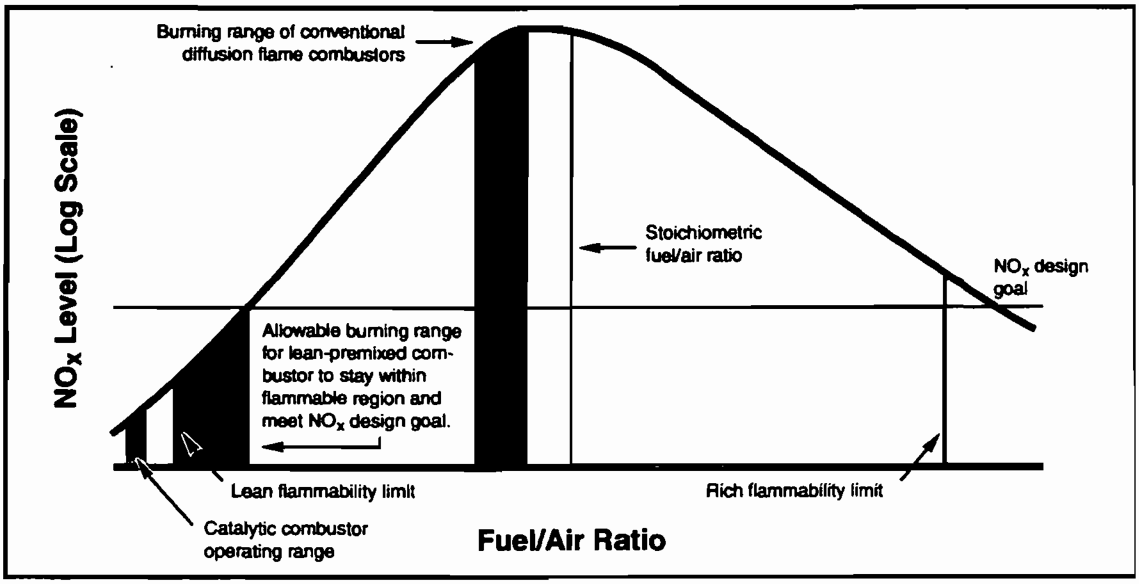


Figure 3. NOx Formation vs. Fuel/Air Ratio.

Dry Low NOx Combustion Systems

The development and implementation of dry low NOx combustor technology is organized into two parallel paths. The Dry Low NOx program addresses the commercial installations scheduled for the near term (1993-1994) which require a NOx level in the range of 15 to 50 ppmvd (@ 15% O_2). The focus of this program is the installation of the Multi-Nozzle Combustor into 501D5 units in late 1993 and early 1994. A description of the combustor and results from recent field tests are presented below. The second parallel path is the Ultra Low NOx program aimed at single digit NOx levels for combustor installation in 1995-1996.

Multi-Nozzle Combustor

Results are presented for two field verification tests of the Multi-Nozzle combustor. The first field test was conducted in 1992 in a 701F (50Hz, 200 MW nominal rating) combustion turbine in Yokohama, Japan. An additional field test was run in 1993 in a 501D5 combustion turbine. Both tests successfully demonstrated the operability of the fuel delivery and combustion systems with emissions below the expected values.

The Multi-Nozzle Combustor is shown in Photograph 1 (at the end of this paper). The combustor consists of eight premixed nozzle/swirler assemblies surrounding a center pilot. The outer swirler sections operate in a lean premixed mode and are stabilized by a center diffusion burning pilot. Details of the premixed burner development, mixing tests, and preliminary laboratory results are given in Reference [2]. The downstream liner section is an advanced double wall design for efficient convection cooling. The fuel system is fed from three separately controlled fuel valves, one for the pilot and two for the premixed burners providing fuel staging capabilities for a smooth start-up.

The fuel staging implemented for the 1993 501D5 field test is shown graphically in Figure 4. The pilot stage and half of the premixed burners (Stage 1) are used from light-off to 30% load. The remaining half of the premixed burners (Stage 2) are brought on between 30% and 50% load. Above 60% load the fuel splits remain the same until full load where the pilot fuel flow rate is decreased for optimum NOx emissions. This fuel staging schedule provides smooth light-off, cross ignition, and load up with no combustion system instabilities.

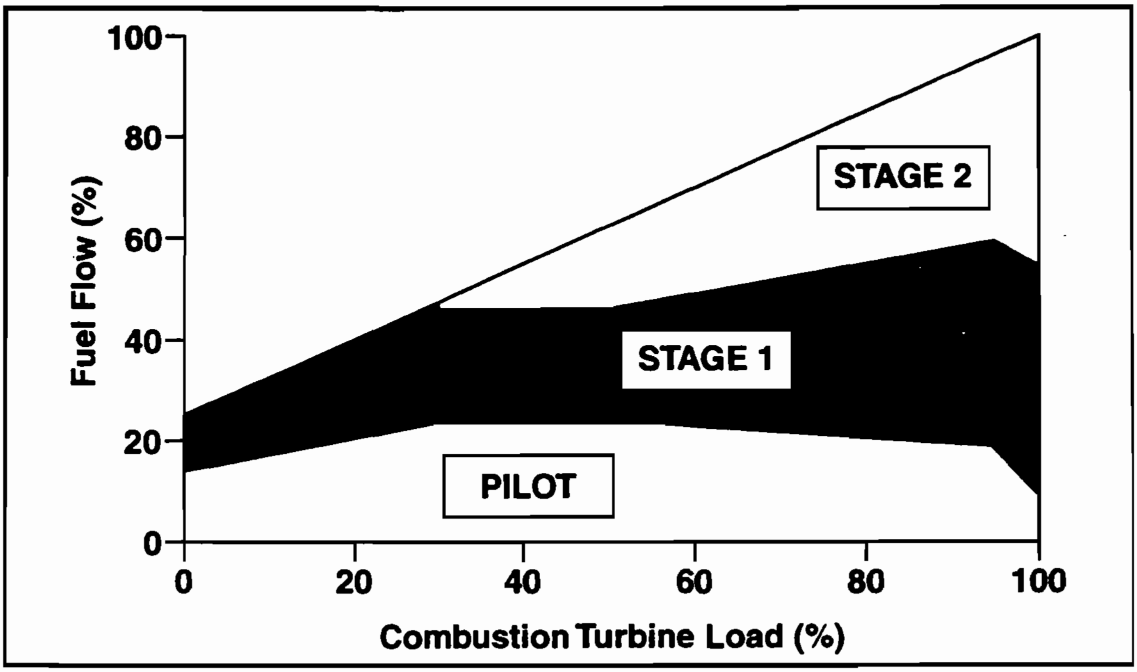


Figure 4. Fuel Staging Schedule for Multi-Nozzle Combustor vs. Load (%).

The NOx emissions measured during the 701F field test are shown in Figure 5 with the levels below the target of 25 ppm. In Figure 5, the combustor emissions are shown over a wide range of combustion turbine firing conditions from start-up to base load for 501D5 and 501F/701F firing levels. The 701F combustion system was able to simulate the 501D5 combustor conditions by using a variable air bypass valve to allow compressor discharge air to bypass the combustion system directly to the transition piece.

The same combustion system was also retrofitted into a 501D5 combustion turbine for a field test. The 501D5 did not have an air bypass valve system like the 701F, thus requiring slight modifications to the fuel staging process during start-up. The fuel delivery system outside the combustor was also adapted to the 501D5 in order to maintain identical fuel injection, premixed section, and combustion zone components. The same combustor is also used for 501F applications (60 Hz, 150 MW nominal rating) utilizing common technology between the engine frames.

The NOx emission results for the 501D5 were similar to the 701F, meeting the target NOx level of 25 ppmvd (@15% O_2) at full base load conditions. Figure 6 illustrates the dependence of NOx emissions on the pilot fuel flow as a percentage of total fuel flow measured during the 501D5 field verification test. The remaining fuel flow to Stage 1 and Stage 2 is split equally. NOx emissions below 25 ppmvd (@15% O_2) were obtained by decreasing the pilot fuel flow from approximately 20% to 10%. Even lower emissions are expected at reduced pilot fuel flow rates.

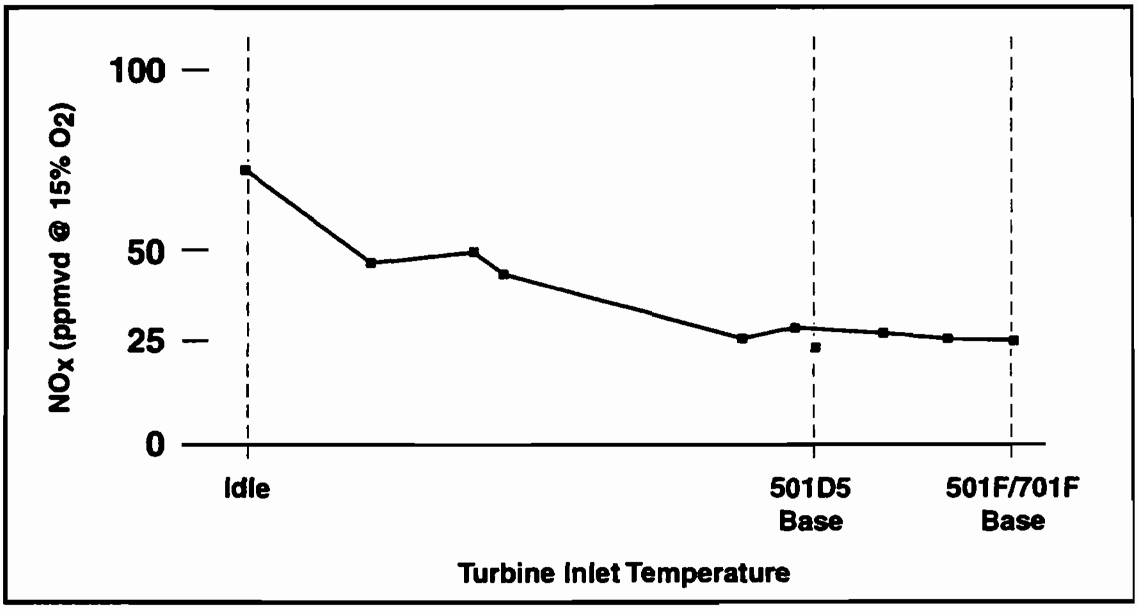


Figure 5. NOx Emissions vs. Turbine Inlet Temperature for 701F Multi-Nozzle Combustor.

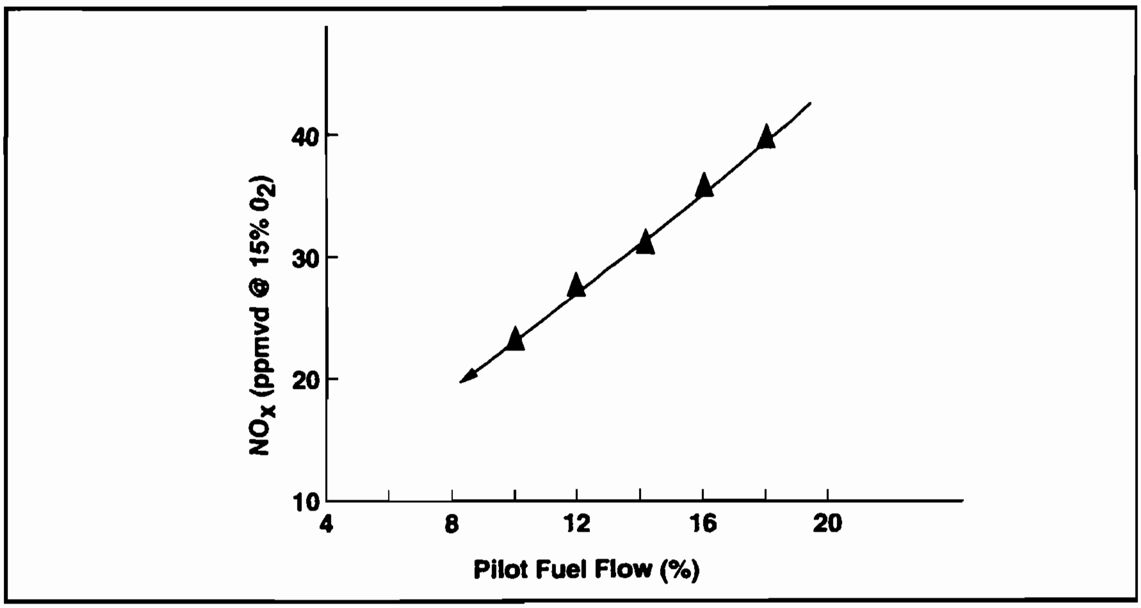


Figure 6. NOx Emissions vs. Pilot Fuel Flow (%) for 501D5 Multi-Nozzle Combustor.

In addition to emission measurements, dynamic pressure fluctuations, combustor wall temperatures, transition wall temperatures, and strain gauges were monitored during the field test. All results from this additional instrumentation were within the design goals for a full production combustor.

The Multi-Nozzle combustor is undergoing further development with the application of a premixed pilot to reduce NOx emissions even further. A dual fuel version of the combustor has been developed and will be implemented in 1994. Additional field operational data will be obtained in 1994 with the scheduled start-up of eight 501D5 combustion turbines with the Multi-Nozzle Combustor.

Ultra Low NOx Program

The Ultra Low NOx program is aimed at obtaining NOx levels below 9 ppm for all Westinghouse combustion turbines including those with "F" class firing temperatures and above. In order to reach single digit NOx levels, Westinghouse is in the process of designing and testing multiple concepts. The Multi-Nozzle Combustor described above is being modified and tested for single digit capability and the Piloted Ring Combustor described below has shown excellent results in laboratory testing. A Multi-Swirler Combustor has also demonstrated single digit NOx capabilities in rig tests. Supplemental development programs cover a wide range of activities to augment the specific combustor performance and to continue development of advanced concepts to reduce NOx levels even further. The goal for the Ultra Low NOx program is to achieve single digit NOx levels in a field test in 1994 providing availability for commercial applications in 1995-1996.

Piloted Ring Combustor

The Piloted Ring Combustor is shown schematically in Figure 7. The combustor consists of two stages in series. The primary stage utilizes two counter directional radial inlet swirlers for premixing fuel and air and stabilizing the primary combustion zone. In the secondary stage premixed fuel and air is fed from a long premixing annulus with natural gas injected through radial fuel pegs in the upstream end. This annulus provides the necessary length to achieve ideal mixing of the natural gas and air before injection into the secondary combustion zone. The combustor operates in a fully premixed mode for the ultra low NOx emissions, but can also operate in the diffusion mode with natural gas or oil supplied from a center nozzle. For additional development details, Willis, et. al. [3] describes the testing of the combustor concept from which the initial design of the Piloted Ring Combustor is based.

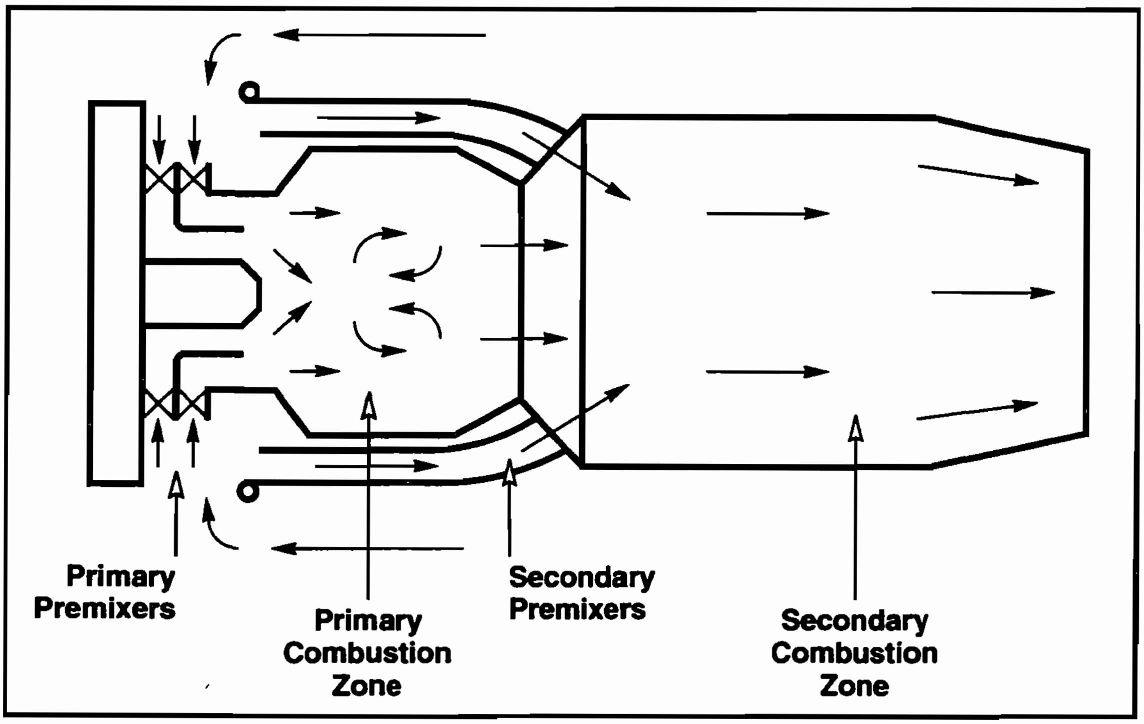


Figure 7. Piloted Ring Combustor.

Results of high pressure testing using this concept have demonstrated the capability of the combustor to achieve single digit NOx. Further testing and analysis has been conducted with a cold flow air model, computational fluid dynamics (CFD), fired mid-pressure tests, and high pressure rig tests. The airflow tests provided insight into the aerodynamics, pressure drop, and fuel mixing capabilities of the combustor. The full scale Lexan airflow model is shown in Photograph 2 (at the end of this paper). CFD analysis was used in conjunction with the airflow testing to verify the results. The grid used to model the Piloted Ring Combustor with CFD is shown in Figure 8. Both cold and reacting flow CFD analysis has yielded valuable data for sizing of fuel injection components, improving combustor aerodynamics, and wall cooling design calculations. The testing of this design will continue in the combustion rig in order to support a field test planned for late 1994.

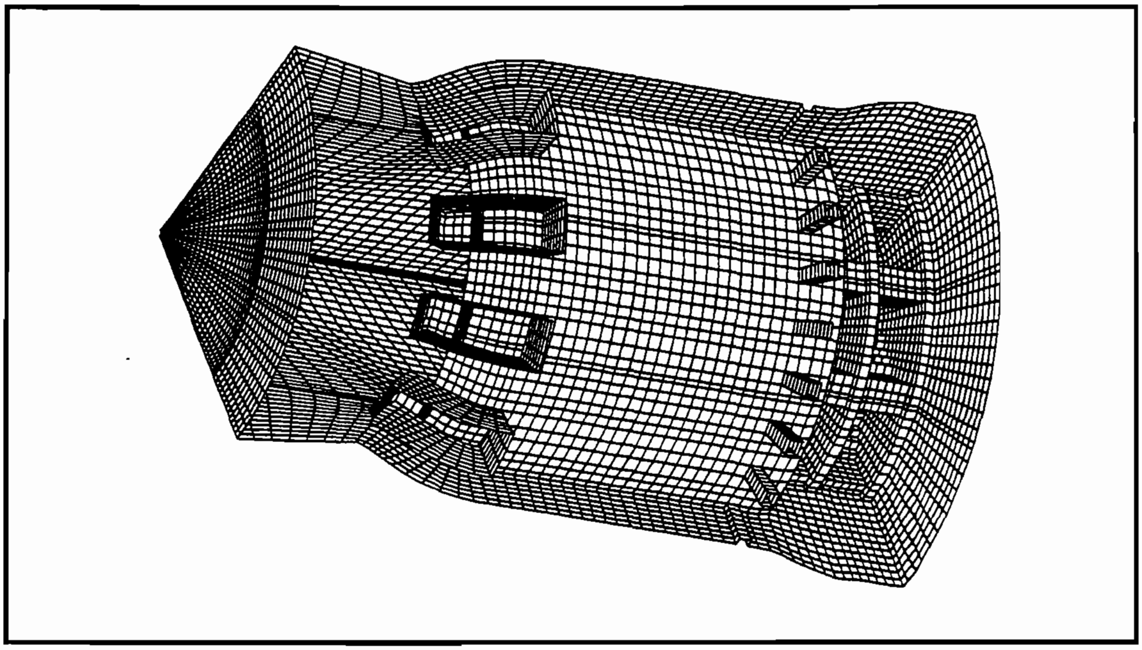


Figure 8. CFD Model of the Piloted Ring Combustor.

Multi-Swirler Combustor

The Multi-Swirler Combustor utilizes annular parallel stages to feed a premixed gas and air mixture to the combustion zone which is stabilized with a center pilot. A schematic of the combustor is shown in Figure 9. Each stage utilizes a multitude of individual swirlers for final mixing and flame holding.

This combustor concept was tested at mid-pressure in 1993 demonstrating NOx levels below 9 ppmvd (@15% O_2). The combustor was operated with a diffusion flame pilot, premixed pilot, and no pilot with stable operation at all conditions and low secondary emissions (CO and UHC). Combustor exit temperatures were also varied from standard 501 and 251 frame levels up to "F" class temperatures with consistent NOx emissions below 9 ppm. The development effort will continue with high pressure combustion tests and a field test planned for 1994-1995.

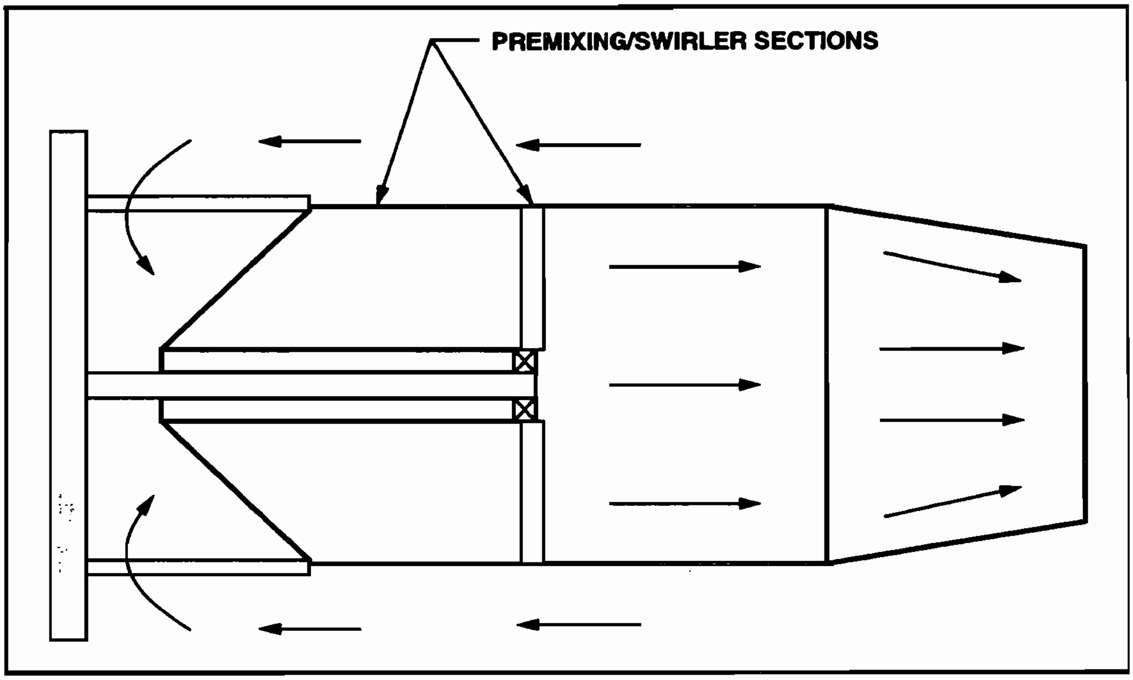


Figure 9. Multi-Swirler Combustor.

Supplemental Developmental Programs

Westinghouse is also proceeding with other programs to further reduce NOx emissions on natural gas and to provide dry low NOx combustors with low NOx emissions operating on oil.

A catalytic combustor program is underway with additional participation from the Westinghouse Science and Technology Center. The focus of this development effort is to integrate catalytic technology into premixed designs in the short term and to strive for the design of an environmentally benign combustion system for the long term. Novel concepts have been evaluated in small bench scale tests and full pressure combustion rig tests.

A program to develop atomizers for dry low NOx oil premixed systems is advancing. This program will concentrate on the evaluation of important parameters such as residence time, mixing uniformity, atomizer type, and equivalence ratio to obtain data for the design of the lowest NOx possible in oil fired combustors.

Summary

A comprehensive low NOx combustor technology program is in place which utilizes past experience and new technology to evaluate multiple designs for all future combustion system needs. With this program, Westinghouse and its global alliances are committed to develop low emission systems that are consistent with regulatory requirements and engine reliability expectations. The following milestones have been achieved:

1. Westinghouse conventional combustion systems have been improved for NOx emissions as low as 15 ppmvd (@15% O_2) and have been proven with long term operation in commercial units.

2. The operability of a dry low NOx system in multiple Westinghouse combustion turbine frames has been successfully demonstrated with NOx emission consistently under 25 ppmvd (@15% O_2).

3. Development combustors have demonstrated NOx emissions of 9 ppmvd and below (@15% O_2) and are being readied for commercial applications in the 1995-1996 time frame.

4. Westinghouse is devoting significant effort to state-of-the-art technologies for the long term reduction and minimization of emissions from combustion turbines.

Acknowledgments

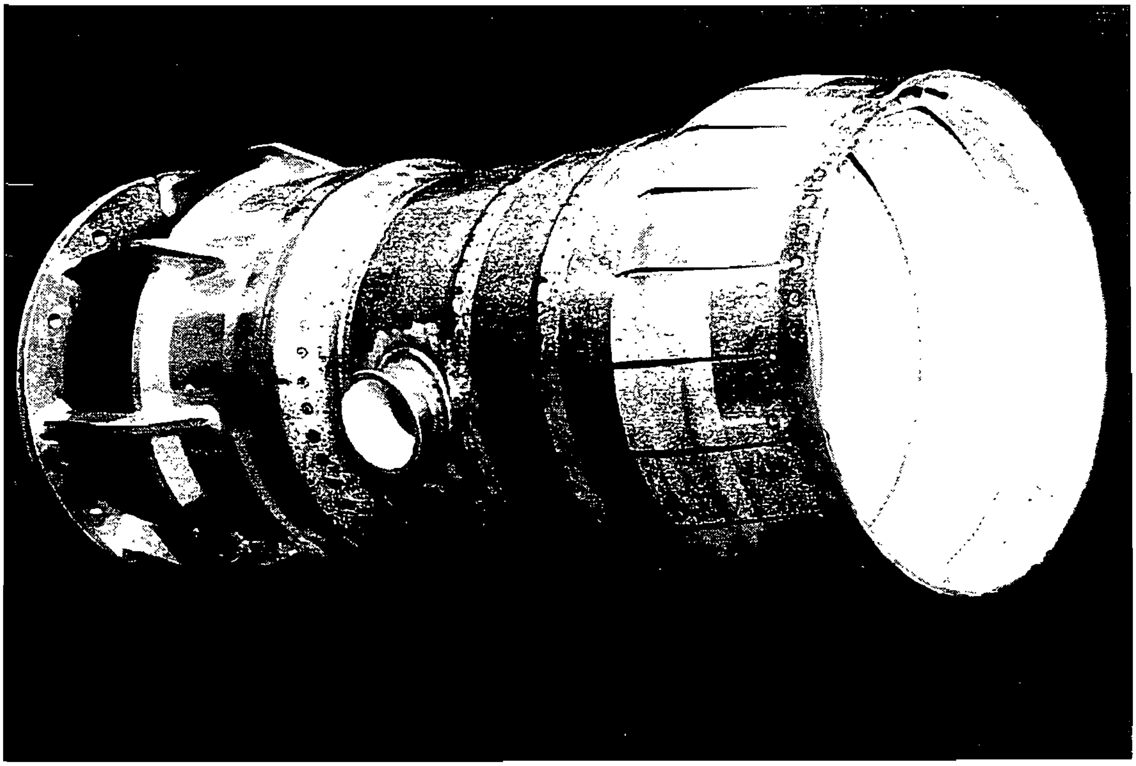
The authors would like to acknowledge the contributions of the individuals in Combustion Technology, at Orlando, Engineering Programs in Hamilton, Ontario and our worldwide technology alliances.

References

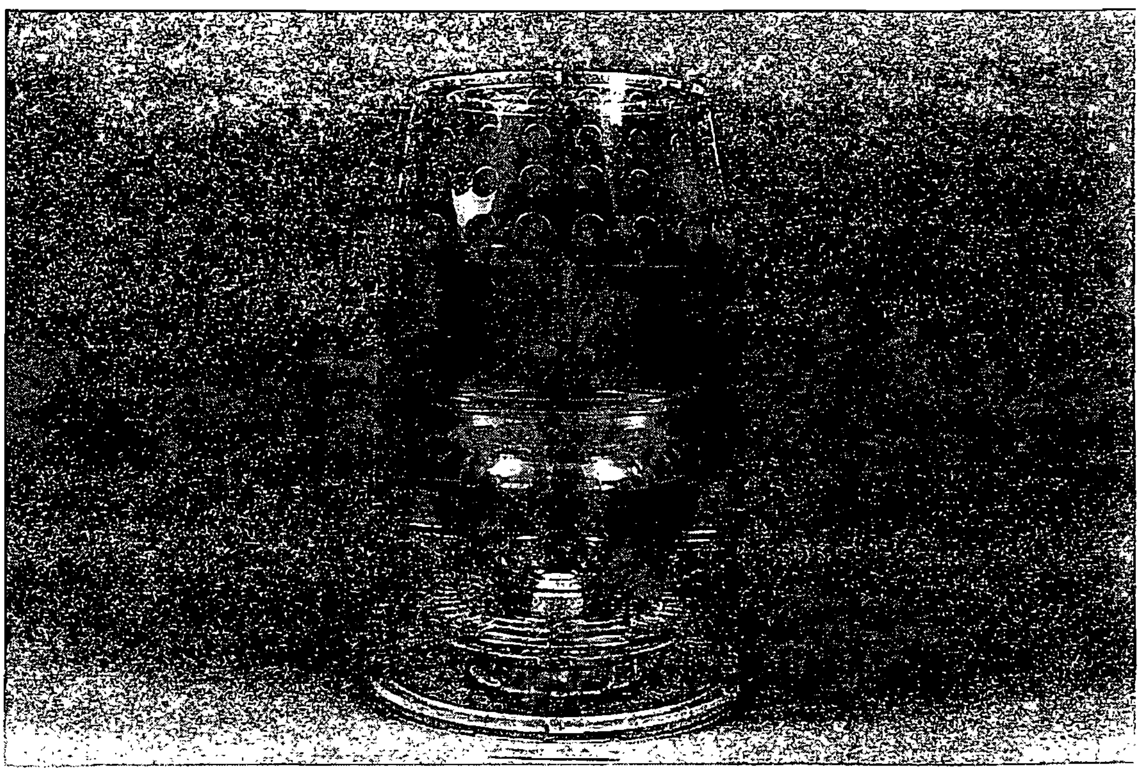
[1] Antos, R. J., 1992, "Emission Control Techniques for Westinghouse Industrial Combustion Turbines," Paper No. 92-136.07, Presented at the Air & Waste Management 85th Annual Meeting, Kansas City, MO., June, 1992.

[2] Matsuzaki, H., Fukue, I., Mandai, S., Tanimura, S., Inada, M., 1992, "Investigation of Combustion Structure Inside Low NOx Combustors for a 1500 C - Class Gas Turbine," ASME Paper No. 92-GT-123.

[3] Willis, J. D., Toon, I. J., Schweiger, T., Owen, D. A., 1993, "Industrial RB211 Dry Low Emission Combustion," ASME Paper No. 93-GT-391.



Photograph 1. Multi-Nozzle Combustor.



Photograph 2. Piloted Ring Combustor airflow model.

ATTACHMENT FDEP-BAR-13

TANKS PROGRAM 2.0
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

Identification

Identification No.:	Fuel Oil
City:	Hardee County
State:	FL
Company:	SECI/ Hardee Unit 3
Type of Tank:	Vertical Fixed Roof

Tank Dimensions

Shell Height (ft):	53
Diameter (ft):	125
Liquid Height (ft):	48
Avg. Liquid Height (ft):	48
Volume (gallons):	4400000
Turnovers:	9
Net Throughput (gal/yr):	37643970

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft):	53.00
Radius (ft) (Dome Roof):	0.00
Slope (ft/ft) (Cone Roof):	0.8480

Breather Vent Settings

Vacuum Setting (psig):	0.00
Pressure Setting (psig):	0.00

Meteorological Data Used in Emission Calculations: Tampa, Florida

TANKS PROGRAM 2.0
EMISSIONS REPORT - DETAIL FORMAT
LIQUID CONTENTS OF STORAGE TANK

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.01	68.83	79.19	72.02	0.0102	0.0086	0.0119	130.000			130.00	Option 4: A=12.1010, B=8907.0

Annual Emission Calculations

Standing Losses (lb):	903.3772
Vapor Space Volume (cu ft):	278161.8
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.039031
Vented Vapor Saturation Factor:	0.987935

Tank Vapor Space Volume

Vapor Space Volume (cu ft):	278161.8
Tank Diameter (ft):	125
Vapor Space Outage (ft):	22.67
Tank Shell Height (ft):	53
Average Liquid Height (ft):	48
Roof Outage (ft):	17.67

Roof Outage (Cone Roof)

Roof Outage (ft):	17.67
Roof Height (ft):	53.000
Roof Slope (ft/ft):	0.84800
Shell Radius (ft):	63

Vapor Density

Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010165
Daily Avg. Liquid Surface Temp.(deg. R):	533.68
Daily Average Ambient Temp. (deg. R):	531.67
Ideal Gas Constant R (psia cuft /(lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	531.69
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqftday):	1492.00

Vapor Space Expansion Factor

Vapor Space Expansion Factor:	0.039031
Daily Vapor Temperature Range (deg.R):	20.71
Daily Vapor Pressure Range (psia):	0.003303
Breather Vent Press. Setting Range(psia):	0.00
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010165
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.008631
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.011934
Daily Avg. Liquid Surface Temp. (deg R):	533.68
Daily Min. Liquid Surface Temp. (deg R):	528.50
Daily Max. Liquid Surface Temp. (deg R):	538.86
Daily Ambient Temp. Range (deg.R):	18.90

Annual Emission Calculations
Vented Vapor Saturation Factor

Vented Vapor Saturation Factor:	0.987935
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010165
Vapor Space Outage (ft):	22.67
Withdrawal Losses (lb):	1184.4292
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010165
Annual Net Throughput (gal/yr):	37643970
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	589049
Maximum Liquid Height (ft):	48
Tank Diameter (ft):	125
Working Loss Product Factor:	1.00
Total Losses (lb):	2087.81

Annual Emissions Report

Liquid Contents	Losses (lbs.): Standing	Withdrawal	Total
Distillate fuel oil no. 2	903.38	1184.43	2087.81
Total:	903.38	1184.43	2087.81

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF MINE RECLAMATION

(FDEP.BMR)

FDEP.BMR-1

__Comment__: Thank you for the opportunity to provide feedback on the Site Certification Application for the above referenced facility. Our concerns were adequately addressed in the May 1994 version of the two-volume application, and in yesterday's informational meeting with other DEP and SECI representatives. Do not hesitate to contact me at 488-8217, if I can be of assistance or can provide further information.

__Response__: Comment acknowledged.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF WATER FACILITIES PLANNING AND REGULATION

(FDEP.BWF)

FDEP.BWF-1

Comment: The mixing zone lengths were calculated using the dispersion model presented by Fischer *et al.* (1979). Please provide information on how the various model parameters and coefficients were estimated.

Response: Fischer *et al.* (1979) presents the following transverse mixing model, applicable for mixing within Payne Creek:

$$C(y') = \int_0^1 \frac{C_i(Y_o')}{(4\pi x')^{1/2}} \sum_{n=-\infty}^{\infty} \{\exp[-(y'-2n-y_o')^2/4x'] + \exp[(y'-2n+y_o')^2/4x']\}\, dy_o'$$

where:

C = dispersed effluent concentration at a point x and y downstream,

Ci = initial effluent concentration (mg/L),

y' = dimensionless y (transverse) coordinate,

x' = dimensionless x (longitudinal) coordinate, and

y_0' = dimensionless effluent source location.

The value x' is defined as:

$$x' = (xEt)/(uW2)$$

where:

x = downstream distance (ft),

Et = transverse mixing coefficient,

u = average velocity (ft/sec), and

W = river width (ft).

The value y' is defined as:

y' = y/W

where:

y = distance across the river (ft), and

W = river width (ft).

Based on site-specific flow monitoring at PC-2 and the worst-case flow conditions of 22 cfs, Payne Creek velocity was estimated to be 0.5 ft/sec. Average depth was estimated to be 2.5 ft. A typical cross-section of Payne Creek near the plant site has been presented in SCA in Figure 2.3.4-1. By continuity and site observations, creek width at this flow and velocity was estimated to be 20 ft.

Shear velocity, u*, was estimated based on Fischer *et al* (1979) as:

$$u^* = \sqrt{gdS}$$

where:

d = depth (ft),

g = gravity = 32.2 ft/sec/sec, and

S = slope (ft/ft).

Payne Creek slope was estimated using USGS topographic data in the vicinity of the proposed discharge; creek slope was determined to be 5 ft of fall in 6,000 ft or 8.33×10^{-4} ft/ft. Based on these data, the shear velocity was estimated to be 0.259 ft/sec.

The effective width of the discharge stream, y_0, was calculated based on continuity, subject to the above velocity and depth data, and the mean maximum discharge rate of 0.33 cfs. Based on the data, the effective width of effluent discharge stream is estimated to be 0.26 ft.

The most critical model coefficient is the lateral or transverse mixing coefficient (Et). Fischer *et al.* (1979) summarized various measurements of the transverse mixing coefficient in natural streams and rivers to facilitate the comparison of data collected from different rivers under different flow conditions. The transverse dispersion coefficient was normalized by dividing the depth (d) and the shear velocity (u*). Based on their review and compilation of available information, Fischer *et al.* (1979) concluded the following:

> Curves and sidewall irregularities increase the (transverse mixing) coefficient such that values of Et/du* in natural streams are hardly ever less than 0.4; if the stream is

> slowly meandering, and the sidewall irregularities are moderate, Et/du* has been found to be usually in the range of 0.4-0.8, and we can use for practical purposes Et/du* = 0.6 + 50 percent.

Based on the information and conclusions presented by Fischer *et al.* (1979) and considering the vegetation and numerous small-scale meanders in Payne Creek the transverse mixing coefficient, in the form of the normalized value Et/du*, was assumed to be equal to 0.6. The Et value was calculated using the average depth of (d) and the previously calculated shear velocity (u*). Based on these data, the transverse mixing coefficient Et is estimated to be 0.389. Given the various factors discussed above, this is a conservative estimate of transverse mixing coefficient for Payne Creek at and below the proposed discharge.

FDEP.BWF-2

Comment: Please provide the historical data for Payne Creek as referenced in 5.1.1-8. Is there a reason why the United States Geological Survey (USGS) site 02295420 data were not used for the thermal mixing zone analysis?

Response: The flow data for Payne Creek as referenced on Page 5.1.1-8 was derived using the methodology described in Section 2.3.4.1.2 of the SCA; flow data are summarized in Table 2.3.4-2. These data and the USGS data were not used in the mixing zone analyses because the cooling reservoir modeling predicted that it would not discharge during the 37 year period of record used for the modeling. Since the reservoir has the capability to discharge (i.e., a fixed crest overflow weir), a scenario was developed to determine what the discharge from the reservoir (and, in the receiving water) would be if rainfall conditions more extreme than observed since 1948 occurred. This hypothetical discharge scenario (described in detail in Section 5.1.1) assumed that a major rainfall event (i.e., 10 year 24 hour) would occur on top of the significant events necessary to achieve the maximum predicted reservoir elevation. Since the goal of this effort was to develop a worst case scenario, it was also assumed that the significant rainfall events necessary to increase reservoir elevation did not increase flows in Payne Creek (i.e., baseline flows in the creek were used).

FDEP.BWF-3

Comment: We suggest that the temperature in the cooling reservoir be monitored monthly.

Response: NPDES permit conditions require monitoring of reservoir water temperatures at the point of discharge during any discharge event. Since the cooling reservoir is a heat dissipation treatment system, the reporting of temperature data during the normal, non-discharging operating conditions would provide data only of interest to the operating personnel on the performance of the reservoir.

FDEP.BWF-4

Comment: In response to the Department of Environmental Protection's comments on the Plan of Study (FDEP-16), the applicant states "The CORMIX3 model is a nearfield model used to estimate thermal and/or chemical impacts in the receiving water (i.e., Payne Creek) resulting from the infrequent reservoir discharges. Was this model used in the determination of the mixing zone lengths: If so, please provide the input and output sets used.

Response: The Fischer *et al.* (1979) transverse mixing model was used to estimate receiving water impacts for the infrequent reservoir discharges. The CORMIX3 was not used in determining the mixing zone lengths. The Fischer model and the CORMIX3 model use similar two-dimensional, superposition, analytical transverse mixing algorithms. The CORMIX3 model's hydrodynamic computational elements are more restrictive than the Fischer model and do not provide the resolution of mixing zone concentrations very near the POD. Derivation of the input parameters to the Fischer model are discussed in response to Comment FDEP.BWF-1.

The input and output sets from the Fischer *et al.* model are presented in Tables 5.1.1-3 and 5.1.1-4 of the SCA.

FDEP.BWF-5

Comment: Section 5.2.1-2 states that plant wastewaters will receive an overall 30:1 dilution based on inflows to the reservoir. Does this predicted dilution take into account the concentrations associated with these inflows?

Response: The predicted dilution does take into account the concentrations associated with the inflows. The dilution (and resulting water quality concentrations) in the cooling reservoir was calculated using a mass balance model that conservatively assumed all analytes were always in the aqueous phase. This model includes all input flows as shown in Figure 3.5.0-1, and their associated concentrations. The reservoir mass balance water quality model results (presented in Table 5.2.1-1) use the flows into and out of the reservoir.

FDEP.BWF-6

Comment: Section 5.2.1-2 states that the long term reservoir water quality was estimated based on the mass balances of all reservoir inflows and outflows. Please characterize these inflows and outflows separately.

Response: The quantities and qualities of the various reservoir inflows and outflows are shown in the attached Table FDEP.BWF-6.

FDEP.BWF-7

Comment: If the model used to calculate the mixing zone lengths assumed a base flow of 22 cubic feet per second, the permit should also contain this stipulation.

Response: As noted in the response to Comment FDEP.BWF-2, since the reservoir has the capability to discharge (i.e., a fixed crest overflow weir), a scenario was developed to determine what the amount of discharge from the reservoir (into Payne Creek) would be if rainfall conditions occurred that were more extreme than observed since 1948. This hypothetical discharge scenario (described in detail in Section 5.1.1) assumed that a major rainfall event (i.e., 10 year/24 hour) would occur on top of the significant events necessary to achieve the maximum predicted reservoir elevation. Since the goal of this effort was to develop a worst case scenario, it was also assumed that the significant rainfall events necessary to increase reservoir elevation did not increase flows in Payne Creek (i.e., baseline flows in the creek were used).

The scenario described above is a conservatively valid analysis that predicts impacts to the receiving waters in a worst-case condition. Integral to the analysis is the fact that the reservoir discharge is over a fixed crest weir whose elevation cannot be changed. The

Table FDEP.BWF–6. Summary of Estimated Long–term Cooling Reservoir Water Quality for 880 MW and Average Load Conditions using Revised Water Balance

	Reservoir Intake/Influent Water Quality								
Parameter	Sept. 1993 Cooling Reservior Quality	Surface Runoff	Surficial Aquifer	Floridan Aquifer Makeup	Treated Neut. Basin Effluent (a)	Other Plant Wastewater (a)	Estimated Cooling Reservoir Quality (880 MW)	FDEP Class III Surface Water Quality Criteria	FDEP Class G2 Ground Water Quality Criteria
Calcium, mg/L as CaCO3	51	63	83	113	1130	113	310		
Magnesium, mg/L as CaCO3	50	39	30	49	490	49	140		
Sodium, mg/L as CaCO3	108	17	30	37	3050	37	210		696
Potassium, mg/L as CaCO3	2	0	1	8	80	8	20		
Total Hardness, mg/L as CaCO3	101	102	113	162	1620	162	440		
Alkalinity, mg/L as CaCO3	96	61	83	160	0	160	360	>20	
Sulfate, mg/L as CaCO3	36	37	30	26	4540	26	250		
Chloride, mg/L as CaCO3	50	21	34	21	210	21	60		704
Silca, mg/L	$1	5.4	17	27	270	27	70		
Fluoride, mg/L	1.81	1	0.57	2	20	2	5.4	10	2
Cyanide, mg/L	<0.005	<0.004	<0.004	<0.005	0.05	<0.005	0.01	0.005	0.2
MBAS, mg/L		0.04	0.04	<0.18	1.8	<0.18	0.48		
Oil and Grease, mg/L	<5	<5	<5	<5	0	<5	<5	5	
Turbidity, NTU	10	1.7	51	14	10	14	31	29 above background	
pH, units	7	7	7.5	7.5	6–9	7.5	7.5	6.0–8.5	6.5–8.5
Total Dissolved Solids, mg/L	185	190	158	342	6860	342	1080		500
Specific Conductivity, umhos/cm		173	225	320	12100	320	1240	1275	
Total Kjeldahl Nitrogen, mg/L	1.57	0.74	0.14	0.39	3.9	0.39	1.2		
Ammonia Nitrogen, mg/L	0.05	0.11	0.07	0.2	2	0.2	0.5		
Unionized Ammonia, mg/L4	0.001	0.001	0.002	0.007	0.022	0.007	0.017	0.02	
Organic Nitrogen, mg/L	1.52	0.65	0.07	0.19	1.9	0.19	0.7		
Nitrate+Nitrite–Nitrogen, mg/L	0.009	0.5	0.085	0.031	0.3	0.031	0.2		10
Total Nitrogen, mg/L	1.58	1.24	0.24	0.421	4.2	0.421	1.4		
Orthophosphorus, mg/L	0.35	0.41	0.47	0.2	2	0.2	0.6		
Total Phosphorus, mg/L	0.82	0.44	2.08	0.2	2	0.2	0.6		
Arsenic, ug/L	<5	<5	<9	<10	100	<10	30	50	50
Barium, ug/L	12	<10	<10	75	750	75	200		2000

Table FDEP.BWF-6. Summary of Estimated Long-term Cooling Reservoir Water Quality for 880 MW and Average Load Conditions using Revised Water Balance

	Reservoir Intake/Influent Water Quality								
Parameter	Sept. 1993 Cooling Reservior Quality	Surface Runoff	Surficial Aquifer	Floridan Aquifer Makeup	Treated Neut. Basin Effluent (a)	Other Plant Wastewater (a)	Estimated Cooling Reservoir Quality (880 MW)	FDEP Class III Surface Water Quality Criteria	FDEP Class G2 Ground Water Quality Criteria
Beryllium, ug/L	<0.05	<1.5	10	<0.45	4.5	<0.45	1.6	0.13	4
Cadmium, ug/L	<2.5	<0.2	6	<0.35	3.5	<0.35	1.0	0.82	5
Chromium, ug/L	5	<10	<10	13	130	13	40	148	100
Copper, ug/L	<5	7	65	3	30	3	9.9	8.3	1000
Iron, ug/L	162	293	1700	420	0	420	990	1000	300
Lead, ug/L	<3	6.1	6.7	1.5	15	1.5	6.8	1.9	15
Manganese, ug/L	<5	7.9	28	28	0	28	63		50
Mercury, ug/L	<0.006	0.24	0.24	<0.006	0.06	0.006	0.097	0.012	2
Nickel, ug/L	<30	16	16	23	230	23	60	111	
Selenium, ug/L	<2.5	<2.5	<2.5	16	160	16	40	5	50
Silver, ug/L	<0.035	<0.04	<0.04	<0.035	0.35	<0.035	0.14	0.07	100
Strontium, ug/L	88	100	100	300	3000	300	800		
Zinc, ug/L	73	7.4	<50	143	1400	143	370	75	5000
Alpha, Gross (pC/L)	12.5	1.7	30	8.4	84	8.4	22.2	15	
Radium 226 (pC/L)	1	0.7	2	3	30	3	7.9	5	

Note: Long term water quality estimates are based on the following water balance components:

Surface Runoff	311,500 gallons/day
Surficial Groundwater Inflow	0 gallons/day
Floridan Aquifer Makeup	2,602,000 gallons/day
Units 1a, 1b & 2 Neutral. Basin	38,200 gallons/day
Units 1a & 1b Other Plant Flows	48,100 gallons/day
Unit 3 Neutralization Basin	14,000 gallons/day
Unit 3 Other Plant Flows	79,600 gallons/day
Seepage thru the Berm	920,000 gallons/day
Leakance	336,000 gallons/day
Discharge	0 gallons/day

(a) concentrations based on flow weighted discharges from Units 1a, 1b, 2, and 3.

probability of the reservoir discharging when Payne Creek flows are less than 22 cfs are extremely remote, but not statistically impossible. If such extreme conditions (less than 22 cfs flow in Payne Creek) become manifest, the reservoir would still need to discharge or else the integrity of the berms could be compromised with ensuing catastrophic results. Therefore, SECI feels that this stipulation is unwarranted.

FDEP.BWF-8

Comment: Section 5.2.1-3 states that mixing zone lengths and widths were based on predicted discharge and streamflow rates for the 25-year, 24-hour storm. Are these the same streamflow rates used to predict the thermal mixing zone length?

Response: The 10-year, 24-hour storm event was utilized to predict the discharge from the reservoir as well as the stream flow in Payne Creek. The flows out of the reservoir and in Payne Creek were identical for both the thermal and chemical mixing zone analyses.

FDEP.BWF-9

Comment: Section 5.2.1-4 described the mixing zone calculations for the parameters listed in Table 5.2.1-2. The analytical detection limits established by the applicant need to be justified.

Response: The water quality laboratories conducting the analyses have the proper state and federal certifications, including a valid FDEP QA/QC Plan. Analytical detection limits can vary from sample to sample due to matrix characteristics and inherent sample interferences. The analytical detection limits used for the chemical analyses are the most stringent allowed by the laboratory's FDEP approved QA/QC plan for any sample's given characteristics.

FDEP.BWF-10

Comment: Section 5.2.1-4 states that the total dilution available in Payne Creek is 67:1. How was this determined?

Response: The volumetric dilution ratio of 67:1 was derived as follows:

a. Payne Creek flow = 22 cfs
b. Reservoir discharge = 0.33 cfs

c. Volumetric Dilution = $\frac{\text{Reservoir discharge}}{\text{Payne Creek Flow}}$

d. Computations: dilution = 0.33/22 = 0.015 or 67:1

FDEP.BWF-11

Comment: Section 5.2.1-5 states that the ambient concentrations for lead and mercury vary with flow. Please provide the ambient flows associated with the ambient concentrations used in the calculations.

Response: See attached Table FDEP.BWF-11.

FDEP.BWF-12

Comment: As stated in 17-302.500 Florida Administrative Code "all surface waters of the State shall at all places and at all times be free from: (1) domestic, industrial, agricultural, or other man-induced non-thermal components of discharges which, alone or in combination with other substances or in combination with other components of discharges (d) are acutely toxic". We request that acute bioassays be performed yearly on the cooling reservoir.

Response: SECI intends to comply with all applicable requirements of FAC 17-302.500 in the unlikely event of a discharge from the cooling reservoir. NPDES permit conditions require monitoring of reservoir water for a variety of parameters at the point of discharge during a discharge event. Since the cooling reservoir is not State waters or waters of the United States but is a heat dissipation treatment system which will discharge only during extreme rainfall events, conducting acute bioassay tests during the normal, non-discharging operating condition would not provide data that would be indicative of water quality during a discharge event. The current NPDES permit for the cooling reservoir does not require whole effluent toxicity testing.

Table FDEP.BWF−11. Comparison of Payne Creek Flow and Mercury and Lead Concentrations

Date	Payne Creek Flow (cfs)	Mercury Concentrations (μg/l)			Lead Concentration (μg/l)		
		Sta. PC−1	Sta. PC−2	Sta. PC−3	Sta. PC−1	Sta. PC−2	Sta. PC−3
11−Oct−88	12.2	<0.2	<0.2	<0.2	<5	<5	<5
08−Nov−88	11.6	<0.2	<0.2	<0.2	6.7	<5	<5
08−Dec−88	4.7	0.5	0.5	0.4	<5	<5	<5
11−Jan−89	2.3	<0.2	<0.2	<0.2	<5	8.9	9.6
15−Feb−89	3.0	<0.2	<0.2	<0.2	<5	9.8	5.0
15−Mar−89	4.2	<0.2	<0.2	<0.2	<5	8.9	6.2

Notes: 1. Flow data is also presented in Table 2.3.4−5 of the SCA.
2. Lead and mercury data is from Section 11.5.4 of the 1989 SCA.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF WETLAND RESOURCE MANAGEMENT

(FDEP.BWRM)

FDEP.BWRM-1

Comment: Please provide a full-size recent aerial photograph of 1":200' scale with a north arrow, jurisdictional lines and the impact and mitigation areas delineated in such a fashion as to not obscure the photographic image.

Response: A recent full size aerial at a scale of 1": 400' of the project site showing the Florida Department of Environmental Protection (FDEP) jurisdictional line and mitigation areas is attached. (A recent aerial at a scale of 1":200' is not currently available from Hardee County or any private source.)

FDEP.BWRM-2

Comment: The narrative states that the forested segment of the unnamed tributary is being encroached upon by weedy species. Please provide a list of the encroaching species.

Response: The species encroaching upon the tributary wetland in order of decreasing abundance include cogon grass (*Imperata cylindrica*), saltbush (*Baccharis halimifolia*), dogfennel (*Eupatorium capillifolium*), grape (*Vitis rotundifolia*), greenbrier (*Smilax bona-nox*), flattop goldenrod (*Euthamia minor*), bahia grass (*Paspalum notatum*), and Carolina willow (*Salix caroliniana*).

FDEP.BWRM-3

Comment: Please specify what material will be placed on the geotextile fabric to create the temporary work pads in the wetlands.

Response: Clean fill consisting of local soil will be used to cover the geosynthetic fabric. This soil will be available from other onsite construction excavation activities. The soil will be removed following installation of the pipe crossing and the wetlands restored to a herbaceous system.

FDEP.BWRM-4

Comment: Please provide a vegetation species list for the drainage ditch to be impacted. The narrative states that the ditch is maintained, please clarify the type of maintenance and the maintenance schedule.

Response: Vegetation present in the east drainage ditch in order of decreasing abundance includes bahia grass, sesbania (*Sesbania exultata*), primrose willow (*Ludwigia peruviana*),


N
0 250 500
Scale in Feet
WETLAND CREATION SITE (0.233 ACRE)
TRIBUTARY WETLAND 9.74 ACRES
TRIBUTARY WETLAND 9.74 ACRES
WETLAND RESTORATION SITE (0.22 ACRE)
DRAINAGE DITCH
ROADSIDE DRAINAGE DITCH
#34095-41
7-6-93
1"=400'

Texas sage (*Cyperus polystachyos*), penneywort (*Hydrocotyle* sp.), and phyla (*Phyla nodiflora*). Because this ditch is located along the entrance road to the power plant, it is mowed every few weeks during the growing season and less frequently during the nongrowing season.

Vegetation present in the western drainage ditch includes cattail (*Typha* sp.), primrose willow, perennial kyllinga (*Cyperus brevifolius*), knot grass (*Paspalum distichum*), climbing hempweed (*Mikania scandens*), wax myrtle (*Myrica cerifera*), penneywort, soft cordgrass (*Juncus effusus*), and smartweed (*Polygonum hydropiperoides*). This drainage ditch is mowed on an infrequent basis only when it dries out.

FDEP.BWRM-5

<u>Comment</u>: Please clarify to where the dewatering effluent will be pumped if it becomes necessary to dewater during the construction of the pipeline supports.

<u>Response</u>: During construction of the Hardee Unit 3 facility, dewatering effluent will be pumped to the onsite detention pond as described in Section 4.3 of the SCA.

FDEP.BWRM-6

<u>Comment</u>: Please provide a vegetation species list for the wetland area to be impacted by the retainment berm.

<u>Response</u>: The species in the retainment berm impact area include in order of decreasing abundance soft cordgrass, yellow goldenrod (*Solidago fistulosa*), saltbush, dogfennel, winged sumac (*Rhus copallina*), coinwort (*Centella asiatica*), maidencane (*Panicum hemitomon*), and chalky bluestem (*Andropogon glomeratus*).

FDEP.BWRM-7

<u>Comment</u>: Please clarify the purpose of the ditch at the base of the retainment berm.

<u>Response</u>: The ditch at the base of the retainment berm will be contoured to direct noncontact site runoff to the stormwater detention pond.

FDEP.BWRM-8

Comment: The drawings for the wetland impacts are illegible, with the exception of the pipeline. Please provide plan view and cross-section drawings similar to the pipeline drawings for the other wetland impacts.

Response: KBN received clarification on this comment from Trudie Bell at FDEP. Figure FDEP.BWRM-8 is attached which clarifies the locations of wetland impacts as originally shown on Figures 7, 9, and 12 of the dredge and fill permit application (SCA Section 10.1.4).

FDEP.BWRM-9

Comment: Please clarify the exact number of trees to be removed for the pipeline construction.

Response: The number of trees to be removed for pipeline construction include 12 sweetgums, 10 dahoon hollies, 12 oaks, 5 American elm, and 2 popash. These trees are all less than 4 ft in height and were planted within the last few years.

FDEP.BWRM-10

Comment: Please provide a vegetation species list for the plants currently found at the mitigation site and at what elevation each species is found.

Response: Tables FDEP.BWRM-10.1 and FDEP.BWRM-10.2 list the vegetation present by elevation for both the wetland creation site and the wetland restoration site, respectively.

FDEP.BWRM-11

Comment: Please revise the mitigation cross-sections to show the vertical elevation related to NGVD and seasonal high and low water.

Response: The revised mitigation cross-section drawings are attached as Figures 5 and 6.

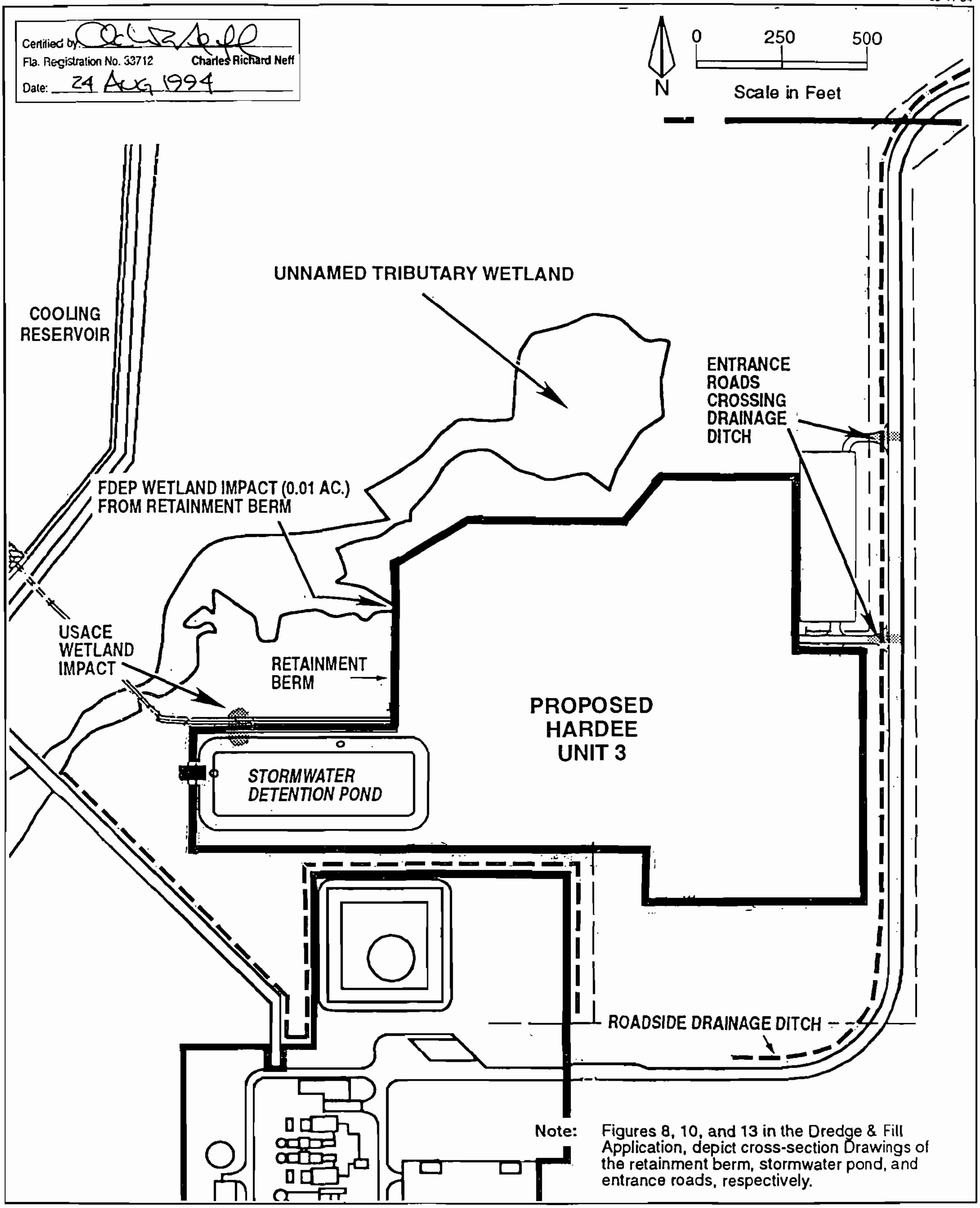


Figure FDEP.BWRM- 8
Plan View of Retainment Berm, Stormwater Pond, and Entrance Roads Where Wetland Impacts Will Occur

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

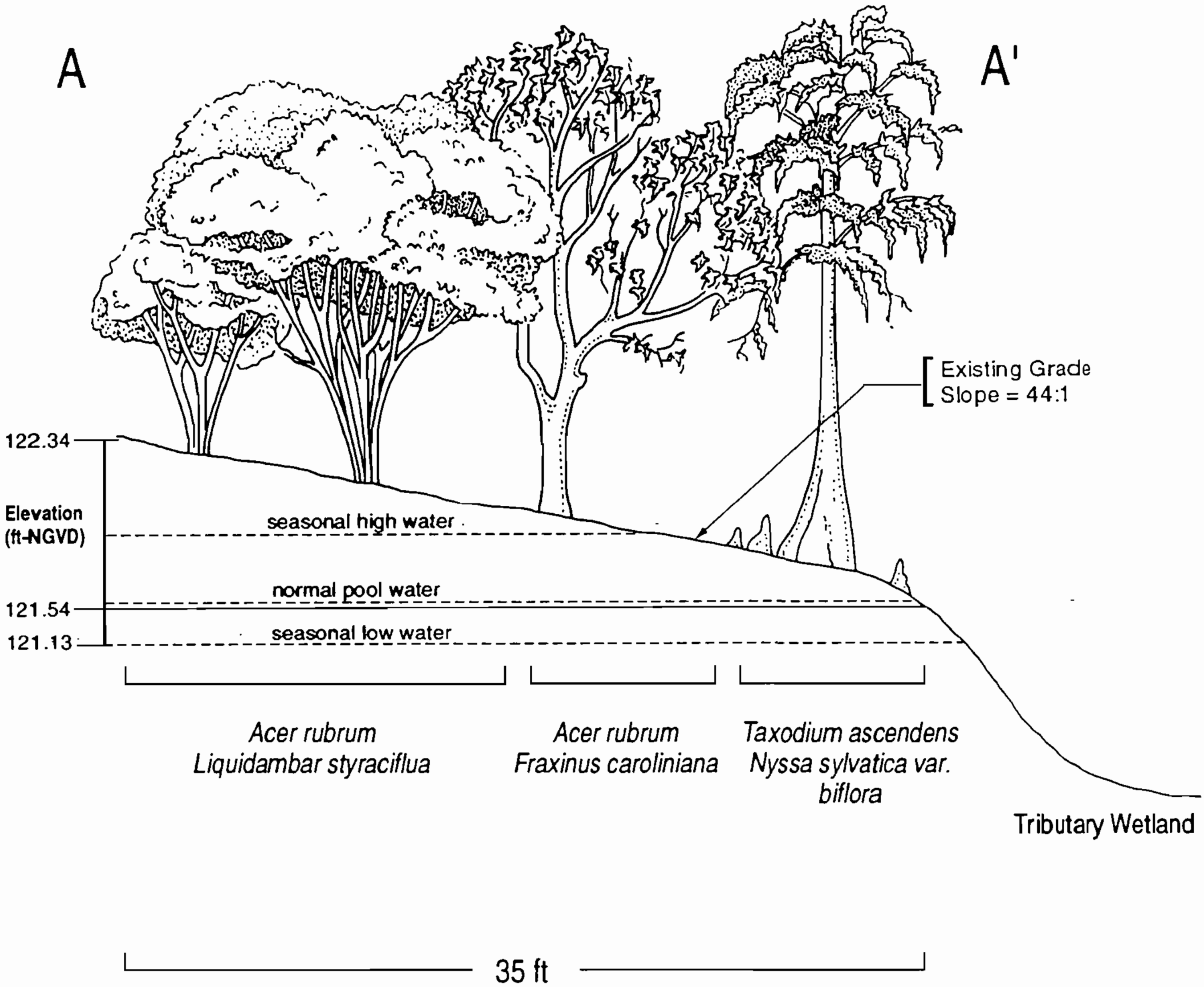
Table FDEP.BWRM-10.1. Vegetation Present at the Wetland Creation site by Elevation. (Note the upland edge of the wetland creation site is 65 ft and the waterward line is 30 ft.)

Vegetation Zone (ft)	Elevation (ft NGVD)	Species
North of 80 ft	122.54 and higher	Predominately bahia grass with scattered dogfennel, saltbush, and tiny headed beakrush (*Rhynchospora microcephala*)
80 - 50 ft	122.54 to 121.99	Saltbush, foxtail grass (*Setaria geniculata*), dogfennel, chalky bluestem, tiny headed beakrush, bahia grass, and lance-leaved beggar-weed (*Desmodium paniculatum*)
50 - 34 ft	121.99 to approximately 121.60	Saltbush, chalky bluestem, goat weed (*Scoparia dulcis*), tiny headed beakrush, and foxtail grass
34 - 20 ft	Approximately 121.60 to 121.34	Chalky bluestem, soft cordgrass, saltbush, primrose willow, foxtail grass, needle-pod rush (*Juncus scirpoides*), and aeschynomeme (*Aeschynomeme americana*).
20 - 12 ft	121.34 to approximately 121.14	Soft cordgrass, foxtail grass, primrose willow, needle-pod rush, climbing hempweed, and Carolina willow
12 - 0 ft	Approximately 121.14 to 120.94	Soft cordgrass, primrose willow, foxtail grass, climbing hempweed

Table FDEP.BWRM-10.2. Vegetation by Elevation at the Wetland Restoration Site. (Note the DEP jurisdictional line is located at 69 ft and 132 ft).

Vegetation Zone (ft)	Elevation (ft NGVD)	Species
South of 0 ft	118.90 and higher	Bahia grass, dogfennel, green brier
0 - 30 ft	118.90 to approximately 118.40	Bahia grass, greenbrier, saw palmetto (*Serenoa repens*), grape, bracken fern (*Pteridium aquilinium*), myrtle holly (*Ilex myrtifolia*)
30 - 69 ft	approximately 118.40 to approximately 118.10	Cogon grass, dogfennel, saltbush
69 -85 ft	approximately 118.10 to approximately 117.80	Saltbush, dogfennel, cogon grass, aeschynomeme
85 - 103 ft	approximately 117.80 to 117.30	Saltbush, dogfennel, aeschynomeme, cogon grass, flat-top goldenrod, ragweed (*Ambrosia artemisiifolia*)
103 to 116 (Creek channel)	117.30 to 117.40	Open water - vegetation on the edge of the creek includes penneywort, primrose willow, ludwigia (*Ludwigia octovalvis*), and smartweed
116 to 132	117.40 to approximately 117.60	Dogfennel, saltbush, primrose willow, climbing hempweed, penneywort, water-hyssop (*Bacopa innominata*), and ludwigia
132 to 150	approximately 117.60 to 118.30	Aeschynomeme, ragweed, bahia grass, dogfennel, hairy indigo (*Indigofera hirsuta*), and saltbush
150 ft and north	118.30 and higher	Aeschynomeme, dogfennel, bahia grass, cesearweed (*Urena lobata*), hairy indigo

Certified by: [signature]
Fla. Registration No. 33712 Charles Richard Neff
Date: 24 AUG 1994



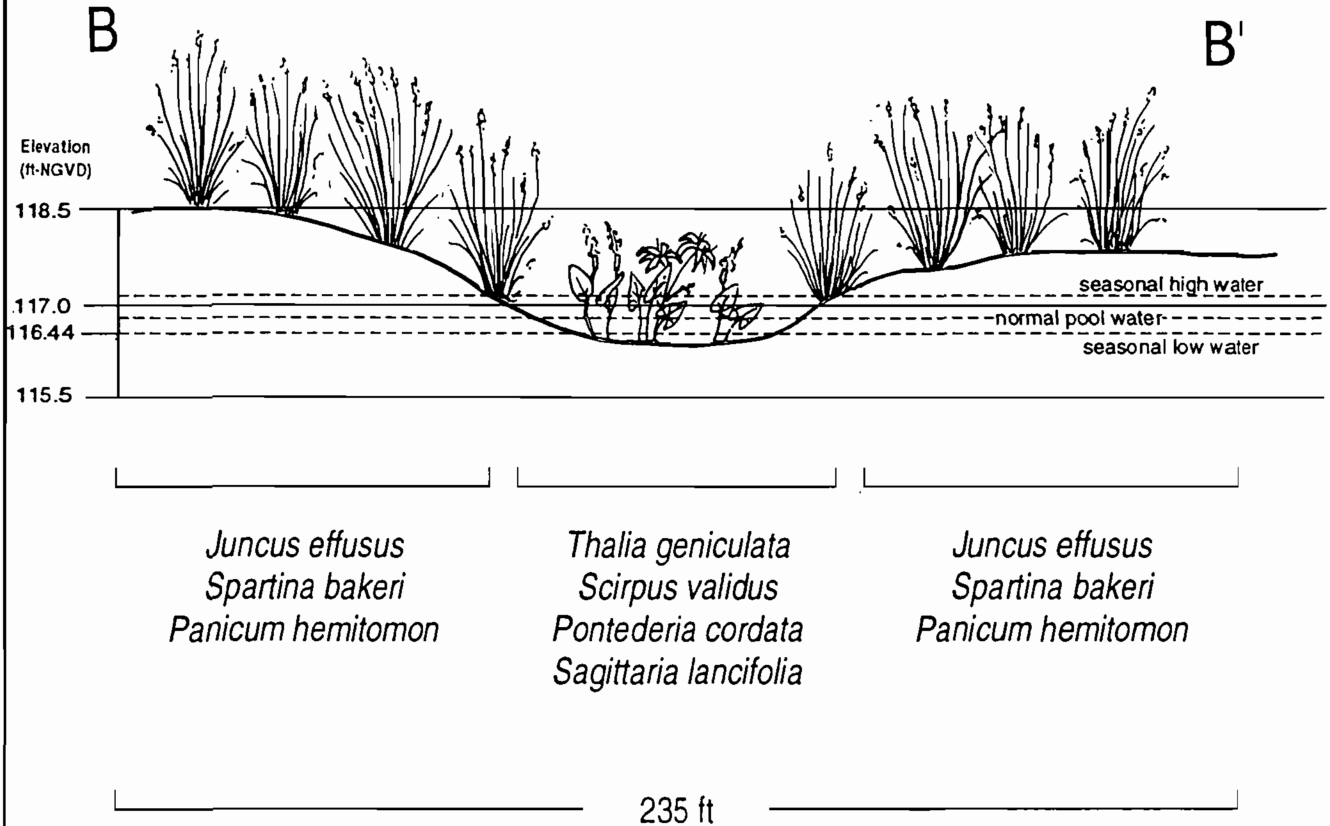
Notes: Wetland restoration area above seasonal high water corresponds with CORP-jurisdictional areas.

Plants will be 3-gallon or larger and planted on 10-ft centers.
Area of wetland mitigation site is 35 ft wide by 290 ft long (0.233 acre).
Seasonal high water = 121.99 ft-NGVD
Normal pool water = 121.55 ft-NGVD
Seasonal low water = 121.13 ft-NGVD

Figure 5
Cross Section of the Wetland Creation Site
(Revised 08/23/94)

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

Certified by: Charles Richard Neff
Fla. Registration No. 33712 Charles Richard Neff
Date: 24 AUG 1994



Notes: Wetland restoration area above seasonal high water corresponds with CORP-jurisdictional areas.

Plants will be bare root seedlings planted on 3-ft centers.
Area of wetland mitigation site is 40 ft wide by 235 ft long (0.22 acre).
Seasonal high water = 117.16 ft-NGVD
Normal pool water = 116.80 ft-NGVD
Seasonal low water = 116.44 ft-NGVD

Figure 6
Cross Section of the Wetland Restoration Site
(Revised 08/23/94)

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
INDUSTRIAL WASTEWATER SECTION

(FDEP.IWW)

FDEP.IWW-1

Comment: The cooling reservoir discharges to Payne Creek, which is projected to occur only for storm events in excess of the 10-year 24-hour storm. The cooling reservoir will be operated by TECO Power Services and SECI, with two separate NPDES permits proposed.

SECI needs to explain which of the existing facilities will be shared with TECO as indicated in section 1.3.1 of the SCA.

Response: Proposed shared facilities at the Hardee Power Station Site include: main entrance road, access road to cooling reservoir, FGT gas pipeline, transmission lines, cooling reservoir, groundwater wells, and switchyard. SECI Hardee Unit 3 will have its own industrial and domestic sewage treatment facilities which will discharge to the existing cooling reservoir. The cooling reservoir is proposed to be jointly used by TPS's existing and planned units and Hardee Unit 3 for condenser cooling and heat dissipation. It is also proposed that SECI and TPS will share a common outfall from the reservoir to Payne Creek as described in the NPDES permit application (Appendix 10.1.2 of the SCA).

FDEP.IWW-2

Comment: The site certification application indicates synthetic gas may be used as an alternative fuel. If synthetic gas is used as a fuel, the SCA will require modification. Under this arrangement it will be necessary to have more extensive internal wastestream monitoring and possibly discharge limits at both facilities.

Response: SECI does not anticipate the use of synthetic fuels at the Hardee Unit 3 facility at this time. If in the future, conditions favor the use of synthetic fuel, SECI will submit an appropriate application for approval to use such fuel.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
SOUTHWEST DISTRICT

(FDEP.SWD)

FDEP.SWD-1

Comment: I have again reviewed the SCA submitted by SECI for their Hardee Unit #3 (PA89-25SA). The information provided is skimpy. Since the WWTP is a small ancillary part of the large power generating facility, they obviously have not designed it yet, or at least have not provided us with that design information. It would be nice to review and approve the WWTP design at this time and address it in the sufficiency review. But that cannot be done.

Response: The waste water treatment plant (WWTP) for the proposed Hardee Unit 3 project has not been designed yet. General characteristics of the proposed treatment facility are presented in Section 3.0 of the SCA. As noted in the responses to comments for the environmental licensing plan of study for the Hardee Unit 3 project, the WWTP will be designed and operated in compliance with the substantive requirements of Chapter 17-600 and -601 F.A.C.

FDEP.SWD-2

Comment: Lacking that, what they have given us is sufficient at this time with the proviso that we have incorporated in the final Site Certification much of the same information and requirements that are contained throughout the Florida Power Corp Site Cert (PA92-33), and especially in Section XV of that document. Using the FPC SC as a starting point, I will draft similar portions to be included in the Hardee Power submittal and will provide them to Mike to forward on to Tallahassee.

Response: SECI will work with FDEP to develop appropriate conditions of certification to address the design and operation of the onsite WWTP for the Hardee Unit 3 project.

FDEP.SWD-3

Comment: The consultant's analysis and choice of a 10 year, 24 hour worst case storm event based on an analysis of the last 37 years of weather data was not provided within the report. Please have the consultant provide the analysis used to determine this worst case storm event.

Response: The 10-year 24-hour rainfall event was not, in and of itself, the "worst case storm event" over the historical period used in the analysis. As described in Section 5.1.1 of the SCA, the reservoir was predicted to have no discharge for the 37-year period modeled even during the observed worst case storm event. However, the reservoir has the capability to discharge (i.e., due to the presence of the fixed crest overflow weir). Therefore, a hypothetical discharge scenario had to be developed to determine what the discharge from the reservoir (into Payne Creek) would be if rainfall conditions more extreme than observed since 1948 occurred. This hypothetical discharge scenario (described in detail in Section 5.1.1 of the SCA) assumed that a major rainfall event (i.e., 10 year 24 hour) would occur on top of the significant events necessary to achieve the maximum predicted reservoir elevation. As noted in Section 5.1.1, the 10-year and 25-year rainfall events were analyzed and both created similar discharge rates from the reservoir. The 10-year event was used for the subsequent mixing zone modeling because it had a smaller Payne Creek flow associated with it and thus created a more conservative mixing zone analysis than a larger rainfall event.

FDEP.SWD-4

Comment: The consultant indicates on page 5.1.1-5 of volume 1 of the submitted certification report that the 10 year, 24 hour storm event would yield 7.5" of rain and the 25 year, 24 hour storm event would yield 9.0" of rain. However, no other storm events were analyzed during the modeling process. In addition, it appears that the modeling routines employed by the consultant allowed for the smaller rainfall event to be considered as the worst case because of frequency of occurrence. However, operating level was considered as 123 feet in the pond and would rise to 123.86 feet, during the 7.5" storm event. No pond elevation analysis was done for the higher rainfall event. There appears to be a flaw in the consultant's analysis of not looking at all rainfall events and deciding on a more conservative event. It appears that consultant is limited to a very narrow pond operating elevation bandwidth and must opt for the more aggressive pond design.

Response: As noted in the response to Comment FDEP.SWD-3, above, the reservoir was predicted to have no discharge for the 37-year period modeled. As such, all rainfall events occurring during that period, including any 10-year and 25-year events which may have occurred were included. However, these rainfall events were insufficient, both as independent events and real-time events, to cause the reservoir to discharge. The analysis methodology used was more conservative than the mere imposition of a single, high intensity event on the reservoir because it included potential for a major rainfall event AFTER the maximum observed events. As seen in Figure 5.1.1-1, the reservoir was below 123.0 ft-msl for 442 of the 444 consecutive months modeled. In fact, the reservoir was typically below 122.5 ft-msl. The reservoir elevation is kept within a closely managed operating range as a means to minimize ground water withdrawals not due to a marginal reservoir design

FDEP.SWD-5

Comment: There appears to only be a two foot elevation between the cooling water reservoir operating elevation and a potential pond discharge. What will happen should the utility need additional cooling capacity, as projected in the analysis, and raise the pond elevation allowing for less storage during a period of wet weather, which may result in a discharge during periods other than the 10 year, 24 hour storm event. It should be noted that most power plant and equipment designs allow for a 10 to 25% operating output above design conditions for short periods. Most gas turbine power plants have this peaking factor built into them during their design phase. Therefore, it is possible that the utility may opt to raise the pond elevation for better heat rejection and increase the power plant output during high demand periods which may coincide with a high rainfall events leading to more frequent discharges than anticipated.

Response: The cooling reservoir can provide heat rejection for the power plant at maximum buildout (i.e., 880-MW) and maximum load at a normal operating level of 122 ft-msl. Since cooling from the reservoir is a function of surface area and not volume, increasing the volume of the reservoir would not significantly increase the surface area and therefore would serve no useful purpose.

It should be noted that 67% of the Hardee Unit 3 generation is derived from the CTs, whose operation does not use water from the cooling reservoir. The remaining 33% of the generation is derived from the HRSG which does utilize the water from the cooling reservoir. The output of the HRSG may be increased above 140 MW only during cooler ambient, and correspondingly lower, reservoir temperatures. This increased output condition was analyzed and was found not to be the controlling reservoir condition.

FDEP.SWD-6

Comment: The consultant should submit for a separate construction permit for the domestic wastewater treatment plant, prior to construction or submit the necessary documentation to demonstrate the capability of the system to operate properly as part of this certification. The permittee should consider removing the nitrate monitoring requirement from the domestic wastewater operating permit and monitor for it in the existing groundwater monitoring wells for the cooling water reservoir. The requirement to monitor for nitrate (as nitrogen) should be added to the GWMP list of monitored parameters.

Response: SECI anticipates developing appropriate conditions of certification addressing the design and operation of the onsite WWTP as part of the certification process. Appropriate information describing the WWTP and its operation will be provided to FDEP for review prior to start of construction as required in the conditions of certification. SECI does not, however, plan to submit a separate permit application for the construction of the WWTP, since this facility, like all other associated with the proposed Hardee Unit 3 project, will be addressed under the site certification being sought through the Florida Electrical Power Plant Siting Act process and the SCA submitted to FDEP.

SECI agrees that the nitrate monitoring requirement should be removed from the domestic wastewater operating permit. SECI does not believe, however, that nitrate monitoring should be required for the groundwater monitoring wells as a result of recycling the treated domestic wastewater to the cooling reservoir. The limited volume of treated domestic wastewater generated at the Hardee Unit 3 project will not have a measurable impact on the water quality of the existing cooling reservoir or adjacent ground water.

FDEP.SWD-7

Comment: The permittee should be required to monitor the discharges from the oily water separator, domestic wastewater treatment plant and neutralization pond prior to their discharging into the cooling pond reservoir.

Response: Low volume wastes, including those identified above, will be routed to the cooling reservoir and are expected to be monitored prior to discharge into the cooling reservoir as required in the NPDES discharge permit. SECI believes that the monitoring requirements of the NPDES permit will be adequate to characterize the discharges into the cooling reservoir and therefore, additional monitoring is not proposed at the present time.

FDEP.SWD-8

Comment: As part of the sinkhole potential and fracture analysis investigations several surface depressions were identified, with some located within the cooling water reservoir area. It is also my understanding that these depressions were ground-truthed. The methods of ground-truthing should be specified as well as the location of the identified depressions, unless this information is located in the referenced document (TPS/SECI, 1989 of the SCA).

Response: Ground-truthing, as referenced in the SCA, consisted of field reconnaissance and inspection of potential sink areas identified from aerial photographs and topographical maps of the site. The areas were identified from the maps and inspected by personnel familiar with surficial karstic features. Results of the ground-truthing for each identified feature are summarized in Appendix 11.4 of the 1989 SCA. Results of the ground-truthing study are provided.

DESCRIPTION OF GROUND-TRUTHING FEATURES

1. Depression, 2-3 feet deep. Vegetation: dead water hyacinths; and grasses; very soggy center.
2. Depression, 1 foot deep. Vegetation: dead water hyacinths; dry; hog wallows nearby.
3. Depression, 1-2 feet deep. Vegetation: water hyacinth with a reed-like grass in the center. I was expecting this depression to have standing water in the center but it is located close to the mining operations and may have been dewatered. Power lines to the east and pipe on ground near east edge of sink. Very small areas which looks like a possible sink near the east edge of orange grove and west of this depression.
4. Depression, 3-4 feet deep. Vegetation: water hyacinth with cattails in center. Standing water in center.
5. Depression, 4 feet deep. Vegetation: mature water oaks and other lowland vegetation, marijuana.
6. Could not verify due to mining operations.
7. Depression, 10-12 feet deep. Vegetation: water lilies and other water vegetation. Standing water in bottom.
8. Depression, 4 feet deep. Vegetation: dead water hyacinth, standing water in center.
9. Depression 6+ feet deep. Vegetation: unidentified reeds and water grasses. Standing water. Wetland.
10. Depression, 4+ feet deep. Vegetation: unidentified; some water lilies; standing water, wetland. Alligator droppings.
11. Depression, continuation of 10, not as deep.
12. Depression, 1-2 feet deep. Vegetation: dead water hyacinths.
13. Depression, 4 feet deep.
14. Depression, 2+ feet deep.
15. Depression, unknown depth, northwest side has scarp could not tell if this was depression rim or just drainage. Drainage developed within trees to a marsh area in center. Center very wet. Vegetation: mature trees, with some wetland vegetation in center. Hard to tell extent of marshy area due to thick vegetation.
16. Depression, 1/2-1 foot in drainage area. Dry possibly due to mine dewatering. Hog wallows nearby.
17. Could not verify due to mining operations.
18. Could not verify because inaccessible.

19. Depression, 1-2 feet deep. Vegetation: mature trees and underbrush, dry.
20. Depression, 2-3 feet deep. Vegetation: mature trees and underbrush, dry.
21. Dragline Pit - man made.
22. Depression, part of it is very disturbed and there is evidence that this was used as a dragline pit. Other parts look like a natural depression. The only way to tell is to obtain old photography (pre-mining) and see if a depression was there originally.

FDEP.SWD-9

Comment: I agree that the findings of the AT&E, 1993 report (Appendix 10.7 of the SCA) do not indicate lost circulation zones, voids or cavities shallower than approximately 90 feet below ground surface. However, examination of the boring logs for B-14 and B-15 (along the east-west trending access corridor to the proposed site) indicate a possible anomaly. Specifically, the SPT blow counts recorded in the logs indicate loose sands to depths significantly greater than the borings located within the proposed site. This apparent anomaly should be interpreted and explained.

Response: Differences in soil characteristics in the general area of the proposed project site are attributable to mining and reclamation activities. In addition, some areas of the project site identified for construction of the power block have not been mined and therefore can be expected to exhibit different characteristics than those that have been filled and recontoured during recent reclamation activities. Specifically, the general area around boring sites B-14 and B-15 has been mined and reclaimed resulting in the SPT blow counts reported in the AT&E, 1993 report. The area to the west has not been mined.

FDEP.SWD-10

Comment: Table 2.3.2-3 indicates that ground water monitoring well HPS-1 had consistently and substantially higher concentrations of arsenic, chromium, lead and gross alpha yet had consistently lower values for TDS (with the exception of HPS-6 for the TDS parameter). This apparent anomalous location should also be interpreted and explained.

Response: Refer to Table FDEP.SWD-10 for a summary of selected groundwater modeling results.

Arsenic--This parameter was not reported at detectable concentrations at HPS-1 for the initial six sampling events. Arsenic was, however, reported at HPS-1 at concentrations ranging between 14 and 20 μg/L since May 1992. The concentration of arsenic in groundwater collected from HPS-1 appears to be trending somewhat lower since the

Table FDEP.SWD-10. *Summary of Selected Groundwater Monitoring Results Reported for Well HPS-1*

		Sampling Event												
Parameter	Standard	7/93	1/93	10/92	9/92	7/92	6/92	5/92	4/92	3/92	1/92	12/91	11/91	10/91
Arsenic (μg/L)	50	15	15	16	16	20	14	16	<10	<10	<10	<10	<10	<10
Chromium (mg/L)	0.10	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	0.10	0.42	0.16
Lead (μg/L)	15	<5	<5	<5	<5	<5	<5	<5	<5	<5	11	<5	36	14
Gross Alpha, total (pCi/L)	15	12.8	12	20	25	19	23.2	13.2	13.2	104	350	756	424	884
Gross Alpha, dissolved (pCi/L)	N/A	11.4	4	13	14.2	14.3	15.4	7.5	7.5	6.4	3.5	--	--	--

maximum concentration was reported in August 1992, however the trend may not be statistically significant. It is noted that the maximum reported concentration (20 μg/L) is twice the method detection level and less than half the primary drinking water standard of 50 μg/L.

There is no obvious pattern of arsenic occurrence for well HPS-1 that explains why this parameter is present at the upgradient monitor well, the most distant location from the Hardee Power Station facilities. The area to the north of well HPS-1 has been undergoing active reclamation of mined areas to the north, however impacts related to the release of arsenic to groundwater are not anticipated by these off-site activities.

<u>Chromium</u>--Chromium was reported at detectable concentrations for the first three sampling events conducted at well HPS-1 (October, November, and December 1991). The reported concentrations of chromium equaled or exceeded the primary drinking water standard during this interval. Since January 1993, this parameter has not been reported at detectable concentrations.

It is likely that the analytical results for the initial sampling events were affected by groundwater turbidity, potentially related to incomplete well development and/or sample collection techniques. It appears that chromium is not a representative constituent of the surficial aquifer, and is not affected by activities at Hardee Power Station.

<u>Lead</u>--Lead was reported at detectable concentrations in three of the four sampling events conducted between October 1991 and January 1992. It was reported that the groundwater sample collected during November 1991 exceeded the primary drinking water standard of 15 μg/L, however the concentration of lead reported for the other two sampling events was slightly below the standard. Lead has not been reported at a detectable concentration in samples collected from HPS-1 since the March 1992 sampling event.

The pattern of lead reported during the initial sampling events at HPS-1 is considered to be similar to the occurrence of chromium, and may be related to sample turbidity. It appears that lead is not a representative constituent of the surficial aquifer, and is not affected by activities at the Hardee Power Station.

Gross Alpha--Gross alpha has been reported at detectable concentrations for the 13 sampling events that were presented in the SCA. The primary drinking water standard of 15 pCi/L has been exceeded in 8 of the 13 sampling events; the most recent sampling event that was reported to exceed the standard was October 1992. The concentrations reported for total gross alpha (unfiltered) have varied greatly during the period of record, with an order of magnitude decline noted following the April 1992 sampling event. However, the concentrations reported for unfiltered samples since April 1992 have ranged between 12 and 25 pCi/L, exceeding the drinking water standard during four of these eight sampling events.

It is noted that filtered and unfiltered samples were submitted for analysis of gross alpha and Radium 226 starting with the January 1992 sampling event. It is likely that sample filtering was implemented to reduce sample turbidity that may have affected the results reported for radionuclide and metal parameters. The substantial decline in gross alpha concentration appears to be related to sample turbidity, and may have been affected by incomplete well development and/or sample collection techniques. The continued occurrence of total gross alpha at concentrations approaching or exceeding the drinking water standard, and reported concentrations of dissolved gross alpha indicate that this parameter is a representative constituent of the surficial aquifer. The occurrence of gross alpha is considered to be an artifact of phosphate mining and reclamation, and is not affected by activities at the Hardee Power Station.

FDEP.SWD-11

Comment: Table 3.5.0-3 indicates that a wastewater sump will receive wastewater streams from several sources (~93,000 gpd). This wastewater sump as well as the following wastewater stream routes should also be placed and identified on the Hardee Unit 3 Plot Plan (Figure 3.2.0-4 of the SCA): sewage treatment plant effluent, equipment and floor drain effluent, neutralization effluent, and the evaporative cooling water.

Response: The Wastewater Collection and Treatment System has not yet been designed therefore location and detailed routing of the wastewater treatment equipment is not available. Conceptual design of the system is as follows:

- The Wastewater Collection Sump will serve as a central collection point for all plant wastewaters including evaporative cooler blowdown, service water treatment system wastewater, sanitary waste treatment plant effluent, steam cycle blowdown, neutralization basin effluent, and oil separator effluent.

- Service water treatment system wastewater will be from backwash of the service water pressure filters.
- Sanitary waste effluent will be from the sewage treatment plant which will process all sanitary wastewater generated on-site.
- Steam cycle blowdown from each HRSG will be collected in a boiler blowdown tank. Each tank will discharge to a hot drain manhole in which blowdown will be cooled prior to discharge to the wastewater collection sump.
- Chemical wastewaters from regeneration of the demineralizers, and from chemical feed area drains will be routed to a neutralization basin. Once the wastewater has been neutralized it will be transferred to the wastewater collection sump.
- Wastewater collected from areas where a potential for oil contamination exists will be routed to the oil separator. These wastewaters include equipment drains, area drains, and precipitation runoff from oil contaminated areas.
- Miscellaneous drains from the water treatment building are also collected in the oil separator. These wastes will be collected by floor drains, piping, manholes, catch basins, trenches, sumps and ditches which will be routed to the oil separator.

FDEP.SWD-12

Comment: Wastestream water quality analyses should also be required such that: Within six months of startup for new facilities the SECI shall provide a wastestream characterization for: ion exchange reject water, the plant-sanitary effluent, boiler blowdown effluent, floor drain effluent, plant island stormwater effluent. Thereafter, a wastestream characterization shall be performed from a surface water sample collected from the Cooling Pond condenser intake structure within six months of the completion of construction but in no event with less frequency than every 5 years. Samples for characterization shall be analyzed for the Primary and Secondary Drinking Water Standards (Chapter 17-550, F.A.C)., Fecal Coliform and the EPA Priority Pollutants. The components identified in the wastestream characterizations shall be collectively designated as ground water indicator parameters that may be used to modify the Ground Water Monitoring Plan.

Response: Analyses of waste streams, including the low volume wastes produced by the Hardee Unit 3 facility, will be conducted in accordance with the requirements of the NPDES permit.

Operational characteristics and discharges associated with the Hardee Unit 3 facility will be similar to those associated with the Hardee Power Station (HPS) existing units (also subject to an NPDES permit). For this reason, SECI maintains that monitoring requirements for the cooling reservoir and groundwater for the Hardee Unit 3 project should not exceed those currently applicable to the HPS existing units.

FDEP.SWD-13

Comment: The TDS contour map included in the SCA (Figure 5.2.1-1) was derived from an unspecified 2-D finite element model. The SECI should provide the input and output files (preferably on an IBM formatted 3½" floppy disk) and reference the finite element software program as well as the version. Any calibration and verification procedures which may have been used should also be described.

Response: The TDS contour map shown in Figure 5.2.1-1 of the 1994 SCA was developed using the groundwater concentration (i.e., C/C_o) versus distance relationship which was originally developed for the 1989 SCA and is included as Figure 5.2.1-2 of the 1994 SCA. For Figure 5.2.1-1, the "new" reservoir water quality values were substituted into the original C/C_o versus distance algorithm to obtain the "new" groundwater quality contours. SCA Figure 5.2.1-2 was originally produced by a subcontractor to the original SCA process. The specific input and output files from the original modeling efforts are not available to SECI at this time.

Since there have been no changes to the existing cooling reservoir and field observations confirm the hydrogeological parameters used in the original modeling, SECI maintains that the model results are an accurate representation of potential groundwater impacts.

FDEP.SWD-14

Comment: The existing and proposed monitoring well locations are acceptable as is the well construction design. The field measurement of pH, specific conductivity and temperature is acceptable. However, water level measurements prior to purging is also required. The field measurement of sulfite is also acceptable since this would actually be more stringent than the minimum required field parameters.

Response: Water level measurements will be taken prior to purging of the groundwater monitoring wells.

FDEP.SWD-15

Comment: The collection of grab samples for the purposes of monitor well sampling is not acceptable. Ground water sampling and analyses shall be performed in accordance with Chapter 17-160, F.A.C. The SECI should reference the approved FDEP CompQAP number and ground water sampling protocol. Recently the State has certified the FPC Polk Power Station which requires the following parameters to be sampled and analyzed on a quarterly basis:

Primary Standards

Parameter	Units
Nitrate (as N)	mg/L
Nitrite (as N)	mg/L
Sodium	mg/L
Turbidity	NTU
Cyanide (as CN)	mg/L
Antimony	mg/L
Arsenic	mg/L
Barium	mg/L
Beryllium	mg/L
Cadmium	mg/L
Chromium	mg/L
Lead	mg/L
Mercury	mg/L
Nickel	mg/L
Selenium	mg/L
Thallium	mg/L
Benzene	mg/L
Fecal Coliform	cts/100 ml
Carbon tetrachloride	mg/L
1,2-Dichloroethane	mg/L
Trichloroethylene	mg/L
para-Dichlorobenzene	mg/L
1,1-Dichloroethylene	mg/L
cis-1,2-Dichloroethylene	mg/L
1,2-Dichlorpropane	mg/L
Ethylbenzene	mg/L
Monochlorobenzene	mg/L
o-Dichlorobenzene	mg/L
Styrene	mg/L
Toluene	mg/l
trans-1,2-Dichloroethylene	mg/L
Xylenes (total)	mg/L
Dichloromethane	mg/L
1,2,4-Trichlorobenzene	mg/L
1,1,2-Trichlorethane	mg/L
Polychlorinated biphenyl (PCB)	mg/L
Tetrachloroethylene	mg/L

1,1,1-Trichloroethane	mg/L
Vinylchloride	mg/L
<u>Secondary Standards</u>	
Foaming Agents	mg/L
Chloride	mg/L
Total Dissolved Solids (TDS)	mg/L
pH*	std. units
Color*	color units
Fluoride (as F)	mg/L
Aluminum	mg/L
Copper	mg/L
Iron	mg/L
Manganese	mg/L
Silver	mg/L
Zinc	mg/L
Sulfate	mg/L
<u>Others</u>	
Temperature*	°C
Total Organic Carbon (TOC)	mg/L
Specific Conductance*	μmhos/cm
Water Level (NGVD)*	feet
Dissolved Oxygen (minimum)	mg/L
Ammonia (as N)	mg/L
Ammonium (as NH4)	mg/L
Vanadium (as valence of +5)	mg/L
Calcium	mg/L
Magnesium	mg/L
Potassium	mg/L
Bicarbonate	mg/L
EPA 601/602 analytes	mg/L
<u>Acid Extractables</u>	
Phenols	mg/L
<u>Base Extractables</u>	
Butyl benzyl phthalate	mg/L
Di-n-butylphthalate	mg/L
Diethylphythalate	mg/L
Dimethylphythalate	mg/L
Dioctylphythalate	mg/L

*Field measurement.

Please note that after four consecutive quarters of data after start of commercial operation the SECI may request a reduction in sampling frequency or specific parameters of the ground water monitoring program. The request shall be considered reasonable when a trend analysis of the parameter indicates no significant or substantial change in the parameter. Specific parameters that are key indicators of the domestic or industrial processes or field measured parameters may not be reduced or eliminated from the ground water monitoring plan.

Since this list is more comprehensive than that proposed in the SCA, and in consideration that the facility has an operational data base, I recommend (in the interest of expediency) that a technical teleconference or meeting be arranged in order to discuss ground water monitoring parameters as well as wastestream analyses.

Response: Groundwater sampling and analyses will be performed in accordance with Chapter 17-160, F.A.C. All sampling and analyses will be performed under a FDEP approved CompQAP. At the present time, SECI has not selected a contractor to conduct the sampling and analyses for the Hardee Unit 3 groundwater monitoring program, and thus can not provide the FDEP-approved CompQAP number. This information will be provided to FDEP prior to initiation of the groundwater monitoring program for the Hardee Unit 3 facility.

SECI proposes to maintain the existing groundwater and surface water monitoring requirements for the Hardee Power Station. SECI proposes to initiate and maintain a groundwater monitoring program for the Hardee Unit 3 facility as described in Appendix 10.5.2 (Groundwater Monitoring) of the SCA. Because of the high degree of similarity in the design and operation of the HPS existing units with the Hardee Unit 3 project, SECI does not believe that additional monitoring requirements for the proposed facility are necessary.

FDEP.SWD-16

Comment: Seminole Electric's calculations predict that the cooling water reservoir will discharge water into Payne Creek only after extreme storm events (i.e., greater than the 10-year, 24-hour storm). Below what level will the pond water have to be maintained in order to ensure this retention capacity? How much fluctuation in pond level occurs between moderate and peak production? The Department must be assured that discharges from the cooling pond will occur infrequently.

Response: To retain the 10-year, 24-hour storm event, the cooling reservoir would have to be at a maximum elevation of 123.4 ft-msl.

The operational elevation of the cooling reservoir is independent of the power output from the facility (see response to FDEP.SWD-5). Therefore, reservoir levels will not be driven by variation in power production.

The cooling reservoir at the Hardee Power Station can only discharge through a fixed weir set at an elevation of 124 ft-msl.

A hypothetical discharge event for the reservoir was created by imposing a 10 year 24 hour rainfall event on the reservoir, assuming the reservoir elevation was above 123 ft-msl at the time of the event. The reservoir elevation was predicted to exceed 123 ft- msl only two times in the 37 year analysis (or, once in 18.5 years). The model also predicted that the reservoir elevation would be at or below 122 ft-msl 87% of the time and at or below 122.5 ft-msl 98% of the time. As noted in the SCA, to conserve groundwater usage, water will typically be added to the reservoir if the reservoir elevation falls below 122 ft-msl. Therefore, discharge from the cooling reservoir will occur infrequently, if at all.

FDEP.SWD-17

Comment: Non-contact surface water runoff from the facility will be routed to a stormwater detention pond with the ability to retain a 25-year, 24-hour storm event. The stormwater pond is designed to retain the first 2.5 cm. of runoff. The treated stormwater will then be discharged to the adjacent unnamed tributary to Payne Creek.

It is my understanding that the facility has applied for a stormwater discharge permit from SWFWMD. Should a permit application also be filed with FDEP? The potential for stormwater contamination is quite high at a large industrial facility such as this and a surface water quality monitoring plan should be developed for this discharge.

Response: The stormwater management plan for Hardee Unit 3 includes strict segregation (via concrete curbs and other appropriate structural means) of contact and non-contact stormwater. Only non-contact stormwater is routed to the stormwater management pond. Any contact stormwater is treated and then routed to the cooling reservoir for reuse.

Approval for the stormwater retention design has been submitted with the SCA which includes review by both SWFWMD and FDEP.

Stormwater contamination is unlikely at Hardee Unit 3 due to the utilization of a number of contact water collection points that route water to the wastewater treatment facility. Any failures in the segregation of contact from non-contact stormwater will be sampled as required under NPDES guidelines.

FDEP.SWD-18

Comment: There is no information in the siting application that address the drinking water review,other than a statement that potable water will be provided in accordance with FAC 17-550 and 555 and that all necessary information will be provided as part of the conditions of certification. Therefore, all necessary information providing reasonable assurance that the potable water portion of this project will meet the requirements of FAC 17-550, 17-551, 17-555 and 17-560 will be required in the conditions of certification.

Response: SECI will work with FDEP in developing appropriate conditions of certification to address the design and operation of the drinking water system for the Hardee Unit 3 facility in accordance with the referenced regulations.

FDEP.SWD-19

Comment: After review of the air resources portion of the Site Certification Application (SCA) and attendance at the June 24 project briefing meeting, the SW District Office Air Program finds the SCA sufficient and has no comments. The key elements of the air portion of the application are the PSD BACT determination and the air quality source impact evaluation which are reviewed by the Bureau of Air Regulation staff in Tallahassee.

Response: Statement acknowledged

FDEP.SWD-20

Comment: The proposed Hardee Unit #3 for Seminole Electric will be taking their solid waste away from the site, and disposing of the wastes at permitted solid waste management facilities. The Solid Waste Section does not have any sufficiency comments.

Response: Statement acknowledged

FDEP.SWD-21

Comment: In general, the wetland mitigation plan provided is consistent with recommendations discussed with (KBN) representatives. If successful, the proposed forested wetland creation and herbaceous restoration and enhancement will adequately compensate for wetland encroachment. Specific details which are absent from the proposal and should be provided to the Department for sufficiency include:

Normal pool, seasonal high water and low water elevations for the tributary wetland and how these elevations relate to the planting elevations for tree species to be installed.

Response: The seasonal high water line in the tributary wetland was estimated at 117.16 ft-NGVD. The normal pool and low water elevations were estimated to be 116.80 and 116.44 ft-NGVD, respectively. At the wetland restoration area, the herbaceous plants will be planted in a cross-section through the tributary wetland. Based on a cross-section elevation of this area, the herbaceous plants will be planted between the estimated low water elevation of 116.44 ft and 118.5 ft-NGVD, which is the landward extent of the USACE jurisdictional area. The seasonal high water will be close to the surface at the upper ends of the wetland restoration site due to seepage slopes and high clay content in the soil which retains moisture. Revised cross-section drawings depicting the planting elevations in relation to water elevations are presented in response FDEP.BWRM-11, Figures 5 and 6.

FDEP.SWD-22

Comment: Coinciding with proposed monitoring events, nuisance species eradication events should be performed to assist establishment of desirable wetland species. Also, installed trees having died from shock or stress should be replaced during each monitoring event.

Response: A monitoring program will be implemented with periodic maintenance events to eradicate any nuisance or exotic species which become established in the wetland creation or wetland restoration areas. As described in the Wetland Mitigation Plan in the Site Certification Application (SCA), the created wetland will be considered successful when the density of trees growing above the herbaceous stratum is equivalent to at least 400 trees per acre. Therefore, any trees which die after the initial planting event will be replaced if the density of planted trees drops below 400 trees per acre.

FDEP.SWD-23

Comment: It should be acknowledged by SECI they will be responsible for the ultimate success of the wetland mitigation which may entail implementing an alternative, remedial mitigation plan.

Response: SECI acknowledges that it will be responsible for the ultimate success of both the wetland creation area and the wetland restoration area. The success of the mitigation areas and the need for any necessary remedial plans will be evaluated during each mitigation monitoring event. In the event that a remedial plan is needed, the plan will be provided to FDEP for approval prior to implementation.

STATE OF FLORIDA
DEPARTMENT OF COMMUNITY AFFAIRS

(DCA)

DCA-1

Comment: Section 5.7 of the application, "Noise Impacts," describes the expected noise during operation of Hardee Unit 3. The Department suggests, however, that the description of the expected noise levels to be produced by the site during operation at full buildout (880 megawatts) should also be included in the application, to assist reviewing agencies in determining the suitability of the site for the proposed expansion.

Response: The sound pressure levels calculated for the Hardee Unit 3 facility while operating were revised to reflect the total site's full buildout of 880 MW (revised Tables 5.7.1-3 and 5.7.1-4). The noise impact revision was accomplished by ratioing, exponentially, the potential total operating capacity of the Hardee Power Station of 440 MW to the current configuration of 295 MW. The 440 MW to 295 MW ratio factor (1.4915) was applied to the background values for both the average minimum sound pressure levels and the average L_{eq} sound pressure levels. The revised background value was used in determining the operational noise impacts of the total facility buildout. The change in the predicted sound pressure levels of the total facility, in dBA, after the background values were revised (representing full buildout of 880 MW), was less than a 1 dBA (0.9 dBA) increase in property line noise levels.

Table 5.7.1-3. Impact Results Using Average L_{eq} Background[a] Values (all values dBA), Revised 7/20/94

Receiver Site	Description	Background	880-MW Facility w/o Background	880-MW Facility w/Background
A	North Boundary of Proposed Site	48.9	64.2	64.3
B	East Boundary of Proposed Site	50.4	64.5	64.7
C	Southeast Boundary of Proposed Site	50.4	56.5	57.0
D	South Boundary of Proposed Site	48.7	54.7	55.7
E	West Boundary of Proposed Site	48.7	57.5	58.0
F	South of Proposed Site (@ Residences)	45.6[b]	44.4	48.1

[a] Background values include noise emissions factor of 1.4915.
[b] Background value based on a previous analyses for predicted noise levels due to the existing Hardee Power Station.

Source: KBN, 1994.

Table 5.7.1-4. Impact Results Using Average Minimum Background[a] Values (all values dBA), Revised 7/20/94

Receiver Site	Description	Background	880-MW Facility w/o Background	880-MW Facility w/Background
A	North Boundary of Proposed Site	46.1	64.2	64.3
B	East Boundary of Proposed Site	47.5	64.5	64.6
C	Southeast Boundary of Proposed Site	47.5	56.5	57.0
D	South Boundary of Proposed Site	41.3	54.7	54.9
E	West Boundary of Proposed Site	41.3	57.5	57.6
F	South of Proposed Site (@ Residences)	45.6[b]	44.4	48.1

[a] Background values include noise emissions factor of 1.4915.
[b] Background value based on a previous analyses for predicted noise levels due to the existing Hardee Power Station.

Source: KBN, 1994.

SOUTHWEST FLORIDA WATER MANAGEMENT DISTRICT

(SWFWMD)

SWFWMD-A1

Comment: The storm water management plan (calculations and construction drawings) was not signed, dated, and sealed by a Florida registered engineer as required by Chapter 471, Florida Statutes. Please provide a certified copy of the storm water management plan.

Response: Signed and sealed calculations and drawings for the storm water management plan have been submitted to the Southwest Florida Water Management District (SWFWMD) under separate cover.

SWFWMD-B1

Comment: Please provide a certified survey of the approved wetland limits in the vicinity of those areas adjacent to proposed construction.

Response: A copy of the certified survey of the onsite wetlands has been provided to SWFWMD and FDEP under separate cover. A copy of the survey is attached.

SWFWMD-B2

Comment: Please provide a numbering system for all on-site wetlands (including those less than 0.5 acre) and for each wetland clearly indicate the index number on the construction drawings. In tabular form, please indicate for each wetland the index number, on-site acreage, impact acreage, and indicate whether the wetland has been claimed by the District, the Army Corps of Engineers, and/or the Department of Environmental Protection (DEP).

Response: Figure 4 in the Dredge and Fill Permit Application (attached) provides a numbering system for all onsite wetlands as well as the expected impact for each wetland. The construction drawings provided in the Dredge and Fill Permit Application correspond to these wetlands. Table SWFWMD-B2 summarizes the wetland areas, impact types, and corresponding construction drawings, as well as the requested wetland acreages, impact acreages, and jurisdictional status for each wetland. This information was originally provided in Appendix 10.1.4 of the SCA.

08-25-94

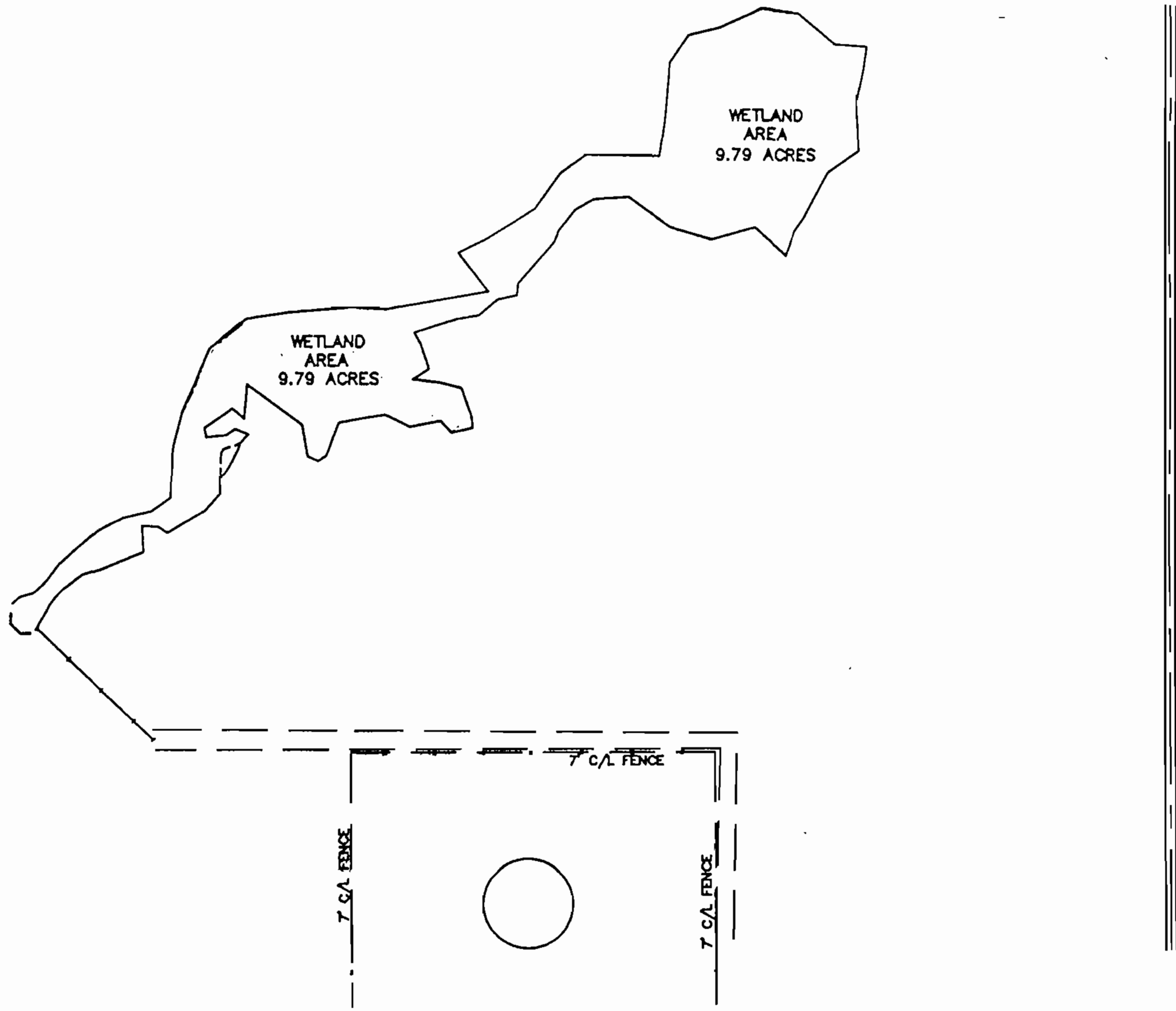


Figure SWFWMD.B1
SWFWMD Jurisdictional Wetland Delineation

Source: Chastain Skillman, Inc.

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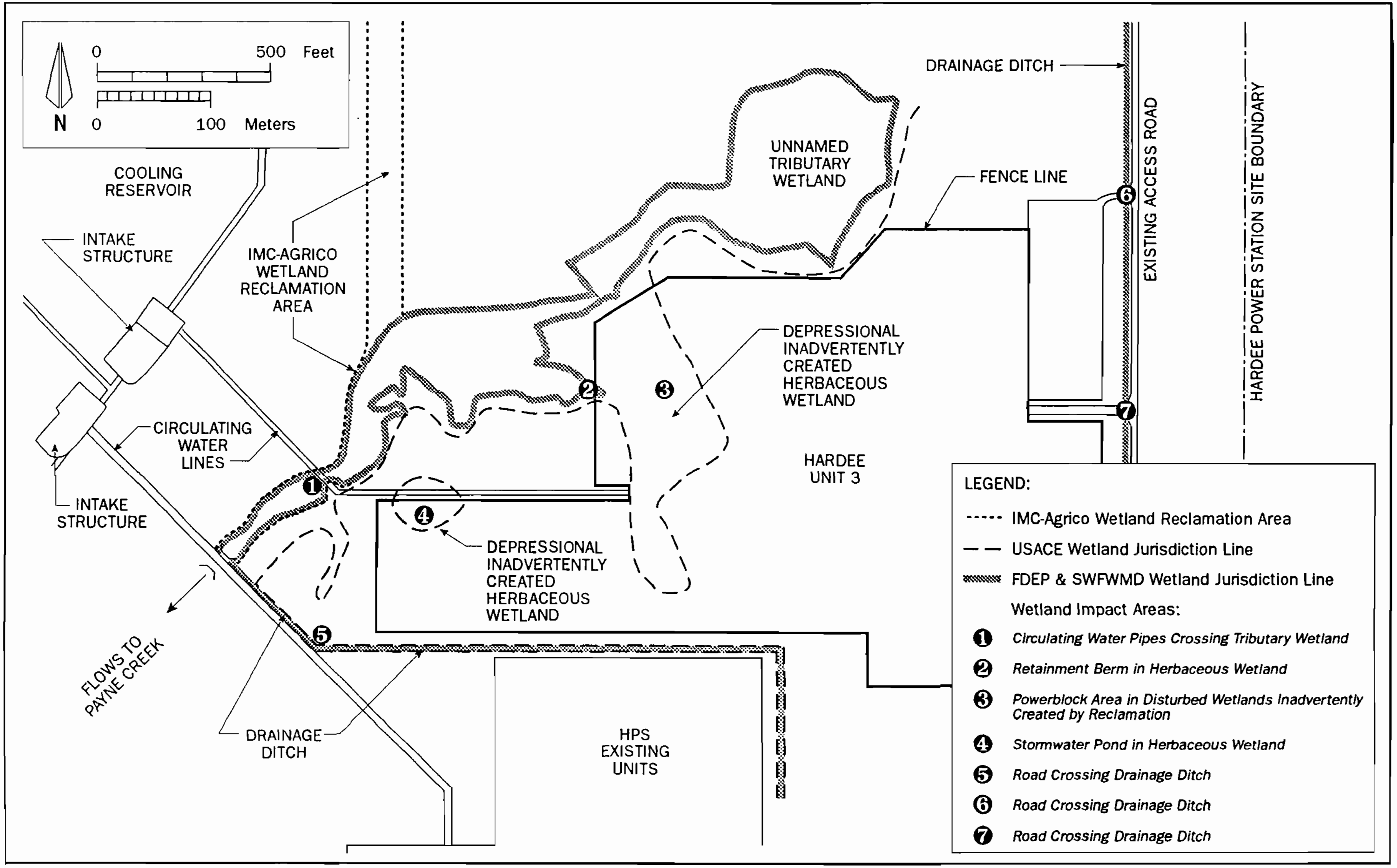

SWFWMD-3

Figure 4
Location of Jurisdictional Wetlands in Relation to Hardee Unit 3 Site Plan

Source: KBN, 1994.

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Table SWFWMD-B2. Summary of Wetlands, Impacts, Acreages, and Jurisdiction (Wetland number corresponds to Figure 4 (attached) from the Dredge and Fill Permit Application), Revised 08/26/94

Wetland Index Number	Type of Wetland	Type of Impact	Corresponding Figures in the Dredge and Fill Application in the SCA	Total Wetland Acreage	Impact Acreage	Jurisdictional Agency
1	Tributary Wetland	Crossing by Circulating Water Pipes	5, 6	9.74	0.06 acre of clearing; 0.015 acre of dredging and filling	SWFWMD, FDEP, USACE
2	Herbaceous portion of tributary wetland	Retainment berm	7, 8	9.74	0.01 acre of fill and 0.003 acre of dredging	SWFWMD, FDEP, USACE
3	Disturbed Herbaceous Wetland	Construction of the Powerblock	7	4.69	4.69 acre of fill	USACE
4	Disturbed Herbaceous Wetland	Construction of a stormwater pond	9, 10	0.55	0.17 acre of fill; 0.30 acre of dredging	USACE
5	Drainage Ditch	Road Crossing	9, 11	---	0.07 acre of filling; 0.01 acre of dredging	FDEP
6, 7	Drainage Ditch	Road Crossing	12, 13	---	0.22 acre of filling; 0.01 acre of dredging	FDEP

SWFWMD-B3

Comment: Please provide construction drawings (plan view and cross-sections) signed, dated, and sealed by a Florida registered engineer for the mitigation area and all proposed construction in wetlands.

Response: Construction drawings for all proposed wetland construction areas are provided in Figures 5 through 13 of the Dredge and Fill Permit Application in the SCA (Appendix 10.1.4). For the two mitigation areas (Figure 4 in the Wetland Mitigation Plan), cross-section elevations were recently surveyed. A signed and sealed plan view drawing of the mitigation site is attached as Figure 4, and cross section drawings presented as Figures 5 and 6 are provided as Response FDEP-BWRM-11.

SWFWMD-B4

Comment: Please provide a complete description of measures to be implemented during construction activities in wetlands to prevent adverse quantity and quality impacts off site. Show all erosion and sediment control measures to be utilized on the construction drawings for the project. Clearly label all turbidity curtains, silt screens, hay bale fences and other turbidity control measures placed.

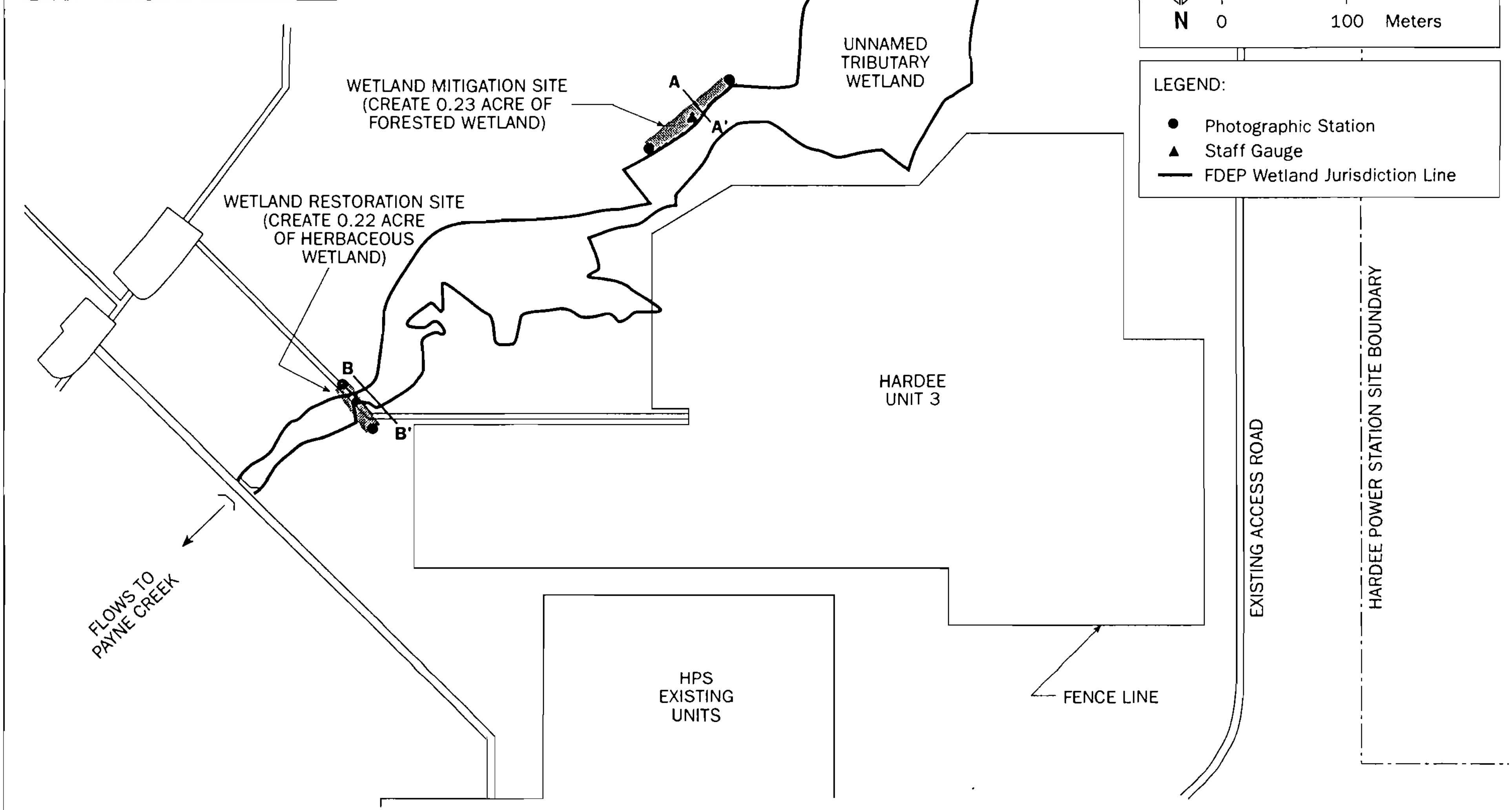
Response: Temporary measures will be used during construction to control erosion and sediment transfer from the site. Silt fences will be used to filter sediments washed from grading areas where the ground slopes away from the site. Areas disturbed during grading operations will be seeded to establish a vegetative cover to reduce erosion on the site. A more detailed description of sedimentation measures is provided in the Erosion and Sedimentation Control Plan in Appendix 10.9 of the SCA. The location of all silt fences is shown on the attached revised Figures 5, 7, 9, and 12 from the dredge and fill permit application.

SWFWMD-B5

Comment: A mitigation plan was submitted along with the DEP application information. Please provide a compensation/mitigation plan as part of the Management and Storage of Surface Waters (MSSW) application or at least a statement that the DEP mitigation plan is also submitted as compensation for impacts under District jurisdiction.

Response: The mitigation plan submitted in the SCA (Appendix 10.1.4) is also submitted as compensation for wetland impacts under SWFWMD jurisdiction.

Certified by: [signature]
Fla. Registration No. 33712 Charles Richard Neff
Date: 24 AUG 1994



SWFWMD-6

Figure 4
Plan View of Mitigation Sites
(Revised 08/23/94)

Source: KBN, 1994.

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09-18-94

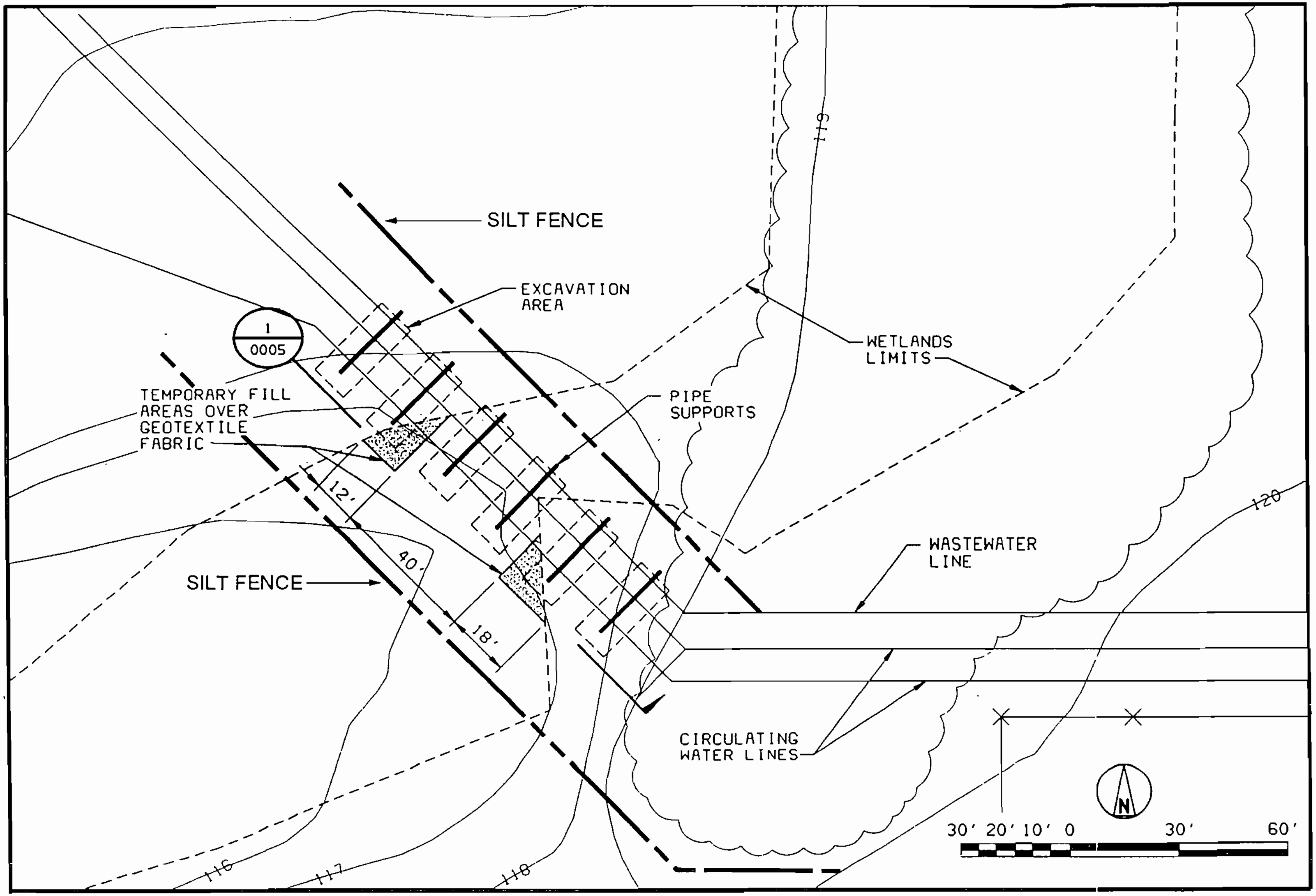

Figure 5
Plan View of the Circulating Water Pipes Crossing the Wetland
(Revised 8/22/94)

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SWFWMD-7

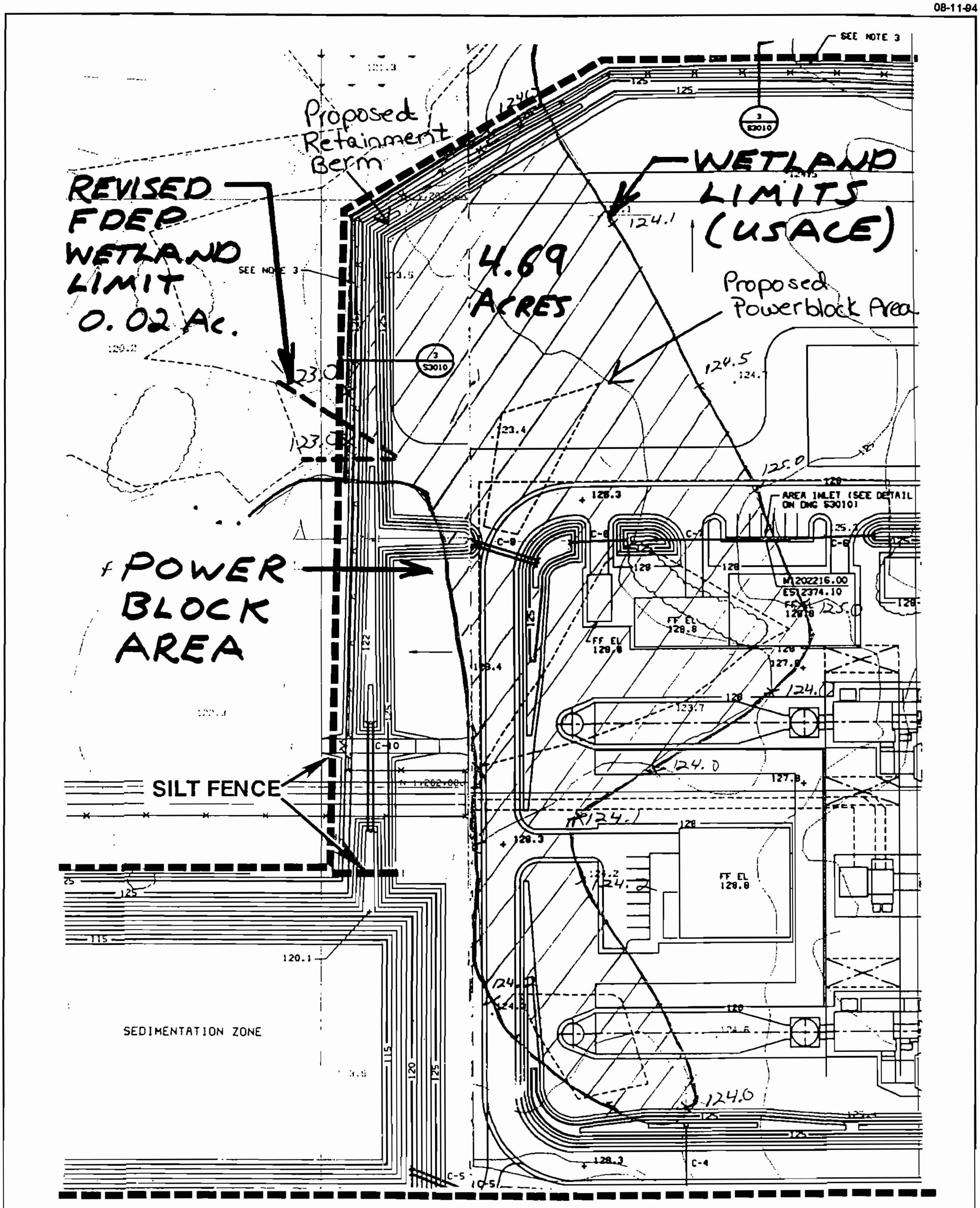

Figure 7
Plan View of the Retainment Berm and Powerblock Area
At Locations Where Wetland Impacts Will Occur
(Revised 8/22/94)

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

03-29-94

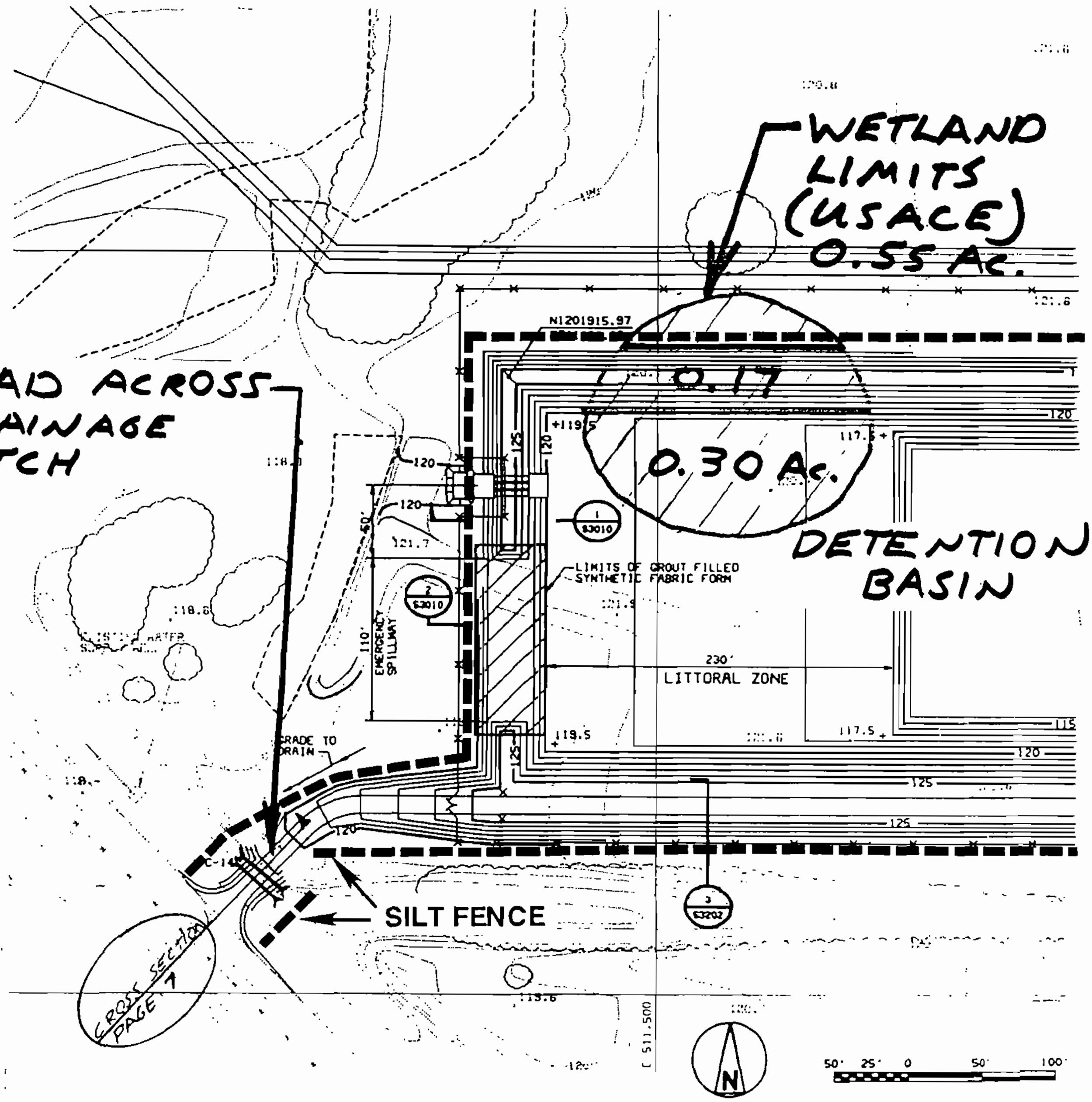

Figure 9
Plan View of the Stormwater Detention Basin (For the Portion Where Wetland Impact Will Occur) and Drainage Ditch Crossing
(Revised 8/22/94)

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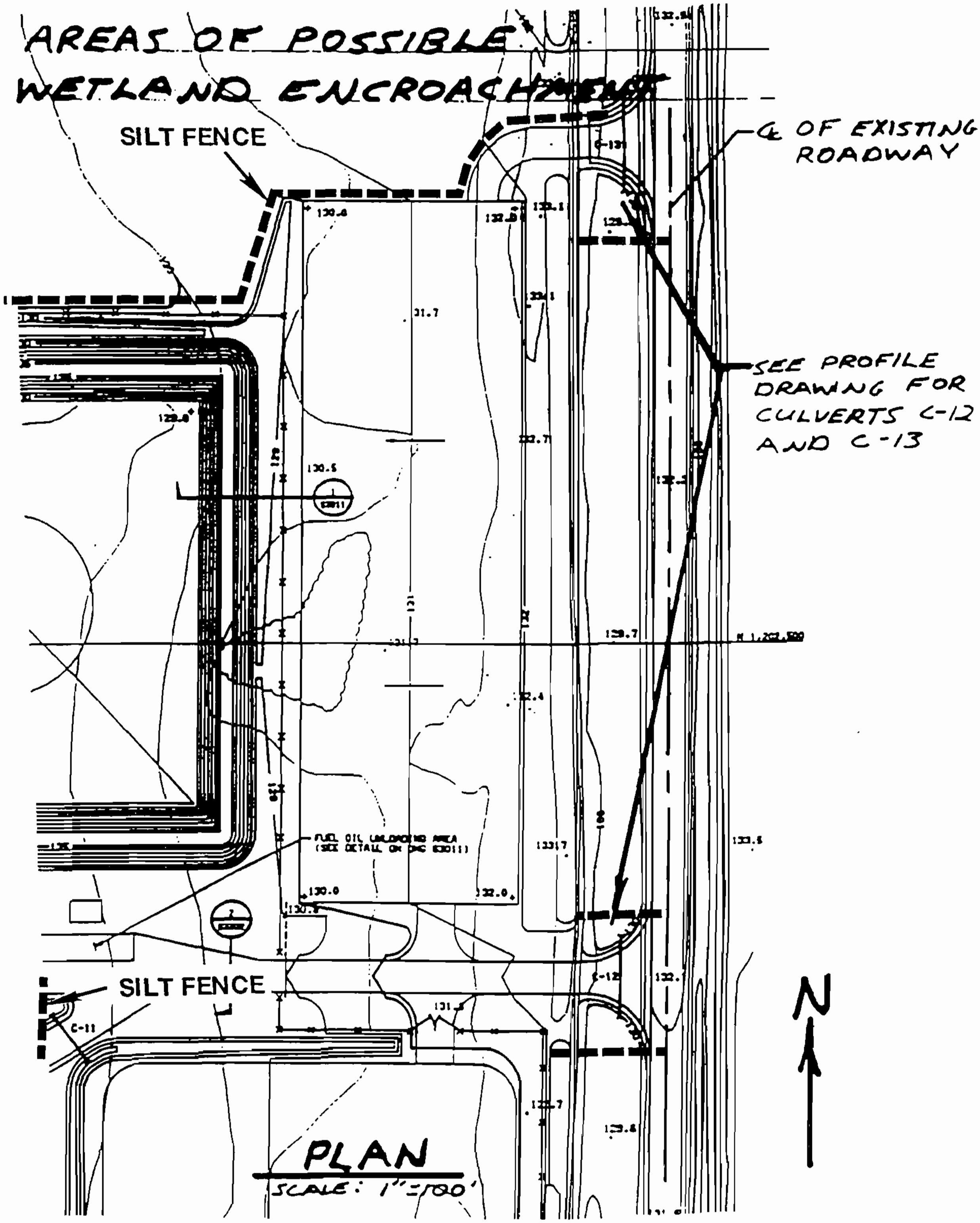


Figure 12
Plan View of the Entrance Road (the Ditch Crossing at Culverts C-12 and C-13 May Impact the Wetlands.)
(Revised 8/22/94)

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

SWFWMD-B6

Comment: Please delineate which portion of the larger mitigation area is proposed for compensation under the MSSW application.

Response: There are two wetland mitigation areas demarcated on Figure 4 of the Wetland Mitigation Plan; a 0.233-acre creation site and a 0.22-acre restoration site. Both of these mitigation areas are proposed for compensation for the MSSW system.

SWFWMD-B7

Comment: Please provide herbaceous ground cover (mulching and/or planting) within the forested mitigation area.

Response: Since grading is not proposed for the forested mitigation area and only minimal disturbance to ground cover will be associated with the mitigation area, SECI is not proposing to provide herbaceous ground cover (mulching and/or planting) at this time due to the existing species on the site. Please refer to Table FDEP.BWRM-10.1, which lists the species currently existing within the creation site. Appropriate measures will be taken to prevent erosion in the mitigation area. However, since the ground cover in the mitigation area will be only minimally disturbed, erosion is not anticipated to occur in this area.

SWFWMD-B8

Comment: Please include all design details of the mitigation area on the construction drawings. Details should include plan and cross-sectional views showing limits of each distinct zone in reference to proposed control elevations, proposed plantings (species, sizes, densities and relative composition) within each zone, mulching details, proposed water elevations (seasonal high water level and normal pool), bottom elevations, and slopes.

Response: The mitigation sites were surveyed on August 2, 1994 to determine vertical elevations and planting zones. The revised plan view drawing is provided in Response SWFWMD-B3 as Figure 4. The revised cross-section drawings are provided in Response FDEP.BWRM-11 as Figures 5 and 6.

The areas surrounding the tributary wetland was initially mined for phosphate and the resultant substrate is higher in clay content and, consequently, has high water-holding capacity. Additionally, the wetland creation site located on the north side of the tributary wetland is relatively low in elevation and has been saturated or inundated during each site visit. With regard to mulching, please see response to SWFWMD-B7.

SWFWMD-C1

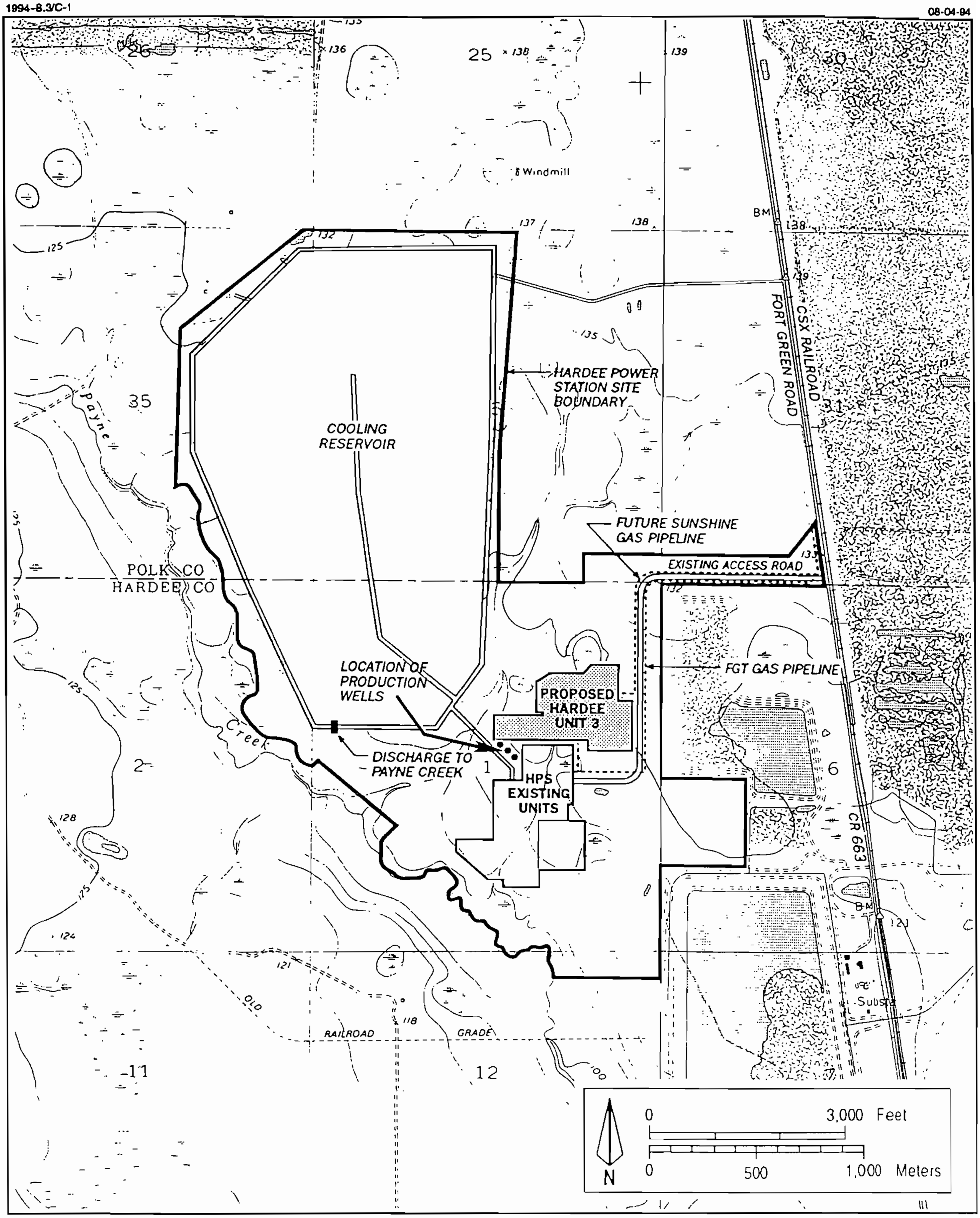
Comment: Please provide a map, not necessarily an aerial, indicating the specific location of the three existing wells, District ID Nos. 1, 2, & 3. Indicate the distances in feet to the nearest north/south and east/west property boundaries. Also, please indicate any numbering/identification system you have placed on these points for referencing.

Response: A map of the Hardee Power Station showing the approximate location of the proposed Hardee Unit 3 facility and the location of the three existing production wells is provide as Figure SWFWMD-C1. These wells are a minimum of 2,200 feet from the nearest east/west property boundary, and a minimum of 3,000 feet from the nearest north/south property boundary. The existing groundwater wells at Hardee Power Station have the following district ID numbers: 209731.00 for Well ID 1, Well ID 2, and Well ID 3.

SWFWMD-C2

Comment: The Water Balance Diagram submitted in support of your SCA, Figure 3.5.0.1, Cooling Reservoir Water Balance, Annual Average Conditions for 880-MW Buildout, indicates an Annual Average Daily quantity of 3.174 MGD from the deep wells, however, your application indicates the current allocation under the Site Certification is 3.8 MGD. Please provide revised water balance diagrams (i.e., diagrams for the proposed 440-MW Hardee Unit 3 and the build-out of 880-MW) consistent with the quantities currently allocated for the Site Certification.

Response: A revised water balance for the average daily case based on the Log-Pierson probability analysis is shown in Figure SWFWMD-C2. It should be noted that the 3.8 mgd average daily value is derived from a statistical analysis of the reservoir model. In the reservoir model, groundwater withdrawals are a summation of the reservoir makeup requirements, Units 1a, 1b, and 2 plant service water requirements, and Unit 3 plant service water requirements (for the 880-MW ultimate site capacity). The variability that exists around the calculated average water demand (i.e., 3.17 mgd) is a function of all three water use components, with reservoir makeup being the dominant factor. The values



SWFWMD-C1
Location of Existing Production Wells on the HPS Site

Sources: USGS, 1987; KBN, 1994.

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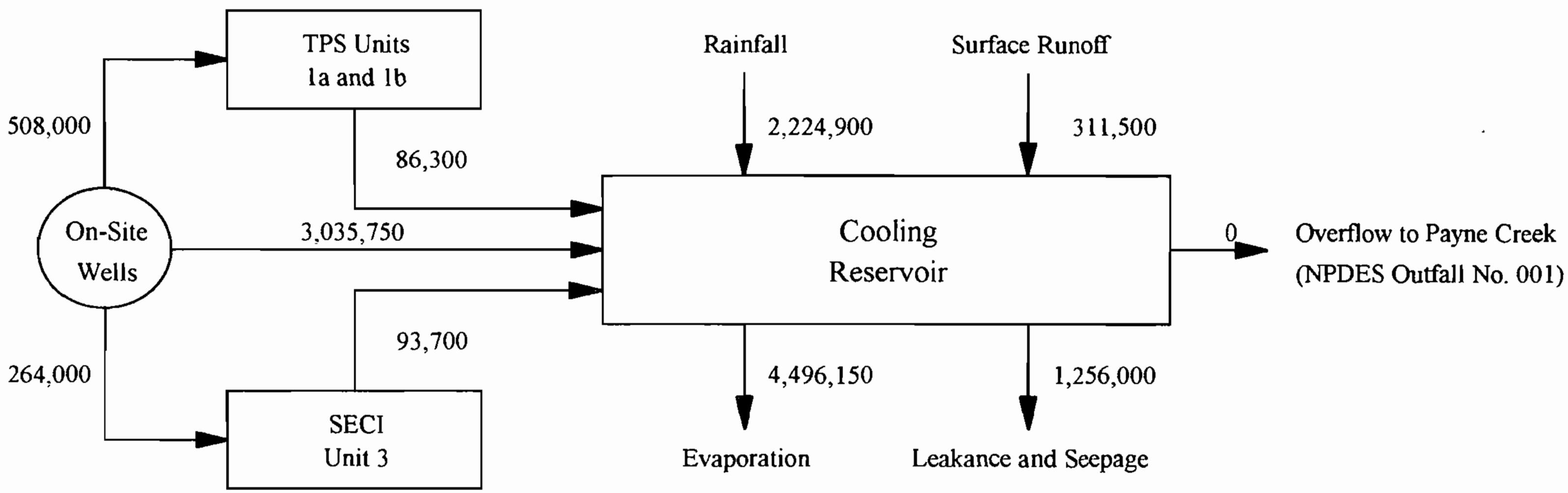


Notes:
1. All flows are in gallons per day.
2. Flows are for the 880 MW plant configuration.

File: CMNT-C2.XLS
Date: 8/23/94

Figure SWFWMD.C2
Water Balance for the Hardee Power Station — Average Conditions
Based on the Log-Pearson Type III Analysis

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

shown in this revised water balance are the component values associated with a 3.8 mgd average daily withdrawal.

SWFWMD-C3

<u>Comment</u>: The Water Balance Diagram submitted in support of your SCA, Figure 3.5.0.2, Cooling Reservoir Water Balance - Worst Case Monthly Conditions for 880-MW Building, indicates a Peak Month Daily quantity of 7.17 MGD from the deep wells, however, your application indicates the current allocation under the Site Certification is 8.64 MGD. Please provide revised water balance diagrams (i.e., diagrams from the proposed 440-MW Hardee Unit 3 and the build-out of 880-MW) consistent with the quantities currently allocated for the Site Certification.

<u>Response</u>: A revised water budget for the daily maximum case based on the Log-Pierson Type III analysis is shown in Figure SWFWMD-C3. The 8.64-mgd daily maximum value is derived from a statistical analysis of the reservoir model. In the reservoir model, groundwater withdrawals are a summation of the reservoir makeup requirements; Units 1a, 1b, and 2 plant service water requirements; and Unit 3 plant service water requirements (for the 880-MW ultimate site capacity). The values shown in this revised water balance are the component values associated with an 8.64-mgd maximum daily withdrawal.

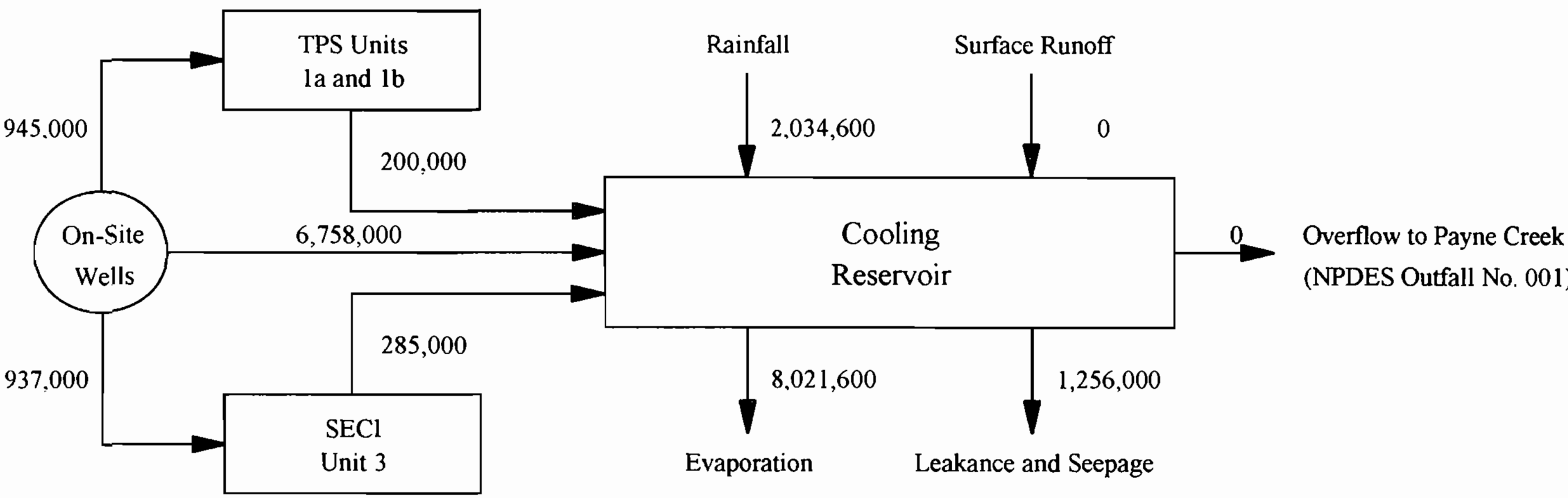
SWFWMD-C4

<u>Comment</u>: A Log-Pearson Type III distribution was provided in support of the Annual Average Daily water requirements for the HPS. Please provide this same type of analysis for the Peak Month Daily water use requirements to support the permitted 8.64 MGD.

<u>Response</u>: The Log-Pearson Type III analysis for the maximum load case is shown in Table SWFWMD-C4. As seen in the table, the maximum withdrawal value calculated by the model (i.e., 8.65 mgd) has a recurrence interval of less than 1 percent. The authorized maximum withdrawal (i.e., 8.64 mgd) is based on permitted pump capacity at the site (i.e., 3 pumps operating at 2,000 gpm each).

SWFWMD-C5

<u>Comment</u>: Please provide a comparison of the water conservation processes and equipment of the proposed plant with other plants of comparable generating capacity and ambient conditions (i.e., HPS existing equipment), including plants using cooling towers and other forms of heat exchangers. Demonstrate that the configuration of the proposed



Notes:
1. All flows are in gallons per day.
2. Flows are for the 880 MW plant configuration.

File: CMNT-C3.XLS
Date: 8/23/94

Figure SWFWMD.C3
Water Balance for the Hardee Power Station — Maximum Condition Based on Log-Pearson Type III Analysis and Maximum Pump Capacity

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

plant optimizes water conservation and that the most water-efficient processes and equipment practicable will be employed.

Response: Combined cycle power plants, such as Hardee Unit 3, are fundamentally more water efficient than traditional power generating technologies that rely solely on water-cooled steam generators for the production of electricity. With combined cycle plants, approximately two thirds of the electrical power generated is produced directly by the combustion turbines, which do not require water for steam or for condenser cooling. This leads to a significant reduction in overall water use for combined cycle plants such as Hardee Unit 3.

As part of the preparation of the certification application for the Hardee Unit 3 project, SECI conducted an extensive Water Alternatives Study (see Appendix 10.10 of the SCA). The objectives of this study were to evaluate the water requirements for the proposed project and to identify potentially available water sources. A major consideration in this study was to minimize water use and maximize water conservation for the Hardee Unit 3 facility. After considering various alterative systems and sources for condenser cooling and other plant water uses, it was determined that use of the existing cooling reservoir and the previously certified use of the Floridan Aquifer as a source of makeup water offered the best overall combination of water conservation and plant efficiency.

Makeup water for condenser cooling is the largest water use for steam cycle power plants. Makeup water cooling is typically achieved by either cooling towers or cooling reservoirs. In cooling towers, cooling is achieved almost exclusively by evaporation. In cooling reservoirs, cooling is achieved by a combination of evaporation, conduction, and radiation. For a given power plant, a cooling reservoir will be more water efficient at rejecting the waste heat load because the excess heat is lost by a combination of processes and does not rely on evaporation alone. As demonstrated in the Water Alternatives Study (Section 2.2), the use of the existing cooling reservoir over new cooling towers for Hardee Unit 3 was found to result in lower overall water use for condenser cooling by approximately 4.5 million gallons per day.

The use of the existing cooling reservoir for Hardee Unit 3 also optimizes water conservation in numerous ways. Since the existing cooling reservoir is capable of supplying all cooling needs for Hardee Unit 3, additional surface area is not needed, thus reducing the overall water evaporation that would result for construction of a new or expanded reservoir. As detailed in the Water Alternatives Study, the existing reservoir receives water input from direct rainfall, overland surface water inflow, ground water inflows, and direct rainfall. This also increases the overall water efficiency of the proposed project by minimizing withdrawal of ground water from the Floridan Aquifer.

The other major water use component of a combined cycle power plant typically include boiler feed water makeup and water and/or steam injection into the gas turbines for air emissions control. The combustion turbines selected for the proposed project utilize advanced dry low-NO_x combustors that do not require water and/or steam injection for air emissions control when firing natural gas, further reducing water needs. Dry low-NO_x combustors can save as much as 400,000 gallons per day over the water and/or steam injection emissions control technology utilized at the existing HPS units.

The number of employees typically needed to operate a combined cycle power plant is relatively low compared to other technologies such as coal fired power plants. The relatively low number of employees projected to be employed at Hardee Unit 3 (estimated at 35 full time employees) will minimize on-site water use for domestic purposes.

The overall handling of water flows and waste streams at Hardee Unit 3 have been designed to optimize water conservation, recycling nearly all onsite water uses. The various low volume waste streams and sewage effluent at Hardee Unit 3 will be treated onsite and recycled to the cooling reservoir where they will be reused for condenser cooling. The design and operation of the existing cooling reservoir has been developed to minimize off site discharge, thus increasing overall water conservation and efficiency in water use.

In conclusion, the overall configuration and design of the Hardee Unit 3 project has been developed to maximize water conservation and reuse.

SWFWMD-C6

Comment: Please provide a comparison of actual groundwater use to KWH of power produced on an Annual Average Daily and Peak Month Daily basis from the existing HPS units for the years 1992 and 1993.

Response: The Hardee Power Station (HPS) existing units consist of a total of 295-MW of generating capacity (one combined cycle unit consisting of two combustion turbines, heat recovery steam generator and a steam turbine, and a stand-alone combustion turbine). The majority of groundwater used for a facility such as the HPS existing units and the proposed Hardee Unit 3 project is for makeup water to the condenser cooling system for the steam cycle. In the case of the HPS existing units, the single steam turbine generator has operated at a very low capacity factor in 1992 and 1993. Since the steam turbine has seen extremely limited operation during 1992 and 1993, the relationship of groundwater pumping to kilowatt-hour produced is not indicative of normal operational conditions as intended for the combined cycle facility when operating at a higher capacity factor. During 1993, a total of 70,353,500 gallons of groundwater was pumped and a total of 276,476 megawatt hours of electricity produced. An average ratio of 254 gallons per MW-hr was recorded during 1993. These usage numbers will vary considerably during normal combined cycle operations and should not be taken as indicative of future water usage.

SWFWMD-C7

Comment: According to the SCA, the existing cooling reservoir can handle the additional heat dissipation requirements for the additional generating capacity (i.e., increase from 660-MW to 880-MW ultimate site capacity). The SCA states that the "engineering rule of thumb" for cooling area per megawatt of generating capacity is 2.0 acres/MW of steam. Based on the ultimate site capacity of 880-MW, the area-to-capacity ratio is 2.04 acres/MW. How much of a "safety factory" is incorporated into the ratio of 2.0 acres/MW?

Originally, the cooling pond had a ratio for area-to-capacity of 2.7 acres/MW (i.e., 570 acres and 210-MW steam cycle), however, only 2.0 acres/MW is currently required. Please provide a detailed explanation addressing the change in this "engineering rule of thumb". Was the cooling reservoir originally designed with an anticipated power generating capacity beyond the initial site capacity of 660-MW? If there is a safety factor designed into the sizing of the cooling pond, what is this site's ultimate power generating capacity?

Response: An engineering rule of thumb is not a hard design criteria but is a rudimentary guide. The final design of any heat dissipation system (e.g., cooling tower, cooling pond, etc.) is directly related to the expected "cool" water temperature in the steam condenser which, in turn, controls the back pressure in the steam turbine. A hypothetical power plant having a low inlet water temperature (i.e., 2°F above ambient) would require a much larger heat dissipation system than an other hypothetical plant that has comparatively high inlet water temperature (e.g., 8°F above ambient). The cooling reservoir was originally sized to optimize the land area that was available for its placement on the property.

For the 880-MW evaluation at the Hardee Power Station, the controlling design parameter for the cooling reservoir is a condenser inlet water temperature of 95°F (i.e., above that temperature, back pressure on the steam turbine would increase and plant efficiency would start to decrease). The frequency distributions of estimated cooling water inlet water temperatures for the cooling reservoir as shown in the Water Alternatives Study indicated that there may be a slightly increased probability of values >95°F in the 880-MW scenario versus the permitted 660-MW case. This increased risk is sufficiently low that it does not justify the construction of cooling towers or increasing the pond surface area.

With regards to the "safety factor" incorporated into the analysis that leads to the decision that the existing cooling reservoir could accommodate the additional heat load from the Hardee Unit 3 project, the calculations used in the analysis are based on very conservative assumptions, such as maximum load factors for the individual units. This approach, coupled with the high degree of flexibility in the operation of a combined cycle power plant, presents a safety factor that is adequate. However, because the studies do show an increased probability of inlet temperatures >95°F for the 880-MW case, SECI believes the existing cooling reservoir is now at its ultimate capacity and there are no plans for increasing the ultimate site capacity of the Hardee Power Station above 880 MW.

SWFWMD-C8

Comment: Water cropping from adjacent phosphate lands to the north is addressed as a possible source of cooling reservoir makeup water. According to the SCA, a pond of 25 acres is considered feasible. Will this concept of water cropping be utilized by SECI, or are these scenarios just conceptual and considered impracticable at this time? If this idea is considered impracticable, what factors would have to be addressed in order for this idea of water cropping to be utilized by SECI to reduce its groundwater pumpage by as much as 18 to 20% with a 25 acre holding reservoir? Solutions to many of the potential problems associated with water cropping have been addressed in the SCA. Are the possible solutions considered economically infeasible? Based on reducing groundwater withdrawals by approximately 20 percent and at an annual average daily withdrawal rate of 3.8 MGD of water from the Floridan aquifer, an approximate cost of $3.2 million is indicated to water crop. Is this cost considered economically infeasible to produce 0.76 MGD of cooling reservoir makeup water?

Response: Water cropping from the adjacent reclaimed lands has been examined in detail in the Water Alternatives Study portion of the SCA (Appendix 10.10). This study ranked the various sources of water and concluded that utilizing the existing groundwater allocation was the most environmentally sound and cost-effective alternative available. The conceptual water cropping scenario on the other hand was found to have potentially adverse impacts to the environment, had a highly variable reliability, could present difficulty in permitting due to diversion of stormwater away from Peace River and would be uneconomical. Therefore, the water cropping alternative will not be used for a source of water to the cooling reservoir.

Several technical factors would have to be addressed before the runoff from the adjacent reclaimed lands could be utilized. These factors include an efficient system to remove suspended solids, total phosphates, and possible pH adjustment. A sediment and coagulation basin would have to be constructed and periodically cleaned out with waste material landfilled. A 25-acre retention pond would have to be constructed and several very large capacity pumps would be required to deliver the water to the cooling reservoir. A pipeline required for delivery to the reservoir would have to receive approval from the agencies since it would have significant environmental impacts (dredge and fill) in forested wetland areas on the project site which would require wetland mitigation. These systems could potentially deliver 0.76 mgd to the cooling reservoir on average which would have the potential effect of reducing makeup from pumping by approximately 20 percent.

If the technical issues could be resolved, several other long-term problems would have to be considered. These would include increased load of colloidal size particles into the cooling reservoir which could cause water quality violations when the reservoir discharges and environmental impacts to Payne Creek and the Peace River. Addressing these impacts would involve long-term environmental studies to address the decreased flows that these aquatic systems would receive. The impacts to downstream water levels would have to be sufficiently low for SWFWMD to accept the decreased water flows.

If all of the issues were adequately addressed, it would remain questionable as to whether this alternative would actually significantly decrease pumping. The large majority of runoff from the adjacent lands would occur during the wet season when the cooling reservoir is receiving adequate rainfall to require only minimal pumping. The extra volume of water from water cropping would cause the cooling reservoir to operate at higher levels which could result in discharges at greater than the design of a 10 year/24 hour storm. Overall, the decrease in groundwater pumping would likely be nominal.

The water cropping alternative is considered economically infeasible as indicated in Section 5.2 of the Water Alternatives Study. The 3.2 million dollars (with a range of -15 to +30 percent) would include only the capital cost of constructing the pond and pipeline and buying pumps. The overhead and maintenance cost is not included in this estimate and would likely be significant over time. As compared to no incremental cost for using the current allocation, it is clear that this alternative could not be economically justified.

In summary, water cropping was determined to be mid-rated of the seven water supply options because of variability of supply and quality, its environmental impacts, and its comparatively high cost.

UNITED STATES DEPARTMENT OF THE INTERIOR
FISH AND WILDLIFE SERVICE

(USFWS)

USFWS-1

Comment: We have reviewed the Best Available Control Technology (BACT) analysis and are satisfied that the analysis is complete. We believe either low NO_x combustors or selective catalytic reduction (SCR) represents BACT for gas-fired cogeneration turbines. We support industry and manufacturer efforts to develop technology which approaches control levels achieved by add-on controls. Such pollution control efforts are advantageous provided similar reductions in pollution can be achieved. We agree that 15 ppm represents a BACT limit which manufacturers are currently comfortable guaranteeing to their customers. We understand that some manufacturers are hoping to design combustors which will achieve even lower rates to further approach the rates achieved by SCR. Earlier this year, we reviewed an application for turbines at Tampa Electric Company's (TECO) Mulberry facility. BACT for TECO's turbines was the use of dry-low NO_x combustors to achieve 9 ppm. Therefore, while we do not object to a BACT emission level of 15 ppm NO_x, we suggest SECI be required to meet the lowest emission rate that is demonstrated as being achievable over a reasonable amount of time. This will help to verify a true BACT limit and may encourage manufacturers to guarantee emission rates lower than 15 ppm.

Response: SECI submits that the emission values proposed in the SCA are BACT and should not be lowered over the life of the facility. See Response to FDEP.BAR-8 for additional discussion.

USFWS-2

Comment: Since fuel oil will only be used as a backup fuel, we agree that water injection represents BACT for control of NO_x during fuel oil use; however, the Hartwell Energy Limited Partnership in Georgia is required to meet a 25 ppm NO_x emission limit when firing oil, using water injection. Therefore, we believe SECI should also be required to meet a 25 ppm NO_x emission limit.

Response: No response needed except for comments on BACT regarding the use of backup fuel oil. DOI states that a facility in Georgia, the Hartwell Energy Limited Partnership, is required to meet a 25 ppm NO_x emission limit when firing oil using water injection. However, based on discussions with the Georgia Department of Environmental Protection (KBN, July 27, 1994), the data were incorrectly entered into the EPA BACT Clearinghouse database. The project was, in fact, limited to a NO_x emission rate of 42 ppm, similar to that proposed for Hardee Unit 3. A copy of the construction permit for the Hartwell Energy Limited Partnership is attached (see condition 6-a). Therefore, we believe that a NO_x emission limit of 42 ppm when firing oil using water injection is BACT.

USFWS-3

<u>Comment</u>: We agree that low sulfur fuel (.05 percent sulfur content) represents BACT to minimize sulfur dioxide emissions. Likewise, we agree combustion control represents BACT for carbon monoxide. Note that Florida required the Auburndale Power Partners, LP, to meet 15 ppm for carbon monoxide emissions, using combustion control. Again, the lowest demonstrated emission limit should be set as BACT.

<u>Response</u>: SECI submits that the emission values proposed in the SCA are BACT.

USFWS-4

<u>Comment</u>: The air quality dispersion modeling analysis was performed correctly--ISCST2 modeling predicted violations of the Class I SO2 increment; however, MESOPUFF II modeling predicted that SECI would not contribute significantly to the violations.

<u>Response</u>: Comment acknowledged.

USFWS-5

<u>Comment</u>: The visibility analysis performed with the EPA VISCREEN model indicates that there should be no impact of a coherent visible plume at Chassahowitzka WA.

<u>Response</u>: Comment acknowledged.

USFWS-6

<u>Comment</u>: SECI adequately addressed potential effects to Class I Air Quality Related Values, including vegetation, wildlife, and soils. However, in the discussion of effects to wildlife, SECI mentions that the concentrations of metals in plants are predicted to be much lower than Service recommended safety levels for wildlife; therefore, adverse effects to fish and wildlife are not expected. We would like to note that accumulation of some metals, particularly mercury, occurs primarily through the aquatic food chain, not through ingestion of terrestrial vegetation. Fish are known to accumulate mercury and pass on toxic amounts to fish-eating birds, mammals, and reptiles.

When we receive new information on air quality-sensitive receptors at Chassahowitzka WA, we will forward it to you for use by future PSD applicants.

<u>Response</u>: Comment acknowledged.

ATTACHMENT USFWS-2

file

State of Georgia
Department of Natural Resources
ENVIRONMENTAL PROTECTION DIVISION

AIR QUALITY PERMIT

Permit No.
4911-073-10941

Effective Date
July 28, 1992

In accordance with the provisions of Georgia's Air Quality Act of 1978 and the Rules, Chapter 391-3-1, adopted pursuant to or in effect under that Act,
HARTWELL ENERGY LIMITED PARTNERSHIP,
P.O. Box 1396, Houston, Texas 77251-1396
is issued a Permit for the following: Construction and operation of two simple-cycle combustion turbines rated at 159 megawatts firing natural gas or No. 2 distillate fuel oil.

location:
East of Highway 181
East of Hartwell
Hart County

This Permit is conditioned upon compliance with all provisions of Georgia's Air Quality Act of 1978, the Rules, Chapter 391-3-1, adopted or in effect under that Act, or any other condition of this Permit.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above; or for any misrepresentation made in the application(s) dated Dec. 31, 1991, supporting data entered therein or attached thereto, or any subsequent submittals or supporting data; or for any alterations affecting the emissions from this source. Additional information submitted by letter of February 26, 1992.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached 7 page(s), which page(s) are a part of this Permit.

Harold F. Reheis
Director
Environmental Protection Division

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

General Requirements

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

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

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

4. Construction shall be completed by no later than December 1, 1994, otherwise this Permit becomes null and void and is no longer in effect.

Allowable Emissions

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

6. The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine when burning fuel oil in the turbine any gases which:

a. Contain nitrogen oxides in excess of that allowed by the following equation:

$$STD = 0.0042 + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis)
F = NO_x emission allowance for fuel-bound nitrogen defined by the following table:

Fuel-bound nitrogen (% by wt.)	F (NO_x % by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.04$	0.04(N)
$N > 0.04$	0.0016

where: N = the nitrogen content of the fuel (% by wt.)

b. Contain carbon monoxide in excess of 25 ppmvd at baseload conditions.

c. Contain particulate matter in excess of 0.0156 pound per million Btu heat input.

d. Contain beryllium in excess of 2.61 pound per 10^{12} Btu heat input.

e. Exhibit greater than 10 percent opacity.

7. The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine when burning natural gas in the turbine any gases which:

a. Contain nitrogen oxides in excess of 25 ppmvd at 15 percent oxygen.

b. Contain carbon monoxide in excess of 25 ppmvd at baseload conditions.

c. Contain particulate matter in excess of 0.0064 pound per million Btu heat input.

d. Exhibit greater than 10 percent opacity.

8. The Permittee shall not burn in any turbine any fuel oil which contains sulfur in excess of 0.05 percent by weight.

9. The Permittee shall not operate any combustion turbine in excess of 2500 hours per calendar year.

10. The Permittee shall comply with the requirements of 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines except as specified below:

    a. The standard for nitrogen oxides in 40 CFR 60.332 shall be replaced by the standards in conditions 6. and 7. of this Permit.

    b. The standard for sulfur dioxide in 40 CFR 60.333 shall be replaced by the standard in condition 8. of this Permit.

    c. Under 40 CFR 60.334(b), the sulfur content and nitrogen content of the fuel oil burned in the turbine(s) shall be determined daily.

       The sulfur content of the natural gas burned in the turbine(s) shall be monitored by the submittal of semiannual analysis of the gas by the supplier. No determination of the nitrogen content of the gas shall be required.

    d. Under 40 CFR 60.334(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 conditions 6. or 7. of this Permit or any period during which the fuel-bound nitrogen of the fuel oil is greater than 0.04 percent by weight.

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

11. If during the operation of any combustion turbine there is a reduction in the available supply of water to the turbine, the Permittee shall reduce the firing rate of fuel to the turbine such that compliance with the NO_x standards in conditions 6. and 7. of this Permit is maintained.

Performance Testing

12. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up, the Permittee shall conduct the following performance tests and furnish to the Division a written report of the results of such performance tests:

    a. An emission test for Nitrogen Oxides (NO_x) on each turbine while burning natural gas and fuel oil in the turbine.

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

    c. Emission tests for Carbon Monoxide (CO) on each turbine while burning natural gas and fuel oil in the turbine.

    d. Emission tests for Particulate Matter (PM) on each turbine while burning fuel oil in the turbine.

    e. Visible emission tests on each turbine while burning natural gas and fuel oil in the turbine.

    f. Emission tests for CO, PM, and visible emissions shall be conducted concurrently.

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

    a. Method 1 for sample point location.

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

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

    d. Method 5 for concentration of particulate matter and associated moisture content.

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

f. Method 10 for concentration of carbon monoxide.

g. Method 19 section 5.2.2 for the determination of fuel sulfur content.

h. ASTM Method D-3431 for the determination of fuel nitrogen content.

i. Method 20 for the concentration of nitrogen oxides.

For Method 5, the minimum sampling time for each run shall be 120 minutes. The probe and filter holder heating system in the sampling train may be set to provide a gas temperature of no greater than 320°F. For Method 3B, Method 3A may be used as an alternative. ASTM Method D4629 may be used in lieu of ASTM D3431. ASTM Method D4294 may be used in lieu of the methods in Method 19 (ASTM D129 and ASTM D1552) for analysis of sulfur in the fuel oil.

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

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

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

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

Monitoring Requirements

17. The Permittee shall comply with all applicable requirements of the continuous monitoring rule upon promulgation of 40 CFR 75.

18. The Permittee shall install, calibrate, operate and maintain on each turbine devices for measuring the quantity of fuel oil, in gallons, and the quantity of natural gas, in cubic feet, burned in the turbine.

19. The Permittee shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio of water to fuel being burned in each turbine in accordance with 40 CFR 60.334.

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

    a. For natural gas, the Permittee shall monitor the sulfur content by the submittal of semiannual analysis of the gas by the supplier. No determination of the nitrogen content shall be required.

    b. For fuel oil, the Permittee shall monitor the sulfur content and the nitrogen content on a daily basis.

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

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

23. The Permittee shall install, calibrate, operate and maintain on each turbine a cumulating hour meter which shows all periods of operation of the turbine.

Notification, Reporting and Recordkeeping

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

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

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

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

For purpose of this permit, "startup" shall mean the setting in operation of a source for its intended purpose.

25. The Permittee shall maintain records of the fuel oil and natural gas consumed by each of the turbines. The records shall be in a permanent form suitable and available for inspection. The records shall be retained for at least two years following date of entry.

26. The Permittee shall submit a written report of excess emissions, as defined by condition 10. of this Permit, to the Division for every calendar quarter. Each report shall include the information specified in 40 CFR 60.334 and any other information specified by the Division. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

27. The Permittee shall submit a written report showing the monthly hours of operation of each turbine, as indicated by the cumulating hour meters, for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

Modifications

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