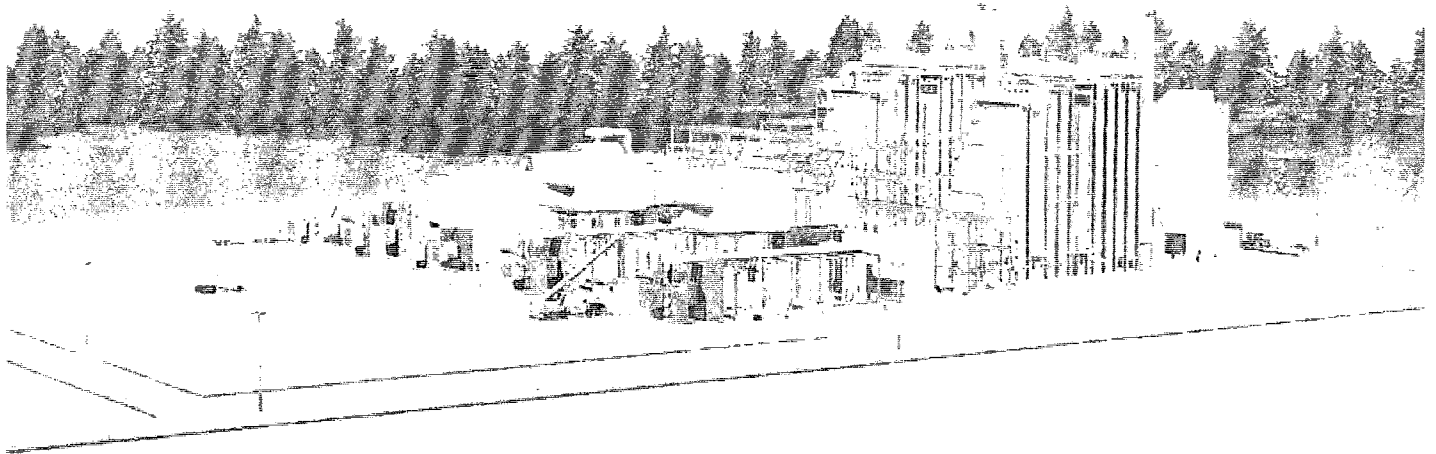


GULF POWER SMITH UNIT 3 Site Certification Application



Volume 1

June 1999



A SOUTHERN COMPANY

ECT

Environmental Consulting & Technology, Inc.

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS

One Energy Place
Pensacola, Florida 32520

850.444.6111



June 7, 1999

Mr. Hamilton S. Oven, Jr.
Siting Coordination Office
Florida Department of Environmental Protection
2600 Blair Stone Road, Mail Stop 48
Tallahassee, FL 32399

DEPARTMENT OF
ENVIRONMENTAL PROTECTION

JUN 07 1999

Re: Smith Unit 3 Project

SITING COORDINATION

Dear Mr. Oven:

Enclosed are 14 copies of the Site Certification Application (SCA) for the Smith Unit 3 Project. The SCA is being submitted on behalf of Gulf Power Company as the applicant. An application for determination of need for the Project was filed with the Florida Public Service Commission on March 15, 1999.

Also enclosed is a check for \$125,000 to cover the application processing fee. Upon the Department's determination of "completeness", please advise us regarding the number of additional copies required by the Department.

We look forward to working with you and the Department on the certification process. If you should have any questions regarding our application, please do not hesitate to call Jim Vick, Manager of our Environmental Affairs Department at 850.444.6311. Also, feel free to contact our environmental consultant, Environmental Consulting & Technology, Inc. (ECT), or our counsel, Hopping Green Sams and Smith (HGSS). Phil Simpson can be reached at ECT at 352.332.0444 and Doug Roberts can be reached at HGSS at 850.425.2320.

Sincerely,

A handwritten signature in black ink that reads "Robert G. Moore". The signature is written in a cursive, flowing style.

Robert G. Moore
Vice-President of Power Generation / Transmission

Enclosures

mrf

cc: James O. Vick
Phil Simpson
Doug Roberts

APPLICANT INFORMATION

Applicant's Official Name: Gulf Power Company

Applicant's Address: One Energy Place

Pensacola, FL 32520-0328

Address of Official Headquarters: One Energy Place

Pensacola, FL 32520-0328

Business Entity (corporation, partnership, co-operative): Corporation

Owner: Southern Company

Names and Titles of Chief Executive Officers: Travis J. Bowden, President

One Energy Place

Pensacola, FL 32520-0328

Names, Addresses, and Phone Numbers of Official Representative Responsible for

Obtaining Certification: James O. Vick

One Energy Place

Pensacola, FL 32520-0328

Site Location (County): Bay County

Nearest Incorporated City: Lynn Haven

Latitude and Longitude: 30° 16' 15W" 85° 42' 05N"

UTMs: Northerly: 3,349,600 Easterly: 625,250 Zone: 16

Section, Township, Range: 26 - 2S - 15W

Location of any directly associated transmission facilities (counties): Bay County

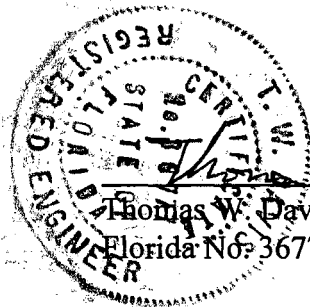
Name Plate Generating Capacity: 574 MW

Capacity of Proposed Additions and Ultimate Site Capacity (where applicable): N/A

Remarks (additional information that will help identify the applicant):

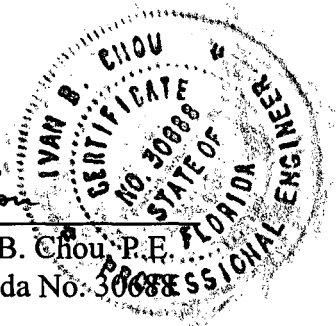
SITE CERTIFICATION APPLICATION
FOR THE
GULF POWER COMPANY SMITH UNIT 3 POWER PROJECT

Environmental Consulting &
Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606



Thomas W. Davis, P.E.
Florida No. 36777

Poor Original



Ivan B. Chou, P.E.
Florida No. 30828

Date

6/4/99

Date

6-4-1999

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LIST OF ABBREVIATIONS, ACRONYMS, AND UNITS OF MEASURE

AAQS	ambient air quality standards
ADT	average daily traffic
ANSI	American National Standards Institute
APCo	Alabama Power Company
ASTM	American Society for Testing and Materials
ATS	advanced technology systems
BACT	best available control technology
BMP	best management practices
bpf	blows per foot
Btu/ft ³	British thermal unit per cubic foot
Btu/kwh	British thermal unit per kilowatt-hour
°C	degrees Celsius
CAA	Clean Air Act
CAES	compressed air energy storage
CC	combined cycle
CEC	cation exchange capacity
CFR	Code of Federal Regulations
cfs	cubic feet per second
cm/sec	centimeter per second
CO	carbon monoxide
CO ₂	carbon dioxide
CR	County Road
CTG	combustion turbine generator
dBA	A-weighted decibel
DOT	Department of Transportation
DSM	demand-side measures
EAR	Evaluation and Appraisal Review
EFOR	equivalent forced outage rate
EMF	electric-magnetic field
EPA	U.S. Environmental Protection Agency
EPC	engineering, procurement and construction
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FDACS	Florida Department of Agriculture and Consumer Services
FDCA	Department of Community Affairs
FDEP	Florida Department of Environmental Protection
FDOT	Florida Department of Transportation
FEMA	Federal Emergency Management Agency
FEPPSA	Florida Electrical Power Plant Siting Act
FGD	flue gas desulfurization
FGFWFC	Florida Game and Fresh Water Fish Commission
FGS	Florida Geological Survey

LIST OF ABBREVIATIONS, ACRONYMS,
AND UNITS OF MEASURE
(Continued, Page 2 of 4)

FGT	Florida Gas Transmission
FLUCFCS	Florida Land Use, Cover, and Forms Classification System
FLUM	Future Land Use Map
FNAI	Florida Natural Areas Inventory
FPC	Florida Power Corporation
FPSC	Florida Public Service Commission
ft	feet
ft/day	feet per day
ft bls	feet below land surface
ft-msl	feet above mean sea level
ft/sec	foot per second
FTU	nephelometric turbidity unit
g/s	gram per second
GE	General Electric
gpd	gallons per day
gpm	gallon per minute
gr S/100 scf	grains of sulfur per 100 standard cubic feet
gr/100 scf	grains per 100 standard cubic foot
gr/100 dscf	grains per 100 dry standard cubic feet
Gulf	Gulf Power Company
ha	hectares
HRSG	heat recovery steam generator
hr/yr	hour per year
H ₂ SO ₄	sulfuric acid
IGCC	integrated gasification combined cycle
IRP	integrated resource planning
ISCST3	Industrial Source Complex Short-Term
ISO	International Standards Organization
K	Kelvin
kg/km ² /month	kilograms per square kilometer per month
kg/km ² /yr	kilograms per square kilometer per year
km	kilometer
km ²	square kilometer
kV	kilovolt
kw-yr	kilowatt-year
lb/hr	pound per hour
LHV	lower heating value
LOS	level of service
m	meter
meq/100g	milli-equivalents per 100 grams
MGD	million gallons per day
mg/kg	milligram per kilogram
mg/L	milligram per liter

LIST OF ABBREVIATIONS, ACRONYMS,
AND UNITS OF MEASURE
(Continued, Page 3 of 4)

MMBtu/day	million British thermal units per day
MMBtu/hr	million British thermal units per hour
mmhos/cm	millimhos per centimeter
MPCo	Mississippi Power Company
mph	miles per hour
msl	mean sea level
MW	megawatt
mwh	megawatt-hour
NCDC	National Climatic Data Center
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NO _x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
NSR	new source review
NWFWMD	Northwest Florida Water Management District
NWS	National Weather Service
NPV	net present value
OAQPS	Office of Air Quality Planning and Standards
O&M	operation and maintenance
O ₂	oxygen
OSHA	Occupational Safety and Health Administration
PCFB	pressurized circulating fluidized bed
PM	particulate matter
PM ₁₀	particulate matter less than or equal to 10 micrometers aerodynamic diameter
POD	point of discharge
ppm	part per million
ppmvd	part per million by dry volume
PSD	prevention of significant deterioration
psf	pound per square foot
PSH	pumped storage hydro
psia	pound per square inch absolute
psig	pound per square inch gauge
PWRR	present worth of revenue requirements
RARE	roadless area review and evaluation
RCRA	Resource Conservation and Recovery Act
RFP	request for proposal
RQD	rock quality designation
SACTI	Seasonal/Annual Cooling Tower Impact
SCA	site certification application
SCS	Southern Company Services
SES	Southern Electric System
SO ₂	sulfur dioxide

LIST OF ABBREVIATIONS, ACRONYMS,
AND UNITS OF MEASURE
(Continued, Page 4 of 4)

SR	State Road
SRPP	Strategic Regional Policy Plan
SSC	species of special concern
SWMP	storm water management plan
tpy	tons per year
TYSP	ten-year site plan
µg/L	microgram per liter
µg/m ³	microgram per cubic meter
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VMT	vehicle miles traveled
VOC	volatile organic compound
WFRPC	West Florida Regional Planning Council
WWTP	wastewater treatment plant

Exec Sum

EXECUTIVE SUMMARY

Gulf Power Company (Gulf) plans to construct, own, and operate a new electric power generating plant in Bay County, Florida. The Smith Unit 3 Project (Smith Unit 3 or the Project) will be capable of producing up to 574 megawatts (MW) of electricity using state-of-the-art technology and clean, natural gas fuel.

Gulf, which is a wholly-owned subsidiary of Southern Company, serves approximately 350,000 customers in northwest Florida. Gulf has determined that in order to continue providing reliable, cost-effective service to its customers, it must add at least 427 MW of new generating resources to its system by summer of 2002. The most cost-effective means to meet this need is construction of Smith Unit 3 at Gulf's existing Lansing Smith Electric Generating Plant north of Panama City, Florida.

On March 15, 1999, Gulf filed a petition with the Florida Public Service Commission to demonstrate that the Project is needed to meet the growing demand for power in the Florida panhandle. The need petition shows that the Project will be a reliable, cost-effective, and environmentally friendly power generation resource in Florida.

ES.1 THE SITE CERTIFICATION APPLICATION

The licensing of electrical power plants in Florida requires compliance with applicable federal, state, and local laws, regulations, and ordinances. The most comprehensive state law governing the licensing of the Smith Unit 3 Project is the Florida Electrical Power Plant Siting Act (FEPPSA). The FEPPSA establishes the State's policy to balance the need for new power plant facilities with the potential effects of the facility's construction and operation on human health, welfare, and environmental resources of the state. To implement this policy, the FEPPSA establishes a centrally coordinated permitting process. The FEPPSA proceedings are initiated when the applicant files a site certification application (SCA) with the Florida Department of Environmental Protection (FDEP), which administers and coordinates the process with affected agencies, governmental entities, other parties, and the applicant. The process concludes with the approval or certification of the power plant by the Governor and Cabinet, sitting as the Siting Board.

The FDEP procedures for implementing the FEPPSA are contained in Chapter 62-17, Florida Administrative Code (F.A.C.). In this case, the SCA for the Project has been prepared in compliance with the requirements contained in the FDEP *Instruction Guide For Certification Applications* (FDEP Form 62-1.211[1], F.A.C.). The SCA demonstrates that the Project will comply with all applicable laws, regulations, and standards.

ES.2 SITE AND VICINITY CHARACTERISTICS

The proposed site for the Project is located at Gulf's existing Lansing Smith Plant in central Bay County, northwest of Panama City (T2S, R15W, Section 36). The site is owned by Gulf, as is all the surrounding property to the site.

Figures ES-1 and ES-2 show the location of the Project within the State of Florida and within Bay County, respectively. Figure ES-3 shows the location of the proposed 50.1-acre site relative to the existing Smith Plant. The site is located at the end of County Road (CR) 2300 which connects to State Road (SR) 77.

The site is currently in silvicultural operations, with planted pine dominating the site. The existing Smith plant is an industrial land use, but otherwise the surrounding vicinity is rural and in a natural state. No residential development is found within a 2-mile radius.

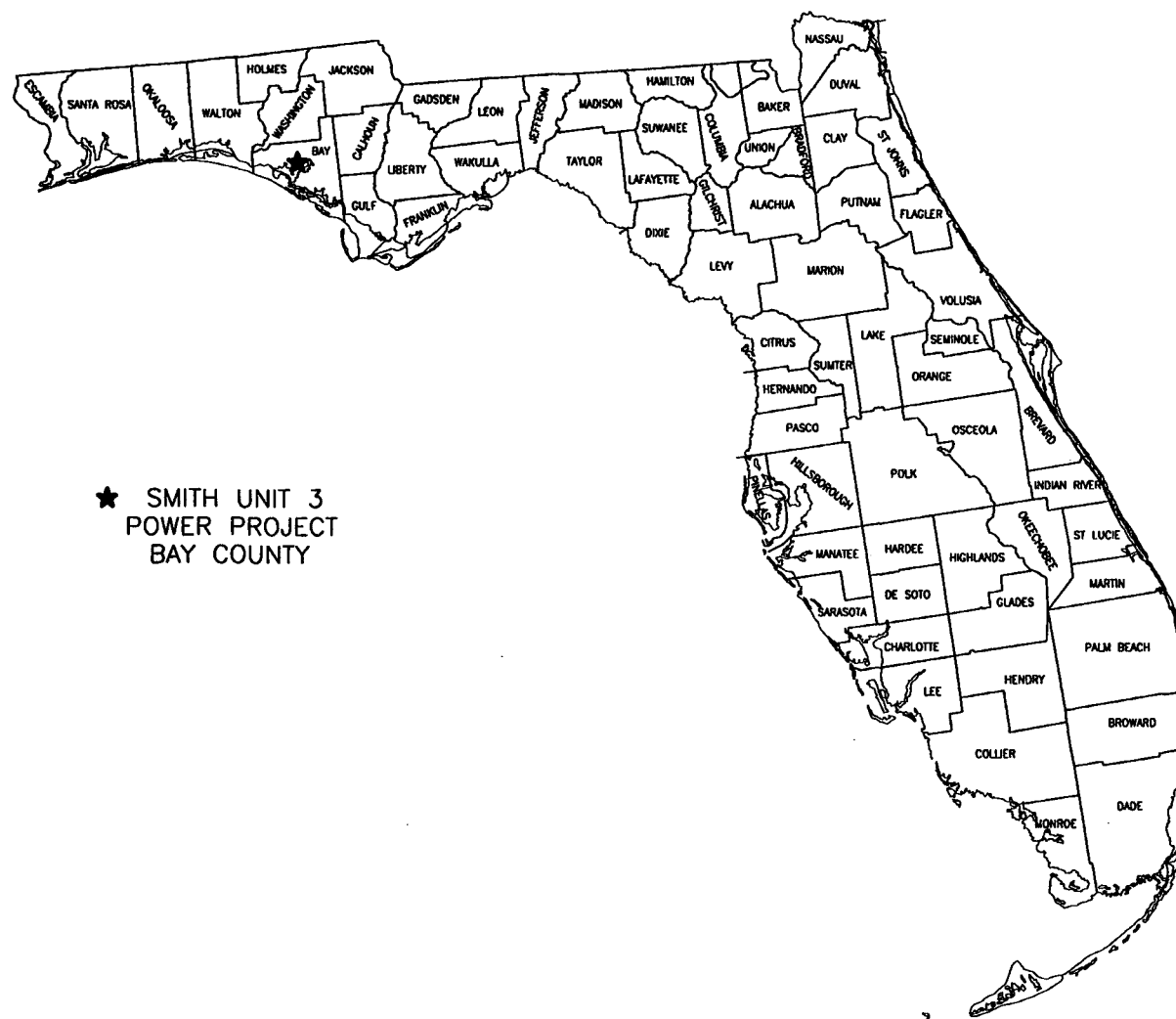
ZONING AND LAND USE REGULATIONS

The Project site is currently located in the Agricultural land use classification as depicted on Bay County's 1990 Adopted Comprehensive Plan Future Land Use Map (FLUM). Power plants are not an allowable use in this land use designation.

To be consistent with the adopted comprehensive plan, Gulf has submitted a large-scale plan amendment application to change the FLUM from Agriculture to Industrial. The Industrial category will allow for development of the Project and will be consistent with the existing designation for the adjacent Lansing Smith Plant (Units 1 and 2). The plan amendment was submitted in May 1999 and is expected to be adopted in Fall 1999.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



★ SMITH UNIT 3
POWER PROJECT
BAY COUNTY

FIGURE ES-1.
SITE LOCATION

Source: ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

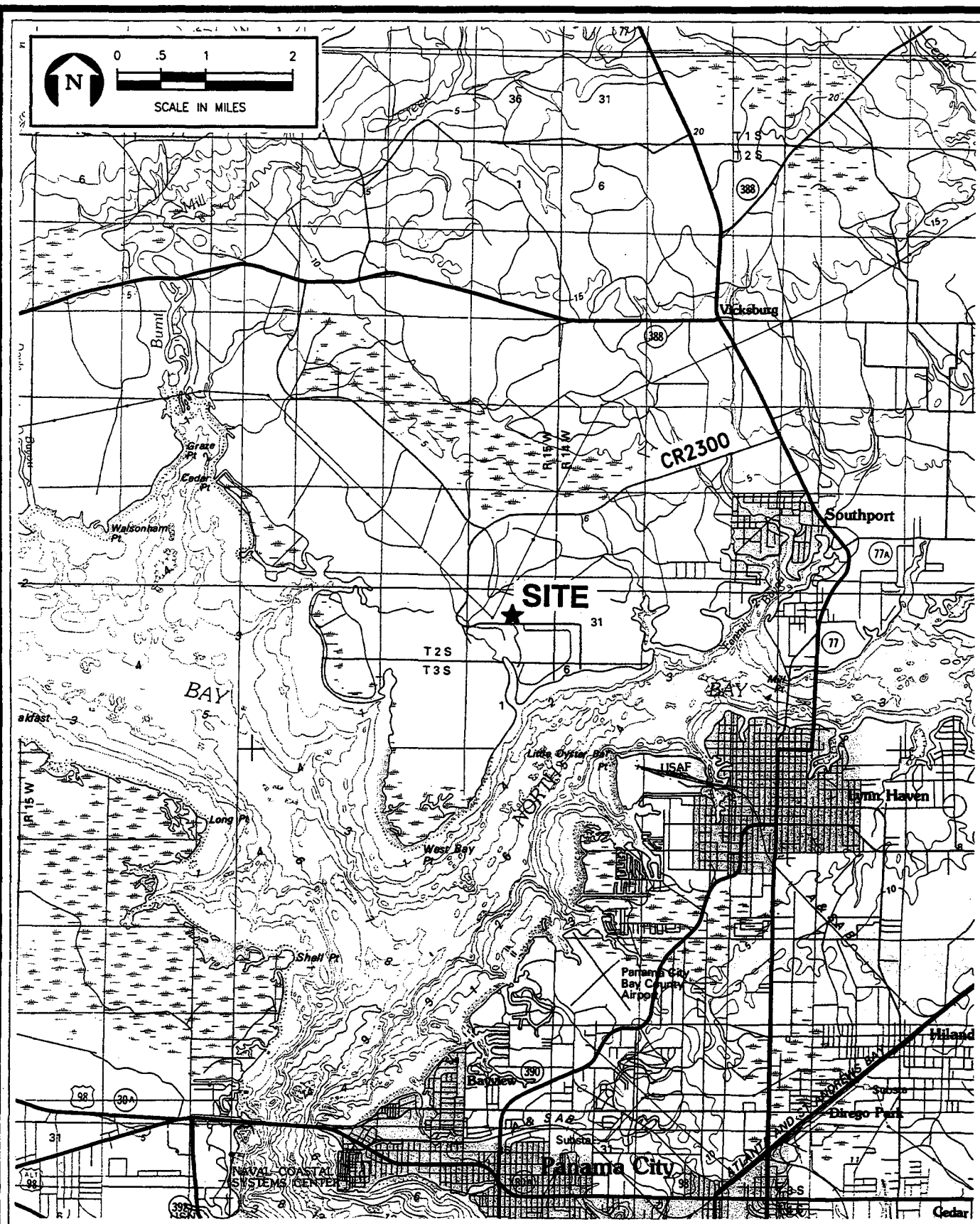


FIGURE ES-2.
SITE LOCATION WITHIN BAY COUNTY

Sources: USGS 30x60-minute topo map: Panama City, FL, 1981.

ECT
Environmental Consulting & Technology, Inc.

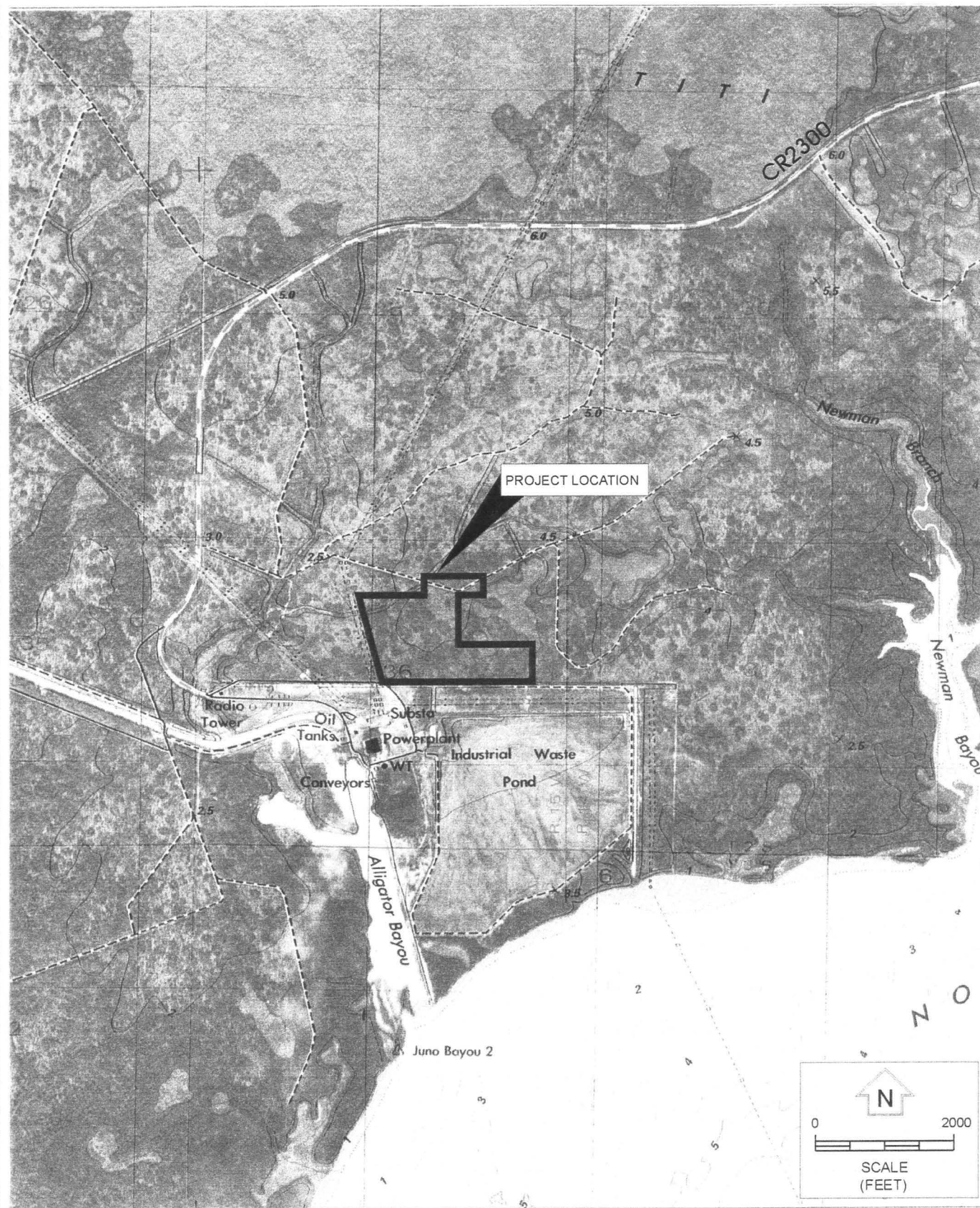


FIGURE ES-3.

PROJECT SITE LOCATION RELATIVE TO
LANSING SMITH PLANT

Sources: USGS topo map of Southport, FL., 1992; ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

In Bay County, zoning is consistent with the land use plan designations. Therefore, when the FLUM is approved, so will the corresponding zoning for the site.

No sensitive natural resource, scenic, or cultural lands are located on the proposed site. No known archaeological or historic resources are located on the site.

GEOLOGICAL FEATURES

The Project site is located on the Pamlico Terrace in an area of low relief between elevation 5 and 8 feet above mean sea level. The site is underlain by a thick sequence of Tertiary-age sediments that generally dip to the southwest. Formations range from the Pleistocene marine terraces (loose, permeable silts and sands) that extend to 20 feet below land surface, to the Bruce Creek Limestone formation (a limestone dominated by macrofossils) that is approximately 300 feet thick.

No geologic faults have been mapped for the site; therefore, faults pose no hazard to site development. Karst development and sinkhole potential are low. Geotechnical investigations performed on the site indicate it can be safely used for the intended Project, providing standard engineering practices are employed.

GROUND WATER

The Smith Unit 3 Project is located in the Econfinia Creek Basin. Four hydrogeologic units define the regional system:

- The surficial aquifer system.
- The intermediate system.
- The Floridan aquifer system.
- The sub-Floridan confining unit.

The Floridan aquifer system provides over 90 percent of the ground water supplies for northwest Florida. The surficial aquifer system is of poor quality and is only used for irrigation and surface water recharge.

SURFACE WATER

There are numerous fresh water wetlands intermixed with the pine plantations of the site vicinity. No natural lakes, ponds, streams, or rivers are found on the site. Most of these wetlands drain to the southwest or west, eventually to West Bay.

The marine environment of St. Andrew Bay is the major surface water feature in the site vicinity. This system has been well studied by Gulf and others. Currently, the Lansing Smith Plant uses surface water from North Bay for once-through cooling at Units 1 and 2. The cooling water is ultimately discharged through a nearly 2-mile-long canal to West Bay, where the thermal mixing zone occurs. The current discharge meets all applicable water quality standards for the Bay which is a Class II water.

ECOLOGICAL FEATURES

Approximately 95 percent of the site is vegetated. Wetlands cover approximately 50 percent of the site but most of these are wet, planted pine plantations. Cypress-titi swamps represent the higher quality wetlands found onsite.

No unique habitats are found onsite. No listed wildlife species were observed onsite and none are likely to depend on the site's resources for their habitat needs. Four listed plant species were found onsite, one of which, the panhandle spiderlily, is endangered. Several specimens of this rare plant were observed in wetlands onsite and offsite.

Existing stresses to terrestrial systems include the presence of the existing Lansing Smith units, logging practices, and prescribed burning. Existing stresses to the marine systems include storm water runoff, pollution from non-point sources, and the thermal discharge of the existing Lansing Smith cooling system.

AIR RESOURCES AND NOISE

Climate in the site vicinity is characteristic of the upper Gulf Coast with mild winters and summer heat, tempered by breezes off the Gulf of Mexico. Prevailing winds are from the north.

The Smith Unit 3 site is located in an area that has been classified as attainment for all criteria air pollutants, which means the site meets all applicable state and federal air standards. The only major air emissions sources in the area are the Smith Units 1 and 2 and a few industrial facilities around St. Andrew Bay.

Ambient noise at the proposed site is dominated by the day-to-day operations of Smith Units 1 and 2. Noise surveys performed by Gulf indicate noise levels around the property boundary currently fall well below the Bay County noise code.

ES.3 PROJECT DESCRIPTION

The Smith Unit 3 Project will utilize state-of-the-art combined cycle (CC) design concepts and equipment to achieve a high level of efficiency in electrical power production. The Project will employ two General Electric Model PG 7241 (FA) gas turbine units which have a proven operating record around the world. These machines will utilize the latest developments in dry low-nitrogen oxides (NO_x) combustion technology to achieve low emissions.

Each combustion turbine generator (CTG) will exhaust into a heat recovery steam generator (HRSG), which will produce steam-generated electricity to supplement the CTGs. Typical plant operation is expected to produce 519 MW when operating at full load. When Gulf employs power augmentation, the unit will be capable of generating up to 574 MW.

Cooling of Smith Unit 3 will feature a creative and environmentally sound combination of utilizing existing Smith Units 1 and 2 cooling water discharge with a cooling tower. This means the Project will actually use hot water from the existing cooling system and discharge cooler water back to the existing discharge canal. The average annual water requirements for this cooling system will be approximately 7.5 million gallons per day (MGD) obtained from the existing 274 MGD hot water discharge from Units 1 and 2.

Other uses of the existing Lansing Smith infrastructure will include the uses of ground water from Gulf's onsite wells, use of the existing domestic wastewater treatment pack-

age plant, use of existing electric transmission and road access, and use of the existing potable water system.

Air pollution control equipment utilizing clean-burning natural gas as a fuel and low-NO_x burners will benefit the air quality in the region. Use of low-sulfur natural gas will limit emissions of particulate matter including particulate matter less than or equal to 10 micrometers diameter. Carbon monoxide and volatile organic compound emissions will be controlled by the use of advanced combustion equipment and operational practices. Dry low-NO_x combustors and low-NO_x burner technology will abate NO_x emissions. Sulfur dioxide and sulfuric acid mist emissions will be controlled by the use of low-sulfur natural gas. Drift eliminators will be employed to limit cooling tower drift to no more than 0.001 percent of the circulating water.

Gulf will require a natural gas supply to the site via a new pipeline lateral. However, Gulf will not own, build, or operate the pipeline. A gas pipeline route will be permitted and licensed separately by the supplier.

No new electric transmission line corridors are required to place Smith Unit 3 into service. A 1,000-foot wire bus connecting Smith Unit 3 to the existing Lansing Smith 230-kilovolt (kV) substation will be constructed across already developed plant property. Smith Unit 3 will require replacement of existing conductors (wires) on approximately 20 miles of existing Gulf 115-kV transmission lines in the Panama City vicinity. However, no new right-of-way, access roads, structures, dredging, or filling will be required for these upgrades. No environmental or land use impacts are anticipated from these upgrades.

ES.4 IMPACTS OF PROJECT CONSTRUCTION

The Smith Unit 3 Project will be located on a 50.1-acre site with development occurring on 32.7 acres of that total. Construction activities will include clearing, grading, development of storm water ponds, power plant construction, final grading, and landscaping.

No explosives will be used in the construction of the facility. Construction impacts will be reduced by use of existing access roads to the site and the Lansing Smith barging terminal for delivery and offloading heavy equipment. Gulf is also proposing use of benign fly ash from the existing Lansing Smith Plant as a fill substitute to help reduce the volume of fill and corresponding truck traffic to the site. Trash and construction debris will be removed or recycled by a licensed contractor.

Construction impacts to surface water systems (including wetlands) will be minimized by developing a drainage plan to allow postconstruction drainage to match preconstruction drainage. Storm water basins will be used to minimize offsite runoff and sedimentation. Best management practices (BMPs) employed for Smith Units 1 and 2 will be modified to include Smith Unit 3 and to protect potential offsite aquatic resources.

Construction impacts on ground water resources are expected to be short term and minimal. Any site dewatering will include the use of storm water ponds to collect and treat the water before recharge or discharge. Construction will not impact any drinking water supplies or other uses of the Floridan aquifer.

Approximately 15.2 acres of wetlands will be impacted during construction. Gulf is submitting a joint FDEP/U.S. Army Corps of Engineers dredge-and-fill application to quantify these impacts. The application will contain a proposed mitigation plan for these lost resources. The remaining acreage (17.4) will be left as natural, vegetated communities (e.g., pine plantation and wetlands). Construction will have minimal impacts on flora and fauna. No impacts to regional populations of any listed species are expected. The panhandle spiderlily (a state-endangered plant) is proposed to be relocated out of construction areas to nearby undisturbed wetlands.

The socioeconomic impacts are largely beneficial. A maximum construction workforce of 325 people will be required, the great majority coming from the Panama City/Bay County area. An average of 180 employees will be used over the 21-month construction period. Construction payroll is expected to total over \$18.4 million, and the impact of

construction on industrial output in Bay County is estimated to be \$113.5 million. Numerous local contractors and vendors will be utilized.

Although traffic on SR 77 and CR 2300 will increase over the construction period due to construction employees and hauling fill to the site, levels are not expected to exceed existing level of service (LOS) on any access road (primarily SR 77) to the site. Gulf is further reducing traffic impacts by spreading out fill hauling over a longer period than the construction period, and by stockpiling fill at the existing Lansing Smith property. This will dilute the truck trips required per day to and from local borrow pits. Gulf is also proposing use of benign fly ash as an alternative fill material which will be used in combination with imported clean fill. Use of fly ash could reduce truck hauling by over 50 percent.

Existing services (schools, fire, police, medical, etc.) in Bay County and nearby communities are adequate to meet short-term demands of construction.

Noise will be generated during construction which will exceed ambient levels. However, noise will be below Bay County standards at Gulf's property boundary. The nearest residential receptor is nearly 2 miles away and will not be affected by construction noise.

ES.5 IMPACTS OF PROJECT OPERATION

Overall, the Project will be a highly efficient and environmentally clean method of producing electrical power. Two positive benefits will be produced over the existing Lansing Smith Generating Facility. First, the reuse of cooling water discharge will mean no additional surface water requirements for once-through cooling will be needed. With the use of the cooling tower, the net impact of operation of Smith Unit 3 will be no increase in the temperature of the existing discharge and a reduction in the discharge volume. Consequently, the heat rejection rate will be reduced by 1.3 percent which will slightly reduce the thermal impacts on the receiving waters of West Bay.

A second major benefit of Smith Unit 3 operations will be a net reduction in NO_x emissions from Lansing Smith due to installation of low-NO_x burner technology and a burner

management system on Smith Unit 1. This results in a significant increase in electrical generating capacity with no increase in NO_x emissions.

The limited use of ground water for process water needs at the Lansing Smith site including Smith Unit 3 will not adversely affect the surficial aquifer or Floridan aquifer at the site. No impacts to existing water supplies or water wells are expected.

During operations, the storm water management plan and BMPs will protect adjacent areas from any storm water runoff impacts. Solid wastes generated will be disposed offsite by licensed contractors.

The best available control technology and PSD review required for Smith Unit 3 will ensure emissions of air-borne pollutants will be minimized. The Project will not cause or contribute to any violation of ambient air quality standards or PSD increments. Secondary air impacts will be negligible. Types and concentrations of air pollutants will not adversely affect soil or vegetation.

No significant ecological effects are anticipated from plant operation. The plant will not affect regional plant and wildlife populations.

Noise impacts will be minimal and confined to the near-plant limits. Noise levels are calculated to be well below Bay County standards.

Existing infrastructure and facilities in Bay County will be sufficient to handle the relatively small increase in operational workforce (29). This workforce will most likely reside locally, but impacts to roads, schools, police, fire, and medical services will be negligible.

Socioeconomic benefits of the Project will be positive. In addition to providing additional inexpensive and reliable electricity to rate payers in Florida, the Project will generate approximately \$1.5 million in additional payroll to Bay County residents. Much of this money will be spent on goods and services. Additionally, Gulf expects to contract \$1.8

million per year to local suppliers of maintenance services/supplies. Traffic generated by the 29 employees will be insignificant on SR 77 and CR 2300. Existing LOSs will not be impacted on area roadways.

ES.6 ALTERNATIVES

The site selected for Smith Unit 3 was driven by the need to be in or close to Panama City and the objective to minimize environmental impacts by locating near existing power plant infrastructure. Smith Unit 3 accomplishes these needs.

The extensive technology and project alternatives analysis performed by Gulf showed that a CC unit located at Gulf's Lansing Smith site using natural gas fuel was the best and lowest cost alternative.

Location at the existing Smith Generating site maximizes use of existing power plant infrastructure (cooling discharge canal, wastewater, potable water, electric transmission, and roads). The site was located on Gulf's property at Lansing Smith to best utilize these infrastructure requirements and minimize onsite environmental impacts. The proposed location, while impacting some wetlands, will avoid wetland impacts associated with longer, interconnecting facility corridors if the site were further from the existing facilities on available Smith property. Moving the site elsewhere would also have the potential to fragment natural communities and wildlife habitat onsite.

ES.7 CONCLUSIONS

In summary, the Project will provide needed low-cost electrical power for Gulf Power rate payers, while minimizing the potential impacts of power generation. The Project will comply with all applicable land use and environmental regulations. The Project should be approved by the Siting Board because it meets pressing local and state needs for electrical power in an environmentally sound manner.

1.0

1.0 NEED FOR POWER AND THE PROPOSED FACILITY

This chapter of the Site Certification Application (SCA) introduces Gulf Power Company (Gulf) and explains why the new generating unit at Gulf's Lansing Smith Plant is needed.

1.1 OVERVIEW

Gulf has determined that in order to provide reliable, cost-effective service to its customers, it must add at least 427 megawatts (MW) of generating resources to its system by the summer of 2002. The most cost-effective way for Gulf to meet this need is to construct a 574-MW natural gas-fired combined cycle (CC) unit at its existing Lansing Smith Electric Generating Plant north of Panama City, Bay County, Florida. This unit will be designated as Smith Unit 3 (or the Project).

Smith Unit 3 is subject to the Florida Electrical Power Plant Siting Act (FEPPSA), Chapter 403, Part II, Florida Statutes. On March 15, 1999, Gulf filed with the Florida Public Service Commission (FPSC) a petition for a Determination of Need for this Project under Section 403.519, Florida Statutes. The following paragraphs summarize the key portions of Gulf's petition to the FPSC. This summary is for informational purposes only. A copy of the petition for need determination is contained as Appendix 10.1. A copy of the FPSC final order will be distributed when that order is issued.

1.2 THE APPLICANT

1.2.1 GENERAL

Gulf Power Company is a wholly-owned subsidiary of the Southern Company. Gulf serves approximately 350,000 customers in Northwest Florida. Gulf's service area is bounded by the Apalachicola River on the east and the Florida/Alabama state line on the west. Gulf's service area is shown on the system map shown in Figure 1.2.1-1.

1.2.2 GENERATION RESOURCES

Gulf owns and operates 11 fossil steam units, one peaking combustion turbine generator (CTG), and one cogeneration facility in Northwest Florida. In addition, Gulf has a 50-percent ownership in two coal units at Mississippi Power Company's (MPCo's) Plant

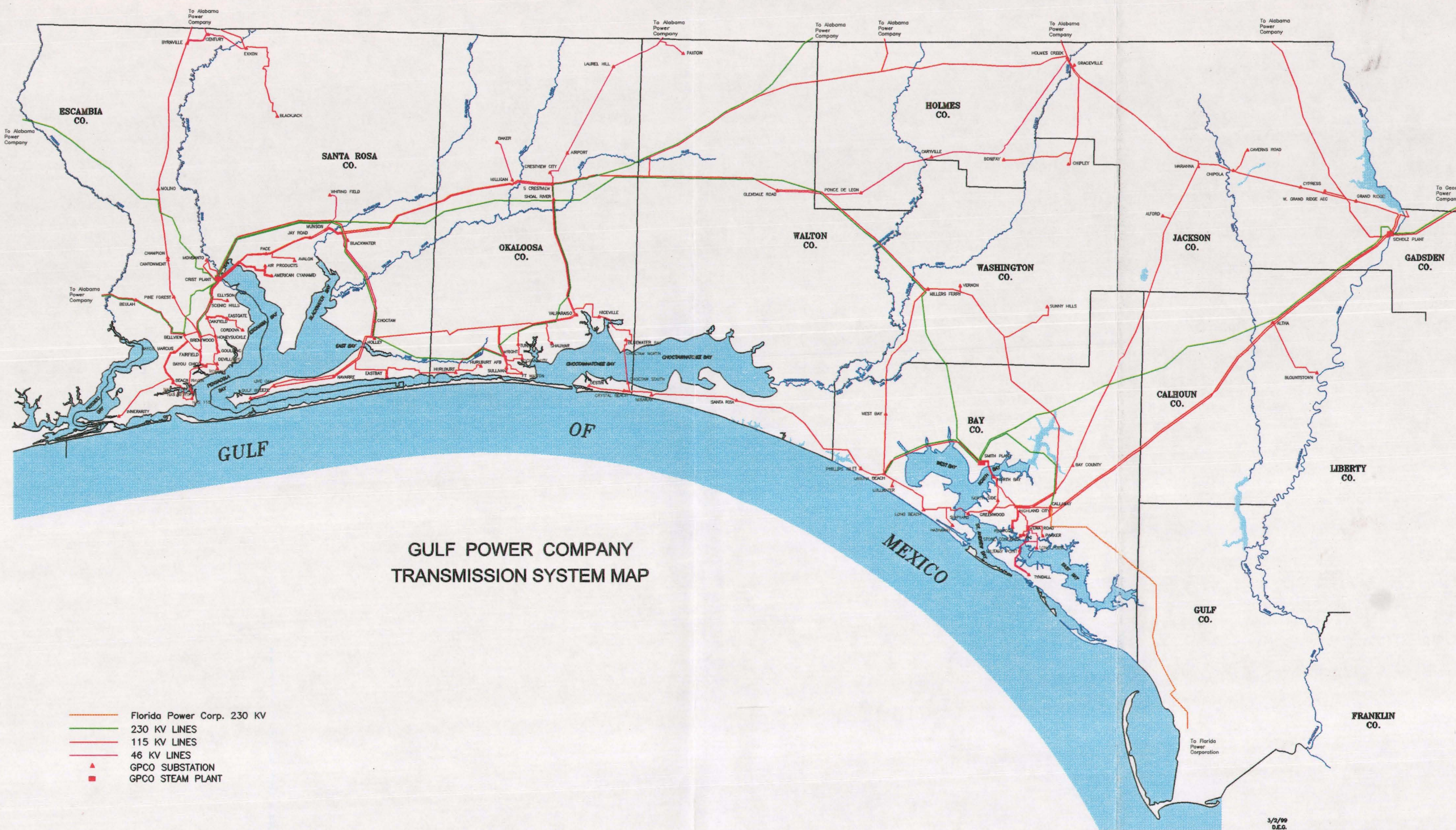


FIGURE 1.2.1-1.

GULF POWER COMPANY SYSTEM MAP

Source: Gulf, 1999.

ECT

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Daniel, and has a 25 percent ownership in Georgia Power Company's Plant Scherer Unit No. 3. Table 1.2.2-1 is a tabulation of Gulf's current generating facilities.

As shown in Table 1.2.2-1, the units owned and operated by Gulf within its service area provide a net summer capability totaling 1,531 MW. Including Gulf's ownership interests of 753 MW in Daniel Units Nos. 1 and 2 and Scherer Unit No. 3, Gulf has a total net summer generating capability of 2,284 MW and a total net winter generating capability of 2,292 MW as of June 1, 1999. In addition to Gulf's installed generating resources, Gulf has a contract with Solutia Corporation for 19 MW of firm capacity that will be in effect until May 31, 2005.

1.2.3 TRANSMISSION FACILITIES

Gulf owns approximately 1,426 miles of 115-kilovolt (kV) and 230-kV transmission lines. Within this transmission system, Gulf has 14 points of interconnection with Alabama Power Company (APCo), Georgia Power Company, Alabama Electric Cooperative, and Florida Power Corporation (FPC). The existing Gulf system in Northwest Florida, including generating plants, substations, transmission lines, and service area, is shown in Figure 1.2.1-1.

1.3 PROJECTED CAPACITY RESOURCE NEEDS

1.3.1 OVERVIEW OF THE PLANNING PROCESS

The planning process for Gulf is tightly coordinated with Southern's integrated resource planning (IRP) process. Gulf participates in that process along with the other Southern operating companies, APCo, Georgia Power, MPCo, and Savannah Electric and Power.

The capacity resource needs of Gulf and the entire Southern Electric System (SES) are driven by the summer peak demand forecast and by the Southern reliability criterion of a 13.5-percent reserve margin target. The demand forecast used for capacity planning is a net number, which already reflects the impact of demand-side measures (DSM). Given the demand forecast and the target reserve margin, the planning process uses a computer simulation model called PROVIEW® to produce a listing of preferred capacity resource plans which provide sufficient capacity to reliably meet the system's needs. The best,

Table 1.2.2-1. Existing Generating Facilities

Unit	Location	Type	Fuel	Commercial Service Date	Retirement Date*	Summer Net Capacity (MW)
Crist 1	Escambia County	FS	Gas	1/45	12/11	24.0
Crist 2	Escambia County	FS	Gas	6/49	12/11	24.0
Crist 3	Escambia County	FS	Gas	2/52	12/11	35.0
Crist 4	Escambia County	FS	Coal	7/59	12/14	78.0
Crist 5	Escambia County	FS	Coal	6/61	12/16	80.0
Crist 6	Escambia County	FS	Coal	5/70	12/15	302.0
Crist 7	Escambia County	FS	Coal	8/73	12/18	495.0
Crist Total						1,038.0
Scholz 1	Jackson County	FS	Coal	3/53	12/11	46.0
Scholz 2	Jackson County	FS	Coal	10/53	12/11	46.0
Scholz Total						92.0
Smith 1	Bay County	FS	Coal	6/65	12/15	162.0
Smith 2	Bay County	FS	Coal	6/67	12/17	192.6
Smith A	Bay County	CTG	Oil	5/71	12/06	31.6
Smith Total						386.2
Pea Ridge	Santa Rosa County	Cogen	Gas	5/98	12/28	14.4
GULF TERRITORIAL UNIT TOTAL						1,530.6
Daniel 1	Mississippi	FS	Coal	9/77	12/27	265.0
Daniel 2	Mississippi	FS	Coal	6/81	12/31	265.0
Daniel Total						530.0
Scherer 3	Georgia	FS	Coal	1/87	12/42	223.3
GULF OFF-SYSTEM UNIT TOTAL						753.3
GULF OWNED GENERATION TOTAL						2,283.9

Note: Cogen = cogeneration.
 CTG = combustion turbine generator.
 FS = fossil steam.

*Retirement dates (2006 through 2042).

Source: Gulf Power Company, 1999.

most cost-effective plan for the entire SES is identified by considering the cost of the various plans on a present worth of revenue requirements (PWRR) basis. The resulting system resource needs are allocated among the operating companies based on reserve requirements. Each company then performs the company-specific studies needed to choose the best way to meet its own capacity and reliability needs.

1.3.2 RESULTS OF RECENT RESOURCE PLANS

The 1998 ten-year site plan (TYSP) showed that Gulf is relying on firm purchased power contracts totaling 143 MW, along with Gulf's reliance on Southern capacity resources, to meet its capacity needs through the year 2001. Due to the decreasing availability of firm power purchases, it is not feasible to replace the purchased power contracts when they expire in 2001. As shown in the 1998 TYSP, Gulf would require an additional 352 MW of capacity in 2002 in order to provide its share of Southern's 13.5-percent minimum reserve margin target. Subsequent updates to Gulf's planning studies show that the summer 2002 capacity shortfall has increased to 427 MW without the addition of new capacity resources. In fact, if no additional capacity is added by 2002, Gulf will have a negative reserve margin on an individual company basis. Table 1.3.2-1 depicts Gulf's reserves both with and without the addition of Smith Unit 3.

The load forecast on which this 427-MW need is based included substantial demand reductions resulting from Gulf's DSM programs and other conservation initiatives. These measures reduced Gulf's summer peak demand by 255 MW in 1998 and will reduce it by a total of 365 MW by the end of 2002. Due to the size of Gulf's need in 2002, Smith Unit 3 cannot be avoided or delayed further by additional DSM programs.

1.3.3 CAPACITY RESOURCE ADDITIONS

Gulf's need for additional supply-side resources through 2001 will be satisfied by the reliance upon SES generation resources as well as purchased power. However, such purchases are only available on a short-term basis. When these arrangements expire at the end of 2001, Gulf must replace them with additional generating capacity to meet its share of system reserve margin requirements.

Table 1.3.2-1. Gulf Power Projected Reserves With and Without Smith Unit 3

Year	Peak Demand (MW)	Starting Capacity (MW)	Capacity Addition (MW)	Ending Capacity (MW)	Reserves (%)
1999	2,175	2,123	198	2,321	6.7
2000	2,207	2,321	-55	2,266	2.7
2001	2,234	2,266	0	2,266	1.4
WITHOUT SMITH UNIT 3					
2002	2,265	2,266	-143	2,123	-6.3
2003	2,280	2,123	0	2,123	-6.9
2004	2,309	2,123	0	2,123	-8.1
2005	2,347	2,123	-19	2,104	-10.4
2006	2,383	2,104	0	2,104	-11.7
2007	2,425	2,104	148	2,252	-7.1
2008	2,466	2,252	0	2,252	-8.7
WITH SMITH UNIT 3					
2002	2,265	2,123	574	2,663	19.1
2003	2,280	2,663	0	2,663	18.3
2004	2,309	2,663	0	2,663	16.8
2005	2,347	2,663	-19	2,644	14.1
2006	2,383	2,644	0	2,644	12.4
2007	2,425	2,640	148	2,788	16.4
2008	2,466	2,784	0	2,784	14.3

Source: Gulf Power Company, 1999.

Beginning in 1997, Gulf performed a number of economic evaluations of potential supply options to determine Gulf's most cost-effective means of meeting its 2002 capacity needs. Based on those evaluations, Gulf determined in early April 1998 that a 500-MW class CC unit at its Lansing Smith Generating Plant (Smith Unit 3) was its best internal choice for meeting the 2002 needs. This option saved over \$40 million net present value (NPV) (1998 dollars) compared to the next best self-build alternative. In order to determine if other, more cost-effective alternatives were available, and to comply with the FPSC rules, Gulf issued a Request for Proposal (RFP) in August 1998 to solicit alternatives to Gulf's construction of this CC unit. After evaluating the proposals, Gulf determined that the self-build option represented by Smith Unit 3 was the most cost-effective alternative available.

1.4 SMITH UNIT 3

1.4.1 OVERVIEW

Smith Unit 3 will be what is commonly referred to as a 2-on-1 CC unit, using the General Electric (GE) "F" Class CTG technology. The two CTGs comprising this unit will have a nominal generating capability of approximately 170 MW each in the absence of power augmentation. The exhaust gases from each of these CTGs will flow through its own heat recovery steam generator (HRSG). On a combined basis, the HRSGs will produce 1,800 pounds per square inch gauge (psig) steam in sufficient quantities to power about 200 MW of a steam turbine/generator capacity. Power augmentation to the two CTGs will increase the total capacity of this unit to 574 MW.

Smith Unit 3 will be a highly efficient, state-of-the-art CC generating unit. Because the new unit will be fueled by natural gas, the environmental concerns associated with the Project are minimal. Smith Unit 3 is expected to provide the customers of Gulf with many years of low cost, reliable, clean energy.

Smith Unit 3 will have a firm supply of natural gas that will come from a new pipeline installation to the Lansing Smith Plant. That pipeline will be owned, permitted, constructed, and operated by a separate and independent gas transmission company. Currently, Gulf does not have any plans to provide for a secondary fuel source for this unit

because of the expected firmness of the natural gas supply. Since this new natural gas pipeline is to be built and owned by someone other than Gulf, the cost estimate does not include any major gas pipeline costs, but does include connection and metering costs.

Smith Unit 3 will be located approximately 1,000 feet (ft) north of the existing Lansing Smith Plant substation. The unit's output will reach Gulf's transmission grid by means of less than 1,000 ft of 230-kV bus.

Smith Unit 3 will have an average annual output of 566 MW, utilizing duct burners at an efficiency of 6,924 British thermal units per kilowatt-hour (Btu/kwh). The unit will have the capability for power augmentation by steam injection to generate up to 574 MW for up to 1,000 hours per year (hr/yr) of peaking generation at a reduced efficiency of 7,271 Btu/ kwh. The costs for the necessary equipment associated with the power augmentation operation are included in the estimate below.

The following is a listing of some of the specific unit characteristics:

- Forced outage rate—3.4 percent.
- Scheduled maintenance outage—2 weeks per year (average).
- Equivalent availability—92 percent.
- Expected average capacity factor—62 percent.
- Fuel consumption (full load)—3,900 million British thermal units per hour (MMBtu/hr).
- Annual fixed operation and maintenance (O&M) (1998\$)—\$2.84 per kilowatt year (kw-yr).
- Variable O&M (1998\$)—\$1.89 per megawatt hour (mwh).

1.4.2 PROJECTED UNIT CONSTRUCTION COSTS

The following is a breakdown of estimated installed costs for Smith Unit 3. This estimate is based on a combination of actual vendor quotes and refined engineering cost analyses and includes the costs necessary to comply with all applicable environmental regulations.

With respect to most of the components that comprise the following costs, this estimate can be considered relatively firm (± 10 percent).

Installed Cost Estimate for Smith Unit 3

Indirects	\$ 25,661,966
Site, general	6,701,846
Steam generator area	39,741,570
Turbine and generator area	91,143,505
Fuel facilities (metering only)	856,111
Plant water systems	13,443,351
Electrical distribution and switchyard (onsite)	12,847,183
Plant instrumentation and controls	2,591,303
Other	<u>3,936,065</u>
TOTAL	\$196,922,900

1.5 COST EFFECTIVENESS OF SMITH UNIT 3

A Need Study, filed with the FPSC Petition for Need Determination, demonstrates that Gulf has a clear need for more capacity; and that Smith Unit 3 is the most cost-effective alternative available, taking into consideration both other Gulf-constructed capacity options and options offered by third parties in response to Gulf's RFP for power supply alternatives.

1.5.1 SELF-BUILD ANALYSIS

1.5.1.1 Initiation of Site-Specific Studies

By the summer of 1997, it was apparent that Gulf would need to add generating resources by 2002 to reliably meet its customers' needs. This need was the result of several factors. Gulf's existing short-term power purchase agreements were scheduled to expire at the end of 2001, at which time Gulf would be left with a negative reserve margin. Continuing to meet Gulf's capacity needs with new, short-term power purchase options was not feasible, since such purchases were becoming not only scarce, but extremely expensive as a resource option. In addition, total SES reserve margins were declining, and Gulf could no longer rely on system-wide reserves to offset its own reserve shortfall. Two of the other operating companies in the SES, APCo and MPCo had engaged in a study to determine their best self-build alternatives in the early part of 1997. This led to the filing for certification of APCo's Barry CC unit and MPCo's Daniel CC unit in August of 1997. As a

member of the SES, Gulf was offered the opportunity to participate in the ownership of the proposed Daniel CC unit.

Based on all these circumstances, Gulf, in late 1997, began evaluating a number of site-specific, self-build generation options for meeting its future demand needs. The following is a listing of the self-build alternatives that were ultimately considered in this evaluation process:

- Participation in MPCo's Daniel CC unit scheduled for a 2001 in-service date.
- Construction of CTGs at Smith Plant.
- Construction of a CC unit at Smith Plant.
- Participation in a cogeneration unit in the Pensacola area.

The self-build evaluation process required the development of plant-specific cost and operating data for each of the alternatives. These data were then used to calculate the total 20-year NPV of costs for each of the generating alternatives. The components of cost considered in the analysis included capital expenditures, fuel supply and transportation costs, O&M expense, transmission improvements, and system energy savings. These options were compared on both a cost per kilowatt and total NPV basis.

1.5.1.2 Significant Cost Drivers

There are several significant cost drivers in the 20-year NPV cost analyses of site-specific alternatives. These include the cost of natural gas transportation, the cost of required transmission improvements, and the amount of energy savings that result from the displacement of less efficient generation.

1.5.1.3 Natural Gas Transportation Costs

One of the key elements in the cost analyses was the development of natural gas (fuel) supply costs for the self-build options. As discussed in Section 5 of the Need Study filed with the Petition for Need Determination, the SES's Fuel Panel creates a forecast of generic fuel costs by type; however, a more refined and site-specific projection must be used in the self-build analysis. Since most of the self-build options were natural gas-fired alternatives, a number of different fuel assumptions were explored in the evaluation.

Natural gas commodity prices and storage costs are fairly competitive throughout the region and can be treated as basically equivalent for any of the specific sites under consideration. On the other hand, there is a great variety in the natural gas transportation rates, particularly when the cost of gas delivered into the State of Florida is compared to gas delivered outside of Florida.

1.5.1.4 System Energy Savings

Another key economic factor is the amount of system energy savings associated with each alternative. System energy savings are dependent on the marginal fuel cost of the alternative. Units with lower delivered fuel prices will dispatch earlier and will run at higher capacity factors than units with higher fuel costs. In turn, these units displace a greater amount of high-priced generation from other units and maximize system energy savings. This factor tended to penalize lower efficiency CTG units, as well as units with fuel purchased under currently existing gas tariff rates inside the state of Florida. The Daniel CC provided the greatest system energy savings because of its low gas transportation costs. The energy savings of the Smith CC with the new pipeline option were slightly less than those of the Daniel unit, although the pipeline capital cost would be an offset to any savings of this option.

1.5.1.5 Transmission Costs

The geographic location of the alternatives surfaced as a major factor in the cost evaluations due to the impact of location on the electric transmission system and the associated cost of needed improvements. Each of the self-build options was analyzed separately to determine any incremental transmission impacts resulting from its installation. These studies revealed that the prevailing network flows through Gulf's system are from the west to the east. As generation is added, particularly west of Gulf's service area, transmission improvements are required to reliably transport the power and provide voltage support to Gulf's load centers. It was determined that capacity additions located almost anywhere except near the Panama City, Florida, area had some negative impact on the transmission system. In fact, the study revealed that the further west the generation alternative was located, the greater the impact on Gulf's transmission system. The cost of

overcoming these impacts was added to the overall cost of each self-build alternative in the evaluation.

1.5.1.6 Capital And O&M Costs

The various options' capital and O&M costs were probably the most straight forward elements of the evaluation. It was clear that participating in a sister company project would have the least capital cost, by enabling Gulf to take advantage of economies of scale. It was also clear that CTGs had lower capital cost and higher operating costs than the CC units.

1.5.1.7 Economic Evaluation

The economic evaluation of the self-build alternatives was approached from a total cost basis using common financial factors to develop a total NPV for each alternative over a 20-year period. The capital costs for the units, pipeline, and transmission were calculated for each self-build alternative as a traditional PWRR. The capacity costs of the cogeneration project and other fixed annual costs were treated like an expense and discounted to yield a NPV of cost. Each self-build option was modeled as an input to the entire SES to determine its effect on the total production and energy costs or savings to the system. The final result of combining these cost components was the total NPV of cost for all of the self-build options.

The evaluation process, which began the previous fall, was completed in April of 1998. As mentioned earlier, in the final analysis the evaluation considered options that were comparable in size to a 2-on-1, F-Class CC technology (approximately 500-MW class) and included all incremental costs associated with the installation of each alternative.

1.5.1.8 Results

The results of the evaluation showed that the Smith CC unit was the lowest cost alternative. Although energy savings was a major factor in the evaluation process, the primary factor that eliminated many of the options was the cost of the transmission improvements required to support new generation at any location outside the Panama City area. The ta-

ble below provides the results of the self-build analyses which demonstrate that Smith Unit 3 is Gulf's most cost-effective self-build alternative.

<u>Self-Build Alternative</u>	<u>NPV of Costs (98\$—millions)</u>
Smith Unit 3	117.1
Smith CTG	158.5
Daniel CC	236.7
Mulat Tower (cogeneration)	239.0

1.6 CONSEQUENCES OF PROJECT DELAY

Beginning with the decision in April 1998 to pursue the installation of Smith Unit 3, Gulf established a project timeline to pinpoint critical dates associated with the successful completion of this unit. Table 1.6.0-1 represents the timeline for Smith Unit 3.

There are a number of elements in the timeline that can and most likely will overlap. For example, the need determination can precede and overlap the permitting, which can overlap equipment procurement. The fact that these elements overlap does not necessarily affect the other processes. However, there are some elements that can affect other elements. For instance, if the need determination were delayed or denied, the environmental permitting would not proceed until the need is resolved.

As mentioned before, recent inquiries in the purchased power market have resulted in fewer and far more costly offers for capacity and energy. Gulf has demonstrated through the steps taken to date that its selection of Smith Unit 3 is the most cost-effective alternative available to meets its customers' load requirements beginning in 2002. Gulf believes that its timeline is reasonable and achievable for a summer 2002 commercial in-service date for Smith Unit 3 in order to prevent having to use this high-priced purchased power. However, if there is a delay of Smith Unit 3 that prevents meeting its June 2002 in-service date, Gulf's customers may pay more for their electrical energy than necessary. Gulf is also concerned with the possibility that without this unit's timely installation, which helps to support SES reserves, there will be additional reliability issues that could affect customer service.

Table 1.6.0-1. Smith Unit 3—Project Timeline

August 21, 1998	Issue RFP
October 16, 1998	Receive proposals and begin evaluations
November 13, 1998	Initial screening complete
December 15, 1999	Begin detailed screening
January 9, 1999	Select short list for negotiations or move forward with self-build option
January 15, 1999	Begin final selection process for gas supplier
February 1, 1999	Solicit vendor proposals for equipment
March 15, 1999	Lock down preliminary engineering for environmental study work for SCA
March 31, 1999	File application for Need Determination
June 1999	File environmental SCA
June 7-8, 1999	Need Determination hearings
August 25, 1999	Final decision on Need Determination
October 31, 1999	Finalize plant design
November 22, 1999	Order remaining equipment
August 1, 2000	Issue bid package for erection of the unit
September 15, 2000	Receive state and federal environmental permits
October 1, 2000	Award erection contract
November 1, 2000	Begin site preparation and begin construction and substation work
January 15, 2002	Complete natural gas supply to plant
February 1, 2002	Begin unit testing and performance checks
May 31, 2002	Project complete

Source: Gulf Power Company, 1999.

2.0

2.0 SITE AND VICINITY CHARACTERIZATION

To assess the potential impacts a project may have, it is necessary to characterize the environment in which the project will be located. This chapter provides that characterization for the Smith Unit 3 Project. This chapter begins by describing the Project site and its Bay County environs. Following the site description are detailed characterizations of the socio-political and bio-physical environment. This chapter contains the following specific sections, per the Florida Department of Environmental Protection (FDEP) *Instruction Guide*:

- 2.1—Site and Associated Facilities Delineation.
- 2.2—Socio-Political Environment.
- 2.3—Biophysical Environment.

2.1

2.1 SITE AND ASSOCIATED FACILITIES DELINEATION

The proposed site for the construction of the Smith Unit 3 Project is located in central Bay County northwest of Panama City (Township 2 South, Range 15 West, Section 36). The site is owned by Gulf and lies immediately north of their existing Lansing Smith Generating Plant.

Figures 2.1.0-1 and 2.1.0-2 show the location of the Project within the state of Florida and within Bay County, respectively. The approximately 50-acre site is bordered on the south by the existing Lansing Smith Generating Plant, on the west by a Gulf electric transmission line corridor, and on the north and east by undeveloped property owned by Gulf. Figure 2.1.0-3 shows the site location on U.S. Geological Survey (USGS) 1:24,000 scale topographic maps (USGS, 1992). Access to the site is provided by County Road (CR) 2300 which terminates at the existing power plant entrance. CR 2300 connects to State Road (SR) 77 to the east.

Figure 2.1.0-4 shows the outline of the proposed site on a recent aerial photograph (dated March 1999) at a scale of 1-inch equals 1,000 ft. Additionally, the joint state/federal dredge-and-fill permit application form (Appendix 10.2.4) will contain a 1-inch equals 400-ft aerial photograph of the site. The site is completely forested and has been logged for many years.

The 574-MW Smith Unit 3 Project will require development of the majority of the 50-acre site. Included in the proposed development will be the generating facility footprint, construction laydown area, gas metering station, storm water ponds, and administration building and parking. The proposed Smith Unit 3 will share facilities with the existing power plant units to the south, including the discharge canal, water wells, the domestic wastewater treatment plant (WWTP), electric transmission lines, and transportation access.

The site is fairly level and low in elevation averaging approximately 5 feet above mean sea level (ft-msl). According to the Federal Emergency Management Agency (FEMA) floodplain map (Figure 2.1.0-5), the entire site is located outside of the 100-year floodplain.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

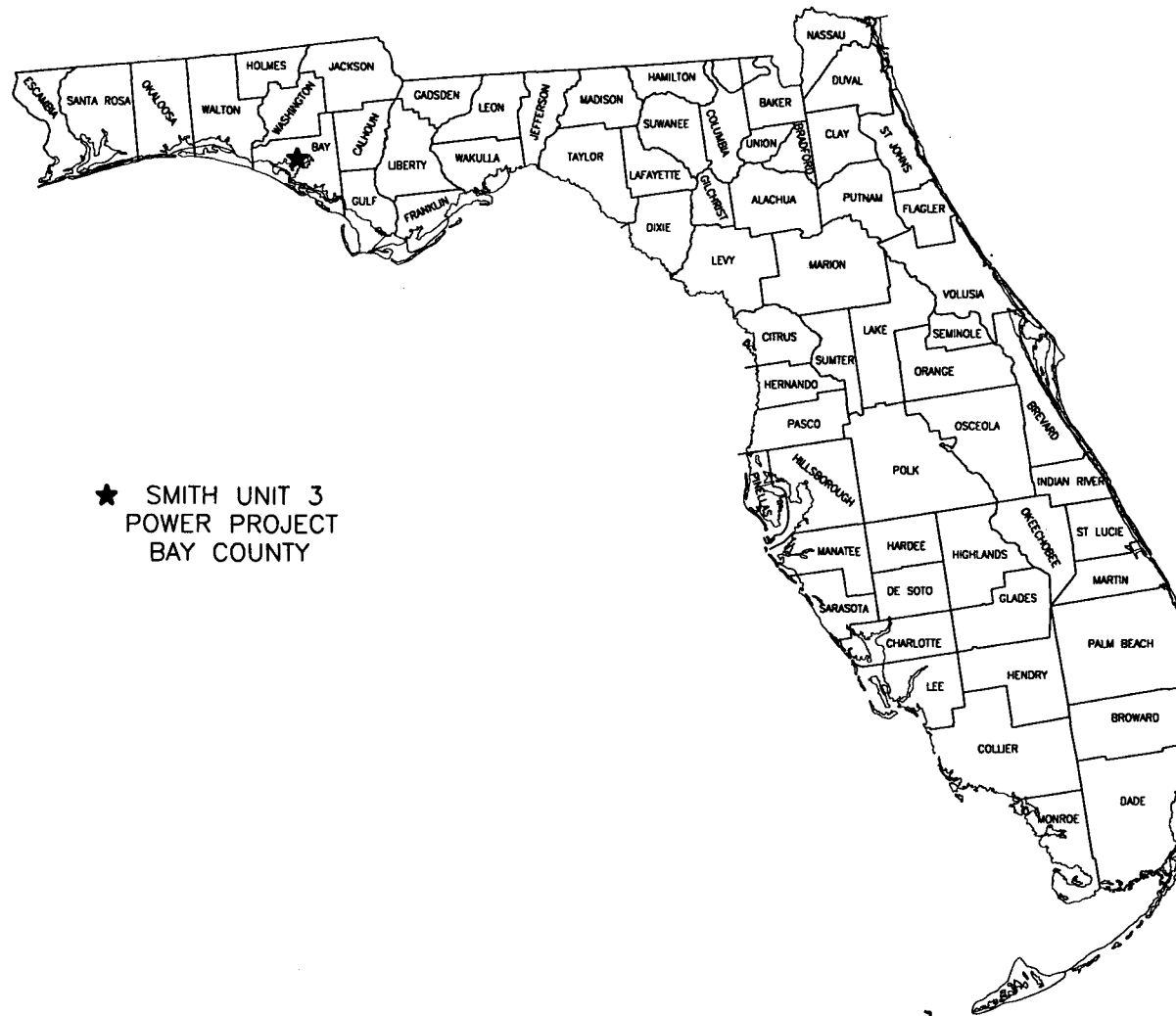


FIGURE 2.1.0-1.

SITE LOCATION WITHIN THE STATE OF FLORIDA

Source: ECT, 1999.

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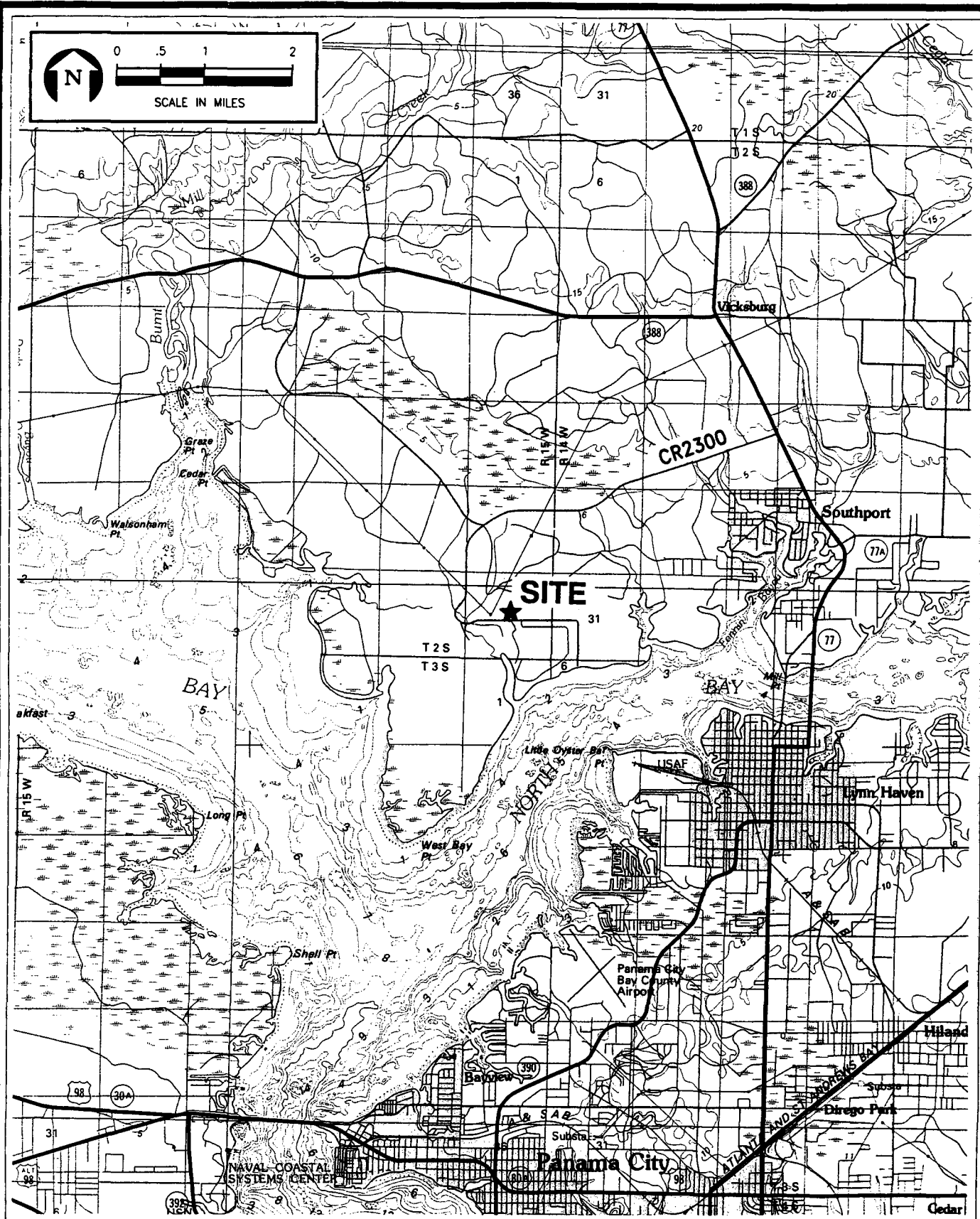


FIGURE 2.1.0-2.
SITE LOCATION RELATIVE TO LOCAL LANDMARKS

Source: USGS 30x60-minute topo map: Panama City, FL, 1981.

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Environmental Consulting & Technology, Inc.

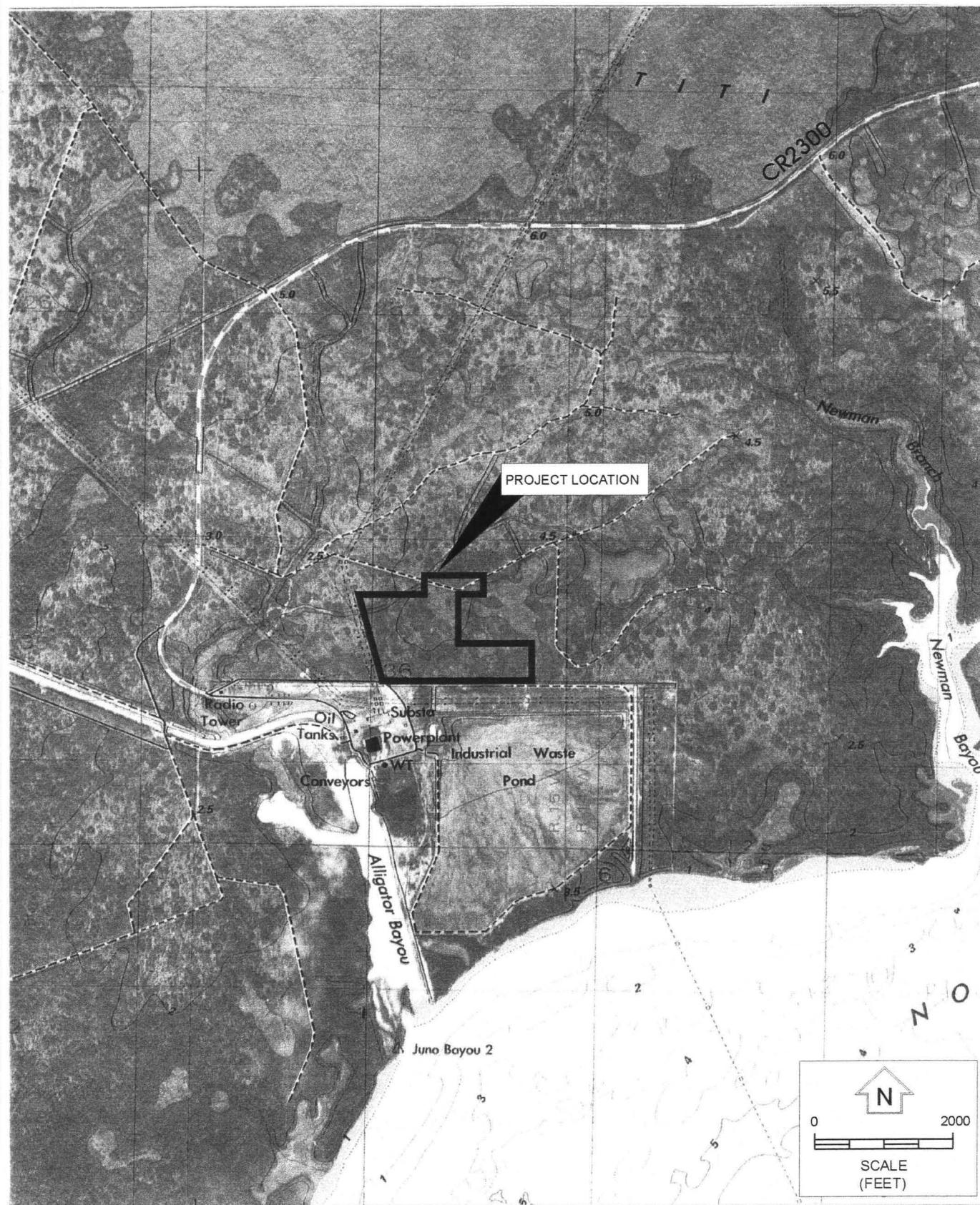


FIGURE 2.1.0-3.

PROJECT SITE LOCATION AND SURROUNDINGS

Sources: USGS topo map of Southport, FL., 1992; ECT, 1999.

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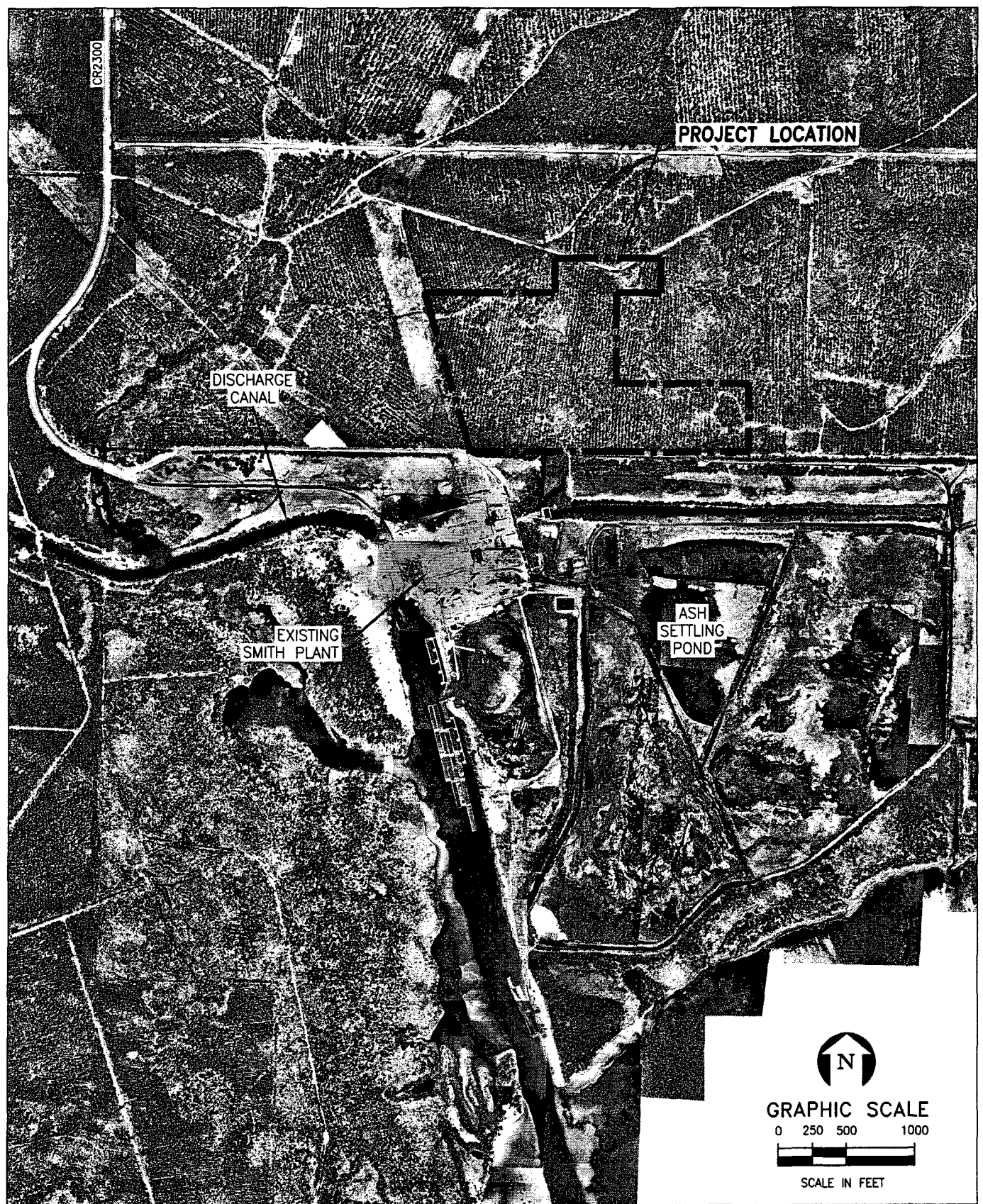


FIGURE 2.1.0-4.

AERIAL PHOTOGRAPH OF SITE LOCATION

Source: Gulf Power, 1999.

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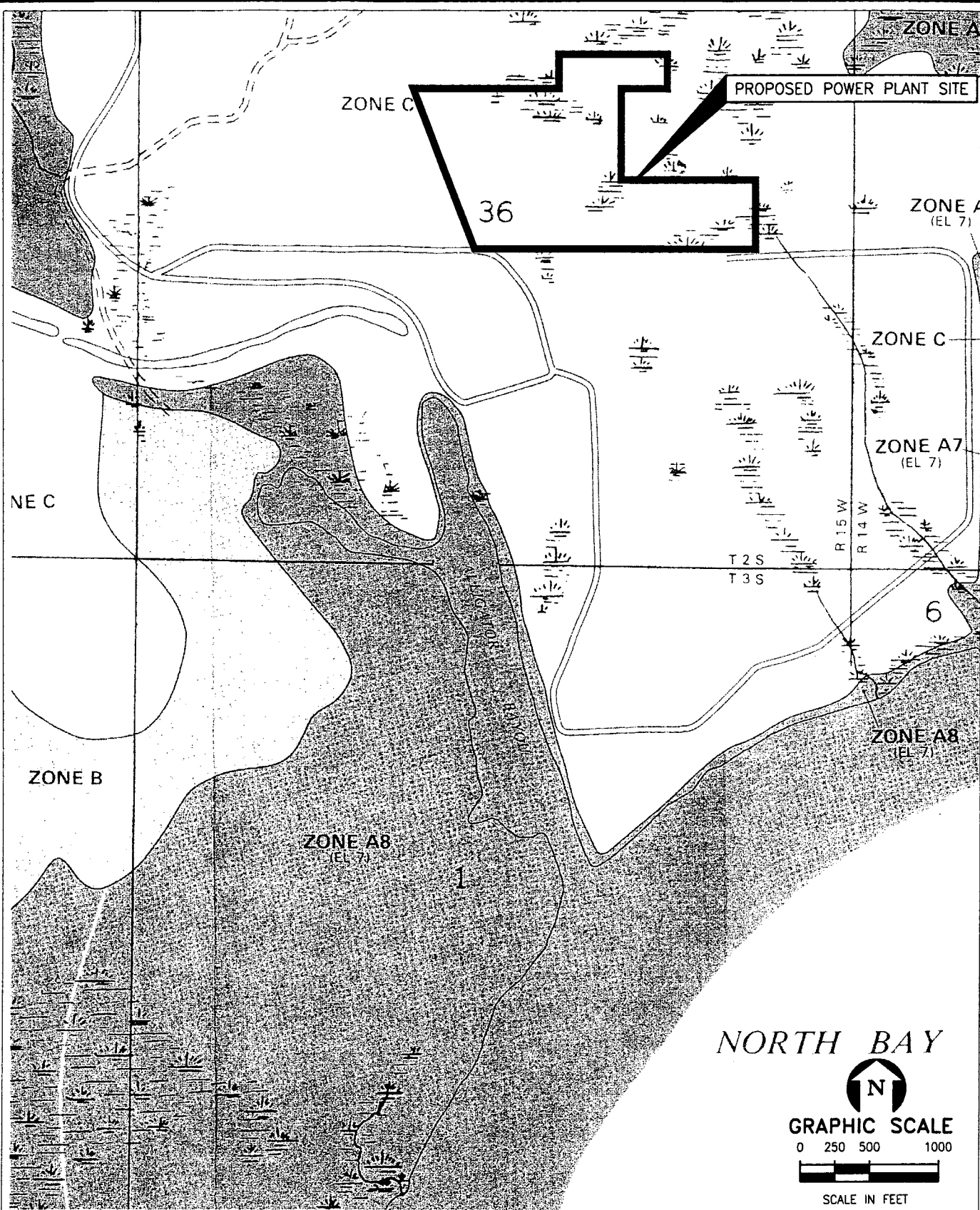


FIGURE 2.1.0-5.

FLOODPLAINS MAP - SMITH UNIT 3

Sources: FEMA; ECT, 1999.

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2.2.1

2.2 SOCIO-POLITICAL ENVIRONMENT

2.2.1 GOVERNMENTAL JURISDICTIONS

The Smith Unit 3 Project site is located in unincorporated Bay County, Florida. Figure 2.2.1-1 depicts the Project site location and its juxtaposition with incorporated and unincorporated areas in a 5-mile radius.

The nearest incorporated city is Lynn Haven, located approximately 2.5 miles southeast of the Project site. Recent annexations into Lynn Haven have included properties located approximately 3 miles east of the Project site. The Future Land Use Element of the Comprehensive Plan notes that the City of Lynn Haven has identified portions of Southport as probable areas for the expansion of sewer service. Panama City, the next closest incorporated city, is located approximately 3.5 miles to the southeast. The 1990 adopted Bay County Comprehensive Plan identifies Southport, located approximately 2 miles northeast of the Project site, as a community (currently unincorporated). Southport is currently undergoing an incorporation process.

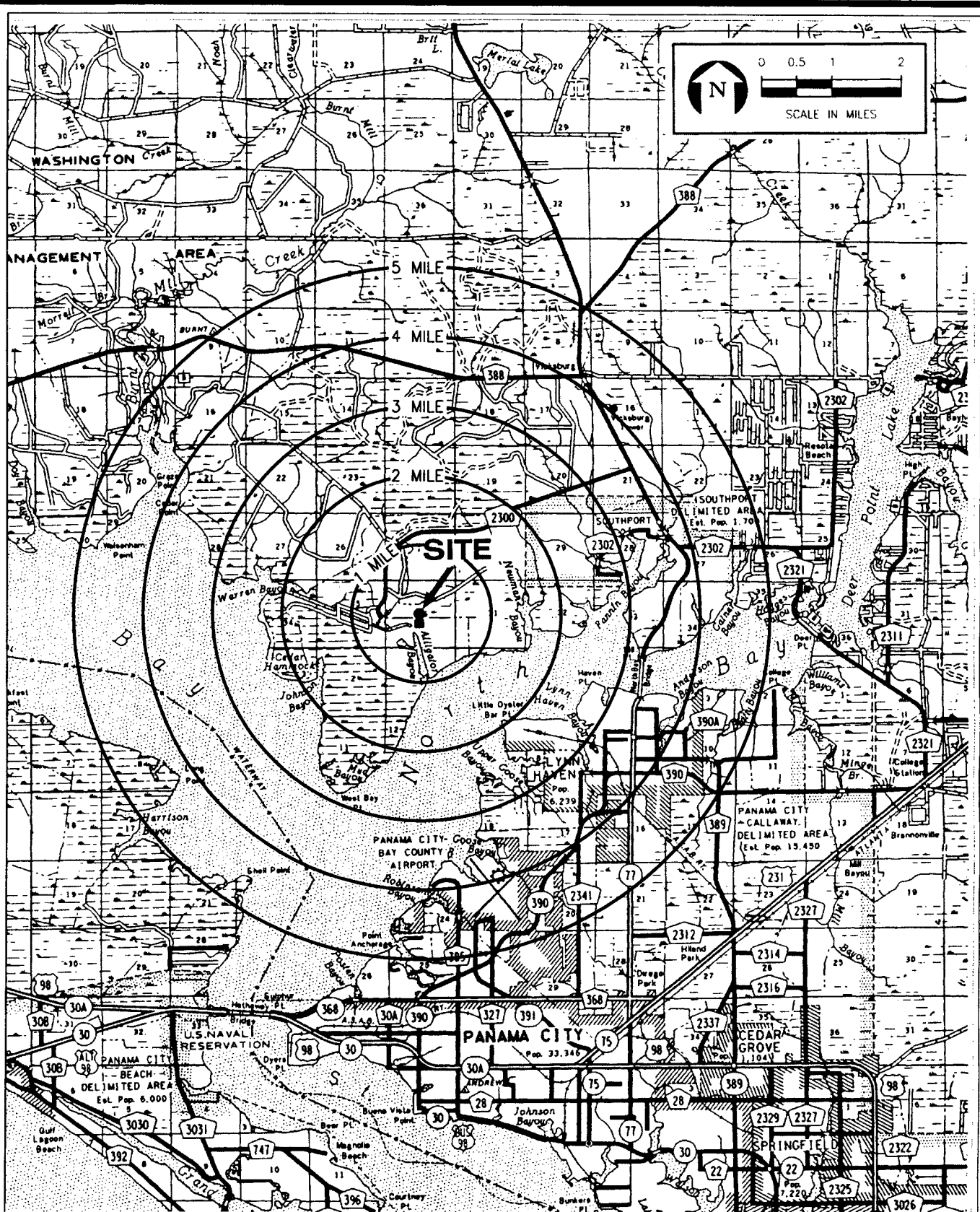


FIGURE 2.2.1-1.

SITE RELATIVE TO INCORPORATED/UNINCORPORATED
AREAS

Sources: FDOT, 1993; ECT, 1999.

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2.2.2 ZONING AND LAND USE PLANS

The Project site is currently in silviculture, primarily, and has never been developed for other uses. Adjacent to the south is the existing Lansing Smith plant. To the west of the Project site are two power line transmission corridors. The current zoning and land use plan designations for the site are described in the following sections.

2.2.2.1 Comprehensive Plan Future Land Use Map

The Project site is currently located in the Agriculture land use classification as depicted on the 1990 Adopted Bay County Comprehensive Plan Future Land Use Map (FLUM). Figure 2.2.2-1 depicts the boundaries of the land use classifications in proximity to the Project site. The existing Lansing Smith plant is designated Industrial and the surrounding lands to the east, north, and west are designated as Agriculture. The allowable uses within the Agriculture designation cannot accommodate the proposed construction of Smith Unit 3.

Bay County is currently updating its 1990 Adopted Comprehensive Plan through the Evaluation and Appraisal Review (EAR) process. In the February 1998 version of the Comprehensive Plan passed by the Bay County Board of Commissioners and submitted to the Florida Department of Community Affairs (FDCA), the allowable uses within the Agriculture designation were expanded to include self-contained industry. While the proposed development of Smith Unit 3 may be compatible with the proposed change, the updated Comprehensive Plan may not be finally adopted and legally in effect until later in 1999.

In order to be consistent with the current adopted Comprehensive Plan, Gulf has submitted a large-scale (greater than 10 acres) plan amendment application to change the FLUM designation from Agriculture to Industrial. The Industrial designation will accommodate the proposed use of the property and is consistent with the existing designation for the adjacent Lansing Smith Plant (Smith Units 1 and 2). The plan amendment application submitted to Bay County included a review of the compatibility of the proposed FLUM change with both the adopted Comprehensive Plan and the February 1998 version of the Comprehensive Plan. The proposed change is compatible with the objectives and policies

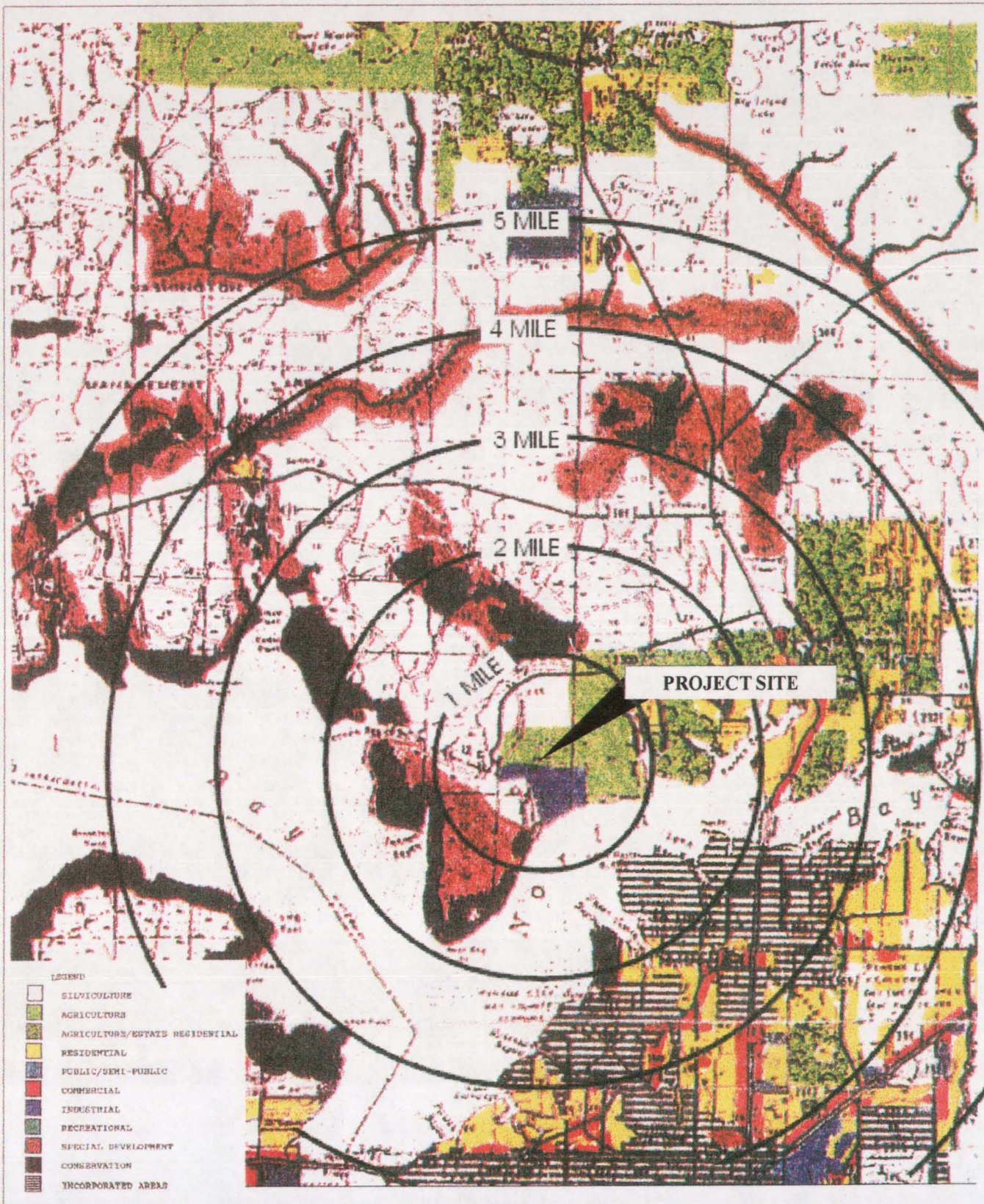


FIGURE 2.2.2-1.

BAY COUNTY LAND USE CATEGORIES

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Sources: Bay County Planning Dept., 1991; ECT, 1999.

of both plans and is consistent with the planning assumptions that industrial expansion would occur in much the same pattern as had existed in the past and those acreage requirements would not significantly change. Smith Unit 3 is an approximately 50-acre expansion of the existing, approximately 700-acre, built-out Lansing Smith plant site.

In May 1999, Bay County transmitted Gulf's requested plan amendment to the FDCA for review. It is anticipated the plan amendment for the site will be adopted by the county in Fall 1999. A copy of Gulf's submitted comprehensive plan amendment is included as Appendix 10.2.1.

2.2.2.2 Zoning

In Bay County, the zoning districts are coincident with the comprehensive plan land use designations. Gulf's large-scale plan amendment application thus seeks to change both the existing FLUM and zoning designation of Agriculture to Industrial. When the plan amendment is approved, the proposed development of Smith Unit 3 will meet all setback, required yard sizes, lot coverage, and other requirements of the Bay County Land Use Code.



2.2.3 DEMOGRAPHY AND ONGOING LAND USE

Recent population trends for the unincorporated areas of Bay County and the nearby incorporated areas of Panama City, Lynn Haven, and Cedar Grove are depicted on Figure 2.2.3-1. The rate of population growth for the state of Florida from 1970 to 1980 and from 1980 to 1990 exceeds that for the entire population of Bay County. The estimated change from 1990 to 1995 for the state and for all of Bay County is nearly the same (8.6 to 8.8 percent, respectively). The rate of increase for unincorporated Bay County exceeds that of the state of Florida for all three time periods. The rate of population increase in unincorporated Bay County exceeds that of Panama City and is generally less than that for Lynn Haven and Cedar Grove. The entire population of Bay County is projected to increase by 7.3 percent from 1995 to 2000, by 6.7 percent from 2000 to 2005, and by 6.1 percent from 2005 to 2010. These projected increases lag behind those for the projected state population increases as a whole.

Existing land uses within a 5-mile radius of the Project site are depicted in Figure 2.2.3-2. Surrounding land uses to the north, east, and west are silviculture. The industrial land use to the south is associated with the existing Lansing Smith Plant. An electric transmission line corridor abuts a portion of the western Project site boundary. The nearest residential development is located over 2 miles to the northeast of the Project site. Field verification of the surrounding land uses was conducted in February 1999. The cities of Lynn Haven, Panama City, and Cedar Grove are located southeast of the Project site across North Bay.

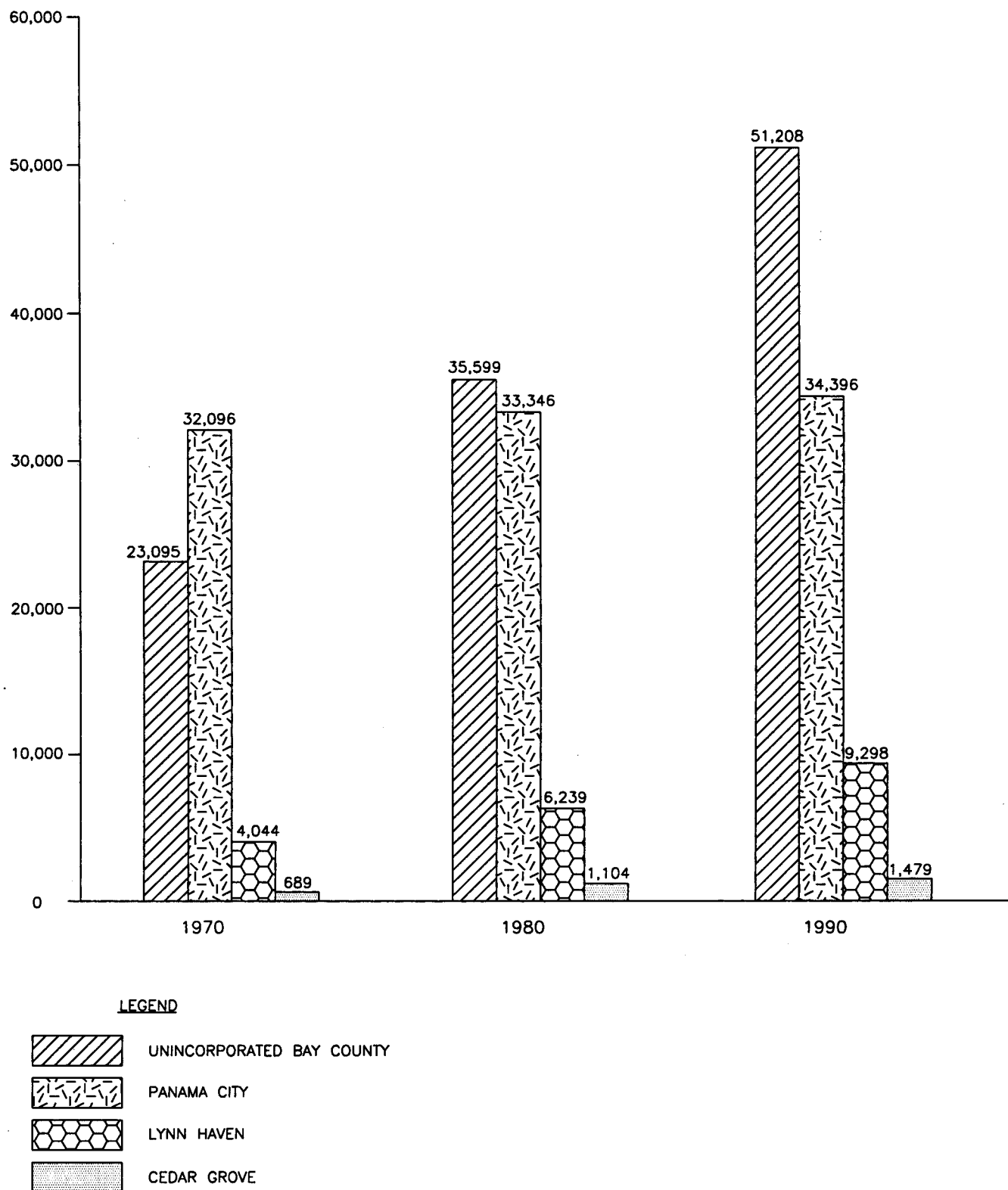


FIGURE 2.2.3-1.
POPULATION TRENDS

Sources: Florida Statistical Abstracts, Bay County Comprehensive Plan; ECT, 1999.

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FIGURE 2.2.3-2.
EXISTING LAND USE MAP OF PROJECT VICINITY

Sources: Bay County Planning and Zoning Dept., 1991; ECT, 1999.

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2.2.4

2.2.4 EASEMENTS, TITLE, AGENCY WORKS

The Project does not need any approvals for easements, title, or crossing of works of any agency.

2.2.5 REGIONAL SCENIC, CULTURAL, AND NATURAL LANDMARKS

The West Florida Regional Planning Council (WFRPC) has prepared a Strategic Regional Policy Plan (SRPP) for its seven-county planning area. The SRPP, prepared in accordance with Section 186.507, Florida Statutes, is a long-range guide for the physical, economic, and social development of the region. The SRPP is required to identify and address significant regional resources and facilities. Using existing information from numerous state and federal agencies, natural resources inventory maps have been compiled for the region. Figures 2.2.5-1 through 2.2.5-6 depict the natural resources in the WFRPC planning area. Regionally significant natural resources within 5 miles of the Project site have been identified as North Bay (surface water resource) and wetlands.

The adopted 1990 Bay County Comprehensive Plan identifies the natural resources of Bay County including:

- Fish and wildlife habitats.
- Critical habitat areas.
- Deer Point Lake watershed.
- Wetlands.
- Vegetative communities.

There are no critical habitat areas or unique fish and wildlife habitats depicted within 5 miles of the Project site (Figure 2.2.5-7). The Project site is located approximately 5.5 miles from the nearest boundary of the Deer Point Lake watershed. The predominant onsite and proximate vegetative community is the North Florida pine flatwoods. This plant community, in Bay County in general, and the Project site specifically, has been extensively logged, resulting in low diversity of plants and a limited amount and diversity of wildlife. The onsite wetlands are isolated systems separate from the major regional wetland systems such as Jackson Titi to the north and Newman Branch to the east. The nearest Conservation land use designations on the FLUM are approximately 1 mile to the south along the northern shore of North Bay and approximately 1 mile northwest of the Project site, associated with Jackson Titi.

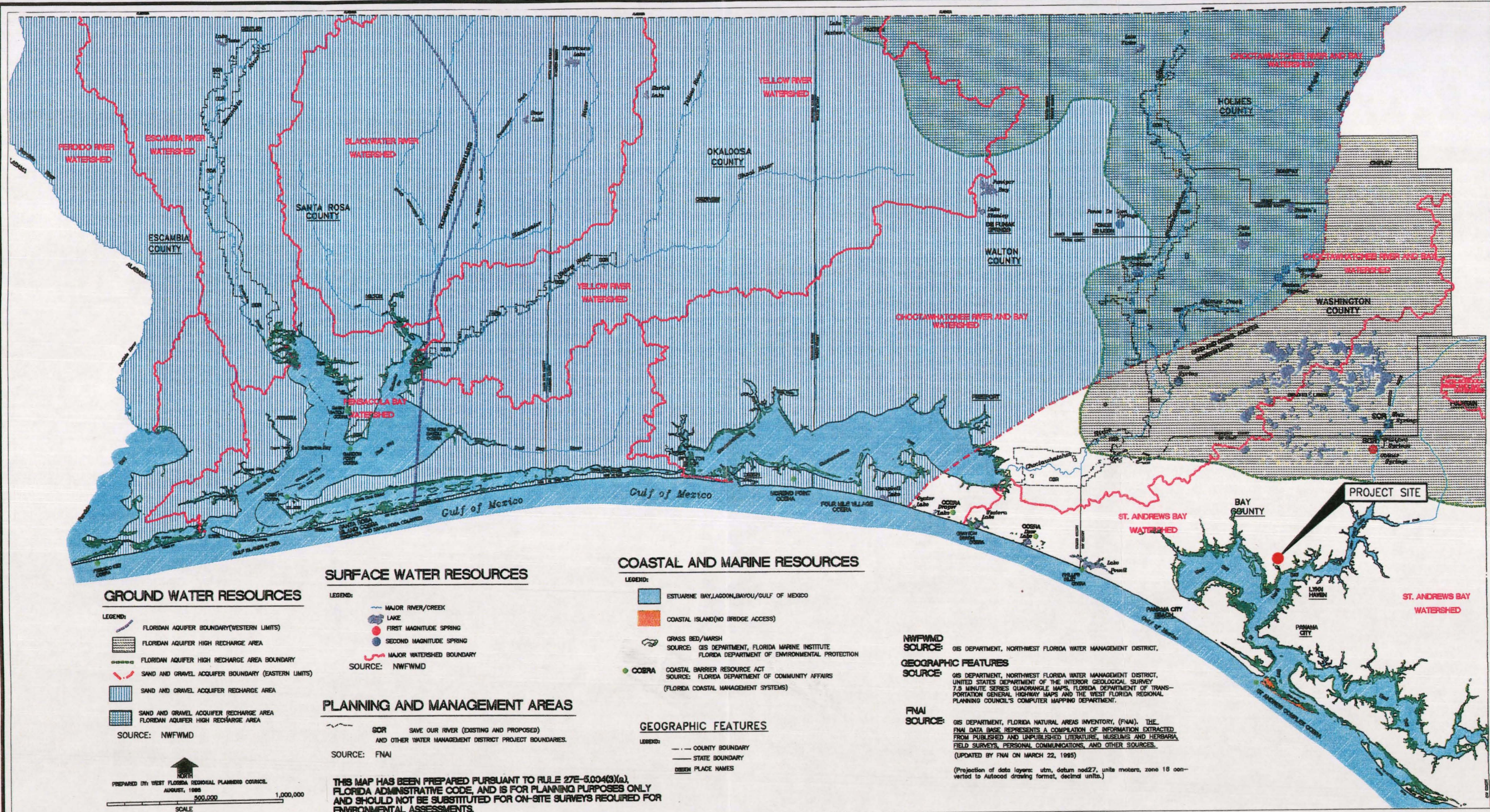


FIGURE 2.2.5-1.
WATER RESOURCES

Sources: West Florida Regional Planning Council, 1996; ECT, 1999.

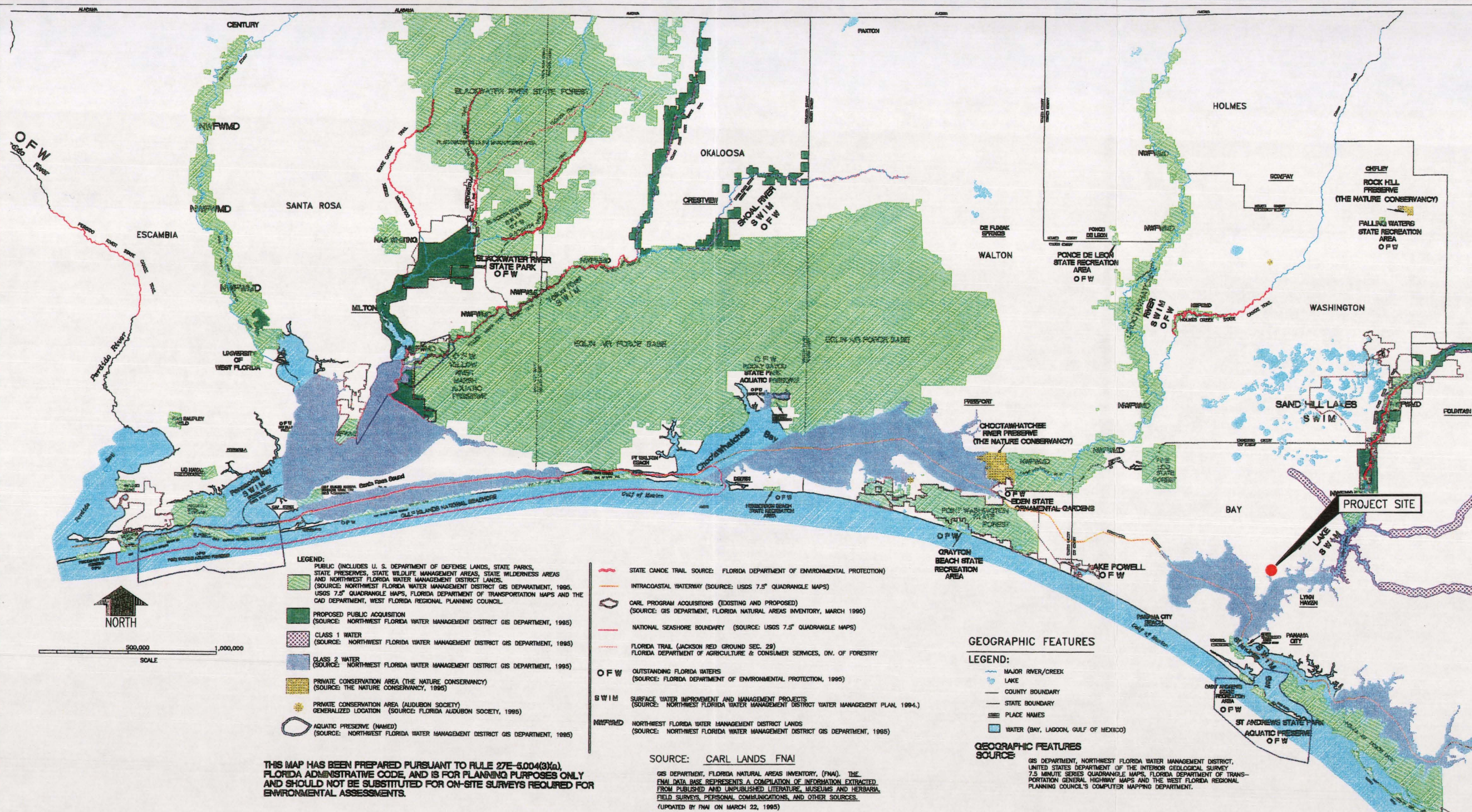


FIGURE 2.2.5-2.
PLANNING AND MANAGEMENT AREAS

Sources: West Florida Regional Planning Council, 1996; ECT, 1999.

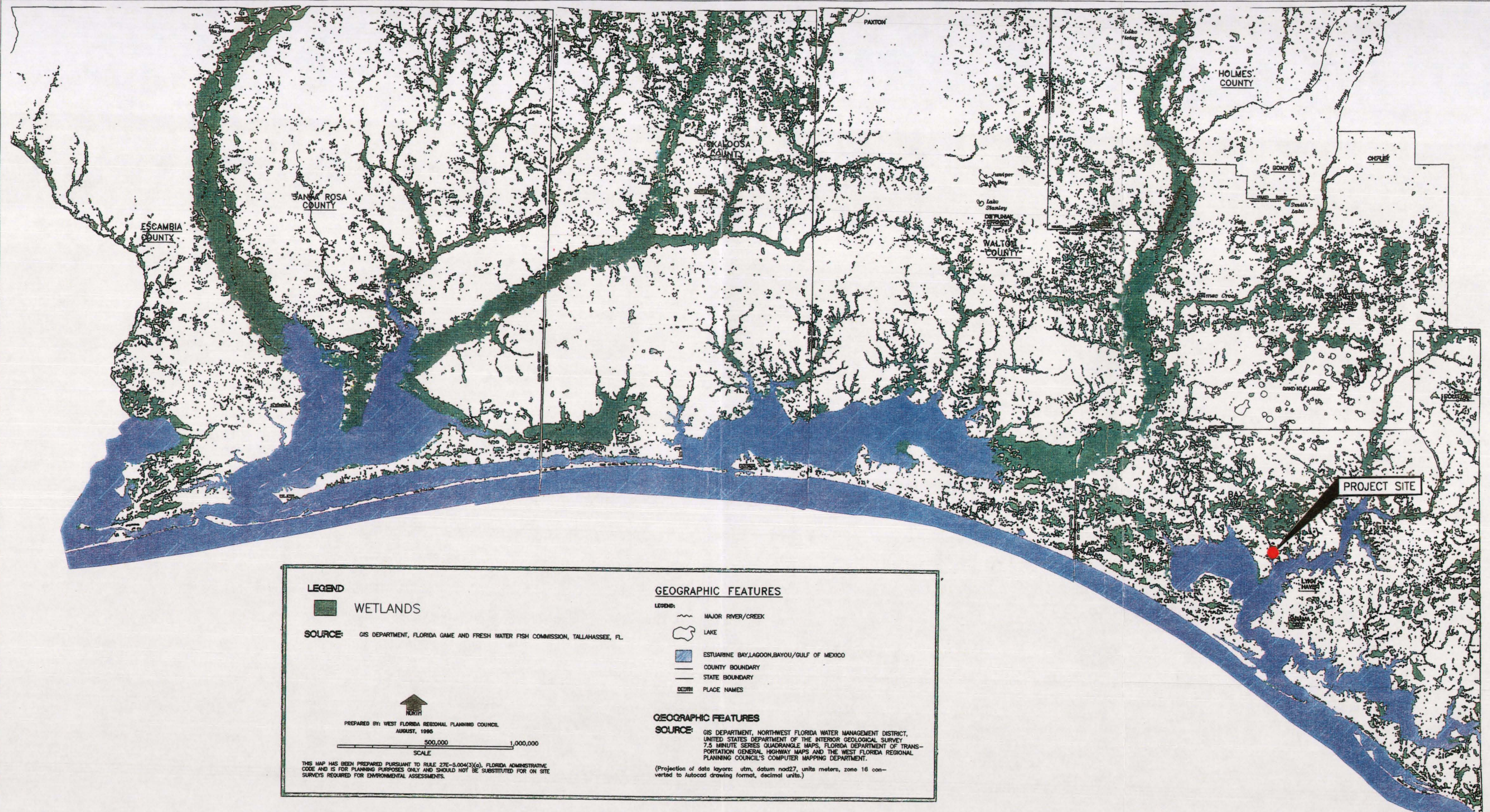


FIGURE 2.2.5-3.
WETLANDS

Sources: West Florida Regional Planning Council, 1996; ECT, 1999.

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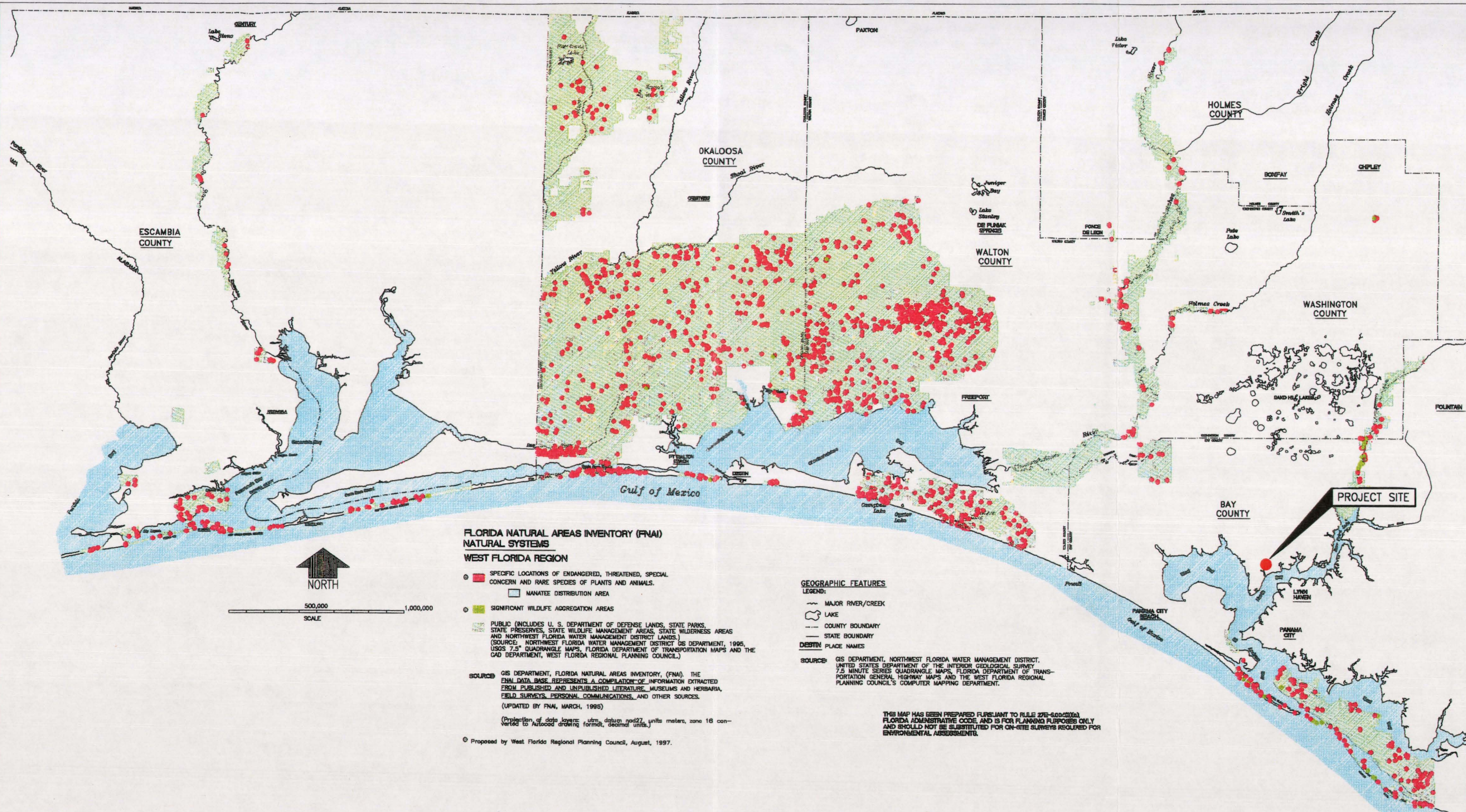


FIGURE 2.2.5-4.
NATURAL COMMUNITIES

Sources: West Florida Regional Planning Council, 1996; ECT, 1999.

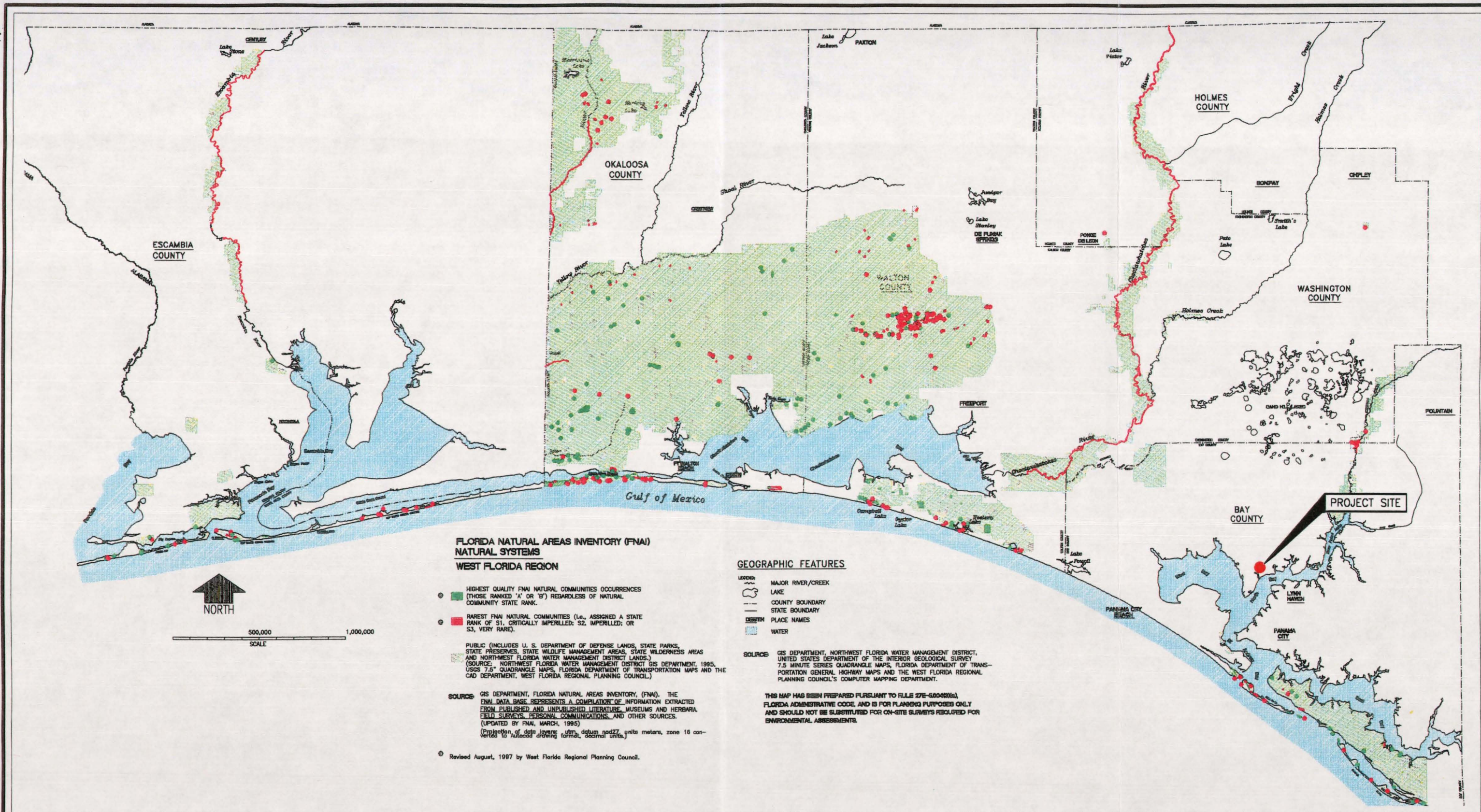


FIGURE 2.2.5-5.
ENDANGERED, THREATENED, SPECIAL CONCERN, AND RARE PLANT AND ANIMAL SPECIES

Sources: West Florida Regional Council, 1995; ECT, 1999.

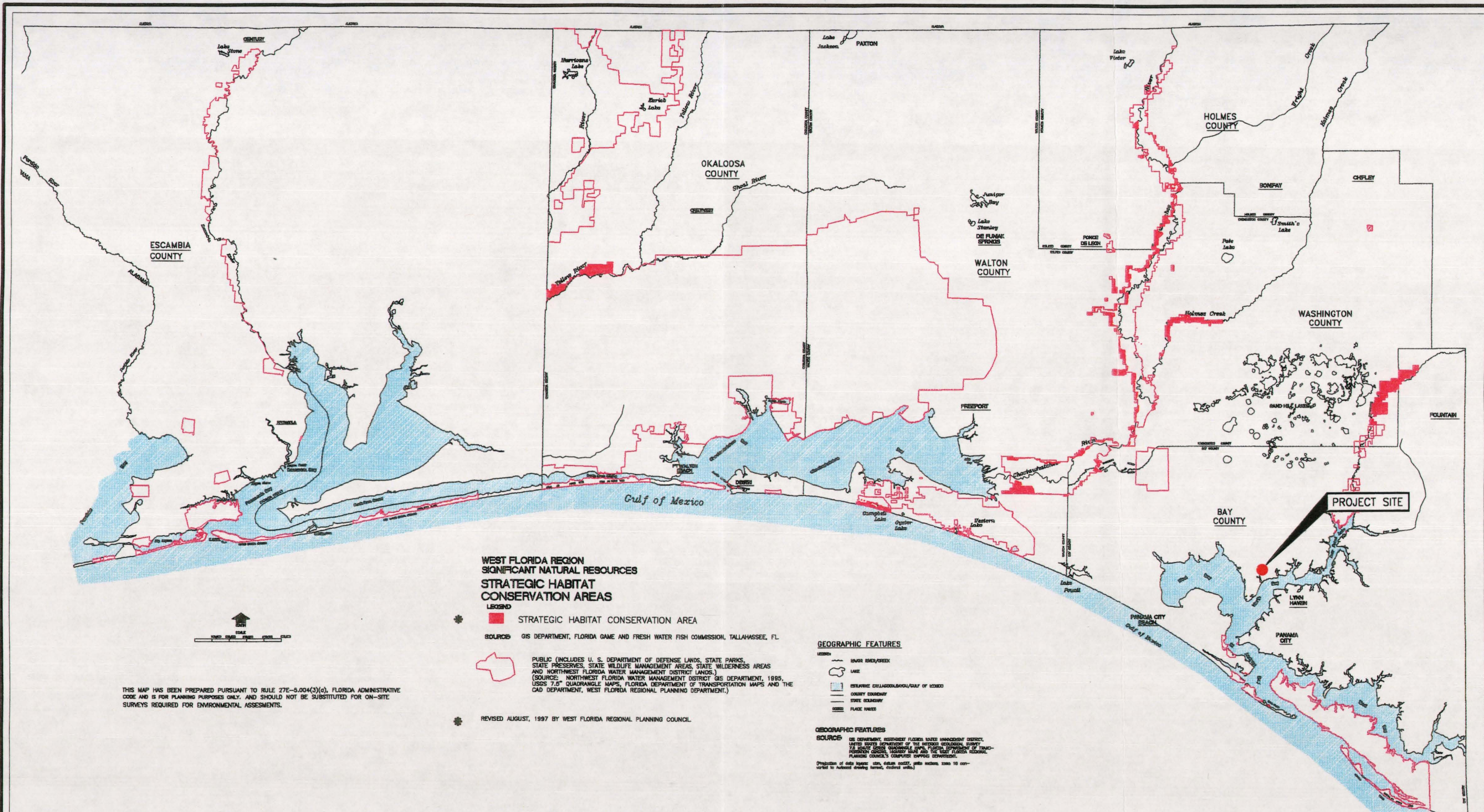


FIGURE 2.2.5-6.
STRATEGIC HABITAT CONSERVATION

Sources: West Florida Regional Planning Council, 1995; ECT, 1999.

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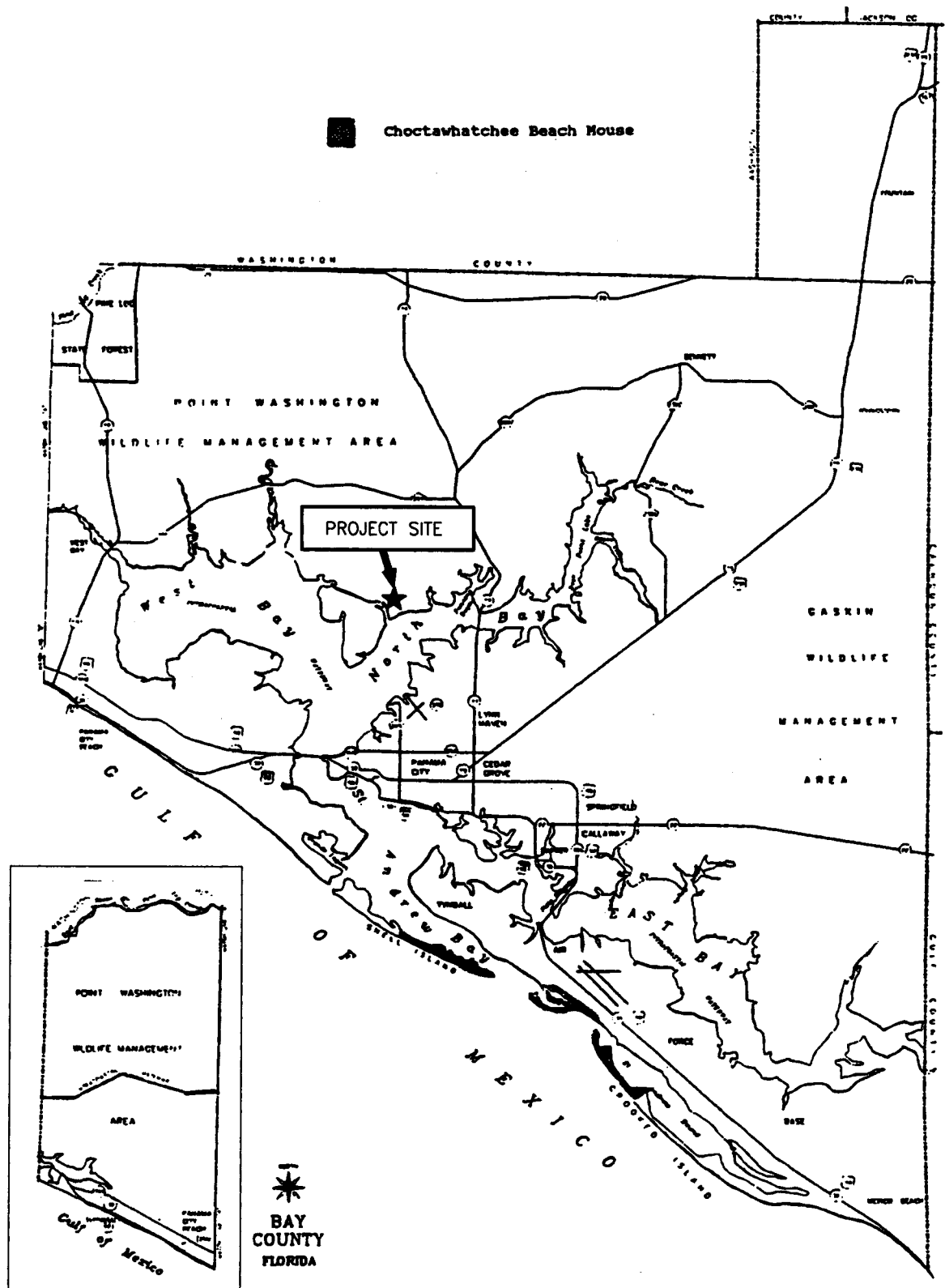


FIGURE 2.2.5-7.
CRITICAL HABITATS

Sources: Bay County Planning & Zoning Dept., 1991; ECT, 1999.

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Figures 2.2.5-8 through 2.2.5-10 depict state and county recreational facilities, federal and private recreational facilities, and potential future recreational facilities within Bay County, respectively. None of these existing or potential future sites are located in proximity to the Project site. The nearest local park is located approximately 4 miles east of the Project site, the nearest regional park is located approximately 10 miles to the south, the nearest federal recreational facility is located approximately 6 miles to the southwest, and the closest potential future recreational area is Deer Point Lake located over 5 miles to the northeast of the Project site.

The following areas are *not* found within a 5-mile radius of the proposed location of the Project site:

- National parks.
- National forests.
- National seashores.
- National memorials or monuments.
- National marine and estuarine sanctuaries.
- Roadless area review and evaluation (RARE) areas.
- National wild and scenic rivers.
- State parks.
- State forests.
- Areas of critical state concern.
- Indian reservations.
- Military lands.

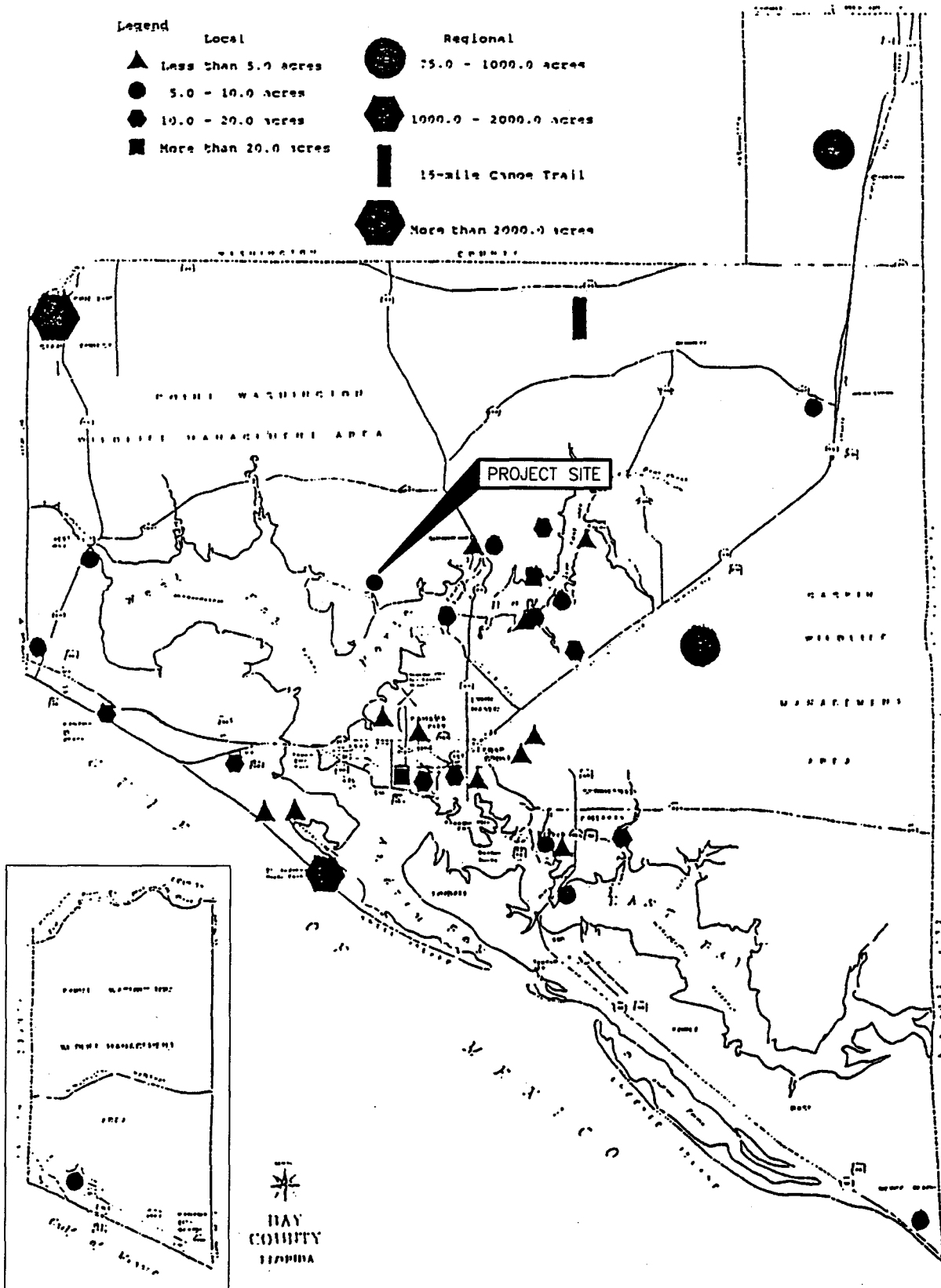


FIGURE 2.2.5-8.

STATE AND COUNTY RECREATIONAL FACILITIES

Sources: Boy County Planning & Zoning Dept., 1991; ECT, 1999.

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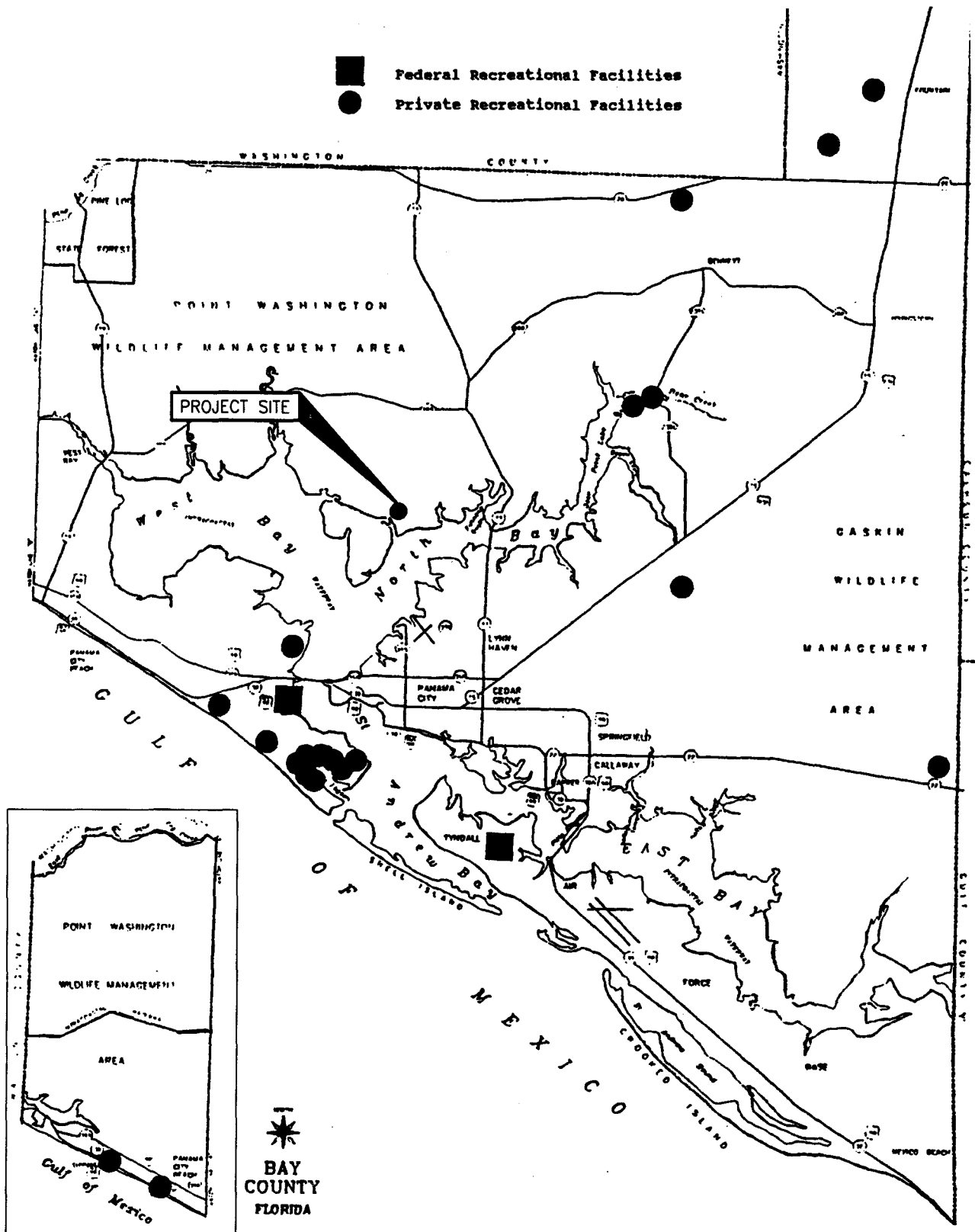


FIGURE 2.2.5-9.
FEDERAL AND PRIVATE RECREATIONAL FACILITIES

Sources: Bay County Planning & Zoning Dept., 1991; ECT, 1999.

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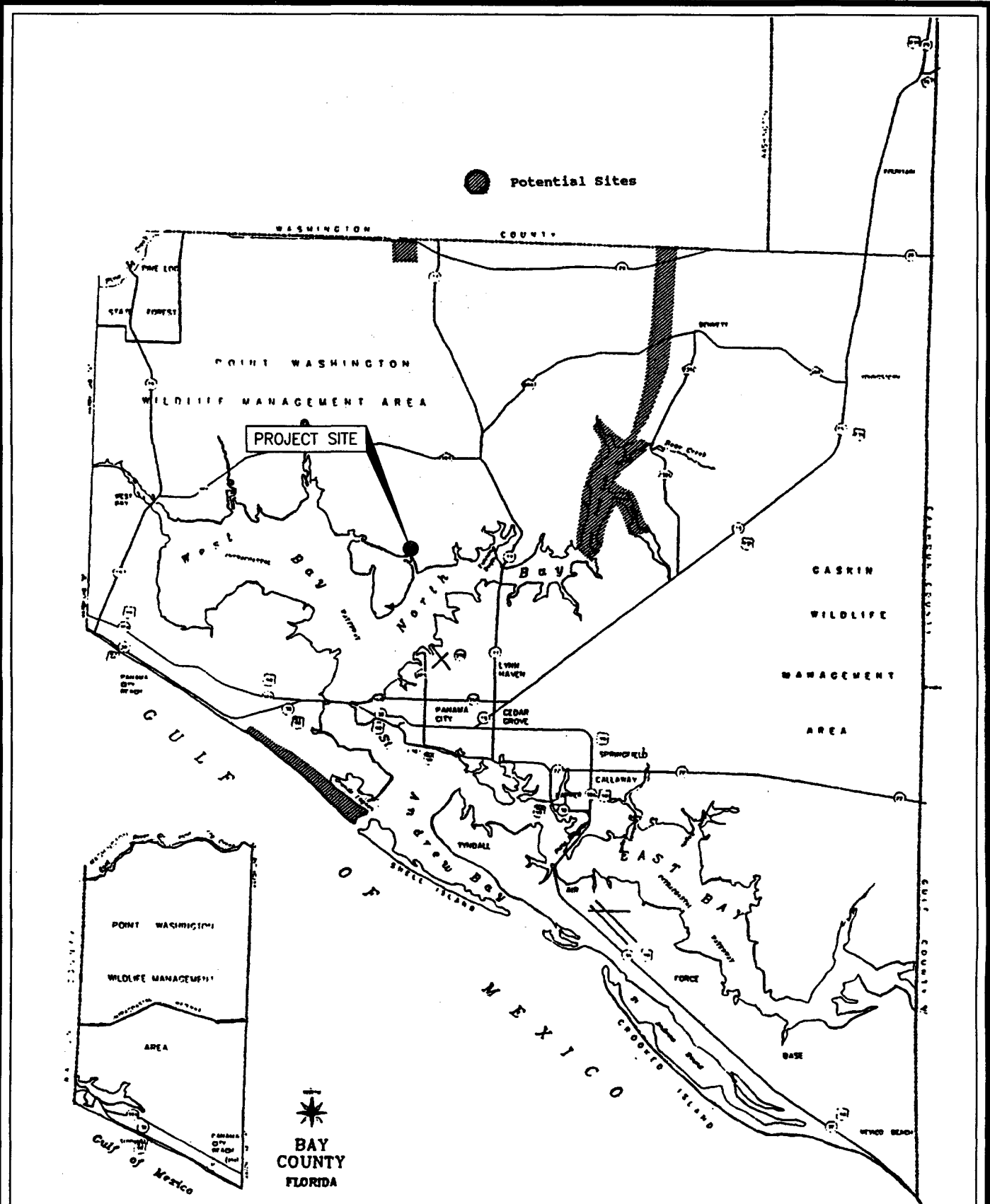


FIGURE 2.2.5-10.
POTENTIAL FUTURE RECREATIONAL FACILITIES

Sources: Bay County Planning & Zoning Dept., 1991; ECT, 1999.

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2.2.6 ARCHAEOLOGICAL AND HISTORIC SITES

A review of the Florida Site File and the National Register of Historic Places by the Florida Department of State, Division of Historical Resources (see Appendix 10.5, Attachment 10.5-A), identified no listed archaeological, historical, or architecturally valuable sites on the lands proposed for the Project. The review concluded that “. . . no significant archaeological or historical sites are recorded for or likely to be present within the project area.”

2.2.7 SOCIOECONOMICS AND PUBLIC SERVICES

2.2.7.1 Socioeconomics

Employment and Income

Several years of the *Florida Statistical Abstract* (Bureau of Economic and Business Research, 1985 and 1990-1997) provide employment and economic information at the county level. Bay County had an estimated labor force of 65,636 persons in 1997. Unemployed persons in 1997 totaled 4,306, an unemployment rate of 6.6 percent. From 1980 to 1996, the unemployment rate in Bay County was consistently greater than the statewide unemployment rate, while the labor force in the same period increased by approximately 21,770 persons.

In terms of employment, major industries in Bay County in 1997 were retail trade (15,857 or 25.9 percent), services (15,387 or 25.1 percent), government (11,787 or 19.2 percent), construction (3,953 or 6.5 percent), and manufacturing (3,482 or 5.7 percent).

Per capita income for Bay County in 1996 was \$22,832 compared to the Florida per capita figure of \$26,804. The difference between nonfarm per capita income compared to the Florida average was less: \$14,908 versus \$16,530. While the population of Bay County ranks 24th out of the state's counties (1990 census and 1997 estimates), its per capita earnings rank 29th. Despite the fact that approximately 55 percent of the existing acreage in Bay County is designated or in use for silviculture, only 2,823 people were employed in agriculture in 1997, ranking Bay County 64th out of 67 counties. Reflecting the 29,000 acres of Bay County occupied by Tyndall Air Force Base and the 655 acres used as the Naval Coastal Systems Center, the 3,336 federal employees rank Bay County 4th in the state in the number of federal government employees.

Housing

According to the 1980 census, there were a total of 42,900 dwelling units in Bay County; 15,574 of which were located in the unincorporated areas. By 1989, the number of dwelling units in the unincorporated areas had increased to 33,494. The types of dwellings are described below:

Structural Type	1980 Number of Units	Percent of Total	1989 Number of Units	Percent of Total
Single family	10,201	65.5	15,150	46.6
Duplex	592	3.8	966	3.0
Multifamily	2,694	17.3	7,507	23.1
Mobile homes	2,087	13.4	8,884	27.3
TOTAL	15,574		32,507	

Sources: Bay County 1990 Comprehensive Plan.
ECT, 1999.

The obvious change from 1980 to 1989 is the large increase in the number of mobile homes and the percentage of the total dwelling units consisting of mobile homes. At least a portion of this increase can be attributed to the two military installations in Bay County, which adds to the mobility of the population. The Housing Element of the adopted 1990 Bay County Comprehensive Plan estimated that approximately 27.6 percent of the dwelling units are seasonally occupied.

Local Government Revenues and Expenditures

According to information provided by the Florida Department of Banking and Finance, revenue sources for Bay County for fiscal year 1994 (in descending amount) are taxes and impact fees (35.3 percent), other sources and transfers (28.1 percent), charges for services (26.8 percent), state and other governments (8.0 percent), fines and forfeits (1.0 percent), and federal grants (0.8 percent). Total revenues for the county for the fiscal year ending 1994 were \$103,154,000.

In descending amount, expenditures for Bay County for fiscal year 1994 were physical and economic environment (32.9 percent); public safety (24.3 percent); transportation (17.3 percent); general government (16.2 percent); debt service (4.8 percent); and human services, cultural, and recreation (4.5 percent). Total expenditures were \$96,366,000 for fiscal year 1994.

2.2.7.2 Public Services

Parks and Recreation

The closest designated recreational land use on the adopted FLUM is associated with Panama City Beach, approximately 8 miles south of the Project site. The Recreation and Open Space Element of the adopted Comprehensive Plan indicates that recreation facilities within Bay County are supplied by the county, the eight municipalities within the county, the state, the federal government, and the private sector. The federal recreation facilities within Bay County are those amenities, such as golf courses, softball/baseball fields, football/soccer fields, and 100 acres of primitive camping located at the Naval Coastal Systems Center and/or at Tyndall Air Force Base. The state-provided facilities are:

- Econfinia Creek canoe trail (at least 9 miles northeast of the Project site).
- Pine Log State Forest (approximately 11 miles northwest of the Project site).
- St. Andrews State Recreation Area (approximately 10 miles south of the Project site).

There are 24 parks provided solely by Bay County or by Bay County and a local municipality listed in the Recreation and Open Space Element of the Comprehensive Plan. The closest of these are located in unincorporated Southport (approximately 4 miles east of the Project site) and within the city of Lynn Haven (approximately 2.5 miles to the southeast).

Educational Services

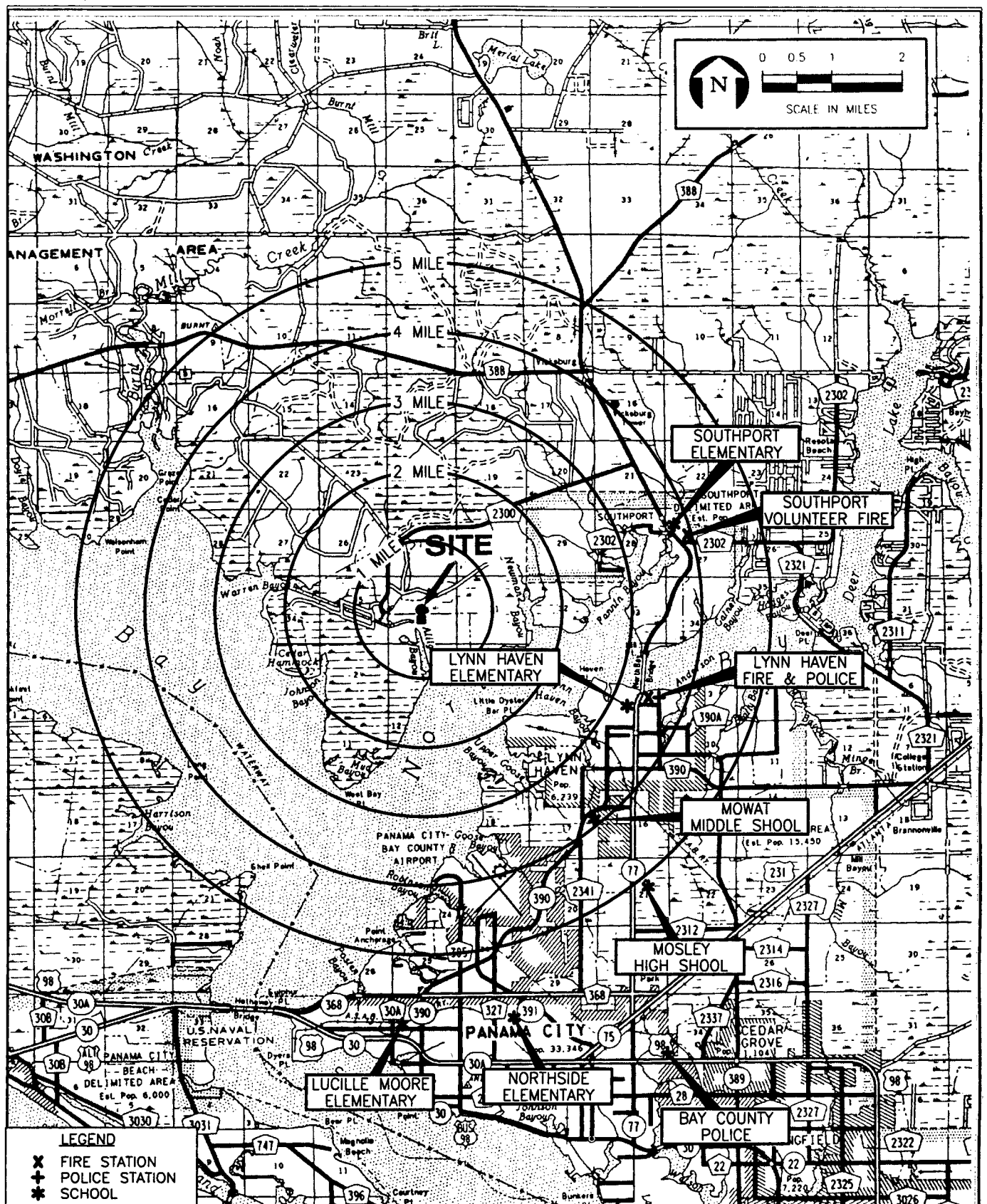
There are elementary schools located in Southport, Lynn Haven, and Panama City within or very close to a 5-mile radius of the Project site. The Mowat Middle School and the Mosley High School are located in Lynn Haven. Figure 2.2.7-1 depicts the locations of nearby educational facilities.

Public Safety

Locations of police stations and fire stations are also depicted on Figure 2.2.7-1. Law enforcement services would be provided by the Bay County Sheriff's office, with the nearest office at 3421 SR 77. The Sheriff's office has mutual aid agreements with the city of

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Lynn Haven (station located at 1412 Pennsylvania Avenue) and Panama City (station located at 1209 15th Street).

The primary responding fire station is Southport Volunteer located on CR 2321, east of SR 77, under the Bay County Fire Control. Secondary response is available from the city of Lynn Haven at 1412 Pennsylvania Avenue. The nearest hospitals to the Project site are Columbia Gulf Coast Medical Center and Bay Medical Center located in Panama City.

Utility Services

There are no public sewer or water treatment facilities or distribution facilities located in proximity to the Project site. The city of Lynn Haven has expanded sanitary sewer distribution north of North Bay along SR 77. Potable water will be provided to Smith Unit 3 from the existing, permitted wells at the Lansing Smith plant. Water treatment facilities are available at the existing plant.

Domestic wastewater generated from the operation of Smith Unit 3 will be treated at the existing treatment plant at the Lansing Smith plant. Treated effluent is discharged to the existing ash pond that discharges intermittently in response to a design storm event. The existing treatment plant has sufficient capacity to treat the domestic wastewater to be generated by the estimated 29 additional full-time employees at Smith Unit 3.

Solid Waste Services

The existing Steelfield landfill has capacity to accommodate the limited amount of solid waste that will be produced when Smith Unit 3 is operational. Currently, solid waste is transported from the Lansing Smith plant by Waste Management, Inc., to the Steelfield landfill. Construction debris will be the responsibility of the selected contractor for construction of Smith Unit 3, which could be handled at the existing offsite landfill.

Transportation

The proposed Smith Unit 3 traffic generated by 29 full-time employees, 18 on the day shift, will access the property from CR 2300. This road provides access and egress to the Lansing Smith Plant, to a branch of the Gulf Coast Community College, and to several

residences. It is not anticipated that the additional traffic generated by the operation of Smith Unit 3 will result in unacceptable level of service (LOS) standards on CR 2300 or SR 77. Both roads currently operate at an acceptable LOS.

2.3

2.3 BIOPHYSICAL ENVIRONMENT

Section 2.3 presents information to characterize the existing biophysical environment of the Project site and vicinity. This characterization provides the baseline from which impacts are assessed. Per the FDEP instructions, this section includes the following subsections:

- 2.3.1—Geohydrology.
- 2.3.2—Subsurface Hydrology.
- 2.3.3—Site Water Budget and Area Users.
- 2.3.4—Surficial Hydrology.
- 2.3.5—Vegetation/Land Use
- 2.3.6—Ecology.
- 2.3.7—Meteorology and Ambient Air Quality.
- 2.3.8—Noise.
- 2.3.9—Other Environmental Features.

These subsections include relevant existing information and the results of field data collection and analyses conducted specifically for the Project.

2.3.1

2.3.1 GEOHYDROLOGY

This section describes the general and site-specific geology of Bay County and the Smith Unit 3 Project area, respectively. The stratigraphy, lithology, structure, and physiography are presented. Several publications, including *Geology of Bay County* (Schmidt and Clark, 1980), and *Florida's Ground Water Quality Monitoring Program Background Hydrogeologic Framework* (Florida Geological Survey [FGS], 1991), characterize the area in detail and provide much of the information for this section.

2.3.1.1 General Geologic Description of the Site Area

Unconsolidated sediments and rock ranging in age from Recent to late Pre-Cambrian underlie Bay County. Figure 2.3.1-1 presents the stratigraphic nomenclature for the geology of Bay County (Schmidt and Clark, 1980). A description of the geologic units is outlined below.

Regional Stratigraphy

Very few deep wells have been drilled in Bay County. Granite of possible late Pre-Cambrian has been encountered in the deepest wells. Paleozoic sediments range from Early Ordovician to Early Devonian (Schmidt and Clark, 1980).

Overlying the Paleozoic rocks, the Triassic Eagle Mills Formation is present in most of Bay County, but thins toward the east. Upper Jurassic formations include the Norphlet, Smackover, Haynesville, and the Cotton Valley Group. Undifferentiated Lower Cretaceous sands and shales overlie the Cotton Valley Group. These sands are overlain by the Upper Cretaceous Tuscaloosa Group. The Eutaw Formation, a calcareous fine sandstone to a sandy chalk with limestone, overlies the Tuscaloosa. The remaining Upper Cretaceous sediments are, in ascending order, the Austin Age, Taylor Age and Navarro Age (Schmidt and Clark, 1980).

ERA	PERIOD	EPOCH	ROCK UNITS OR FORMATIONS, AND DESCRIPTIONS		APPROXIMATE DEPTH IN FEET BELOW SURFACE (NOT TO SCALE)
CENOZOIC	QUATERNARY	RECENT	UNDIFFERENTIATED QUARTZ SANDS		100
		PLEISTOCENE	UNDIFFERENTIATED CLAYEY SANDS AND GRAVELS		
	NEOGENE	PLIOCENE	JACKSON BLUFF FORMATION GRAY-OLIVE GREEN, CLAYEY, SANDY, SHELL MARL.		300
			UPPER	INTRACOASTAL FORMATION GRAY-OLIVE GREEN, SANDY, ARGILLACIOUS, POORLY CONSOLIDATED VERY MICROFOSSILIFEROUS CALCARENITE.	
		MIDDLE MIOCENE	BRUCE CREEK LIMESTONE WHITE TO LIGHT YELLOW, MODERATELY INDURATED, GRANULAR LIMESTONE.		400
			CHIPOLA FORMATION SANDY, VERY LIGHT-ORANGE, FOSSILIFEROUS LIMESTONE.		
		LOWER	TAMPA STAGE LIMESTONES SANDY, MICRITIC, WHITE TO LIGHT GRAY LIMESTONES.		500
		PALEOGENE	OLIGOCENE	SUWANNEE LIMESTONE	LIGHT GRAY TO YELLOW GRAY, DOLOMITIC LIMESTONE, OFTEN HIGHLY ALTERED, SUCROSIC, ALTERED FOSSIL TYPES.
	MARIANNA LIMESTONE				
	EOCENE		OCALA LIMESTONES	LIGHT ORANGE TO WHITE, HIGH POROSITY LIMESTONES; SMALL AMOUNTS OF SAND AND CHERT; GLAUCONITE IN LOWER FACIES ABUNDANT MICRO-FOSSILS.	1,000
			LISBON	CREAM-COLORED, GLAUCONITIC, SANDY LIMESTONE; LIGHT GRAY CLAY; SOFT PYRITIC LIMESTONE; GRAY, CALCAREOUS, GLAUCONITIC SAND.	
			TALLAHATTA	CREAM-COLORED, GLAUCONITIC, SANDY, CLAYEY LIMESTONE, AND GRAY, SANDY, CALCAREOUS CLAY.	
			UNDIFFERENTIATED WILCOX	SANDY, CREAM-COLORED, GLAUCONITIC LIMESTONE; CALCAREOUS SAND; GRAY, PASTY LIMESTONE; MICACEOUS CLAY.	
	PALEOCENE	UNDIFFERENTIATED MIDWAY	GRAY, MICACEOUS, SANDY CLAY; WITH SEAMS OF SANDY, SOFT LIMESTONE.	3,000	
	MESOZOIC	UPPER CRETACEOUS	SELMA GROUP	MARLS, CALCAREOUS CLAYS, AND LIMESTONE; INTERBEDDED SANDS, GLAUCONITIC, MICACEOUS.	7,000
EUTAW FORMATION			CALCAREOUS SANDSTONE, SANDY CHALK, MARINE AND NON-MARINE SANDS AND SHALES.		
TUSCALOOSA FORMATION					
LOWER		UNDIFFERENTIATED	REDDISH-BROWN SHALES AND SANDSTONES.		
JURASSIC		COTTON VALLEY GROUP	VARICOLORED MUDSTONE AND SANDSTONE, RED-GRAY, CALCAREOUS SHALES, SANDSTONES, MICRITE, LIMESTONE, DOLOMITIC LIMESTONES, RED SANDSTONES, SILTSTONES AND SHALES.	10,000	
		HAYNESVILLE FORMATION			
SMACKOVER FORMATION					
NORFLEET FORMATION					
TRIASSIC	EAGLE MILLS FORMATION	MICACEOUS SANDSTONES; ARGILLACEOUS SILTSTONES; WELL INDURATED SHALES; OFTEN CONTAINS SILLS AND DIKES OF IGNEOUS ROCKS.	11,000		
PALEOZOIC	CAMBRIAN	QUARTZITE/META-ARKOSE	13,000		
PRE-CAMBRIAN	GRANITE	"BASEMENT"?			

FIGURE 2.3.1-1.

GEOLOGY OF BAY COUNTY

Sources: Schmidt and Clark, 1980; SCS, 1999; ECT, 1999.

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Cenozoic sediments lie unconformably over the upper Cretaceous sediments. The undifferentiated sandy clay and soft limestone of the Midway Stage is overlain by Undifferentiated Wilcox, which includes glauconitic shale. Overlying the Wilcox, in ascending order, are the Tallahatta and Lisbon Formations, Ocala, Marianna and Suwannee Limestones (Schmidt and Clark, 1980).

The Tampa Stage Limestone, which overlies the Suwannee, may grade into the overlying Chipola and Bruce Creek Limestones. The Bruce Creek Limestone is overlain by the Intracoastal Formation or the Jackson Bluff Formation. The Bruce Creek Limestone is more indurated than the Intracoastal Formation which can also be distinguished from the Bruce Creek by the olive-green color and abundant microfossils (Schmidt and Clark, 1980).

The Intracoastal Formation is overlain by the Jackson Bluff Formation. In Bay County, the Jackson Bluff Formation occurs as a thin, blanket-like deposit and consists of calcareous sandy clay to clayey sand with macrofossils. Sand covers the Jackson Bluff Formation. The surficial unit consists of clayey and silty sand and gravel (probably Citronelle), reworked clayey sands (Pliocene), terrace sands (Pleistocene), and Recent coastal sands. The Pliocene and Pleistocene sands are related to fluctuating sea levels during glacial and interglacial periods. The Recent sands are the result of longshore marine forces (Schmidt and Clark, 1980).

Lithology

Generalized descriptions of the hydrogeologic units in the vicinity of the Project site are presented in Figure 2.3.1-2. The units are summarized below:

- *Surficial Aquifer System* consists of undifferentiated terrace marine and fluvial deposits, the Citronelle, and underlying undifferentiated Pliocene deposits.
- *Intermediate System* consists of the coarse clastics of the Jackson Bluff Formation and the Intracoastal Formation.
- *Floridan Aquifer System* in this area includes the Bruce Creek Limestone and the Suwannee Limestone.

		PANHANDLE FLORIDA	
SYSTEM	SERIES	FORMATION	HYDROSTRATIGRAPHIC UNIT
QUATERNARY	HOLOCENE	UNDIFFERENTIATED TERRACE MARINE AND FLUVIAL DEPOSITS	SURFICIAL AQUIFER SYSTEM
	PLEISTOCENE		
TERTIARY	PLIOCENE	CITRONELLE FORMATION UNDIFFERENTIATED	INTERMEDIATE AQUIFER SYSTEM OR INTERMEDIATE CONFINING UNIT
	MIOCENE	COARSE CLASTICS/JACKSON BLUFF FORMATION ALUM BLUFF GROUP PENSACOLA CLAY INTERCOASTAL FORMATION HAWTHORN FORMATION CHIPOLA FORMATION BRUCE CREEK LIMESTONE ST. MARKS FORMATION CHATTAHOOCHEE FORMATION	
		CHICKASAWHAY LIMESTONE SUWANNEE LIMESTONE MARIANNA LIMESTONE BUCATUNNA CLAY	FLORIDAN AQUIFER SYSTEM
		OCALA GROUP LISBON FORMATION TALLAHATTA FORMATION OLDER ROCKS UNDIFFERENTIATED	
		UNDIFFERENTIATED	
	PALEOCENE	UNDIFFERENTIATED	SUB-FLORIDAN CONFINING UNIT
CRETACEOUS AND OLDER		UNDIFFERENTIATED	

* Terminology follows usage of Florida Bureau of Geology.

FIGURE 2.3.1-2.

RELATIONSHIP BETWEEN REGIONAL HYDROGEOLOGIC UNITS AND MAJOR STRATIGRAPHIC UNITS IN
THE FLORIDA PANHANDLE

Sources: Southeastern Geological Society, 1986; SCS, 1999; ECT, 1999.

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- *Sub-Floridan Confining Unit* is overlain by a vast thickness of sediment and rock, which effectively eliminates leakage from the bottom of the Floridan aquifer system and limits the importance of the unit in this area.

Site Area Stratigraphy

The Project site is located on the Pamlico Terrace in an area of low relief between elevation zero and 10 ft-msl. The site is underlain by a thick sequence of Tertiary-age sediments that generally dip to the southwest. Sediments in the area are primarily marine and estuarine and represent ancient coastal environments or marine terraces. After the marine terraces were deposited, they were mixed with underlying sediments during a marine transgression occurring in the Pleistocene Epoch. They consist of a sand, clay, silt, and shell mixture. Formations identified include:

- *Recent Sediments*—These units consist of loose, relatively permeable silts and sands and extend to approximately 20 feet below land surface (ft bls).
- *Jackson Bluff Formation*—A Pliocene-aged sandy clay to clayey sand unit found sporadically throughout Bay County. In the Project area, the unit is encountered at approximately 20 ft bls with variable thickness ranging from 1 to 7 ft.
- *Intracoastal Formation*—A wedge-shaped deposit of calcareous silts and sands with varying amounts of clay. This unit occurs below the Jackson Bluff Formation to approximately 100 ft bls in the vicinity of the Project site.
- *Bruce Creek Limestone*—A white to light yellow-gray, moderately indurated limestone dominated by macrofossils. The unit has a maximum thickness along the coast of about 300 ft.

Site Area Structure

The thick sequence of marine sediments underlying Bay County is controlled in part by the Apalachicola Embayment, which is the dominant geologic structure in the Central Florida Panhandle. The Apalachicola Embayment is a southwesterly plunging basin characterized by increased sedimentation toward the coast, where total thickness can reach up to 15,000 ft (Schmidt and Clark, 1980). Additional regional structures that affect the geology of Bay County include the Chattahoochee Anticline. Figure 2.3.1-3 presents the principal geologic structures in North Florida.

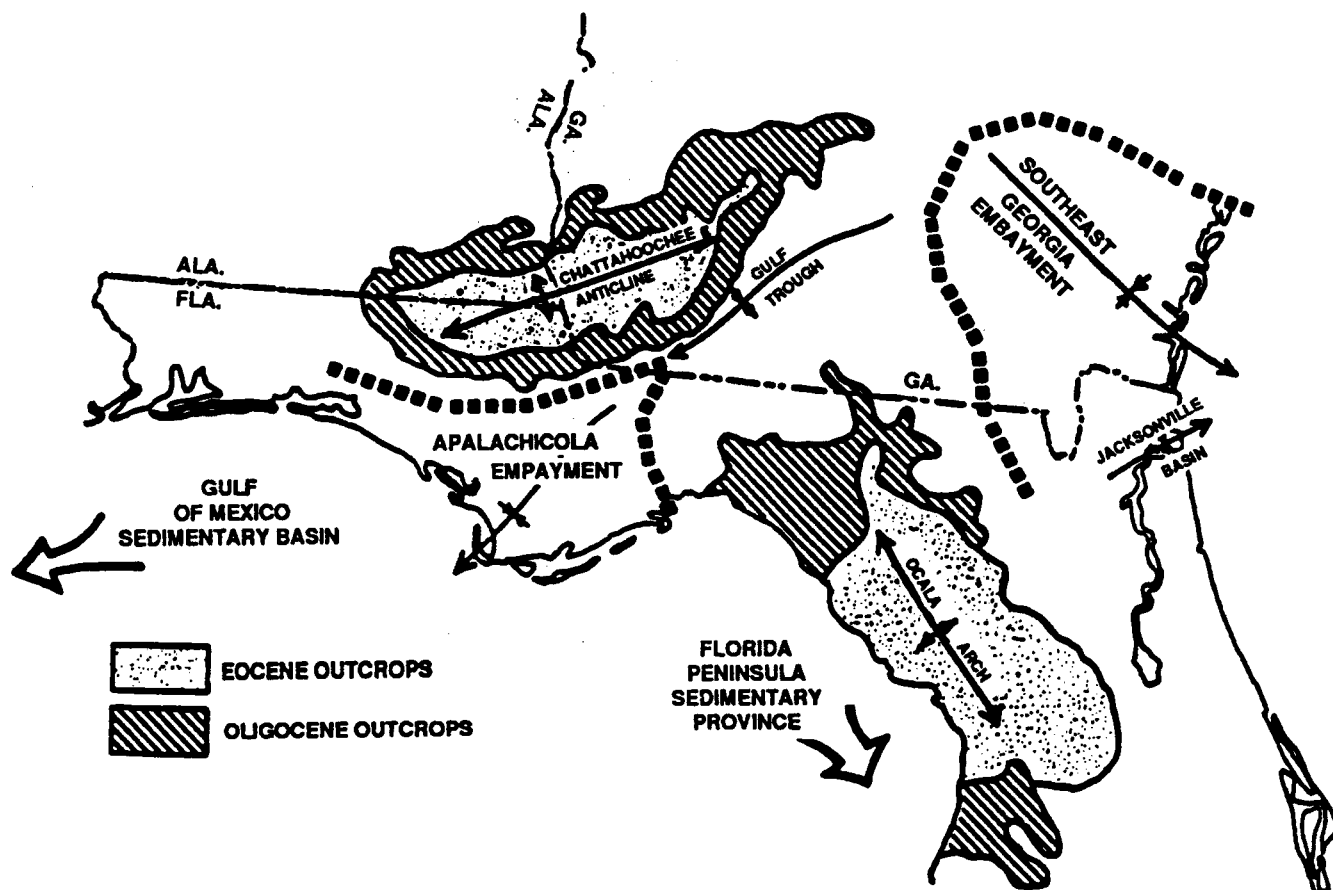


FIGURE 2.3.1-3.

REGIONAL GEOLOGIC STRUCTURES OF THE FLORIDA PANHANDLE

Sources: Schmidt, 1984; SCS, 1999.

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Although faults within the upper limestone of the Floridan aquifer have been reported, no geologic evidence supports this claim (Schmidt and Clark, 1980). Seismic activity should not pose a threat to the proposed development and operation of Smith Unit 3.

Site Area Physiography

Bay County is located within the Coastal Plain physiographic province, East Gulf Coastal Plain section. Bay County lies within four physiographic subdivisions: Sand Hills, Sinks and Lakes, Flat-Woods Forest, and Beach Dunes and Wave Cut Bluffs. The largest portion of the county, including the Project area, lies within the Flat-Woods Forest. This division is characterized by slightly rolling to flat terrace land at elevations below 70 ft-msl. The Flat-Woods Forest is generally well drained except for low-lying areas surrounding the bays. This includes the 0 to 10-ft terraces in the Project area. These low-lying areas may be inundated during extended rains.

The geomorphology of Northwest Florida is the result of the interaction of depositional and erosional events associated with sea level fluctuations. Bay County is located within the northern or proximal geomorphic division (White, 1970). Within this division, Bay County is predominantly located within the Gulf Coastal Lowlands, often characterized by poorly drained, swampy areas (FGS, 1991).

Ancient terraces in Bay County, in descending order, include:

- The Coharie and High Pliocene Terraces, at 170 to 215 and 215 to 320 ft-msl.
- The Wicomico and Okefenokee Terraces at 70 to 100 and 100 to 170 ft-msl.
- Talbot and Fenholoway Terraces at 25 to 42 and 42 to 70 ft-msl.
- Silver Bluff and Pamlico Terraces at 0 to 10 and 10 to 25 ft-msl.

2.3.1.2 Detailed Site Lithologic Description

In September 1998, a site investigation was initiated. Sampling locations were chosen based on the proposed location of Smith Unit 3 and access to the site. The drilling was performed by Southern Company Services' (SCS's) Geotechnical Field Services in Atlanta, Georgia, using a CME 850 truck-mounted rig. Soil characterization and permeability testing were performed at Southern Earth Sciences, Inc., in Panama City, Florida, and

SCS's Concrete and Soil Laboratory at Varnons, Alabama. Cation exchange capacity (CEC) testing was performed by Law Engineering in Pensacola, Florida.

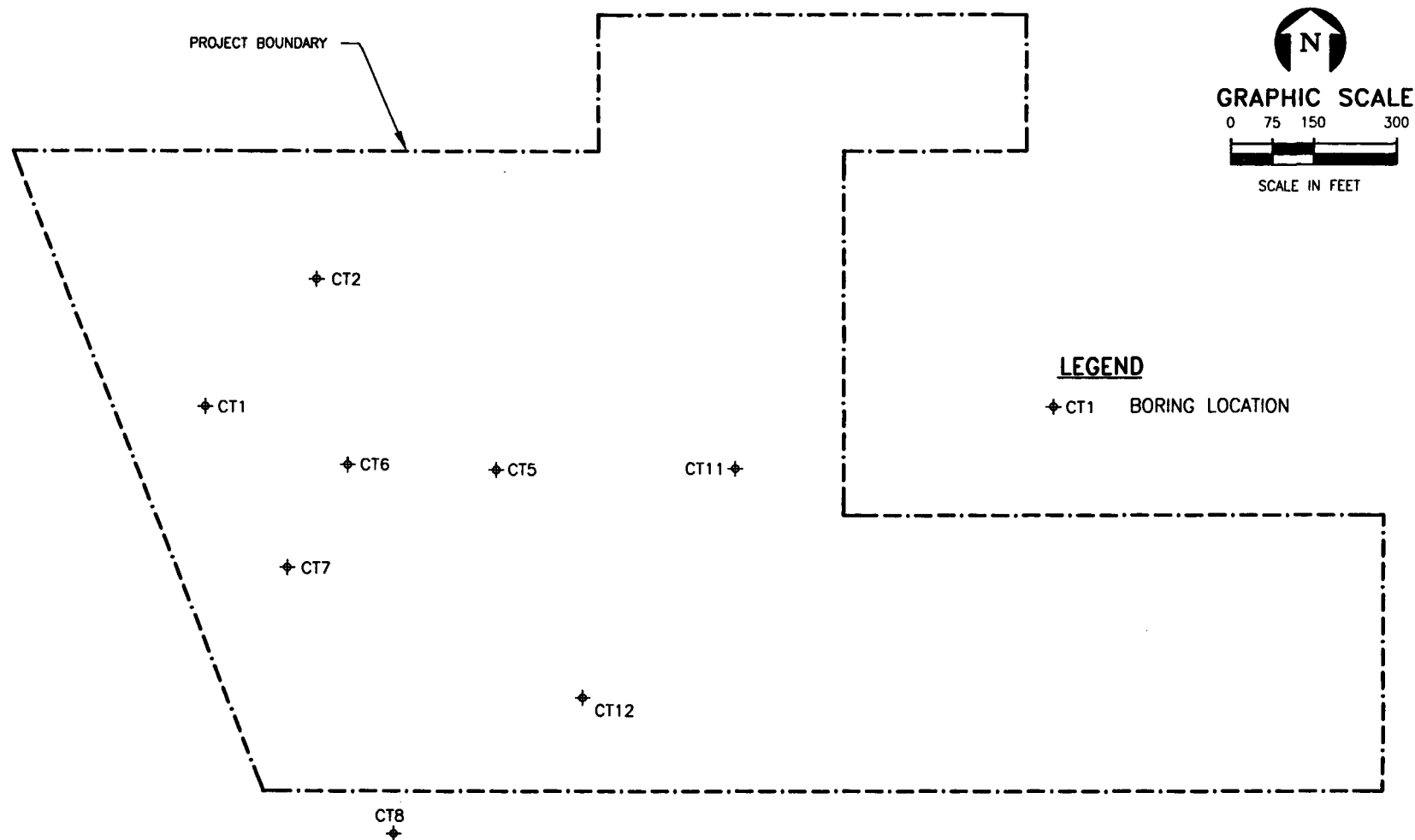
Standard penetration test borings using hollow-stemmed augers and mud rotary were taken to refusal, approximately 100 ft bls. Seven deep borings were completed and 12 piezometers were installed in the proposed area. Seven piezometers were installed within the surficial sediments and five piezometers were installed within the deeper sediments of the Intracoastal Formation, below the clay of the Jackson Bluff Formation, which acts as a semi-confining bed at the site. Rock coring was performed at two locations; approximately 10 ft of consolidated limestone was cored. A boring location map is presented in Figure 2.3.1-4. Figures 2.3.1-5 and 2.3.1-6 present the geologic cross-sections based on the site investigation. Boring logs are included in Attachment 10.5-C of Appendix 10.5.

Based on the investigation, three hydrogeologic units were identified:

- The surficial aquifer system.
- The intermediate system.
- The Floridan aquifer system.

Surficial Aquifer System—The study area is underlain by approximately 15 to 20 ft of surficial sediments of black organic topsoil and tan to brown, slightly silty fine- to medium grained sands to medium- to coarse-grained sands. Laboratory grain-size classification identifies the surficial soils as SP to SM, poorly graded sands and silty sands.

Slug testing was performed in the shallow piezometers. Tests were analyzed using the Bouwer and Rice method (1976 and 1989). The slug tests were performed by quickly raising and lowering the water level of the well and measuring the rate of equilibrium. A solid slug was lowered rapidly into the well and the resulting change in head (ΔH) measured with respect to time. After the water stabilized, the slug was withdrawn and the resulting rise in water level recorded.



NOTE: CT3 AND CT4 ARE LOCATED IN AN OFF-SITE LOCATION.

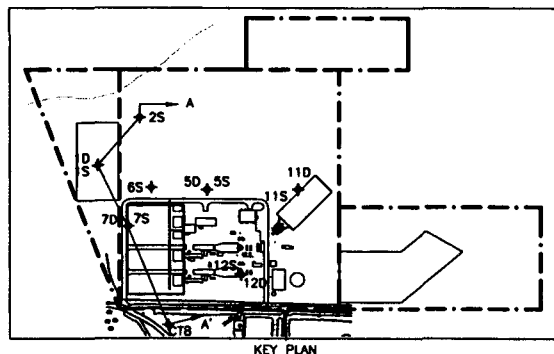
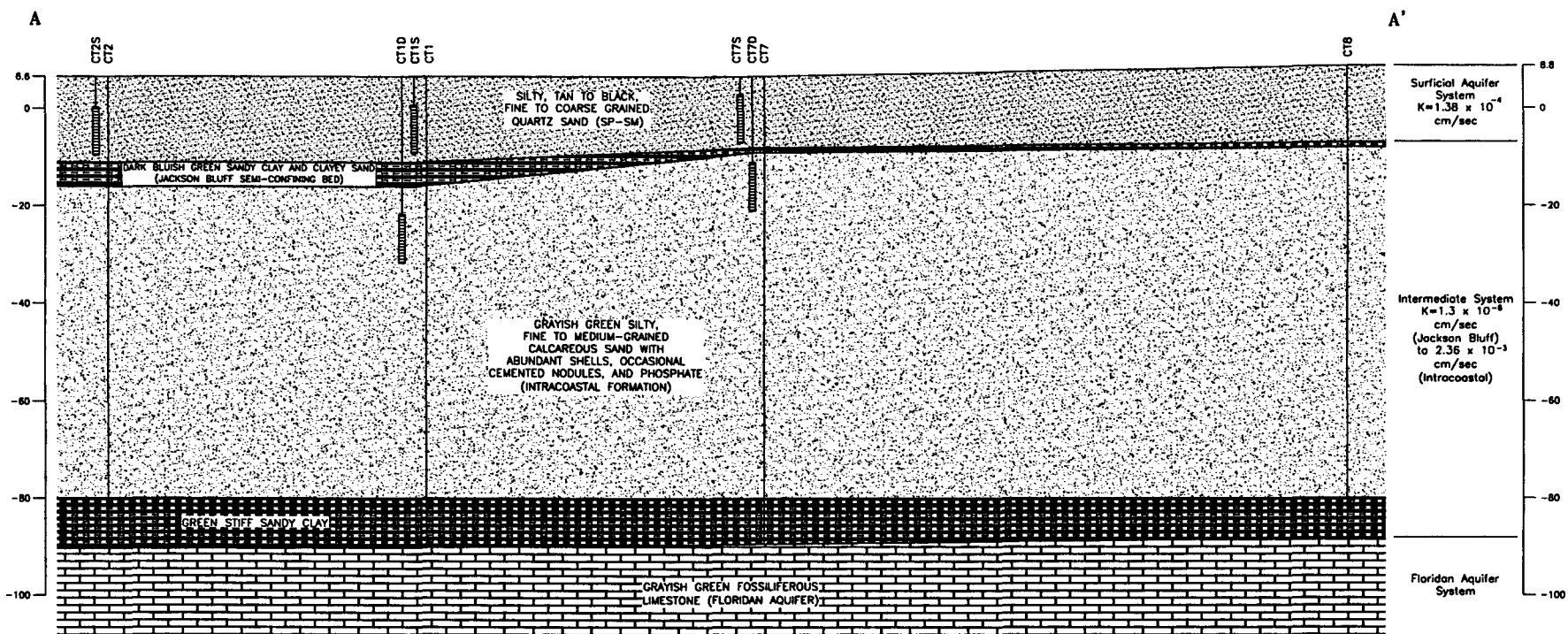
FIGURE 2.3.1-4.

SITE INVESTIGATION BORING LOCATION MAP

Source: SCS, 1999.

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HORIZONTAL SCALE: 1" = 140'
 VERTICAL SCALE: 1" = 35'

FIGURE 2.3.1-5.
 GEOLOGIC CROSS-SECTION A-A'

Source: SCS, 1999.

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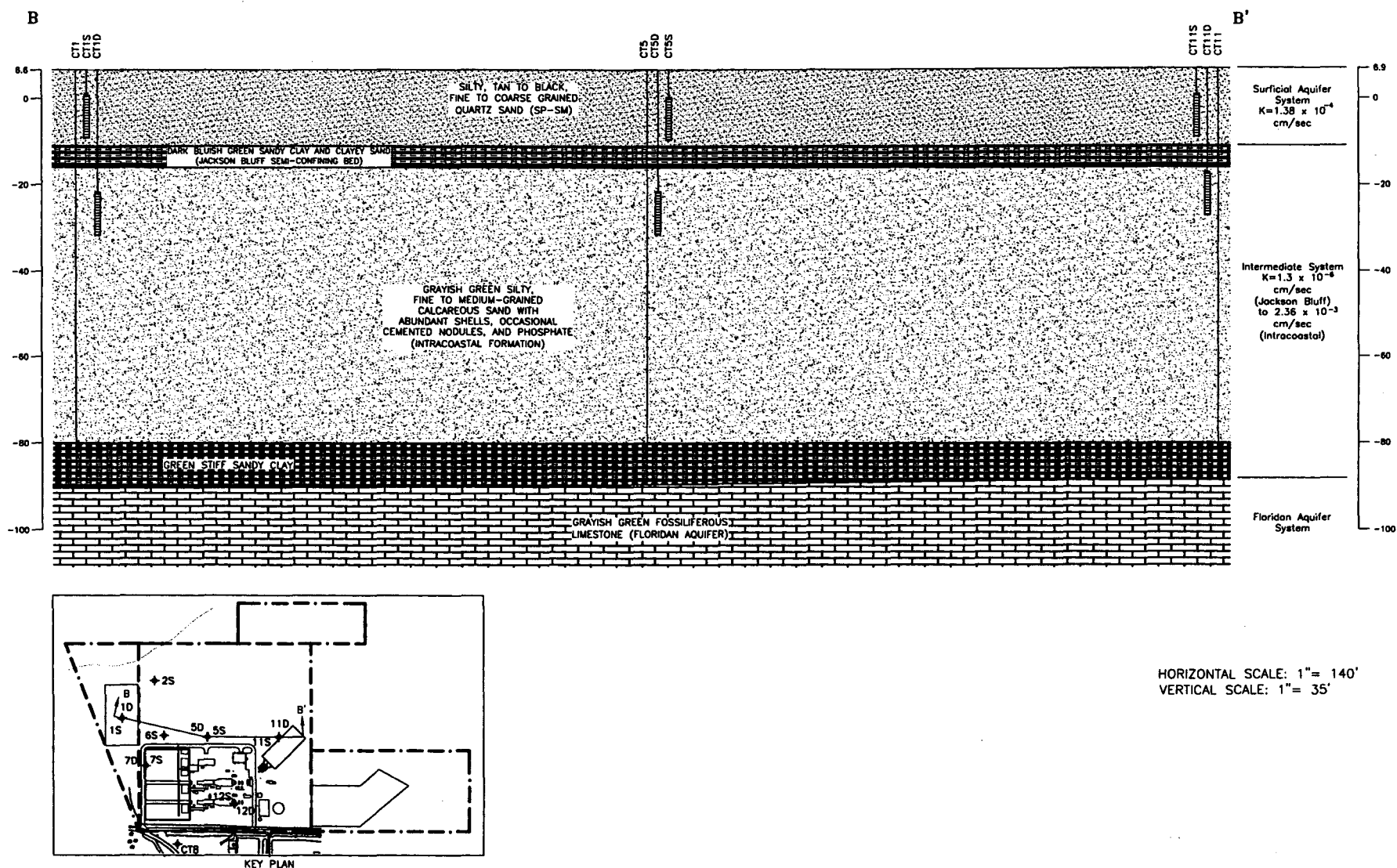


FIGURE 2.3.1-6.

GEOLOGIC CROSS-SECTION B-B'

Source: SCS, 1999.

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The average hydraulic conductivity of the surficial unit is 2.9×10^{-4} centimeters per second (cm/sec). The average results of the slug tests for the surficial aquifer are presented in Table 2.3.1-1. Test results and data sheets are included in Attachment 10.5-E of Appendix 10.5.

Table 2.3.1-1. Hydraulic Conductivity of the Surficial Aquifer

Surficial Piezometer	Hydraulic Conductivity (ft/day)	Hydraulic Conductivity (cm/sec)
CT1S	0.25	8.85×10^{-3}
CT2S	0.39	1.38×10^{-4}
CT5S	1.89	6.68×10^{-4}
CT6S	0.44	1.54×10^{-4}
CT7S	1.16	4.10×10^{-4}
Average	0.83	2.9×10^{-4}

Note: ft/day = feet per day.

Source: SCS, 1999.

Intermediate System—The intermediate system, below the surficial sands, consists of the Jackson Bluff Formation and the Intracoastal Formation. At about 20 ft bls, the sediments become dark bluish-green to olive-gray, clayey, fine- to medium-grained calcareous sands with shell fragments and abundant phosphorite. This is identified as the Jackson Bluff Formation. The Jackson Bluff Formation is consistent across the area and has been identified in other investigations at the Lansing Smith Plant as a leaky confining layer between the surficial aquifer and the Intracoastal Formation. In the Project area, the formation is from 1 to 7 ft thick. The unit is recognized by the distinct color and composition change from the overlying quartz sands and the consistently very low blow counts recorded from standard penetration tests. Counts are often weight of hammer. An undisturbed Shelby tube sample was collected from one boring and subjected to a falling head permeability test in the laboratory with a result of 1.3×10^{-6} cm/sec, indicating a silt or silty sand. Grain-size analysis of the sandy portion of the sample indicates a Unified Soil Classification of SM, a silty sand.

Below the Jackson Bluff Formation, the sediments are described as grayish green, silty, fine-grained calcareous sand with whole shells, shell fragments, loosely cemented nod-

ules and abundant phosphorite. This unit, identified as the Intracoastal Formation, is approximately 75 ft thick in the Project area. Blow counts range from 17 to 1. Some thin layers of clay were observed in the split-spoon samples. Grain-size analyses of samples collected from the Intracoastal Formation identify the sediments as SM, silty sands with up to 40 percent fines. Above the contact with the underlying rock, approximately 10 ft of stiff, green clay was encountered. Grain-size analysis of the clay yields a Soil Classification of ML, a clayey silt with 76.5 percent fines. Laboratory testing on a sample indicates a permeability of 5.8×10^{-7} cm/sec.

Slug testing of three piezometers in the Intracoastal Formation indicate an average hydraulic conductivity of 2.09×10^{-3} cm/sec. The results of the slug testing are presented in Table 2.3.1-2.

Table 2.3.1-2. Hydraulic Conductivity of the Intermediate System

Intermediate Piezometer	Hydraulic Conductivity (ft/day)	Hydraulic Conductivity (cm/sec)
CT1D	5.66	2.00×10^{-3}
CT5D	5.47	1.93×10^{-3}
CT7D	6.69	2.36×10^{-3}
Average	5.94	2.09×10^{-3}

Source: SCS, 1999.

Floridan Aquifer System—Six borings were taken to auger refusal. The consolidated limestone was encountered between 95.5 and 98.3 ft bls at each boring, indicating that the top of the rock is very consistent across the site. Ten feet of rock was cored in two locations. Recovery in 5-ft runs ranged from 60 to 100 percent with some loss due to washout of fines. The upper foot is very hard and consolidated and darker in color. The underlying grayish green rock is softer, highly fossiliferous, porous, and shows some evidence of water movement along fractures. Complete loss of water occurred at the top of rock due to high porosity. The thickness of this unit was not determined in the drilling program but the thickness of the Floridan aquifer is estimated at over 700 ft in Bay County.

Cation Exchange Capacity—CEC is a measure of the uptake and release of ions from a clay surface. Exchange of ions between clay minerals and the surrounding environment can have a pronounced effect on the properties of the clay minerals (e.g., elasticity, compressibility, permeability, etc.) present in soils. The CEC of a clay mineral is one way to determine the extent to which the structure and properties of a clay mineral and the surrounding soil may change under certain conditions.

Four samples were collected from the borings for determination of CEC. Samples were taken at varying depths from borings CT-7 and CT-8 using a split-spoon sampler. The results of the CEC tests are listed in Table 2.3.1-3. The low CEC values indicate that the types of clays present in the soils are not highly reactive (i.e., will not readily exchange ions or water). These values are similar to CECs for clays in the kaolinite and illite groups, which are among the most common and least reactive of the clay minerals.

Table 2.3.1-3. CEC of Clayey Portions of the Intermediate System

Sample Location	Hydrogeologic Unit	Depth of Sample (ft)	CEC (meq/100g)
CT-7	Intermediate Unit	15-15.5	4.37
CT-8	Intermediate Unit	13-15	11.4
CT-8	Intermediate Unit	78.8-80.3	3.66
CT-8	Intermediate Unit	83.8-85.3	5.76
CT-8	Intermediate Unit	93.8-95.3	16.8

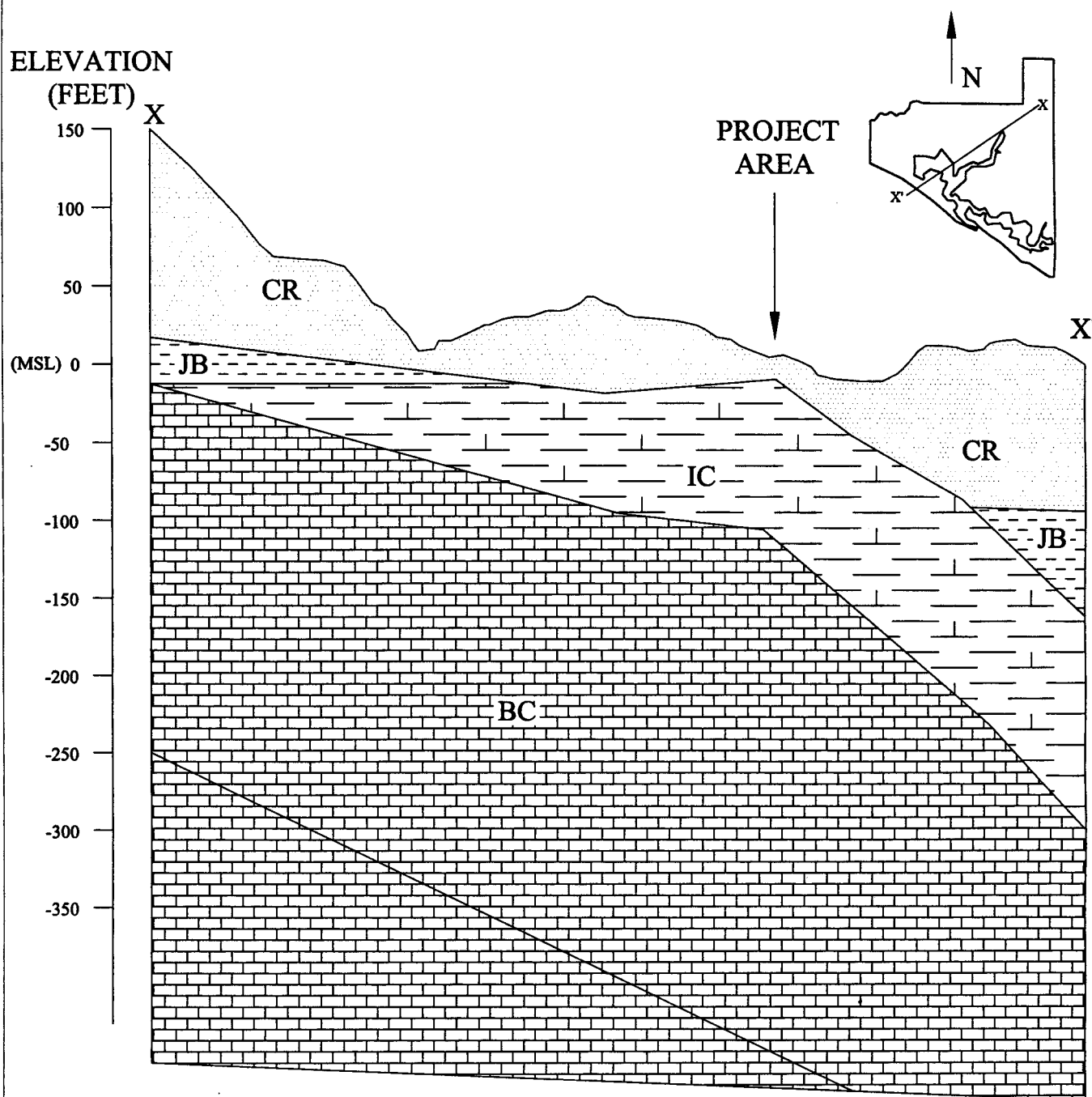
Note: meq/100g = milli-equivalents per 100 grams.

Source: SCS, 1999.

2.3.1.3 Geologic Maps

Geology

Figure 2.3.1-7 is based on a geologic cross-section of Bay County from Schmidt and Clark (1980). The cross-section shows the approximate location of the Lansing Smith Plant and the Project area. The surficial sediments are shown as Pliocene and Recent sands underlain by the Intracoastal Formation. The Jackson Bluff Formation, although not shown due to the thinness of the unit, was encountered during drilling.



LEGEND:

CR = CITRONELLE FORMATION AND RECENT SANDS

JB = JACKSON BLUFF FORMATION

IC = INTRACOASTAL FORMATION

BC = BRUCE CREEK LIMESTONE

FIGURE 2.3.1-7.

GEOLOGIC CROSS-SECTION OF BAY COUNTY,
FLORIDA

Sources: Schmidt and Clark, 1980; SCS, 1999.

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Soil

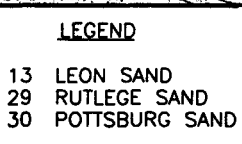
Soil types in the area of the Project have been mapped by the Natural Resource Conservation Service, formerly known as the Soil Conservation Service (1984). The soils are within the low flatwood map unit known as Pottsburg-Leon-Rutlege (Figure 2.3.1-8).

Most of the soils in this unit occur in cutover woodlands in large, broad, nearly level areas of Bay County. The soils are described to a depth of about 80 inches (Soil Conservation Service, 1984).

The soil type underlying most of the Project site is the Pottsburg (30). This unit is poorly drained. The surficial layer is a dark gray sand over a grayish brown and light brownish gray sand. A layer of light gray to white sand grades into an organic, dark gray to black, stained sand; slopes are 0 to 2 percent. The water table occurs within 10 inches of the surface for 4 to 6 months of most years with some of the low-lying areas ponded for 2 to 6 months. The permeability is rapid to moderate and internal drainage is slow (Soil Conservation Service, 1984).

The Leon soils (13) are also poorly drained with a very dark gray surface layer overlying a light gray to gray sand. Below the light sand is a brown or black organic stained layer which grades into a light brownish gray sand over a very dark brown organic stained layer. The soils slope from 0 to 2 percent. The water table is within 10 inches of the surface for 1 to 4 months of the year and at 10 to 40 inches for up to 9 months. Permeability is rapid in the upper layers and moderate in the subsoil (Soil Conservation Service, 1984).

The Rutlege soils (29) are poorly drained sands with a black to very dark gray surface layer underlain by a gray or light gray sand. Slopes range from 0 to 2 percent. The water table is at or near the surface for 4 to 6 months or ponded for 4 to 6 months for most years. The permeability is rapid and internal drainage is very slow (Soil Conservation Service, 1984).



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2.3.1.4 Bearing Strength

With little exception, the soils beneath the area to be developed offer low to moderate bearing capacity, and are subject to compression from structural loading and shock or vibration. This compression would yield intolerable settlement potential for the relatively high plant component loadings if placed on mats or conventional shallow-bearing foundations. Development and support of the components are possible by the use of deep foundations, soil density improvement, and preloading of the soils in select structural loading situations. These judgments are based on the geotechnical investigations and evaluations detailed below.

For this initial phase of work, seven soil test borings were performed in the general plant area, typically to depths of about 100 ft, to define top of rock. Test borings, performed according to the American Society for Testing and Materials (ASTM) D1586, provide standard penetration resistance (N) values which are general indicators of soil density or consistency and bearing capacity. The split spoon samples recovered are valuable for visual soils identification by the geologist, and laboratory testing for classification and engineering purposes. Select borings were also supplemented by rock coring (ASTM D2113) to determine the bearing character of the Floridan aquifer rock by way of percent recovery and rock quality designation (RQD). Additionally, about 30 shallow auger or post-hole probes were conducted to map the distribution and thickness of surficial organics and topsoil across the site. Figures 2.3.1-6 and 2.3.1-7 present the generalized geologic profile constructed from the boring program, and Attachment 10.5-C of Appendix 10.5 presents detailed test boring logs.

The Smith Unit 3 facility components which will impose significant structural loading include:

- Engineered/constructed fill, 2 to 6 ft, to achieve underslab grade and meet flood freeboard requirements; this will produce a wide-area loading of 250 to 750 pounds per square foot (psf).
- HRSG which will apply an average slab loading in the range of 2,000 to 3,000 psf, with lateral loading as well.

- Stack and CTG, which will impose loading similar to the HRSG, but also include uplift (overturning) loads.
- Cooling Tower and Water Treatment Building, estimated at 750 to 1,000 psf.
- Demineralized Water Tank, up to 100 ft in diameter, for a uniform circular load of up to 3,000 psf.

The bearing capacity considerations and anticipated foundation behavior under the expected loadings outlined above can be summarized as follows, for each major stratum encountered.

Surface Organics

The 12 to 18 inches of very loose organic silts and silty sand topsoil are not suitable for foundation support, nor can they be densified sufficiently in place. They require excavation, and may be used as topsoil atop the new fill if blended properly with other soils to adjust the organic content and consistency.

Surficial Sands

N-values up to 30 blows per foot (bpf) in the upper 10 ft indicate firm to medium-dense relative density. The bearing capacity is limited by the denser sands' thickness, however, and only very light structures on narrow pads or footings bearing at 2,500 psf or less can be founded in these soils. Below 10 ft, N-values as low as 1 and 2 indicate very loose density, precluding any heavy loading without proper densification or preloading prior to construction.

Jackson Bluff Clay

This thin clay layer is normally encountered at about 20 ft deep. N-values of essentially zero (weight-of-hammer) up to two indicate very soft consistency and excessive settlement potential for sensitive structures such as the HRSG, turbines, and stack. Heavy structural loads will have to be transferred through this layer by means of piles or stone columns. Due to clayey consistency, an approach of preloading to minimize settlements for intermediate-loaded structures such as the tank, water treatment building, or cooling tower would probably require a minimum of 6 months for this layer.

Intracoastal Sands

These calcareous silty and clayey sands have relative densities of very loose to firm between depths of about 20 to 75 ft, as reflected by N-values varying from 2 to 16 bpf. Below 75 ft, N-values tend to increase, approaching 30 bpf in some cases, indicating medium relative density. The upper portion of this stratum presents the critical lower densities which dictate the need for deep foundations or soil density improvement in all but a few loading situations. Where both fines content and relative density are low (below 10 percent), these sands are susceptible to further densification from machinery vibration or pile driving. Additionally, where N-values occur at less than about 6 or 7 bpf, these sands could consolidate from the weight of added fill, and impose negative friction, or downdrag, on piles installed through them. The low bearing capacity or strength of this material thus dictates that any significant thickness of fill should be placed as early into the construction schedule as possible, to maximize available preload times, even if piling is used for structural loading.

Floridan Aquifer

The rock core samples obtained to date indicate a fairly competent top-of-rock condition, but only for the upper few feet. Fractured and voided portions further below would indicate that hard driving will be required to adequately and safely seat the piles extending to these depths, varying from 80 to 100 ft deep. The bearing capacity of the rock will be determined by the joint frequency, orientation, and hardness as determined by unconfined compressive strength testing on intact rock cores.

To support the detailed design phase of the Project, more quantitative subsurface information pertaining to allowable bearing capacity and settlement potential will be gathered through the use of Marchetti Dilatometer soundings, and unconfined compression test and RQD analyses of rock cores.

Geotechnical evaluation of data points to:

- Bearing on/into the Floridan aquifer limerock by full displacement piles to support the very heavy settlement-sensitive CTG components, HRSG, and stack.

- Increase of the compression modulus of the Intracoastal Sands by preloading of vibroreplacement (stone columns) to decrease settlement potential and increase bearing capacity sufficient to support lighter, less settlement-sensitive structures such as the cooling tower and water tank.

Neither pile driving nor vibrocompaction/vibroreplacement procedures present an undue threat to ground water quality.

With the very high water table at this site, the use of a single-stage well point dewatering system and sheet-pile bracing of an excavation up to 15 ft deep will be required for installation of large-diameter piping to be placed underground between the CTG units.

2.3.2 SUBSURFACE HYDROLOGY

The Smith Unit 3 Project is located in the Econfinia Creek Basin. A recent Northwest Florida Water Management District (NFWMD) publication (Richards, 1997) characterized the area in detail. The general and site-specific subsurface hydrology are summarized below.

Within the Project area, four hydrogeologic units define the regional system. The general hydrogeologic sequence includes:

- The surficial aquifer system.
- The intermediate system.
- The Floridan aquifer system.
- The Sub-Floridan confining unit.

The surficial and Floridan aquifer systems are composed of moderately to highly-permeable sediments. These systems transmit and store large quantities of water. The intermediate and Sub-Floridan systems are low-permeability sediments and form regionally extensive confining units (Richards, 1997). The Southeastern Geological Society's ad hoc Committee on Florida Hydrostratigraphic Unit Definition defined the various aquifer systems in the state. Figure 2.3.1-2 shows the nomenclature and relationship between the hydrogeologic sequence and major stratigraphic units in the Florida Panhandle.

2.3.2.1 Subsurface Hydrological Data for the Site

Surficial Aquifer System—The surficial aquifer system occurs over most of the NFWMD area and the top of the system is the natural land surface. The surficial aquifer system is made up of unconsolidated silty and organic fine- to coarse-grained quartz sands. The sediments range in age from Pliocene to Holocene. Ground water normally occurs under water table conditions. Regionally, the surficial aquifer system ranges in thickness from 0 to 80 ft. The aquifer at the Project site normally has a thickness of 15 to 20 ft. Although the surficial aquifer has been developed in some areas of Bay county, low permeability and thickness preclude this system as a water source at the subject site (Gulf correspondence to NFWMD, March 1999). Figure 2.3.2-1 shows the thickness of the

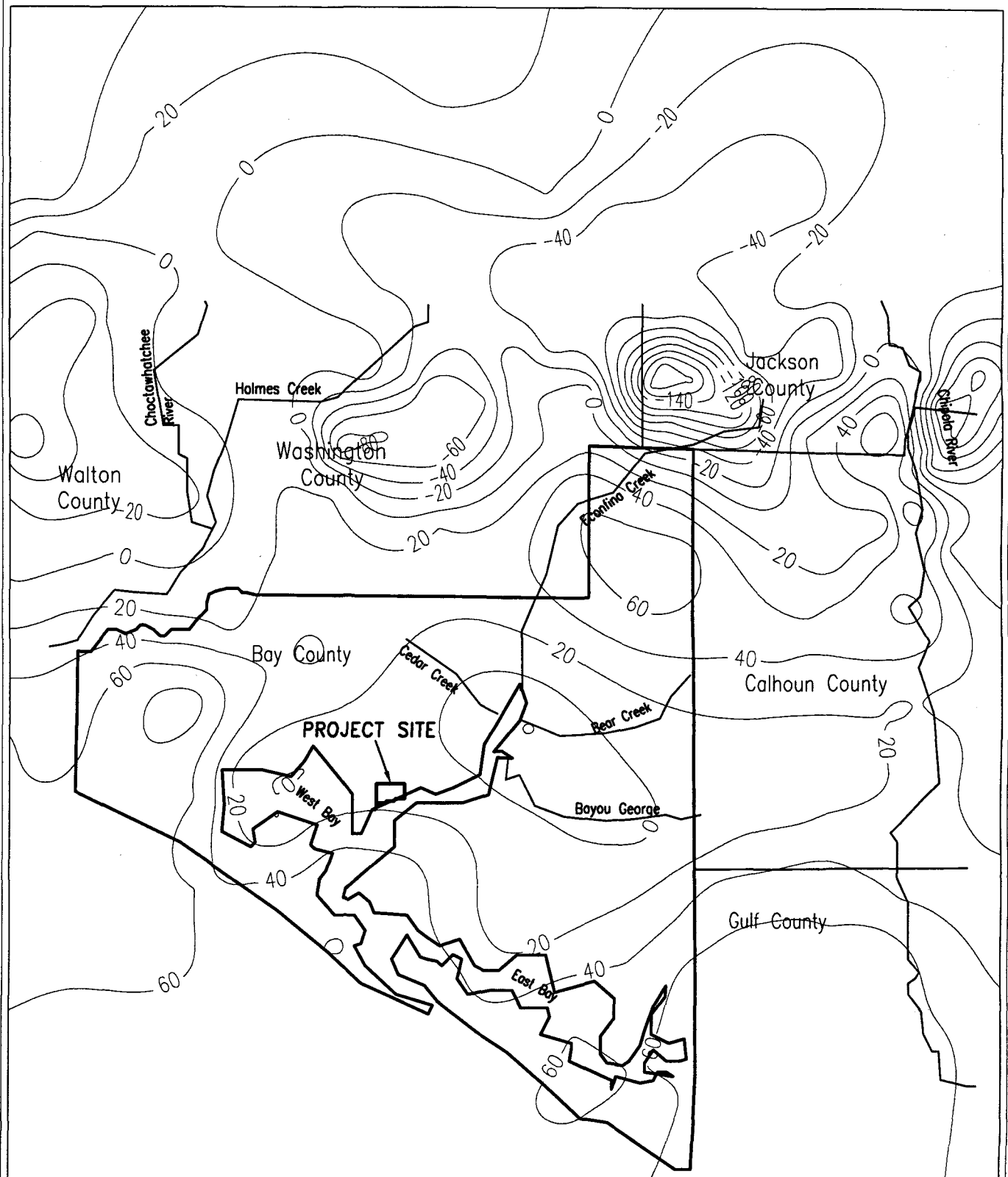


FIGURE 2.3.2-1.

THICKNESS OF THE SURFICIAL AQUIFER

Sources: Richards, 1997; SCS, 1999; ECT, 1999.

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surficial aquifer based on Richards (1997), modified to include site-specific information. This agrees with the thickness of the surficial unit as encountered in the site investigation.

In the Project area, seven piezometers were installed in the surficial aquifer system (Figure 2.3.2-2). Maximum and minimum readings since installation are given in Table 2.3.2-1. Seasonal fluctuations in the surficial aquifer at Plant Smith range from a low elevation of 2.07 in November to elevation 10.33 in February (adjacent monitoring well at existing Smith Plant). Figures 2.3.2-3 through 2.3.2-6 present the water table contour maps derived from the recently installed piezometers. Direction of ground water flow appears to be toward piezometer CT6S. Short-term flow directions can change with precipitation events.

Table 2.3.2-1. Water Table Elevations in the Surficial Aquifer

Piezometer ID	Water Table Elevation (ft)			
	February 1999	March 1999	April 1999	May 1999
CT1S	6.42	6.43	4.34	6.67
CT2S	6.49	6.49	4.39	6.76
CT5S	7.16	6.70	4.77	6.97
CT6S	5.84	6.18	4.17	6.28
CT7S	6.11	6.18	4.38	6.62
CT11S	NA	NA	6.93	9.07
CT12S	NA	NA	5.86	8.25

Source: Gulf Power Company, 1999.

Horizontal Ground Water Flow—Horizontal ground water flow velocity (V) for the surficial water bearing unit can be estimated using the formula:

$$V = KI/\eta$$

Where: K = hydraulic conductivity
I = hydraulic gradient
 η = estimated effective porosity

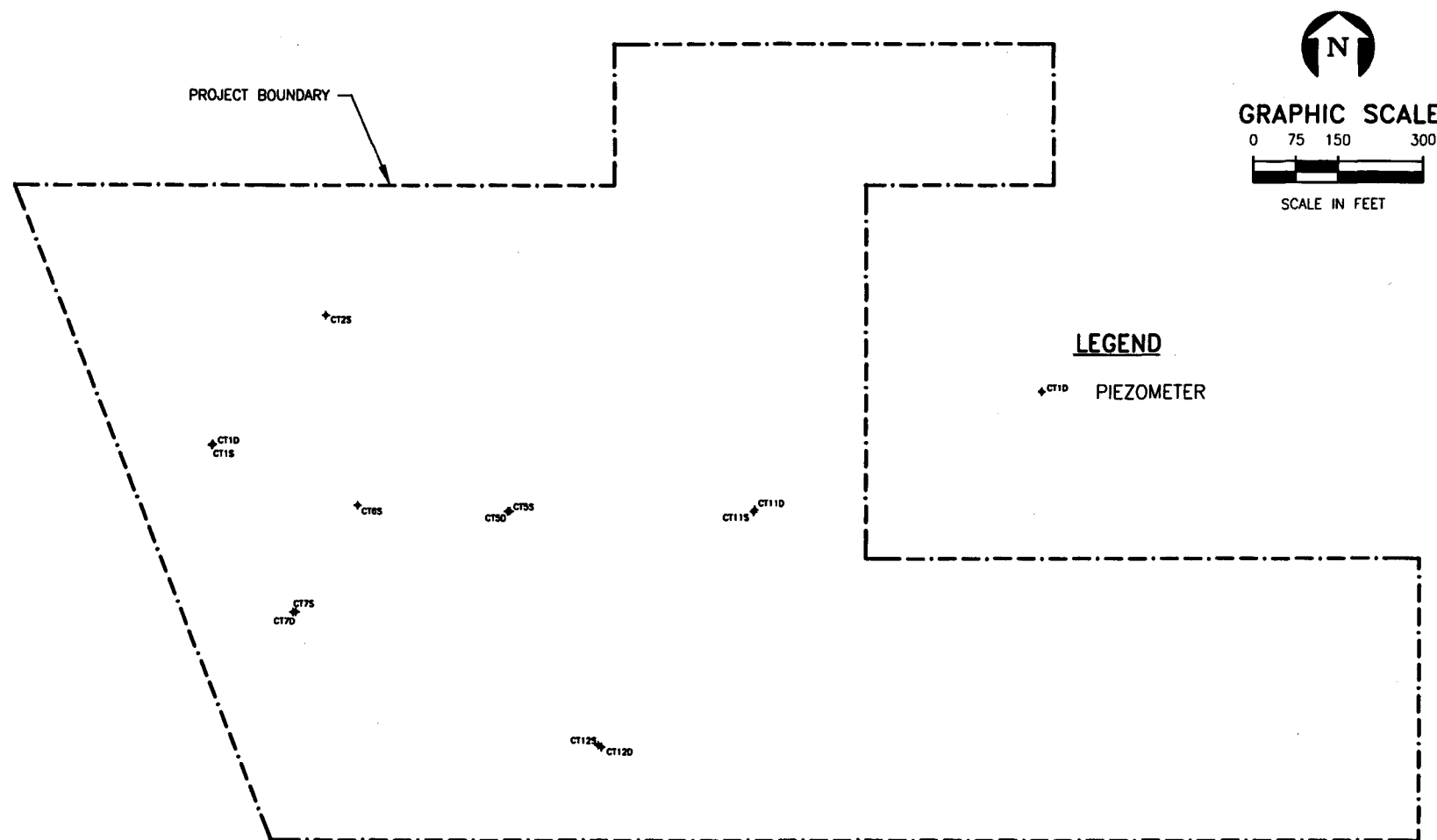


FIGURE 2.3.2-2.
PIEZOMETER LOCATION MAP

Sources: SCS, 1999; ECT, 1999.

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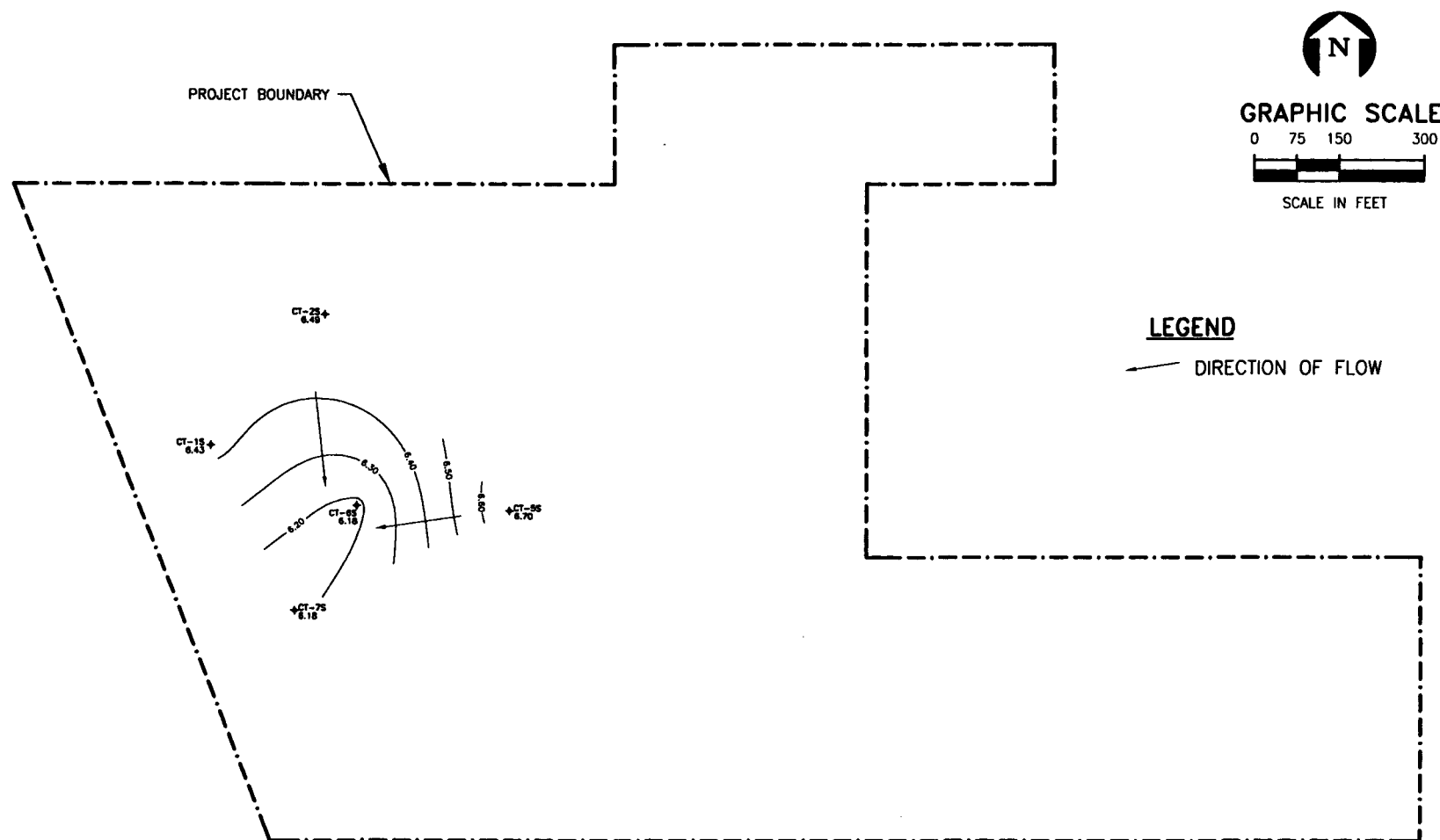


FIGURE 2.3.2-4.

WATER TABLE CONTOUR MAP OF THE SURFICIAL AQUIFER

MARCH 1999

Source: SCS, 1999.

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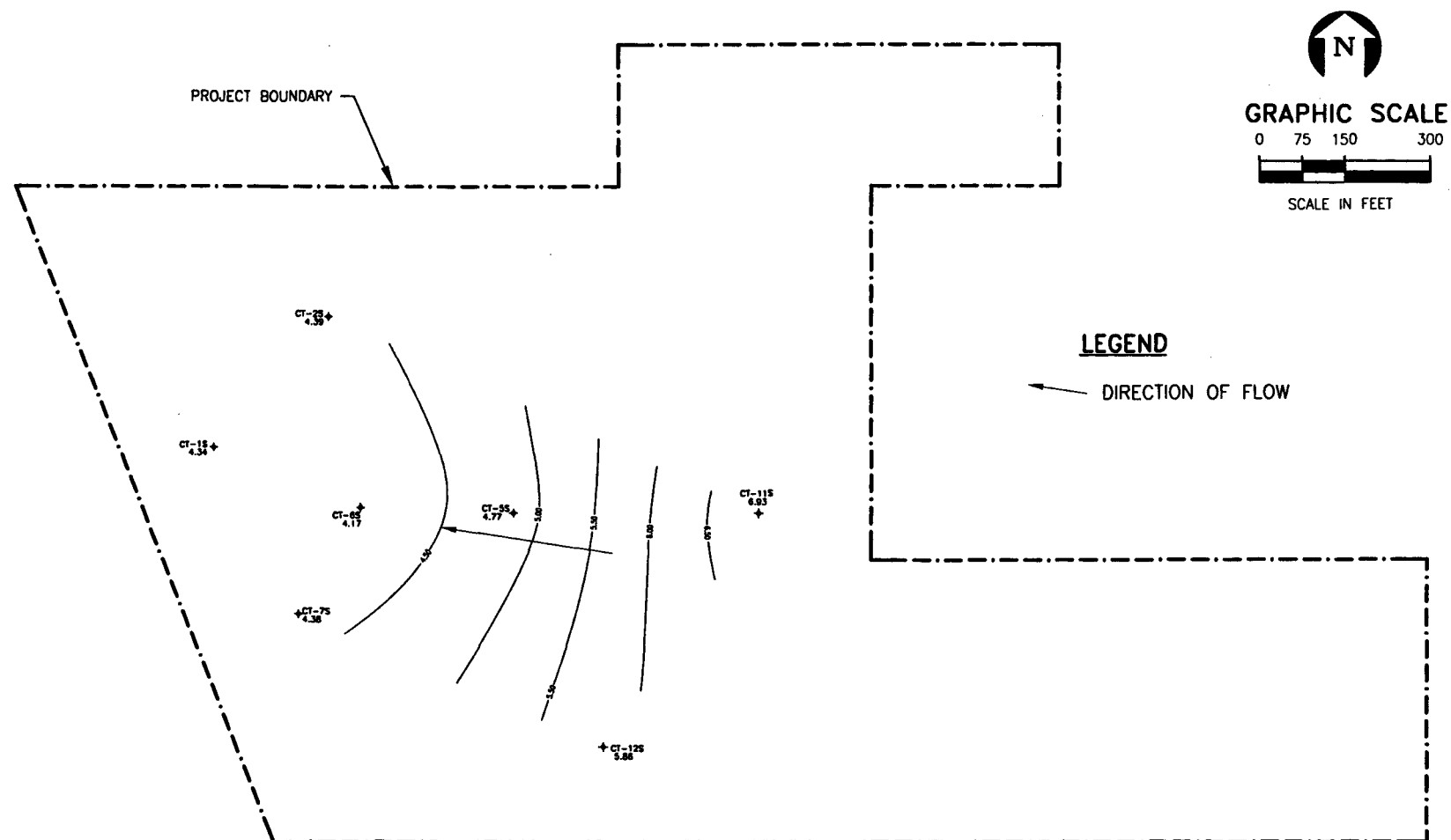


FIGURE 2.3.2-5.

WATER TABLE CONTOUR MAP OF THE SURFICIAL AQUIFER

APRIL 1999

Source: SCS, 1999.

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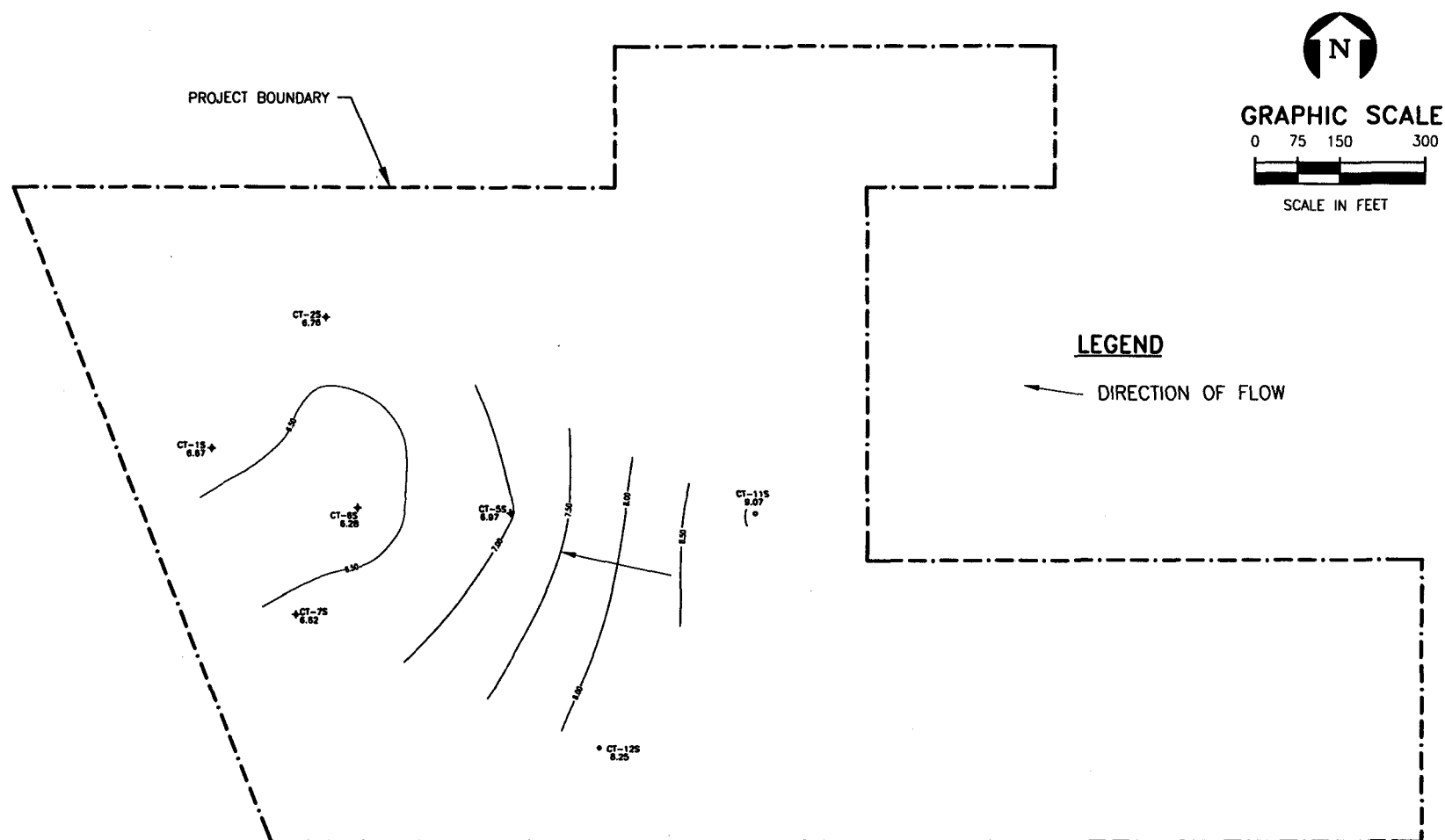


FIGURE 2.3.2-6.

WATER TABLE CONTOUR MAP OF THE SURFICIAL AQUIFER

MAY 1999

Sources: SCS, 1999; ECT, 1999.

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In the absence of measured values for effective porosity, a value of 0.20 was used. This is based on default values from *Volume II, RCRA Facility Investigation (RFI) Guidance* (U.S. Environmental Protection Agency [EPA], 1989), for soil classified as SP and SM. An average hydraulic conductivity value of 2.9×10^{-4} cm/sec (0.82 ft/day) was used in the calculation. Maximum difference in head (7.17 ft at CT5S and 5.84 ft at CT6S) over a distance of 270 ft gives a maximum hydraulic gradient of 4.93×10^{-3} .

$$V = \frac{(2.9 \times 10^{-4} \text{ cm/sec})(4.93 \times 10^{-3})}{0.20} = 7.15 \times 10^{-6} \text{ cm/sec} = 0.020 \text{ ft/day} = 7.39 \text{ ft/year}$$

Water Quality—The surficial aquifer system is not a major source of water in the NFWMD but is mainly used for irrigation and to maintain surface water features. Water in the surficial aquifer is soft and generally unmineralized. The sand-rich aquifer has the ability to sorb metals and anions in moderate amounts.

The report entitled *Florida's Ground Water Quality Monitoring Program Background Hydrogeochemistry* (FGS, 1992) is a compilation of the initial quantification of background ground water quality in each of the major aquifer systems. The report provides details of the temperature, pH, total dissolved solids, specific conductance, cations, anions, trace metals and organics identified through analyses of thousands of wells throughout the state.

Based on the report, the total dissolved solids in the surficial aquifer system are low, which indicates minimum weathering of the host rock materials. Concentrations range from 15 to 1,000 milligrams per liter (mg/L). The median concentration is 74 mg/L, with concentration increasing toward the coast. The chloride distribution in the surficial aquifer in the NFWMD is low due to the continental influences by precipitation. Concentrations ranges from 1.8 to a maximum of 410 mg/L, with a median of 7 mg/L (FGS, 1992). Figures 2.3.2-7 and 2.3.2-8 show the distribution of the total dissolved solids and chloride in the surficial aquifer system.

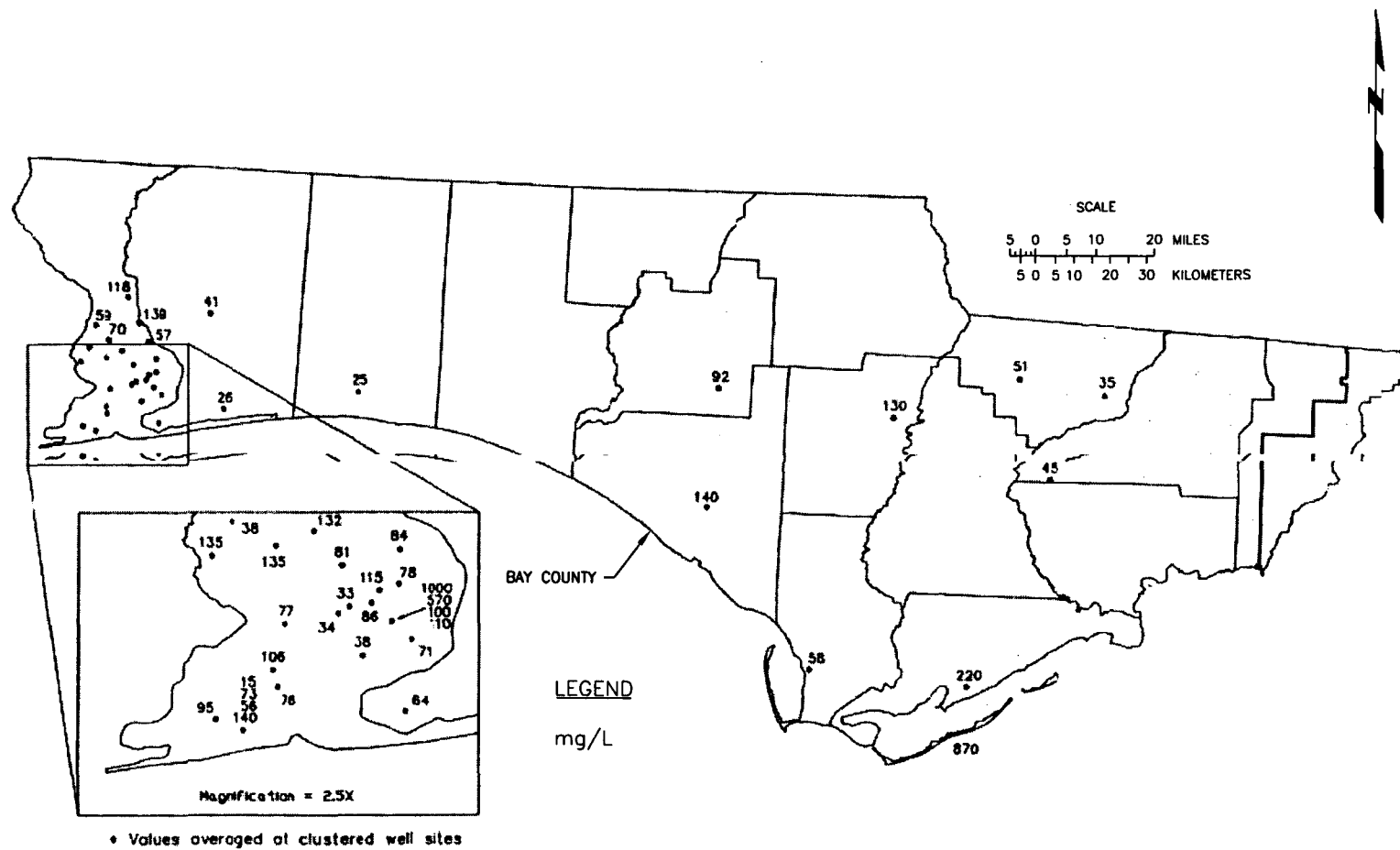


FIGURE 2.3.2-7.

DISTRIBUTION OF TOTAL DISSOLVED SOLIDS IN THE
SURFICIAL AQUIFER SYSTEM OF THE PANHANDLE

Sources: FGS, 1992; SCS, 1999; ECT, 1999.

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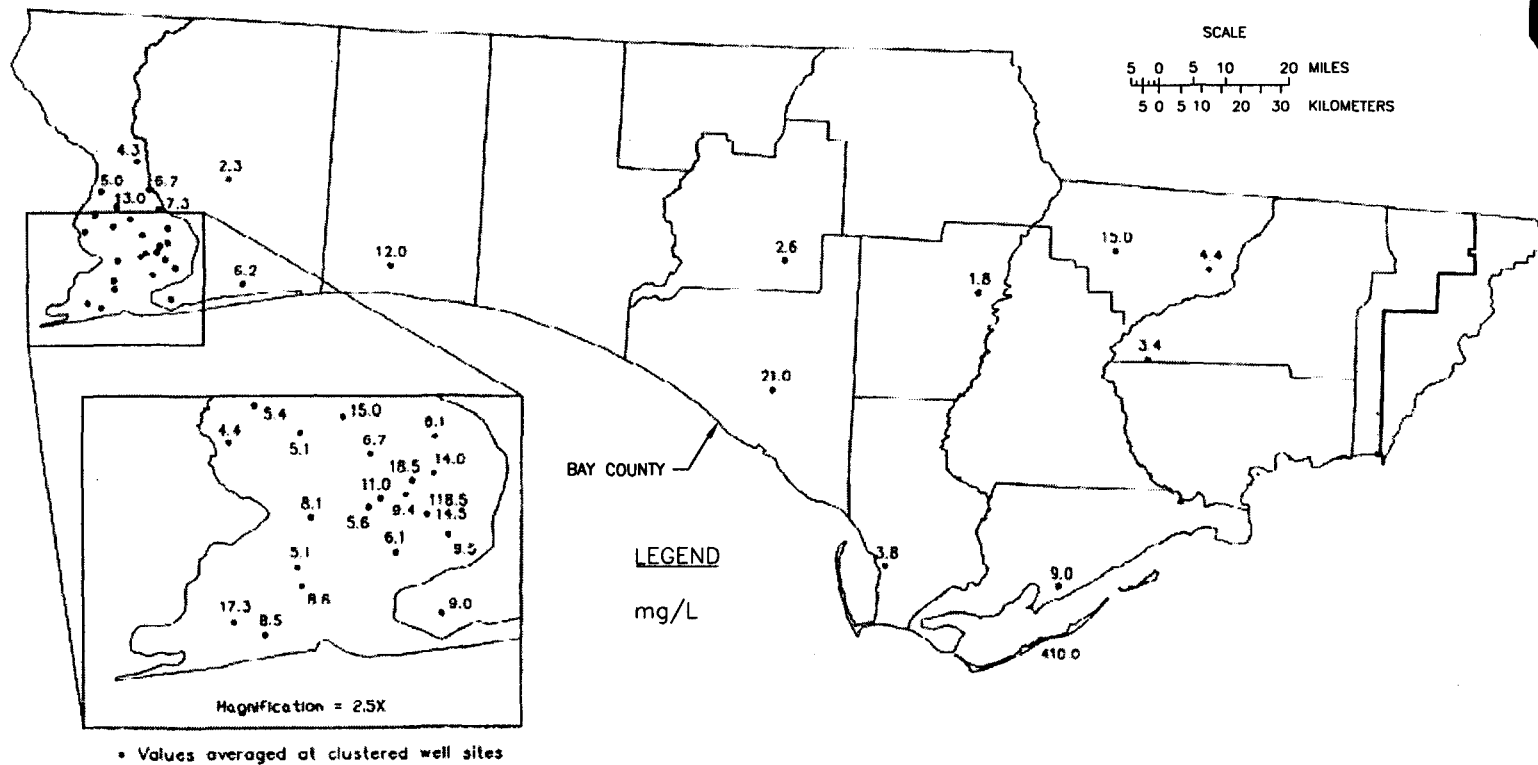


FIGURE 2.3.2-8.

DISTRIBUTION OF CHLORIDES IN THE SURFICIAL AQUIFER SYSTEM
OF THE PANHANDLE

Sources: FGS, 1992; SCS, 1999; ECT, 1999.

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Specific Yield—A series of aquifer tests were conducted at the Lansing Smith Plant site in January 1995 to evaluate the water table well performance (*Lansing Smith Electric Generating Plant Combustion Turbine Area Remedial Action Plan* (SCS, 1995). The values derived from the pumping test are applicable to the Project area. Based on the testing, the average specific yield (Sy) of the surficial aquifer is 0.17.

Intermediate System—The thick heterogeneous intermediate system retards ground water exchange between the surficial aquifer and the Floridan aquifer system. The sediments exhibit lower permeability than the surficial sands. Clays in the unit may have high sorption capacities. In Bay County, carbonate beds and/or coarse clastics may be interbedded with the fine-grain sediments (Richards, 1997).

The intermediate system in the Econfinia Creek Basin is Middle Miocene to Upper Pliocene in age and includes the Jackson Bluff and Intracoastal Formations. The thickness of the system ranges from less than 50 to approximately 100 ft. Figure 2.3.2-9 shows the regional thickness of the intermediate system (Richards, 1997). In the Project area, the thickness of the system as determined by borings ranges from 77.0 to 82.8 ft and includes the Jackson Bluff and the Intracoastal Formations (Figure 2.3.2-10).

The Jackson Bluff Formation ranges from 1 to 7 ft thick in the Project area. The unit was encountered in all borings in the Project area as well as unrelated investigations at the Lansing Smith Plant site, where the unit ranges in thickness from 2 to 4 ft. The sediments are clayey sands and act as a semi-confining bed between the surficial quartz sands and the underlying calcareous sands of the Intracoastal Formation. Falling head permeability testing in the laboratory yielded a value of 1.3×10^{-6} cm/sec for the clayey portion of a Shelby tube sample collected from the Jackson Bluff Formation.

The Intracoastal Formation at the site underlies the Jackson Bluff Formation. Five piezometers were installed in the Intracoastal below the clay. Slug testing yielded an average

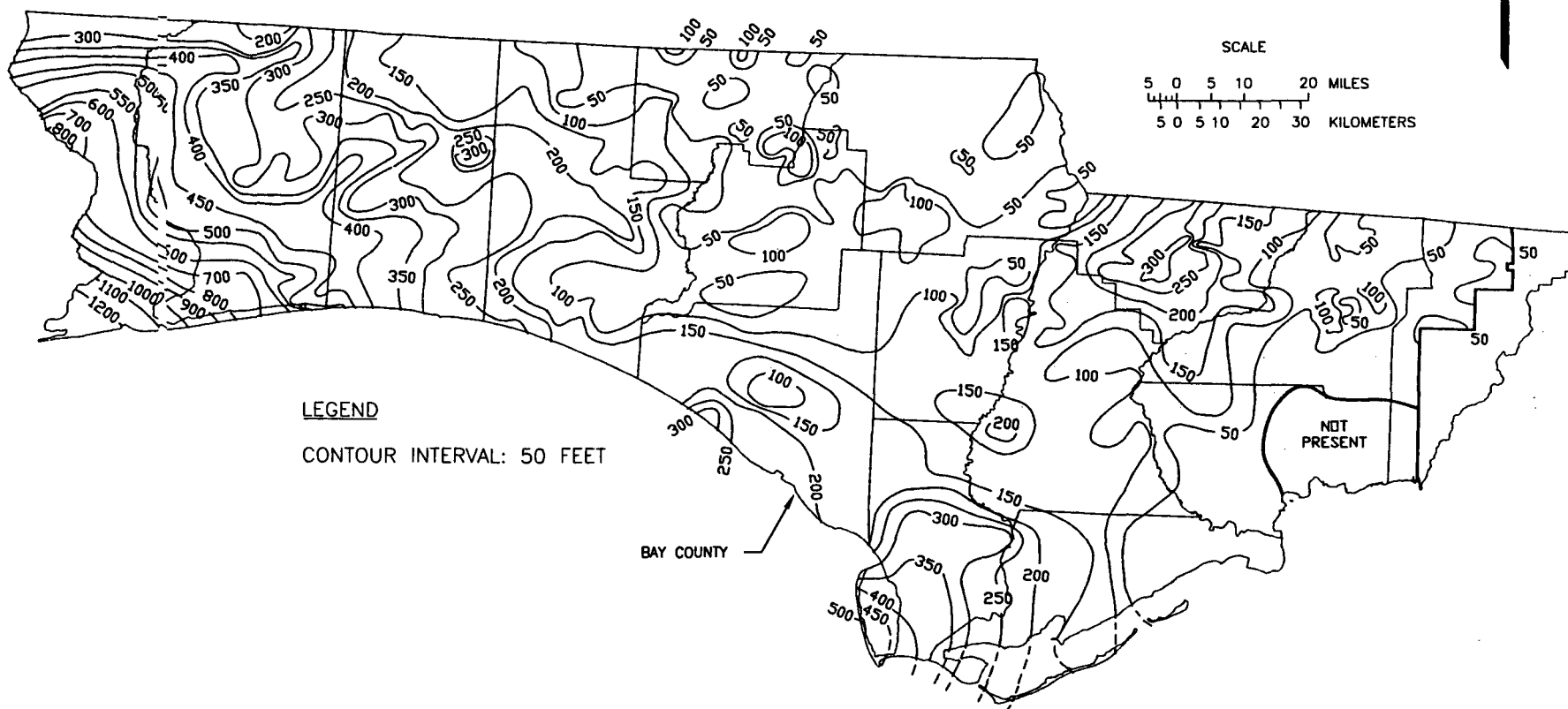


FIGURE 2.3.2-9.

REGIONAL THICKNESS OF THE INTERMEDIATE AQUIFER SYSTEM

Sources: FGS, 1991; SCS, 1999; ECT, 1999.

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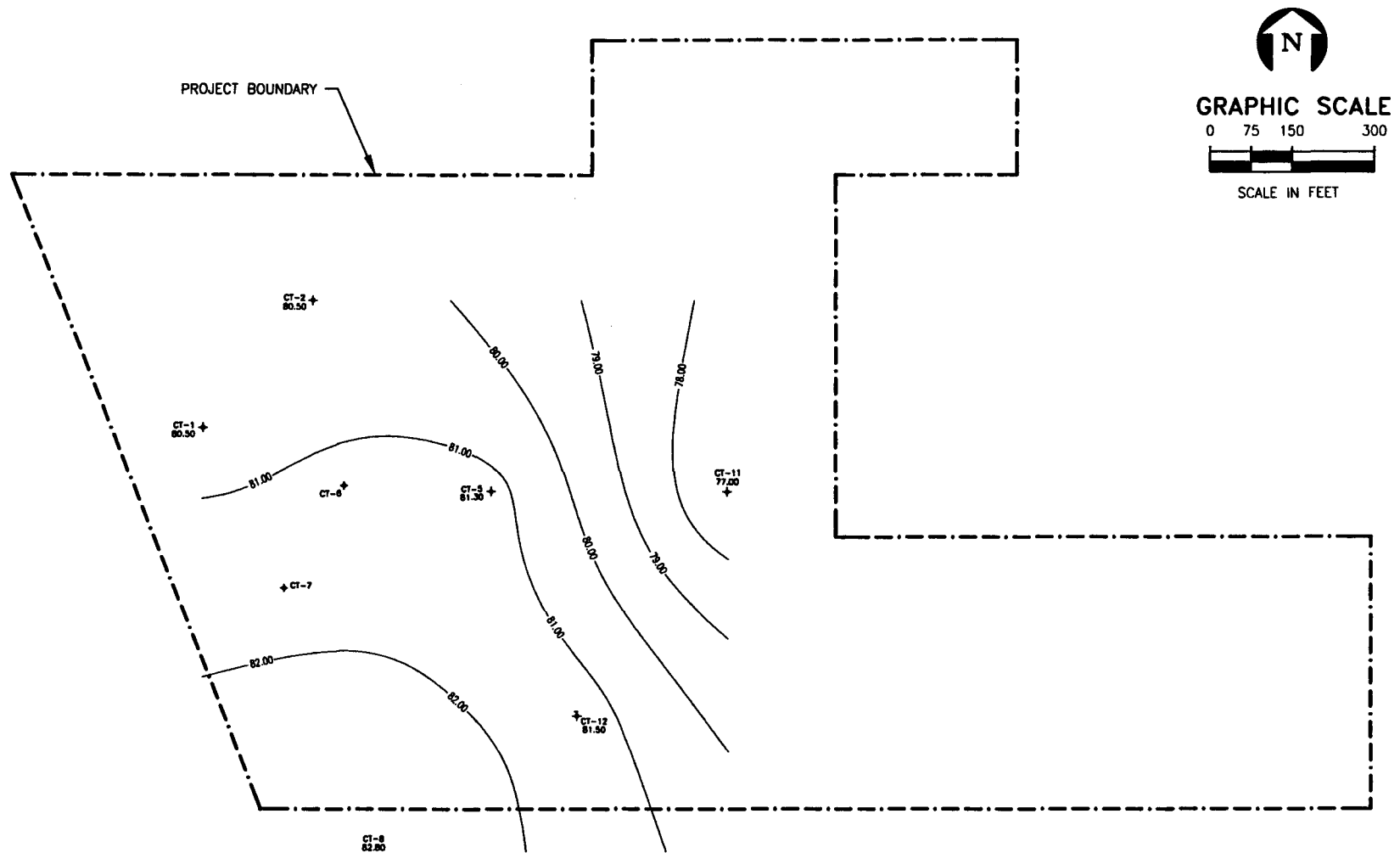


FIGURE 2.3.2-10.

ISOPACH MAP OF THE INTERMEDIATE SYSTEM IN THE PROJECT AREA

Source: SCS, 1999.

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hydraulic conductivity of 2.09×10^{-3} cm/sec (Table 2.3.2-2). Figures 2.3.2-11 through 2.3.2-14 present the piezometric surface maps. Ground water flow direction is to the west and southwest.

Table 2.3.2-3. Potentiometric Surface in the Intermediate Unit

Piezometer ID	Water Table Elevation			
	February 1999	March 1999	April 1999	May 1999
CT1D	4.22	4.19	1.72	2.92
CT5D	4.42	4.63	2.15	3.25
CT7D	4.13	4.29	1.73	2.97
CT11D	NA	NA	5.70	6.98
CT12D	NA	NA	3.73	5.01

Source: SCS, 1999.

Horizontal Ground Water Flow—Horizontal ground water flow velocity for the intermediate water bearing unit can be estimated using the formula:

$$V = KI/\eta$$

Where: K = hydraulic conductivity
I = hydraulic gradient
 η = estimated effective porosity

In the absence of measured values for effective porosity, a value of 0.20 was used. This is based on default values from *Volume II, RCRA Facility Investigation (RFI) Guidance*, (EPA, 1989) for soil classified as SM. An average hydraulic conductivity value of 2.09×10^{-3} cm/sec was used in the calculation. Hydraulic gradient was computed between CT-1D and CT-5D at the March reading. The difference in head between the two piezometers of 0.44 ft over a distance of 540 ft gives a gradient of 8.1×10^{-4} .

$$V = \frac{(2.09 \times 10^{-3} \text{ cm/sec})(8.1 \times 10^{-4})}{0.20} = 8.46 \times 10^{-6} \text{ cm/sec} = 0.024 \text{ ft/day} = 8.75 \text{ ft/year}$$

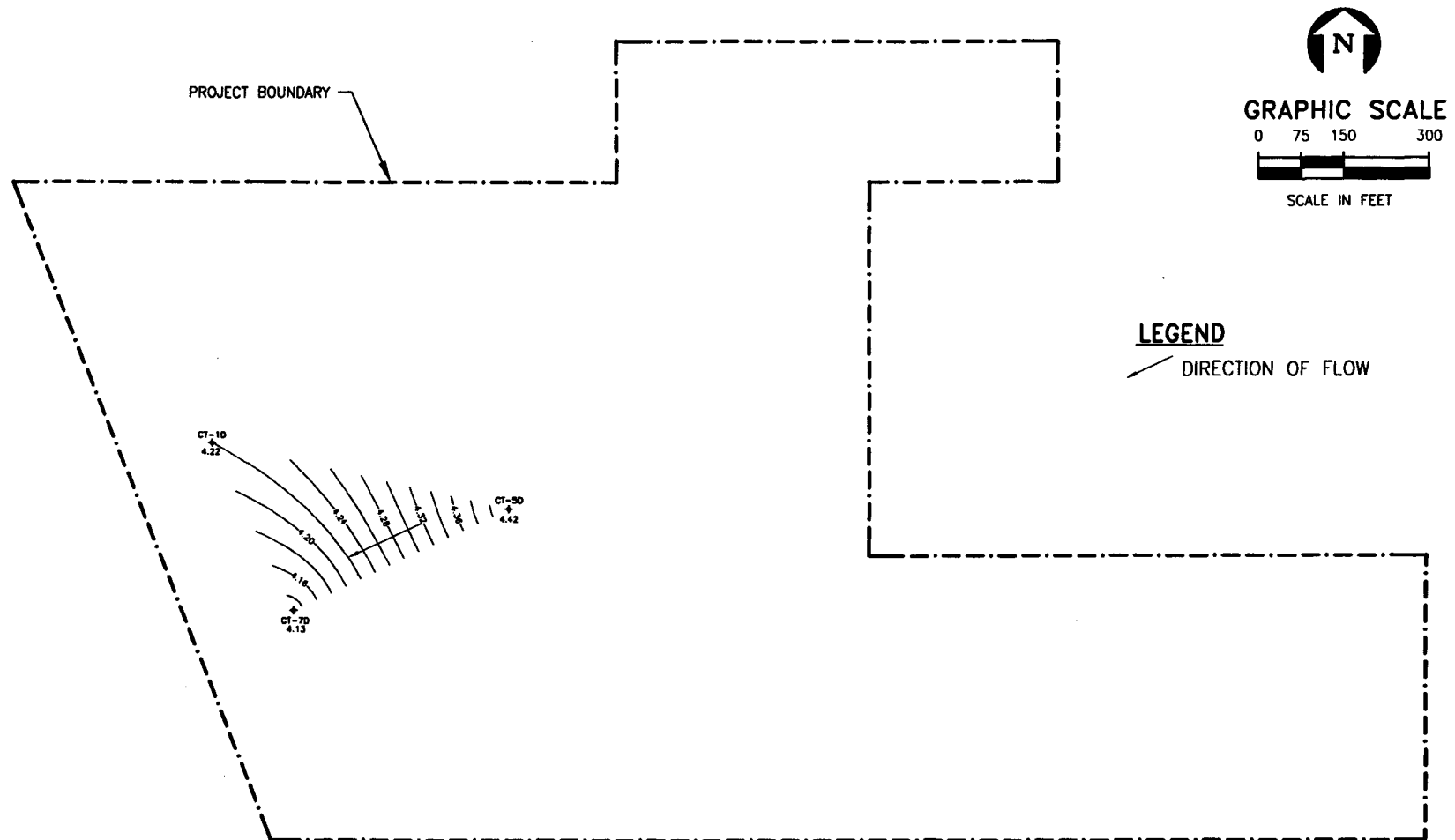


FIGURE 2.3.2-11.
POTENTIOMETRIC SURFACE OF THE INTERMEDIATE AQUIFER
FEBRUARY 1999
Source: SCS, 1999.

2-74

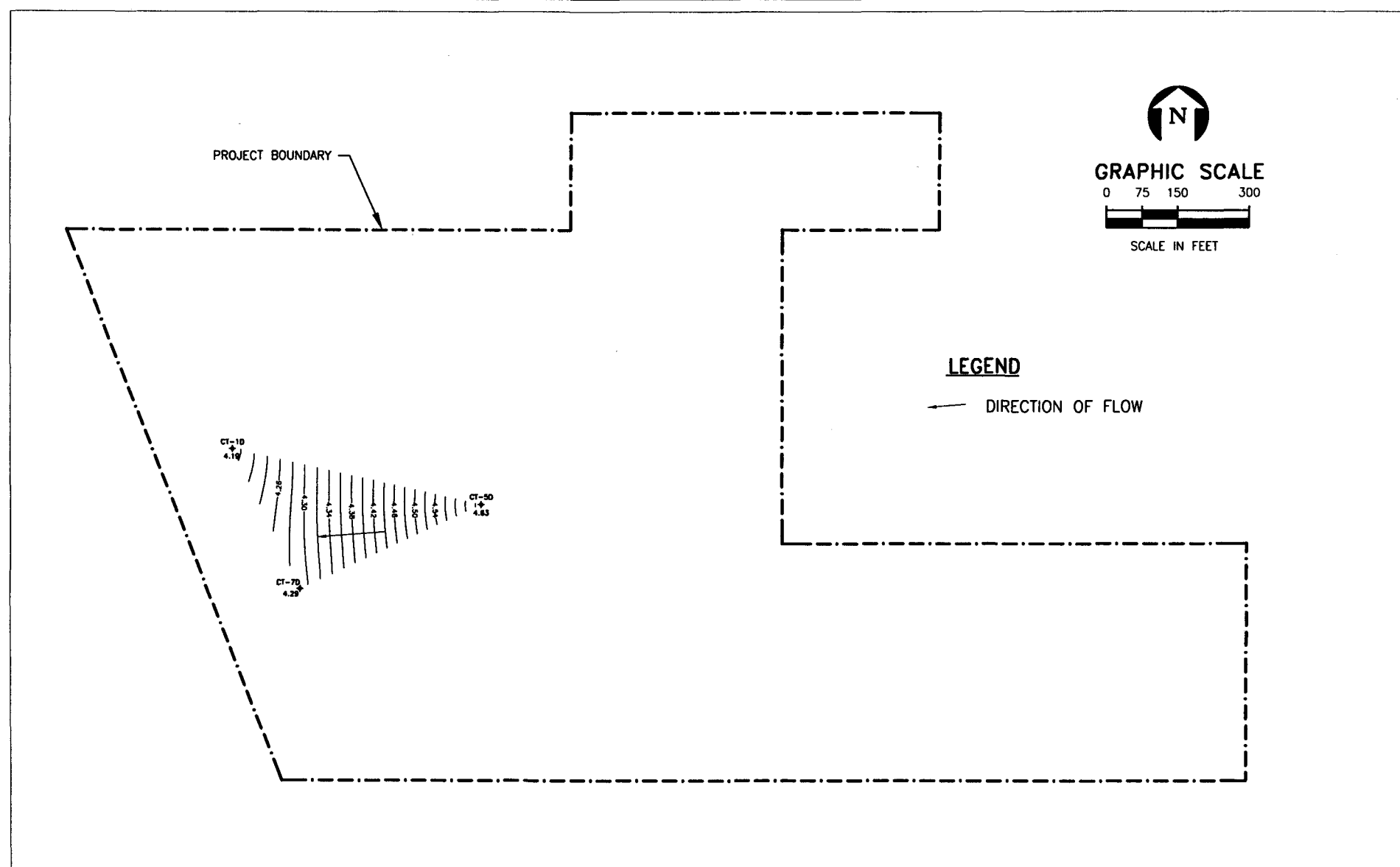


FIGURE 2.3.2-12.

POTENTIOMETRIC SURFACE OF THE INTERMEDIATE AQUIFER

MARCH 1999

Source: SCS, 1999.

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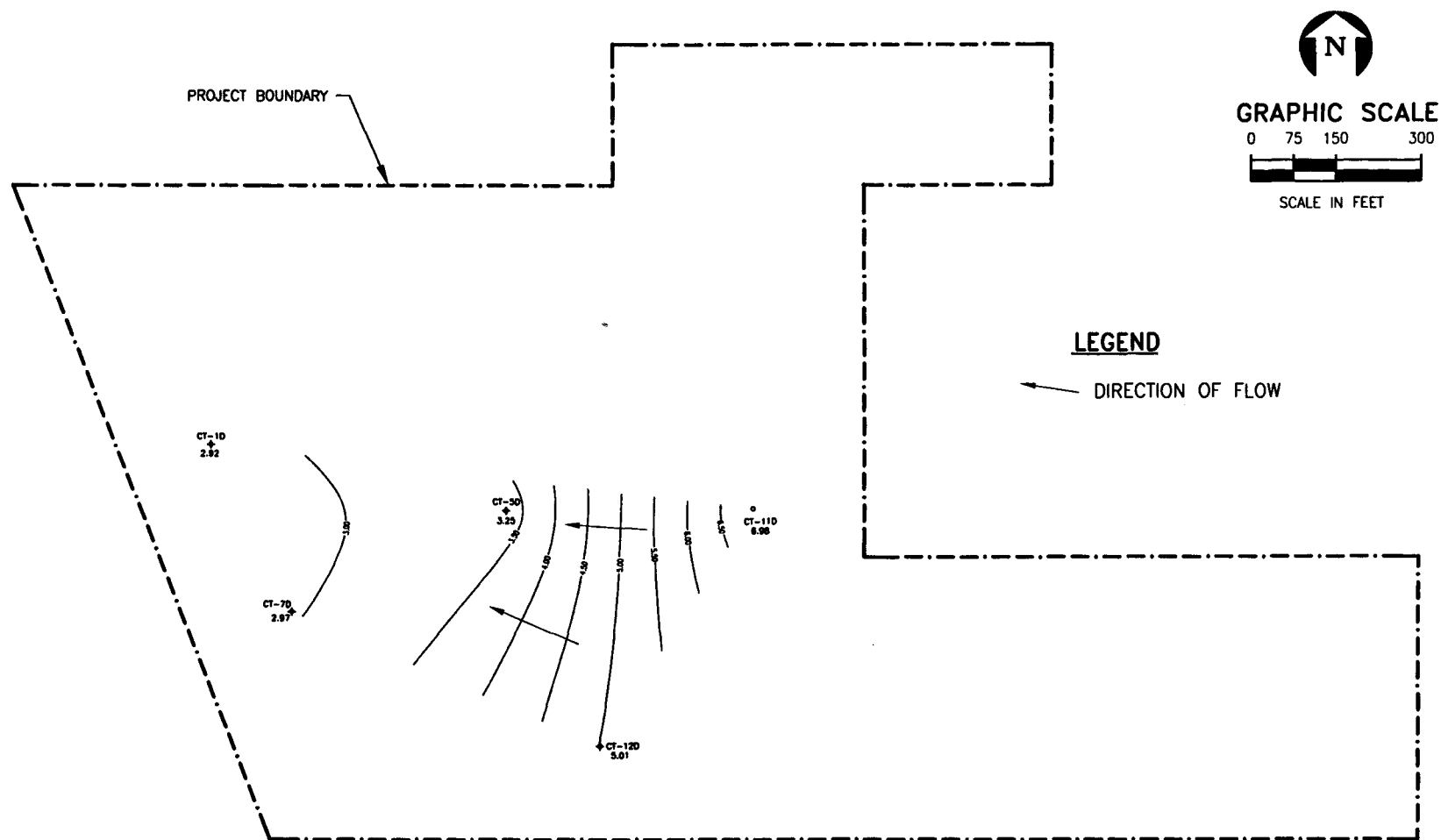


FIGURE 2.3.2-14.
POTENTIOMETRIC SURFACE OF THE INTERMEDIATE AQUIFER
MAY 1999
Source: SCS, 1999.

Water Quality—The intermediate system aquifer is generally not an important water-bearing unit in Northwest Florida. Locally, the unit provides limited amounts of water for small, domestic potable wells. The total dissolved solids in the intermediate system range from 36 to 390 mg/L, with a median value of 165 mg/L (FGS, 1992). The distribution of chlorides in the aquifer shows considerable variability. Chloride concentrations are low in the northern part of the district where the rainfall is dominated by continental influence. Concentrations increase toward the coast. Based on the data from the Ground Water Quality Program, the minimum concentration within Northwest Florida is 1.7 mg/L and the maximum is 58.0 mg/L, with a median of 5.3 mg/L. Figures 2.3.2-15 and 2.3.2-16 show the distribution of the total dissolved solids and chloride in the intermediate system aquifer.

Floridan Aquifer System—The Floridan aquifer system is the most prolific aquifer system in the southeastern United States and underlies all of Florida. The system provides more than 90 percent of the water supplies in Northwest Florida except in parts of Santa Rosa County and Escambia County (FGS, 1992). The Floridan dips to the south and ranges from over 100 ft-msl in the northern part of the Panhandle to more than 300 ft below sea level in Bay County. The elevation of the top of the Floridan ranges from about 50 ft-msl to 50 ft below sea level throughout most of the Econfinia Creek Basin where the aquifer is approximately 500 to 600 ft thick (Richards, 1997).

Ground water availability in the Floridan is a function of permeability, thickness, proximity to unsuitable water, and recharge rates. Where the intermediate system is thin and permeable, higher recharge rates occur and secondary porosity is enhanced, increasing aquifer permeability (Richards, 1997). In the Coastal portion of Bay County, in the Project area, the Floridan is thick but low recharge rates, low permeability, and proximity of salt water within and above the Floridan may result in low to moderate ground water availability.

IMAGE QUALITY

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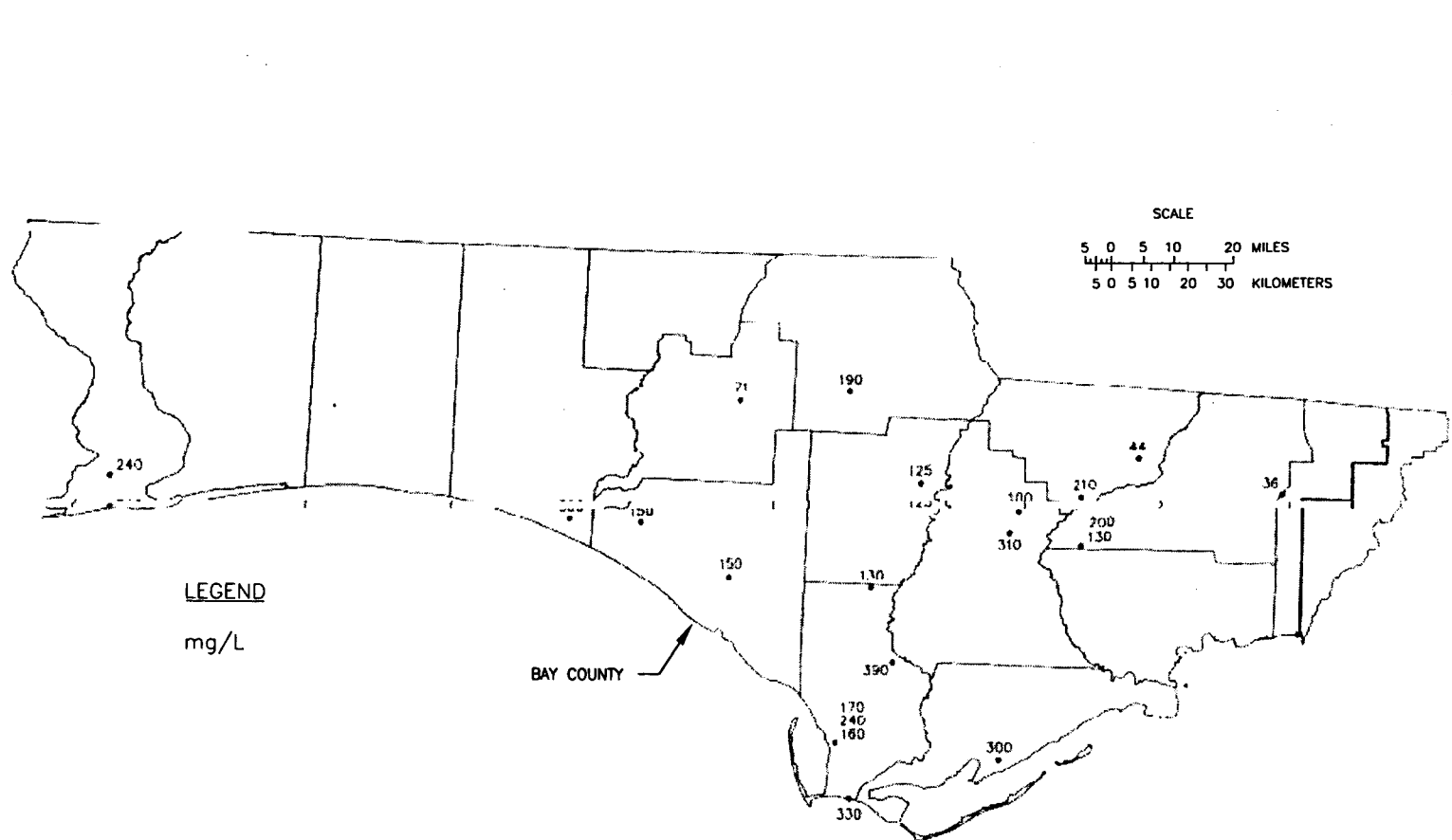


FIGURE 2.3.2-15.

DISTRIBUTION OF TOTAL DISSOLVED SOLIDS IN THE INTERMEDIATE AQUIFER SYSTEM

Sources: FGS, 1992; SCS, 1999; ECT, 1999.

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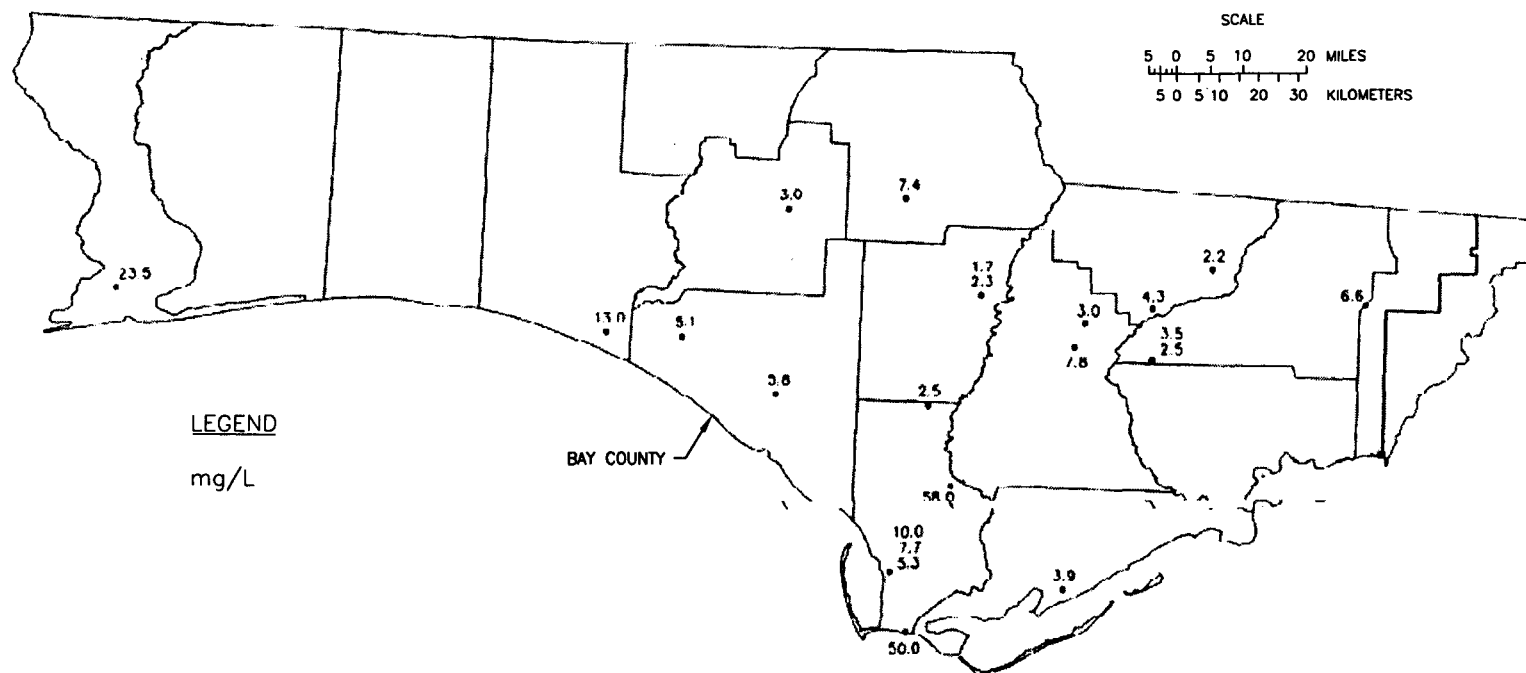


FIGURE 2.3.2-16.

DISTRIBUTION OF CHLORIDES IN THE INTERMEDIATE AQUIFER SYSTEM

Sources: FGS, 1992; SCS, 1999; ECT, 1999.

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Figures 2.3.2-17 and 2.3.2-18 represent the elevation of the top and bottom of the Floridan aquifer system in the Econfinia Creek Basin and surrounding area. Figure 2.3.2-19 represents the top of the Floridan as defined by the drilling investigation at the Project site. Top of the rock of the Floridan was encountered at approximately 100 ft bls consistently across the site. The transmissivity of the Floridan in the Project area is estimated at 4,000 square feet per day.

The potentiometric surface varies widely throughout the state and may be affected by extensive pumping of ground water. Figure 2.3.2-20 shows the potentiometric surface of the Floridan in Bay and surrounding counties. No deep wells were installed in the Floridan aquifer during the drilling investigation.

Water Quality

The quality of the Floridan unit has been extensively studied since the aquifer is the most important source of water to the state. Compared to the surficial and intermediate sands and clays, the mineral assemblage in the Floridan is less complex, consisting mostly of calcite and dolomite and as a result, the unit contains a high calcium content compared to the overlying units. In Bay County, total dissolved solids in the Floridan are related to the salt-water zone and flow systems. High concentrations are often the result of contact with soluble carbonates and mixing with saline water at the bottom of the aquifer and at the coast. Concentrations are lowest in the interior areas where the aquifer is recharged by rainfall and the residence time is shorter. Within Northwest Florida, the total dissolved solids concentration of the Floridan ranges from 42 to 810 mg/L, with a median of 200 mg/L (FGS, 1992). Figure 2.3.2-21 shows the distribution of total dissolved solids in the Floridan aquifer.

The chloride distribution in the Floridan aquifer in the Project area is similar to the other aquifer systems in the state. Concentrations are generally low inland, in recharge areas and shallow wells. Concentrations are highest in deeper wells near the coast and in areas of salt water intrusion caused by pumping. Within Northwest Florida, the chloride distribution ranges from 1.7 to 300 mg/L, with a median of 6.3 mg/L. Figure 2.3.2-22 shows the distribution of chloride concentration in the Floridan aquifer.

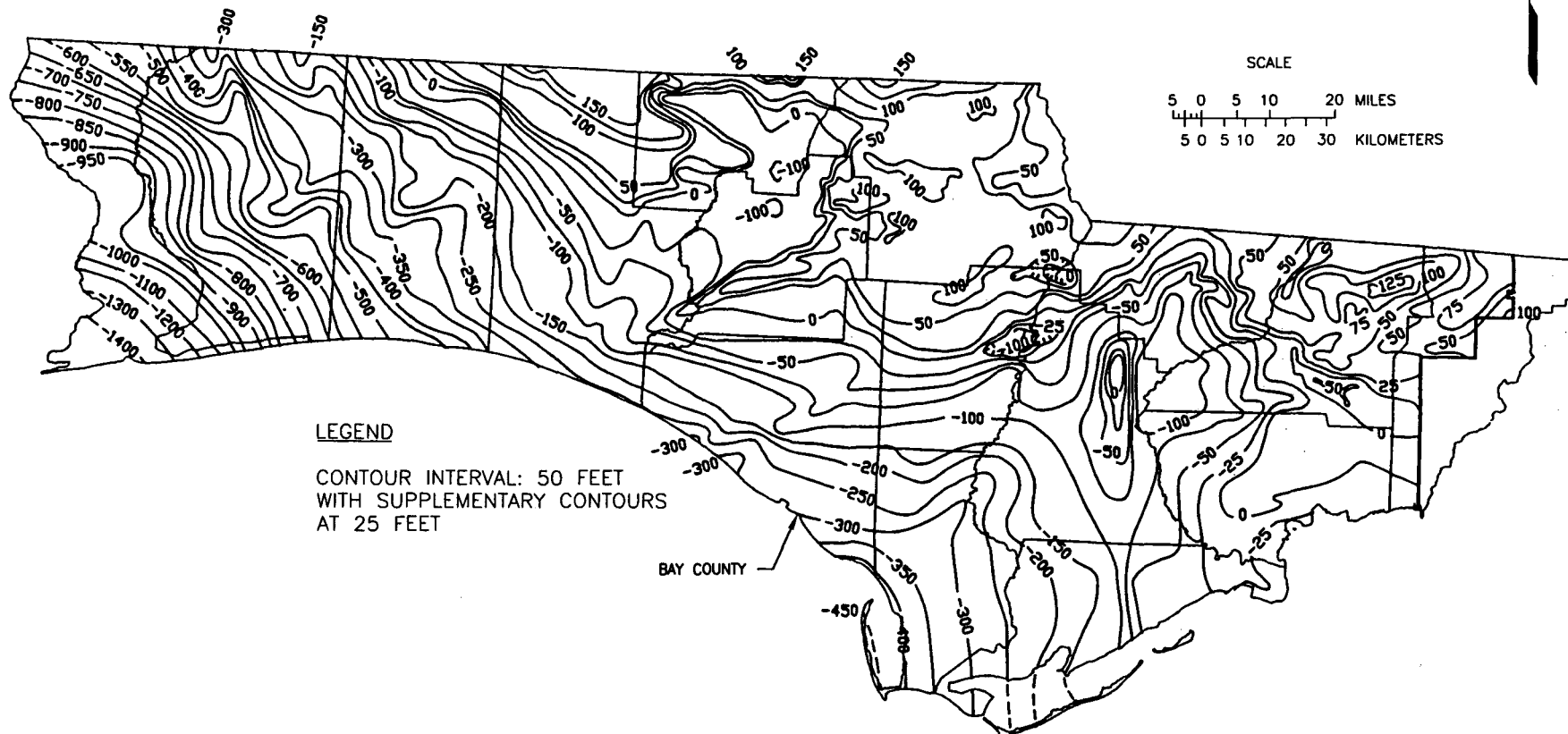


FIGURE 2.3.2-17.
ELEVATION OF THE TOP OF THE FLORIDAN AQUIFER

Sources: FGS, 1991; SCS, 1999; ECT, 1999.

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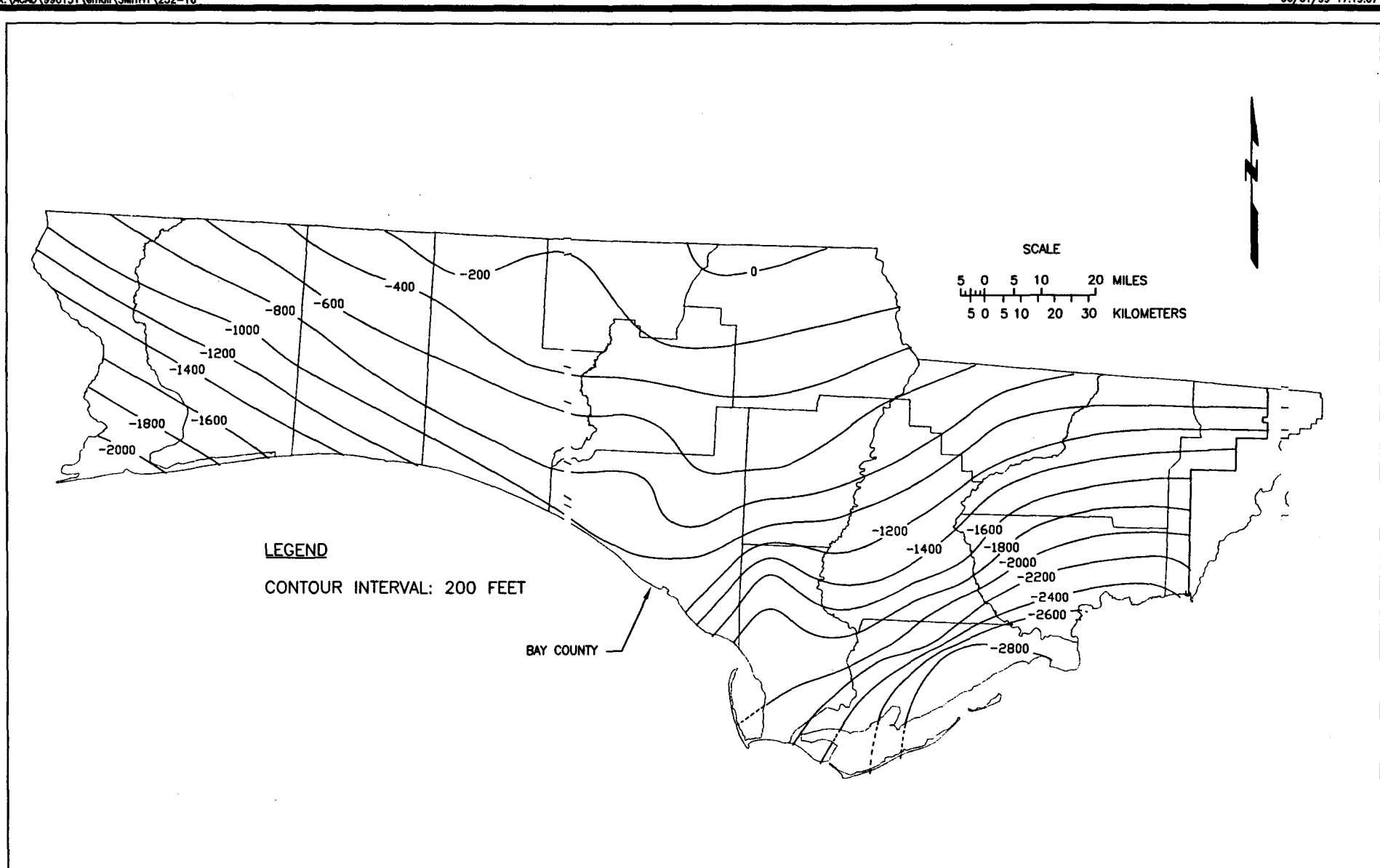


FIGURE 2.3.2-18.
ELEVATION OF THE BOTTOM OF THE FLORIDAN AQUIFER

Source: FGS, 1992.

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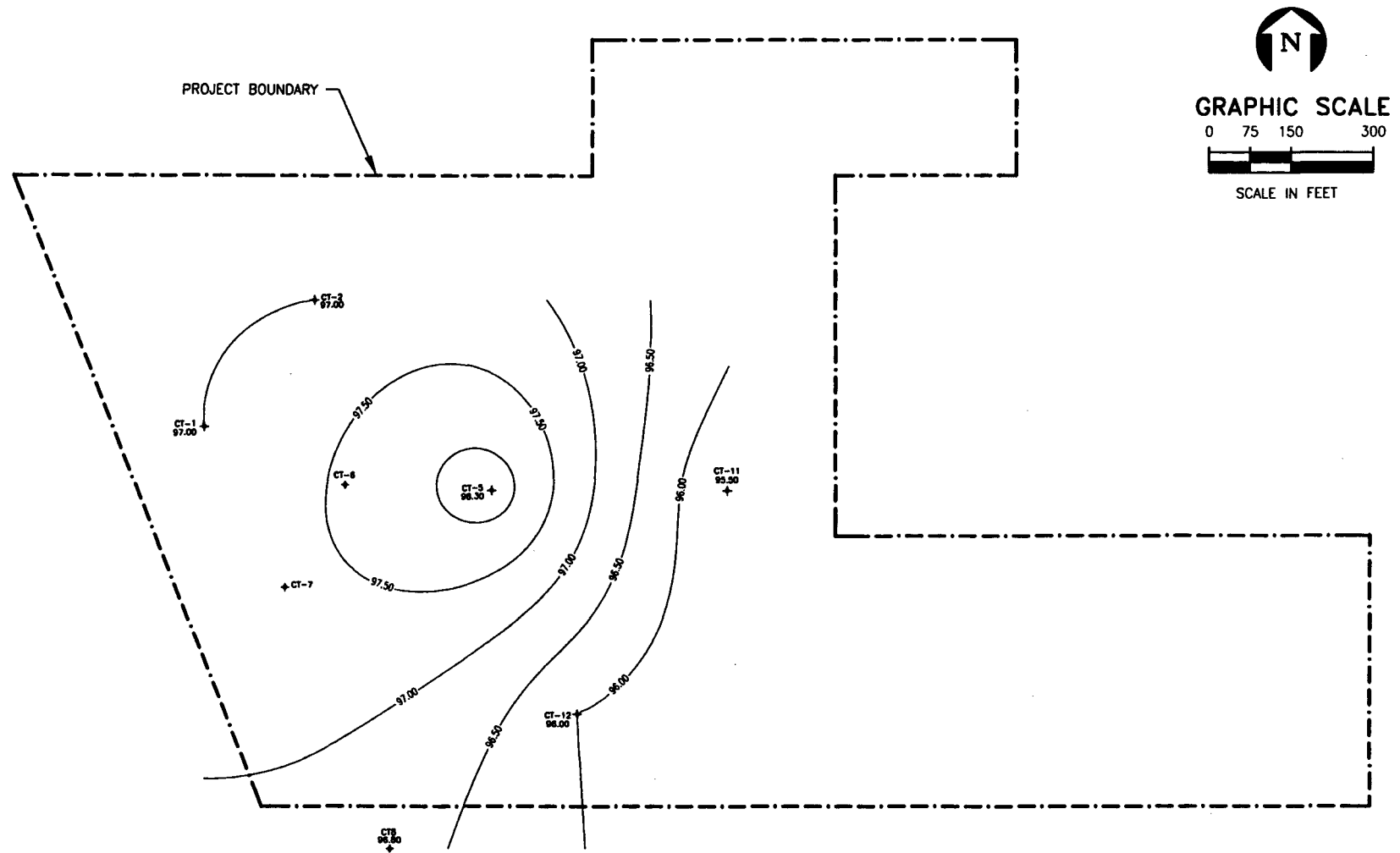


FIGURE 2.3.2-19.
ELEVATION OF THE TOP OF THE FLORIDAN AQUIFER IN PROJECT AREA

Source: SCS, 1999.

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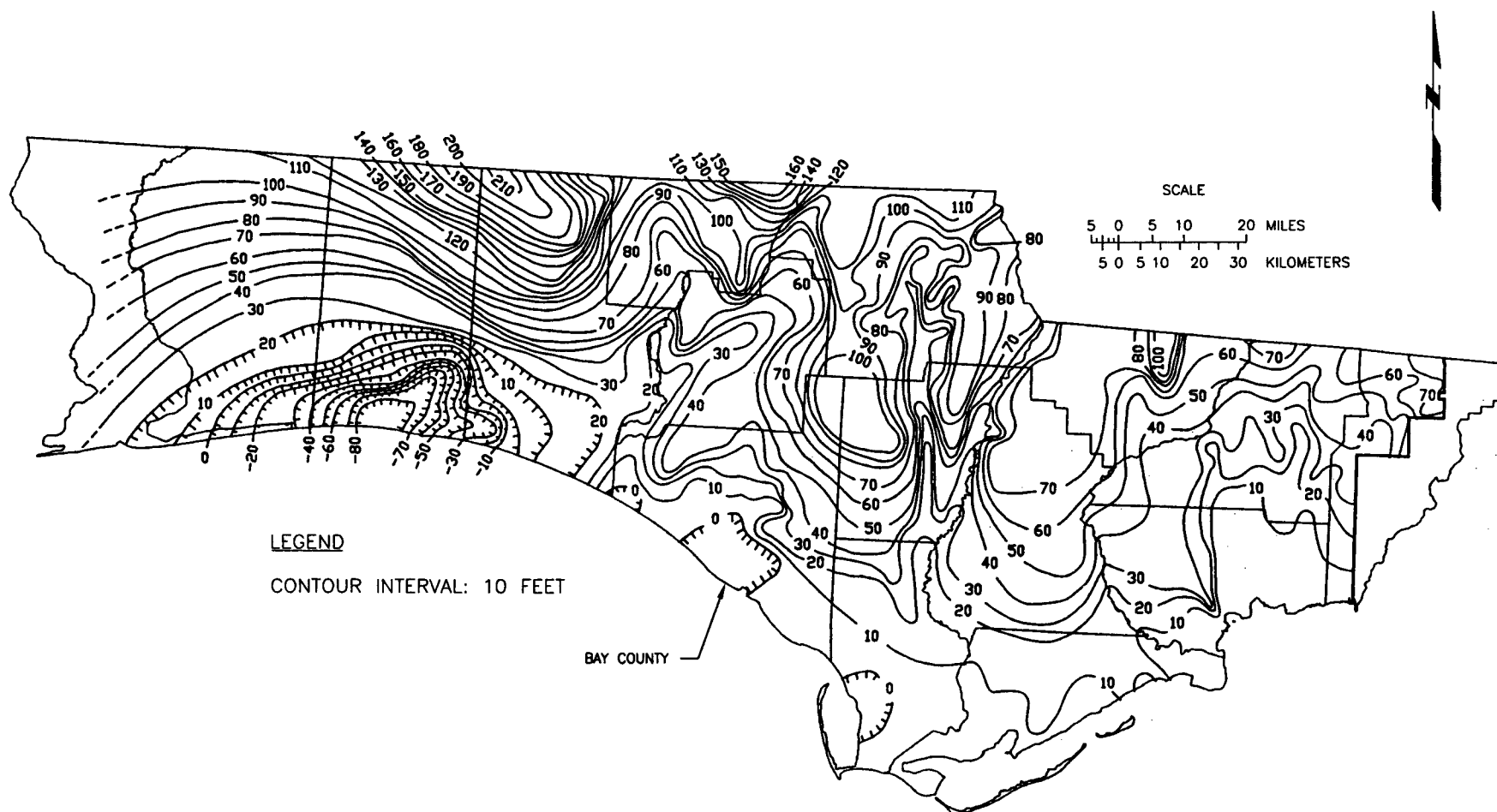


FIGURE 2.3.2-20.

POTENTIOMETRIC SURFACE OF THE FLORIDAN AQUIFER IN BAY AND SURROUNDING COUNTIES

Sources: FGS, 1991; SCS, 1999; ECT, 1999.

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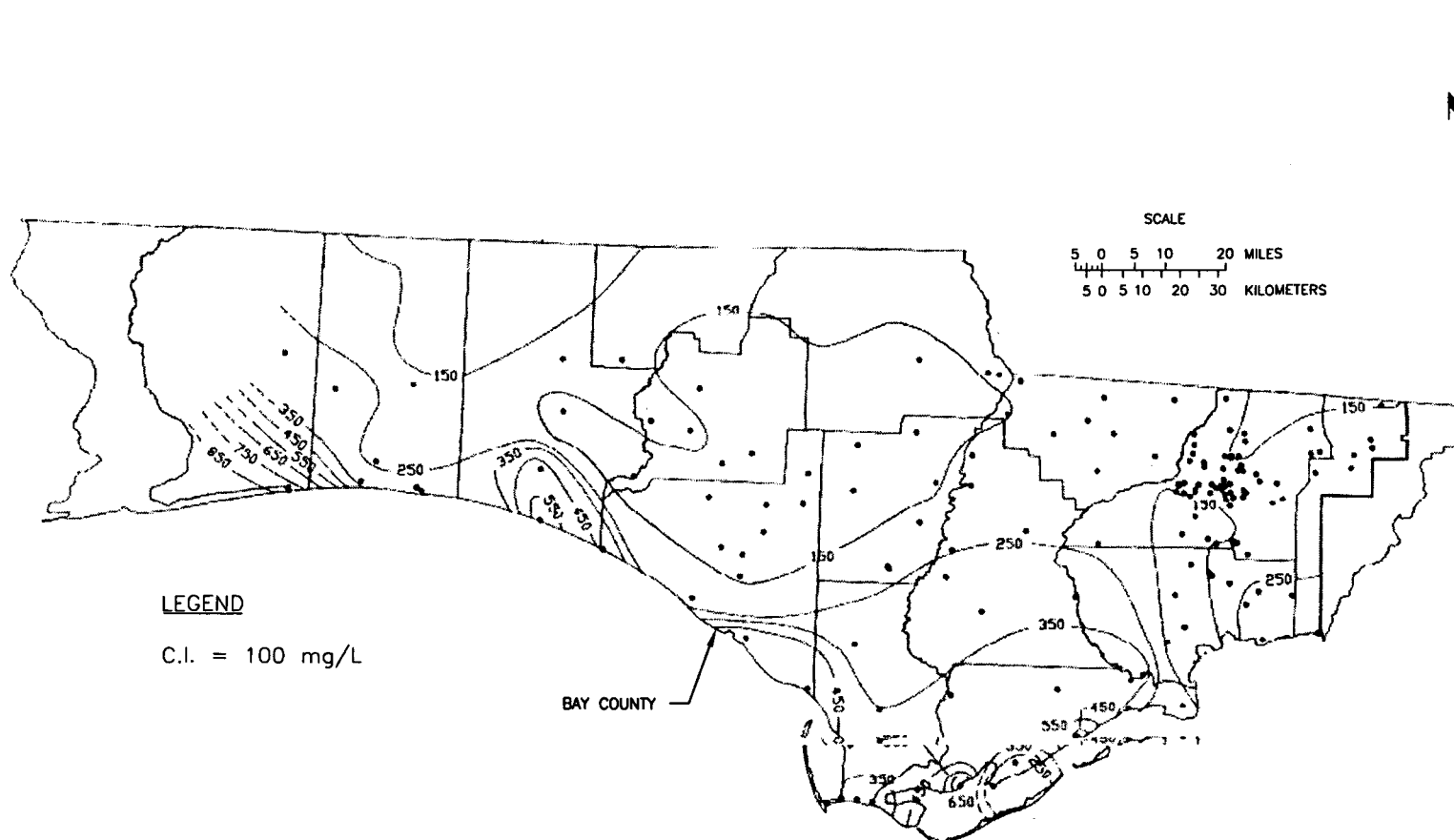


FIGURE 2.3.2-21.

DISTRIBUTION OF TOTAL DISSOLVED SOLIDS IN THE FLORIDAN AQUIFER

Sources: FGS, 1992; SCS, 1999; ECT, 1999.

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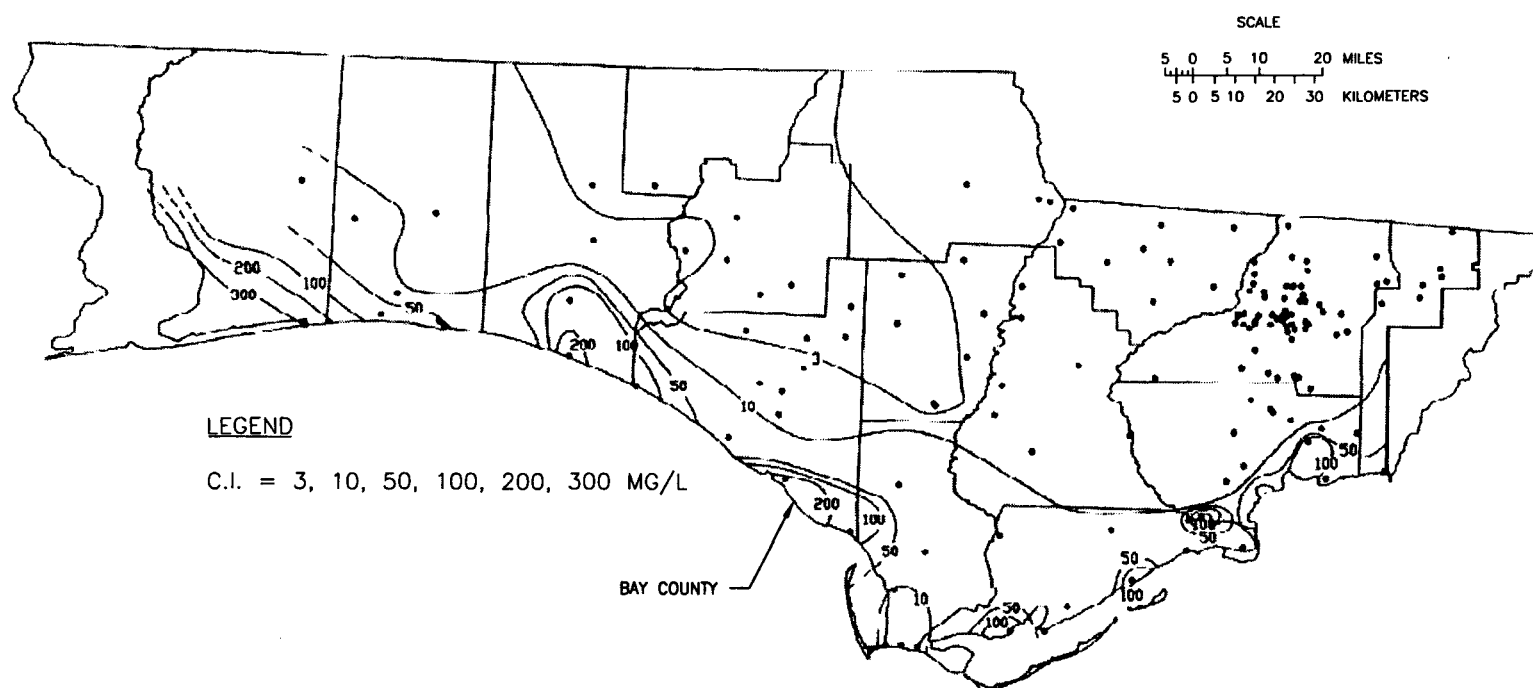


FIGURE 2.3.2-22.

DISTRIBUTION OF TOTAL CHLORIDE IN THE FLORIDAN AQUIFER

Sources: FGS, 1992; SCS, 1999; ECT, 1999.

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2.3.2.2 Karst Hydrogeology

Florida is underlain by carbonate units subject to dissolution by slightly acidic recharge from rainfall. Karst topography is the irregular surface that results from the solution cavities. Sinkholes are one of the most notable features of karst topography and are usually recognizable on topographic maps as circular features, often filled with water.

Figure 2.3.2-23, prepared by the NFWFMD, shows the areas of sinkhole development within the district. In the northern portion of Bay County within the Sand Hill Lakes area, karst topography is recognized by the lack of perennial or intermittent streams, and the presence of closed surface water drainage basins. The ground water within the surficial aquifer percolates through the intermediate system and recharges the Floridan aquifer. In the southern portion of the county, near the Project area, the limestone is deeply buried and sinkhole activity is extremely rare. Since sinkholes and collapse features are responses to water moving down into the limestone, they generally form in areas where the limestone aquifer is being recharged. The area around the Smith Unit 3 Project site is identified as an area of generally no recharge to the Floridan aquifer (Stewart, 1980).

The onsite investigation of the Project area found no evidence of sinkhole development. The probability of karst development is very low and unlikely to occur in the Project area.

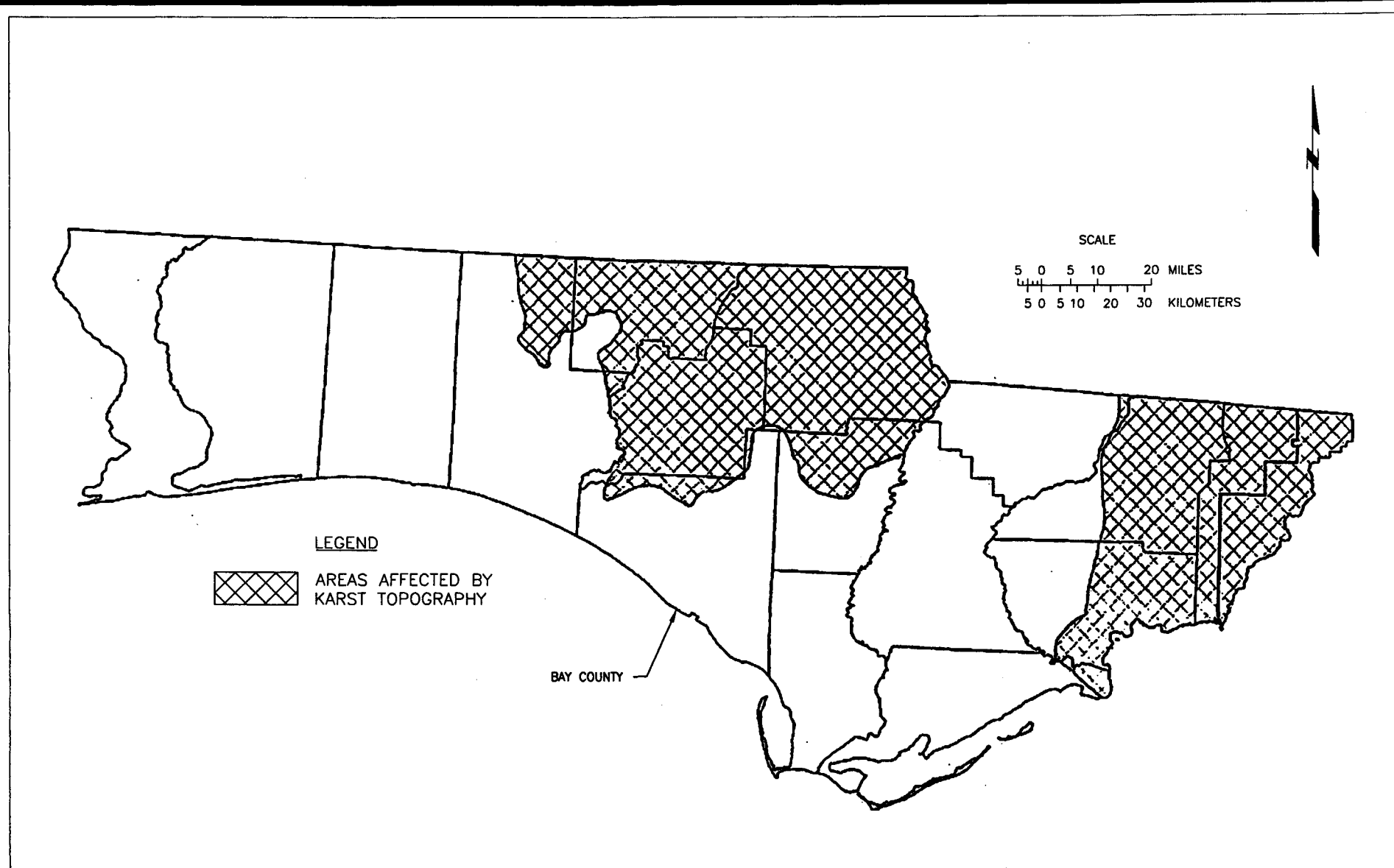


FIGURE 2.3.2-23.

AREAS OF KARST DEVELOPMENT IN THE NORTHWEST FLORIDA
WATER MANAGEMENT DISTRICT

Sources: FGS, 1991; SCS, 1999; ECT, 1999.

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2.3.3

2.3.3 SITE WATER BUDGET AND AREA USERS

2.3.3.1 Site Water Budget

The Project site is located in Northwest Florida near West Bay, near the city of Southport, north of Panama City. Most of the information in this section is taken from the NFWFMD *Water Resources Assessment 98-2* (1998), except as noted.

Precipitation

The weather conditions in the Project area are subtropical. Data on rainfall, including both monthly and yearly averages, were obtained for the Panama City rain gauging location. The monthly averages were calculated from the precipitation occurring from January 1931 to December 1997. These precipitation records were provided by the National Climatic Data Center (NCDC). The calculated monthly averages are shown in Table 2.3.3-1.

Table 2.3.3-1. Monthly Rainfall Averages in the Panama City Area

Month	Precipitation (inches)
January	4.47
February	4.41
March	5.63
April	4.1
May	3.14
June	5.28
July	8.53
August	8.08
September	5.85
October	3.26
November	3.91
December	4.33

Source: NCDC, 1999.

For the reported years of 1931 through 1997, the average yearly precipitation was calculated to be 61.52 inches of rain per year.

Average Monthly Temperature Information

From the temperature records of Panama City spanning the years of 1972 through 1997, the average monthly temperatures shown in Table 2.3.3-2 are recorded from the Southeast Regional Climate Center.

Table 2.3.3-2. Average Monthly Temperatures for the Panama City Area

Month	Temperature (°F)
January	51
February	54
March	60
April	66
May	73
June	79
July	81
August	81
September	77
October	68
November	60
December	53

Note: °F = degrees Fahrenheit.

Source: NCDC, 1999.

Estimated Yearly Evaporation

NCDC's Technical Report 33 (1982) indicates approximately 48 inches of lake evaporation occur yearly in the Panama City area.

Estimated Yearly Evapotranspiration

"The potential evapotranspiration can be estimated as being equal to the lake evaporation during the same period, since moisture is removed from leaves of plants by the same process as it is evaporated from water surfaces" (Roberson *et al.*, 1995). Therefore, the estimated evapotranspiration for the Panama City Area would be approximately 48 inches per year.

Estimated Yearly Runoff

From the 61.52 average inches per year of rain, the bay's drainage basin of 1,036 square miles, and a runoff coefficient of 0.3 (Roberson *et al.*, 1995), the rational equation was used to determine the average yearly runoff of 1,408 cubic feet per second (cfs).

Estimated Peak Runoff

From the *Rainfall Frequency Atlas of the United States for Durations from 30 Minutes to 24 Hours and Return Periods from 1 to 100 Years*, or Technical Paper 40 (TP40) published by Soil Conservation Service (1961) the 1-hour, 100-year average extreme precipitation amount was given as 4.3 inches an hour. Using the 100-year flood figure, the area of the bay's drainage basin (1,036 square miles), and a runoff coefficient of 0.3 (Roberson *et al.*, 1995), the rational equation was used to determine the peak runoff as being 862,449 cfs.

Estimated Yearly Ground Water Recharge

Hydrologic inputs to the surficial aquifer system include infiltration from precipitation, irrigation application of water from the Upper Floridan aquifer, streamflow, and upward leakage from the Upper Floridan aquifer. The entire area is essentially a recharge area for the surficial aquifer. Outputs from the surficial aquifer system include evapotranspiration, streamflow, pumping/withdrawals, and downward discharge to the Upper Floridan aquifer in areas being pumped. Based on slug testing and pump testing in the area, lateral movement of ground water in and out of the basin is slight due to small gradients and low permeability.

Within the basin, recharge and discharge patterns for the surficial aquifer system are related to the hydrogeologic conditions of the Upper Floridan aquifer. In many areas, the surficial aquifer system serves to store water temporarily for later percolation to the Upper Floridan aquifer. This recharge function of the surficial aquifer system to the Upper Floridan aquifer is important because most of the water that is withdrawn from the Upper Floridan aquifer, as well as natural discharge, originated as locally derived recharge.

In areas where the potentiometric surface of the Upper Floridan aquifer is above the water table, a discharge condition exists for the Upper Floridan aquifer, and the water is discharged to the surficial aquifer system. However, where this condition exists, there also could be recharge to the surficial aquifer system due to precipitation if the surficial sediments have an unsaturated zone that is sufficiently thick to accommodate this infiltration. Therefore, in these areas the surficial aquifer system can receive recharge from above and below.

Surface drainage also affects the extent to which precipitation may become recharge. Where the definition of surface drainage is low, more water is available from gross precipitation to become recharge to the surficial aquifer system. Conversely, where stream systems are well defined, more precipitation is lost to runoff and less is available to recharge the aquifer.

Areas along the northern boundary of Bay County are recharge areas for both the surficial aquifer system and the Floridan aquifer. Recharge rates to the surficial aquifer system are high, and most of the water that enters the surficial aquifer system moves downward relatively quickly to recharge the Upper Floridan aquifer. Based on the information from *Florida's Ground Water Quality Monitoring Program Background Hydrogeologic Framework* (FGS, 1991), the area surrounding and including the existing Smith site and the Project area has generally no recharge to the Floridan aquifer system.

2.3.3.2 Area Uses

Historically, the Floridan and intermediate aquifer systems have supplied a large portion of public and industrial water supplies in Panama City. However, over time the steady growth of the area and increased pumping resulted in the depression of the potentiometric surface of the Floridan aquifer around Panama City. With the added threat of salt water intrusion in the area, an alternate source of fresh water was created. Deer Point Lake was completed in 1961 and now supplies two-thirds of the fresh water used in Bay County.

Most of the consumption is commercial self-supply use and public supply. In 1995, the total average water use in Bay County was 55 million gallons per day (MGD) of which

public supply accounted for approximately 40 percent. Ground water, which supplies about one-quarter of all water used in the Bay County region, is withdrawn primarily for public supply, domestic self-supply, small public systems and recreational irrigation. Table 2.3.3-3 presents the 1995 water use and the projected uses for the year 2000 and 2020.

Table 2.3.3-3. County Water Use and Demand Data

Consumer	1995 (MGD)	2000 (MGD)	2020 (MGD)
Public supply	24.32	24.20	36.86
Domestic self supply and small public supply	2.24	1.77	4.33
Commercial-industrial	27.69	27.69	27.69
Recreational irrigation	1.90	1.99	2.53
Agricultural irrigation	0.00	0.00	0.00
Power generation	0.41	0.67	0.67
Total	56.56	59.06	72.08

Source: NFWWMD, 1998.

Domestic supply and small public supply systems account for approximately 4 percent of the total average water use in 1995. The commercial-industrial category accounts for approximately 52 percent. The Deer Point Lake Reservoir is the source of the majority of this water which is consumed mostly by Stone Container Corporation, Arizona Chemical Division of International Paper, and Tyndall Air Force Base. Recreation and irrigation use very small percentages of the total average water use. Golf courses were the major recreational users and agricultural irrigation is minimal, less than 1 MGD in 1995. Water consumed by Gulf for the Lansing Smith Electric Generating Plant is mostly used for once-through cooling and returned to West Bay.

The projected increase in water use from 1995 to 2020 is 15.5 MGD. The majority of the increase is expected from public supply. Currently, Panama City Beach gets approximately 3.5 MGD, or about one-third of its average daily demand, from the Floridan aquifer. It is assumed that by 2020, 90 percent of the freshwater demand will be met by surface water.

Major Water Sources

Deer Point Lake was created by constructing a low-head causeway dam across North Bay. The reservoir has approximately 285 miles of shoreline, 4,698 surface acres and a total drainage area of 442 square miles. Deer Point Lake has four principal tributaries: Econfina, Bear, Bayou George, and Big Cedar Creeks. Econfina Creek is the largest contributor of stream inflow under average flow conditions, contributing over 500 cfs. The Floridan aquifer discharges along the middle of Econfina Creek contributing to the large streamflow and base flow. Water quality of the ground and surface waters of the watershed are of high quality. Major surface waters within the Deer Point Lake drainage basin are designated as Class I waters based on their eventual use as public water supply.

The Floridan aquifer is the major ground water source in the Project area. The Floridan aquifer is thick but low recharge rates, low permeability, and proximity of salt water within and above the Floridan aquifer result in reduced ground water availability. A detailed discussion of hydrologic characteristics of the Floridan aquifer is included in Section 5.3.2.

Impacted Sources

The Smith Unit 3 Project will not impact the Deer Point Lake Reservoir. The water used at the plant is supplied by water wells installed at the plant. These wells are screened in the Floridan aquifer and Gulf has demonstrated in the ground water modeling report (Attachment 10.5-G of Appendix 10.5) that the withdrawal will not significantly affect the other users of the Floridan aquifer system.

Potable Water Wells Within 1 Mile of the Site

A water well inventory of public supply and private wells was conducted within a mile radius of the Project area. The survey included information obtained from Gulf files and data provided by the NFWMD Office.

Results from the survey indicate that there are no private or municipal wells within 1 mile of the Project area, most of which is within Gulf's plant property. Three water supply

wells, which are utilized for both drinking water and for production water supply, are located at the existing Plant site (Figure 2.3.3-1). The three wells were installed in 1961 and 1971 but one was redrilled in 1985. The plant's water supply wells are screened at depths approaching 150 ft or greater. Details are presented in Table 2.3.3-4.

Table 2.3.3-4. Existing Gulf Water Supply Well Details

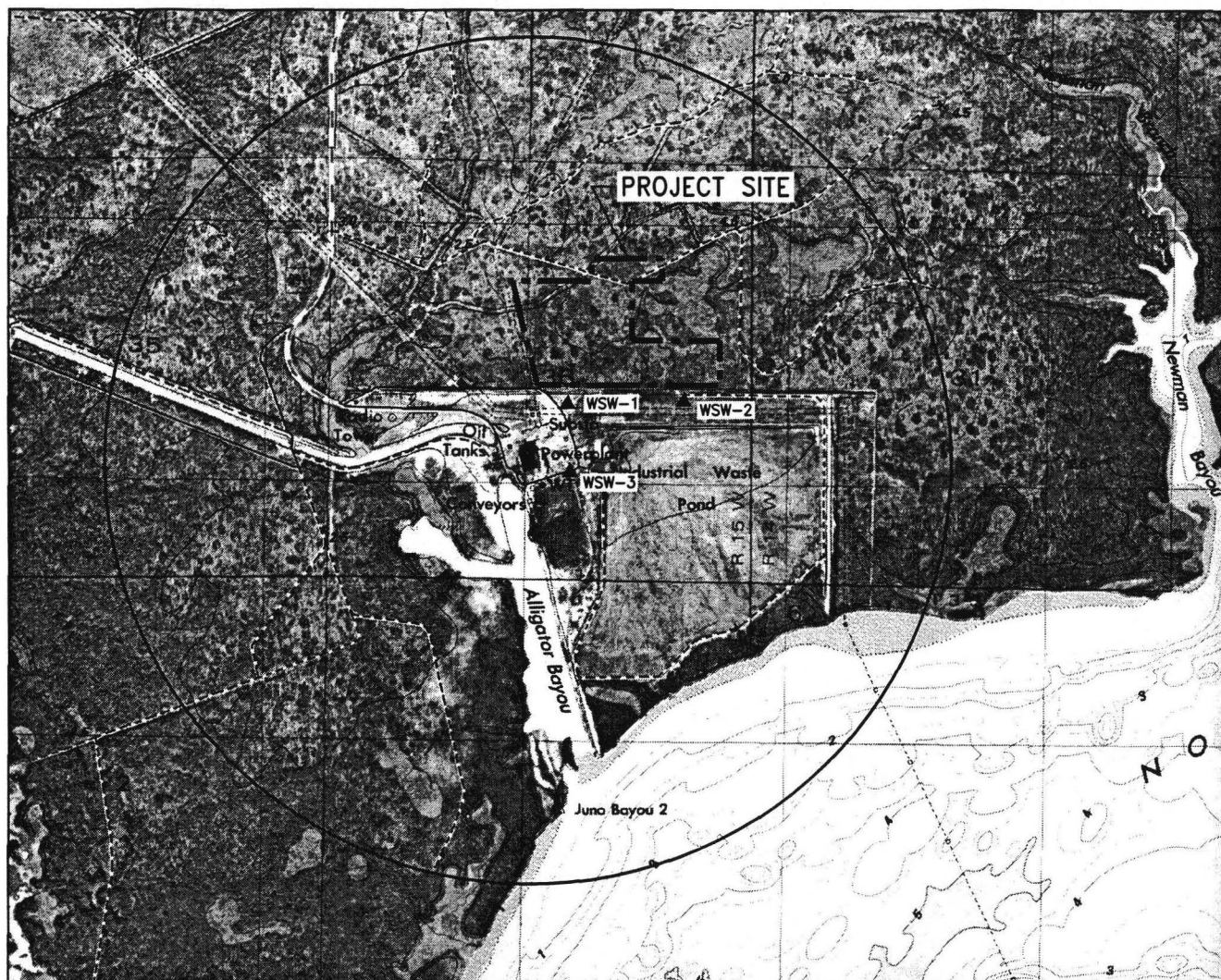
Well Number*	Installation Date	Depth (ft)	Diameter (inches)	Screened (open) Interval
WSW1	06/23/61	370	18	148—370
WSW2	07/18/61	307	18	95—307
WSW3	10/18/85	400	14	150—400

*WSW4 is scheduled to be installed later this year.

Source: Gulf Power Company, 1999.

IMAGE QUALITY

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PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



LEGEND

▲ APPROX. WATER WELL LOCATION

1000 0 1000 2000 3000 4000 5000 FEET

FIGURE 2.3.3-1.

WATER WELL INVENTORY WITHIN 1 MILE OF
THE PROJECT AREA

Sources: USGS, 1992; SCS, 1999; ECT, 1999.

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2.3.4

2.3.4 SURFICIAL HYDROLOGY

2.3.4.1 Fresh Water Environment

The site is located on the northern end of a peninsula between North and West Bays of St. Andrew Bay in Panama City, Florida. Four hydrologic subbasins surround the proposed site as shown in Figure 2.3.4-1. Surface water runoff generally flows from the northeast to southwest, discharging to the existing cooling water outflow canal of the existing power plant. Warren Bayou, which is located at the end of the outfall canal, has special seasonal harvest restrictions from the Marine Fisheries Commission, and is a Class II surface water.

Surface waters in the area of the site consist of depressional features typically less than 12 inches in depth. These Class III surface water wetlands slowly convey runoff to the outfall canal. Stream sizes are of small width (less than 20 ft) with ephemeral flow habits. The floodplains of the streams are wide (greater than 10 times the channel width), with no apparent levees. Stream channels are not incised and are non-alluvial in nature. Tree coverage is greater than 90 percent along the banks of the streams. Sinuosity of the channels is generally straight, aided by the ditching as part of the silvicultural activities. Slopes in the vicinity of the site are mild (less than 0.1 percent).

Flow rates for the subbasins are summarized in Table 2.3.4-1. Flows are generally low due to the mild slopes and significant depressional storage available at the site. .

2.3.4.2 Marine Environment

Gulf's existing Smith Plant uses water from North Bay of the St. Andrew Bay estuary system for its cooling water source and discharges into West Bay of the same estuary as shown in Figure 2.3.4-2. The proposed Smith Unit 3 Project will use the existing cooling system water as a cooling water source and discharge to the existing canal. Therefore, the baseline marine environment is described in this section.

The St. Andrew Bay estuarine system is located in northwest Florida and encompasses an area of approximately 243 square kilometers (km²) or 60,045 acres (SCS, 1998). Most of the bay's drainage basin is located in Bay County and totals approximately 2,683 km² or

IMAGE QUALITY

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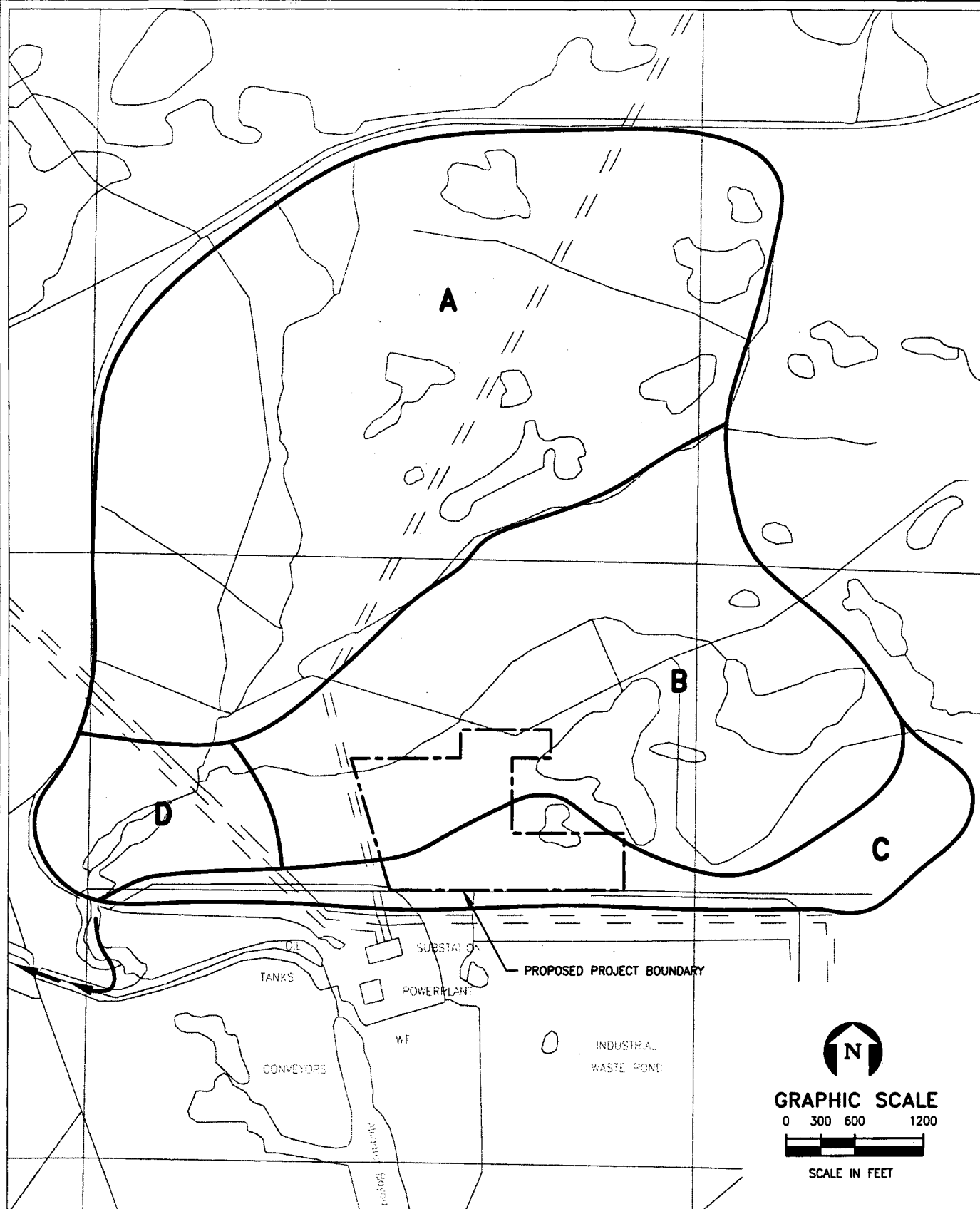


FIGURE 2.3.4-1.
HYDROLOGIC BASINS

Source: US Geodoto, 1997; ECT, 1999.

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Table 2.3.4-1. Summary of Hydrologic Conditions

Basin	Hydrologic Soil Group	CN	TC (min)	Area (acres)	Runoff (cfs)				
					1-year	5-year	10-year	25-year	100 year
A	D	77	700	507.8	55	112	142	173	234
B	D	77	463	300.1	45	92	117	142	193
C	D	77	277	91.5	21	42	54	65	88
D	D	77	163	4.7	19	38	48	59	80

Note: CN = basin average curve number.
TC = time of concentration.

Runoff estimations were calculated using the Soil Conservation Services's Unit Hydrograph Methodology. Rainfall estimates for the site were taken from Soil Conservation Service's (1961) TP-40 for the 24-hour duration. The results reflect the site conditions for relatively long times of concentration due to the flat slopes and rills established during silvicultural activities at the site.

Source: Soil Conservation Service, 1961.

IMAGE QUALITY

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FIGURE 2.3.4-2.
WEST BAY AND NORTH BAY OF ST. ANDREW
ESTUARY SHOWING THE PLANT LOCATION AND
INTAKE AND DISCHARGE CANALS

Source: SCS, 1998.

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1,036 square miles of flatwood forests, sinks and lakes, sand hills, and coastal beach sand dunes.

West Bay, which receives the existing once-through cooling water, covers an area of approximately 7,627 hectares (ha) (18,846 acres) or 31 percent of the total surface area of the St. Andrew Bay system. West Bay has a mean depth of approximately 2.1 meters (6.9 ft) and receives approximately 7 percent of the total basin stream flow from Crooked Creek and Burnt Mill Creek. Major bayous draining into West Bay include Harrison Bayou, Botheration Bayou, Doyle Bayou, Warren Bayou, and Johnson Bayou. West Bay is considered a positive estuary in that drainage inflow exceeds evaporation. This results in a net inflow of saline water along the bottom towards the head of the estuary and a net outflow of less dense (fresher) water along the surface toward the Gulf of Mexico. The heavier, more saline waters from St. Andrew Bay are driven into the lowest layers of West Bay creating strong vertical density gradients due to differences in salinity concentration. This phenomenon occurs in West Bay even though this bay does not directly receive large volumes of fresh water. However, fresh water that North Bay receives from Deer Point Lake tends to be directed into West Bay by strong tidal currents in St. Andrew Bay. This results in large vertical differences in salinity concentrations in West Bay waters (SCS, 1998).

The cooling water discharge from the Lansing Smith Plant travels approximately 3,200 meters (3,501 yards) from the plant in a manmade canal and discharges into Warren Bayou and ultimately into West Bay, as shown in Figure 2.3.4-2. West Bay has very little commercial or residential development along its shores. Salt marsh and low swampy areas form most of the bay shorelines. A major alteration of the shoreline has occurred on both sides of Warren Bayou where Marifarms, Inc., constructed extensive dikes to create large ponds during the 1970s for shrimp farming. After Marifarms, Inc., ceased operations, the dikes were breached during the mid-1980s to allow the former marsh to become re-established. Salt marsh, dominated principally by black needlerush (*Juncus roemerianus*) and smooth cordgrass (*Spartina alterniflora*), forms most of the bay shoreline. Seagrass beds comprised of turtle grass (*Thalassia testudinum*), shoal grass (*Halodule*

wrightii), and widgeon grass (*Ruppia sp.*) extend in the direction of the bay from shore-line mudflats to approximately the 2.0-meter (6.56 ft) depth contour (SCS, 1998).

Tides in West Bay are predominantly diurnal (i.e., one high and one low water level per day). The average difference in height between mean high water and mean low water is approximately 0.5 meter. Mean tide level is approximately 0.2 meter (0.66 ft) above mean sea level (msl) of 0.0 meter. Extreme low water occurs at approximately -0.6 meter (1.97 ft) msl. Daily tide cycles for West Bay are predicted from the Pensacola, Florida, tidal reference station for a subordinate tidal station located near the mouth of West Bay Creek (Intercoastal Waterway). High water levels in West Bay occur 18 minutes after high water levels at Pensacola and are slightly higher (<0.1 meter, or 0.33 ft). Low water levels in West Bay occur approximately 83 minutes later than in Pensacola. Low water level height predictions for West Bay are lower (<0.1 meter, or 0.33 ft) than in Pensacola (SCS, 1998).

West Bay has several distinct hydrological zones that are defined by tidal fluctuations. The salt marsh that lies along most of the shoreline is inundated at high tide and partially or wholly exposed during low tide periods. The marsh acts as a natural filter for the fresh water inputs flowing through them. Biologically, they provide food and habitat for marine organisms, and they are important nursery areas for a variety of fin and shellfish. The mud flats lying along the shore are a transition zone between marsh and marine pelagic ecosystems. Silt, plant, and animal detritus tend to settle out in this zone leaving an organic, anaerobic layer. The mud flats are normally exposed during low tides, and water depths at high tide vary between 0.2 to 0.5 meter (0.66 to 1.64 ft). The 0.3 to 0.9-meter (0.98 to 2.95 ft) depth contour area extending seaward from the mudflats consists of the intertidal zone (frequently exposed at low tide) and the infratidal zone (exposed at extreme low tides). In some areas of the bay, this zone may extend up to 1,234 meters (1,350 yards) from shore. In the area around Warren Bayou, the surface area between the 0.3 and 0.9-meter (0.98 and 2.95 ft) depth contour is the most extensive shallow water zone. At extreme low water (-0.6 meter, or 1.97 ft below msl) most of this area can be left exposed, but during normal low tides, the depth contour area greater than 0.3 meter (0.98 ft) is always covered with water. The 1.2- to 1.8-meter depth contour marks the be-

ginning of the pelagic or open water zone. This zone is always covered with water. The 1.8-meter depth contour line is the transition zone between the shallow water and deeper bay water. The deep-water zones include the 2.1- to 3.7-meter (6.89 to 12.14 ft) depth contour, 4- to 5.5-meter (13.12 to 18.05 ft) depth contour, and greater than 5.8-meter (19.02 ft) depth contour (SCS, 1998).

North Bay (Figure 2.3.4-2), the source of the Lansing Smith Plant's cooling water, covers an area of approximately 3,569 ha (8,819 acres) or 15 percent of the total surface area of the St. Andrew Bay system. Average depth of the bay is approximately 3 meters (9.8 ft) at 0.0 msl tide. Deer Point Lake, to the northeast of the plant, is the major fresh water input into North Bay. Bear Creek and Econfinia Creek are the major tributaries to Deer Point Lake. These two streams contribute approximately 60 percent of the total basin stream flow to the St. Andrew Bay system.

Tidal characteristics in North Bay are similar to those of West Bay. Mean tide level (0.2 meter, or 0.66 ft) diurnal range in tide level (0.5 meter, or 1.64 ft), and extreme low water (-0.6 meter, or 1.97 ft-msl) are the same in North Bay as in West Bay.

The phase of the tide for North Bay differs from West Bay and is predicted from the Pensacola, Florida, tidal reference station to the Lynn Haven subordinate station. High water level in North Bay occurs approximately 6 minutes earlier than in Pensacola and 24 minutes earlier than in West Bay. Low water level in North Bay occurs approximately 20 minutes later than in Pensacola and 63 minutes earlier than in West Bay. Water level height predictions for North Bay and West Bay are similar—that is, high water level predictions are higher (<0.1 meter, or 0.33 ft) and low water level predictions are lower (<0.1 meter, or 0.33 ft) than in Pensacola (SCS, 1998).

Several water quality studies have been completed on West Bay and North Bay, beginning in the early 1970s, and have continued to the present day. SCS (1998) summarized much of this water quality data that was available in STORET. The results for data from 1972 through 1991 for the following three locations are provided in Table 2.3.4-2:

(1) West Bay entrance (confluence with) to Warren Bayou; (2) West Bay N Breakfast Point—Buoy C5; and (3) North Bay—Flasher 5.

Table 2.3.4-2. STORET Data from 1972 through 1991

Parameter	(1) West Bay	(2) West Bay	(3) North Bay
Temperature. (°C)	34.08	22.17	21.38
Dissolved oxygen (mg/L)	5.53	6.82	6.37
pH (units)	7.76	7.59	8.1
Conductivity (mmhos/cm)	32,167	37,533	41,600
Dissolved oxygen, sat. (%)	72.3	78.9	71.69
Chlorides (mg/L)	13,967	—	7,884.3
Turbidity (FTU)	3.0	4.7	2.0
Alkalinity (mg/L)	91	—	110.0
Total organic carbon (mg/L)	—	13.57	—
Total Nitrogen (mg/L)	0.46	0.12	0.250
Total Phosphorus (mg/L)	0.023	—	0.019
Aluminum (µg/L)	—	1,000.0	—
Cadmium (µg/L)	0.50	7.0	—
Chromium (µg/L)	25.0	100.0	—
Copper (µg/L)	25.0	20.0	—
Iron (µg/L)	90.0	140.0	—
Lead (µg/L)	9.7	17.0	—
Manganese (µg/L)	—	20.0	—
Mercury (µg/L)	0.20	0.43	—
Nickel (µg/L)	—	20.0	—
Zinc (µg/L)	10.0	—	—

Note: °C = degrees Celsius.
FTU = nephelometric turbidity unit.
mg/L = milligram per liter.
mmhos/cm = millimhos per centimeter.
µg/L = microgram per liter.

Source: SCS, 1998.

2.3.5 VEGETATION/LAND USE

The land use/vegetation types present at the Smith Unit 3 Project site were characterized during site visits on March 8 and 9, April 7 through 9, and May 17-18, 1999. There are no natural water bodies or waterways on the Project site. The only water bodies on the Project site are manmade ditches that either occur along the edges of the internal roadways or that form connections to the natural drainage features. Since these water bodies are artificially created systems, no aquatic baseline studies were performed onsite. Impacts to these drainages are assessed in subsequent sections of this SCA; therefore, the analyses focused on the terrestrial ecological resources on the site. During these ecological surveys, vegetation and land uses were inspected and described qualitatively.

The majority of the site consists of pine plantation and cypress-titi swamp. The existing land use and vegetation types occurring on the site are shown in Figure 2.3.5-1. Figure 2.3.5-2 depicts land use and vegetative cover types within a 5-mile radius of the site.

The currently developed portions of the site (unpaved road) comprise about 1.3 acres or 2.6 percent of the site; vegetated portions, including a transmission line corridor, cover 48.8 acres or 97.4 percent of the site. Approximately 26.5 acres (52.9 percent) support wetland communities: 10.2 acres of cypress-titi swamp, 15.4 acres of wet pine plantation, 0.4 acre of ditch, and 0.5 acre of marsh. The marsh and 0.1-acre of ditch are situated underneath the existing transmission line right-of-way.

Table 2.3.5-1 is a list of the land use/vegetation types present on the site classified according to Levels II and III as per the Florida Land Use, Cover, and Forms Classification System (FLUCFCS).

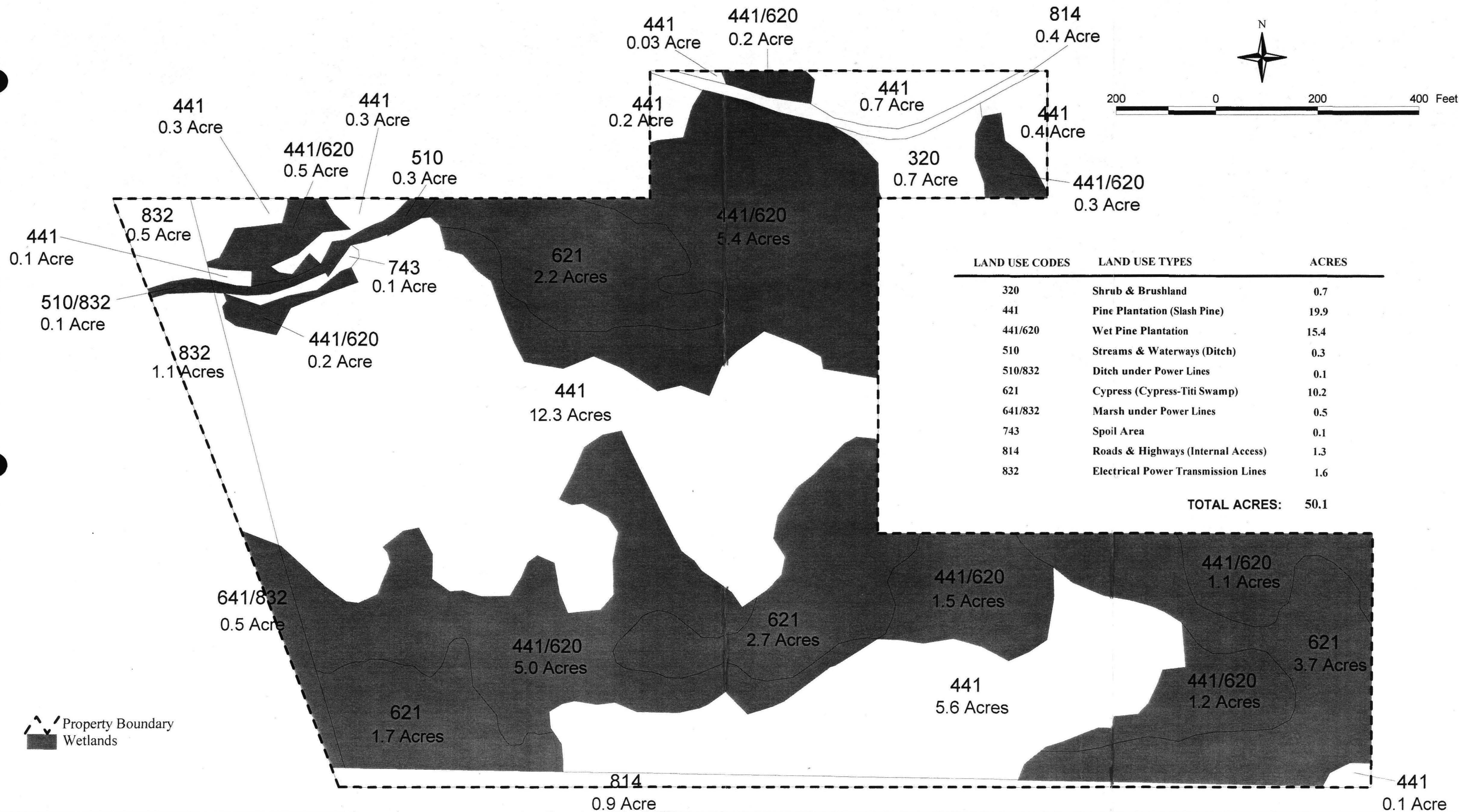
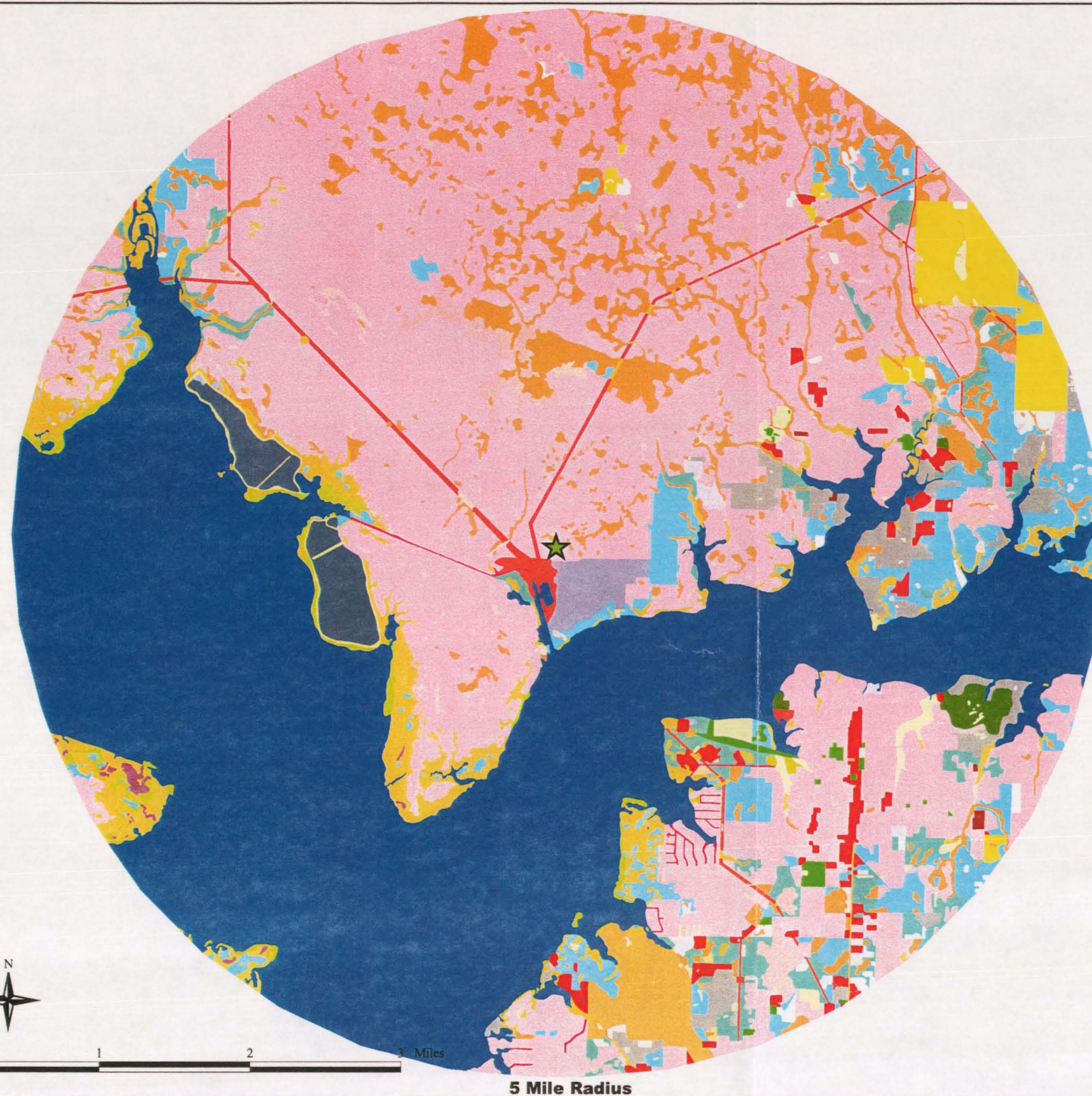


FIGURE 2.3.5-1.
 LAND COVER/VEGETATION MAP
 Source: ECT, 1999.



- LEGEND**
- ★ Site Location
- Land Use/Land Cover
- 110 Residential, Low Density
 - 120 Residential, Medium Density
 - 130 Residential, High Density
 - 140 Commercial and Services
 - 150 Industrial
 - 160 Extractive
 - 170 Institutional
 - 180 Recreational
 - 190 Open Land
 - 210 Cropland and Pastureland
 - 250 Specialty Farms
 - 320 Shrub and Brushland
 - 410 Upland Coniferous Forest
 - 430 Upland Hardwood Forest
 - 440 Tree Plantations
 - 510 Streams and Waterways
 - 520 Lakes
 - 530 Reservoirs
 - 540 Bays and Estuaries
 - 610 Wetland Hardwood Forest
 - 620 Wetland Coniferous Forest
 - 630 Wetland Forest Mixed
 - 640 Vegetated Non-Forested Wetlands
 - 650 Non-Vegetated Wetlands
 - 690 Wetland Scrub Shrub
 - 710 Beaches
 - 720 Sand Other Than Beaches
 - 740 Disturbed Land
 - 810 Transportation
 - 820 Communications
 - 830 Utilities
 - 840 Solid Waste Disposal

FIGURE 2.3.5-2.

LAND USE/VEGETATION TYPES WITHIN A 5-MILE RADIUS OF THE SMITH UNIT 3 PLANT SITE

Sources: FDEP, 1999 ; ECT, 1999.

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Table 2.3.5-1. Land Cover Types Present on the Smith Unit 3 Site

FLUCFCS Land Use Code	Land Use Type	Aerial Coverage (acres)
320	Shrub and brushland	0.7
441	Pine plantation (slash pine)	19.9
441/620	Wet pine plantation	15.4
510	Streams and waterways (ditch)	0.3
510/832	Ditch under power lines	0.1
621	Cypress (cypress-titi)	10.2
641/832	Marsh under power lines	0.5
743	Spoil areas	0.1
814	Roads and highways (internal access)	1.3
832	Electrical power transmission lines	1.6
TOTAL		50.1

Source: ECT, 1999.

2.3.6 ECOLOGY

2.3.6.1 Species-Environmental Relationships

Aquatic Systems (Fresh Water)

No natural fresh water streams, rivers, or lakes exist on the site of the proposed Project; therefore, no fresh water aquatic systems are described.

Aquatic Systems (Marine)

Several major studies describing the aquatic ecology of North Bay and West Bay have been completed at Gulf's facility that include the 316(b) study (Law Engineering Testing Company, 1977); *A Thermal Plume Characterization and Environmental Assessment: Warren Bayou and West Bay, St. Andrew Bay* (Law Environmental, Inc., 1993); and *Plant Lansing Smith Environmental Monitoring Program* (SCS, 1998). In addition, several earlier studies were completed by the Florida Game and Fresh Water Fish Commission (FGFWFC) that described the general aquatic community.

The general region that encompasses the intake and discharge canals is bounded by deltas, which support an extensive salt marsh. Feeder bayous are sluggish, slow-moving streams with currents noticeable only at high tide. To the south, salt marsh dominated principally by black needlerush, and smooth cordgrass form most of the bays' shorelines (SCS, 1998).

Early fishery studies in the mid to late 1950s conducted on the North Bay area in the vicinity of what is now Deer Point Lake, provided descriptions of fish populations of the study area. Gill nets, rotenone, explosives, and an otter trawl were used in sampling the fish populations of North Bay and its tributaries. As expected, marine fishes were found to predominate in the waters of high salinity. The principal commercial marine species in order of decreasing numerical abundance were mullet, pinfish, sea catfish, speckled trout, silver perch, and redfish. FGFWFC also reported that these relative amounts are expected to fluctuate during the year. At spawning time, mullet and redfish move into open Gulf waters, while speckled trout move into the inner bays. Pinfish probably move into open deep waters to spawn. Some of the less abundant species, such as the naked and large-

mouth gobies and hogchokers are believed to spawn in water of low salinity under certain conditions (SCS, 1998).

In the mid-1970s, the distribution of sea grasses, benthic macroinvertebrates, and fishes was studied by Law Engineering in detail within the study area. SCUBA procedures were used to map the location and extent of sea grass zones and to collect quantitative samples of macrophytes. Quantitative samples were taken in each sea grass zone, along each transect with an Ekman dredge. In addition, qualitative and limited quantitative sampling of fishes was performed along each transect. Warren Bayou was found to be essentially devoid of grasses, but so was an unaffected area in Johnson Bayou. Benthos productivity was reported to be highest "immediately adjacent" to the thermal discharge (confluence of Warren Bayou with West Bay). Some of the more abundant fish species collected in West Bay were the bay anchovy and spotted sea trout (SCS, 1998).

Many of the surveys conducted in the mid-1970s were repeated by Law Environmental, Inc. (1993). They conducted extensive benthic macroinvertebrate and sea grass surveys to help document potential thermal impacts from the Lansing Smith facility thermal plume. They developed a sea grass map of the area as shown in Figure 2.3.6-1, and compared the results to a similar study completed in 1975 (Law Engineering Testing Company, 1977). They concluded that (although there is considerable seasonal variation) the estimates of sea grass biomass were greater in 1992 than reported in 1975. The greatest sea grass biomass occurred at stations within the influence of the thermal plume; however, no sea grass was observed in the discharge canal and the immediate discharge area into Warren Bayou.

The results of the benthic macroinvertebrate study from 1991 and 1992 (Law Environmental, Inc., 1993) stated that 238 taxa comprised of 104,568 individuals were enumerated during the program. Collections from sample stations located within the thermal influence of the Lansing Smith Plant's heated discharge yielded 199 taxa comprised of 46,880 organisms (156 sample replicates), compared to 202 taxa comprised of 57,688 benthic macroinvertebrates (132 sample replicates) collected from control areas.

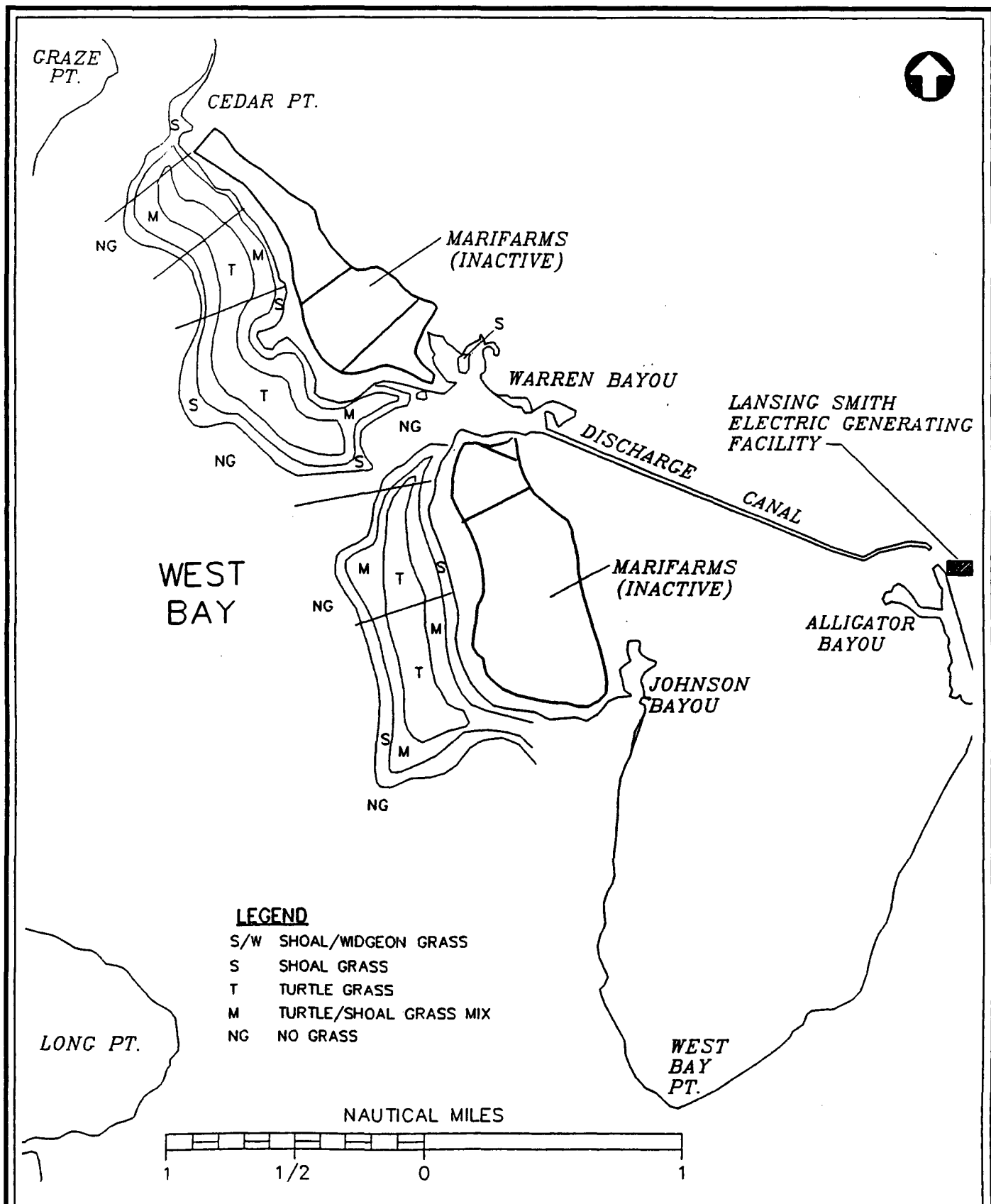


FIGURE 2.3.6-1.

SEA GRASS DISTRIBUTION

Source: Law Environmental, Inc., 1993.

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The results exhibited some seasonality with the number of taxa, number of individuals, and organisms the lowest for all sample stations during August 1991. Sample stations located closest to the discharge canal had fewer benthic macroinvertebrates compared to other stations within the area of thermal influence and compared to control stations. Benthic macroinvertebrate population parameters improved by November 1991 and remained largely unchanged in February and May 1992.

The study also reported that the Shannon-Weaver Diversity values for individual sample stations and grouped stations were lowest during August 1991, with November 1991 values slightly higher. The sample located in the direct thermal discharge had the lowest Shannon-Weaver Diversity value (0.92) of the study during August 1991. This value had improved by 137 percent by November 1991 and remained constant through May 1992. Similar low species diversity was reported for this sample station by Law (1982).

The benthic macroinvertebrate communities within the area of thermal influence were compared to communities in background (control) areas. The Shannon-Weaver Diversity values were at least 95 percent of control areas during all seasons studied. This value exceeded the FDEP biological integrity criterion of 75 percent of established background levels.

In addition to the extensive aquatic impact assessment conducted in 1991 and 1992, Gulf initiated an annual monitoring program in 1993. Field studies focused on pertinent physical, chemical, and biological characteristics during the warmest season of the year to coincide with periods of maximum power plant generation and maximum thermal stress. Three control stations and three stations within the thermal plume region were established and monitored. A total of 305 species of benthic macroinvertebrates was identified (SCS, 1998), of which 220 were classified as salt water tolerant.

Most of the previous work in the study area focused on sea grasses and macroinvertebrates to help assess potential impacts of the thermal plume. Consequently, most of the aquatic ecology information available refers to these two components of the aquatic system. The area is also an important recreational fishing area, and the thermal plume tends

to concentrate fish in the area during the cooler months. Also, parts of the area are classified as Class II waters designed to support shellfish propagation and harvesting, although no major shellfish beds were observed within the direct influence of the thermal discharge. There was no mention in any of the literature reviewed of any threatened or endangered aquatic species within the influence of the thermal plume. However, listed aquatic species that exist in the general region include those listed in Table 2.3.6-1.

Table 2.3.6-1. Marine/Aquatic Species Likely to Occur in the Project Vicinity (Discharge Outfall)

Common Name/ Scientific Name	Status*		Likelihood of Occurrence
	USFWS	State	
Atlantic ridley turtle <i>Lepidochelys kemp</i>	E	E	Low
Atlantic loggerhead turtle <i>Caretta c. caretta</i>	T	T	Low
Atlantic sturgeon <i>Acipenser oxyrinchus</i>	—	SSC	Low
West Indian manatee <i>Trichechus manatus latirostris</i>	E	E	Low

*Status: USFWS = U.S. Fish and Wildlife Service.
State = Florida Game and Fresh Water Fish Commission.
E = endangered.
T = threatened.
SSC = Species of Special Concern.

Source: ECT, 1999.

Terrestrial Systems—Flora

The following descriptions of plant community/association types and land uses are based upon qualitative vegetation field surveys conducted in March, April, and May 1999. A plant species inventory of the site by plant community type is provided in Table 2.3.6-2. Taxonomy of plant species names follows the *Guide to Vascular Plants of Florida* (Wunderlin, 1998). A discussion of potential impacts to these habitat types resulting from power plant development is provided in Section 4.4.

Shrub and Brushland—320

Approximately 0.7 acre (1.4 percent) of the site contains shrub and brushland. The only area of the shrub and brushland vegetation type occurs at the northern portion of the site

Table 2.3.6-2. Plant Species Inventory by Plant Community Type

Scientific Name	Common Name	Plant Community Type*					
		441				510	743
		320	441/620	621	641/832	510/832	814
832							
<u>Trees</u>							
<i>Acer rubrum</i>	Red maple		X				
<i>Cliftonia monophylla</i>	Black titi		X	X			
<i>Cyrilla racemiflora</i>	Titi	X	X	X	X	X	X
<i>Ilex myrtifolia</i>	Myrtle-leaf holly		X	X			
<i>Juniperus silicicola</i>	Southern red cedar						X
<i>Magnolia grandiflora</i>	Southern magnolia	X					
<i>Magnolia virginiana</i>	Sweet bay	X	X	X	X		
<i>Nyssa sylvatica</i>	Swamp tupelo			X			
<i>Persea palustris</i>	Swamp bay		X				
<i>Pinus elliotii</i>	Slash pine	X	X	X			
<i>Quercus laurifolia</i>	Laurel oak		X				X
<i>Quercus nigra</i>	Water oak		X				
<i>Quercus virginiana</i>	Live oak	X					X
<i>Sapium sebiferum</i>	Popcorn tree						X
<i>Taxodium ascendens</i>	Pond cypress		X	X			
<u>Shrubs</u>							
<i>Callicarpa americana</i>	Beautyberry	X					
<i>Clethra alnifolia</i>	Sweet pepperbush			X		X	
<i>Hypericum fasciculatum</i>	Sandweed		X				
<i>Hypericum myrtifolium</i>	St. John's wort						X
<i>Ilex coriacea</i>	Large gallberry			X			
<i>Ilex glabra</i>	Gallberry	X	X		X		

Table 2.3.6-2. Plant Species Inventory by Plant Community Type (Continued, Page 2 of 5)

Scientific Name	Common Name	Plant Community Type*					
		441 320 832	441/620	621	641/832	510 510/832	743 814
<i>Lyonia ferruginea</i>	Staggerbush	X					
<i>Lyonia lucida</i>	Fetterbush	X	X	X			
<i>Lythrum alatum</i>	Losestrife					X	
<i>Myrica cerifera</i>	Wax myrtle	X	X	X			X
<i>Myrica heterophylla</i>	Northern bayberry			X			
<i>Rhus copallina</i>	Winged sumac	X					
<i>Serenoa repens</i>	Saw palmetto	X					X
<i>Stillingia aquatica</i>	Corkwood			X			
<i>Vaccinium corymbosum</i>	Highbush blueberry		X	X			
<i>Vaccinium stamineum</i>	Deerberry	X					
Herbs							
<i>Aletris lutea</i>	Yellow colic-root		X				
<i>Andropogon virginicus</i>	Broomsedge	X	X				X
<i>Aristida beyrichiana</i>	Wiregrass	X	X		X		X
<i>Aster eryngiifolius</i>	Thistleleaf aster	X	X				
<i>Calopogon pallidus</i>	Pale grasspink	X					
<i>Carex glaucescens</i>	Sedge		X				
<i>Crotalaria lanceolata</i>	Rattle-box	X					
<i>Dichanthelium erectifolium</i>	Dichanthelium grass	X	X				
<i>Dichanthelium scoparium</i>	Velvet grass			X	X	X	
<i>Dichanthelium sp.</i>	Dichanthelium grass	X	X				
<i>Drosera capillaris</i>	Pink sundew					X	

Table 2.3.6-2. Plant Species Inventory by Plant Community Type (Continued, Page 3 of 5)

Scientific Name	Common Name	Plant Community Type*					
		441 320 832	441/620	621	641/832	510 510/832	743 814
<i>Eriocaulon compressum</i>	Pipewort		X		X		
<i>Eriocaulon decangulare</i>	Common pipewort		X		X		
<i>Eupatorium capillifolium</i>	Dog fennel						X
<i>Euthamia caroliniana</i>	Slender goldenrod	X					
<i>Hymenocallis henryae</i>	Panhandle spiderlily		X		X		
<i>Hypoxis juncea</i>	Common stargrass	X					
<i>Juncus marginatus</i>	Shore rush				X		
<i>Juncus scirpoides</i>	Rush				X		
<i>Lachnanthes caroliniana</i>	Red root		X		X		
<i>Lachnocaulon anceps</i>	Bog buttons		X				
<i>Lophiola aurea</i>	Goldencrest	X					
<i>Ludwigia lanceolata</i>	Lance-leaf primrose willow				X	X	
<i>Lycopodiella sp.</i>	Clubmoss	X	X				
<i>Medicago lupulina</i>	Black medic						X
<i>Melilotus albus</i>	White sweet clover						X
<i>Osmunda cinnamomea</i>	Cinnamon fern		X	X			
<i>Osmunda regalis</i>	Royal fern		X	X	X		
<i>Panicum hemitomon</i>	Maidencane					X	
<i>Panicum rigidulum</i>	Redtop panicum				X	X	
<i>Polygala lutea</i>	Bog bachelor's button	X	X				
<i>Pontederia cordata</i>	Pickernelweed					X	
<i>Proserpinaca pectinata</i>	Mermaid-weed				X	X	
<i>Pteridium aquilinum</i>	Bracken fern	X					

Table 2.3.6-2. Plant Species Inventory by Plant Community Type (Continued, Page 4 of 5)

Scientific Name	Common Name	Plant Community Type*					
		441 320 832	441/620	621	641/832	510 510/832	743 814
<i>Pterocaulon pycnostachyum</i>	Blackroot	X					
<i>Rhexia alifanus</i>	Meadow beauty	X					
<i>Rhexia lutea</i>	Yellow meadowbeauty	X	X				
<i>Rhexia mariana</i>	Pale meadow beauty		X				
<i>Rubus argutus</i>	Blackberry	X	X				X
<i>Rudbeckia fulgida</i>	Orange coneflower	X					
<i>Sagittaria graminea</i>	Grassy arrowhead		X		X		
<i>Sarracenia flava</i>	Trumpets		X		X		
<i>Spiranthes vernalis</i>	Spring ladiestresses	X					
<i>Syngonanthus flavidulus</i>	Shoe buttons	X	X				
<i>Utricularia subulata</i>	Bladderwort					X	
<i>Verbena braziliensis</i>	Brazilian vervain						X
<i>Verbesina chapmanii</i>	Chapmans crownbeard	X					
<i>Viola lanceolata</i>	Bog-white violet		X		X		
<i>Viola palmata</i>	Early blue violet	X					
<i>Woodwardia areolata</i>	Netted chainfern		X	X			
<i>Woodwardia virginica</i>	Virginia chainfern		X	X			
<i>Xyris caroliniana</i>	Yellow-eyed grass		X				X
<u>Vines</u>							
<i>Smilax bona-nox</i>	Catbrier	X	X				
<i>Smilax glauca</i>	Wild sarsaparilla		X				
<i>Smilax laurifolia</i>	Bamboo-vine		X	X			

Table 2.3.6-2. Plant Species Inventory by Plant Community Type (Continued, Page 5 of 5)

Scientific Name	Common Name	Plant Community Type*					
		441 320 832	441/620	621	641/832	510 510/832	743 814
<i>Toxicodendron radicans</i>	Poison ivy	X	X				
<i>Vitis rotundifolia</i>	Scuppernong	X	X				X

*The plant community types on the site have been classified using the Florida Land Use, Cover, and Forms Classification System (FLUCFCS):

320	Shrub and brushland.	621	Cypress (cypress-titi)
441	Pine plantation (slash pine).	641/832	Marsh under power lines.
441/620	Wet pine plantation.	743	Spoil areas.
510	Streams and waterways (ditch).	814	Roads and highways (internal access).
510/832	Ditch under power lines.	832	Electrical power transmission lines.

Source: ECT, 1999.

along the southern edge of the existing roadway. This area was created by clearing and allowing the regrowth of vegetation. Currently, the area is vegetated by the same species as occur in the adjacent dry pine plantation, except for the planted pines.

Pine Plantation (Slash Pine)—441

Approximately 35.3 acres (70.4 percent) of the site contains slash pine plantation. The original natural pinelands in the area were cleared of the existing vegetation and have been planted with slash pine, harvested, and then replanted over the years. These silvicultural activities have significantly altered the vegetation composition/distribution of the pine stand over time. Currently, the pine plantation on the site is characterized by a dense canopy of even-aged slash pines approximately 20 years old. The site was recently burned. The controlled fire did not damage the planted pines, but much of the understory vegetation was consumed by the burn. Consequently, the understory layers were open and sparsely vegetated in places. The pine plantation on the site consists of both dry and wet communities. Dry pine plantation comprises 19.9 acres or 39.7 percent of the site. The dry pine plantations are characterized by the presence of bracken fern in the ground layer. Other nonwoody components of the ground layer include broomsedge, wiregrass, shoe buttons, blackberry, meadow beauty, slender goldenrod, and dichanthelium grasses. The shrub layer contains gallberry, saw palmetto, wax myrtle, fetterbush, staggerbush, winged sumac, beautyberry, and deerberry. The subcanopy contains widely spaced individuals of southern magnolia, titi, live oak, and water oak.

Approximately 15.4 acres or 30.7 percent of the site contains wet pine plantation. Wet pine plantation is situated along the landward edge of the natural drainage features on the site. Wet pine plantation has a subcanopy of swamp bay, sweet bay, titi, myrtle-leaf holly, laurel oak, and water oak. The shrub layer contains wax myrtle, sweet pepperbush, fetterbush, and sandweed. The herb layer is characterized by the presence of red root, broomsedge, pipewort, sedges, yellow-eyed grass, grassy arrowhead, netted chain fern, Virginia chain fern, royal fern, yellow colic-root, and trumpets. Vines also occur throughout the pine plantation and consist mostly of scuppernong, catbrier, bamboo-vine, wild sarsaparilla and poison ivy. The wet pine plantation areas are marginal wetlands consisting of relatively low to moderate habitat quality.

Streams and Waterways (Ditches)—510

Ditches occur along the roadsides and as upland cut connections to the natural drainage features on the site. The ditched connections to the swamps on the site had standing water during the site surveys in the spring of 1999. The ditches are all small with the largest being approximately 10 ft in width and about 3 ft deep. The ditches support the growth of herbs along the shallow reaches of the ditch bottom, such as lance-leaf primrose willow, mermaids'-weed, red-top panicum, velvet grass, netted chain fern, pickerelweed, and grassy arrowhead. Shrubs, such as sweet pepperbush, fetterbush, titi, and black titi also occur along the ditch edges. The drainage ditches that partially cross the transmission line right-of-way and the site are about 0.4 acre in size or 0.8 percent of the site.

Cypress (Cypress-Titi Swamp)—621

This forested wetland community occurs on 10.2 acres (20.3 percent) of the site and forms the natural drainage patterns on the property. This swampland is dominated by pond cypress in the canopy. The dense subcanopy/shrub strata are vegetated by black titi, sweet bay, fetterbush, myrtle-leaf holly, titi, highbush blueberry, wax myrtle, large gallberry, and sweet pepperbush. The ground layer is rather depauperate consisting mostly of royal fern, netted chain fern, and Virginia chain fern. Cypress-titi swamp is a forested wetland of relatively moderate to high quality.

Marsh—641

A portion of the transmission line right-of-way that occurs along the southwestern corner of the site contains a marshy area. The marsh was probably created when cypress-titi-swamp and/or wet pineland was cleared for construction of the power lines. This marsh area is periodically maintained in a slow growing, primarily herbaceous stage of growth. This marshy area is approximately 0.5 acre in size or 1 percent of the site. Herbaceous plants of the marsh include trumpets, red root, red-top panicum, grassy arrowhead, royal fern, lance-leaf primrose willow, pipewort, shore rush, and mermaid's-weed. Several root sprouts of woody species were also observed and include sweet bay, titi, and gallberry. This marsh habitat is of relatively low quality.

Spoil Areas—743

Spoil taken from the excavation of the ditches on the site was deposited in piles along the sides of the ditches. These spoil piles have become vegetated by plants primarily associated with the pine plantations. The largest spoil area occurs at the northwestern corner of the site (0.1 acre or 0.2 percent).

Roads and Highways (Internal Access Roads)—814

A roadway forms the southern site boundary and another roadway also crosses the most northern portion of the site. These roadways are unvegetated and occupy 1.3 acres (2.6 percent of the site).

Electrical Transmission Lines—832

A portion of an existing electrical transmission line right-of-way forms the western property boundary. The southern portion of the existing right-of-way consists of marsh (0.5 acre or 1 percent of the site). Another smaller area is crossed by a ditch (0.1 acre or 0.2 percent of the site). The remainder is upland, which occupies about 1.6 acres (3.2 percent) of the site. The upland portion of the right-of-way is maintained in an herbaceous stage of growth for safety and access reasons. The herbs and woody root sprouts in the upland areas are plants associated with the adjacent pine plantations.

Terrestrial Systems—Fauna

Wildlife

Presence and likelihood of onsite terrestrial vertebrates were assessed during site visits by terrestrial ecologists on March 8 through 9 and on April 7 through 8, 1999. Table 2.3.6-3 presents a list of wildlife species observed during the site surveys.

Birds

The approximately 50-acre Smith Unit 3 Project site consists of low slash pine plantation with wetland forest systems across the site. Approximately half of the site is considered uplands and half is considered wetlands. All of the property has been the subject of silvicultural activities for many years. Therefore, wildlife diversity is not especially high and contains those species normally expected in pine flatwoods habitats. Lack of shrub

Table 2.3.6-3. Wildlife Species Observed Onsite March 8-9 and April 7-8, 1999

Common Name	Scientific Name
<u>Amphibians</u>	
Southern toad	<i>Bufo terrestris</i>
Pinewoods tree frog	<i>Hyla femoralis</i>
Crickit frog	<i>Acris gryllus</i>
Southern chorus frog	<i>Psuedacris nigrita</i>
<u>Reptiles</u>	
Florida box turtle	<i>Terrapene carolina bauri</i>
Dusky pygmy rattlesnake	<i>Sistrurus miliarius barbouri</i>
<u>Birds</u>	
Eastern brown pelican*	<i>Pelecanus occidentalis</i>
Southern bald eagle*	<i>Haliaeetus l. leucocephalus</i>
Red shouldered hawk	<i>Buteo lineatus</i>
American kestrel	<i>Falco sparverius</i>
Killdeer	<i>Charadrius vociferous</i>
Mourning dove	<i>Zenaida macroura</i>
Red-bellied woodpecker	<i>Melanerpes carolinus</i>
Pileated woodpecker	<i>Dryocopus pileatus</i>
Eastern phoebe	<i>Sayornis phoebe</i>
Great crested flycatcher	<i>Myiarchus crinitus</i>
Bluejay	<i>Cyanocitta cristata</i>
American crow	<i>Corvus brachyrhynchos</i>
Purple martin*	<i>Progne subis</i>
Carolina chickadee	<i>Parus carolinensis</i>
Tufted titmouse	<i>Parus bicolor</i>
Carolina wren	<i>Thryothorus ludovicianus</i>
American robin	<i>Turdus migratorius</i>
Gray catbird	<i>Dumetella carolinensis</i>
Northern mockingbird	<i>Mimus polyglottos</i>
Pine warbler	<i>Dendroica pinus</i>
Palm warbler	<i>Dendroica palmarum</i>
Common yellowthroat	<i>Geothlypis trichas</i>
Northern cardinal	<i>Cardinalis cardinalis</i>
Eastern towhee	<i>Pipilo erythrophthalmus</i>
Red-winged blackbird	<i>Agelaius phoeniceus</i>
Common grackle	<i>Quiscalus quiscula</i>
<u>Mammals</u>	
Opossum	<i>Didelphis virginiana</i>
Raccoon	<i>Procyon lotor</i>
Bobcat	<i>Felis rufus</i>
Eastern gray squirrel	<i>Sciurus carolinensis</i>
White-tailed deer	<i>Odocoileus virginianus</i>

*Species observed offsite near the existing Lansing Smith plant.

Source: ECT, 1999.

wetlands or extensive marsh habitats onsite exclude the use of the site by wading bird species.

Shorebirds and other water-loving birds (e.g., eagles, ospreys) are present offsite to the south along St. Andrew Bay. Although such species may fly over the site, the habitats onsite do not represent valuable habitats for foraging or nesting for these species. No nests of these species were observed onsite. Common bird species present onsite include bluejays, cardinals, pine and palm warblers, chickadees, titmice, wrens, catbirds, mockingbirds, red-bellied woodpeckers, and red-shouldered hawks.

No listed bird species were observed onsite, although the listed brown pelican and bald eagle were observed offsite along the Lansing Smith Plant intake canal and near St. Andrew Bay.

Mammals

Common species of mammals are present onsite and evidence was found of five species: raccoon, opossum, bobcat, gray squirrel, and white-tailed deer.

Reptiles and Amphibians

The low wet habitats onsite support various amphibians and reptiles. Commonly heard amphibians included the pinewoods treefrog, cricket frog, and chorus frog. Reptiles observed included the Florida box turtle and dusky pygmy rattlesnake. Surveyors onsite reported seeing an eastern diamondback rattlesnake. The site is generally too low and wet to support the gopher tortoise or its commensals.

Threatened and Endangered Species

Flora

Potentially occurring listed plant species for the Project site are shown in Table 2.3.6-4. This list was derived from a review of the existing literature and the most recent databases of the U.S. Fish and Wildlife Service (USFWS), Florida Natural Areas Inventory (FNAI), and FGFWFC. Listed plant species searches of the site were conducted in March through May 1999.

Table 2.3.6-4. Protected Plant Species Known to Occur in Bay County and Potential for Occurrence in the Project Area

Scientific Name Common Name	Designated Status		Habitat	Likelihood of Occurrence
	USFWS	State		
<i>Andropogon arctatus</i> Pine-woods bluestem	—	T	Flatwoods	Not likely; marginal habitat
<i>Asclepias viridula</i> Southern milkweed	—	T	Wet pinelands, flatwoods	Suitable habitat, species not observed on Project site
<i>Aster spinulosus</i> Pine-woods aster	—	E	Moist to dry pineland and swamps	Suitable habitat, species not observed on Project site
<i>Baptisia megacarpa</i> Apalachicola wild indigo	—	E	Woodlands, ravines, near streams	Not likely; suitable habitat lacking
<i>Calamintha dentata</i> Toothed savory	—	T	Sandhills, dry bluffs	No suitable habitat present
<i>Calamovilfa curtissii</i> Curtiss' sandgrass	—	T	Pineland, wet prairie, marsh	Suitable habitat, species not observed on Project site
<i>Calycanthus floridus</i> Sweet shrub	—	E	Slope and bottomland forest	Not likely; marginal habitat
<i>Carex baltzellii</i> Baltzell's sedge	—	T	Hammocks, bluffs	No suitable habitat present
<i>Chrysopsis godfreyi</i> Godfrey's golden aster	—	E	Dunes and scrub	No suitable habitat present
<i>Cornus alternifolia</i> Alternate-leaved dogwood	—	E	Rich woods, near streams	No suitable habitat present
<i>Drosera filiformis</i> Thread-leaf sundew	—	E	Edges of lakes	No suitable habitat present
<i>Drosera intermedia</i> Spoon-leaved sundew	—	T	Seepage slopes, wet flatwoods, marshes, sinkholes, ditches	Suitable habitat, species not observed on the Project site
<i>Epidendron conopseum</i> Green-fly orchid	—	C	Cypress and hardwood swamps, moist hammocks	Suitable habitat, species not observed on Project site
<i>Eriocaulon nigrobracteatum</i> Dark-headed hatpins	—	E	Seepage bogs	No suitable habitat present

Table 2.3.6-4. Protected Plant Species Known to Occur in Bay County and Potential for Occurrence in the Project Area

Scientific Name Common Name	Designated Status		Habitat	Likelihood of Occurrence
	USFWS	State		
<i>Euphorbia telephioides</i> Telephus spurge	T	E	Wet flatwoods	Suitable habitat, species not observed on Project site
<i>Gentiana pennelliana</i> Wiregrass gentian	—	E	Wet flatwoods, pine plantations, roadside ditches	High likelihood of occurrence
<i>Habenaria nivea</i> Snowy orchid	—	T	Bogs, wet pine savannas and flatwoods, wet prairies	No suitable habitat present
<i>Hedeoma graveolens</i> Mock pennyroyal	—	E	Sandhills, wet flatwoods, pond margins	High likelihood of occurrence
<i>Hymenocallis henryae</i> Panhandle spiderlily	—	E	Cypress, pine flatwoods, pine plantations	Present
<i>Hypericum lissophloeus</i> Smooth-barked St. John's wort	—	E	Pond margins, sinks	No suitable habitat present
<i>Illicium floridanum</i> Florida anise	—	T	Wooded ravines, steep heads, floodplain forest	No suitable habitat present
<i>Kalmia latifolia</i> Mountain laurel	—	T	Slope forest, river banks, creek swamps	No suitable habitat present
<i>Lachnocaulon digynum</i> Bog button	—	T	Wet acid sands, bogs, pond margins	No suitable habitat present
<i>Lilium catesbaei</i> Southern red lily	—	T	Wet flatwoods, bogs	No suitable habitat present
<i>Lupinus westianus</i> Gulf Coast lupine	—	T	Coastal dunes, disturbed open sandy areas	No suitable habitat present
<i>Lycopodiella cernua</i> Nodding club-moss	—	C	Wet depressions, ditches, moist areas	Suitable habitat, species not observed on Project site
<i>Lythrum curtissii</i> Curtiss' loosestrife	—	E	Swampy woods, seepages	No suitable habitat present

Table 2.3.6-4. Protected Plant Species Known to Occur in Bay County and Potential for Occurrence in the Project Area

Scientific Name Common Name	Designated Status		Habitat	Likelihood of Occur- rence
	USFWS	State		
<i>Macbridea alba</i> White birds-in-a-nest	T	E	Wet pine flatwoods and savannahs	Suitable habitat, species not observed on Project site
<i>Macranthera flammea</i> Hummingbird flower	—	E	Bogs, acid swamps, creek banks	No suitable habitat pre- sent
<i>Magnolia macrophylla</i> Bigleaf magnolia	—	E	Bluffs, hammocks, bayheads	No suitable habitat pre- sent
<i>Magnolia pyramidata</i> Pyramid magnolia	—	E	Forest bluffs	No suitable habitat pre- sent
<i>Osmunda cinnamomea</i> Cinnamon fern	—	C	Swamps and wetland	Present
<i>Osmunda regalis</i> Royal fern	—	C	Swamps and wetlands	Present
<i>Oxypolis filiformis</i> sub. <i>green- manii</i> Giant water-dropwort	—	E	Acid swamps, shallow water of cypress ponds and flatwoods depres- sions, roadside ditches	Suitable habitat, species not observed on the Project site
<i>Paronychia chartacea</i> Crystal lake nailwort	T	E	Shores of karst lake, scrub	No suitable habitat pre- sent
<i>Physostegia godfreyi</i> Apalachicola dragon-head	—	T	Bogs, pine flatwoods, savannas, ditches	Suitable habitat, species not observed on the Project site
<i>Pinckneya bracteata</i> Hairy fever tree	—	T	Bays, seepage swamps, hillside bogs	No suitable habitat pre- sent
<i>Pinguicula ionantha</i> Violet-flowered butterwort	T	E	Flatwoods, bogs, shallow water	High likelihood of oc- currence
<i>Pinguicula lutea</i> Yellow butterwort	—	T	Bays, seepage swamps, hillside bogs	No suitable habitat pre- sent
<i>Pinguicula planifolia</i> Chapman's butterwort	—	T	Bogs, swamps, mar- gins of peaty ponds, ditches and canals	No suitable habitat pre- sent
<i>Pinguicula primuliflora</i> Primrose-flowered butterwort	—	E	Shallow water, swamps, boggy banks, and seepage heads of streams	No suitable habitat pre- sent

Table 2.3.6-4. Protected Plant Species Known to Occur in Bay County and Potential for Occurrence in the Project Area

Scientific Name Common Name	Designated Status		Habitat	Likelihood of Occurrence
	USFWS	State		
<i>Pityopsis flexuosa</i> Bent golden aster	—	E	Sandy oak and pine woods	No suitable habitat present
<i>Platanthera ciliaris</i> Yellow fringed orchid	—	T	Bogs, swamps, marshes, pine savannas, flatwoods, floodplain forests, forest slopes	Suitable habitat, species not observed on Project site
<i>Platanthera integra</i> Yellow fringeless orchid	—	E	Swampy meadows, boggy depressions in wet woods	No suitable habitat present
<i>Pogonia divaricata</i> Rosebud orchid	—	T	Low pinelands and savannas, pitcher plant bogs, swamps, steep banks	Suitable habitat, species not observed on the Project site
<i>Polygonella macrophylla</i> Large-leaved jointweed	—	T	Sand pine-oak scrub	No suitable habitat present
<i>Rhexia parviflora</i> Small-flowered meadowbeauty	—	E	Margins of open cypress swamps	Suitable habitat, species not observed on the Project site
<i>Rhexia salicifolia</i> Panhandle meadowbeauty	—	T	Pond margins, coastal swales	No suitable habitat present
<i>Rhynchospora crinipes</i> Hairy-peduncled beakrush	—	E	Roadsides, ditches, pond borders	Suitable habitat, species not observed on the Project site
<i>Rhynchospora stenophylla</i> Narrow-leaved beakrush	—	T	Bogs, flatwoods	Suitable habitat, species not observed on the Project site
<i>Rudbeckia nitida</i> St. John's Susan	—	E	Moist flatwoods, prairies, roadside ditches	Suitable habitat, species not observed on the Project site
<i>Sarracenia leucophylla</i> White-top pitcherplant	—	E	Bogs, creek swamps, wet prairies	Suitable habitat, species not observed on the Project site
<i>Sarracenia psittacina</i> Parrot pitcher plant	—	T	Flatwoods, bogs	Suitable habitat, species not observed on the Project site

Table 2.3.6-4. Protected Plant Species Known to Occur in Bay County and Potential for Occurrence in the Project Area

Scientific Name Common Name	Designated Status		Habitat	Likelihood of Occurrence
	USFWS	State		
<i>Sarracenia purpurea</i> Decumbent pitcher plant	—	T	Bogs, swamps, savannas, flatwoods	Suitable habitat, species not observed on the Project site
<i>Sarracenia rubra</i> Sweet pitcherplant	—	T	Bogs, wet pinelands, seepage slopes	Not likely; marginal habitat
<i>Scutellaria floridana</i> Florida skullcap	E	E	Wet flatwoods, grassy openings	Not likely; marginal habitat
<i>Silene virginica</i> Virginia campion	—	E	Rich or dry woods	No suitable habitat present
<i>Spiranthes laciniata</i> Lace-lip	—	T	Swamps, marshes, flatwoods	Not likely; marginal habitat
<i>Stewartia malacodendron</i> Silky camellia	—	E	Bluffs, steepheads, bayheads	No suitable habitat present
<i>Verbesina chapmanii</i> Chapman's crownbeard	—	T	Wet flatwoods, seepage slopes	Present
<i>Xyris isoetifolia</i> Quillwort yellow-eyed grass	—	E	Bogs, acid pond margins	No suitable habitat present
<i>Xyris longisepala</i> Karst pond xyris	—	E	Margins of sandhill ponds	No suitable habitat present
<i>Xyris scabrifolia</i> Harper's yellow-eyed grass	—	T	Bog, seepage slope, wet prairie	Suitable habitat, species not observed on the Project site

Notes: USFWS = U.S. Fish and Wildlife Service.

State = Florida Department of Agriculture and Consumer Services.

E = Endangered.

T = Threatened.

C = Commercially exploited.

Source: ECT, 1999.

Four listed plant species were found on the site: royal fern (*Osmunda regalis*), cinnamon fern (*Osmunda cinnamomea*), Panhandle spiderlily (*Hymenocallis henryrae*), and Chapman's crownbeard (*Verbesina chapmanii*). Royal fern and cinnamon fern occur within all of the wetlands on the site. These ferns are very common within the state of Florida. They are listed as commercially exploited species by the Florida Department of Agriculture and Consumer Services (FDACS) and it is illegal to remove them from a site without a property owner's permission. Panhandle spiderlily is a state-listed endangered species. This endemic spiderlily is a perennial herb with green and white flowers that are usually borne two per stem. It occurs in cypress depressions in flatwoods, margins of pine flatwoods, and the scrubby borders to pine plantations in Bay, Gulf, Liberty, and Walton Counties. It blooms from May through June. Several populations of this rare spiderlily were present throughout the wet pine plantation and marsh on the site.

Chapman's crownbeard (*Verbesina chapmanii*) is a perennial herb in the daisy family with opposite leaves and solitary yellowish-orange flowers. This composite inhabits wet flatwoods and seepage slopes within Bay, Franklin, Gulf, Liberty, Wakulla, and Washington Counties. It blooms May through August. This state-listed threatened species that is currently under federal consideration for listing has been found on the site along the existing transmission corridor.

Three other listed plant species have a high likelihood for occurrence on the site due to the presence of suitable habitat on the site and records for these species within the Project vicinity. Wiregrass gentian (*Gentiana pennelliana*) is a small herb with linear-spatulate leaves and solitary white flowers spotted with blue-green on the inside of the corolla. It occurs in wet flatwoods, slash pine plantations, and roadside ditches in Bay, Calhoun, Franklin, Gadsden, Gulf, Leon, Liberty, Wakulla, and Walton Counties. It blooms from October through February. This state-listed endangered species has been found just outside a 5-mile radius of the site. Potential habitat does exist on the site for wiregrass gentian; however, no populations of this species were observed on the Project site in March, April, or May 1999.

The Panhandle butterwort (*Pinguicula ionantha*) is a perennial herb with flat basal rosettes of bright green, glaucous leaves and light violet to white flowers. This carnivorous plant occurs in flatwoods, bogs, and shallow water areas in Bay, Franklin, Gulf, Liberty, and Wakulla Counties. It blooms from February through April. This species, which is federally-listed as threatened and state-listed as endangered, has been found within a 5-mile radius of the site and could potentially occur on the property. However, Panhandle butterwort was not observed during the site surveys in March, April, or May 1999.

Mock pennyroyal (*Hedeoma* [*Stachydeoma*] *graveolens*) is an herbaceous to woody mint with white flowers having a lower lip with a distinctive mottled purple band and purple lobes. This species, which is being considered for federal listing, inhabits sandhills, wet flatwoods, and pond margins in Bay, Calhoun, Franklin, Leon, and Liberty Counties. It blooms from May through October. Populations of mock pennyroyal have been found at or just outside a 5-mile radius of the power plant site. Although potential habitat exists on the site, no individuals of mock pennyroyal were discovered during site searches in the spring of 1999.

Twenty-one other listed plant species were determined as potentially occurring on the site due to the availability of suitable habitat. None of these species were observed during the searches conducted on the property.

Fauna

Table 2.3.6-5 presents potentially occurring state or federally listed wildlife species on the site. The list was developed from the FNAI matrix, FGFWFC, and USFWS records as well as personal observations by Gulf employees or its consultants.

As previously mentioned, the only potentially occurring listed species actually observed were the Southern bald eagle and brown pelican. The eagle was observed flying offsite to the south of the site. This threatened species is not known to nest in the site vicinity. The nearest known nests are found approximately 5 miles to the east along North Bay (Pers. communication from FGFWFC, 1999). Certainly the eagles forage along the bay near the

Table 2.3.6-5. State or Federally Listed Wildlife Species Potentially Occurring Onsite*

Common Name	Status†		Likelihood of Occurrence
Scientific Name	USFWS	FGFWFC	
<u>Amphibians</u>			
Gopher frog <i>Rana capito</i>	—	SSC	Suitable habitat is marginal. Not likely to occur onsite.
<u>Reptiles</u>			
American alligator <i>Alligator mississippiensis</i>	T (S/A)	SSC	Marginal habitat exists onsite. Likelihood of occurrence is low.
Eastern indigo snake <i>Drymarchon corais couperi</i>	T	T	Suitable habitat is present; species not observed onsite.
Gopher tortoise <i>Gopherus polyphemus</i>	—	SSC	Suitable habitat is marginal due to wetness. Likelihood of occurrence is low.
Alligator snapping turtle <i>Macrolemys temminckii</i>	—	SSC	Suitable habitat is lacking. Not likely to occur onsite.
Florida pine snake <i>Pituophis melanoleucus mugitus</i>	—	SSC	Xeric habitats lacking; not likely to occur onsite.
<u>Birds</u>			
Little blue heron <i>Egretta caerulea</i>	—	SSC	Suitable habitat is marginal. Likelihood of occurring onsite is low.
Snowy egret <i>Egretta thula</i>	—	SSC	Suitable habitat is marginal. Likelihood of occurring onsite is low.
Tricolored heron <i>Egretta tricolor</i>	—	SSC	Suitable habitat is marginal. Likelihood of occurring onsite is low.
White ibis <i>Eudocimus albus</i>	—	SSC	Suitable habitat is marginal. Likelihood of occurring onsite is low.
Arctic peregrine falcon <i>Falco peregrinus tundruis</i>	E (S/A)	E	Migratory species may forage over coastal areas near the site. Suitable habitat onsite is lacking.
Southeastern kestrel <i>Falco sparverius paulus</i>	—	T	Suitable habitat onsite is lacking. Corridor next to site may provide suitable foraging habitat.
Bald eagle <i>Haliaeetus l. lueocephalus</i>	T	T	Nesting habitat is lacking. Birds are present (foraging) just south of site along bay.
Woodstork <i>Mycteria americana</i>	E	E	Suitable habitat is marginal. Likelihood of occurrence onsite is low.

Table 2.3.6-5. State or Federally Listed Wildlife Species Potentially Occurring Onsite*

Common Name Scientific Name	Status†		Likelihood of Occurrence
	USFWS	FGFWFC	
Brown pelican <i>Pelecanus occidentalis</i>	—	SSC	Suitable habitat onsite is lacking. Birds use open water areas of bay and discharge canal to the south.
Red-cockaded woodpecker <i>Picoides borealis</i>	E	T	Nesting habitat is absent due to logging. Foraging habitat is present onsite. No known colonies within 5 miles.
Least tern <i>Sterna antillarum</i>	—	T	No known nesting within 5 miles of site. Habitat is lacking onsite.
<u>Mammals</u>			
Florida black bear <i>Ursus americanus floridanus</i>	—	T	Habitat is present although more suitable black bear habitat is several miles northwest of the site according to FGFWFC (1999).

*List developed from FNAI (1999), FGFWFC (1999), and USFWS (1999). Marine species are not included.

†Status:

E = endangered.

T = threatened.

SSC = species of special concern.

E (S/A) = endangered due to similarity of appearance.

USFWS = U.S. Fish and Wildlife Service (1999).

FGFWFC = Florida Game and Fresh Water Fish Commission (1999).

FNAI = Florida Natural Areas Inventory (1999).

existing Lansing Smith Plant, but the proposed Project site does not represent suitable habitat for foraging or nesting for this species.

The brown pelican, now listed as a species of special concern (SSC) by FGFWFC was observed along the existing Lansing Smith Plant's discharge canal southwest of the Project site. No significant habitats for this bird are present on the Project site.

No wading birds were observed onsite and the site does not contain any suitable nesting habitats for these species. Foraging would most likely be limited to the marshy area under the existing powerline right-of-way. The FGFWFC (Pers. communication, 1999) does not show any known wading bird colony sites within 6 miles of the Project site.

The nearest designated Critical Habitat is along the Gulf of Mexico on Shell Island and Crooked Island which has been designated Critical Habitat for the Choctawhatchee beach mouse (*Peromyscus polionotus allopshys*). This mouse is federally and state endangered. However, this habitat area is well over 15 miles from the Project site.

FNAI records indicate two other listed species occurring within 5 miles of the Project site. These are the red-cockaded woodpecker (*Picoides borealis*) and the Eastern indigo snake (*Drymarchon corais couperi*). The red-cockaded woodpecker has been reported 5 miles from the site to the northwest. There is no suitable habitat onsite due to past logging practices. The Eastern indigo snake has been reported approximately 4 miles away to the northeast. Habitat is suitable onsite for this species although none were observed during 4 days of wildlife surveys.

2.3.6.2 Preexisting Stresses

Terrestrial

The existing Lansing Smith Plant facility, transmission line corridor, and access roads are the greatest preexisting stresses to biota on the site. The original vegetation was cleared and has been periodically maintained within the transmission line right-of-way for safety and access reasons. The second greatest preexisting stress on the site was the logging of the original pinelands for timber. These areas were also cleared of the original understory

layers and plowed before the replanting with slash pine. The lands are now managed by controlled fires to reduce the amount of fuel within the understory. Additionally, the logging practices have altered drainage patterns across the site due to logging roads and culverts; furrows for the rows of pine trees; and during harvest, excessive site disturbances due to heavy equipment.

Aquatic/Marine

In order to assess potential impacts of the modifications to the Lansing Smith facility on the aquatic community, it is first necessary to identify the existing stresses (both natural and anthropogenic) on the region. Typical natural stresses to the aquatic community include temperature extremes, salinity variations, water level fluctuations, turbidity increases, and dissolved oxygen reductions. The natural phenomena that can produce these stresses include drought, excessive rainfall, severe weather (freezing, high temperature, wind, etc.), and hurricanes. The natural stresses that have been best documented in the study area are salinity variations and excess temperature. During the 1991 and 1992 surveys (Law Environmental, Inc., 1993), a decrease in the presence of sea grass was reported with increased temperature for the August and November 1991 sampling episodes. In addition, benthic macroinvertebrate populations were generally at their lowest during August 1991 for both the thermally influenced areas and control areas. In contrast, the highest values occurred in November 1991 which suggests (1) there is natural seasonal variability in the region, probably influenced by temperature; and (2) the populations respond/recover quickly as the communities increased from low values in August to high values in November. This observation of natural seasonal variability, in part, was the impetus for initiating the monitoring program in 1993 to examine the aquatic community and effects of the thermal plume during the high water temperature season (SCS, 1998).

In addition to natural seasonal temperature stress, the effect of variable salinity was documented in the region. In 1994, abnormally high fresh water runoff resulting from torrential rains produced a reduction in salinity, temperature, and other associated chemical parameters. This natural change in the estuary resulted in an 85 percent reduction in benthic fish food production from 1993 to 1994 (SCS, 1998). This amounted to a reduc-

tion of benthic productivity of 258 pounds per acre in 1993 to 75 pounds per acre in 1994. Despite this dramatic change, the estuary responded to normal production in 1995.

In addition to the natural stresses mentioned above, the receiving water in the estuary is subject to potential stress from effluent from the existing facility. To examine the potential stress from the effluent, an extensive water quality monitoring program near the facility was completed (SCS, 1998) from 1993 to 1997 at 18 stations in North and West Bays. The study reported the water quality as good and the summary results of the water quality analyses are presented in Table 2.3.6-6. In summary, water quality stress from manmade sources appears minimal and water quality parameters are within applicable water quality standards.

The thermal effluent from the Lansing Smith facility provides an existing source of potential stress to the aquatic community. The extent of the thermal plume and the effects of the discharge have been studied extensively (Law Engineering, 1976; Law Environmental, Inc., 1982; Law Environmental, Inc., 1993; and SCS, 1998). The National Pollutant Discharge Elimination System (NPDES) permit for the facility limits the monthly average temperature rise above ambient to 18.0 °F between April and September, and 20°F between October and March. The historical monthly average intake and discharge temperatures for the past 3 years are plotted in Figure 2.3.6-2. In addition, the monthly average plant discharge and ΔT are provided in the same figure. This information is provided as a record of existing conditions at the site to help assess the potential impacts of the proposed additions to the facility.

The effects of this thermal discharge on the aquatic community have been studied for three decades. The extent of the thermal plume and, consequently, the aerial extent of potential impacts is shown in Figure 2.3.6-3 for a plume during ebb tide and in Figure 2.3.6-4 for a plume during flood tide. These illustrations were obtained during a study by Law Environmental, Inc. (1993), that was conducted specifically to delineate the extent of the thermal plume during worst-case conditions (i.e., summer) and evaluate if the

Table 2.3.6-6. Summary of Water Quality Data from 18 Background Stations Collected Between 1993 and 1997

Parameter	West Bay	North Bay
Dissolved oxygen (mg/L)	3.13 to 10.39	4.96 to 9.53
pH (units)	7.26 to 9.15	7.17 to 9.54
Turbidity (FTU)	0.6 to 3.50	<0.20 to 9.10
Conductivity (mmhos/cm)	10.8 to 45.7	7.38 to 41.5
Hardness (mg/L)	940 to 13,000	700 to 4,400
Alkalinity (mg/L)	28 to 100	25 to 91
Total nitrogen (mg/L)	0.16 to 2.10	<0.10 to 1.90
Total phosphorus (mg/L)	0.010 to 0.17	0.029 to 0.064
Total organic carbon (mg/L)	<2.0 to 13.0	<2.0 to 14.0
Chloride (mg/L)	3,300 to 18,000	2,500 to 15,000
Total suspended solids (mg/L)	2.2 to 41.0	1.2 to 21.0
Sulfate (mg/L)	460 to 2,400	370 to 2,200
Aluminum (mg/L)	<0.10 to 28.0	0.075 to 0.70
Arsenic (mg/L)	<0.0020 to 0.0028	<0.0020 to 0.0140
Boron (mg/L)	0.76 to 3.4	0.60 to 13.0
Calcium (mg/L)	65 to 930	49 to 330
Chromium(mg/L)	<0.01 to <0.01	<0.01 to <0.01
Copper (mg/L)	<0.01 to <0.01	<0.01 to <0.01
Iron (mg/L)	<0.03 to 0.79	<0.03 to 0.72
Lead (mg/L)	<0.005 to <0.01	<0.005 to 0.005
Magnesium (mg/L)	190 to 2,800	140 to 940
Mercury (mg/L)	<0.0002 to 0.0004	<0.0002 to 0.00035
Nickel(mg/L)	<0.02 to 0.51	<0.02 to 0.023
Potassium(mg/L)	60 to 1,000	47 to 360
Selenium (mg/L)	<0.002 to <0.002	<0.002 to 0.002
Sodium (mg/L)	1,800 to 22,000	1,400 to 9,800
Vanadium (mg/L)	<0.01 to 0.012	<0.01 to <0.10
Zinc (mg/L)	<0.02 to <0.04	<0.02 to <0.04

Source: SCS, 1998.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

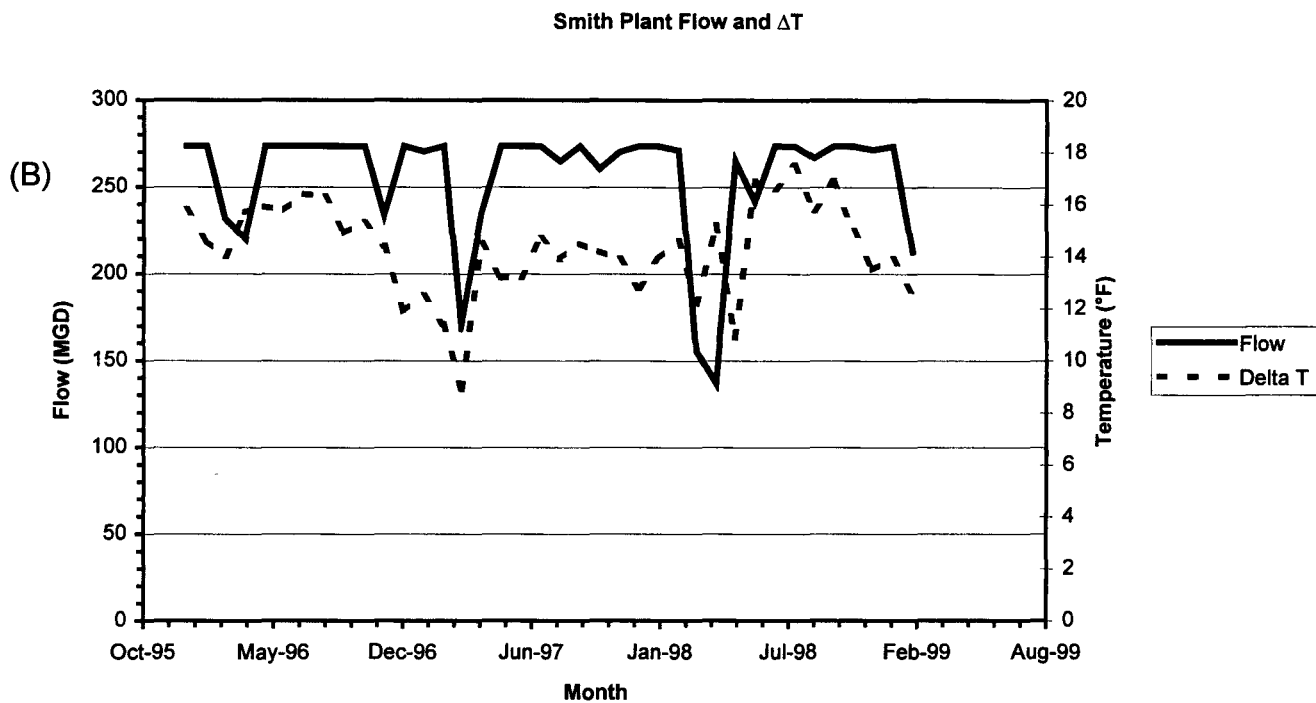
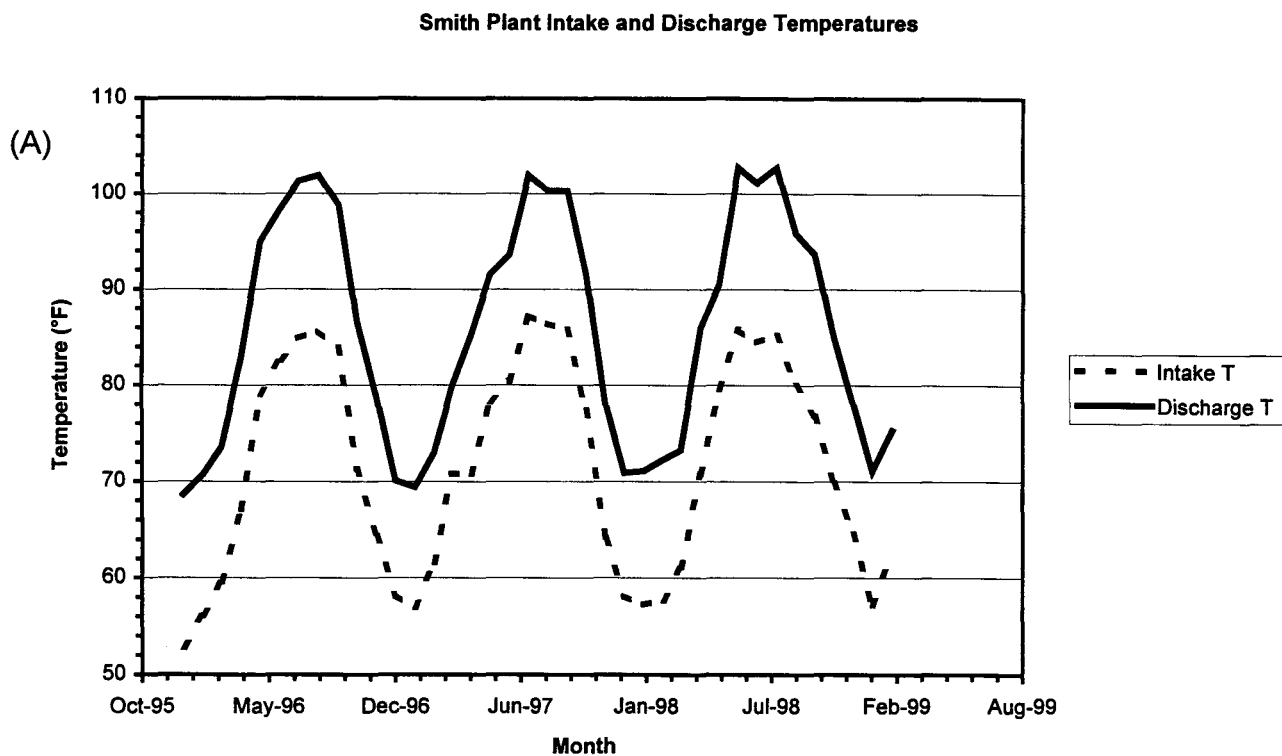


FIGURE 2.3.6-2.

THE LANSING SMITH PLANT MONTHLY INTAKE AND DISCHARGE TEMPERATURE (A) AND DISCHARGE FLOW AND ΔT (B)

Sources: GPC, 1999; ECT, 1999.

ECT

Environmental Consulting & Technology, Inc.

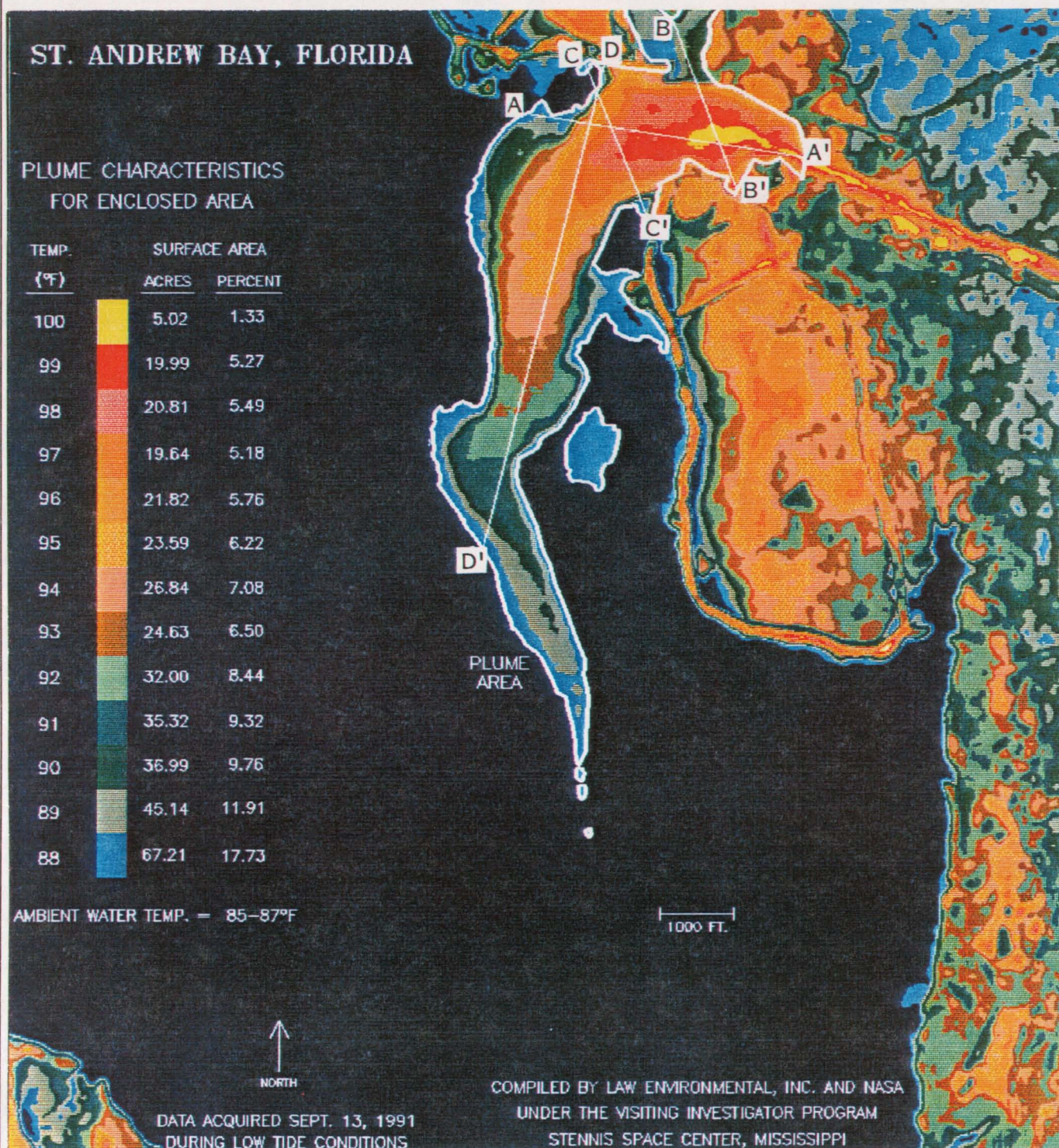


FIGURE 2.3.6-3.

THERMAL PLUME DURING EBB TIDE

Source: Law Environmental, Inc., 1993.

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Environmental Consulting & Technology, Inc.

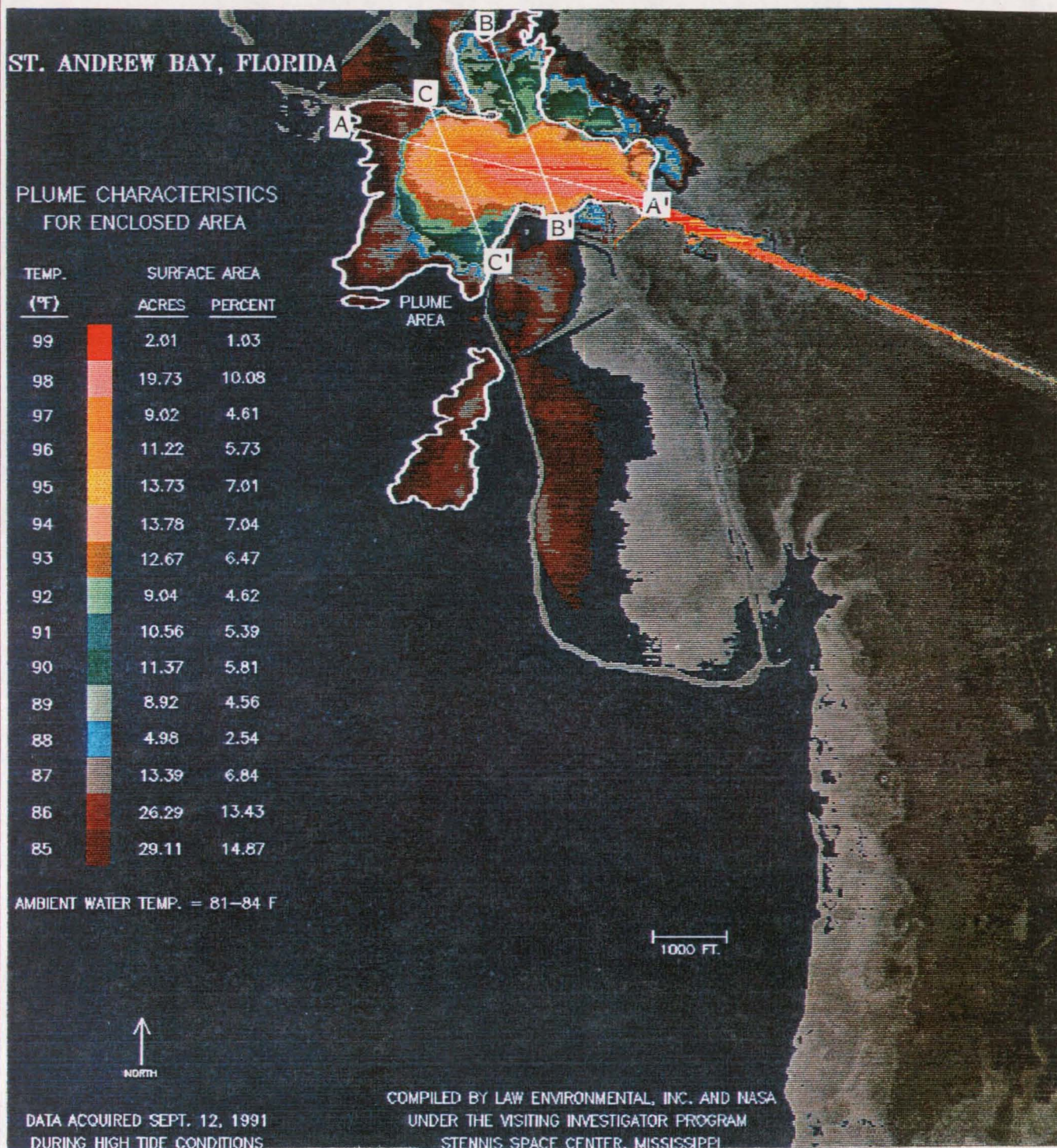


FIGURE 2.3.6-4.

THERMAL PLUME DURING FLOOD TIDE

Source: Law Environmental, Inc., 1993.

ECT
Environmental Consulting & Technology, Inc.

thermal plume might "...cause substantial damage or harm to the aquatic life or vegetation." Thermal plume delineation was completed using remote sensing techniques. Potential stress to the system was assessed by establishing biological and environmental sampling stations within and outside of the thermally affected areas. The study included thermal plume delineation, sea grass mapping, *in situ* water quality measurements, benthic macroinvertebrate sampling, and sediment analysis. The study (Law, 1993) provided the following conclusions:

Thermal Plume Characterization

- Using remote sensing technology, the areal coverage of the thermal plume under low water level/ebb current conditions and high water level/flood current conditions was determined to be approximately 153 ha (379 acres) and 79 ha (196 acres), respectively. The areal extent of the thermally influenced area has remained largely unchanged.
- Over 57 percent (88 ha [217 acres]) of the surface area of the plume was 2.8°C (5°F) or less above ambient water temperature under low water level/ebb current conditions, compared to 42 percent (33 ha [82 acres]) noted during high water level/flood current conditions.
- The zone of greatest thermal influence was more spatially restricted in Warren Bayou during low water level/ebb current conditions.
- There was rapid cooling of the thermal discharge in the receiving waters. The rapid cooling was attributed to dilution of the plume with the cooler waters of West Bay combined with increased tidal, current, and wind/wave actions.

Sea Grass Communities

- Estimates of sea grass biomass were greater in 1991 and 1993 (Law, 1993) studies for comparable seasons and sample stations than reported in previous studies.
- The greatest total sea grass biomass estimates were measured at sample stations located within the area of thermal influence.
- Areal distribution of sea grasses within the study area has not changed substantially from 1975 to 1992.

- Overall, sea grass species composition and estimated biomass within thermally influenced areas were similar to or exceeded control area measurements.

Benthic Macroinvertebrates

- Number of taxa, number of individuals, and organisms per square meter were lowest for all sample stations during August 1991. Sample stations located closest to the discharge canal had considerably fewer benthic macroinvertebrates compared to other stations within the area of thermal influence and compared to control stations. Benthic macroinvertebrate population parameters improved by November 1991 and remained largely unchanged in February and May 1992.
- Comparing benthic macroinvertebrate communities within the area of thermal influence to communities in background (control) areas, Shannon-Weaver Diversity values were at least 95 percent of control areas during all seasons studied. This value exceeded the biological integrity criterion of 75 percent of established background levels.

The study concluded that other than the station located directly in the discharge canal, there was no substantial damage to the aquatic life and/or vegetation in the region.

Following this study, a continued monitoring program was begun in 1993 (SCS, 1998) to document potential thermal stresses on the aquatic community during the summer season. Water quality, temperature, benthic macroinvertebrate, and artificial substrate (oyster-shell samplers) sampling was conducted annually at nine stations in West Bay (thermally influenced) and nine stations in North Bay (controls). Biological components were sampled only at three of the nine stations in each Bay. Through the first 5 years of monitoring (1993 through 1997) the study has concluded:

- Based on the biological stability, the water quality conditions in West Bay are essentially unaffected by the discharge and significant impact has been found to be limited to less than 0.15 mile of Warren Bayou.
- Based on biological integrity tests and effluent toxicity tests, no toxicity problems have been indicated to exist.

2.3.6.3 Measurement Programs

The terrestrial ecology surveys conducted for this Project were specifically designed to obtain the baseline information necessary to characterize the site as required by specific regulatory requirements and as needed for the impact assessment. The required information includes: (1) identification of important flora and fauna on and in the vicinity of the site, including state and federally listed species; (2) the relationship between species and their environment; and (3) the identification of the extent, distribution, type, successional status, preexisting stresses, species composition, and diversity of plant communities on the site.

As preparation for site reconnaissance and field surveys, a literature search/agency consultation was conducted to review maps and aerial photographs and to obtain current listings of endangered and threatened species. Subsequent to the review of maps and literature, up to four ecologists conducted three site evaluations: one on March 8—9, 1999; one on April 7 through 9, 1999; and one on May 17—18, 1999. The purposes of these site visits were to locate potentially sensitive or unique areas, classify major vegetation communities on the site, identify land uses and existing stresses and impacts, identify any observed endangered or threatened species, delineate all wetland areas both natural and artificially created, verify the wetland delineations with FDEP and the U.S. Army Corps of Engineers (USACE) personnel, and conduct qualitative studies of the habitats onsite.

For the aquatic environments near the site, Gulf Power and its consultants have studied various physical and biological components for years. In addition, Gulf monitors various aquatic parameters for compliance with its existing industrial wastewater permit (NPDES). Much of these studies are summarized throughout this SCA.

2.3.7 METEOROLOGY AND AMBIENT AIR QUALITY

2.3.7.1 Climatology/Meteorology

The climate in the panhandle of Florida is typical of the upper Gulf Coast. Winters are mild and the summer heat is tempered by the southern breezes from the Gulf of Mexico.

The National Weather Service (NWS) station at the Apalachicola Municipal Airport, 88 kilometers (km) southeast of the site, is the nearest first-order surface observation facility. Due to limited data available for dispersion modeling input, the Apalachicola data has been supplemented with Pensacola data. The NWS station at the Pensacola Regional Airport, 161 km west of the site, is the next closest first-order surface observation facility. The nearest east coast station recording mixing heights is Apalachicola. Thus, consistent with FDEP guidance, NWS surface and mixing height observations from Pensacola and Apalachicola were used as dispersion modeling input.

Table 2.3.7-1 provides a summary of monthly mean and extreme temperatures based on NWS data collected at the Apalachicola Municipal Airport (NCDC, 1992); the period of record for these data is through 1991. The Apalachicola NWS station is located approximately 88 km southeast of the Project site. Based on these data, January exhibits the lowest mean minimum temperature (45.1°F) and the lowest normal mean monthly temperature (52.8°F). The highest mean daily maximum temperature (88°F) occurs in July and August. The maximum mean monthly temperature (81.5°F) occurs in July. The highest and lowest record temperatures of 102°F and 9°F were experienced in July 1932 and January 1935, respectively.

Normal annual rainfall is approximately 55 inches. Rainfall is generally well distributed throughout the year, with the greatest amounts falling in July through September. The highest normal monthly rainfall is 8.7 inches in September. May and October are the driest months, with an average of 3 inches of precipitation. Record monthly precipitation occurred in September 1946, when 22.6 inches of rain were recorded. February has the highest mean monthly windspeed of 8.9 miles per hour (mph). The lowest mean monthly windspeed of 6.4 occurs in July and August. The prevailing wind is from the north. The

Table 2.3.7-1. Meteorological Data from Apalachicola, Florida

LATITUDE: 29°44'N		LONGITUDE: 85°02'W		ELEVATION: FT. GRND		19 BARO		22 TIME ZONE: EASTERN		WBAN: 12632				
	(a)	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	YEAR
TEMPERATURE °F:														
Normals														
-Daily Maximum		60.5	62.4	68.0	75.1	81.7	86.6	88.0	88.0	85.3	78.2	69.2	63.0	75.5
-Daily Minimum		45.1	46.9	53.4	60.7	67.3	72.9	75.0	74.7	72.3	62.1	52.7	47.0	60.8
-Monthly		52.8	54.7	60.7	67.9	74.5	79.8	81.5	81.4	78.9	70.2	61.0	55.0	68.2
Extremes														
-Record Highest	62	79	80	85	90	98	101	102	99	96	93	87	82	102
-Year		1957	1957	1982	1967	1986	1930	1932	1986	1932	1941	1935	1931	JUL 1932
-Record Lowest	62	9	21	22	36	47	48	63	62	50	37	24	13	9
-Year		1985	1951	1980	1987	1981	1984	1981	1986	1967	1989	1950	1962	JAN 1985
NORMAL DEGREE DAYS:														
Heating (base 65°F)		401	311	168	30	0	0	0	0	0	24	154	320	1408
Cooling (base 65°F)		23	23	35	117	295	444	512	508	417	185	34	10	2603
% OF POSSIBLE SUNSHINE	56	58	61	65	74	77	71	64	64	66	74	67	57	67
MEAN SKY COVER (tenths)														
Sunrise - Sunset	58	5.7	5.6	5.6	4.8	4.7	5.3	6.1	5.9	5.5	4.0	4.6	5.7	5.3
MEAN NUMBER OF DAYS:														
Sunrise to Sunset														
-Clear	61	10.1	9.7	10.6	12.4	12.7	9.1	6.4	7.1	10.0	16.1	13.3	9.9	127.7
-Partly Cloudy	61	7.6	6.7	8.2	8.8	10.3	13.0	13.1	13.0	9.8	7.5	7.7	7.7	113.5
-Cloudy	61	5.1	11.8	12.2	8.8	8.0	7.9	11.5	10.8	10.2	7.4	8.9	13.4	115.9
Precipitation														
.01 inches or more	62	8.9	8.5	7.8	5.6	5.4	9.6	14.7	13.7	11.1	5.3	6.3	8.1	104.9
Snow, ice pellets, hail														
1.0 inches or more	62	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*
Thunderstorms	55	1.6	2.4	3.8	3.4	4.9	9.8	16.3	15.7	9.8	1.7	1.5	1.6	72.4
Heavy Fog Visibility														
1/4 mile or less	55	6.2	4.6	5.4	2.5	0.9	0.3	0.1	0.1	0.1	0.6	2.1	4.3	27.2
Temperature °F														
-Maximum														
90° and above	62	0.0	0.0	0.0	0.2	0.6	5.8	8.3	8.1	3.5	0.1	0.0	0.0	26.6
32° and below	62	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	*
-Minimum														
32° and below	62	3.0	1.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.7	6.8
0° and below	62	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AVG. STATION PRESS. (mb)	16	1020.3	1019.4	1017.3	1016.4	1015.3	1015.9	1016.9	1016.3	1015.6	1017.3	1018.8	1020.6	1017.5
RELATIVE HUMIDITY (%)														
Hour 01	37	83	83	86	86	87	87	87	88	86	83	83	84	85
Hour 07	41	85	86	86	86	85	85	86	88	88	86	85	86	86
Hour 13 (Local Time)	37	66	65	65	64	65	67	71	75	69	62	63	67	67
Hour 19	41	79	76	76	74	72	74	76	77	78	76	78	79	76
PRECIPITATION (inches):														
Water Equivalent														
-Normal		3.51	3.64	4.04	3.25	2.94	4.81	7.09	7.53	8.66	3.19	2.82	3.50	54.98
-Maximum Monthly	62	20.80	9.19	14.33	12.14	12.14	18.32	18.07	21.08	22.55	12.09	9.00	9.68	22.55
-Year		1991	1960	1959	1983	1991	1965	1984	1970	1946	1959	1947	1986	SEP 1946
-Minimum Monthly	62	0.04	0.38	0.71	0.09	0.25	0.30	0.75	1.85	0.60	0.01	0.04	0.30	0.01
-Year		1957	1938	1939	1942	1983	1977	1976	1951	1972	1935	1931	1955	OCT 1935
-Maximum in 24 hrs	62	6.18	7.12	8.17	7.76	7.07	5.34	6.75	5.93	11.71	6.32	5.84	4.15	11.71
-Year		1991	1988	1948	1964	1959	1949	1975	1986	1932	1965	1930	1931	SEP 1932
Snow, ice pellets, hail														
-Maximum Monthly	62	0.4	1.2	T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	T	1.2
-Year		1977	1958	1980									1989	FEB 1958
-Maximum in 24 hrs	62	0.4	1.2	T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	T	1.2
-Year		1977	1958	1980									1989	FEB 1958
WIND:														
Mean Speed (mph)	43	8.3	8.7	8.9	8.5	7.7	7.1	6.4	6.4	7.8	8.0	8.0	8.0	7.8
Prevailing Direction through 1956		N	N	SE	SE	SE	SW	W	SW	NE	NE	N	N	N
Fastest Mile														
-Direction (!!!)	47	E	E	E	SE	SE	E	N	NE	E	NW	SE	SE	E
-Speed (MPH)	47	48	42	54	51	47	55	63	59	67	56	47	42	67
-Year		1960	1969	1931	1933	1937	1972	1930	1939	1947	1941	1948	1945	SEP 1947
Peak Gust														
-Direction (!!!)	6	W	W	NW	W	N	NW	S	E	SE	SE	SW	E	SW
-Speed (mph)	6	41	49	41	43	61	38	41	68	68	44	85	47	85
-Date		1991	1991	1990	1988	1990	1986	1988	1985	1985	1985	1985	1986	NOV 1985

Source: NCDC, 1992.

annual average windspeed is 7.8 mph. The highest recorded windspeed was 67 mph in September 1947.

Table 2.3.7-2 provides a summary of monthly mean and extreme temperatures based on NWS data collected at the Pensacola Regional Airport (NCDC, 1998); the period of record for these data is through 1997. The Pensacola NWS station is located approximately 100 miles (161 km) west of the Project site. Based on these data, January exhibits the lowest mean minimum temperature (43.0°F) and the lowest normal mean monthly temperature (52.1°F). The highest mean daily maximum temperature (90.1°F) and the maximum mean monthly temperature (82.2°F) occur in July. The highest and lowest record temperatures of 106°F and 5°F were experienced in July 1980 and January 1985, respectively.

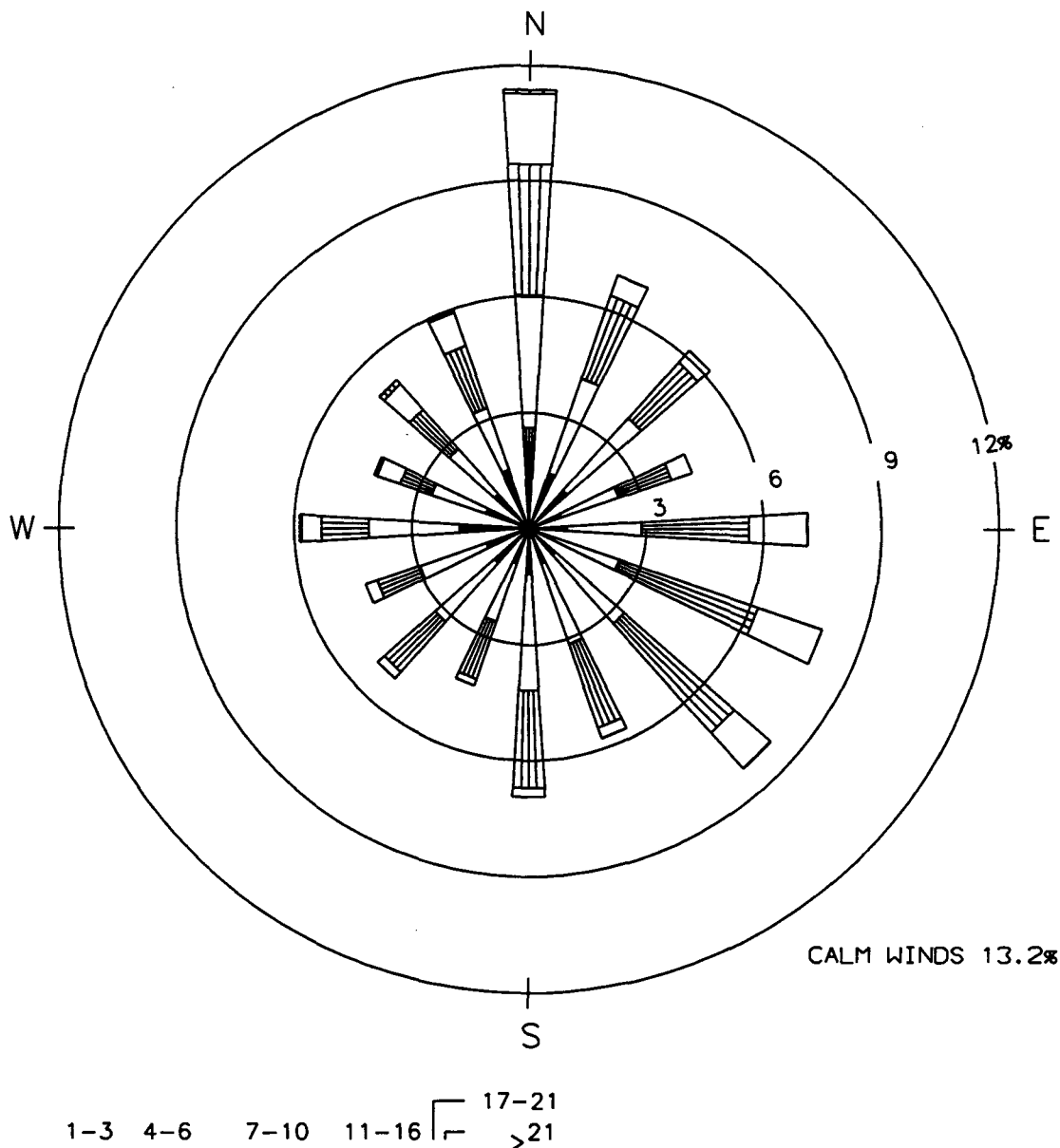
Normal annual rainfall is approximately 62 inches. Rainfall is generally well distributed throughout the year, with the greatest amounts falling in July and August. Summer rainfall is generally derived from local showers or thunderstorms. The highest normal monthly rainfall is 7.4 inches in July. April and November are the driest months, with an average between 3 to 4 inches of precipitation. Record monthly precipitation occurred in June 1994, when 21.1 inches of rain were recorded. April has the highest mean monthly windspeed of 12.1 mph. The lowest mean monthly windspeed of 7.3 mph occurs in August. The prevailing wind is from the north. The annual average windspeed is 9.7 mph. The highest recorded windspeed was 53 mph in September 1979.

Summarizing the surface data used for modeling, Figures 2.3.7-1 and 2.3.7-2 present a 3-year annual wind rose (1988-1990) for Apalachicola Municipal Airport, and a 5-year annual wind rose (1986-1990) for Pensacola Regional Airport, respectively. The wind roses are based on surface wind direction and windspeed observed at the two stations. Figures 2.3.7-3 and 2.3.7-4 present the seasonal wind roses for the same stations. The values presented in the figures represent the percent of the time that the wind blows from a particular direction at a given speed. The predominant wind direction at both stations is from the north, which occurred approximately 11 percent of the time at Apalachicola and 16 percent of the time at Pensacola.

Table 2.3.7-2. Meteorological Data from Pensacola, Florida

LATITUDE:		LONGITUDE:		ELEVATION (FT):		TIME ZONE:		WBAN: 13699							
30° 28' 23" N		87° 11' 15" W		GRND: 121 BARO: 121		CENTRAL (UTC+ 6)									
ELEMENT		POR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
TEMPERATURE °F	NORMAL DAILY MAXIMUM	30	59.8	62.9	69.4	76.6	83.2	88.7	89.9	89.2	86.4	79.1	70.1	62.9	76.5
	MEAN DAILY MAXIMUM	41	61.2	63.9	69.8	76.4	83.4	89.1	90.1	89.8	86.7	79.5	69.6	63.2	76.9
	HIGHEST DAILY MAXIMUM	34	80	82	86	96	98	101	106	104	98	92	85	81	106
	YEAR OF OCCURRENCE		1997	1972	1991	1987	1996	1988	1980	1986	1997	1973	1973	1978	JUL 1980
	MEAN OF EXTREME MAXS.	41	74.7	75.8	81.3	85.3	91.8	96.0	96.6	95.7	93.8	88.5	80.7	76.4	86.4
	NORMAL DAILY MINIMUM	30	41.4	44.1	51.3	58.5	65.7	71.8	74.2	73.8	70.3	59.4	51.0	44.4	58.8
	MEAN DAILY MINIMUM	41	43.0	45.0	51.4	58.3	65.8	72.0	74.3	73.8	70.2	59.8	49.9	44.6	59.0
	LOWEST DAILY MINIMUM	34	5	15	22	33	48	56	61	62	43	32	25	11	5
	YEAR OF OCCURRENCE		1985	1996	1980	1987	1997	1984	1967	1992	1967	1993	1976	1989	JAN 1985
	MEAN OF EXTREME MINS.	41	24.6	27.2	33.8	43.5	54.3	64.0	69.6	68.6	58.6	43.4	33.3	26.5	45.6
	NORMAL DRY BULB	30	50.6	53.6	60.4	67.6	74.5	80.3	82.1	81.5	78.4	69.3	60.6	53.7	67.7
	MEAN DRY BULB	41	52.1	54.5	60.6	67.3	74.5	80.5	82.2	81.8	78.4	69.7	59.8	53.9	67.9
	MEAN WET BULB	13	43.9	47.2	51.7	56.5	63.3	68.2	69.4	69.2	66.1	58.0	52.1	46.7	57.7
	MEAN DEW POINT	13	39.1	42.4	47.2	52.2	59.9	65.4	67.1	67.0	63.3	54.1	48.2	42.6	54.0
	NORMAL NO. DAYS WITH:														
MAXIMUM ≥ 90°	30	0.0	0.0	0.0	0.1	2.3	13.3	17.4	15.3	8.1	0.4	0.0	0.0	56.9	
MAXIMUM ≤ 32°	30	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	
MINIMUM ≤ 32°	30	7.0	3.9	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	4.7	17.1	
MINIMUM ≤ 0°	30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
H/C	NORMAL HEATING DEG. DAYS	30	471	331	184	38	0	0	0	0	0	39	183	371	1617
	NORMAL COOLING DEG. DAYS	30	25	12	42	116	295	459	530	512	402	172	51	20	2636
RH	NORMAL (PERCENT)	30	73	71	72	72	73	74	77	78	75	71	74	75	74
	HOUR 00 LST	30	79	78	80	82	84	84	86	87	84	80	81	80	82
	HOUR 06 LST	30	81	81	83	85	86	86	88	90	87	84	84	83	85
	HOUR 12 LST	30	62	59	58	56	58	60	64	65	61	55	60	63	60
	HOUR 18 LST	30	71	68	68	66	67	68	71	74	71	69	74	74	70
S	PERCENT POSSIBLE SUNSHINE	5	48	53	61	63	67	67	57	58	60	71	64	49	60
W/O	MEAN NO. DAYS WITH:														
	HEAVY FOG (VISBY≤1/4 MI)	27	5.7	4.7	5.6	3.8	1.6	0.4	0.4	0.2	0.6	1.6	3.5	4.5	32.6
	THUNDERSTORMS	27	1.7	2.9	4.2	3.9	5.4	10.0	14.6	13.7	6.6	1.8	1.9	1.5	68.2
CLOUDINESS	MEAN:														
	SUNRISE-SUNSET (OKTAS)	29	5.2	4.7	4.8	4.3	4.4	4.4	4.7	4.6	4.2	3.6	4.0	4.8	4.5
	MIDNIGHT-MIDNIGHT (OKTAS)	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	MEAN NO. DAYS WITH:														
	CLEAR	29	7.8	8.7	8.8	9.8	9.4	7.0	4.4	5.9	9.9	13.3	11.3	8.6	104.9
PARTLY CLOUDY	29	7.1	6.7	8.2	9.5	11.1	14.9	16.9	15.1	10.7	9.0	7.8	6.7	123.7	
CLOUDY	29	16.1	12.9	14.0	10.7	10.6	8.1	9.7	10.1	9.5	8.7	10.9	15.7	137.0	
PR	MEAN STATION PRESSURE (IN)	23	30.02	29.98	29.92	29.91	29.86	29.87	29.91	29.90	29.89	29.95	29.99	30.02	29.93
	MEAN SEA-LEVEL PRES. (IN)	12	30.15	30.11	30.06	30.02	30.00	30.00	30.05	30.02	30.03	30.06	30.11	30.16	30.06
WINDS	MEAN SPEED (MPH)	21	9.9	10.8	11.2	12.1	9.9	9.6	7.9	7.3	9.1	8.8	9.3	9.9	9.7
	PREVAIL. DIR (TENS OF DEGS)	16	36	36	12	14	18	18	21	18	01	36	36	35	35
	MAXIMUM 2-MINUTE:														
	SPEED (MPH)	25	35	35	35	35	32	32	35	35	53	35	35	34	53
	DIR. (TENS OF DEGS)		22	16	31	32	24	33	09	32	10	13	21	10	10
	YEAR OF OCCURRENCE		1987	1984	1993	1990	1994	1972	1993	1993	1979	1985	1972	1988	SEP 1979
	PEAK GUST:														
SPEED (MPH)															
DIR. (TENS OF DEGS)															
YEAR OF OCCURRENCE															
PRECIPITATION	NORMAL (IN)	30	4.68	5.40	5.63	3.77	4.20	6.40	7.42	7.39	5.32	4.21	3.54	4.29	62.25
	MAXIMUM MONTHLY (IN)	34	18.77	11.66	12.96	15.52	10.31	21.14	20.36	14.14	15.71	16.15	13.27	9.58	21.14
	YEAR OF OCCURRENCE		1991	1966	1979	1964	1987	1994	1979	1987	1988	1995	1995	1982	JUN 1994
	MINIMUM MONTHLY (IN)	34	0.60	1.06	0.87	0.38	0.08	0.86	1.69	2.53	0.39	0.00	0.30	0.57	0.00
	YEAR OF OCCURRENCE		1981	1991	1967	1987	1988	1979	1970	1990	1984	1978	1981	1980	OCT 1978
	MAXIMUM IN 24 HOURS (IN)	34	5.44	4.70	11.10	7.51	5.01	6.77	5.14	5.92	10.02	15.40	4.90	4.52	15.40
	YEAR OF OCCURRENCE		1978	1982	1979	1964	1987	1970	1975	1987	1967	1995	1995	1964	OCT 1995
	NORMAL NO. DAYS WITH:														
PRECIPITATION ≥ 0.01	30	9.8	9.2	9.0	6.1	7.1	10.2	13.6	12.6	8.8	4.8	7.6	9.7	108.5	
PRECIPITATION ≥ 1.00	30	1.3	1.6	1.9	1.2	1.5	1.9	2.2	2.6	1.7	1.3	1.1	1.4	19.7	
SNOWFALL	NORMAL (IN)	30	0.1	0.1	T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	T	0.2
	MAXIMUM MONTHLY (IN)	34	2.5	1.9	T	0.0	0.0	0.0	0.0	T	0.0	0.0	0.0	T	2.5
	YEAR OF OCCURRENCE		1977	1973	1993					1993				1993	JAN 1977
	MAXIMUM IN 24 HOURS (IN)	34	1.5	1.9	T	0.0	0.0	0.0	0.0	T	0.0	0.0	0.0	T	1.9
	YEAR OF OCCURRENCE		1977	1973	1993					1993				1993	FEB 1973
	MAXIMUM SNOW DEPTH (IN)	39	0	2	0	0	0	0	0	0	0	0	0	0	2
	YEAR OF OCCURRENCE			1973											FEB 1973
	NORMAL NO. DAYS WITH:														
SNOWFALL ≥ 1.0	30	0.1	0.*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	

Source: NCDC Asheville, NC; 1998.



WINDROSE

STATION NO. 12832

Apalachicola, FL

PERIOD: 1988-1990

NOTES:

DIAGRAM OF THE FREQUENCY OF OCCURRENCE FOR EACH WIND DIRECTION. WIND DIRECTION IS THE DIRECTION FROM WHICH THE WIND IS BLOWING. EXAMPLE - WIND IS BLOWING FROM THE NORTH 11.4 PERCENT OF THE TIME.

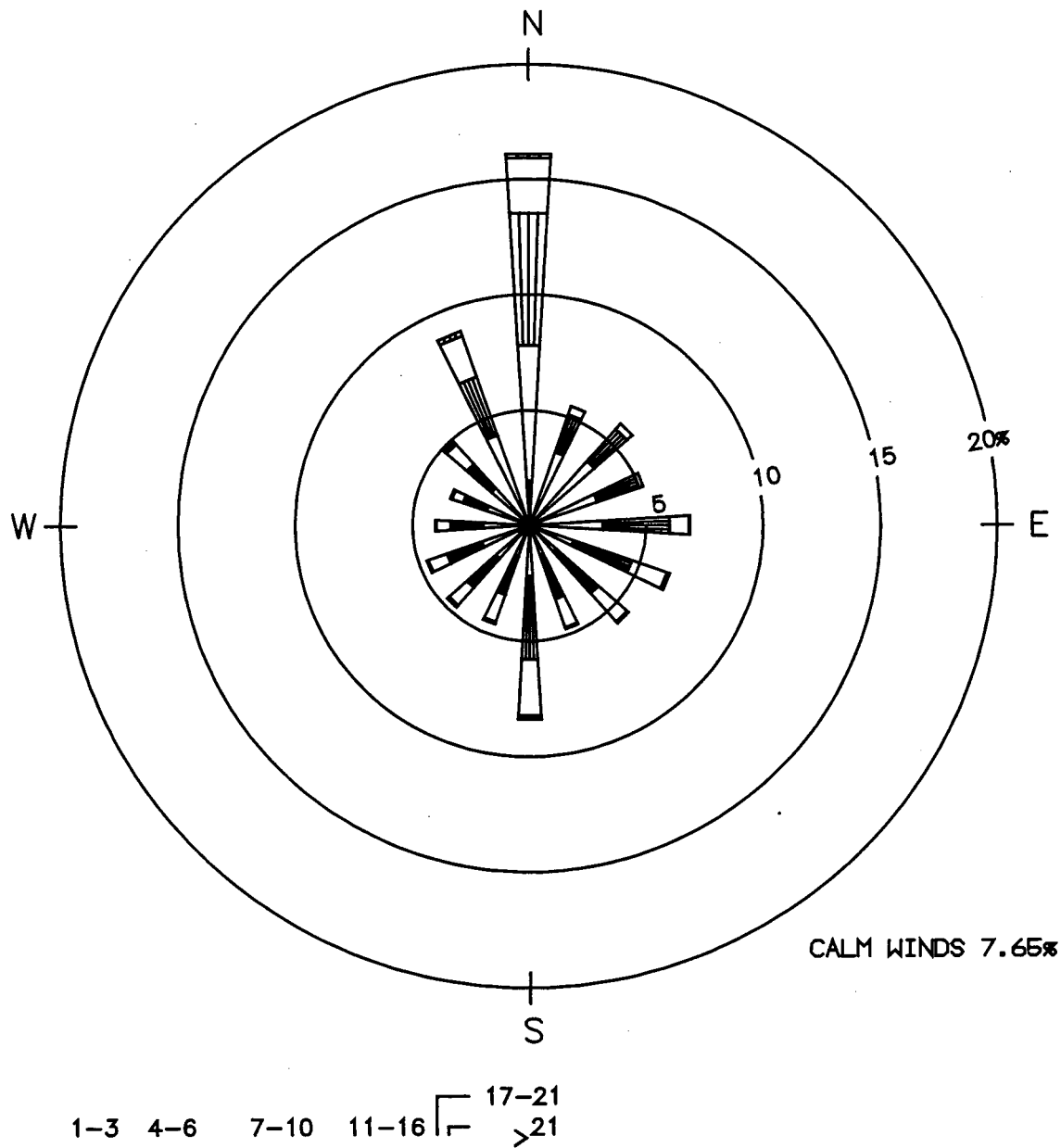
FIGURE 2.3.7-1.

3-YEAR ANNUAL WIND ROSE FOR APALACHICOLA MUNICIPAL AIRPORT (1988 - 1990)

Sources: NCDC, 1999; ECT, 1999.

ECT

Environmental Consulting & Technology, Inc.



NOTES:
 DIAGRAM OF THE FREQUENCY OF
 OCCURRENCE FOR EACH WIND DIRECTION.
 WIND DIRECTION IS THE DIRECTION
 FROM WHICH THE WIND IS BLOWING.
 EXAMPLE - WIND IS BLOWING FROM THE
 NORTH 16.1 PERCENT OF THE TIME.

WINDROSE

STATION NO. 13899

Pensacola, Florida

PERIOD: 1986-1990

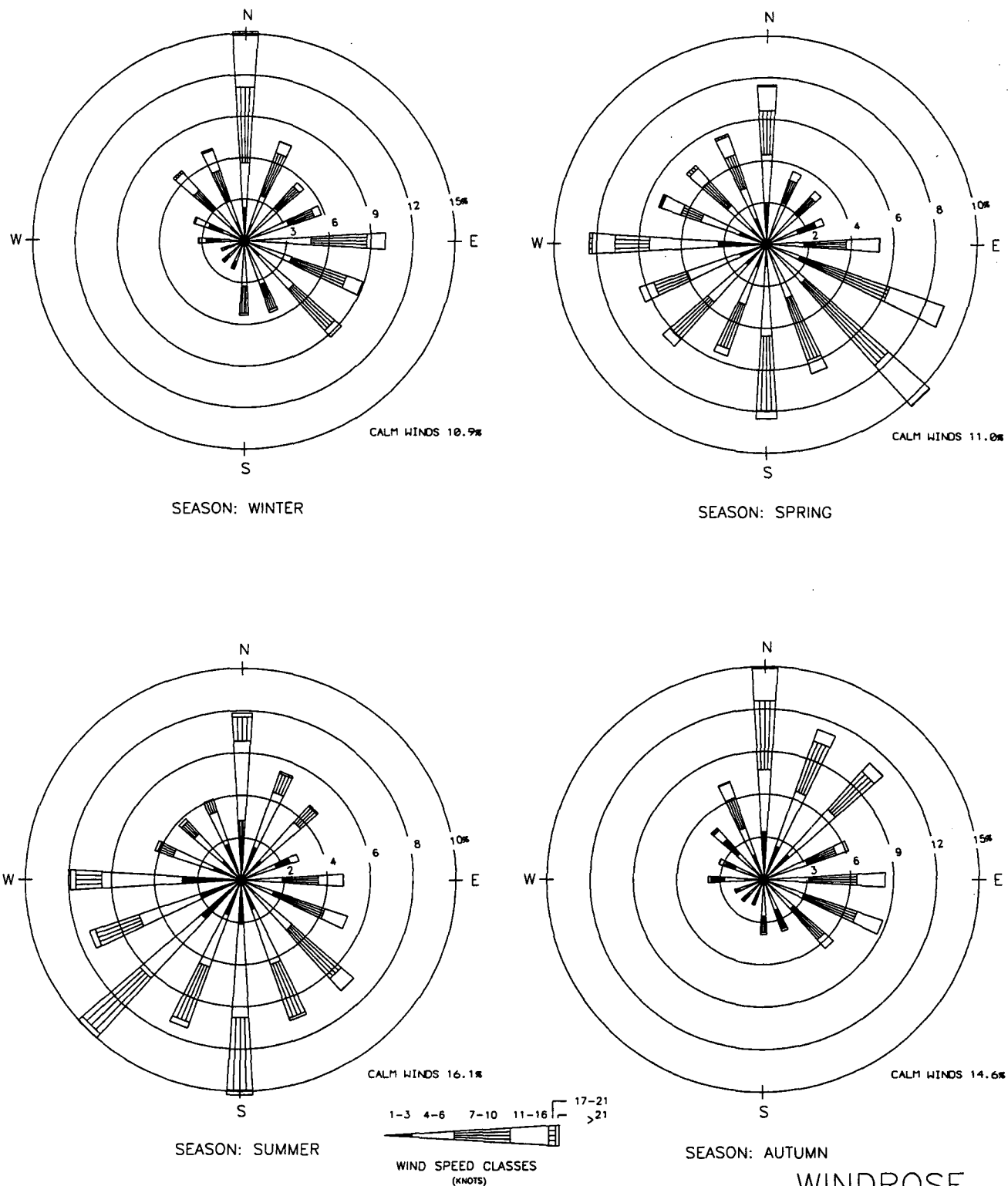
FIGURE 2.3.7-2.

5-YEAR ANNUAL WIND ROSE FOR PENSACOLA
 REGIONAL AIRPORT (1986 - 1990)

Source: NCDC, 1999; ECT, 1999.

ECT

Environmental Consulting & Technology, Inc.



NOTES:
DIAGRAM OF THE FREQUENCY OF
OCCURRENCE FOR EACH WIND DIRECTION.
WIND DIRECTION IS THE DIRECTION
FROM WHICH THE WIND IS BLOWING.
EXAMPLE - WIND IS BLOWING FROM THE
NORTH 14.9 PERCENT OF THE TIME.

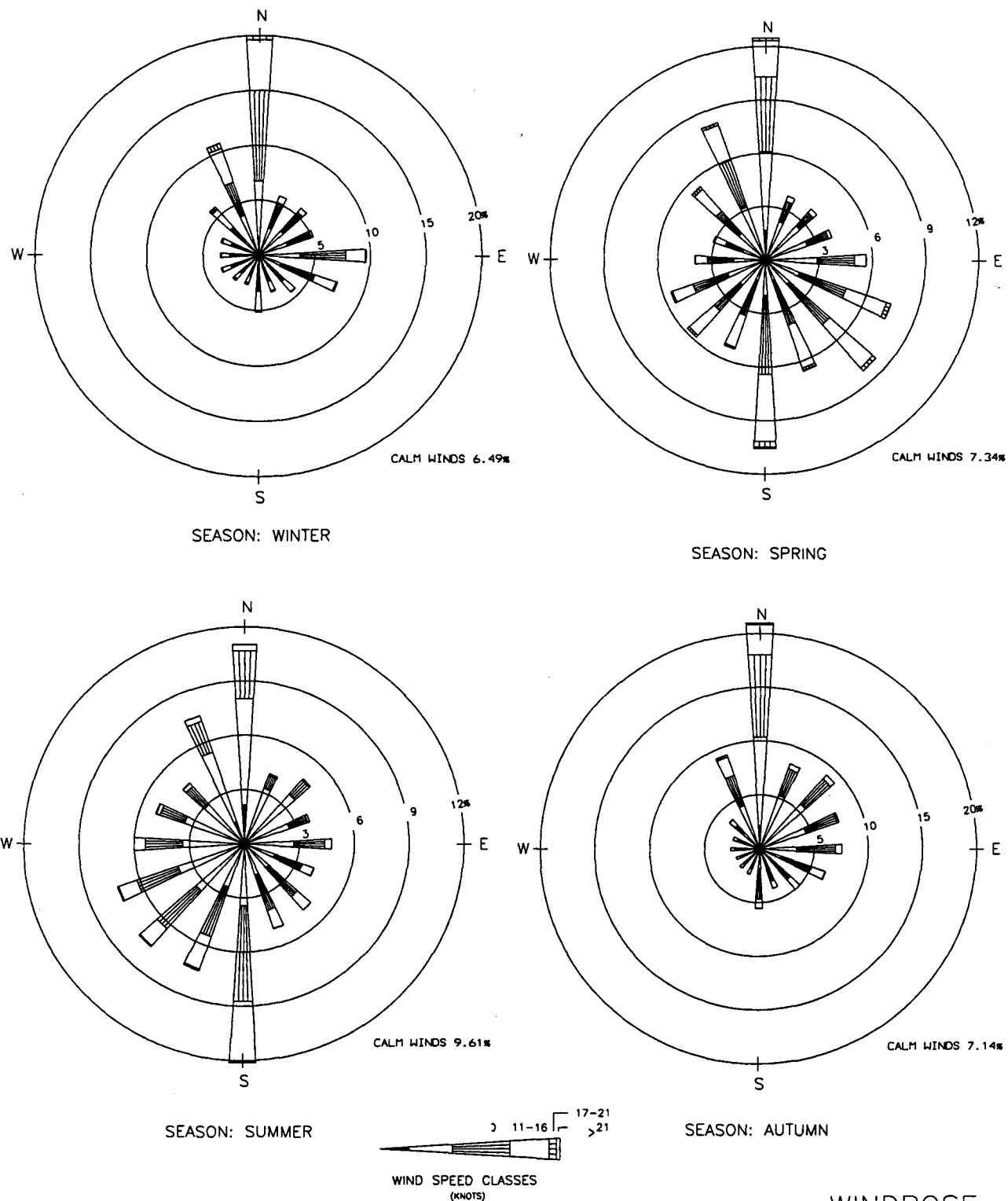
WINDROSE
STATION NO. 12832
Apalachicola, FL
PERIOD: 1988-1990

FIGURE 2.3.7-3.

3-YEAR SEASONAL WIND ROSE FOR
APALACHICOLA MUNICIPAL AIRPORT (1988 - 1990)

Sources: NCDC, 1999; ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.



NOTES:
 DIAGRAM OF THE FREQUENCY OF
 OCCURRENCE FOR EACH WIND DIRECTION.
 WIND DIRECTION IS THE DIRECTION
 FROM WHICH THE WIND IS BLOWING.
 EXAMPLE - WIND IS BLOWING FROM THE
 NORTH 21.0 PERCENT OF THE TIME.

FIGURE 2.3.7-4.

5-YEAR SEASONAL WIND ROSE FOR PENSACOLA
 REGIONAL AIRPORT (1986 - 1990)

Source: NCDC, 1999; ECT, 1999.

ECT
 Environmental Consulting & Technology, Inc.

Table 2.3.7-3 presents the annual and seasonal pattern of atmospheric stability in the Apalachicola area, as characterized by the 3-year modeling period of record. During the summer, unstable conditions are present approximately 17 percent of the time because of strong insulation. During the winter, the occurrence of unstable conditions is reduced to 2 percent of the time. Neutral stability is more common in the winter, occurring approximately 46 percent of the time. Stable conditions are uniformly distributed throughout the year, occurring 39 to 47 percent of the time.

Table 2.3.7-4 presents the annual and seasonal pattern of atmospheric stability in the Pensacola area, as characterized by the 5-year period of record. During the summer, unstable conditions are present approximately 13 percent of the time because of strong insulation. During the winter, the occurrence of unstable conditions is reduced to 2 percent of the time. Neutral stability is more common in the winter, occurring approximately 43 percent of the time. Stable conditions are uniformly distributed throughout the year, occurring 39 to 44 percent of the time.

The mixing height defines the upper limit of the surface boundary layer and, thus, is an important factor in determining the atmosphere's dispersion characteristics. The annual and seasonal averaging morning and afternoon mixing heights for Apalachicola, as calculated by NWS, are presented in Table 2.3.7-5. The lowest mixing heights occur in the morning in the winter and the highest mixing heights occur in the afternoon in the summer.

Thunderstorms are the most common severe weather in the area, occurring on an average of 72 days each year at the NWS Apalachicola observation station and 68 days each year at the NWS Pensacola observation station. Thunderstorms occur most frequently during the summer, but may occur at any time during the year.

Table 2.3.7-3. Annual and Seasonal Average Distribution of Atmospheric Stability Classes for Apalachicola, Florida (1986 through 1990)

Season	Occurrence (%) of Stability Class					
	Very Unstable	Moderately Unstable	Slightly Unstable	Neutral	Slightly Stable	Moderately Stable
Winter	<0.1	2.3	12.0	46.8	13.9	25.1
Spring	0.6	8.3	18.7	33.0	11.8	27.6
Summer	1.6	15.8	20.6	16.9	11.8	33.3
Fall	0.2	6.3	17.1	29.1	13.3	33.9
Annual	0.6	8.2	17.2	31.4	12.7	30.0

Sources: NCDC, 1999.
ECT, 1999.

Table 2.3.7-4. Annual and Seasonal Average Distribution of Atmospheric Stability Classes for Pensacola, Florida (1986 through 1990)

Season	Occurrence (%) of Stability Class					
	Very Unstable	Moderately Unstable	Slightly Unstable	Neutral	Slightly Stable	Moderately Stable
Winter	<0.1	1.8	7.9	59.4	14.7	16.2
Spring	0.8	5.7	14.7	43.7	15.0	20.1
Summer	2.5	10.7	18.5	25.4	15.9	27.0
Fall	0.3	6.6	14.3	35.3	17.2	26.5
Annual	0.9	6.2	13.8	40.8	15.7	22.5

Sources: NCDC, 1999.
ECT, 1999.

Table 2.3.7-5. Annual and Seasonal Average Mixing Heights for Apalachicola, Florida (1986 through 1990)

Season	Mixing Height (meters)	
	Morning	Afternoon
Winter	395.1	604.1
Spring	486.7	1,114.2
Summer	607.9	1,287.9
Fall	460.2	1,031.7
Annual	487.5	1,031.6

Sources: NCDC, 1999.
ECT, 1999.

2.3.7.2 Ambient Air Quality

The Smith Unit 3 Project site is located in an area that FDEP classifies as attainment for all criteria pollutants (Section 62-204.240, F.A.C.). This means that the area meets all state and federal ambient air quality standards (AAQS), which are given in Table 2.3.7-6. Ambient air monitoring data are available with which to generally characterize the existing conditions in the vicinity of the site. Table 2.3.7-7 lists the ambient monitoring stations closest to the Project site for each criteria pollutant, per FDEP reports for calendar years 1997 and 1998. Figure 2.3.7-5 shows the locations of these stations relative to the Project site. Data for particulate matter less than or equal to 10 micrometers aerodynamic diameter (PM₁₀) are available at one location in Bay County. For all other pollutants the closest monitoring stations are outside the county. Ambient data for sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), ozone, and lead have been collected in the Pensacola, Tallahassee, and Jacksonville areas and would not be truly representative of Bay County. Given the rural nature of the site, existing concentrations of these pollutants, which are usually associated more closely with urban environments, should be well below the applicable standards.

With the caveats just given as to the extent to which available monitoring data are representative of the Project site, Tables 2.3.7-8 through 2.3.7-13 present summaries of the available data. In addition, Tables 2.3.7-14 through 2.3.7-16 present Gulf Power's air monitoring data summaries for NO₂, TSP, and SO₂, respectively. These presentations of data are consistent with the conclusion that the Project site—Bay County in general—is characterized as having good air quality.

Another indicator of existing air quality is proximity to other emission sources. In this vein, the air quality of the Project site benefits from a lack of other sources in the area. Bay County has, in general, less heavy industry than many counties in Florida. The largest sources of air emissions are the existing units of the Lansing Smith Plant, the Stone Container Corporation pulp mill, the Arizona Chemical Company gum and wood chemicals plant, and the Bay County waste incinerator (information according to EPA's

Table 2.3.7-6. National and Florida AAQS (microgram per cubic meter [$\mu\text{g}/\text{m}^3$])

Pollutant	Averaging Time	National AAQS		Florida AAQS
		Primary	Secondary	
PM ₁₀	Annual arithmetic mean	50	50	50
	24-hour maximum*	150	150	150
PM _{2.5}	Annual arithmetic mean	15	15	NA
	24-hour maximum†	65	65	NA
SO ₂	Annual arithmetic mean	80	NA	60
	24-hour maximum‡	365	NA	260
	3-hour maximum‡	NA	1,300	1,300
NO ₂	Annual arithmetic mean	100	100	100
CO	8-hour maximum‡	10,000	NA	10,000
	1-hour maximum‡	40,000	NA	40,000
Ozone	8-hour maximum**	157	157	NA
	1-hour maximum††	235	235	235
Lead	Calendar quarter arithmetic mean	1.5	1.5	1.5

*Standard is attained when the 99th percentile 24-hour concentration is less than or equal to the standard.

†Standard is attained when the 98th percentile 24-hour concentration is less than or equal to the standard.

‡ Maximum concentration not to be exceeded more than once per year.

** Standard is attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard.

†† Standard is attained when the 3-year average number of days with a maximum hourly concentration above the standard is less than 1.0. (The national AAQS 1-hour standard is no longer in effect in Florida. It has been replaced by the 8-hour standard.)

Note: NA = not applicable.

Sources: 40 CFR 50.
Rule 62-204.240, F.A.C.
ECT, 1999.

Table 2.3.7-7. Ambient Air Quality Monitoring Stations Closest to the Smith Unit 3 Project Site

Pollutant	FDEP Station No.	Station Location		Relative to Project Site (km)
		County	City	
PM ₁₀	3480-004-F02 12-005-1004	Bay	Panama City	13 SE
	3740-003-F02 12-045-1003	Gulf	Port St. Joe	60 SE
SO ₂	3540-004-F01 12-033-0004	Escambia	Pensacola	161 W
	3540-022-F02 12-033-0022	Escambia	Pensacola	161 W
NO ₂	3540-004-F01	Escambia	Pensacola	161 W
CO	1960-080-H01 12-031-0080	Duval	Jacksonville	441 E
	1960-083-H01 12-031-0083	Duval	Jacksonville	441 E
	1960-084-H01 12-031-0084	Duval	Jacksonville	441 E
	1960-095-H01 12-031-0085	Duval	Jacksonville	441 E
Ozone	2340-003-F01	Leon	Tallahassee	158 NE
	12-073-0012	Leon	Tallahassee	158 NE
Lead	1960 032 H01 12-031-0032	Duval	Jacksonville	441 E
	1960-084-H01 12-031-0084	Duval	Jacksonville	441 E

Sources: FDEP, 1997 and 1998.
ECT, 1999.

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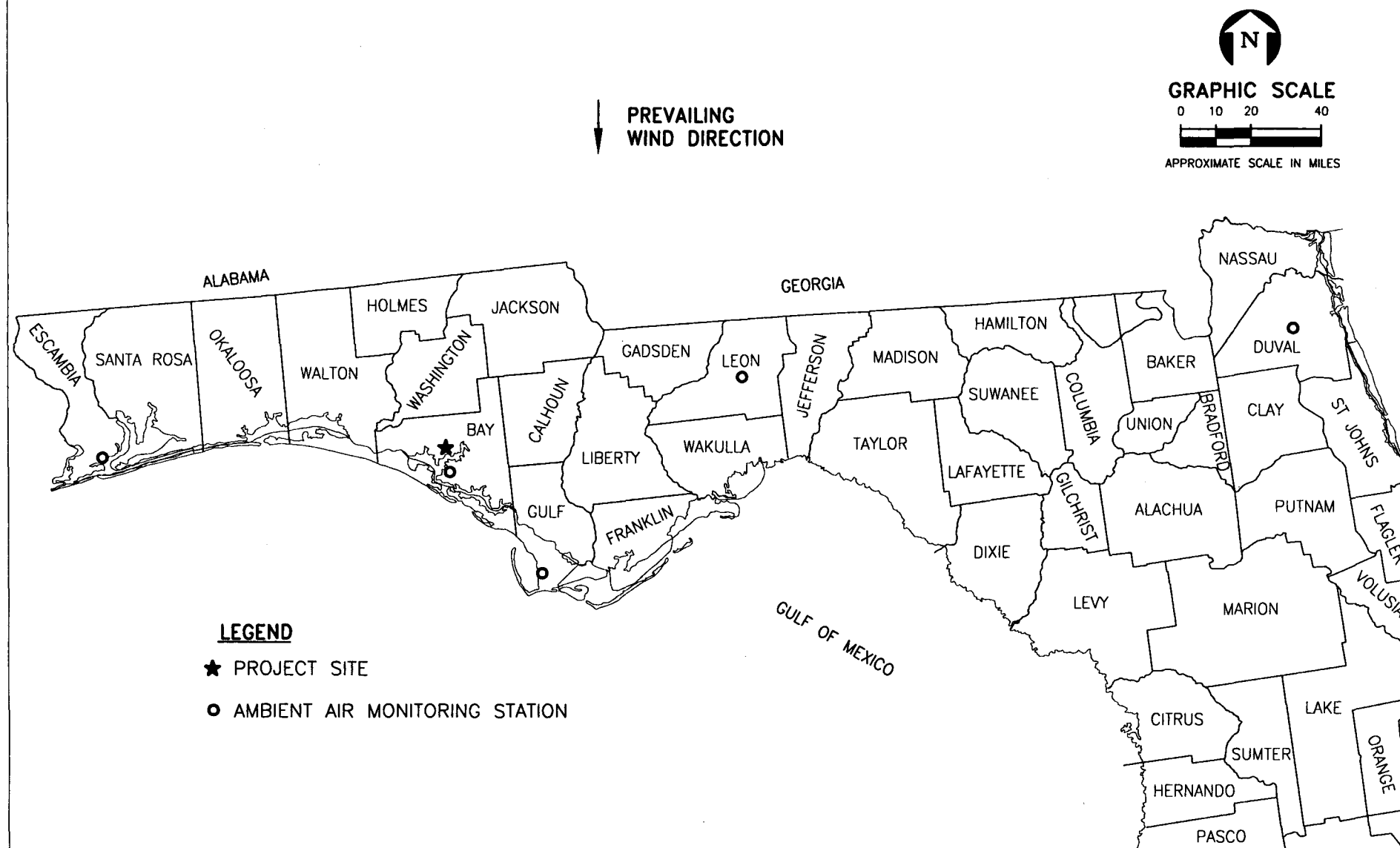


FIGURE 2.3.7-5.
LOCATIONS OF CLOSEST FDEP
AIR QUALITY MONITORING STATIONS

Source: ECT, 1998.

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Table 2.3.7-8. Summary of FDEP PM₁₀ Monitoring Near the Smith Unit 3 Project Site

Location	Site Identification Number	Year	24-Hour Measurement		Annual Arithmetic Mean (µg/m ³)
			Highest (µg/m ³)	Second-highest (µg/m ³)	
Panama City	3480-004-F02	1997	62	52	25
	12-005-1004	1998	73	64	28
Port St. Joe	3740-003-F02	1997	65	54	23
	12-045-1003	1998	73	65	26

Note: The 24-hour ambient PM₁₀ standard is 150 µg/m³, attained when the 99th percentile concentration is less than or equal to the standard; the annual ambient PM₁₀ standard is 50 µg/m³, annual arithmetic mean.

Source: FDEP, 1998 and 1999.

Table 2.3.7-9. Summary of FDEP SO₂ Monitoring Near the Smith Unit 3 Project Site

Location	Site Identification Number	Year	Highest 3-Hour Average (µg/m ³)	Highest 24-Hour Average (µg/m ³)	Annual Average (µg/m ³)
Pensacola	3540-004-F01	1997	233	98	11
	12-033-0004	1998	253	60	10
Pensacola	3540-022-F02	1997	333	114	12
	12-033-0022	1998	264	63	10

Note: The 3-hour ambient standard is 1,300 µg/m³, not to be exceeded more than once per year.
The 24-hour ambient standard is 260 µg/m³, not to be exceeded more than once per year.
The annual ambient standard is 60 µg/m³, arithmetic mean.

Source: FDEP, 1998 and 1999.

Table 2.3.7-10. Summary of FDEP NO₂ Monitoring Near the Smith Unit 3 Project Site

Location	Site Identification Number	Year	Annual Average (µg/m ³)
Pensacola	3540-004-F01	1997	16

Note: The annual ambient standard is 100 µg/m³, arithmetic mean.

Source: FDEP, 1998 and 1999.

Table 2.3.7-11. Summary of FDEP CO Monitoring Near the Smith Unit 3 Project Site

Location	Site Identification Number	Year	Highest 1-Hour Average ($\mu\text{g}/\text{m}^3$)	Highest 8-Hour Average ($\mu\text{g}/\text{m}^3$)
Jacksonville	1960-080-H01	1997	3,420	2,280
	12-031-0080	1998	9,576	5,130
Jacksonville	1960-083-H01	1997	7,980	3,420
	12-031-0083	1998	5,586	3,534
Jacksonville	1960-084-H01	1997	6,840	4,560
	12-031-0084	1998	6,954	3,762
Jacksonville	1960-095-H01	1997	7,980	3,420
	12-031-0095	1998	5,016	2,280

Note: The 1-hour ambient standard is $40,000 \mu\text{g}/\text{m}^3$, not to be exceeded more than once per year.
The 8-hour ambient standard is $10,000 \mu\text{g}/\text{m}^3$, not to be exceeded more than once per year.

Source: FDEP, 1998 and 1999.

Table 2.3.7-12. Summary of FDEP Ozone Monitoring Near the Smith Unit 3 Project Site

Location	Site Identification Number	Year	1-Hour Measurement	
			Highest ($\mu\text{g}/\text{m}^3$)	Second-highest ($\mu\text{g}/\text{m}^3$)
Tallahassee	2340-003-F01	1997	135	110
Tallahassee	12-073-0012	1998	202	190

Note: The 1-hour ambient ozone standard is $235 \mu\text{g}/\text{m}^3$, attained when the 3-year average number of days with a maximum hourly concentration above the standard is less than 1.0.

Source: FDEP, 1998 and 1999.

Table 2.3.7-13. Summary of FDEP Lead Monitoring Near the Smith Unit 3 Project Site

Location	Site Identification Number	Year	Quarterly Arithmetic Average ($\mu\text{g}/\text{m}^3$)			
			1	2	3	4
Jacksonville	1960-032-H01	1997	0.0	0.0	0.0	0.0
	12-031-0032	1998	0.01	0.02	0.01	0.02
Jacksonville	1960-084-H01	1997	0.0	0.0	0.0	0.0
	12-031-0084	1998	0.01	0.01	0.01	0.02

Note: The ambient standard is $1.5 \mu\text{g}/\text{m}^3$, calendar quarterly arithmetic mean.

Source: FDEP, 1998 and 1999.

Table 2.3.7-14. Summary of 1993-1998 Gulf Power NO₂ Monitoring

Location	Site Identification Number	Year	Geometric Mean* ($\mu\text{g}/\text{m}^3$)
North remote Lynn Haven	2420-004J02	1993	5
		1994	5
		1995	5
		1996	6
		1997	13
		1998	3

Note: The annual ambient standard is 100 $\mu\text{g}/\text{m}^3$, arithmetic mean.

*Average of four quarterly geometric means.

Sources: Gulf Power Company, 1999.
ECT, 1999.

Table 2.3.7-15. Summary of 1993-1998 Gulf Power TSP Monitoring

Location	Year	Geometric Mean* ($\mu\text{g}/\text{m}^3$)
Smith Plant	1993	22
	1994	22
	1995	23
	1996	19
	1997	19
	1998	25

*Average of four quarterly geometric means.

Sources: Gulf Power Company, 1999.
ECT, 1999.

Table 2.3.7-16. Summary of 1993-1998 Gulf Power SO₂ Monitoring

Location	Site Identification Number	Year	Highest 3-Hour Average (µg/m ³)	Highest 24-Hour Average (µg/m ³)	Annual Average (µg/m ³)
North remote Lynn Haven	2420-007J02	1993	138	47	
		1994	238	44	
		1995	700	154	
		1996	1,005	76	
		1997	529	152	16
		1998	584	199	6
East remote Lynn Haven	2420-005J02	1993	183	27	
		1994	597	166	
		1995	504	256	
		1996	721	248	
		1997	490	178	17
		1998	629	202	11

Note: The 3-hour ambient standard is 1,300 µg/m³, not to be exceeded more than once per year.
The 24-hour ambient standard is 260 µg/m³, not to be exceeded more than once per year.
The annual ambient standard is 60 µg/m³, arithmetic mean.

Sources: Gulf Power Company, 1999.
ECT, 1999.

“AIRSData” online emissions database, 1997 data). These three other facilities are located in Panama City, approximately 19 km east, and 16 km southeast of the Project site, as shown in Figure 2.3.7-6.

2.3.7.3 Measurement Programs

No program to measure existing meteorological or ambient air quality conditions was undertaken for the Project. Given the low impacts predicted for the Project’s combustion emissions, the use of existing data was deemed appropriate. Section 8.0 of the PSD application (Appendix 10.2.7) provides justification for the use of available ambient air data.

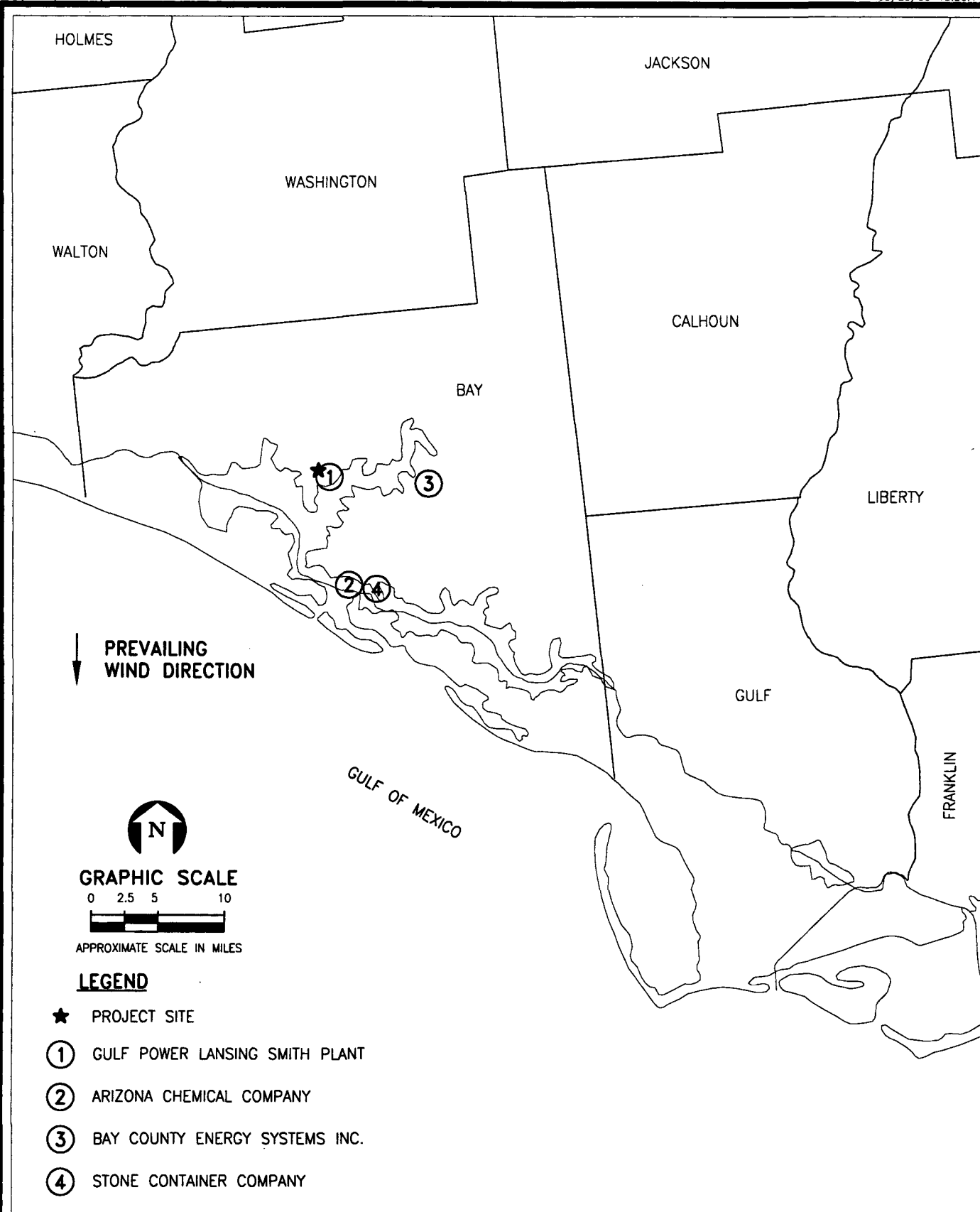


FIGURE 2.3.7-6.

OTHER AIR EMISSION SOURCES IN BAY COUNTY

Source: ECT, 1999.

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2.3.8 NOISE

The Smith Unit 3 Project site is located directly north of the existing Lansing Smith Plant property and approximately 3,000 ft east of the southern terminus of CR 2300 at the plant entrance. The closest residence is approximately 2 miles to the northeast. The plant site is currently planted in pine for silvicultural purposes as are the surrounding properties to the east, west, and north. The area to the south is designated industrial (existing Lansing Smith plant).

The only manmade noise sources in the area are from the existing Lansing Smith Plant. Every 20 to 25 years the pine is harvested. This adds to the noise levels from the Lansing Smith plant. Natural noise sources include wind, insects, and birds.

A comprehensive sound level survey was conducted at the existing plant and at the coal handling system during June 1989. Sound level measurements were made throughout the plant and at numerous points around the plant site boundaries at that time.

Measurements of the A-weighted sound level were made using a Bruel & Kjaer Model 2215 sound level meter. The instrument was equipped with a Bruel & Kjaer Model 4165 microphone to meet the requirements of American National Standards Institute (ANSI) S1.4-1983 for Type 1 precision sound level meters. A windscreen was used to reduce, but not eliminate, wind-generated noise. Calibration of the sound level meter was performed before and after each group of measurements using a Bruel & Kjaer Model 4230 calibrator. Sound level measurements were made for 5- to 10-minute periods around the plant. The overall sound levels measured at the west Gulf property boundary from the existing Smith Plant were 40.3 A-weighted decibels (dBA) and from the coal handling area were 42.3 dBA.

The Bay County Land Use Code defines the maximum noise level that shall not be exceeded in the receiving land use. The receiving land uses in the area are silvicultural to the east, west, and north, and residential 2 miles to the northeast of the site. For agricultural, silvicultural or industrial land use, noise levels shall not exceed 75 dBA. For residential, conservation, or special development land use, daytime noise levels shall not ex-

ceed 60 dBA and 55 dBA at night. The distance between the existing power plant and these land uses will attenuate the noise so as not to exceed the limits.

2.3.9 OTHER ENVIRONMENTAL FEATURES

The previous sections have provided detailed descriptions of the environmental features of the Smith Unit 3 Project site and surrounding areas. No other special or significant environmental features exist on the site which require additional information.

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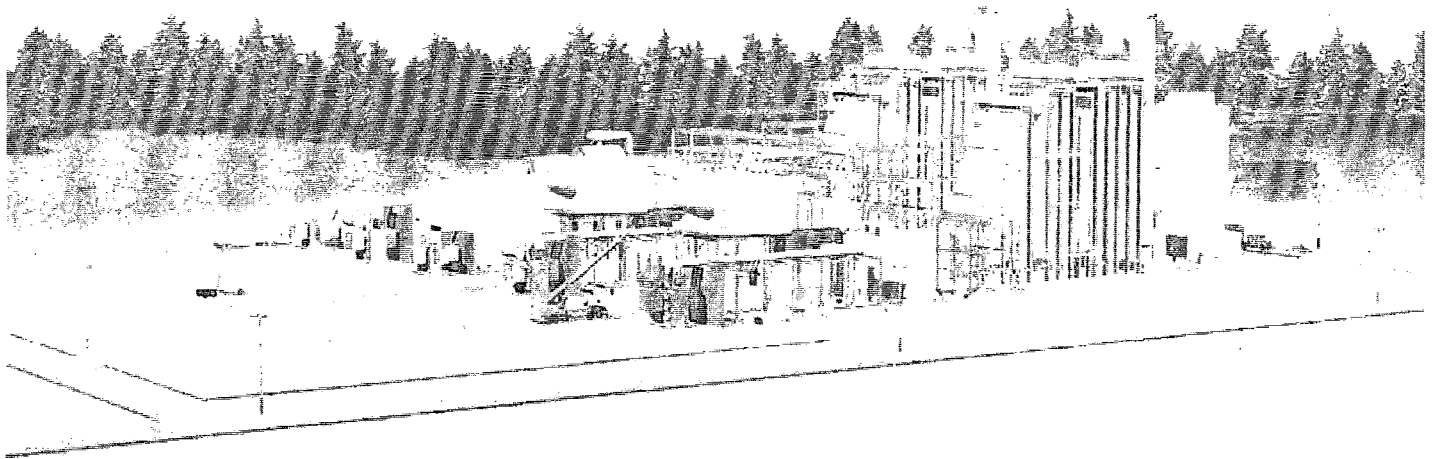
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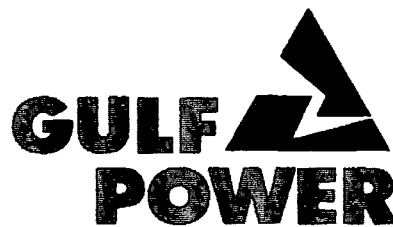
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GULF POWER SMITH UNIT 3 Site Certification Application



Volume 2

June 1999



A SOUTHERN COMPANY

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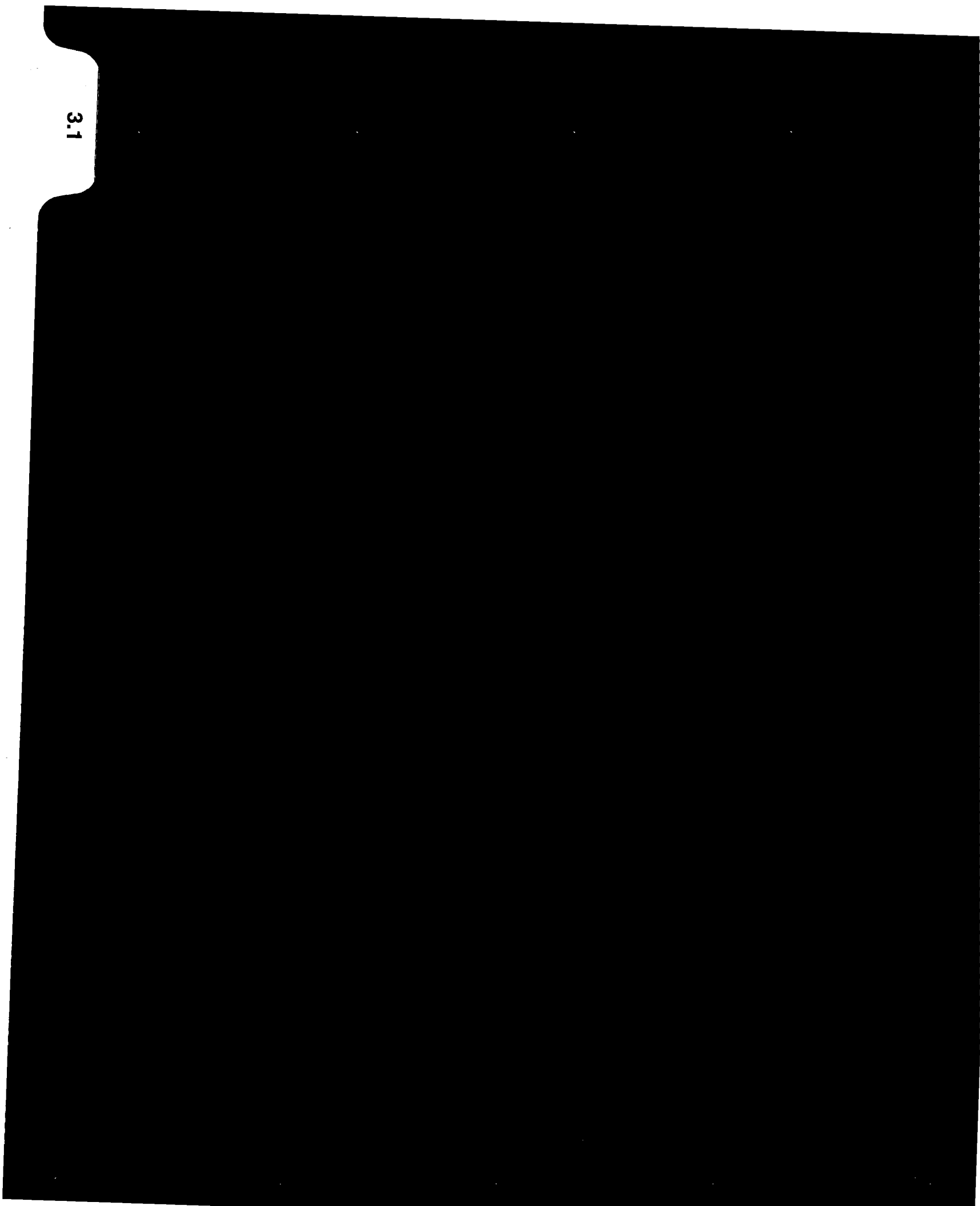
3.0

3.0 THE PLANT AND DIRECTLY ASSOCIATED FACILITIES

This chapter provides descriptions of the proposed power plant facilities, the key components and systems of the plant and their operations, and the directly associated facilities which will comprise the Smith Unit 3 Power Project. The descriptions include, to the extent possible, estimates of the expected character, quality, and quantity of discharges and emissions from the plant facilities and operations. Also, proposed measures and systems to control and, as necessary, treat the expected emissions and discharges are described in order to provide reasonable assurance that the plant operations comply with applicable regulatory requirements and standards. The specific sections in this chapter are:

- 3.1—Background.
- 3.2—Site Layout.
- 3.3—Fuel.
- 3.4—Air Emissions and Controls.
- 3.5—Plant Water Use.
- 3.6—Chemical and Biocide Waste.
- 3.7—Solid and Hazardous Waste.
- 3.8—Onsite Drainage System.
- 3.9—Materials Handling.

The descriptions presented in this chapter are based on Project plans and available engineering and design information for the proposed Smith Unit 3 facility.



3.1 BACKGROUND

3.1.1 OVERVIEW

The Smith Unit 3 Project will add a new 500-MW class CC power plant to Gulf's existing Lansing Smith Plant. The Project will be constructed on a 50-acre site adjacent to the existing facility, which is located in Bay County, just north of Panama City, Florida. The new plant will produce electrical power by burning natural gas in two gas turbines and two HRSGs which will have supplemental burners.

Typical plant operation is expected to produce 519 MW when operating with the gas turbines at full load with no supplemental firing of the HRSGs at ambient conditions of 65°F and 60 percent relative humidity. Net plant output can achieve 574 MW during peak firing operation with the gas turbines utilizing power augmentation and the HRSGs supplementally fired to their maximum capability with natural gas.

The Project is currently scheduled to begin commercial operation on June 1, 2002, pending approval by the appropriate regulatory and environmental agencies. The onsite construction schedule is anticipated to last 21 months with onsite activities beginning as early as September 2000. The major construction activities include the following:

- Site clearing and grubbing.
- Site excavation, filling, and grading.
- General site improvements (lighting, fences, etc.).
- Excavation and installation of piles.
- Installation of underground piping and utilities.
- Concrete foundation completion.
- Erection of support building and structures.
- Erection of HRSGs, gas turbines, and steam turbines.
- Installation of auxiliary support equipment.
- Installation of interconnecting piping and wiring.
- Equipment testing and startup.
- Interconnection to electrical power grid.

- Plant acceptance testing.
- Final site landscaping and cleanup.

All construction activities will be performed in a manner that will minimize overall environmental impacts to the site and the general locale as much as possible. Existing roads to the Lansing Smith Plant will be used for overall site access. Site clearing and grubbing will consist of the removal of trees, vegetation, and underlayment from the site; excavation and grading will involve the removal of some quantity of additional underlayment and replacement with suitable soil and other appropriate fill for proper preparation of the site.

Gulf is proposing to use fly ash, an industrial coal combustion by-product generated from the burning of bituminous coal, as an alternative replacement fill material in lieu of natural backfill materials to be supplied from a local borrow pit. Fly ash is readily available at the Smith site where the ash handling process involves an ash sluice system wherein ash is hydraulically transferred from plant boilers to a permitted, onsite ash pond. The material can be excavated, de-watered, and beneficially re-used as a suitable alternative fill material for the Smith Unit 3 construction.

The use of piles for proper foundation support are anticipated with required pile driving being performed following completion of the site excavation, filling, and grading. The site development process will be properly managed to minimize the impacts of site runoff and soil erosion on the surrounding estuaries and wetlands.

Major equipment is currently anticipated to be delivered to the site by barge utilizing the existing site intake canal. The temporary barge unloading facility will be integrated into the existing barge unloading structures utilized at the Lansing Smith Plant. Other equipment will be received by truck at the site using existing roads to the Lansing Smith Plant. Due to the use of the existing Lansing Smith Plant site, the overall impact of additional noise levels, increased dust levels, and increased overall activity at the site is expected to have a minimal impact on the surrounding community.

3.1.2 MAJOR POWER PLANT COMPONENTS AND SYSTEMS AND THEIR OPERATION

The Smith Unit 3 Project will consist of the following major equipment pieces:

- Two 170-MW natural gas-fueled gas turbines with dry low-NO_x combustors.
- Two triple-pressure reheat HRSGs, each equipped with a supplemental duct burner for the production of additional steam.
- One 200-MW reheat steam turbine exhausting to a single steam condenser.
- A once-through cooling water system, including a mechanical draft cooling tower for circulating cooling water to the steam condenser and the service water cooling system.
- Auxiliary support systems including pumps, transformers, heat exchangers, building/control room, etc.

The integrated plant will represent a state-of-the-art CC facility which has been designed for highly efficient, continuous operation while minimizing the overall level of air emissions and overall environmental impact. The gas turbines will be GE model PG 7241(FA) units, which have a proven operating record in the United States and around the world. The GE 7FA gas turbines will utilize the latest developments in dry low-NO_x combustor technology to achieve the low emission limits at all anticipated load points. Each GE 7FA gas turbine is rated at 170 MW at standard International Standards Organization (ISO) conditions of 59°F ambient temperature and sea level elevation.

Each gas turbine exhausts into a HRSG designed and manufactured by Vogt-NEM. The HRSGs will be of the triple-pressure design and will include integral deaerators with the low-pressure section for improved efficiency. Each HRSG will be equipped with a supplemental burner that will be used for the production of additional steam. Each supplemental burner will be designed for firing natural gas only and will use the best available low-NO_x burner technology for minimizing overall air emissions.

The steam produced by the HRSGs will be utilized in a condensing reheat steam turbine with a single, low-pressure admission port. The steam turbine will typically operate with

steam conditions of 1,800 psig, 1,050°F. The steam turbine will be designed and manufactured by GE.

Figure 3.1.2-1 presents a process flow diagram showing a representative CTG/HRSG system and other principal plant systems. The CTGs will fire only natural gas; no other fuels are planned.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

GE 7FA Two on One Combined Cycle

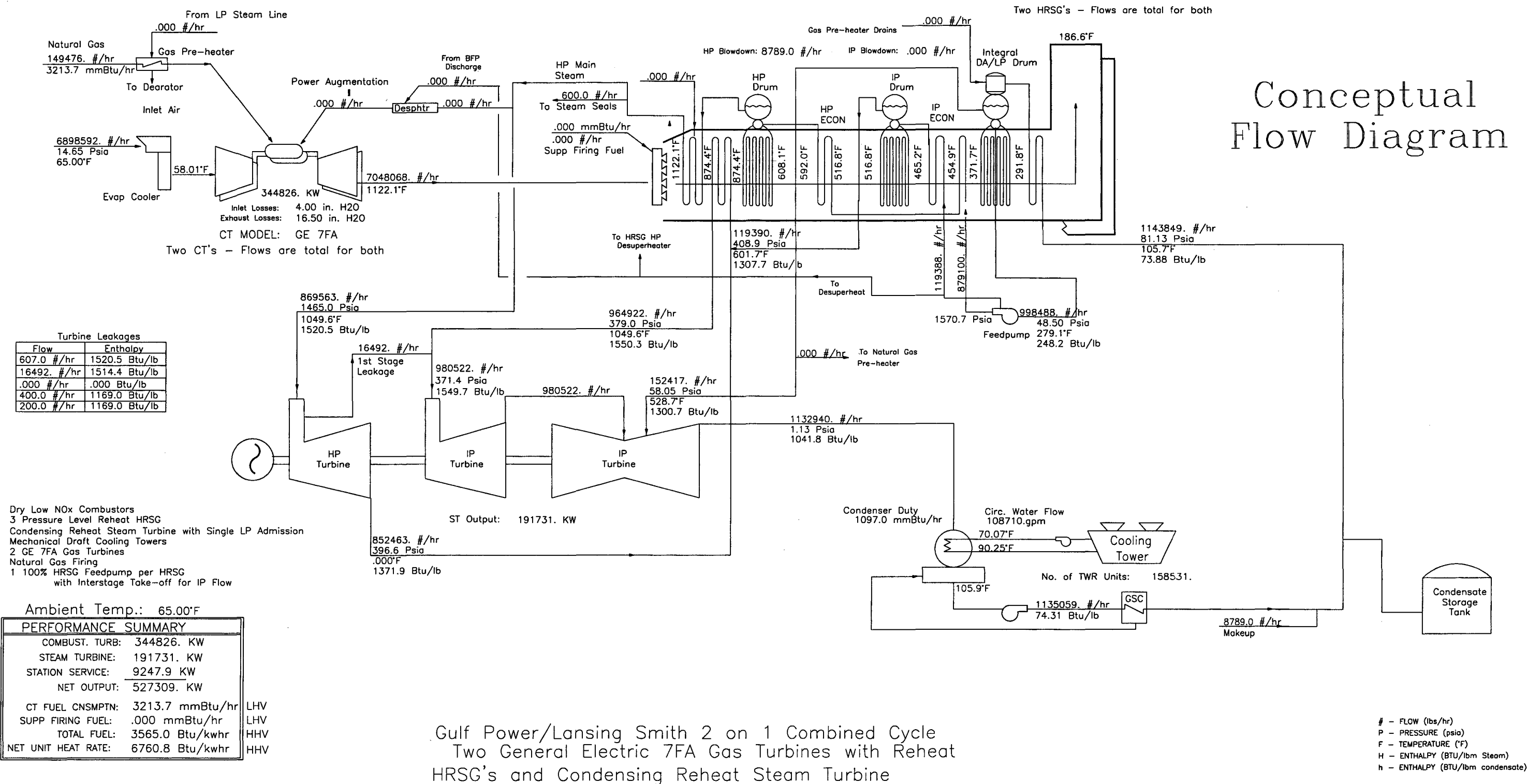


FIGURE 3.1.2-1.

CONCEPTUAL FLOW DIAGRAM

(FOR ACTUAL FLOWS SEE FIGURES 3.5.0-1 AND 3.5.0-2)

Source: SCS, 1999.

Gulf Power/Lansing Smith 2 on 1 Combined Cycle
Two General Electric 7FA Gas Turbines with Reheat
HRSG's and Condensing Reheat Steam Turbine

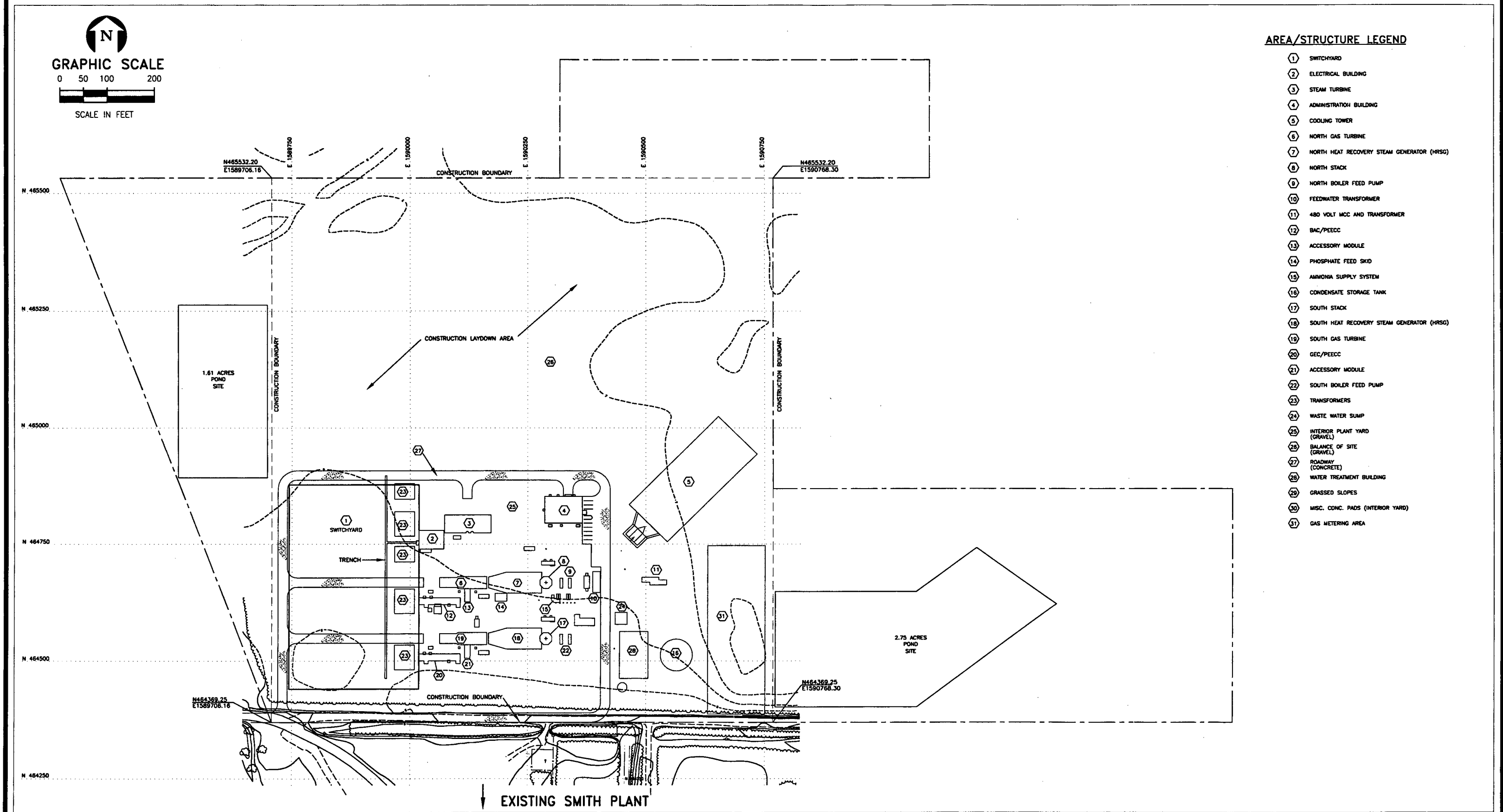
3.2 SITE LAYOUT

The general plant layout showing all major equipment is shown in Figure 3.2.0-1. Access to the site will be via a paved road (as described in Section 3.9.1).

The existing onsite 115-kV Lansing Smith substation will be expanded within the existing developed area to provide a breaker-and-a-half configuration, into which Smith Unit 3 will be connected. A breaker-and-a-half scheme has three breakers in series between the main buses. Two circuits are connected between the three breakers. This pattern is repeated along the main buses so that one-and-a-half breakers are used for each circuit. Under normal operating conditions, all breakers are closed and both buses energized. A circuit is tripped by opening the two associated breakers. The breaker-and-a-half scheme is superior in flexibility, reliability, and safety. Eight new breakers will be added to the existing substations to accommodate this reconfiguration. Within the substation, repositioning of three existing 115-kV transmission lines will be necessary.

Figure 3.2.0-2 provides an artist's rendering of the plant, consistent with the general plant layout, shown previously. The figure is essentially an oblique view. The water balance diagrams (Figure 3.5.0-1 and 3.5.0-2) show a schematic of the various interties/connections that will be made between Smith Unit 3 and the existing Smith facilities.

Smith Unit 3 will be constructed with its own substation consisting of the individual generator step-up transformers and station service transformers. This unit substation will connect to the existing Lansing Smith 230-kV substation by means of approximately 1,000 ft of wire bus. The wire bus section connecting Smith Unit 3 to the existing Lansing Smith substation will be constructed on already developed plant site property and, therefore, will not result in any additional environmental impacts. The existing Lansing Smith 230-kV substation will require a bus rearrangement and extension in order to accommodate the new unit's connection. This bus arrangement will also be performed on already developed plant property. In addition, six of the Lansing Smith 230-kV circuit breakers, one Highland City 115-kV breaker, and one Laguna 115-kV breaker will require replacement, in-place, and will not cause any environmental impact to the area.



3-9

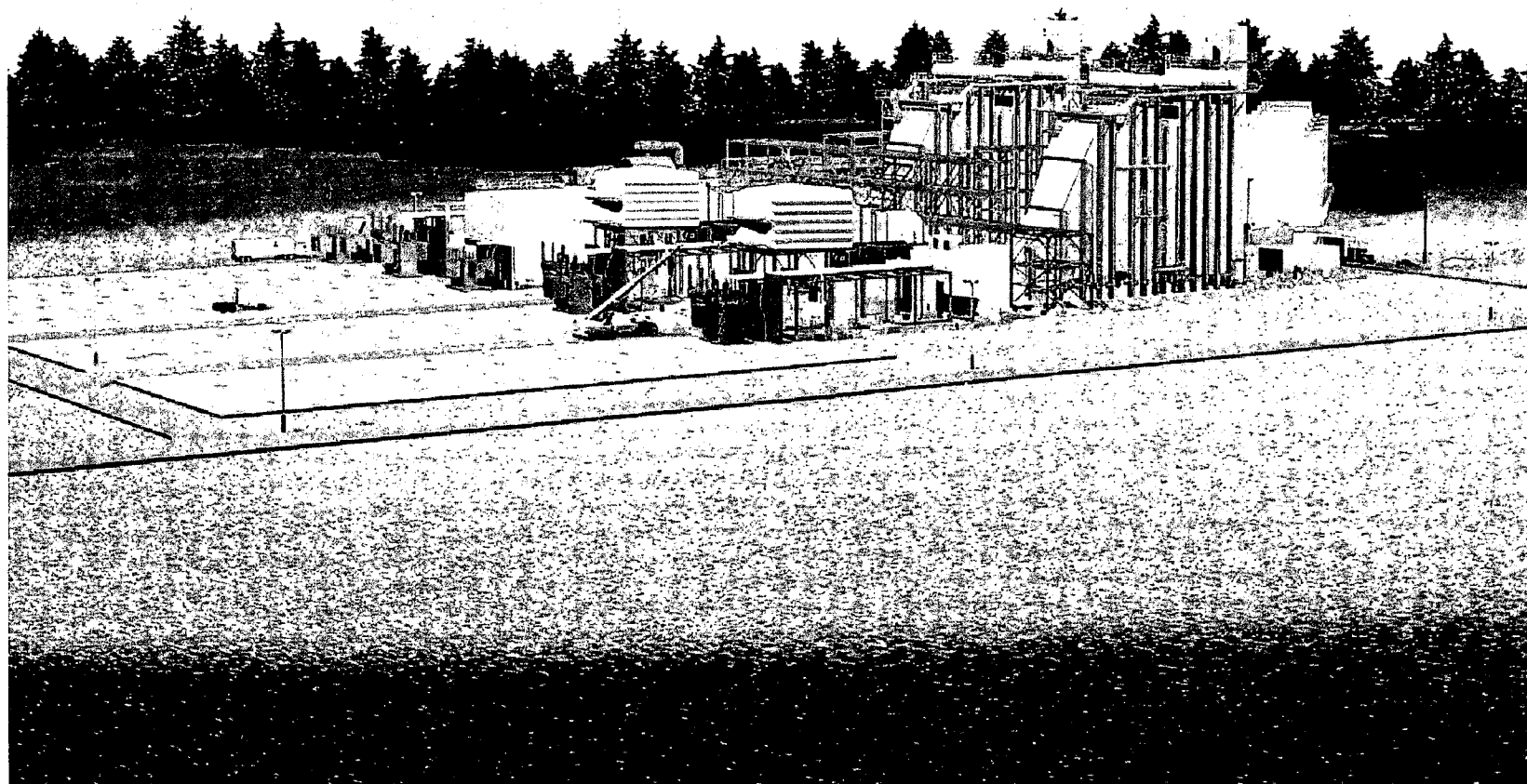


FIGURE 3.2.0-2.

RENDERING OF PROPOSED SMITH UNIT 3 (OBLIQUE VIEW)

Source: SCS, 1999.

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As a result of the addition of the new generation at Smith Plant, there are portions of three existing Gulf Power transmission lines that will require a change of the existing conductor to a conductor with higher ampacity in order to relieve contingency overloads. The existing offsite line sections requiring the replacement of conductor are (1) Smith—Greenwood 115-kV line (7.5 miles), (2) Smith—Highland City 115-kV line (7.6 miles), and (3) Highland City—Callaway 115-kV line (4.1 miles) (see Figure 3.2.0-3). This replacement of conductor will be performed on existing rights-of-way and will not necessitate the replacement or addition of transmission line structures or new access roads. Therefore, no additional impact will be caused as a result of this associated transmission upgrade resulting from the addition of Smith Unit 3 (see Section 6.1).

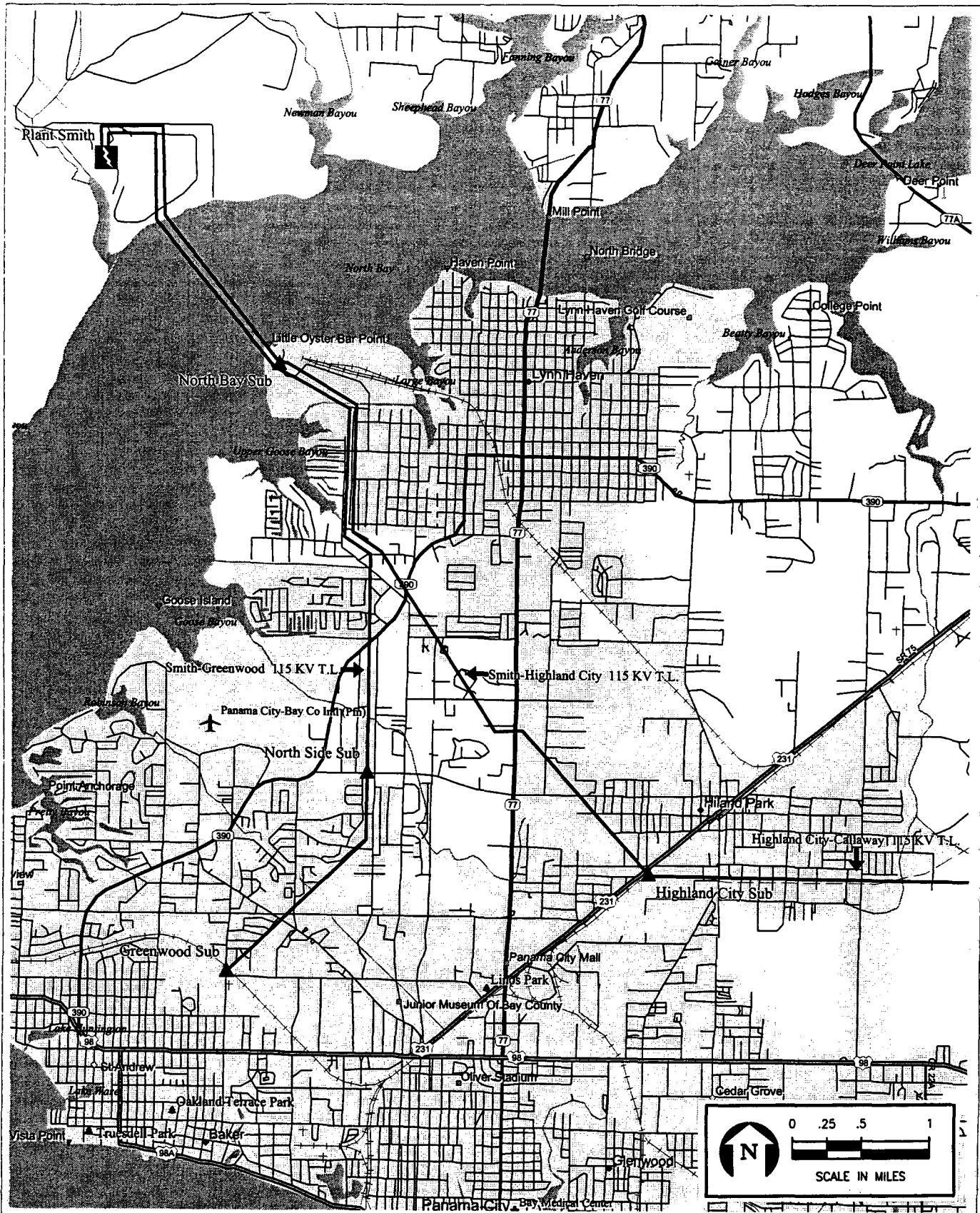


FIGURE 3.2.0-3.
TRANSMISSION UPGRADES

Sources: DeLorme, 1996; SCS, 1999.

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3.3

3.3 FUEL

The CTGs to be built at Smith Unit 3 fire on natural gas only. No alternate fuel will be available. Natural gas will be delivered to the site through a new pipeline lateral. The pipeline lateral will be connected to Florida Gas Transmission's (FGT's) pipeline system in Washington County, Florida. The interconnect will occur south of the town of Wausau and near where FGT's pipeline system crosses SR 77. The length of the pipeline lateral from FGT to Plant Smith is approximately 29 miles. A meter station and associated equipment will be constructed at Plant Smith. The plant will consume approximately 87,000 million British thermal units per day (MMBtu/day) on peak summer days and 100,000 MMBtu/day on cold days.

Table 3.3.0-1 presents a typical composition for the natural gas fuel.

Natural gas will be delivered to Smith Unit 3 by a new pipeline to be constructed by the pipeline vendor. The new pipeline's point of interconnection with existing facilities will occur South of Wausau, Florida, in Washington County, adjacent to SR 77. The pipeline lateral route will follow SR 77 south from FGT to a point where SR 77 intersects Gulf's transmission line in Bay County. Then it will parallel the transmission line into the plant.

The pipeline lateral will be licensed and permitted in separate applications by the pipeline vendor. The applications and detailed information about the pipeline will be evaluated by the appropriate regulatory agencies in separate, future proceedings. Chapter 6.0 of this SCA presents a preliminary overview of the proposed pipeline route and potential impacts.

Table 3.3.0-1. Typical Natural Gas Composition

Component	Mole Percent (by volume)
<u>Gas Composition</u>	
Pentane+	0.2
Propane	0.7
I-butane	0.2
N-butane	0.1
Nitrogen	0.4
Methane	94.5
CO ₂	0.8
Ethane	3.2
<u>Other Characteristics</u>	
Heat content (LHV)	944 Btu/ft ³ at 14.73 psia, dry
Sulfur content (maximum)	2.0 gr/100 scf

Note: Btu/ft³ = British thermal unit per cubic foot.
gr/100 scf = grain per 100 standard cubic foot.
LHV = lower heating value.
psia = pound per square inch absolute.

Source: Gulf Power Company, 1999.

3.4

3.4 AIR EMISSIONS AND CONTROLS

3.4.1 AIR EMISSION TYPES AND SOURCES

The principal sources of air emissions from Smith Unit 3 will be the two natural gas-fired CTGs. The pollutants emitted in the largest quantities will be NO_x and CO; lesser amounts of particulate matter (PM/PM₁₀), SO₂, volatile organic compounds (VOCs), and sulfuric acid (H₂SO₄) mist will also be emitted from the CTGs. Another source of PM/PM₁₀ emissions will be the cooling tower, whose drift will contain dissolved, condensable solids.

As indicated previously, GE has been selected as the CTG vendor. Table 3.4.1-1 provides maximum hourly criteria pollutant emission rates (exclusive of startup and shutdown) for each GE 7241FA CTG/HRSG unit. Maximum hourly noncriteria pollutant (i.e., H₂SO₄ mist) emission rates are summarized in Table 3.4.1-2. The highest hourly emission rates for each pollutant are provided, taking into account load and ambient temperature, to develop maximum hourly emission estimates for each CTG/HRSG unit. Maximum hourly emission rates for PM/PM₁₀, NO_x, CO, and VOCs, in units of pounds per hour (lb/hr), are projected to occur for operations at 100-percent load, steam power augmentation and duct burner firing, and 95°F ambient temperature. For PM/PM₁₀, hourly emission rates are projected to be independent of CTG load and ambient temperature based on GE emissions data. Maximum hourly rates for SO₂ and H₂SO₄ mist are projected to occur for operations at 100-percent load, duct burner firing, and 0°F ambient temperature.

Table 3.4.1-3 presents projected maximum annualized criteria and noncriteria emissions for the facility. The maximum annualized rates were conservatively estimated assuming base load operation for 7,760 hr/yr with duct burner firing and evaporative cooling at an average annual ambient temperature of 59°F (i.e., Case 6 operating conditions) and base load operation for 1,000 hr/yr with steam power augmentation, evaporative cooling, and duct burner firing at an average annual ambient temperature of 95°F (i.e., Case 11 operating conditions). Cooling tower PM/PM₁₀ emissions and total facility annual emissions are also shown in Table 3.4.1-3.

Table 3.4.1-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	PM/PM ₁₀ *		SO ₂		NO _x		CO		VOC		Pb	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	0†	20.8	2.62	12.7	1.60	78.7	9.91	78.7	9.91	10.2	1.29	Neg.	Neg.
	65‡	20.9	2.63	11.9	1.50	82.9	10.45	75.4	9.49	9.8	1.23	Neg.	Neg.
	95**	21.5	2.65	12.4	1.57	113.3	14.28	116.6	14.69	16.8	2.12	Neg.	Neg.
75	0	19.8	2.50	9.3	1.18	56.1	7.07	46.2	5.82	5.2	0.66	Neg.	Neg.
	65	19.8	2.50	8.6	1.09	51.7	6.51	42.9	5.41	5.2	0.65	Neg.	Neg.
	95	19.8	2.50	8.2	1.04	49.5	6.24	40.7	5.13	4.2	0.53	Neg.	Neg.
50	0	19.8	2.50	7.4	0.94	44.0	5.54	37.4	4.71	4.4	0.55	Neg.	Neg.
	65	19.8	2.50	6.9	0.87	41.8	5.27	35.2	4.44	4.4	0.55	Neg.	Neg.
	95	19.8	2.50	6.6	0.83	39.6	4.99	34.1	4.30	5.0	0.63	Neg.	Neg.

Note: g/s = gram per second.
 lb/hr = pound per hour.
 Neg. = negligible.

* Excludes H₂SO₄ mist.

† Emission rates include supplemental duct burner firing.

‡ Emission rates include use of evaporative cooler and supplemental duct burner firing.

** Emission rates include use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
 GE, 1999.
 Gulf Power, 1999.

Table 3.4.1-2. Maximum Noncriteria Pollutant Emission Rates for Three Loads and Three Ambient Temperatures (per CTG/HRSG Unit)

Unit Load (%)	Ambient Temperature (°F)	H ₂ SO ₄ mist	
		lb/hr	g/s
100	0*	1.46	0.184
	65†	1.36	0.172
	95‡	1.43	0.180
75	0	1.07	0.135
	65	0.99	0.125
	95	0.94	0.119
50	15	0.85	0.108
	65	0.80	0.100
	95	0.76	0.095

Note: g/s = gram per second.

*Emission rates include supplemental duct burner firing.

†Emission rates include use of evaporative cooler and supplemental duct burner firing.

‡Emission rates include use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table 3.4.1-3. Maximum Annualized Emission Rates for Smith Unit 3

Pollutant	CTG/HRSG Units	Cooling Tower	Facility Totals
NO _x	756.9	N/A	756.9
CO	701.3	N/A	701.3
PM/PM ₁₀ *	183.6	68.9	252.5
SO ₂	104.5	N/A	104.5
VOC	92.8	N/A	92.8
H ₂ SO ₄ mist	12.0	N/A	12.0

Note: N/A = not applicable.

*Excludes H₂SO₄ mist.

Sources: ECT, 1999.
 GE, 1999.
 Gulf Power, 1999.

Details of the annualized emission calculations are also included in the supporting documentation for the prevention of significant deterioration (PSD) permit application (see Appendix 10.2.7). Stack parameters for the natural gas-fired CTG/HRSG units are provided in Table 3.4.1-4.

3.4.2 AIR EMISSION CONTROLS

The conceptual design of the Smith Unit 3 incorporates state-of-the-art technology at every step, starting with the selection of advanced firing temperature F-class CTGs. The high efficiency of the Project will reduce emissions per unit of output by producing each MW-hour of electricity with less combustion of fuel. The use of natural gas as the only fuel for the CTGs also has the benefit of reducing emissions. The supplemental duct burners will employ low-NO_x burners to reduce NO_x emissions.

Table 3.4.2-1 presents a summary of air emission controls. The use of low-sulfur natural gas, along with highly efficient combustion, will limit PM/PM₁₀ emissions from the CTGs and supplemental duct burners. CO and VOC emissions from the CTGs and supplemental duct burners will be controlled by the use of advanced combustion equipment and operational practices to obtain efficient combustion. Highly efficient combustion will, in turn, result in low CO and VOC emission rates. The CTGs and supplemental duct burners will be equipped with dry low-NO_x combustors and low-NO_x burners, respectively, to abate NO_x emissions. SO₂ and H₂SO₄ mist emissions will be controlled by the use of low-sulfur natural gas. Natural gas sulfur content will be no more than 2 grains per 100 dry standard cubic feet (gr/100 dscf). Finally, the use of drift eliminators to limit drift to no more than 0.001 percent of circulating water will control PM/PM₁₀ emissions from the cooling tower.

3.4.3 BEST AVAILABLE CONTROL TECHNOLOGY

The PSD air permitting regulations require detailed consideration of alternative means of emission control on a pollutant-by-pollutant basis. The purpose of this control technology review process is to determine the best available control technology (BACT). As defined by Rule 62-210.200, Florida Administrative Code (F.A.C.), BACT represents an emission limitation that reflects the maximum degree of pollutant reduction achievable, determined

Table 3.4.1-4. Stack Parameters for Three Unit Loads and Three Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	0*	121	36.7	190	361	81.5	24.8	16.8	5.11
	65†	121	36.7	186	359	74.2	22.6	16.8	5.11
	95‡	121	36.7	170	350	73.3	22.3	16.8	5.11
75	0	121	36.7	170	350	62.6	19.1	16.8	5.11
	65	121	36.7	166	348	58.7	17.9	16.8	5.11
	95	121	36.7	180	355	58.1	17.7	16.8	5.11
50	0	121	36.7	159	344	50.2	15.3	16.8	5.11
	65	121	36.7	155	341	47.6	14.5	16.8	5.11
	95	121	36.7	173	351	47.9	14.6	16.8	5.11

Note: m = meter.
 K = Kelvin.
 m/sec = meter per second.

*Stack parameters reflect supplemental duct burner firing.

†Stack parameters reflect use of evaporative cooler and supplemental duct burner firing.

‡Stack parameters reflect use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
 GE, 1999.
 Gulf Power, 1999.

Table 3.4.2-1. Summary of Air Emission Controls

Pollutant	Means of Control
<u>CTGs and Duct Burners</u>	
PM/PM ₁₀	<ul style="list-style-type: none">• Exclusive use of low-sulfur natural gas.• Efficient and complete combustion.
CO and VOC	<ul style="list-style-type: none">• Efficient and complete combustion.
NO _x	<ul style="list-style-type: none">• Use of advanced dry low-NO_x combustor technology.
SO ₂ /H ₂ SO ₄ mist	<ul style="list-style-type: none">• Exclusive use of low-sulfur natural gas.
<u>Cooling Tower</u>	
PM/PM ₁₀	<ul style="list-style-type: none">• Efficient drift elimination.

Source: ECT, 1999.

on a case-by-case basis, with consideration given to energy, environmental, and economic impacts. BACT emission limitations must be no less stringent than any applicable new source performance standards (NSPS) (40 Code of Federal Regulations [CFR] 60), National Emission Standards for Hazardous Air Pollutants (NESHAPs) (40 CFR 61), and state emission standards (Chapter 62-296, F.A.C., Stationary Sources—Emission Standards).

A complete BACT evaluation for Smith Unit 3 is contained in the PSD permit application in Appendix 10.2.7. Proposed BACT emission limitations for the CTGs are summarized in Table 3.4.3-1. An abbreviated discussion of the BACT review is provided in the following sections. Note that NO_x emissions from Smith Unit 3 are not subject to PSD review because there will be a net reduction in NO_x emissions from the Lansing Smith Plant due to the installation of low-NO_x burner technology and an improved burner management system for Smith Unit 1.

3.4.3.1 Methodology

The BACT analysis was performed in accordance with the EPA *top-down* method. The first step in the top-down BACT procedure was the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, post-process stack controls that reduce emissions after they are formed, and combinations of these two control categories. Following the identification of available control technologies, the next step in the analysis was to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the *EPA New Source Review (NSR) Workshop Manual* (EPA, 1990). The third step in the top-down BACT process was the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness. Assessment of energy, environmental, and economic impacts was then performed. The economic analyses of the technologies used the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1996). The fifth and final step was the selection of a BACT emission limitation corresponding to the most stringent technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds. Control technology analyses using the five step *top-*

Table 3.4.3-1. Summary of Proposed BACT Emission Limitations

Pollutant	Proposed BACT Emission Limits	
	(ppmvd @ 15% O ₂)	(lb/hr)
GE PG7241 (FA) CTG/HRSG (per CTG/HRSG Unit)		
A. All Operating Scenarios		
PM/PM ₁₀		10% opacity
SO ₂		Fuel ≤2.0 gr S/100 scf
H ₂ SO ₄		Fuel ≤2.0 gr S/100 scf
B. With or Without Steam Power Augmentation, Without Duct Burner Firing		
CO	13.0	58.3
VOC	2.7	6.6
C. With Duct Burner Firing, Without Steam Power Augmentation		
CO	15.8	78.7
VOC	3.6	10.2
D. With Duct Burner Firing and Steam Power Augmentation		
CO	22.9	116.6
VOC	5.8	16.8
Cooling Tower		
PM/PM ₁₀	0.001 percent drift loss rate	

Note: O₂ = oxygen.
ppmvd = part per million by dry volume.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

down BACT method were prepared for combustion products, products of incomplete combustion, and acid gases, respectively. The following is a summary of the BACT analyses that are contained in the PSD permit application.

3.4.3.2 Summary of BACT Determinations

PM/PM₁₀

Available technologies considered for controlling PM/PM₁₀ from CTG/HRSG units include the following postprocess controls:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Post-process stack controls for PM/PM₁₀ are not appropriate for CTG/HRSG units because of the very low concentrations of PM/PM₁₀ emissions in the exhaust. The use of good combustion practices and clean fuels is considered to be BACT. The CTGs and supplemental duct burners will use the latest burner technology to maximize combustion efficiency and minimize PM/PM₁₀ emission rates. Combustion efficiency, defined as the percentage of fuel that is completely oxidized in the combustion process, is projected to be greater than 99 percent. The CTGs and supplemental duct burners will be fired exclusively with natural gas.

For the cooling tower, the only practical means of limiting PM/PM₁₀ emissions in drift are to limit cooling water cycles of concentration (i.e., to keep dissolved solids at lower concentrations) and/or apply drift eliminators. Because of Gulf Power's desire to limit water use, cooling water will be recycled to the maximum practical degree. Drift eliminators will then be used to limit drift to no more than 0.001 percent of circulating water flow.

CO

There are two available technologies for controlling CO from CTG/HRSG units:

- Combustion process design.
- Oxidation catalysts.

Combustion process controls involve CTG combustion chamber and duct burner designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTGs, approximately 99 percent, CO emissions from CTGs are inherently low. CO emissions from the CTG/HRSG units at base load with or without steam power augmentation, and without duct burner firing, will be less than or equal to 13 ppmvd at 15 percent O₂. With duct burner firing and no steam power augmentation, CO emissions from the CTG/HRSG units at base load will be less than or equal to 16 ppmvd at 15 percent O₂. With duct burner firing and steam power augmentation, CO emissions from the CTG/HRSG units at base load will be less than or equal to 23 ppmvd at 15 percent O₂; this operating condition, however, will occur for no more than 1,000 hr/yr. These CO emissions are consistent with recent FDEP CO BACT determinations for CTG/HRSG units; e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5.

Oxidation catalyst was determined not to be cost effective for the Smith Unit. 3. An economic evaluation of an oxidation catalyst system having an 80-percent CO removal efficiency was performed for the CTG/HRSG units using OAQPS and project-specific economic cost factors. Base case CO emissions are estimated to be 80 lb/hr per CTG/HRSG unit resulting in a controlled CO emission rate of 16 lb/hr. Base case CO emissions were conservatively estimated assuming 7,760 hr/yr operation at base load, evaporative cooling, duct burner firing, 59°F ambient temperature and 1,000 hr/yr, base load, steam power augmentation, evaporative cooling, and duct burner firing, 95°F ambient temperature per CTG/HRSG unit. Cost effectiveness of oxidation catalyst for CO emissions was determined to be \$1,567 per ton of CO removed for each CC unit. Based on the high control costs, use of oxidation catalyst technology to control CO and VOC emissions was not considered to be economically feasible.

In addition, a CO oxidation catalyst control system does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to carbon dioxide (CO₂). From an air quality perspective, the only potential benefit of a CO oxidation catalyst control system is to prevent the possible formation of a localized area with elevated concentrations of CO. Accordingly, the use of oxidation catalyst to control CO from CTG/HRSG units is typically required only for facilities located in CO nonattainment areas. The Lansing Smith Plant is located in Bay County, Florida, which is designated as having air quality that meets or is better than the national and Florida AAQS for all criteria pollutants, including CO. Dispersion modeling of CO emissions from Smith Unit 3 indicate that maximum CO impacts, without oxidation catalyst, will be insignificant.

Use of combustion controls and good operating practices to minimize incomplete combustion are proposed as BACT for the CTG/HRSG units. These control methods are consistent with prior FDEP BACT determinations for CO emissions from CTG/HRSG units.

SO₂ and H₂SO₄ mist

Technologies employed to control SO₂ and H₂SO₄ mist emissions from combustion sources consist of fuel treatment and postcombustion add-on controls (i.e., flue gas desulfurization [FGD]) systems. These controls are applied to facilities burning high-sulfur fuels (e.g., coal). There have been no applications of FGD technology to CTG/HRSG units because low-sulfur fuels are typically utilized. The proposed CTG/HRSG units will be fired exclusively with natural gas. The sulfur content of natural gas is more than 100 times lower than the fuels (e.g., coal) employed in conventional coal-fired boilers utilizing FGD systems. In addition, CTG/HRSG units operate with a significant amount of excess air which generates high exhaust gas flow rates. Because FGD SO₂ removal efficiency decreases with decreasing inlet SO₂ concentration, application of a FGD system to a CTG/HRSG exhaust stream would result in very low SO₂ removal efficiencies. Since the CTG/HRSG will produce a low SO₂ exhaust stream concentration, the SO₂ removal efficiencies would be unreasonably low, thus making FGD technology technically infeasible for CTG/HRSG units.

Because post-combustion SO₂ and H₂SO₄ mist controls are not appropriate, use of low-sulfur fuel is considered to represent BACT for the CTG/HRSG units. Natural gas will contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr S/100 scf).

3.4.4 DESIGN DATA FOR CONTROL EQUIPMENT

Control of air emissions for the Smith Unit 3 will be accomplished by the use of highly efficient process technologies and clean fuels. These process technologies and fuels will achieve low emission rates without the application of post-combustion control equipment. Process descriptions, emission rates and exhaust gas characteristics, and fuel specifications are provided in Section 3.3 of this SCA.

3.4.5 DESIGN PHILOSOPHY

Air emission controls planned for the Smith Unit 3 have been designed to fully comply with all applicable state and federal regulations. Specific design concepts are summarized as follows:

- Application of BACT for all affected pollutants and emission sources.
- Use of low-sulfur fuel.
- Use of efficient combustion to minimize emissions of pollutants associated with incomplete combustion.

The Project will use the most efficient technology available to convert natural gas to electrical power. On a total power production basis, CTG/HRSG air emissions are minimized by using technology that produces the most power for each unit of fuel consumed at near complete combustion. CTG/HRSG emissions, on a pound-per-megawatt basis, are well below the rates generated by conventional natural gas-, oil-, and coal-fired power plants.

Air emission control technologies planned for the Project reflect the application of BACT for each affected pollutant and emission source. The proposed BACT limitations are well below applicable state and federal emission standards (e.g., NSPS).

3.5

3.5 PLANT WATER USE

The Smith Unit 3 Project will be designed to minimize the overall impact of both water intake and water discharge on the local environment. The primary use of water will be for the cooling water system and for steam cycle makeup. The following list presents the expected major water usages during continuous plant operation.

- Cooling tower blowdown.
- Cooling tower evaporation.
- Gas turbine evaporative cooler evaporation.
- Gas turbine evaporative cooler blowdown.
- HRSG blowdown.
- Gas turbine on-line compressor water wash.
- Gas turbine steam injection losses (during power augmentation operation only).

Other water flows that must be considered include:

- Equipment cooling system losses (leaks, evaporation, etc.).
- Plant washdown.
- HRSG chemical cleaning (typically occurs once every 3 to 5 years).
- Potable water consumption by on-site personnel.
- Site runoff and wastewater.

The cooling water system has by far the greatest water need of all of the systems. Figures 3.5.0-1 and 3.5.0-2 present the proposed water budget flow diagram for the Project for normal operation and for power augmentation, respectively. Tables 3.5.0-1 and 3.5.0-2 present the breakdown of the water balance numbers under normal operating scenario and under power augmentation scenario, respectively.

3.5.1 HEAT DISSIPATION SYSTEM

3.5.1.1 System Design

The heat dissipation system is designed to meet all of the equipment cooling requirements of the plant, including the cooling requirements of the steam condenser. The major components of the system include:

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
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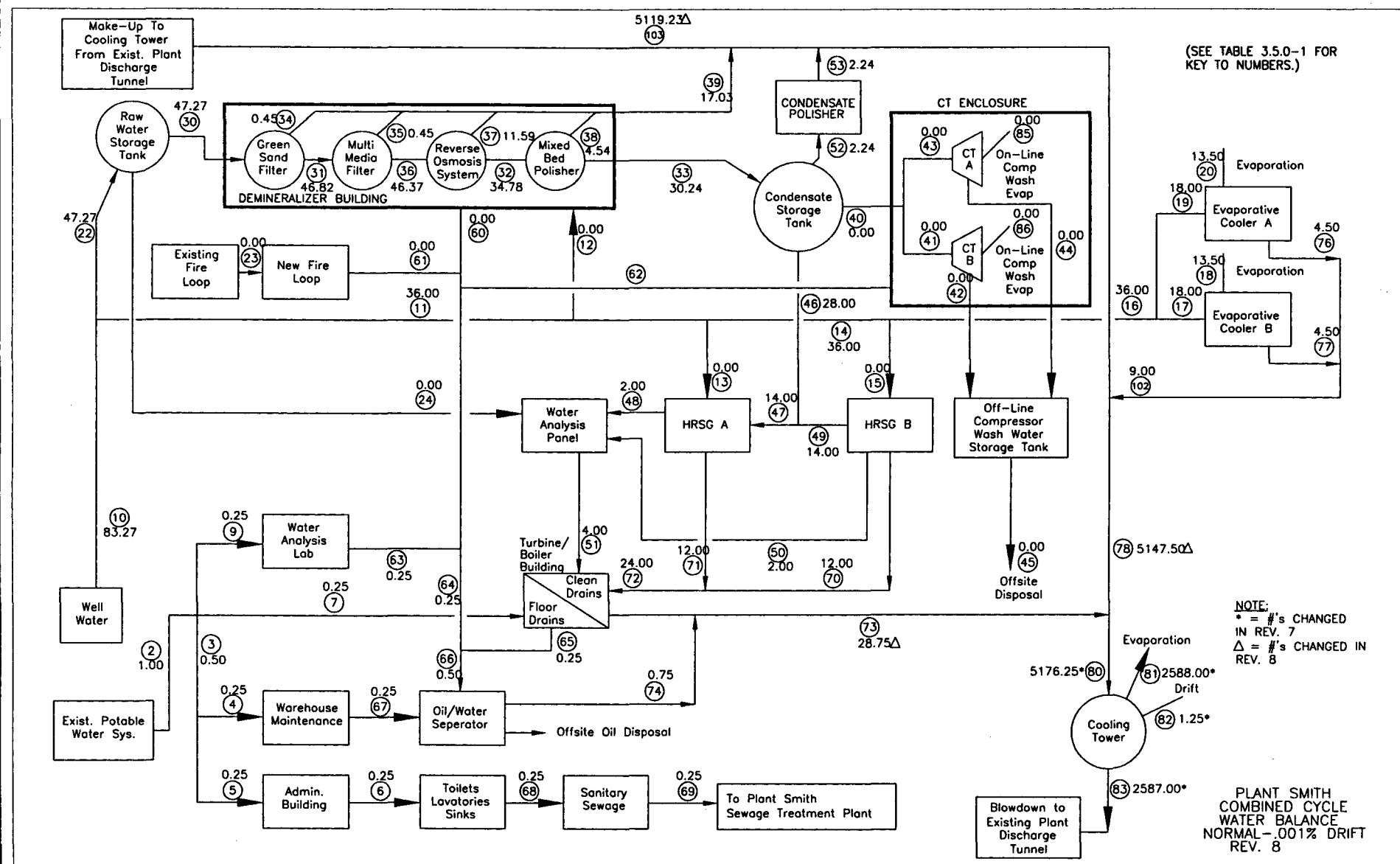


FIGURE 3.5.0-1.
 WATER BUDGET FLOW DIAGRAM - NORMAL OPERATING SCENARIO

Source: SCS, 1999 (Rev. 8).

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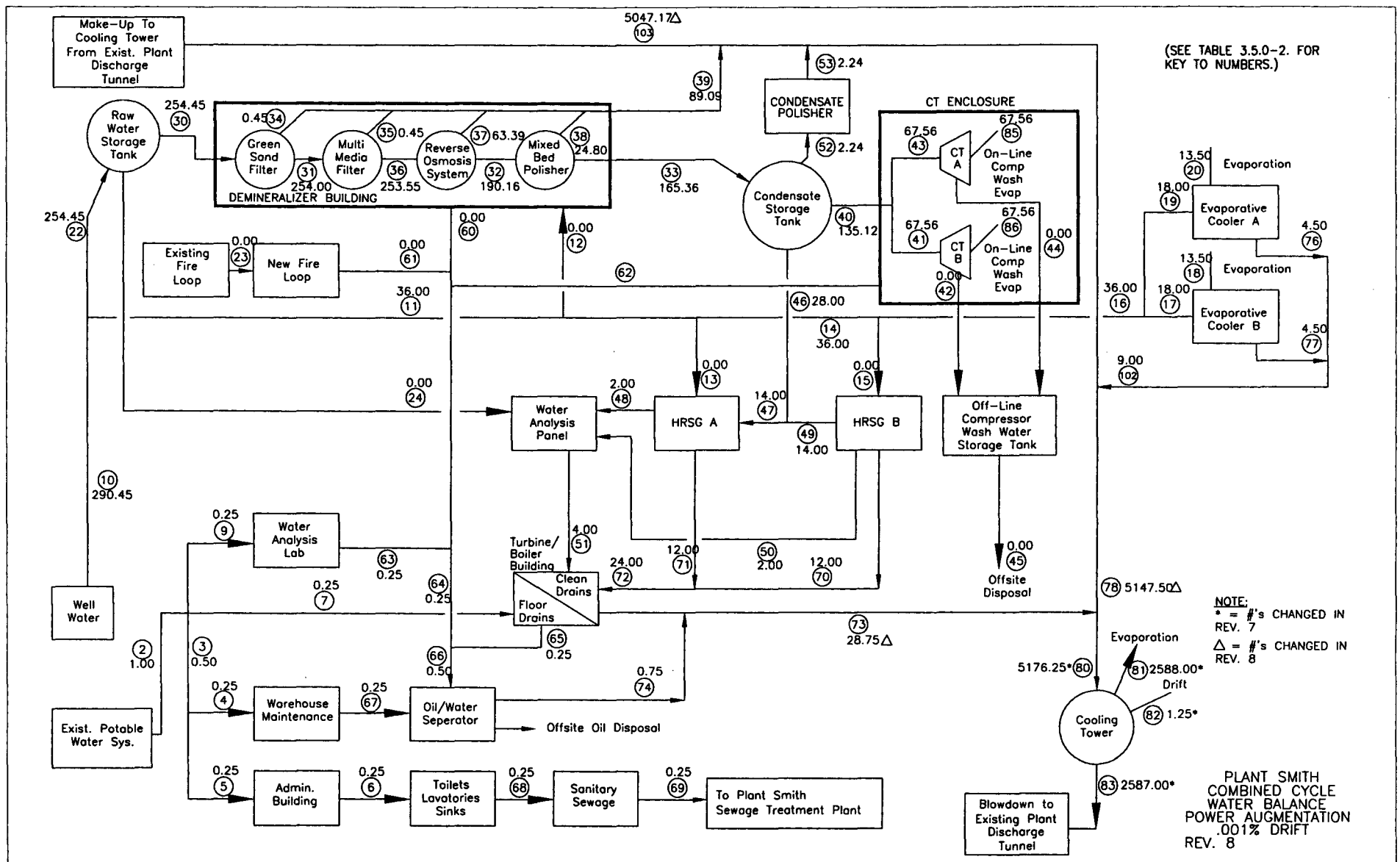


FIGURE 3.5.0-2.

WATER BUDGET FLOW DIAGRAM - POWER AUGMENTATION SCENARIO

Source: SCS, 1999 (Rev. 8).

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Table 3.5.0-1. Water Balance Under Normal Operating Conditions

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)																
	Flow (gpm) *24 hr avg. *	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease	
1																
2 Potable Water	1.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
3 Potable Water to Warehouse and Admin Building	0.50	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
4 Potable Water to Warehouse	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
5 Potable Water to Admin. Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
6 Potable Water to Toilets, Sinks	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
7 Potable Water to Turbine/Boiler Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
8																
9 Potable Water to Water Analysis Lab.	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
10 Well Water to Evap. Coolers and Demineralizer	83.27	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
11 Well Water to Evap Coolers, and Demineralizer	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
12 Well Water to Demin Building	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
13 Well Water to HRSG A	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
14 Well Water to HRSG B and Evap. Coolers	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
15 Well Water to HRSG B	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
16 Well Water to Evaporative Coolers	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
17 Well Water to Evaporative Cooler B	18.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
18 Evaporative Cooler B - Evaporation	13.50				0.00					0.00						
19 Well Water to Evaporative Cooler A	18.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
20 Evaporative Cooler A - Evaporation	13.50				0.00					0.00						
21																
22 Well Water to Raw Water Storage Tank	47.27	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
23 Well Water to Fire Protection Pumps	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
24 Well Water to Water Analysis Panel Coolers	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
25																
26																
27																
28																
29																
30 Makeup Water to the Demineralizer	47.27	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
31 Green Sand Filter Effluent	46.82	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
32 Reverse Osmosis Permeate to Mixed Bed Polisher	34.78	1.25	0.16	4.38	5.80	3.74	0.02	2.44	0.00	6.20	6.17	0.26	0.00	60.00	0.00	
33 Mixed Bed Effluent to Condensate Storage Tank	30.24	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
34 Green Sand Filter Backwash	0.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	800.00	60.00	0.00	
35 Multi Media Filter Backwash	0.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	800.00	60.00	0.00	
36 Filtered Water to Reverse Osmosis System	46.37	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00	
37 Reverse Osmosis Concentrate	11.59	965.33	123.00	571.73	1660.05	806.52	53.69	674.86	0.00	1535.07	7.40	59.23	0.00	60.00	0.00	
38 Mixed Bed Regenerant Waste	4.54	0.00	0.00	460.00	460.00	1.97	459.00	0.00	0.00	460.97	7.00	0.00	0.00	60.00	0.00	
39 Total Demineralizer Waste	17.03	669.92	85.35	519.47	1274.73	558.45	159.55	471.53	0.00	1189.53	7.26	41.13	42.28	60.00	0.00	
40 Condensate to CT's	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
41 Condensate Makeup to CT B	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
42 CT B Off-Line Wash Water	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
43 Condensate Makeup to CT A	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
44 CT A Off-Line Wash Water	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
45 Off-Line Wash Water to Off-Site Disposal	0.00															
46 Condensate Makeup to HRSG's	28.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
47 Condensate Makeup to HRSG A	14.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
48 HRSG A Boiler water samples to Water Analysis	2.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
49 Condensate Makeup to HRSG B	14.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
50 HRSG B boiler water samples to Water Analysis	2.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
51 Boiler Water sample drains	4.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	9.6	0.01	0.00	77.00	0.00	
52 Demin H2O to Cond. Polisher for Regen	2.24	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	

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Table 3.5.0-1. Water Balance Under Normal Operating Conditions (Continued, Page 2 of 4)

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)																
	Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease	
53	Condensate Polisher Regenerant Waste	2.24	27.25	44.28	904.70	976.23	106.60	520.00	132.54	0.22	759.36	8.29	30.54	800.00	120.00	0.00
54																
55																
56																
57																
58																
59																
60	Clean Drains from Demineralizer	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
61	Drains from Fire Protection Pump Room	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
62	Drains from CT Enclosure	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
63	Drains from Water Analysis Laboratory	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
64	Drain Header from Wtr Lab, CT's, and Fire Prot.	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
65	Floor Drains from Turbine/Boiler Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
66	Drain Header from Turb/Blr ,CT's ,Fire Prot ,Wtr La	0.50	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
67	Drains from Warehouse	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
68	Drains from Toilets, Lavatories, and Sinks	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
69	Sanitary Sewage Drain to Treatment System	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	3.00	413.93	7.50	15.30	0.00	60.00	0.00
70	HRSG B Blowdown	12.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	3.00	2.00	212.00	0.00
71	HRSG A Blowdown	12.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	3.00	2.00	212.00	0.00
72	Total Blowdown from HRSG's	24.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	0.50	2.00	212.00	0.00
73	Clean Drains from Turbine/Boiler Building	28.75	0.00	0.00	0.27	0.27	0.00	0.13	0.18	8.35	8.66	9.61	0.42	1.67	187.69	0.00
74	Effluent from Oil Water Sperator	0.75	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	10.00
75																
76	Blowdown from Evaporitive Cooler A	4.50	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
77	Blowdown from Evaporitive Cooler B	4.50	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
78	River Water and Evap. Cooler Blowdown	5147.50	430.71	2377.58	11998.32	14806.62	55.49	2896.81	12248.33	0.00	15200.63	7.97	0.20	6.95	85.88	0.00
79																
80	Cooling Tower Makeup	5176.25	428.32	2364.38	11931.68	14724.38	55.18	2880.72	12180.30	0.05	15116.25	7.97	0.20	6.92	86.45	0.00
81	Cooling Tower Evaporation	2588.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.00	0.00	0.00	0.00
82	Cooling Tower Drift	1.25														
83	Cooling Tower Blowdown (2 COC)	2587.00	856.64	4728.75	23863.37	29448.76	110.36	5761.44	24360.60	0.09	30232.50	7.97	0.41	13.85	86.00	0.00
84																
85	CT - A Power Augmentation Steam to Atms.	0.00														
86	CT - B Power Augmentation Steam to Atms.	0.00														
87																
88																
89																
90																
91																
92																
93																
94																
95																
96																
97																
98																
99																
100																
101																
102	Blowdown from Evaporative Coolers	9.00	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
103	Raw Water to the Cooling Tower	5119.23	430.00	2390.30	12061.94	14882.24	53.30	2912.00	12313.53	0.00	15278.83	7.98	0.00	6.50	86.00	0.00
104																

Table 3.5.0-1. Water Balance Under Normal Operating Conditions (Continued, Page 3 of 4)

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)															
	Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
<hr/>															
Water analysis	North Bay mg/l	as CaCO3		Well Water mg/l	as CaCO3	RO Concentrate mg/l	as CaCO3		RO Permeate as CaCO3				Mixed Bed as CaCO3		
Calcium	172.00	430.00		96.60	241.50	386.13	965.33		0.50	1.25			0.000	0.000	
Magnesium	583.00	2390.30		7.44	30.50	30.00	123.00		0.04	0.16			0.000	0.000	
Sodium	5533.00	12061.94		67.00	146.06	262.26	571.73		2.01	4.38			0.003	0.007	
Total Cations		14882.24			418.06		1660.05			5.80				0.007	
Bicarbonate	65.00	53.30		204.88	168.00	806.52	661.35		4.56	3.74			0.000	0.000	
Sulfate	2800.00	2912.00		13.26	13.79	53.69	55.84		0.02	0.02			0.003	0.003	
Chloride	8733.00	12313.53		162.51	229.14	674.86	951.55		1.73	2.44			0.003	0.004	
Phosphate	0.00	0.00		0.00	0.00	0.00	0.00		0.00	0.00			0.000	0.000	
Total Anions		15278.83			410.93		1668.74			6.20				0.007	
pH	7.98			7.5		7.4			6.17				5.64		
Silica	0.792	0.66		15.3	12.70	59.23	49.16		0.26	0.22			0.01	0.01	
TSS	6.5			0		0			0				0		
Temperature	86 F			60 F		60 F			60 F				60 F		
Oil and Grease	0			0		0			0				0		
Boiler pH	9.6								Note:CO2 Stripper on RO Effluent						
Cooling tower basin temperature	86 F														
<hr/>															
Water analysis (Calculated in Spreadsheet)	Cooling Tower Blowdown mg/l	as CaCO3		Oil Water Separator Effluent mg/l	as CaCO3										
Calcium	342.66	856.64		96.60	241.50										
Magnesium	1153.35	4728.75		7.44	30.50										
Sodium	9545.35	23863.37		58.42	146.06										
Total Cations		29448.76			418.06										
Bicarbonate	134.59	110.36		204.88	168.00										
Sulfate	13849.62	5761.44		33.15	13.79										
Chloride	17277.02	24360.60		162.51	229.14										
Phosphate	0.06	0.00		0.00	0.00										
Total Anions		30232.50			410.93										
pH	7.97			7.50											
Silica	0.49	0.41		18.43	15.30										
TSS	13.85			0.00											
Temperature	86 F			60.00 F											
Oil and Grease	0			10.00											

Table 3.5.0-1. Water Balance Under Normal Operating Conditions (Continued, Page 4 of 4)

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)														
Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
Assumptions														
1 1% Blowdown from the HRSG = 12 gpm/HRSG														
2 Water Analysis panel coolers will utilize closed loop cooling system.														
3 Water Analysis samples will flow continuously at an average of 750 ml/min. Newing will have 2 sample panels each consisting of 10 samples. Total flow .75 l/min x 10 x 2 = 15 l/min or 4 gpm														
4 Line 33 & 34 - Backwash will be approximately 2X service flow. Assume one backwash per week. 304 gpm for 15 min = 4560 gallons to the tank. Drain tank at .45 gpm (24 hour flow). Assume one pound of solids for each square foot of filter surface area. 152gpm/5 gpm/sqft = 30.4 sqft > 30.4 pounds of solids (Line 33 & 34) ppm = pounds of solids / pounds of water = parts/1,000,000 = 800 ppm														
5 Line 70,71 - Assumed 2 ppm TSS blown. Value obtained from Chevron Generation Facility.														
6 Line 76, 77 - Evaporative coolers operate at 2 cycles of concentration.														
7 All flows in spreadsheet are 24 hour flows.														
8 Blowdown constituents based on letter from Sheppard T. Powell ref. Newington Project TSS based on Chevron operating experience.														
9 Rev 1 - The water analysis included in the spreadsheet for Bay water is from data collected during July and August, 1993-1997 at the circulating water intake to the Plant. (NB1R)														
10 Rev 1 - Cooling tower blowdown, evaporation, and drift updated 3/30/99 per Jim Cuchens spreadsheet for over pressure mode.														
11 Assumed same solid loading for condensate polisher as the multimedia filter for backwash TSS.														
12 Seawater Silica number per Doug Helms email dated Thursday April 1 (792 ppb)														
13 Adjusted boiler blowdown for Phosphate Treatment Assumed 10 ppm of phosphate in the blowdown. This assumption is based on a letter from Jack Siegmund at Shepard T. Powell, letter dated January 18, 1999.														

Table 3.5.0-2. Water Balance Under Power Augmentation Scenario

	Flow (gpm) *24 hr avg.*	(All elements are listed as Calcium Carbonate Equivalent, CaCO ₃)								Total Anions	pH	Silica	TSS	Temp	Oil&Grease
		Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate						
1															
2 Potable Water	1.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
3 Potable Water to Warehouse and Admin Building	0.50	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
4 Potable Water to Warehouse	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
5 Potable Water to Admin. Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
6 Potable Water to Toilets, Sinks	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
7 Potable Water to Turbine/Boiler Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
8															
9 Potable Water to Water Analysis Lab.	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
10 Well Water to Evap. Coolers and Demineralizer	290.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
11 Well Water to Evap Coolers, and Demineralizer	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
12 Well Water to Demin Building	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
13 Well Water to HRSG A	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
14 Well Water to HRSG B and Evap. Coolers	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
15 Well Water to HRSG B	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
16 Well Water to Evaporative Coolers	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
17 Well Water to Evaporative Cooler B	18.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
18 Evaporative Cooler B - Evaporation	13.50				0.00					0.00					
19 Well Water to Evaporative Cooler A	18.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
20 Evaporative Cooler A - Evaporation	13.50				0.00					0.00					
21															
22 Well Water to Raw Water Storage Tank	254.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
23 Well Water to Fire Protection Pumps	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
24 Well Water to Water Analysis Panel Coolers	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
25															
26															
27															
28															
29															
30 Makeup Water to the Demineralizer	254.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
31 Green Sand Filter Effluent	254.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
32 Reverse Osmosis Permeate to Mixed Bed Polisher	190.16	1.25	0.16	4.38	5.80	3.74	0.02	2.44	0.00	6.20	6.17	0.26	0.00	60.00	0.00
33 Mixed Bed Effluent to Condensate Storage Tank	165.36	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
34 Green Sand Filter Backwash	0.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	800.00	60.00	0.00
35 Multi Media Filter Backwash	0.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	800.00	60.00	0.00
36 Filtered Water to Reverse Osmosis System	253.55	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
37 Reverse Osmosis Concentrate	63.39	965.33	123.00	571.73	1660.05	806.52	53.69	674.86	0.00	1535.07	7.40	59.23	0.00	60.00	0.00
38 Mixed Bed Regenerant Waste	24.80	0.00	0.00	460.00	460.00	1.97	459.00	0.00	0.00	460.97	7.00	0.00	0.00	60.00	0.00
39 Total Demineralizer Waste	89.09	689.26	87.82	536.32	1313.40	576.08	166.13	482.47	0.00	1224.68	7.25	42.30	8.08	60.00	0.00
40 Condensate to CT's	135.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41 Condensate Makeup to CT B	67.56	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
42 CT B Off-Line Wash Water	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
43 Condensate Makeup to CT A	67.56	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
44 CT A Off-Line Wash Water	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
45 Off-Line Wash Water to Off-Site Disposal	0.00														
46 Condensate Makeup to HRSG's	28.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
47 Condensate Makeup to HRSG A	14.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
48 HRSG A Boiler water samples to Water Analysis	2.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
49 Condensate Makeup to HRSG B	14.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00

Table 3.5.0-2. Water Balance Under Power Augmentation Scenario (Continued, Page 2 of 4)

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)																
	Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease	
50	HRSG B boiler water samples to Water Analysis	2.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
51	Boiler Water sample drains	4.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	9.6	0.01	0.00	77.00	0.00	
52	Demin H2O to Cond. Polisher for Regen	2.24	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00	
53	Condensate Polisher Regenerant Waste	2.24	27.25	44.28	904.70	976.23	106.60	520.00	132.54	759.36	8.29	30.54	800.00	120.00	0.00	
54																
55																
56																
57																
58																
59																
60	Clean Drains from Demineralizer	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
61	Drains from Fire Protection Pump Room	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
62	Drains from CT Enclosure	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
63	Drains from Water Analysis Laboratory	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
64	Drain Header from Wtr Lab, CT's, and Fire Prot.	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
65	Floor Drains from Turbine/Boiler Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
66	Drain Header from Turb/Blr ,CT's ,Fire Prot ,Wtr La	0.50	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
67	Drains from Warehouse	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
68	Drains from Toilets, Lavatories, and Sinks	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
69	Sanitary Sewage Drain to Treatment System	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	3.00	413.93	7.50	15.30	0.00	60.00	0.00
70	HRSG B Blowdown	12.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	3.00	2.00	212.00	0.00
71	HRSG A Blowdown	12.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	3.00	2.00	212.00	0.00
72	Total Blowdown from HRSG's	24.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	0.50	2.00	212.00	0.00
73	Clean Drains from Turbine/Boiler Building	28.75	0.00	0.00	0.27	0.27	0.00	0.13	0.18	8.35	8.66	9.61	0.42	1.67	187.69	0.00
74	Effluent from Oil Water Separator	0.75	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	10.00
75																
76	Blowdown from Evaporitive Cooler A	4.50	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
77	Blowdown from Evaporitive Cooler B	4.50	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
78	River Water and Evap. Cooler Blowdown	5147.50	434.40	2345.36	11837.02	14616.78	62.87	2858.39	12082.73	0.00	15003.99	7.95	0.80	6.86	85.52	0.00
79																
80	Cooling Tower Makeup	5176.25	431.99	2332.33	11771.28	14535.60	62.52	2842.52	12015.62	0.05	14920.70	7.91	0.80	6.83	86.09	0.00
81	Cooling Tower Evaporation	2588.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.00	0.00	0.00	0.00	
82	Cooling Tower Drift	1.25														
83	Cooling Tower Blowdown (2 COC)	2587.00	863.98	4664.66	23542.56	29071.20	125.03	5685.03	24031.24	0.09	29841.40	7.91	1.59	13.66	86.00	0.00
84																
85	CT - A Power Augmentation Steam to Atms.	67.56														
86	CT - B Power Augmentation Steam to Atms.	67.56														
87																
88																
89																
90																
91																
92																
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96																
97																
98																

Table 3.5.0-2. Water Balance Under Power Augmentation Scenario (Continued, Page 3 of 4)

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)																
	Flow (gpm) *24 hr avg. *	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease	
99																
100																
101																
102 Blowdown from Evaporative Coolers	9.00	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00	
103 Raw Water to the Cooling Tower	5047.17	430.00	2390.30	12061.94	14882.24	53.30	2912.00	12313.53	0.00	15278.83	7.98	0.00	6.50	86.00	0.00	
104																
105																
Water analysis	North Bay mg/l	as CaCO3		Well Water mg/l	as CaCO3		RO Concentrate mg/l	as CaCO3		RO Permeate as CaCO3				Mixed Bed as CaCO3		
Calcium	172.00	430.00		96.60	241.50		386.13	965.33		0.50	1.25			0.000	0.000	
Magnesium	583.00	2390.30		7.44	30.50		30.00	123.00		0.04	0.16			0.000	0.000	
Sodium	5533.00	12061.94		67.00	146.06		262.26	571.73		2.01	4.38			0.003	0.007	
Total Cations		14882.24			418.06			1660.05			5.80				0.007	
Bicarbonate	65.00	53.30		204.88	168.00		806.52	661.35		4.56	3.74			0.000	0.000	
Sulfate	2800.00	2912.00		13.26	13.79		53.69	55.84		0.02	0.02			0.003	0.003	
Chloride	8733.00	12313.53		162.51	229.14		674.86	951.55		1.73	2.44			0.003	0.004	
Phosphate	0.00	0.00		0.00	0.00		0.00	0.00		0.00	0.00			0.000	0.000	
Total Anions		15278.83			410.93			1668.74			6.20				0.007	
pH	7.98			7.5			7.4			6.17				5.64		
Silica	0.792	0.66		15.3	12.70		59.23	49.16		0.26	0.22			0.01	0.01	
TSS	6.5			0			0			0				0		
Temperature	86 F			60 F			60 F			60 F				60 F		
Oil and Grease	0			0			0			0				0		
Boiler pH	9.6									Note: CO2 Stripper on RO Effluent						
Cooling tower basin temperature	86 F															
Water analysis (Calculated in Spreadsheet)	Cooling Tower Blowdown mg/l	as CaCO3		Oil Water Separator Effluent mg/l	as CaCO3											
Calcium	345.59	863.98		96.60	241.50											
Magnesium	1137.72	4664.66		7.44	30.50											
Sodium	9417.02	23542.56		58.42	146.06											
Total Cations		29071.20			418.06											
Bicarbonate	152.48	125.03		204.88	168.00											
Sulfate	13665.94	5685.03		33.15	13.79											
Chloride	17043.44	24031.24		162.51	229.14											
Phosphate	0.06	0.09		0.00	0.00											
Total Anions		29841.40			410.93											

Table 3.5.0-2. Water Balance Under Power Augmentation Scenario (Continued, Page 4 of 4)

	Flow (gpm) *24 hr avg.*	(All elements are listed as Calcium Carbonate Equivalent, CaCO3).							Total Anions	pH	Silica	TSS	Temp	Oil&Grease
		Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate					
pH	7.91			7.50										
Silica	1.92	1.59		18.43	15.30									
TSS	13.66			0.00										
Temperature	86 F			60.00 F										
Oil and Grease	0			10.00										

Assumptions

- 1 1% Blowdown from the HRSG = 12 gpm/HRSG
- 2 Water Analysis panel coolers will utilize closed loop cooling system.
- 3 Water Analysis samples will flow continuously at an average of 750 ml/min. Newing will have 2 sample panels each consisting of 10 samples. Total flow .75 l/min x 10 x 2 = 15 l/min or 4 gpm
- 4 Line 33 & 34 - Backwash will be approximately 2X service flow.
Assume one backwash per week.
304 gpm for 15 min = 4560 gallons to the tank.
Drain tank at .45 gpm (24 hour flow).
Assume one pound of solids for each square foot of filter surface area.
152gpm/5 gpm/sqft = 30.4 sqft > 30.4 pounds of solids
(Line 33 & 34) ppm = pounds of solids / pounds of water = parts/1,000,000 = 800 ppm
- 5 Line 70,71 - Assumed 2 ppm TSS blown. Value obtained from Chevron Generation Facility.
- 6 Line 76, 77 - Evaporative coolers operate at 2 cycles of concentration.
- 7 All flows in spreadsheet are 24 hour flows.
- 8 Blowdown constituents based on letter from Sheppard T. Powell ref. Newington Project
TSS based on Chevron operating experience.
- 9 Rev 1 - The water analysis included in the spreadsheet for Bay water is from data collected during July and August, 1993-1997 at the circulating water intake to the Plant. (NB1R)
- 10 Rev 1 - Cooling tower blowdown, evaporation, and drift updated 3/30/99 per Jim Cuchens spreadsheet for over pressure mode.
- 11 Assumed same solid loading for condensate polisher as the multimedia filter for backwash TSS.
- 12 Seawater Silica number per Doug Helms email dated Thursday April 1 (792 ppb)
- 13 Adjusted boiler blowdown for Phosphate Treatment Assumed 10 ppm of phosphate in the blowdown.
This assumption is based on a letter from Jack Siegmund at Shepard T. Powell, letter dated January 18, 1999.

- Mechanical draft cooling tower.
- Circulating water pumps.
- Intake system for receiving cooling water makeup.
- Discharge system for discharge of cooling tower blowdown.
- Chemical treatment system for treatment of the cooling tower makeup.
- Steam condenser for condensing the exhaust of the steam turbine.
- Heat exchanger interface with the service water cooling system.
- Heat exchangers within the service water cooling system for equipment cooling.

The system utilizes a closed loop cooling circuit that circulates cooled water from the mechanical draft cooling tower to the equipment heat exchangers. Heated water is returned to the mechanical draft cooling tower where it is cooled via an evaporative cooling process. In the evaporative cooling process, a certain amount of water is lost through evaporation and drift. A certain amount of water must also be discharged from the cooling tower in order to maintain the required water quality within the cooling tower. These cooling tower losses must be replaced with water from an outside source.

The cooling tower will use bay water taken from the existing Lansing Smith cooling water system to makeup all losses. The existing system for Units 1 and 2 uses once-through cooling with water taken from North Bay passing directly through the condenser and being discharged directly into a discharge canal, which leads to West Bay. The cooling water makeup system for Smith Unit 3 will actually use hot water exiting the existing Unit 1 and 2 system and will discharge water back to the discharge canal from the cool water side of the new Unit 3 cooling tower. In essence, the new facility will act to reduce the amount of heat currently discharged into the cooling water discharge canal.

The mechanical draft cooling tower will be of a counter flow design. The system is expected to have an overall heat duty of 1,445 MMBtu/hr. Based on operation with two cycles of concentration the amount of makeup water for Unit 3 is expected to average approximately 5,120 gallons per minute (gpm) or 7,372,800 gallons per day (gpd). The dis-

charge from the existing Units 1 and 2 cooling system averages 190,000 gpm or 274 MGD.

3.5.1.2 Source of Cooling Water

The source of cooling water will be the existing discharge flow of the existing Lansing Smith generating units which uses bay water from North Bay. The average annual water intake for the new cooling system is estimated to be approximately 7.5 MGD.

3.5.1.3 Dilution System

A new dilution system will not be included as part of the facility. As the cooling tower blowdown is discharged into the existing cooling water canal, some dilution effects will be realized from the existing discharge canal before the water mixes with the receiving waters in West Bay. The addition of the new cooling water cycle has been designed to lower the total discharge temperature for both the new and existing units.

3.5.1.4 Blowdown, Screened Organisms, And Trash Disposal

The cooling tower blowdown will be discharged into the existing cooling water discharge canal. The average annual discharge rate is expected to be 2,587 gpm or 3.7 MGD. As the makeup water will be taken from the existing cooling water system, no new trash screens will be used; therefore there will be no additional disposal of organisms or trash.

3.5.1.5 Injection Wells

Injection wells will not be used.

3.5.2 DOMESTIC/SANITARY WASTEWATER

All domestic and sanitary wastewater will be routed to the existing Lansing Smith Plant sewer system. That existing system has the permitted capacity to handle the increased flows generated by Smith Unit 3. Based on a conservative consumptive rate of 35 gpd per person, the total average flow is expected to be 1,015 gpd. However, a more realistic figure is 20 gpd per person or 580 gpd for total average flow.

3.5.3 POTABLE WATER SYSTEMS

Potable water will be taken from the existing potable water system at the Lansing Smith Plant. Based on an average consumptive rate of 35 gpd per person the average consumption rate is expected to be approximately 1,015 gpd based on 29 full-time employees. This existing system already has adequate production and treatment capacity to serve the demands of the proposed Unit 3.

3.5.4 PROCESS WATER SYSTEMS

The following systems will require process water of varying qualities:

- Gas turbine evaporative coolers (filtered water).
- Gas turbine on-line compressor water wash (demineralized water for both on-line wash and off-line wash).
- Gas turbine steam injection system (demineralized water—increases steam cycle makeup).
- General steam cycle makeup (demineralized water).
- Plant washdown (potable water).
- Fire protection (filtered water).
- HRSG chemical cleaning (filtered/potable water—typically occurs once every 3 to 5 years)

Raw ground water taken from the existing Lansing Smith Plant well system will be used as the precursor for both filtered water production and demineralized water production. A reverse osmosis water treatment facility with a multimedia filter and a mixed bed polisher will be used for producing demineralized water.

3.5.4.1 Gas Turbine Evaporative Cooling

Evaporative coolers will be provided on the CTGs for operation during the hot months of the year. During warm days when the ambient air temperature exceeds 65°F, the turbine inlet ambient air is cooled by the evaporative cooler, thus providing denser air for combustion and improving the electrical power output. Based on GE standard practice, approximately 18 gpm (based on 24 hours a day) of filtered water will be required for

makeup to the evaporative coolers for each CT. Assuming four cycles of concentration, approximately 9 gpm from each enclosure will be blown down to a drain. The blowdown rate is a function of the makeup water quality. The better the makeup water quality, the higher the allowable cycles of concentration within the system. Filtered water will be used for this service.

3.5.4.2 Gas Turbine Off- and On-Line Compressor Water Wash

GE makes provisions for on-line and off-line washes of the CTG. In both cases, demineralized water will be required. In the on-line wash case, the wash water will evaporate in the CTG exhaust stream. In the off-line case, the waste water will be collected and tested to determine if the waste water is hazardous or not. The waste water will be collected and trucked from the site for disposal in a manner appropriate to its waste classification. Off-line wash flow rate will be about 80 gpm for approximately 20 minutes. Table 3.5.4-1 presents the CTG cleaning wash water quality requirements.

Table 3.5.4-1. GE CTG Cleaning Water Quality Requirements
(GEK-103623B applies to water or water and detergent solution)

Constituent	Units	Concentration
Off-Line Washing		
Total solids (suspended and dissolved)	ppm	100
Total alkali metals	ppm	25
Other metals which may promote hot corrosion (i.e., lead, vanadium)	ppm	1.0
pH		6.5 to 7.6
On-Line Washing		
Total solids (suspended and dissolved)	ppm	5
Total alkali metals and other metals which may promote hot corrosion (i.e., lead, vanadium)	ppm	0.5
pH		6.5 to 7.5

Note: ppm = part per million.

Source: Gulf Power, 1999.

3.5.4.3 Gas Turbine Power Augmentation

Power augmentation will require 113,450 lb/hr of steam for each gas turbine for up to 1,000 hr/yr. This will require approximately 227 gpm of demineralized water per CTG or 454 gpm for both gas turbine units to meet the steam requirement. Water will be available to support power augmentation for a normal schedule of 10 hours per day for 5 days a week, with storage capacity to support a peak power augmentation event for 2 weeks at 12 hours per day for 5 days a week.

3.5.4.4 Steam Cycle Makeup

All steam cycle makeup will be achieved with demineralized water. Makeup requirements to the steam cycle will be a function of operation. Makeup will replace high pressure and intermediate pressure drum blowdown and replace steam lost during power augmentation. At 1 percent blowdown, 12 gpm will be required for each HRSG and 227 gpm per CTG will be required for power augmentation. For two HRSG/CTG operation, 478 gpm of makeup will be required during power augmentation and 24 gpm for non-power augmentation operation.

3.5.4.5 Other

Other water usage will include water for fire protection, equipment washdown, and HRSG chemical cleaning. In general, the requirements for these uses will be for either filtered or potable water. Usage for these applications will not occur everyday but will occur infrequently.

3.6

3.6 CHEMICAL AND BIOCIDES WASTE

The following waste streams will be produced:

- Cooling tower blowdown.
- Gas turbine off-line compressor water wash drains.
- Gas turbine and equipment drains.
- Waste water sump.
- Transformer enclosure drains.
- Storm water runoff
- Chemical cleaning wastes.
- Greensand filter backwash.
- Multimedia filter backwash.
- Reverse osmosis concentrate.
- Reverse osmosis waste cleaning.
- Mixed bed regenerate.

3.6.1 COOLING TOWER BLOWDOWN

Generally, the tower cooling water will require a scale inhibitor and possibly a silt dispersant to maximize the tower operation. A biocide such as sodium hypochlorite will be used to control microbiological fouling in the system. As part of the biocide program, the blowdown valve will be closed during chlorination until chlorine residuals are at an acceptable level. At this time, no dechlorination system is planned.

3.6.2 GAS TURBINE OFF-LINE COMPRESSOR WATER WASH DRAINS

The off-line compressor water wash will produce waste water that will be collected and tested to determine if the waste water is hazardous or not. The waste water will be collected and trucked from the site for disposal in a manner appropriate to its waste classification. Off-line wash flow rate will typically be about 80 gpm for approximately 20 minutes.

3.6.3 GAS TURBINE AND EQUIPMENT DRAINS

The drainage from various pieces of equipment or areas where there is the possibility of oil spills or oil contamination will be drained to an oil-water separator before draining to the site waste water sump. These areas include selective areas at the steam turbine, both gas turbine generator acoustic enclosures, and both gas turbine enclosures.

3.6.4 WASTEWATER SUMP

The wastewater sump will collect the wastewater from the oil-water separator and pump the combined waste to the cooling tower basin.

3.6.5 TRANSFORMER ENCLOSURE DRAINS

Transformers containing oil will be curbed to contain any oil leakage. The contents of the enclosure will be checked periodically for oil contamination. If contaminated, the oil will be removed and disposed in an appropriate manner. Uncontaminated water will be drained and released to the site runoff water system.

3.6.6 STORM WATER RUNOFF

The site storm water runoff will be designed for sheet runoff for collection in two holding ponds.

3.6.7 CHEMICAL CLEANING WASTES

Periodically (approximately once every 3 to 5 years) the HRSGs will require chemical cleaning. Strong phosphate and acid solutions are used in the chemical cleaning process and the resulting waste streams are unsuitable for typical disposal methods. Nonhazardous chemical cleaning waste streams will be diverted to the existing onsite metals cleaning pond for disposal.

3.6.8 GREENSAND FILTER BACKWASH

Greensand filters are utilized to remove dissolved iron, manganese, and hydrogen sulfide from the makeup water prior to the demineralization equipment. The greensand contained in the filters is designed to oxidize the iron, manganese, and hydrogen sulfide to their insoluble states and then capture the elements as a suspended solid. The greensand is re-

generated by backwashing and then feeding potassium permanganate to restore the oxidation potential of the media. The backwash/rinse water will contain suspended solids comprised of mainly ferric hydroxide and small amounts of unreacted potassium permanganate.

3.6.9 MULTIMEDIA FILTER BACKWASH

When the multimedia filter differential pressure is exceeded, filter water will be pumped through the filter in reverse flow to remove the collected suspended solids. The multimedia backwash will contain suspended solids trapped by the media that passed through the pretreatment equipment. The frequency of backwashes is dependent on the solids loading from the pretreatment equipment. There is no chemical addition to the multimedia filter during backwash.

3.6.10 REVERSE OSMOSIS CONCENTRATE

A reverse osmosis system operates by forcing makeup water across a membrane to make demineralized water. The reverse osmosis system operates at 75 percent recovery, meaning that 75 percent of the inlet water is made into demineralized water and 25 percent goes to waste. The wastewater contains four times the inlet concentration of dissolved solids and is routed to the cooling tower basin for use as part of the cooling water makeup. The reverse osmosis system will produce concentrate only during operation.

3.6.11 REVERSE OSMOSIS WASTE CLEANING

The reverse osmosis cleaning waste contains dissolved solids and suspended solids trapped on the membrane surface and in the membrane spacers. The reverse osmosis system is cleaned if the permeate flow reduces by 10 to 15 percent or the differential pressure increases by 15 to 25 percent. These contaminants are removed by conducting a low pH followed by a high pH clean. Sulfuric acid will be used as the low pH cleaner and sodium hydroxide will be used as the high pH cleaner. The sulfuric acid will remove scale formations in the membranes. The sodium hydroxide targets organics.

3.6.12 MIXED BED REGENERATE

Mixed bed polishers are regenerated by adding sulfuric acid to the cation resin and sodium hydroxide to the anion resin. The sulfuric acid gives up the hydrogen molecule to replenish the cation with exchangeable hydrogen molecules. The waste from the cation regeneration will contain cations, such as calcium, magnesium, and sodium, attached to a sulfate molecule from the sulfuric acid. The anion is regenerated with sodium hydroxide, with the hydroxide molecule replenishing the anion resin. The sodium portion of the sodium hydroxide will combine with the anions from the resin to form the waste product. In general, sulfates and sodium salts are waste products from the mixed bed ion exchangers. The mixed bed regenerate will be routed to the cooling tower basin.

Poor Original

3.7 SOLID AND HAZARDOUS WASTE

3.7.1 SOLID WASTES

Solid wastes produced by the facility include the following materials:

- Water treatment wastes.
- Used gaskets for piping flanges, pumps, etc.
- Spent air filters.
- Spent turbine parts removed during major maintenance activities.
- Other items typical of a power generating facility.
- Used oils and lubricants.

All solid waste will be hauled offsite for disposal in an approved landfill or, if appropriate, recycled. Used oils and lubricants will be hauled offsite for either proper disposal or recycling, if possible. An estimated 220 gallons of used oils and lubricants will be collected per month. All other solids are estimated to comprise approximately 300 pounds per month.

The suspended solids produced during the greensand filter and the multimedia filter backwash will be discharged to the cooling tower. The backwash streams will produce approximately 9 pounds per day of suspended solids.

3.7.2 HAZARDOUS WASTES

The existing Smith facility is categorized as a conditionally exempt small-quantity generator of hazardous wastes in accordance with Resource Conservation and Recovery Act (RCRA) standards. It is not anticipated that Smith Unit 3 will change this status. Waste streams are expected to be limited to painting and general maintenance operations. No process waste streams should meet the criteria of hazardous wastes.

The following hazardous chemicals are expected to be utilized onsite:

- Closed loop cooling water
- ~~o Nitrite or~~ molybdate corrosion inhibitor—used to prevent corrosion in metal pipes and valves

- o Ethylene glycol or propylene glycol antifreeze
- HRSG
 - o Ammonia—used for pH control and to prevent corrosion
 - o Trisodium phosphate—used to prevent caustic corrosion of boiler
- Cooling tower
 - o Sodium hypochlorite—biocide
 - o Polyacrylate or polyacralmide-dispersant—prevents solids from building up in circulating water loop
- Water treatment plant
 - o Sulfuric acid—used to clean reverse osmosis system
 - o Sodium hydroxide—used as high pH cleaner in reverse osmosis
 - o Sodium bisulfite—removes oxidizing agents
 - o Sodium hypochlorite—chlorinates the water
 - o Scale inhibitor—removes precipitants; prevents fouling
 - o Potassium permanganate—regeneration of greensand filter
- General
 - o Miscellaneous detergents
 - o Lubricating oils and greases

All usage and handling of these hazardous chemicals will be done in a manner to fully contain and properly control both the use of the chemical/mixture and the disposal of any resulting effluent of waste stream. All wastes will be managed in accordance with FDEP and EPA rules. Collection and disposal at offsite facilities will be performed by licensed contractors and appropriately licensed treatment/disposal facilities.

In addition, all chemical handling, storage and usage will be in accordance with Department of Transportation (DOT) and Occupational Safety and Health Administration (OSHA) HazCom standards. Proper controls will be established to avoid hazardous chemical accidental leaks or spills.

Adequate emergency response mechanisms will be maintained should an accidental spill or release of hazardous chemicals or substances occur.

3.8 ONSITE DRAINAGE SYSTEM

This section describes the drainage systems that will be used to control runoff and potential impacts of erosion on the project site and surrounding property. A copy of the storm water management plan (SWMP) is included in Appendix 10.2.2.

3.8.1 DESIGN CONCEPTS

The site drainage facilities for the new Smith Unit 3 plant will be constructed and operated to control storm water runoff on the site during construction and operation of the plant. The system is designed using FDEP and Bay County criteria for control of quality and quantity of runoff. Offsite drainage will be diverted around the site to existing conveyance systems. The onsite drainage system will be independent systems consisting of swales, channels, pipes, and culverts arranged and sized to intercept runoff from the various pervious and impervious surfaces. The runoff will be conveyed to two wet detention ponds. Discharge from both storm water ponds will be to adjacent wetland systems.

The onsite wet detention ponds are sized to control runoff rates from the 24-year, 24-hour storm event. Interior drainage collection systems are sized for the 100-year, 24-hour storm event.

3.8.2 SITE LAYOUT AND IMPERVIOUS AREAS

As shown on the site plan (Figure 3.2.0-1), approximately 10.33 acres of the site is impervious surface, inclusive of the normal pool wet area of the ponds. The remaining 22.37 acres of the site will be pervious surfaces of grass or landscaping. Roads and parking will make up 2.01 acres of impervious area, with the remainder attributed to buildings, equipment, and foundations.

3.8.3 SURFACE RECEIVING WATERS

Discharge from the wet detention ponds will be to adjacent wetlands following natural drainage patterns. The pond in the southeastern portion of the site will discharge to existing wetlands that drain through an 18-inch culvert to a ditch along the south side of the site. The northwestern pond will discharge to a channelized wetland system to the west.

3.8.4 GROUND RECEIVING WATERS

Infiltration of storm water both on- and offsite will be minimal since ground water levels are typically at or near ground elevations.

3.8.5 DIVERSION OF OFFSITE DRAINAGE

The proposed grades onsite will somewhat impede existing drainage patterns. To allow flow to continue along current drainage patterns, a ditch will be constructed along the northwest corner of the site, diverting flows around the site and back to the existing flow channel. Drainage areas to the east of the site will continue to flow south into improved culverts along the access road. The culverts will continue to outfall to the existing drainage ditch along the south side of the road.

3.8.6 EROSION CONTROL MEASURES

Prior to the initiation of construction activities, silt fencing or straw bales will be placed along the outside edge of the site boundary. Silt fencing and straw bales will be utilized to control transport of sediment from the site. Ditch bottoms and side slopes will be stabilized to protect against erosion using grassing or matting as needed. Disturbed areas will be minimized to limit erosion potential. Finished slopes will be gradual in order to limit velocities which may promote erosion.

3.8.7 RUNOFF CONTROL

The proposed drainage collection system will utilize swales, culverts, and sloped surfaces to convey runoff to the wet detention ponds. Swales will have a maximum of 3:1 horizontal to vertical side slopes. Longitudinal slopes are minimized in order to limit velocities. Culverts are designed to withstand heavy equipment loading and accommodate pre-existing flow conditions. The onsite collection system will route runoff to the storm water ponds in such a manner as to limit ponding onsite to the maximum extent possible.

3.8.8 LOCATION OF DISCHARGE POINTS FOR STORM RUNOFF

Runoff from the site will be conveyed to the storm water detention ponds and outfall to adjacent wetland systems.

3.8.9 STORM WATER DETENTION PONDS

The storm water detention ponds will be constructed during the initial phase of construction to provide control of storm water runoff and sedimentation during site work.

The ponds are located in upland areas adjacent to wetlands which normally receive runoff. Berms will contain the runoff, since the normal water levels are considered to be at the existing ground surface. The northwest and southeast ponds have normal pool elevations of 6.4 and 6.9 ft-NGVD, respectively.

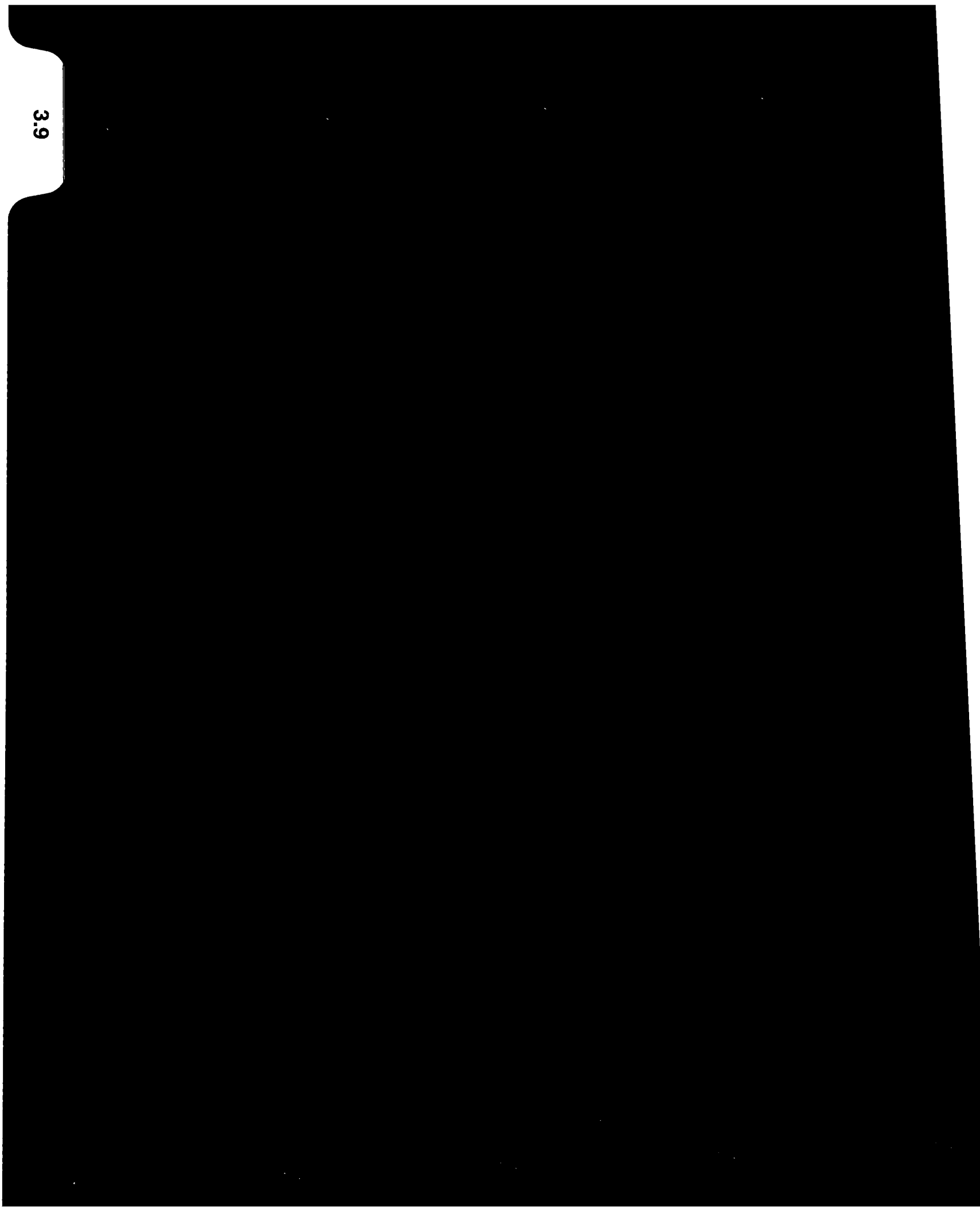
Planted littoral shelves will cover at least 35 percent of the normal pool elevation. The permanent pool volume is controlled by a minimum residence time of 14 days during the wet season (June to October).

The 1-inch treatment volume is controlled by orifices located in the outfall structures. Treatment storage is from 6.4 to 7.7 ft in the northwest pond, and 6.9 and 8.15 ft in the southeast pond. A 1.75-inch orifice controls the treatment volume in the northwest pond, such that no more than the first half of the volume is discharged within the first 60 hours following the storm. A minimum elevation of 7.08 ft is maintained at hour 84 (24-hour duration storm plus 60 hours). Similarly, a 2.5-inch orifice controls the discharge in the southeast pond to a minimum of 7.6 ft.

Weirs are located above the required treatment volume for both ponds. These weirs are used to attenuate flows at the predevelopment rates of 58 and 128 cfs. These rates are high due to the significant wet areas associated with the predevelopment condition. The post-development discharges from both ponds are less than the allowable rates. Discharge

rates of 46 and 68 cfs result in high water levels of 8.54 and 8.98 ft for the northwest and southeast ponds, respectively.

During construction, the ponds will serve as sedimentation basins to prevent silt and debris from being transported to downstream wetlands. The detention basins will be constructed to allow removal of accumulated sediments via 10-ft access berms around the top of both ponds.



3.9 MATERIALS HANDLING

3.9.1 CONSTRUCTION MATERIALS AND EQUIPMENT

The Smith Unit 3 Project site is located approximately 5 miles southwest of the intersection of SR 77 and CR 2300. Access to the site is provided by an existing road originating from CR 2300. Materials and equipment required for construction of the Smith Unit 3 Project will be delivered to the site using existing roads and waterways.

During the construction phase of the Smith Unit 3 Project, the entrance to the plant access road off CR 2300 will be improved (graded and surfaced with gravel) to support construction activities. A detailed transportation analysis for the Smith Unit 3 Project was not required due to the below-threshold traffic volumes expected for construction and the fact that existing road and waterways are adequate for the projected construction-related traffic and material delivery.

After construction of Smith Unit 3 is complete, a permanent access road will be constructed (sub-base, base course, grading, paving and striping, etc.) in accordance with Florida Department of Transportation (FDOT) requirements.

Most materials and equipment required for the construction of the Smith Unit 3 will be delivered to the site via standard transport trucks. Some of the larger items such as the HRSG modules, steam turbines, generators, and transformers, will be delivered by barge via the Port of Panama City to an offloading site at the existing Lansing Smith Plant. Materials and equipment will be unloaded and moved around the site using cranes, trucks, and forklifts.

The total laydown and storage space needed for construction will be located onsite at the Smith Unit 3 Project site. Construction materials and plant equipment will be stored such that they do not create safety or environmental hazards. Bags, containers, bundles, etc., will be stacked, interlocked (if possible), and limited in height so that they are stable and secure against sliding or collapse. Storage areas will be kept free from an accumulation of materials that constitute hazards from fire, explosion, or spills. Suitable fire extinguishing equipment will be kept near flammable materials.

Storm water runoff control measures for the laydown areas include surface runoff collection in swales. Storm water runoff collected in the swales servicing the onsite laydown and storage area, will be routed to the storm water detention ponds.

During the construction phase of the Smith Unit 3, the plant access road and site area will be sprayed with water, as necessary, to minimize fugitive dust emissions generated from construction activities during dry weather conditions. Water for dust control will be acquired from the storm water detention ponds or onsite wells.

3.9.2 OPERATIONS MATERIALS

Materials and supplies used for the operation of the Project will be delivered by truck. Natural gas will be delivered via an underground pipeline to the Project site gas metering station. The handling and storage of fuels and other operational chemicals are discussed in Sections 3.3 and 3.6, respectively. Handling and management of hazardous wastes are discussed in Section 3.7. Other operational wastes will be handled and stored in compliance with applicable safety and environmental regulations.

REFERENCES

Gulf Power Company. 1999. Personal communication with Florida Gas Transmission.

U.S. Environmental Protection Agency (EPA). 1990. New Source Review Workshop Manual. Prevention of Significant Deterioration and Nonattainment Area Permitting. Office of Air Quality, Planning, and Standards; Research Triangle Park, NC.

U.S. Environmental Protection Agency (EPA). 1996. Office of Air Quality Planning and Standards Control Cost Manual. Fifth Edition. EPA 453/B-96-001. Research Triangle Park, NC.

4.0

4.0 EFFECTS OF SITE PREPARATION AND PLANT ASSOCIATED FACILITIES CONSTRUCTION

This chapter identifies and discusses the potential impacts from construction of the proposed power plant on the social, physical, and natural resources of the site and vicinity. In accordance with the FDEP instructions, this chapter includes the following sections:

- 4.1—Land Impact.
- 4.2—Impact on Surface Water Bodies and Users.
- 4.3—Ground Water Impacts.
- 4.4—Ecological Impacts.
- 4.5—Air Impacts.
- 4.6—Impact on Human Populations.
- 4.7—Impact on Landmarks and Sensitive Areas
- 4.8—Impact on Archaeological and Historic Sites.
- 4.9—Noise Impacts.
- 4.10—Special Features.
- 4.11—Variances.

The potential impacts are presented in terms of their relationships with the resources and populations described in Chapter 2.0 as well as in terms of compliance with applicable regulations and standards.

4.1

4.1 LAND IMPACT

As discussed in Section 2.3.5, the area to be utilized for the construction of Smith Unit 3 is approximately 32.7 acres of the 50-acre Project site. The remainder of the property will remain as planted pine, subject to harvesting, or as undisturbed wetlands. The 32.7-acre area includes the power block, the construction laydown area, the new switchyard, ancillary facilities, the gas metering station, and the storm water ponds. Approximately 28 of the total acres will be filled to overcome the limitations of the native soils, to provide a stable base for the proposed development, and to minimize the likelihood of flooding. The proposed elevation of Smith Unit 3 will be similar to that of the existing adjacent Lansing Smith plant site. The existing elevation of the Project site is approximately 5 to 8 ft-msl. The proposed elevation is approximately 10 ft-msl. The remaining 4± acres proposed for development are for the construction of storm water treatment and storage ponds.

4.1.1 GENERAL CONSTRUCTION IMPACTS

The general site preparation and construction activities associated with the overall development of the Project site include the following:

- Construction of temporary storm water basins/ditches.
- Sequential dewatering of low areas of the site.
- Clearing/grubbing of all uncleared portions of the construction area and laydown area.
- Stabilizing, grading, filling, and contouring the area for power plant facilities.
- Construction of permanent storm water management basins.
- Performing ground work as necessary for construction of facility footings; foundations; and underground utilities, including electrical, water, wastewater, and other piping systems.
- Power plant facilities construction.
- Earthmoving, grading, recontouring, and landscaping.

Site preparation will consist of clearing and grubbing, followed by grading and leveling. Approximately 32.7 acres of the 50-acre site will require clearing. Vegetative debris from

site clearing will be disposed in accordance with local requirements. Topsoil that is suitable for reuse will be stockpiled for landscaping and in establishing vegetation after construction has been completed. During early site preparation activities, temporary storm water management structures and soil erosion and sedimentation control devices (e.g., ditches, retention basin, berms, siltation fencing, and/or hay bales) will be used to minimize runoff during the construction phase. Site preparation and construction activities will not require any explosives. Suitable clean fill material will be imported to the site from one or two local Bay County borrow pits.

In addition to fill material used from outside sources, Gulf has proposed the use of fly ash generated by Smith Units 1 and 2 as a fill material. Fly ash is an industrial coal-combustion by-product generated at the existing coal-fired units. The fly ash is currently stored in the ash pond, but can be dewatered and used for fill material. EPA, in its March 8, 1999, report to Congress, recognizes coal combustion by-products as generally benign substances possessing low risk as an environmental contaminant and encourages the utilization of coal combustion by-products. FDEP has reviewed the composition of Smith's fly ash and supporting documentation which is included in Attachment 10.5-H in Appendix 10.5. The use of fly ash as a fill substitute will reduce the outside fill requirements by as much as 235,000 cubic yards and could eliminate up to 11,000 truckloads of fill hauling (22,000 trips on local roadways). The following subsections provide additional details on general construction impacts.

4.1.1.1 Use of Explosives

The Project will not use explosives for any portion of the construction work.

4.1.1.2 Laydown Areas

Laydown areas for storage of construction materials and plant equipment components will be required for construction of the Project. Approximately 14 acres of land will be needed for storage and staging of materials and equipment. The area north of the Smith Unit 3 power block will be used as onsite laydown and storage.

Laydown areas will be cleared of existing vegetation, graded for proper drainage, and a course of gravel base material applied (if necessary). Wood timbers will be used, as appropriate, to help keep plant equipment components and materials stored safely off the ground. After construction is complete and laydown areas are no longer needed, wood timbers will be removed and the surface areas will be graded for drainage and planted with grass.

4.1.1.3 Temporary and Permanent Plant Roads

An existing unpaved road originating from CR 2300 provides access to the Project site. This plant access road will be improved and maintained during the construction phase of the Project. Road improvements during the construction phase include grading the existing surface and applying base course and gravel materials to the graded surface to accommodate construction traffic.

After construction of the power plant is complete, final improvements will be made to the site access road to convert it into a permanent plant road. The permanent plant road will be designed to handle the heaviest expected load during the life of the plant. Runoff collected from the road will be directed to the onsite collection system and routed to the storm water treatment ponds for treatment and storage.

4.1.1.4 Railroads

There are no railroads within or proximate to the Project site. Heavy plant equipment components, including the CTGs, HRSGs, transformers, condenser, and boiler feed water pumps, will be shipped to the site via barge. The equipment will be offloaded at the Lansing Smith plant via the existing intake canal from Alligator Bayou. Heavy haul trailers will be used to deliver the equipment to the site.

4.1.1.5 Bridges

There are no overhead bridges within or proximate to the Project site. Most of the heavy plant equipment will arrive by barge to the existing Lansing Smith site.

4.1.1.6 Service Lines

The Smith Unit 3 CTGs will operate on natural gas. FGT will design, furnish, install, and maintain an underground pipeline (and gas metering station) that will supply natural gas to the site on a continuous basis.

Pipelines for well water, sanitary sewer, and potable water will be installed, as necessary, to provide these services to the Smith Unit 3 as interconnections with existing facilities of the Lansing Smith plant.

4.1.1.7 Disposal of Trash and Other Construction Wastes

No significant impacts from construction wastes are anticipated. During construction, the craft and management labor force will utilize portable chemical toilets. A qualified and licensed contractor will furnish the toilets, along with routine maintenance and service. Sanitary wastes generated during construction will be removed from the site, transported, and properly disposed by the contractor in an approved disposal and treatment facility. All portable toilets will be removed from the plant site upon completion of the construction phase of the Project.

The Project will attempt to minimize the amount of construction waste generated and will seek to segregate and recycle as much waste material as possible. As mentioned earlier, Gulf proposes reuse of fly ash from Smith Units 1 and 2 for fill material. Certain construction wastes, such as scrap steel, aluminum, copper, lumber, paper, and cardboard, etc., may be segregated for recycling, providing there is sufficient interest from local recycling firms. An authorized and licensed waste handling contractor will remove all other construction waste materials from the site for proper disposal at the Bay County Steel-field landfill.

4.1.1.8 Clearing, Site Preparation, and Earthwork

The Project area will be cleared of all vegetation and organic matter. Rough grading, excavation, and backfill activities will be performed to prepare the site for underground utilities, concrete foundations, and surface drainage. Backfill materials will be imported to the site from Bay County borrow pits for constructing concrete foundations, to raise

the existing site elevation to overcome native soil limitations, to provide a stable base, and to approximately match the elevation of the existing Lansing Smith plant site.

After construction of the new Project is essentially complete, any remaining areas that do not have an impervious surface will be revegetated with native grasses and plant life.

4.1.1.9 Impact of Construction Activities on Existing Terrain

The existing terrain is relatively flat with an average of less than 0.5 percent slope. The majority of site runoff drains to the west. As previously stated, the Project site will be cleared, graded, and contoured to ensure adequate drainage, and to raise the existing site elevation to approximately that of the existing Lansing Smith plant site.

A storm water gravity flow collection system and detention ponds will be constructed to attenuate the required volume of runoff collected from the Project site. A series of swales, ditches, and basins will collect surface storm water and transport it to the detention ponds. The postdevelopment drainage pattern for the site will very closely match the predevelopment drainage pattern. The storm water detention ponds will discharge to existing wetlands located west of the Smith Unit 3 site.

Construction activities will involve equipment, such as dozers, scrapers, graders, loaders, haul trucks, compactors, dewatering pumps, cranes, welding machines, air compressors, concrete pumps, cranes, forklifts, etc. Fugitive dust and internal combustion engine emissions and noise will be generated during the construction phase of the Project and are discussed in greater detail in Sections 4.5 and 4.9, respectively.

4.1.2 ROADS

Access for the construction activities will be provided by an existing access road from CR 2300. CR 2300 connects to SR 77 in a "T" intersection. No new roads are proposed for construction as a result of this Project.

4.1.3 FLOOD ZONES

The Project site is located in flood zone C, an area of minimal flooding. Construction of the Project with the attendant drainage plan should not increase flooding potential on the site nor subject adjacent properties to increased flooding.

4.1.4 TOPOGRAPHY AND SOILS

The Project site will be altered to construct the new facilities. Existing vegetative cover will be cleared and grubbed on the eastern side of the existing power line easement, and structural and general fill will be added to elevate the site to design elevations. Soil excavated for the storm water detention ponds and major equipment foundations may be used as general fill or structural fill, if appropriate. Fill will be required to raise the site to overcome the limitations of the native soils, to provide a stable base, and to approximate the elevation of the existing Lansing Smith plant site.

Since the site is in a generally flat area (i.e., little topographic relief), the fill should not cause adverse impacts to site topographic conditions. Very little, if any, runoff currently flows onto the proposed site. Therefore, the fill will not impede existing drainage patterns. Added fill, with compaction, will shift areas of any percolation within the site. Percolation will be limited to pervious areas and the storm water ponds. Runoff will be managed with the storm water management system (i.e., ponds, weirs, orifices, etc.) to mimic preconstruction conditions.

A discussion of the potential for subsidence and sinkhole formation was provided in Section 2.3.1. Based on their low probability of occurrence, construction activities are not expected to cause these phenomena.

Certain structures at the plant will be visible from varying distances because the structures will protrude above the existing tree line. There is only limited residential development located east of the Project site and, thus, there are few if any developments that would have their views obstructed by the plant. Only the relatively taller plant structures (e.g., exhaust stacks, HRSG, cooling tower, etc.) will be visible from public viewpoints in

the vicinity of the plant. The taller structures (which range up to 121 ft tall) will be an addition to the existing structures at Smith Units 1 and 2.

During construction, erosion at the site will be managed with the erosion control plan (see Sections 3.8.6 and Appendix 10.2.2). After construction, pervious areas will be planted predominantly with native grasses to control erosion. Sediments suspended in collected runoff water will be controlled in the storm water detention ponds. Maintenance of the detention ponds will include excavation of deposited materials as necessary to maintain the required storage volume. Sediments cleaned from the ponds will be used onsite for landscaping purposes.

4.2 IMPACT OF SURFACE WATER BODIES AND USES

4.2.1 IMPACT ASSESSMENT

4.2.1.1 Fresh Water Systems

Portions of the plant will be located on existing wetland systems. Natural drainage patterns through the wetland systems are from the east to the southwest. Two locations are impacted where flows move through the existing site. The wetland system on the southern portion of the site currently discharges to a ditch located on the south side of the site boundary through an 18-inch culvert. To accommodate offsite areas draining to this area, two 18-inch culverts will be installed just east of the site to allow flows to continue discharging to the same ditch. Pre-existing flow which currently moves through the ditch on the northwest corner of the site will be re-routed around the proposed plant site. The re-routing will allow for the same capacity of flow to discharge through the redirected channel.

Adjacent wetland systems will be protected with sediment and erosion control systems as described in Appendix 10.2.2. Silt fencing, hay bales, sediment sumps, vegetative covers, and other methods will be used to minimize impacts during construction.

Wetland systems adjacent to the site will not be used by the Project for any specific purpose other than as a buffer from other development. The wetlands will remain viable through the maintenance of site hydrology.

4.2.1.2 Marine Waters

The construction impacts on the marine water quality will be limited to construction activities in the existing plant's discharge tunnel. No additional dredging of the intake canal is needed to accommodate the supply barges. The canal is currently used to barge coal to the facility.

Water quality impacts in the discharge canal during construction will be limited to activities during construction of the cooling tower blowdown discharge structure and the new intake structure for cooling tower makeup water. Both these pipes will be installed within the existing Smith cooling water discharge housing. The impacts are expected to be lim-

ited to minor increases in turbidity during construction. Approved construction techniques will be used and the extent of the turbidity will be minimized by using silt screens as practical. The impacts are expected to be temporary with no long-term effects.

4.3

4.3 GROUND WATER IMPACTS

4.3.1 IMPACT ASSESSMENT

The proposed site preparation and facility construction activities for Smith Unit 3 Project are not expected to cause any long-term ground water impacts on- or offsite.

Temporary dewatering activities will be required during the initial phase of construction of the Project, as discussed in the previous section. Existing grade elevations are between approximately 5 and 8 ft-msl. Ground water levels are estimated to occur anywhere from existing grade to 2 ft below existing grade. Fluctuations in ground water levels are expected to occur throughout the year due to rainfall, natural drainage systems, and man-made drainage systems.

Minor dewatering systems will be installed and maintained throughout the civil engineering phase of construction. The dewatering systems are necessary for excavation, backfill, and certain construction operations. It is anticipated that well point(s) and a ditch system will be used to lower the ground water elevation sufficiently below the bottom of excavation to preclude problems with backfilling, soil compaction, and other related activities.

The storm water detention ponds will be installed immediately after clearing and grubbing activities are complete and will be utilized during the construction phase of the Project for collection of ground water. Water from the dewatering process will be pumped to a drainage ditch system. Silt fencing and bales of straw or hay will be used in the ditch system to remove the majority of silt before entering the detention ponds. Additional silt and sand will settle out in the detention ponds, after which water from the detention ponds will either percolate or be discharged offsite with all offsite discharges monitored for turbidity (see Section 4.2.1).

The storm water detention ponds will be excavated to a depth that guarantees a permanent pool volume adequate to provide a 14-day residence time during the wet season (June to October). The storm water detention ponds will be designed to retain 1.1 acre-feet of storm water runoff volume (design volume will also accommodate dewatering

flow), in addition to the permanent pool volume. The storm water detention ponds are designed to release the retained volume in a controlled fashion such that 50 percent of the retained volume will be released during the first 48 hours after receipt. An outlet pipe located in the storm discharge structure maintains the permanent pool elevation.

After excavation, backfill, compaction, construction of the permanent plant drainage system, and certain concrete construction activities are complete, the dewatering system will be removed.

Much of the dewatering discharge volume from the surficial aquifer will be offset by the increased infiltration and recharge of water to the aquifer system from the new detention ponds, and by the decreased evapotranspiration that accompanies a lowered water table. Therefore, any potential surficial aquifer impacts from dewatering activities will be insignificant and short term.

Minor chemical effects can result from dewatering activities through the mobilization of constituents from the soils into the dewatering discharge and from oxidation of the ground water. The surficial aquifer sediments at the site are composed predominantly of fine- to coarse-grained quartz sands (which are not readily soluble), with low amounts of several soluble constituents (including calcite, phosphate, and iron). Oxidation can cause the dissociation of calcite, releasing bicarbonate and calcium anions, which can increase the hardness of water. Oxidation of the dissolved iron can cause ferrous iron to form ferric iron. However, because the surficial aquifer stratum is composed primarily of silica sands, oxidation reactions will be minimal and potential ground water quality impacts will be insignificant. The shallow aquifer materials will also act to filter out the suspended solids, absorb dissolved constituents, and thereby limit or preclude migration of these constituents in the surficial aquifer.

Construction contractors will be required to implement practices to minimize the potential for spills of fuels or chemicals. Maintenance will be performed only in designated areas. In the unlikely event that spills do occur, they will be managed in an approved manner, in accordance with local, state, and federal regulations.

The use of fly ash as fill material will not pose a threat to ground water supplies. Toxicity testing on the fly ash generated at the existing Smith Plant shows the composition to be nonhazardous and nontoxic.

Construction activities are not anticipated to have any effect on the Upper Floridan aquifer because a low permeability confining layer (the intermediate system) separates the surficial and Floridan aquifer systems (see Section 2.3.1). Similarly, temporary dewatering activities in the surficial aquifer will not affect drinking water supplies or other uses of the Floridan aquifer system.

In conclusion, the proposed construction activities for the Project are not expected to adversely impact onsite or offsite ground water resources.

4.3.2 MEASURING AND MONITORING PROGRAM

Ground water monitoring is not proposed as part of the construction activities for the Project. Construction activities are not expected to cause permanent ground water impacts. In the unlikely event that there is a fuel spill or other release, assessment and recovery of the spill or release would be conducted in accordance with FDEP requirements.

4.4

4.4 ECOLOGICAL IMPACTS

4.4.1 IMPACT ASSESSMENT

4.4.1.1 Aquatic Systems—Fresh Water

As discussed in Section 2.3.6.1, there are no onsite natural open water aquatic systems (ponds, lakes, or streams). The only aquatic resources potentially impacted by this Project are manmade ditches located onsite. Ditches on the site consist of roadside ditches and the drainage ditch connection to the natural forested wetlands on the property. The latter of these ditches will be rerouted around the construction area to maintain pre-construction flows. The SWMP addresses this issue (Appendix 10.2.2).

There is a possibility of offsite secondary impacts to the downstream reaches of the drainage features onsite. Land clearing and construction activities could cause increased turbidity and siltation due to eroded materials being transported by surface runoff. By using best management practices (BMPs) during construction (e.g., silt fencing and/or hay bales), potential increases in turbidity and sedimentation in downstream reaches will be minimized (Appendix 10.2.3). With these controls in place, aquatic species will not be significantly impacted by construction activities.

4.4.1.2 Aquatic Systems—Marine

The construction impacts to the marine aquatic ecology will be limited to the construction activities in the existing discharge canal near the plant. The use of the intake canal for delivery of construction supplies via barge should have minimal effect on the aquatic ecology because the canal is already being used to barge coal to the facility. No additional construction in the intake canal is required.

The construction impacts on the aquatic ecology in the discharge canal will be limited to increased turbidity from installation of the cooling tower intake and discharge structures. Approved construction techniques will be used and the extent of the turbidity will be minimized by using silt screens as practical. Impacts are expected to be temporary with no long-term effect.

4.4.1.3 Terrestrial Systems—Flora

The power plant and associated onsite facilities such as parking lots, maintenance building, offices, storm water retention and sedimentation ponds, switchyard, gas metering station, water treatment facilities, cooling towers, and construction laydown areas will occupy approximately 32.7 acres of land. Of this, approximately 16.7 acres are upland communities and 15.2 acres are wetlands. The remaining 0.8-acre consists of internal access roadway. Figure 4.4.1-1 shows the areas impacted and the locations and extent of the remaining land use and vegetation types occurring within the Project area to be developed. To compensate for the loss of 15.2 acres of wetlands resulting from construction of the proposed Project, a mitigation plan has been proposed for agency approval. This plan is included in the USACE 404/FDEP dredge-and-fill permit application.

Approximately 0.7 acre of shrub and brush; 3.4 acres of upland slash pine; 6.8 acres of wet pine plantation; 0.2 acre of ditch, 3.8 acres of cypress-titi swamp; 0.5 acre of marsh; 0.1 acre of spoil; 0.5 acre of road; and 1.4 acres of ruderal, maintained upland habitat under the power lines will be left intact. The upland and wetland communities and wildlife habitats to be left intact on the site and other undisturbed uplands and wetlands in the Project vicinity have the potential to be indirectly affected. These secondary effects could include a temporary lowering of ground water levels, increased sedimentation, increased surface runoff, erosion, fugitive dust, and damage due to heavy equipment movement. However, the utilization of BMPs during construction should ensure minimal or no secondary impacts to offsite plant communities.

All of the plant species considered to be of local and/or regional importance by USFWS, FNAI, and FGFWFC (FDACS) were reviewed for actual presence or likelihood of occurrence on the site based upon range and habitat suitability. Of the 63 plant species reviewed which are known to occur in Bay County (Table 2.3.6-2), 27 species were determined as possibly occurring on the site due to the availability of suitable habitat. Of these, four were observed on the site. These are royal fern (*Osmunda regalis*), cinnamon fern (*Osmunda cinnamomea*), Chapman's crownbeard (*Verbesina chapmanii*), and panhandle spiderlily (*Hymenocallis henryae*). Royal fern and cinnamon fern are listed by the

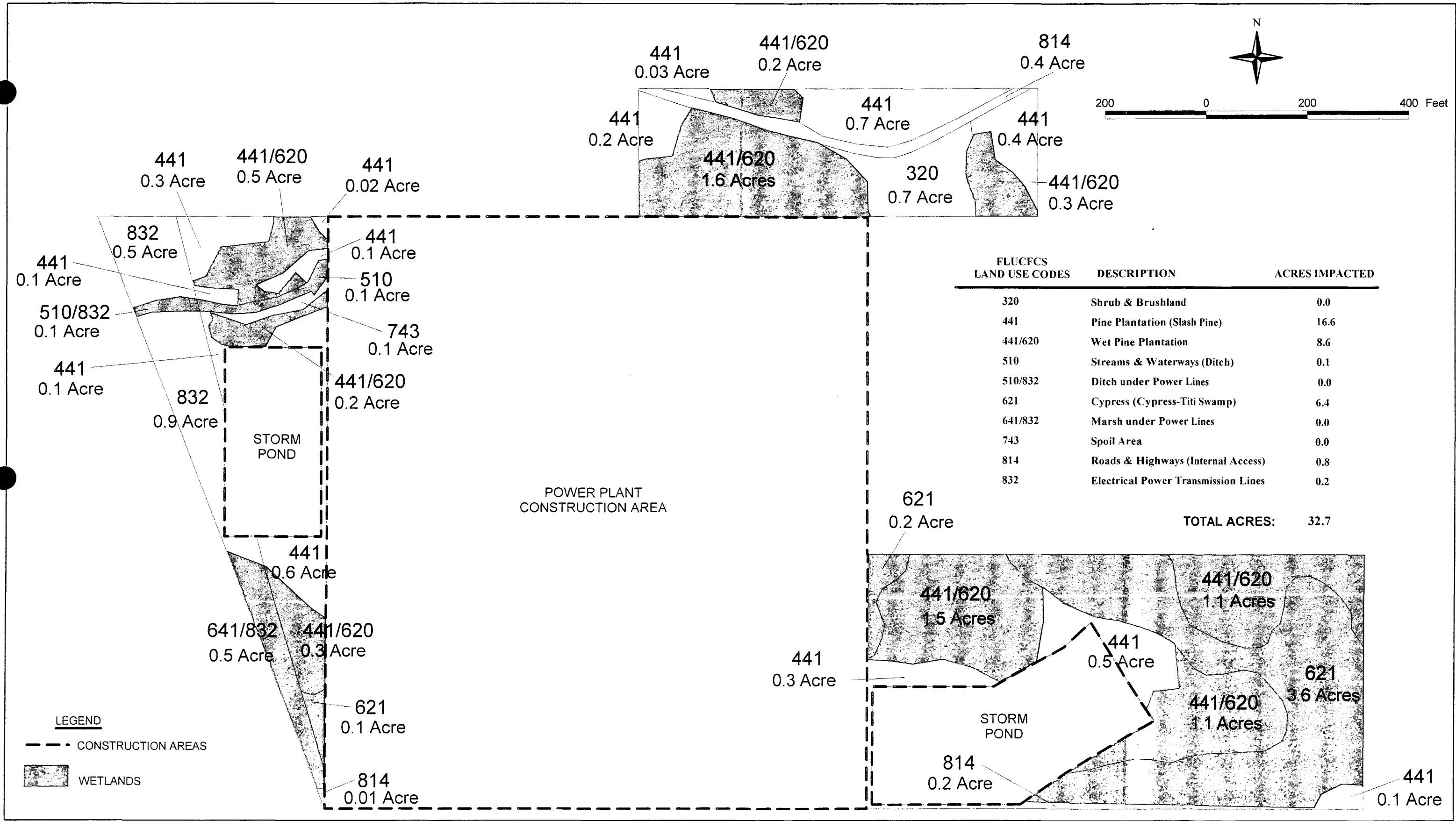


FIGURE 4.4.1-1.
LAND USE/VEGETATION CONSTRUCTION IMPACTS

Source: ECT, 1999.

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State due to the potential for commercial exploitation rather than any endangerment; they are common and found throughout Florida. Royal ferns and cinnamon ferns were observed to be occasional within the wetlands situated within areas of proposed power plant construction. Since royal ferns and cinnamon ferns are common throughout the region, no significant impacts to regional populations will be associated with power plant development. Only a very small portion of the existing transmission line right-of-way (0.2 acre) is scheduled for development of a storm water pond. Chapman's crownbeard was observed growing throughout the open, maintained grassy areas underneath the transmission lines. No significant impacts to regional populations of Chapman's crownbeard should be associated with the proposed activities. Panhandle spiderlilies are extremely rare and only occur within a few counties in the Florida Panhandle. Currently, this state-listed endangered species is a candidate for federal listing. Several populations of this rare spiderlily are located within the wetlands to be developed on the site. These spiderlilies should transplant easily. Therefore, to mitigate for any potential impacts to regional populations, all of the spiderlilies growing within the areas of construction will be relocated into similar wetland habitats on Gulf's property that will not be disturbed by the proposed development activities.

4.4.1.4 Terrestrial Systems—Fauna

Construction impacts to wildlife resources at the Project site may occur in the form of direct impacts (displacement, mortality) in the proposed construction area or indirect impacts (noise, human presence) in preserved onsite and surrounding natural habitats. In the area to be cleared for construction, mobile fauna will be displaced. Less motile or fossorial species may be lost during clearing and earth-moving activities.

The most conspicuous faunal elements are birds. It is unlikely that the clearing of about 32.7 acres of natural habitat will impact regional bird populations due to their mobility and abundance of similar, adjacent habitat. Also, many of the bird species observed are adaptable to human-induced habitat changes. Reptiles and amphibians are more likely to be affected by construction. To decrease the risk of mortality of these less motile animals, the site will be directionally cleared to provide opportunity for these animals to retreat to the offsite pine flatwoods to the west, north, and east of the construction site.

Power plant construction is not expected to affect regional wildlife populations of any endangered, threatened, or species of special concern. Of the 18 important wildlife species evaluated for this Project (Table 2.3.6-1), none were observed onsite. Two listed species, the bald eagle and eastern brown pelican, were observed along the shore of the existing Lansing Smith property. The brown pelican also utilizes the existing discharge canal. However, due to the lack of suitable foraging/nesting habitat on the proposed Project site, no impacts from construction are anticipated to these or other listed species. Construction of the intake/discharge pipes in the existing discharge canal will represent a temporary disturbance to any wildlife foraging activities in the canal. If any listed species do reside onsite, they will seek adjacent identical habitats off the Project site during construction.

4.4.2 MEASURING AND MONITORING PROGRAM

The results of the ecological measuring program conducted on the site in support of this SCA are described in Section 2.3.6. No continued monitoring programs are warranted or proposed for biological resources during the construction phase of the proposed Project. Any mitigation required as a result of state and federal wetlands permitting may require monitoring, but the extent of such mitigation and resultant monitoring is to be determined.

4.5 AIR IMPACTS

4.5.1 EMISSIONS

Three general activities will generate air emissions during construction of the Smith Unit 3 Project. First, land clearing, site preparation, and vehicle movement will generate fugitive dust emissions. Second, open burning of cleared land debris may be required and would result in air emissions. And third, internal combustion engines will release NO_x, CO, and other combustion products.

The quantity of any emissions released during the construction process will generally be very low, but will vary on an hourly and daily basis as construction progresses. Fugitive dust emissions will be greater during the land clearing and site preparation phases. Fugitive dust emissions will also be greater during the more active construction periods as a result of increased vehicle traffic on the site.

Open burning would result in emissions of PM, CO, NO_x, and hydrocarbons. This activity would be conducted intermittently for short periods of time. The land clearing and construction debris to be burned would generally consist of wood products and other relatively clean-burning components. Emissions would depend upon the amount and moisture content of the debris. This site has been periodically burned in the past to support the silvicultural operation.

Increased emissions from internal combustion engines will occur during the site preparation and facility construction due to the amount of onsite construction equipment using engines for site excavation and grading, concrete placement, and structural steel and major equipment installation. Potential minor sources of VOCs include:

- Evaporative losses from onsite painting.
- Refueling of construction equipment.
- The application of adhesives and waterproofing chemicals.

4.5.2 EMISSION CONTROL MEASURES

Fugitive dust emissions from the construction site will be minimized using appropriate dust suppression control methods. These standard control methods will include paving or place-

ment of gravel on roads, applying water to roads and other exposed surfaces, or other methods, as needed. Existing public access roads (i.e., SR 77 and CR 2300) leaving the site are currently paved to serve the existing station. No new access roads to the Project site are proposed. Spilled and tracked dirt (or other materials) will be removed from SR 77, CR 2300, and other paved areas in a timely manner. Of course, all construction-related fugitive dust emissions will be temporary and will stop once construction is completed. Emissions from open burning will be limited by removing materials whose burning would produce excessive smoke (e.g., green vegetative materials), and by conducting this activity in compliance with applicable state and local regulations and ordinances.

4.5.3 POTENTIAL IMPACTS AND MONITORING PROGRAMS

The air quality impacts caused by construction activity will vary as a function of the level of activity, the specific nature of the activity, the weather conditions while the activity is occurring, and the emission controls applied to the activity. However, even under worst-case conditions, the maximum ambient impacts caused by construction emissions are expected to be very small and limited to the specific area of the site under construction. Also, any potential emissions are expected to be well below any applicable AAQS. Therefore, no air quality monitoring programs are needed or will be conducted during the construction of the Smith Unit 3 Project.

4.6 IMPACT ON HUMAN POPULATIONS

4.6.1 LAND USE IMPACTS

The existing land uses in the area surrounding the Project site are silviculture to the east, north, and west, and the existing Lansing Smith plant (designated industrial) to the south. There is an electrical transmission line located along the western Project boundary. The Lansing Smith plant is the only development within 2 miles of the Project site.

Gulf has submitted a large-scale (over 10 acres) plan amendment to Bay County to change the FLUM designation from Agriculture to Industrial in order to accommodate the development of Smith Unit 3. The zoning district is coincident with the land use designation in Bay County.

4.6.2 CONSTRUCTION EMPLOYMENT

As shown in Table 4.6.2-1, the number of estimated construction personnel over the 21-month construction ranges from 75 to 325, with an average of 180 employees/month. It is estimated that approximately 75 percent of the construction workers will be daily commuters (living within commuting distance currently) and approximately 25 percent will be weekly commuters (temporary residents). A small percentage of these construction workers will be from out of state. Construction will normally occur during daylight hours and occur during one shift per day.

Table 4.6.2-1. Estimated Manpower and Payroll During Construction

	Sept. 1, 2000 to Dec. 31, 2000	Jan. 1, 2001 to June 30, 2001	July 1, 2001 to Dec. 31, 2001	Jan. 1, 2002 to May 31, 2002
Manpower	75	225	325	100
Hours/Period	78,000 ^{2,3}	234,000	338,000	88,000
Estimated payroll	\$1,950,000 ^{1,4}	\$5,850,000	\$8,450,000	\$2,200,000
Total construction payroll	\$1,950,000	\$7,800,000	\$16,250,000	\$18,450,000

¹Expected average pay of \$25 per hour.

²Forty-hour standard work week.

³One-shift per day.

⁴Base salary/hourly wage only.

Source: Gulf Power Company.

Total construction costs, excluding equipment, are estimated at \$63 million, and the construction payroll and indirect costs are estimated to be approximately \$23.7 million, of which a portion of the money will be spent locally on goods/services, rent, etc. According to the U.S. Department of Commerce (1999) multipliers specific to Bay County, the impact of construction on industrial output is estimated to be \$113.5 million. The construction impacts on local employment opportunities, therefore, are beneficial although short term. Indirect employment in the local area will occur primarily in retail and wholesale trade, business services, health services, and eating and drinking establishments.

4.6.3 CONSTRUCTION TRAFFIC IMPACTS

Some construction-related transportation impacts are expected as a result of the movement of construction workers and vehicles to and from the Smith Unit 3 Project site. All access to the site will be via CR 2300 and SR 77.

Based on past construction experience and traffic analyses for similar power plants, a construction-related trip generation rate of 2.0 and a vehicle occupancy rate of 1.4 is expected for Smith Unit 3. Based on these trip generation and vehicle occupancy rates, a maximum of 464 trips per day will be generated at the peak construction period, which lasts approximately 6 months. During the entire construction period, an average of 257 trips per day is projected. In addition, an estimated 20 to 60 deliveries per day are expected for the duration of construction.

Using only imported fill for construction, Gulf estimates up to 20,000 truckloads of fill will be required from one or two borrow pit locations in Bay County. However, assuming the use of fly ash is approved as fill material, up to 11,000 truckloads of fill could be eliminated.

In either case, Gulf proposes to stockpile fill on developed portions of the Lansing Smith Generating Plant months in advance of the construction start date. This will spread the number of fill deliveries out over a longer period, further minimizing impacts to traffic. If warranted, Gulf will place appropriate "truck entering highway" warning signs at the borrow pit locations as well as at SR 77 and CR 2300.

Based on current LOS numbers provided by FDOT, construction traffic will not adversely affect traffic flows on SR 77 nor require traffic improvements.

4.6.4 HOUSING IMPACTS

Based on the anticipated 25 percent of construction workers commuting on a weekly basis, these workers would not impact housing availability. Rental units and hotels in nearby Panama City and Panama City Beach, both tourist and seasonal visitor destinations, should be ample to provide for the projected workforce. It is not anticipated that a significant number of these workers will permanently relocate to Bay County as a result of the Project. Construction of Smith Unit 3 will not have a significant impact on housing availability in Bay County. The construction phase of the Project will increase the use of rental units/hotels and will provide a positive economic benefit.

4.6.5 PUBLIC FACILITIES AND SERVICES

Construction-related impacts to public services, such as police, fire, and medical are not expected to be significant. Potable water will be provided from permitted wells at the Lansing Smith plant site. The Steelfield landfill has adequate capacity to accept solid waste and construction debris. Wastewater disposal will be accommodated by temporary facilities; no public sewer service is currently available to the Project site. With minimal relocations to Bay County as a result of the proposed development of Smith Unit 3, existing facilities and services will be adequate to meet the demands on these services.

4.7 IMPACT ON LANDMARKS AND SENSITIVE AREAS

No construction-related environmental impacts are expected on those offsite, sensitive areas identified in Section 2.2.5. As discussed in Section 4.5, fugitive dust emissions will be properly controlled so that no impact on visibility will occur. The Project site itself is surrounded on three sides by planted pine and on the fourth by the existing Lansing Smith plant site. As discussed in Section 4.9, due to attenuation with distance, construction noise will not affect the quality of the recreational experiences in the area. The recreational and historic resources in the area are located at least 3 miles northeast or southeast of the Project site. Therefore, there are no impacts expected to occur to offsite landmarks or sensitive areas due to construction of this Project.

4.8 IMPACT ON ARCHAEOLOGICAL AND HISTORIC SITES

No archaeological or historic sites have been identified within the Project site (see Section 2.2.6). Therefore, no impacts to such resources are anticipated as a result of the construction of this Project. If such resources should be discovered during site clearing activities, the Florida Department of Historic Resources will be notified.

4.9 NOISE IMPACTS

Construction of the Project is expected to be typical of other power plants in terms of schedule, equipment utilized, and types of activities. Power plant construction can generally be divided into several phases, with the noise level varying with the construction phase (based on Barnes *et al.*, 1977). The various construction phases are:

- Site preparation and excavation.
- Concrete pouring.
- Clean up.
- Steel erection.
- Mechanical and electrical.
- Startup and testing.

The typical high-pressure steam- or air-blow activity, a repetitive, short-duration noise, is generally assessed separately because of the high noise levels and the potential for significant impact.

A complete construction equipment inventory was developed with the high noise level equipment identified for evaluation. The loudest equipment types generally operating at a site during each construction phase are presented in Table 4.9.0-1. The composite average or equivalent site noise level, representing noise from all equipment averaged over the work day, is also presented.

Average (equivalent) construction noise levels projected at the north, east, and west property boundaries are presented in Table 4.9.0-2. Construction noise levels were not projected for a residence because the nearest residence is approximately 2 miles from the site. These noise results are conservative because the only attenuating mechanism assumed was divergence of the sound waves; no attenuation from vegetation or intervening structures was factored into the analysis. Average noise levels during the loudest construction activities are projected to be between 51 and 63 dBA to the north, 38 and 50 dBA to the east, and 44 and 56 dBA to the west. The highest construction noise will be due to the use of pile drivers.

Table 4.9.0-1. Construction Equipment and Composite Site Noise Levels

Construction Phase	Loudest Construction Equipment	Equipment Noise Level at 50 ft (dBA)	Composite Site Noise Level at 50 ft (dBA)
Site clearing and excavation	Bulldozer	90	89
	Truck	82	
	Backhoe	84	
	Grader	85	
	Tractor scraper	87	
	Compactor	83	
Concrete pouring	Ready-mix truck	84	102
	Mobile crane	85	
	Concrete pump	82	
	Pile driver	102	
Steel erection	Pneumatic tools	90	90
	Air Compressor	76	
	Mobile crane	85	
	Cherry picker	80	
Mechanical	Pneumatic tools	90	89
	Air compressor	76	
	Mobile crane	85	
Cleanup	Truck	84	86
	Front-end loader	87	

Sources: Barnes *et al.*, 1977.
Gulf Power Company, 1999.

Table 4.9.0-2. Average Construction Noise Levels (dBA) at Gulf Power Property Boundaries

Construction Phase	Noise Level (dBA)		
	North	East	West
Site clearing and construction	50	37	43
Concrete pouring	63	50	56
Steel erection	51	38	44
Mechanical	50	37	43
Cleanup	47	34	40

Source: ECT, 1999.

High-pressure steam- or air-blows to clean piping systems produce noise levels of approximately 130 dBA at 50 ft. This noise source translates to a level of approximately 91 dBA at the nearest property boundary which is to the north. This level of noise could represent a significant, though short-term (i.e., occurring sporadically over a 4- to 6-week period) noise impact. However, no adverse impacts are expected because the steam- or air-blows have a duration of only a few minutes and noise receptors (residences) are located nearly 2 miles away.

4.10

4.10 SPECIAL FEATURES

There are no unusual products, raw materials, garbage disposal services, incinerator effluents, or residues produced during construction that will have an adverse affect on the environment and ecological systems of the site and the adjacent areas. Construction debris can be accepted at the existing Bay County Steelfield landfill.

4.11 VARIANCES

Construction of the Project will meet all applicable local, state, and federal regulations. No variances for construction will be required.

REFERENCES

- Barnes, J.D., Miller, L.N., and Wood, E.W. 1977. Power Plant Construction Noise Guide. Report No. 3321, Bolt Beranek and Newman, Inc., Cambridge, MA.
- U.S. Department of Commerce. 1999. RIMS II Multipliers for Bay County, FL. Economics and Statistics Administration, Washington, DC.

5.0 EFFECTS OF PLANT OPERATION

This section provides a description and assessment of impacts the plant's operations will have on the site and vicinity. Where practicable, the impacts are quantified and described in terms of short-term, long-term, local, etc. Where required, descriptions of operational monitoring and measurement programs are presented. Consistent with FDEP requirements, this chapter provides the following sections:

- 5.1—Effects of the Operation of the Heat Dissipation System.
- 5.2—Effects of Chemical and Biocide Discharges.
- 5.3—Impacts on Water Supplies.
- 5.4—Solid/Hazardous Waste Disposal Impacts.
- 5.5—Sanitary and Other Waste Discharges.
- 5.6—Air Quality Impacts.
- 5.7—Noise.
- 5.8—Changes in Non-Aquatic Species Populations.
- 5.9—Other Plant Operation Effects.
- 5.10—Archaeological Sites.
- 5.11—Resources Committed.
- 5.12—Variances.

As was the case in Chapter 4.0, the existing environmental conditions described in Chapter 2.0 constitute the baseline for assessing impacts. In addition, applicable rules and regulations are employed to assess impacts.

5.1

5.1 EFFECTS OF THE OPERATION OF THE HEAT DISSIPATION SYSTEM

5.1.1 TEMPERATURE EFFECT ON RECEIVING BODY OF WATER

The existing Gulf facility uses once-through cooling water at a flow rate of about 190,000 gpm (273.6 MGD) with a permitted temperature increase of 18.0°F for April to September and 20°F for October to March.

The proposed facility will withdraw cooling tower makeup water from the discharge canal of the existing facility at a rate of about 5,120 gpm (5,048 gpm during power augmentation). This makeup water will be supplemented with water collected from the evaporative coolers, the demineralizer, the condensate polisher, and the clean drains from the turbine/boiler building such that the total makeup water to the cooling tower will be 5,176 gpm for both normal and power augmentation modes. The cooling tower will be operated at approximately two cycles of concentration such that water loss from evaporation and drift will be about 2,589 gpm. The resulting cooling tower blowdown will be 2,587 gpm and will be discharged from the cold side of the cooling tower into the existing discharge canal downstream of the cooling tower makeup water intake. Consequently, there will be no increase in the temperature of the water returned to the discharge canal, but there will be a reduction in volume from 5,120 to 2,587 gpm (from 5,047 to 2,587 gpm for power augmentation operation). The net impact of the operation of the proposed facility will be no increase in the temperature of the existing discharge and a reduction in the discharge volume of 2,587 gpm (2,587 gpm for power augmentation) from the existing 190,000 gpm. Consequently, the Smith Plant site's heat rejection rate will be reduced by about 1.3 percent, which will slightly reduce the size of the thermal plume and resultant thermal impacts and provide a positive effect in the receiving waters of West Bay. Gulf's modified NPDES permit application for the Smith Unit 3 Project is included as Appendix 10.2.5.

5.1.2 EFFECTS ON AQUATIC LIFE

As presented in the previous section, the existing thermal discharge temperature is projected to remain about the same, and the volume discharge (because of evaporative losses from the new cooling tower) is expected to be reduced by 1.3 percent for both the normal

and power augmentation operation. The reduced volume will result in a slightly smaller thermal plume and, consequently, will have a small positive effect on the marine aquatic ecology.

Should the proposed facility be offline for maintenance such that the cooling tower ceases operation, the effects of the shutdown would be minimal on the existing discharge, and no effects on the aquatic ecology of the discharge canal would be expected.

5.1.3 BIOLOGICAL EFFECTS OF MODIFIED CIRCULATION

Since the proposed facility will withdraw cooling tower makeup water from the discharge of the existing facility, the impacts of the cooling water withdrawal and return (blow-down) to the existing canal are expected to be minimal. The cooling tower makeup water withdrawal will not change any of the entrainment or impingement values of the once-through cooling system because no additional water from North Bay will be needed. Because of the small volume relative to the existing discharge, no effects of scouring or sedimentation are expected.

5.1.4 EFFECTS OF OFFSTREAM COOLING

5.1.4.1 Impacts

The cooling tower will transfer heat from plant processes to the atmosphere through the evaporation and dispersion of cooling water. Depending on the meteorological conditions, warm, moist air leaving the tower may become cooled to the point of saturation causing the water to condense and form a visible plume. Ground level fogging may occur if this plume does not rise. The drift from the tower carries dissolved and suspended solids which are deposited locally and may have the potential to affect soils and vegetation. The magnitude of these impacts was assessed using the Seasonal/Annual Cooling Tower Impact (SACTI) model.

SACTI was developed by Argonne National Laboratory for the Electric Power Research Institute (EPRI) (1984) and is generally accepted for plume impact analysis by industry and regulatory agencies. The code used for this modeling study was the most current re-

lease (dated September and November 1990). The model requires both meteorological data and cooling tower design information to evaluate plume characteristics.

Hourly surface meteorological data collected at the Apalachicola and Pensacola stations and twice daily mixing height data collected at the Apalachicola station by NWS were used for the years 1986 through 1990. Long-term monthly clearness indices and daily solar insolation values were obtained from the SACTI documentation.

The Project's linear mechanical draft cooling tower will consists of ten cells. Each cell will house a 33-ft diameter fan. The cooling tower will be arranged in an approximately northeast-southwest orientation. The circulating flow rate through the tower will be approximately 125,000 gpm per cell, and the drift loss rate will be a maximum of 0.001 percent, producing approximately 1.25 gpm of drift. The effective air flow rate of the tower will be about 11,764,000 standard cubic feet per minute and will reject approximately 1,250 MMBtu/hr.

The SACTI model calculations utilized a polar coordinate receptor grid system centered on the tower. Receptors were placed surrounding the tower at 22.5-degree intervals at varying distances. For the salt deposition and plume length computations, 100-meter intervals out to 10,000 meters were used. For plume fogging hours computations, 100-meter intervals out to 1,600 meters were used. For plume height computations, 10-meter intervals up to 1,000 meters were used.

The results of the SACTI modeling on a seasonal and annual basis are given in Table 5.1.4-1.

A cooling tower plume may reduce visibility if it crosses the path of ground-based or air traffic. CR 2300 is located about 1,200 meters west of the cooling tower. At CR 2300, the SACTI model predicts a plume height of 137 meters above the ground. The occurrence of the plume is predicted to be 2 percent of the time. Because terrain around the plant site is

Table 5.1.4-1. SACTI Modeling Results for the Gulf Power Project

Season	Maximum Salt Deposition (kg/km ² /month)	Fogging (hours/season)	Typical Plume Length (meter)	Typical Plume Height (meter)
Winter	4,844 @ 100 meters SSE of tower	0.4 @ 1,200 meters W of tower	600 meters SW of tower	150 meters SW of tower
Spring	8,735 @ 200 meters NW of tower	0.5 @ 1,100 meters ESE and SE of tower	600 meters SW of tower	150 meters SW of tower
Summer	4,432 @ 100 meters NW of tower	0.3 @ 200 meters NW and SSE of tower	600 meters SSW of tower	150 meters SSW of tower
Fall	6,407 @ 100 meters WNW of tower	0.2 @ 1,200 meters S of tower	600 meters SW of tower	150 meters SW of tower
Annual	5,456 @ 100 meters WNW of tower	0.4 @ 1,200 meters S and W of tower	600 meters SW of tower	150 meters SW of tower

Source: ECT, 1999.

flat, visibility on the nearby roadway is not expected to be degraded by the formation of this elevated visible plume.

The frequency of visible plume formation in all directions decreased to about 17 percent on an annual basis at 700 meters downwind of the tower. With respect to potential visibility impacts to air traffic, the nearest airport is located approximately 3 miles south of the plant site. At that distance, the visible plume is not expected to hinder the safe operation of aircraft during take-off or landing.

Induced ground-level fogging may infrequently occur during plume downwash conditions. However, this locally induced fog will dissipate rapidly due to the high winds associated with such plume downwash conditions. Most ground-level fogging is predicted to occur within 900 meters of the tower. Plume fogging is predicted to persist from the south and west at a distance of 1,100 meters for only 1.5 hours per year. Based on experience with existing cooling towers, typical meteorological conditions, local terrain, land use, and the conservative nature of the SACTI model predictions, plume fogging on CR 2300 is not expected.

Seasonal and annual salt deposition rates were calculated to a distance of 10,000 meters downwind of the cooling tower. The maximum salt deposition was predicted to be 8,735 kilograms per square kilometer per month ($\text{kg}/\text{km}^2/\text{month}$) in the spring within 200 meters of the tower. The maximum annual average deposition onsite was predicted to be 5,456 $\text{kg}/\text{km}^2/\text{month}$. The maximum annual average offsite salt deposition rate was predicted to be 460 $\text{kg}/\text{km}^2/\text{month}$. This value occurred 700 meters north of the tower.

Saline drift can impact plants by absorption of salt accumulated in the soil. Accumulation will occur if the annual deposition rate of salt exceeds the rate at which the salt is washed from the soil by precipitation. The result of studies (Mulchi, C.L. *et al.*, 1978) with sandy loam soil suggest that a deposition rate of about 10,000 $\text{kg}/\text{km}^2/\text{month}$ of sodium chloride can cause some accumulation of salt in the soil. Because the maximum annual average offsite deposition rate and the overall maximum deposition rate in the spring are lower

than the monthly threshold value that could cause salt accumulation in the soil, no significant soil impacts are expected.

An investigation of the potential effects of cooling tower drift on vegetation was conducted in which predicted salt deposition rates were compared to known salt injury thresholds. A predicted salt deposition rate is presented as the amount of salt deposited over a unit area per season and year at a certain direction and distance away from the tower.

Near the proposed power plant site boundary, predicted salt deposition rates on an annual basis range from 1,164 to 5,520 kilograms per square kilometer per year ($\text{kg}/\text{km}^2/\text{yr}$). The greatest predicted depositions are located to the north and south of the proposed power plant.

Native vegetation associated with pine flatwoods occurs onsite and along property boundaries. Salt deposition could range from 4,092 to 5,520 $\text{kg}/\text{km}^2/\text{yr}$ of salt on the north and south property boundaries, and at higher rates within the site. Two plant species found onsite that are considered intolerant or having a very low resistance to salt have been identified. These are sedge (*Carex glaucescens*) and royal fern (*Osmunda regalis*). FPC (1988) states that these two plants have a leaf injury threshold similar to that of the flowering dogwood (*Cornus florida*). Curtis *et al.* (1976) found that the leaf injury threshold for the dogwood was 9,000 $\text{kg}/\text{km}^2/\text{yr}$. Given that the sedge and royal fern have the same threshold as the dogwood, it can be concluded that the salt deposition should have no adverse effect on natural vegetation onsite or near the property boundary based on salt deposition projections.

5.1.4.2 Monitoring

No monitoring of cooling tower operations is proposed.

5.1.5 MEASUREMENT PROGRAM

Since the operation of the proposed facility is expected to slightly reduce the existing thermal impacts, no additional monitoring other than that required by the issued NPDES permit is recommended.

5.2 EFFECTS OF CHEMICAL AND BIOCIDES DISCHARGES

5.2.1 INDUSTRIAL WASTEWATER DISCHARGES

Four industrial waste streams from the proposed facility will be indirectly discharged to the existing discharge canal. These include discharges from the (1) demineralizer (17.03 gpm for normal operation and 89.09 gpm during augmentation); (2) condensate polisher (2.24 gpm); (3) evaporative coolers (9.0 gpm); and (4) clean drains from the turbine/boiler building (28.0 gpm). These four streams combine with the cooling tower makeup water from the discharge canal and the total volume is pumped to the cooling towers. After approximately two cycles of concentration, the cooling tower blowdown water is returned to the discharge canal. The impacts of the cooling tower blowdown are discussed in the next section. Appendix 10.2.5 contains Gulf's modified NPDES application.

5.2.2 COOLING TOWER BLOWDOWN

The cooling water will be treated to control fouling, scaling, and biofouling. The biocide used will be sodium hypochlorite. The cooling tower blowdown will be closed until the residual chlorine dissipates; therefore, no impacts to aquatic communities are expected.

Generic chemicals will be used to control fouling, and include polyacrylate or a polyacralimide. The cooling tower blowdown containing these water treatment chemicals will be discharged to the existing discharge canal and will be diluted by approximately 71:1 prior to reaching the NPDES point of discharge (POD) Outfall D001. The water treatment chemicals will be at very low levels such that there will be no expected impacts to the aquatic system.

The cooling tower is designed for two-cycle operation, which means that most water quality parameters will be concentrated two-fold prior to discharge to the existing discharge canal. The water quality of the makeup water from the once-through cooling water in the discharge canal (used for design purposes) and the projected water quality of the cooling tower blowdown for normal operation and power augmentation are provided in Table 5.2.2-1. In addition, the water quality of the mixed discharges as the effluent enters

Table 5.2.2-1. Water Quality Parameters of the Gulf Smith Unit 3 Cooling Water

	Makeup Water (normal)	Makeup Water (Augmentation)	Blowdown (Normal)	Blowdown (Augmentation)	POD (D001) (Normal)	POD (D001) (Augmentation)	Class II Marine Standards†
Flow (gpm)	5,120	5,048	2,587	2,587	187,467	187,539	—
Calcium (mg/L)	172	172	343	346	174	174	—
Magnesium (mg/L)	583	583	1,154	1,139	591	591	—
Sodium (mg/L)	5,416	5,416	10,955	10,809	5,493	5,491	—
Total cations (mg/L)	6,171	6,171	12,452	12,294	6,258	6,256	—
Biocarbonate (mg/L)	65	65	135	152	66	66	—
Sulfate (mg/L)	2,801	2,801	5,544	5,470	2,839	2,838	—
Chloride (mg/L)	8,730	8,730	17,275	17,043	8,848	8,845	—
Phosphate (mg/L)	0	0	0.09	0.09	<0.01	<0.01	—
Total anions (mg/L)	11,596	11,596	22,954	22,665	11,755	11,751	—
pH (units)	7.98	7.98	7.97	7.91	7.98	7.98	6.5-8.5
Silica (mg/L)	0.00	0.00	0.5	1.9	0.007	0.026	—
TSS (mg/L)	6.5	6.5	13.8	13.7	6.6	6.6	—
Temperature (°F)	86	86	86	86	86	86	—
Oil and grease (mg/L)	0.00	0.00	0.00	0.00	0.00	0.00	≤5.0
Antimony (mg/L)*	<0.02	<0.02	<0.04	<0.04	<0.02	<0.02	≤4.3
Arsenic (mg/L)*	<0.01	<0.01	<0.01	<0.01	<0.02	<0.02	<0.05
Beryllium (mg/L)*	<0.04	<0.04	<0.08	<0.08	<0.04	<0.04	≤0.00013
Cadmium (mg/L)*	<0.005	<0.005	<0.01	<0.01	<0.005	<0.005	≤0.0093
Chromium (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.05
Lead (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.0056
Nickel (mg/L)*	<0.04	<0.04	<0.08	<0.08	<0.04	<0.04	≤0.0083
Selenium (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.071

Table 5.2.2-1. Water Quality Parameters of the Gulf Smith Unit 3 Cooling Water (Continued, Page 2 of 2)

	Makeup Water (normal)	Makeup Water (Augmentation)	Blowdown (Normal)	Blowdown (Augmentation)	POD (D001) (Normal)	POD (D001) (Augmentation)	Class II Marine Standards†
Silver (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	—
Thallium (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.0063
Zinc (mg/L)*	<0.02	<0.02	<0.04	<0.04	<0.02	<0.02	≤0.086
Mercury (mg/L)*	<0.0002	<0.0002	<0.0004	<0.0004	<0.0002	<0.0002	<0.000025
Copper (mg/L)*	<0.002	<0.002	<0.04	<0.04	<0.02	<0.02	<.0029
Cyanide (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤1.0

* Because of two cycles of concentration, the concentration will approximately double in the blowdown. Input from process streams to the cooling tower are expected to be below detection limits for these parameters. Values shown as less than (“<”) are below the detection limits.

† Pursuant to the facility’s NPDES permit, “the actual limit shall be the water quality standard set forth in F.A.C. 62-302.530 for Class II waters...or the concentration of the intake cooling water, whichever is greater.”

Source: Gulf, 1999.
ECT, 1999.

public waters at the POD (NPDES Outfall D001) is provided. The water quality parameters of the cooling tower blowdown listed in Table 5.2.2-1 include the contributions of the internal industrial waste streams that are cycled through the cooling tower.

The water quality parameters listed exhibit the approximate two-fold increase in the water quality parameters with relatively small variances caused by the addition of the internal waste streams (comparing the makeup water with the blowdown). Two exceptions to this are silica (increases to a maximum of 1.9 mg/L) and phosphate (increases to a maximum of 0.09 mg/L), which are higher because of constituents in the waste streams and chemical additives. However, both of these parameters are still within applicable water quality standards.

As the cooling tower blowdown is discharged to the existing discharge canal (the original source of the makeup water), it will be diluted in the discharge from Units 1 and 2 by approximately 71:1 prior to reaching Outfall D001. The net result of withdrawing the makeup water and concentrating the constituents approximately two-fold in the cooling tower prior to reintroducing the water to the canal is to increase the concentration of the constituents of the final mixture of cooling water in the canal by approximately 1.3 percent. In addition, there will be a slight increase in some of the water quality parameters resulting from the process streams being recycled to the cooling tower. The net result of the two-cycle concentration, the inclusion of the internal process streams to the cooling tower makeup water, and the final mixing with the existing once-through cooling water is provided in Table 5.2.2-1. The parameter values presented in the table are the final projected concentrations at Outfall D001 and all parameters are expected to comply with Class II and Class III marine water quality standards on established permit limits as shown in the modification to the NPDES application presented in Appendix 10.2.5. Consequently, no long-term adverse impacts are expected on the water quality or aquatic systems in the receiving water (the thermal impacts were discussed in Section 5.1).

5.2.3 MEASUREMENT PROGRAMS

The analyses provided above were completed using historical data and engineering estimates of process streams for the proposed facility modification. The water quality of the intake and discharge water for the existing facility was supplemented with water quality samples collected in April 1999.

5.3 IMPACTS ON WATER SUPPLIES

5.3.1 SURFACE WATER

The Smith Unit 3 Project proposes to use cooling water from the existing discharge canal for the existing Smith plant and to use process water supplied by ground water from existing permitted wells onsite. As shown in the water balance diagram presented in Figures 3.5.0-1 and 3.5.0-2, surface water withdrawals from the discharge canal will be 5,120 gpm and 5,048 gpm (during power augmentation). Consequently, the Smith Unit 3 Project will not affect surface water quantities or quality, or affect the surface water hydrology of the surrounding area. The plant's proposed use of ground water will not affect surface waters. The operation of the proposed plant is expected to have no impacts on surface water supplies.

5.3.2 GROUND WATER

5.3.2.1 Impacts from Plant Pollutants

The proposed power plant will not have any direct discharges to ground water other than percolation from onsite storm water ponds. Therefore, the normal plant operations will not adversely affect ground water quality.

Use of fly ash mixed with clean fill as a base for the power plant will not affect ground water from any leaching of constituents. Toxicity testing results on the proposed fly ash are in Attachment 10.5-H of Appendix 10.5.

The plant design includes preventive measures to isolate any impacts from plant pollutants on ground water resources as a result of accidents or other unusual circumstances. These preventive measures are discussed in Sections 5.2, 5.3.4, and 5.4. Even if pollutants were to escape and permeate downward into the aquifer systems, they could be controlled and recovered with relative ease. The surficial aquifer includes appreciable amounts of organic matter, silts, and clays which would attenuate migration by adsorbing pollutants. Horizontal migration in the surficial aquifer would also be minimal because the natural hydraulic-gradient is essentially flat which limits the velocity of ground water flow.

The presence of the intermediate system, including the Jackson Bluff, between the surficial and Floridan aquifer systems will serve to attenuate downward migration, by retarding downward flow due to its low permeability.

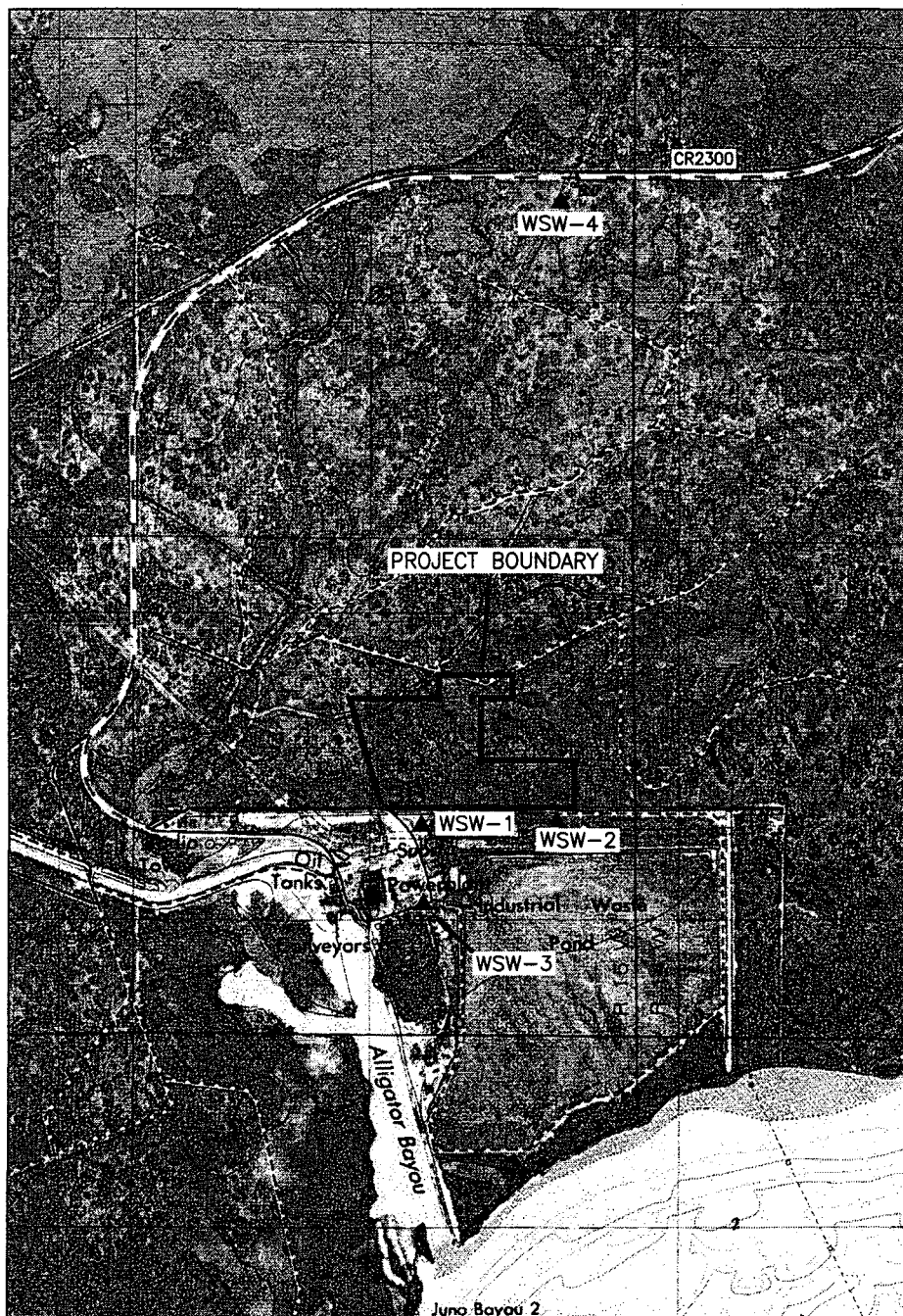
5.3.2.2 Impacts from Ground Water Withdrawals

Gulf Power has made significant efforts to evaluate the existing water supply for the operation of the plant. These efforts are discussed in the modeling study included in Appendix 10.5, Attachment 10.5-G. The total additional daily water requested is an increase of 0.5 MGD over the permitted amount of 0.7 MGD (a total Smith plant site requirement of 1.2 MGD for high quality process water). The additional water will be obtained from a previously approved new well to be installed in Fall 1999 at the location shown on Figure 5.3.2-1 and described in Appendix 10.5, Attachment 10.5-G.

The ground water modeling evaluations determined that 1.2 MGD of ground water can be reasonably and safely withdrawn from the Floridan aquifer system at the Project site. It was also determined that 0.72 MGD (annual average) can be withdrawn from the new well without causing significant adverse impacts.

Results of the ground water withdrawal study show that:

- Adding the fourth well will not adversely affect the Floridan aquifer system or the nearest major user.
- Regional head declines are only attributable to countywide water production increases over time.
- Operating the four permitted wells will not affect the surficial aquifer system or its related wetlands.
- Some minor upconing of chloride-bearing water will occur but will not significantly affect the Floridan aquifer system or the nearest major user, the City of Lynn Haven.
- The upconing is local in nature, will not degrade the Floridan aquifer system, and is expected to dissipate rapidly.



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1000 0 1000 2000 3000 4000 5000 FEET

SCALE 1:24000

FIGURE 5.3.2-1.
NEW WELL LOCATION (WSW-4)

Source: SCS, 1999.

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- Operating the new well will allow the existing plant wells to operate at a lower rate, which will allow their chloride levels to decrease.

For each criterion, the conclusion is that the proposed annual average withdrawal rate of 1.2 MGD is not expected to cause significant adverse impacts. The current permitted allowable withdrawal rate is 0.7 MGD. Section 5.3.5 describes the ground water monitoring program that will be used to document water level, flow, and water quality conditions both prior to and during operation of the power plant. This monitoring will further ensure that significant impacts do not occur.

5.3.3 DRINKING WATER

The small quantity of drinking water and other potable water required by Smith Unit 3 personnel (slightly over 1,000 gpd) will be supplied by the four permitted wells onsite. There will be no discharges from the plant to any drinking water sources. Cooling tower blowdown will be discharged to the existing discharge canal which empties into Warren Bayou on West Bay. Process wastewater and sanitary wastewater will be sent to the existing Lansing Smith WWTP for treatment. That facility currently has ample capacity to handle the small amount of wastewater generated by Smith Unit 3.

No impacts to the regional drinking water supplies are anticipated as discussed in Section 5.3.2.

5.3.4 LEACHATE AND RUNOFF

Following construction, the SWMP (see Appendix 10.2.2) will provide guidance in protecting adjacent water bodies. Erosion and sedimentation should be minimal due to grass and other vegetative cover reducing velocities of runoff, which inhibits suspension of soils. Most silts that do reach suspension will be deposited within the storm water ponds. The ponds will also treat runoff through biological uptake from vegetation on the littoral shelf. Regular maintenance of the ponds will include removal of sediments and other debris which may have been washed from the site.

Increased attention on source control has shifted the NPDES program to not only look at point sources, but also non-point sources. Non-point sources are loosely defined as storm water runoff outfalls. To clean up the outfalls, the program proposes to limit the sources which may contribute to pollution associated with runoff. BMPs are proposed to limit pollution potential. The BMPs for the Project are detailed in the BMP plan (Appendix 10.2.3). Included are measures to contain spills in secondary containment, placing high-risk materials under cover, employee training, storage systems, and tracking of materials. These measures will help in the prevention of impacts to adjacent water bodies.

5.3.5 MEASUREMENT PROGRAMS

Chloride sampling is proposed to occur quarterly from existing wells 1 through 4. In addition, flow measurements will also be recorded on water withdrawn from the onsite supply wells. Monitoring will be in accordance with all conditions issued with the modified water use permit.

5.4

5.4 SOLID/HAZARDOUS WASTE DISPOSAL IMPACTS

5.4.1 SOLID WASTE

The anticipated types and quantities of solid waste that will be generated by the Smith Unit 3 Project are described in Section 3.7. All solid wastes generated at the plant will be disposed at an offsite licensed landfill designed and permitted to receive such wastes. No onsite impacts will result from these wastes.

Internal facility processes and general maintenance activities at the facility are expected to periodically generate nonhazardous petroleum-contaminated products. Petroleum products such as waste oils or spent lubricating oils will be collected onsite and transferred to a permitted aboveground storage tank and burned for energy recovery in Smith Unit 2. Materials such as petroleum-contaminated liquids and sludges from oil/water separators and hydrocarbon liquids from fuel/gas filter separators will be periodically serviced by a contractor and transported offsite to a permitted facility for appropriate treatment and disposal. Used oil filters generated through general maintenance processes will be collected and recycled as scrap metal. No onsite impacts will result from the handling of these waste oil products.

5.4.2 HAZARDOUS WASTE

Small quantities of hazardous wastes will be routinely generated at the proposed Smith Unit 3 Project plant site as discussed in Section 3.7.2. It is anticipated that the Smith Unit 3 Project will be a conditionally exempt small-quantity generator. As such, the facility will not be required to meet requirements for large-quantity generators or other small-quantity generators, as specified in 40 CFR Parts 260 through 263 and Parts 270 through 272. Specialty contractors conducting activities such as metal cleaning of the HRSG will be responsible for proper removal of waste products resulting from their contracted activities.

5.5 SANITARY AND OTHER WASTE DISCHARGES

Sanitary wastewater from the plant will be discharged via sewer line to the adjacent Smith Plant package wastewater treatment facility, which has available permitted capacity to handle Smith Unit 3 wastewater. There will be no sanitary discharges other than to the WWTP. All discharges from the WWTP will meet Gulf's existing industrial wastewater permit limits. Therefore, sanitary effluent from the Smith Unit 3 Project will have no effect on the environment. Wastewater from the oil/water separator and wastewater from the neutralization tank will be discharged to the cooling tower basin. Cooling tower blowdown will be discharged to the existing Lansing Smith discharge canal which empties into Warren Bayou and West Bay. The point of discharge for this system will meet all applicable state and federal water quality standards per the industrial wastewater treatment permit conditions.

5.6

5.6 AIR QUALITY IMPACTS

5.6.1 IMPACT ASSESSMENT

5.6.1.1 Introduction

Analyses were conducted to calculate the potential air quality impacts of emissions from Smith Unit 3. These analyses are described in detail in the PSD permit application contained in Appendix 10.2.7. This section presents a summary of the approach used and the results obtained. The results demonstrate that the operation of Smith Unit 3 will not cause or contribute to a violation of any PSD increment or AAQS.

5.6.1.2 Regulatory Applicability and Overview of Impact Analyses

Under federal PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and approved by EPA or by the state agency if PSD review authority has been delegated or approved for the state. A *major stationary source* is defined as any 1 of 28 named source categories that has the potential to emit 100 tons per year (tpy) or more, or any other stationary source that has the potential to emit 250 tpy or more, of any pollutant regulated under CAA. *Potential to emit* means the capability at maximum design capacity to emit a pollutant after the application of control equipment.

The existing Lansing Smith Plant is classified as a major facility because it falls into one of the named source categories (i.e., fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input) and has the potential to emit more than 100 tpy of at least one pollutant regulated under CAA (see Table 5.6.1-1). Smith Unit 3 constitutes a major modification to a major facility because Unit 3 will result in a significant net emission increase of at least one pollutant regulated under CAA. Therefore, the facility must undergo PSD review. Furthermore, more than one pollutant is subject to review. Table 5.6.1-1 summarizes the facility's proposed annual emissions and compares the projected totals to the significant emission rate thresholds for PSD review. Note that NO_x emissions from Smith Unit 3 are not subject to PSD review because there will be a net reduction in NO_x emissions from the Lansing Smith Plant due to the installation of low-NO_x burner technology and an improved burner management system for Lansing Smith Unit 1.

Table 5.6.1-1. Projected Emissions Compared to PSD Significance Rates

Pollutant	Projected Annual Emissions (tpy)*	Significance Rate (tpy)	Subject to PSD Review?
PM	263	25	Yes
PM (PM ₁₀)	263	15	Yes
SO ₂	105	40	Yes
NO _x	-9	40	No
CO	701	100	Yes
Ozone/VOC	93	40	Yes
Lead	0.0006	0.6	No
H ₂ SO ₄ mist	12	7	Yes
Fluorides	0	3	No
Mercury	Neg.	0.1	No
Beryllium	0	0.0004	No
Total reduced sulfur (including hydrogen sulfide)	0	10	No
Reduced sulfur compounds (including hydrogen sulfide)	0	10	No
Vinyl chloride	0	1	No
Asbestos	0	0.007	No

*See Table 3.4.1-3 for details.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source. PSD review requirements are contained in Chapter 62-212.400, F.A.C., *Prevention of Significant Deterioration*. Major sources may be required to undergo the following reviews related to PSD for each pollutant emitted in significant amounts:

- Control technology review.
- Air quality analysis (monitoring).
- Source impact analysis.
- Source information.
- Additional impact analyses.

The control technology review includes determination of BACT for each applicable pollutant. BACT emission limits cannot exceed applicable emission standards (e.g., NSPS). The air quality analysis (monitoring) portion of PSD review may require continuous ambient air quality monitoring data to be collected in the impact area of the proposed source. The source impact analysis requires demonstration of compliance with federal and state AAQS and allowable PSD increment limitations. Projected ambient impacts on designated nonattainment areas and federally promulgated Class I PSD areas must also be addressed, if applicable. Source information, including process design parameters and control equipment information, must be submitted to the reviewing agencies. Additional analyses of the proposed source's impact on soils, vegetation, and visibility, especially pertaining to Class I PSD areas, must be performed, as well as analysis of impacts due to growth in the area associated with the proposed source.

In addition to PSD review requirements, FDEP has developed a strategy to control toxic emissions from stationary sources so that these emissions will not endanger public health. The strategy is based on comparing the predicted ambient impact of individual toxic air contaminants with each chemical's *air reference concentration*. A reference concentration is an ambient exposure level that is not likely to cause appreciable health risks. Due to recent legislative changes to the Administrative Procedures Act, FDEP's air toxics strategy is no longer used in the evaluation of air permits; reference the Division of Air Resources Man-

agement *Revised Guidance on the Permitting of Sources Emitting Hazardous Air Pollutants* guidance memo dated November 20, 1998. However, the FDEP's former air toxics policy and air reference concentrations are still considered useful in evaluating toxic air pollutant impacts. Because the Smith Unit 3 CTGs will be fired exclusively with natural gas, the only toxic air contaminant emitted in more than trace amounts is H₂SO₄ mist. An analysis of the Project's impacts of H₂SO₄ mist with respect to FDEP's air reference concentration for this air contaminant is provided in Section 7.3 of the PSD permit application contained in Appendix 10.2.7.

5.6.1.3 Analytical Approach

Air Quality Models

Two air quality dispersion models were used in the analysis of impacts for the Smith Unit 3 Project. These models were:

- SCREEN3.
- ISCST3.

SCREEN3 is a screening model that calculates 1-hour average concentrations from a single source over a range of meteorological conditions. SCREEN3 was used to provide conservative estimates of impacts from the CTGs in order to select the worst-case operating configurations.

The Industrial Source Complex Short-Term (ISCST3) model (EPA, 1998) was used for refined analyses. The ISCST3 model is a steady-state Gaussian plume model that can be used to assess air quality impacts from a wide variety of sources. It is capable of calculating concentrations for averaging times ranging from 1 hour to annual.

Meteorological Data

Detailed meteorological data are needed for modeling with the ISCST3 model. For this effort, meteorological data were selected consistent with EPA (1995) guidance and FDEP practice. Specifically, surface data from Apalachicola Municipal Airport (1988—1990) and Pensacola Regional Airport (1986, 1987) and mixing height data from Apalachicola Mu-

municipal Airport for the 5-year period 1986 through 1990 were approved by FDEP and employed.

Emission Source Input Data

Emission parameters for Smith Unit 3 sources were based primarily on information provided by equipment vendors for the Project. Some emission inputs were derived using EPA and other emission factors and facility design data (see Attachments B and C of PSD Application in Appendix 10.2.7).

5.6.1.4 Summary of Air Quality Impacts

Criteria pollutant emissions from the two CTG/HRSG units were modeled using the ISCST3 model. Table 5.6.1-2 summarizes the results of the maximum facility impact modeling runs for the criteria pollutants. As appropriate, the maximum impacts are compared to the modeling significance levels. Table 5.6.1-2 shows that impacts were found to be less than significant for all averaging times and all pollutants subject to review. Due to the low Project impacts, no further analysis of air quality impacts is required (i.e., evaluation of other, existing air emission sources in the area).

In addition, modeled Project impacts are below the PSD *de minimis* ambient impact levels for all pollutants and averaging periods. Accordingly, by rule the Project qualifies for an exemption from preconstruction ambient air quality monitoring requirements for all pollutants.

5.6.1.5 Other Air Quality-Related Impacts

Impacts Due to Associated Growth

Construction of Smith Unit 3 will occur over an approximate 15-month period. There will be an average of approximately 180 workers during that time with a peak employment of approximately 325 construction workers. It is anticipated that most of these construction personnel will be drawn from within Bay County (e.g., the Panama City area) and will commute to the job site. While not readily quantifiable, the temporary increase in vehicle-miles-traveled (VMT) in the area would be insignificant, as would any temporary increase in vehicular emissions.

Table 5.6.1-2. Maximum Smith Unit 3 Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu\text{g}/\text{m}^3$)	Significance Level ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	0.1	1.0
	24-hour	1.7	5.0
	3-hour	7.6	25.0
PM ₁₀	Annual	0.5	1.0
	24-hour	13.4	5.0
CO	8-hour	38.4	500
	1-hour	111.2	2,000

Source: ECT, 1999.

The Smith Unit 3 Project will employ a total of 29 operational workers at Project build-out. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. It is expected that most of these persons will be drawn from outside the region.

In the year 2000, the population of Bay County is estimated to be 150,099 persons. The workforce needed to operate the proposed plant, therefore, represents a small fraction of the population already present in the immediate area. While some small increase in area VMT could occur, associated air quality impacts in Bay County will be minimal.

Finally, a new industrial facility can sometimes generate growth in other industrial or commercial operations needed to support the new facility. Given the site's proximity to Panama City, however, the existing commercial infrastructure should be more than adequate to provide any support services that the proposed facility might require. Therefore, no air quality impacts due to associated industrial/commercial growth would be expected. Any significant industrial development resulting from the establishment of Smith Unit 3 would be independently subject to PSD and other environmental review requirements.

Impacts on Visibility and on Soils, Vegetation, and Wildlife

No visibility impairment at the local level is expected due to the types and quantities of emissions projected from Smith Unit 3 emission sources. The opacity of combustion exhausts from the facility will be low due to the exclusive use of clean, natural gas. Emissions of primary particulates and sulfur oxides due to combustion will also be low due to the exclusive use of natural gas. The potential for regional haze formation in the area due to Smith Unit 3 emissions of SO₂, NO_x, and PM/PM₁₀ is expected to be minimal. Based on the relatively isolated location of the Lansing Smith Plant and existing land use, the proposed Smith Unit 3 will not adversely affect aesthetic or visual qualities in the area.

Certain air pollutants in acute concentrations or chronic exposures can impact soils, vegetation, or wildlife resources. Based on available literature and air emissions projected for this

Project, the following summary of potential impacts is provided. The PSD application (Appendix 10.2.7) provides a more detailed analysis of potential air emissions on natural resources.

Soils impacts can result from SO₂ and NO_x deposition creating an acidic reaction or lowering of soil pH. In this case, the site soils are naturally acidic, and the low SO₂ and NO_x emissions from the Project will not adversely affect plant vicinity soils.

Vegetation is sometimes affected by acute exposures to high concentrations of pollutants, often resulting in foliar damage. Lower dose exposure over longer periods of time (chronic exposure) can often affect physiological processes within plants causing internal and external damage. Based on an evaluation of the literature for effects from SO₂, acid rain (H₂SO₄ mist), NO_x, CO, and combinations of these pollutants (synergistic effects), no impacts to regional vegetation are anticipated due to the low emission rates from the Project.

Releases of pollutants can also affect wildlife through inhalation, exposure through skin, or ingestion. However, based on low emission levels from this Project, natural dispersion of emissions, and mobility of wildlife, no impacts to regional wildlife resources are expected.

Based on this assessment, it was concluded that emissions from Smith Unit 3 will not result in impacts that will cause harm to soils, vegetation, or wildlife.

5.6.2 MONITORING PROGRAMS

No specialized monitoring of ambient air quality is planned, nor is additional ambient monitoring warranted given the low impacts on air quality predicted for the Project. Gulf Power will continue to operate its existing ambient air monitoring sites for SO₂, NO_x, and PM.

The Smith Unit 3 CTGs will be subject to 40 CFR 60, Subpart GG (NSPS) and 40 CFR 75 (*Acid Rain Program*). Continuous monitoring of fuel consumption will be conducted for the Smith Unit 3 CTGs as required by Subpart GG. Monitoring of fuel sulfur and nitrogen con-

tent will also be performed pursuant to Subpart GG, 60.334(b). Initial performance testing of the CTGs for NO_x and SO₂ emissions will be conducted as required by Subpart GG, 60.335.

Continuous emissions monitoring of NO_x and a diluent (O₂ or CO₂) will be conducted in accordance with the provisions of 40 CFR 75. Monitoring of SO₂ and CO₂ emissions will be conducted using procedures specified in 40 CFR 75, Appendices D and G, respectively.

Initial and periodic compliance testing of pollutants emitted by Smith Unit 3 will be conducted pursuant to FDEP requirements as specified in the SCA Approval Order. FDEP test methods are specified in Section 62-297.401, F.A.C.

5.7 NOISE

Potential operational noise impacts were assessed for three Gulf property boundaries (not Project boundaries). Figure 5.7.0-1 shows the location of the model receptors assessed in this analysis. Noise level data for the operating equipment were obtained from vendors and constructing engineers. The noise data are presented in Table 5.7.0-1.

While some portions of the site perimeter will remain vegetated or be revegetated after construction is complete, for this analysis, noise from the proposed operation was conservatively assumed not to be attenuated due to vegetation buffers at the modeled receptors. A substantial vegetative buffer exists between the facility and the property boundaries; however a conservative approach was again used for this noise analysis in that no credit was taken for the noise attenuation that will occur because of this vegetation. Similarly, while other noise attenuating factors will be present (e.g., screening of noise by structures), no credit other than distance was taken at any receptor for any noise attenuation that will occur.

Table 5.7.0-2 presents the results of the noise analysis at each of the receptor locations. The predicted noise levels at the north, east, and west property boundaries are all less than the Bay County sound level limit of 75 dBA (Bay County Land Use Code Section 6.05.01) for agricultural, silvicultural, and industrial land use types. Given the conservatism associated with this analysis, it can be concluded that the Project will comply with the county standard. As noted above, the attenuation effects of the vegetative barrier located between the power plant and the property boundaries were not included in the evaluation. The actual noise impact due to the facility is expected to be lower.

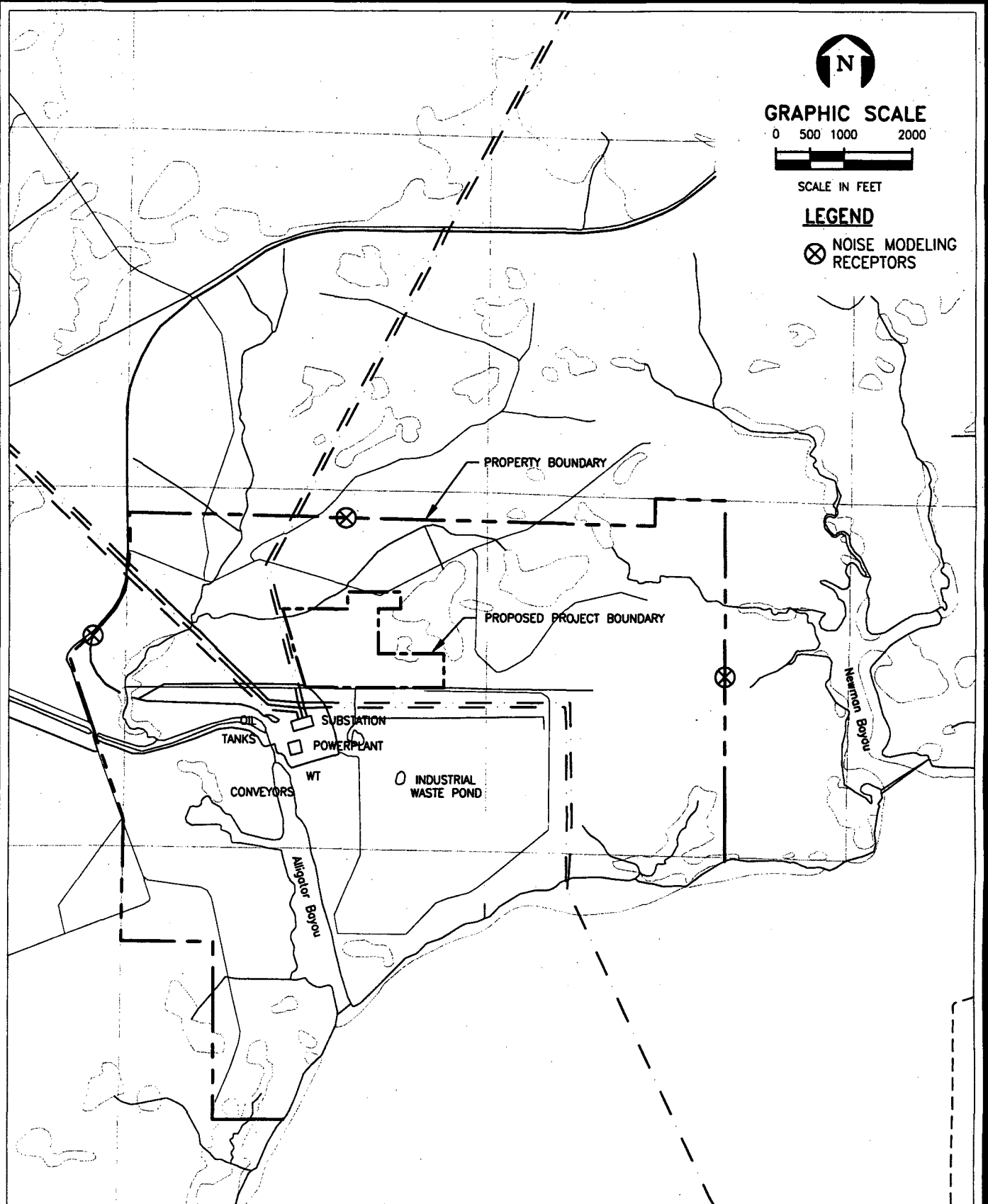


FIGURE 5.7.0-1.
NOISE MODELING RECEPTORS

Source: US Geodata, 1997; ECT, 1999.

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Table 5.7.0-1. Operating Equipment Noise Levels

Equipment Description	Sound Pressure Level (dB re 20 μ PA) Octave Band Center Frequency (hertz)									Sound Level (dBA)	Reference Distance (ft)
	31.5	63	125	250	500	1,000	2,000	4,000	8,000		
Boiler Feed Pump 1	NA	89	86	87	90	87	85	80	85	92	3
Boiler Feed Pump 2	NA	89	86	87	90	87	85	80	85	92	3
Boiler Feed Pump 3	NA	89	86	87	90	87	85	80	85	92	3
Boiler Feed Pump 4	NA	89	86	87	90	87	85	80	85	92	3
Boiler Feed Pump Motor 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	93	3
Boiler Feed Pump Motor 2	NA	NA	NA	NA	NA	NA	NA	NA	NA	93	3
Boiler Feed Pump Motor 3	NA	NA	NA	NA	NA	NA	NA	NA	NA	93	3
Boiler Feed Pump Motor 4	NA	NA	NA	NA	NA	NA	NA	NA	NA	93	3
Steam Turbine	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Gas Turbine 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Gas Turbine 2	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Condensate Pumps and Motor 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	86	3
Condensate Pumps and Motor 2	NA	NA	NA	NA	NA	NA	NA	NA	NA	86	3
Circulating Water Pump and Motor 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Circulating Water Pump and Motor 2	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Cooling Tower	NA	64	65	65	72	75	76	78	78	84	25

NA = not available.

Source: GPC, 1999.

Table 5.7.0-2. Modeled Ambient Noise Impacts

Receptor	Smith Unit 3 Sound Level (dBA)	Sound Level Limit (dBA)*
North Property Boundary	42	75
East Property Boundary	29	75
West Property Boundary	35	75

*Bay County Land Use Code Section 6.05.01.

Source: ECT, 1999.

5.8

5.8 CHANGES IN NON-AQUATIC SPECIES POPULATIONS

5.8.1 IMPACTS

Potential adverse effects to onsite or local upland and wetland habitats due to power plant operations are commonly a result of air emissions and cooling system operation. As stated in Section 5.6 of this SCA, no significant impacts to either onsite or local/regional plant and wildlife communities are anticipated from the air emissions or cooling system operation associated with power plant operation. In addition, no impacts on listed plant or animal species discussed in Section 2.3.6 will result from plant operations.

5.8.2 MONITORING

Monitoring programs are not proposed due to the negligible impacts to ecological resources associated with plant operation.

5.9 OTHER PLANT OPERATION EFFECTS (TRAFFIC)

5.9.1 IMPACTS

All of the traffic to be generated by the proposed development will access and leave the Project site from CR 2300. For a worst-case scenario, all of the expected new trips to be generated are assigned to the road segment from SR 77/CR 2300 to the south approach to Bailey Bridge. The estimated number of new trips is based on trip generation rate for power plants of 2.35 and a vehicle occupancy rate of 1.4. The proposed development will generate approximately 49 new daily trips based on 29 new plant employees. The existing, projected, and acceptable average daily traffic (ADT) and LOS are as follows:

	Existing ADT/LOS (1998)	Projected ADT/LOS (2002)	Acceptable ADT/LOS
SR 77/CR 2300 south to Bailey Bridge	15,800 (C)	17,456 (C)*	24,800 (D)

*From CR 388 South to Bailey Bridge.

Source: FDOT, 1999.

The impact of the proposed operation of Smith Unit 3 on the state and county road system will not degrade the existing LOS of C on this roadway segment. If the proposed Smith Unit 3 is approved, the plant is anticipated to be operational in June 2002. The anticipated ADT on SR 77 from south of CR 388 to Bailey Bridge in 2002 is approximately 17,456 and with the Project traffic would be 17,505, well below the maximum acceptable LOS (D) of 24,800.

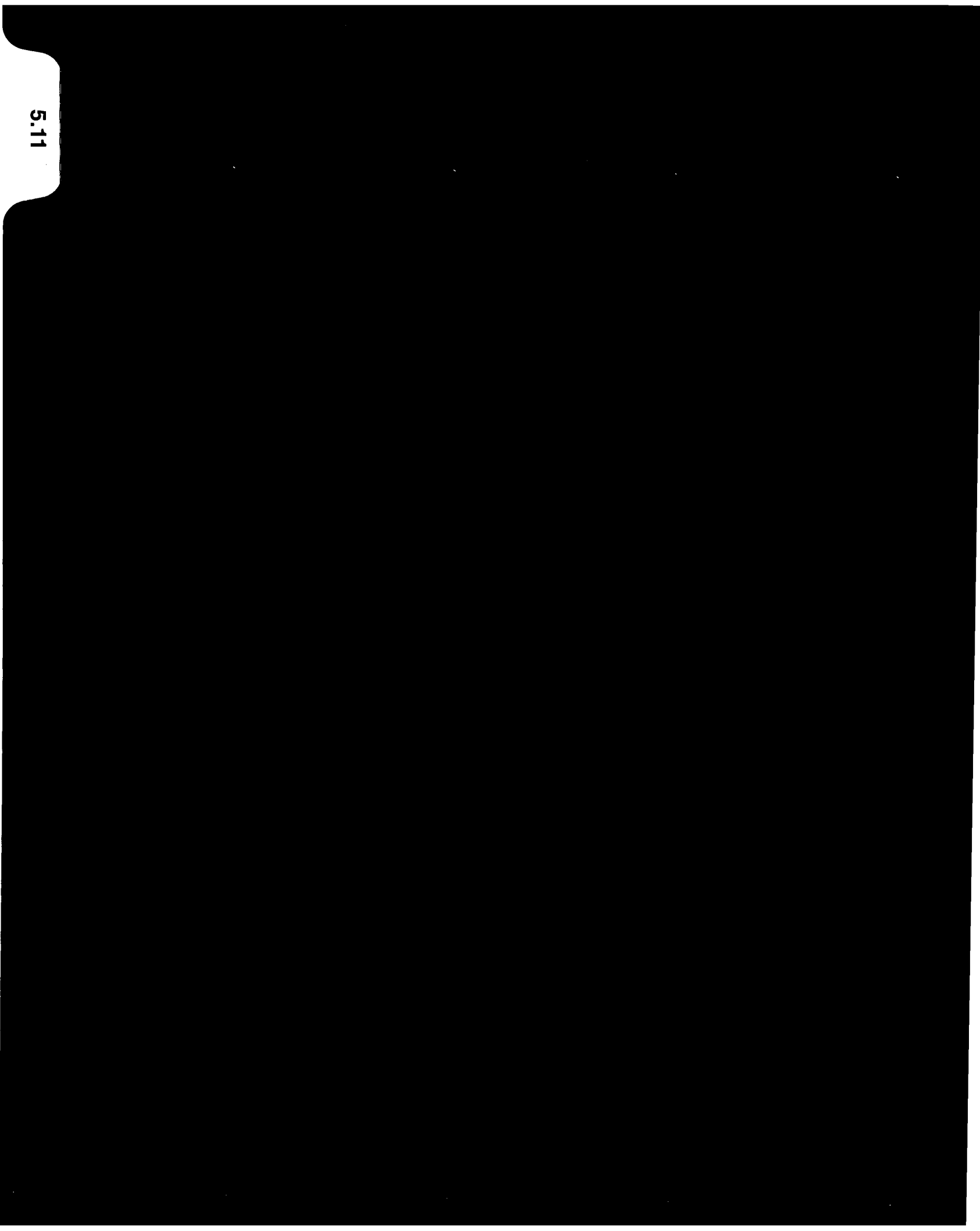
According to FDOT District 3 personnel, the SR 77 segment from Bailey Bridge to CR 2300 is scheduled to begin project development and engineering studies in 2000 with right-of-way acquisition to also begin in 2000. The four-laning of this road segment is scheduled to begin in 2005 (but is not in the current FDOT 5-year plan through 2004).

5.9.2 MONITORING

Due to the small traffic volume created as a result of operation of Smith Unit 3, no traffic monitoring studies are required or proposed.

5.10 ARCHAEOLOGICAL SITES

Based on a review of cultural resources potentially occurring onsite (see Sections 2.2.6 and 4.8), the Division of Historic Resources concluded no significant historical or archaeological sites are expected to be found at the proposed site (Appendix 10.5, Attachment 10.5-A). Therefore, no onsite post-construction monitoring or restoration activities are required.



5.11 RESOURCES COMMITTED

The major irreversible and irretrievable commitments of state and local resources due to the operation of the Smith Unit 3 Project are as follows:

- Use of land.
- Consumption of natural gas.
- Consumptive use of water (ground water).
- Consumption of air quality increments.

The use of land by the Project, while irreversible, will be relatively small. The site consists of 50.1 acres, and approximately 32.7 acres will be cleared for the Project. The remaining acreage, including wetlands, will remain in its natural state.

Natural gas will be consumed by the CTGs. The quantities are presented in Chapter 3.0. While the Smith Unit 3 Project will produce electricity in an efficient manner using state-of-the-art technology, which will result in efficient use of fuel, the natural gas consumed represents an irreversible and irretrievable commitment of energy resources for the production of electricity.

Water evaporated by the cooling tower as part of the heat rejection process represents a consumptive use of water. This consumptive use will be minimized by the reuse of heated cooling water discharged to the outfall. Ground water consumed for high quality uses by the operation of the plant will be withdrawn in a manner which will result in acceptable impacts, as determined using criteria developed by the NFWFMD.

The air quality increments consumed by air pollutant emissions from the Project will be negligible. The Project's emissions will create no impediment to any additional industrial growth in the area, nor will they have significant impacts on the area's air quality.

5.12

5.12 VARIANCES

No variances from any federal, state, or local regulations, standards, or guidelines will be needed for operation of this Project.

REFERENCES

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6.0

6.0 TRANSMISSION LINES AND OTHER LINEAR FACILITIES

In this application, Gulf Power is not seeking certification of any new transmission line corridors or natural gas pipeline corridors.

This particular site was selected largely in part because of its proximity to Gulf's existing Lansing Smith Generating Station. Smith Unit 3 will be able to share many facilities already in place at the site including transmission line access.

6.1 TRANSMISSION LINES

As discussed in Section 3.2 of this SCA, Smith Unit 3 will be constructed with its own onsite substation which will be connected to the existing Lansing Smith 230-kV substation by means of approximately 1,000 ft of wire bus. The wire bus will be located and constructed on already developed plant site property and, therefore, will not require any new transmission corridor. No environmental or land use impacts are expected from this transmission tie.

As also mentioned in Section 3.2, certain transmission system improvements will be required on Gulf's existing transmission grid within Bay County (see Figure 3.2.0-4). These all involve re-conductoring on existing transmission lines and existing rights-of-way. Reconductoring involves the replacement of the wires or conductor in a transmission line. The basic method used to re-conductor the lines will be to remove the old conductor from the suspension clamp at each structure, place the old conductor in a wire roller (pulley), attach a pulling rope to the old conductor, pull the rope in by pulling out the old conductor, attach the new conductor to the rope, pull the new conductor in place with the rope, remove the conductor from the rollers, and install the conductor into the suspension clamp. The removal of the old wire and installation of the new conductor will be accomplished by standard tension stringing methods at each end of the line sections. Existing right-of-way access roads will be utilized for this effort. No new transmission line corridors, structures, access roads, etc., will be necessary for the re-conductoring. Similarly, no dredging or filling of wetlands will be required. Therefore, no environmental or land use impacts are expected from these system upgrades. The reconducted

lines will meet FDEP's standards for electric-magnetic field (EMF) levels as outlined in Chapter 62-814, F.A.C.

6.2 NATURAL GAS PIPELINE

The Smith Unit 3 Project will burn natural gas only and, as discussed in Section 3.3, a new natural gas pipeline will have to be built to serve the Project. A pipeline lateral is proposed to connect with FGT's pipeline system in Washington County.

Gulf Power is not proposing to permit, build, or own the gas pipeline. FGT will be responsible for the permitting, engineering, construction, operation, and maintenance of the new gas pipeline. The gas pipeline route has not been finalized, but is expected to interconnect with the existing FGT system south of the town of Wausau in Washington County. The new pipeline will be approximately 29 miles long and most likely will follow SR 77 south to Bay County. At the point where SR 77 intersects Gulf's existing transmission line at SR 388, the gas pipeline is expected to follow the transmission line to the Smith Plant (see Figure 6.2.0-1).

The pipeline lateral will be permitted, constructed, and operated by FGT. FGT will submit appropriate state and federal permit applications separate from this application. It is expected that permitting of the pipeline will occur in the same timeframe as certification of Smith Unit 3.

A gas meter station will be required at the Smith Unit 3 site. This facility will be owned by Gulf Power and, therefore, is included in the site plan for this Project's certification.

6.3 OTHER LINEAR FACILITIES

The only other linear facilities required for this Project will be various onsite pipes connecting the Unit 3 site with the existing Lansing Smith Generating Station's facilities. The most notable of these will be the required cooling water intake and discharge pipelines which will connect Smith Unit 3 to Gulf's existing discharge canal on the property. The new pipelines will be constructed on cleared, already developed property at the

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

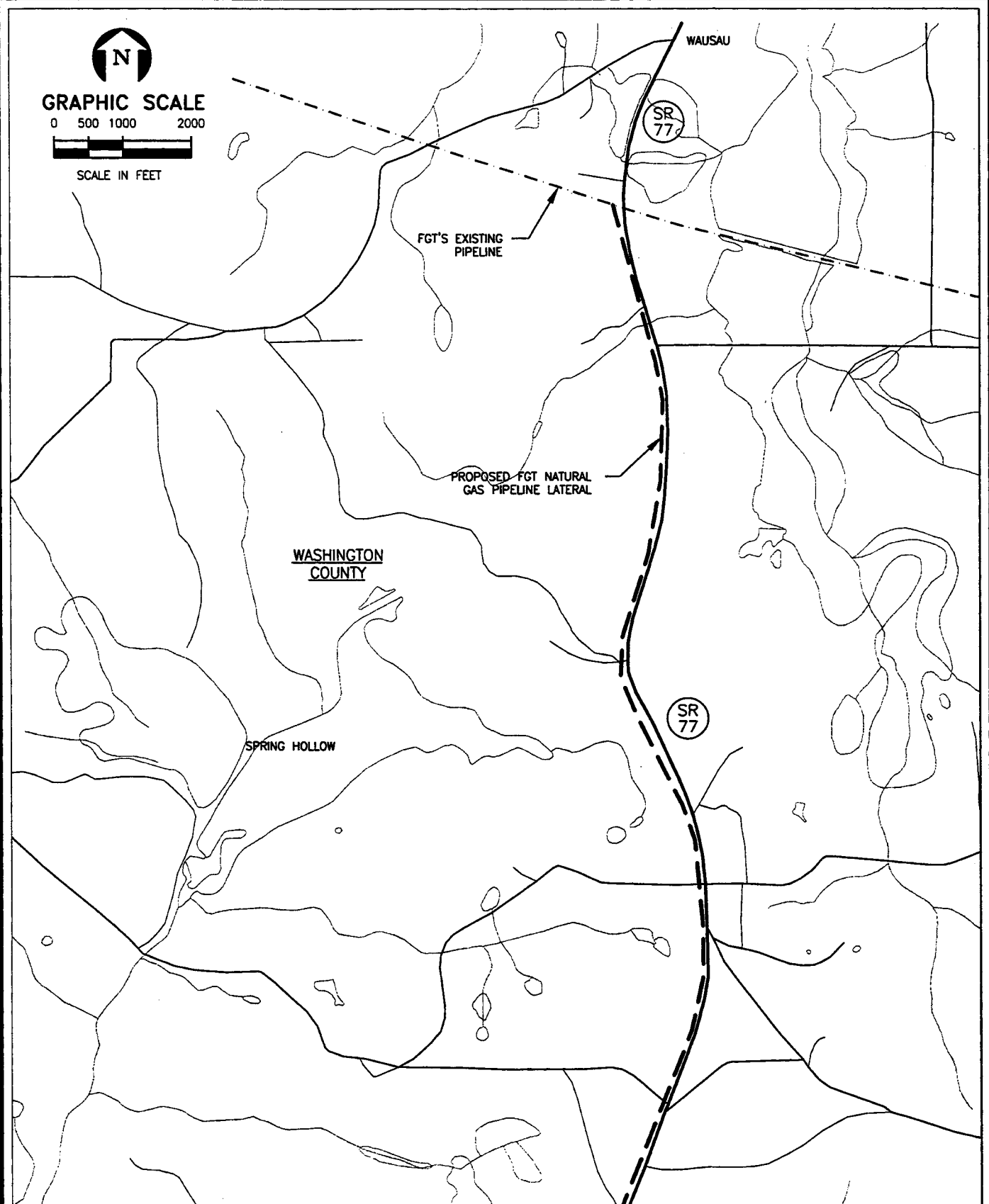


FIGURE 6.2.0-1. (PAGE 1 OF 8)
PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

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Environmental Consulting & Technology, Inc.

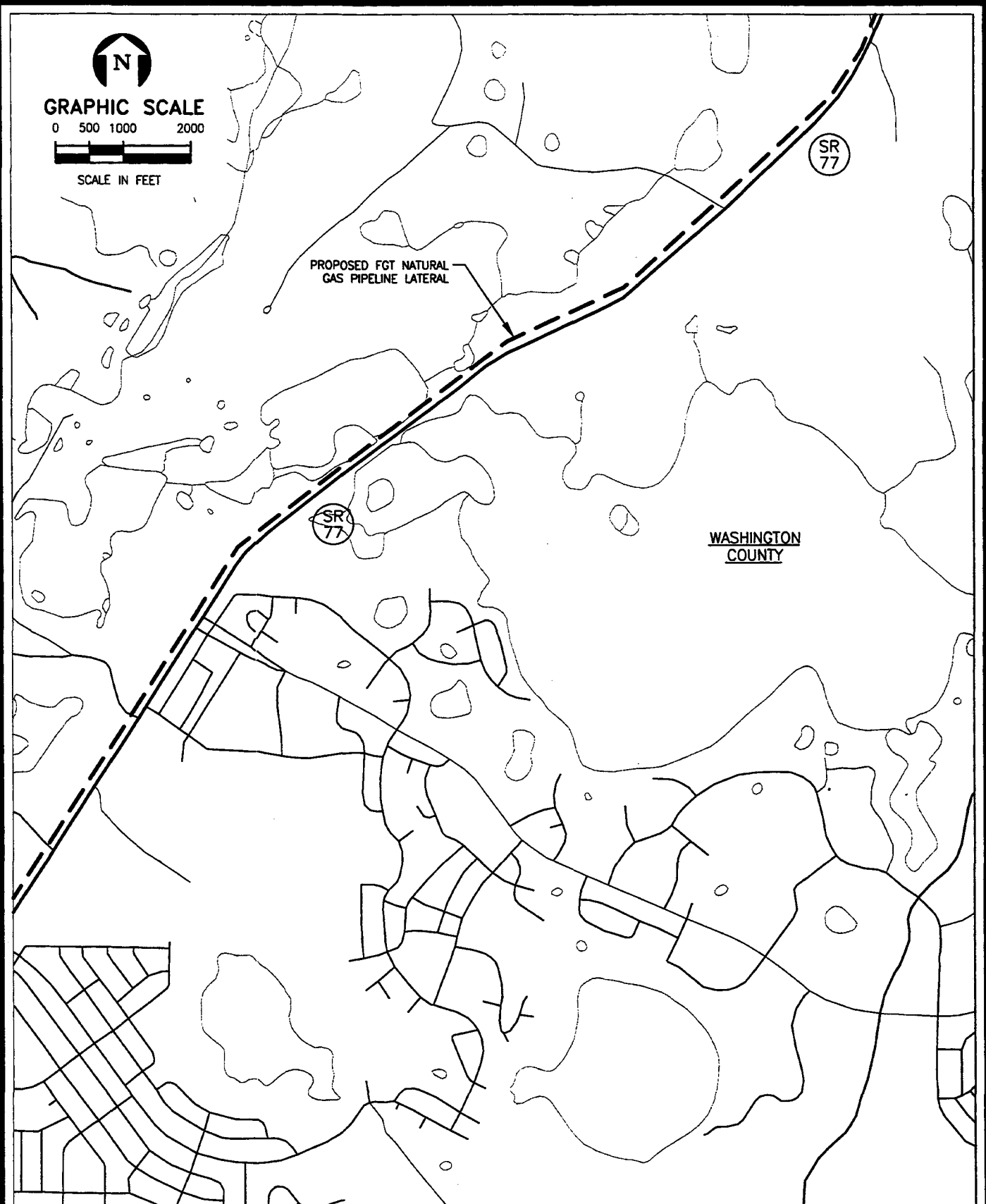


FIGURE 6.2.0-1. (PAGE 2 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: US Geodata, 1997; ECT, 1999.

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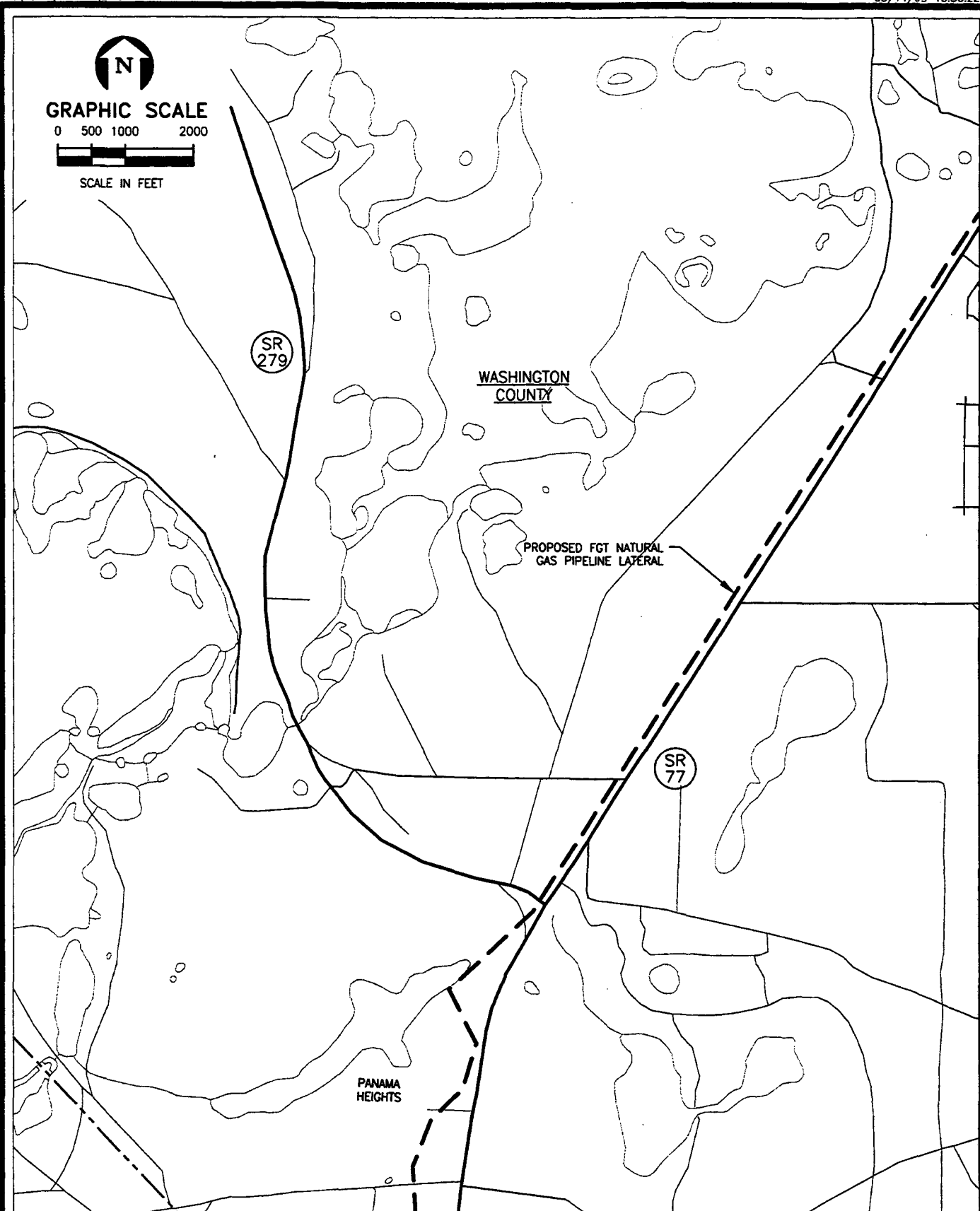


FIGURE 6.2.0-1. (PAGE 3 OF 8)
PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

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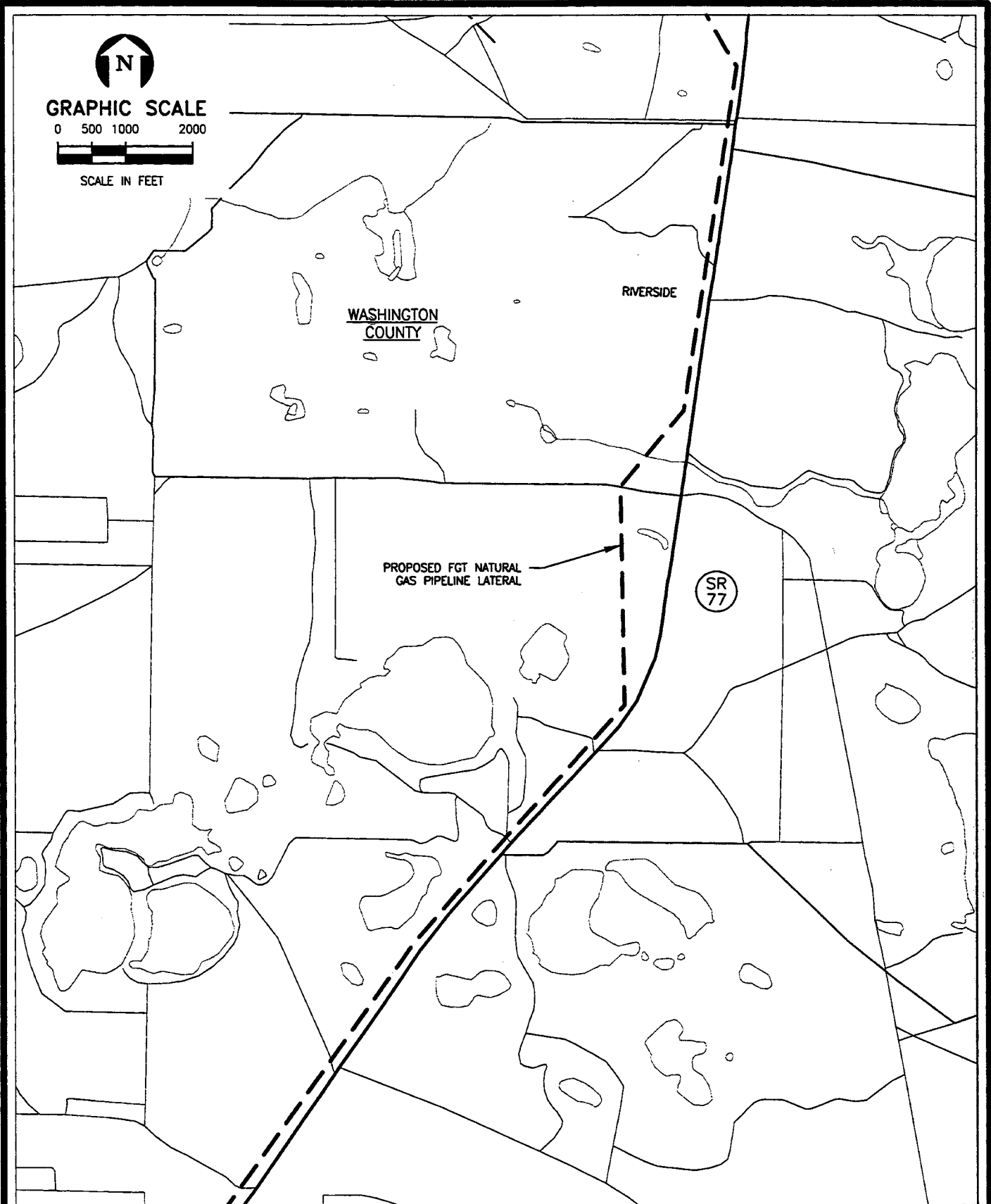


FIGURE 6.2.0-1. (PAGE 4 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodato, 1997; ECT, 1999.

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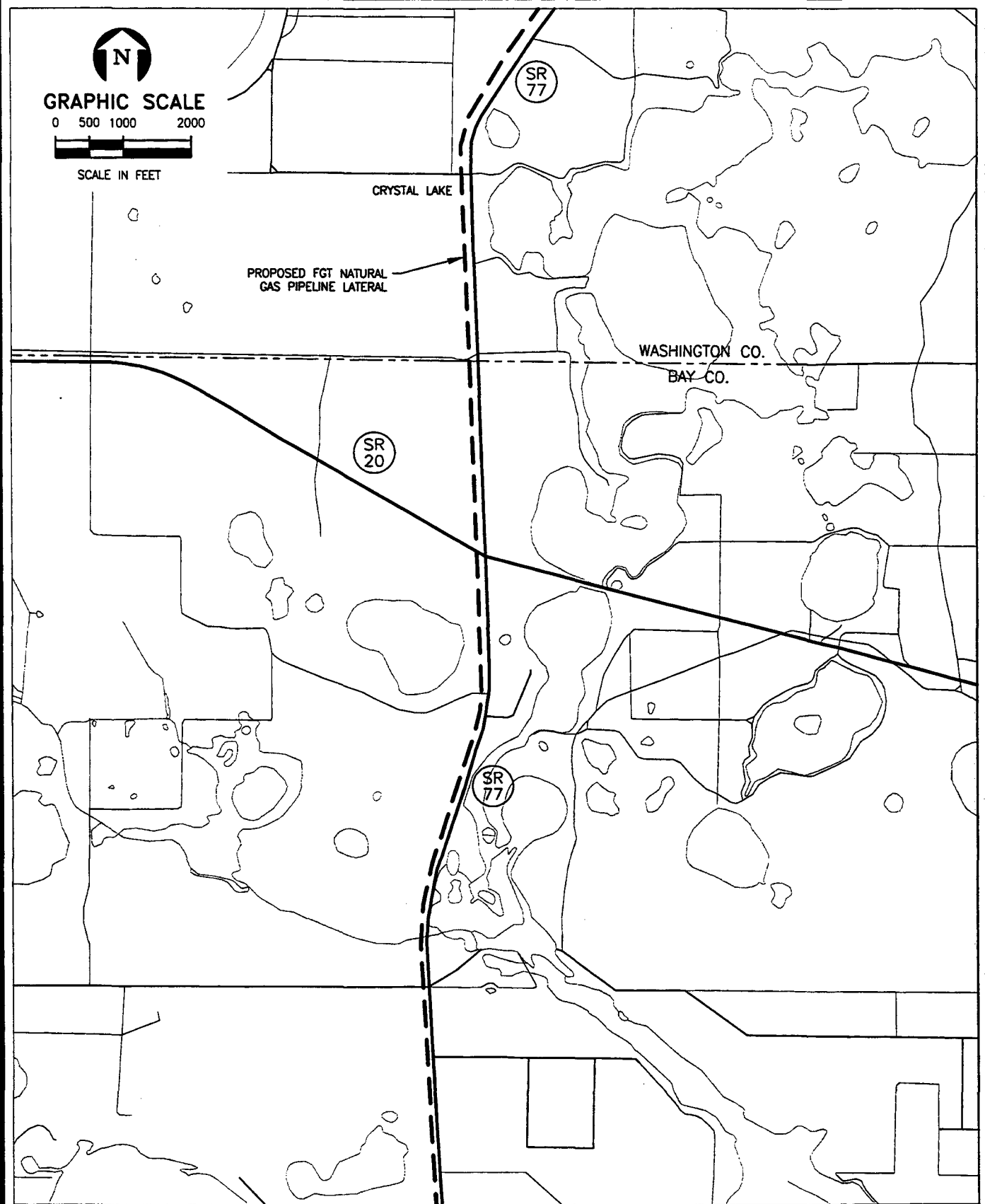


FIGURE 6.2.0-1. (PAGE 5 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

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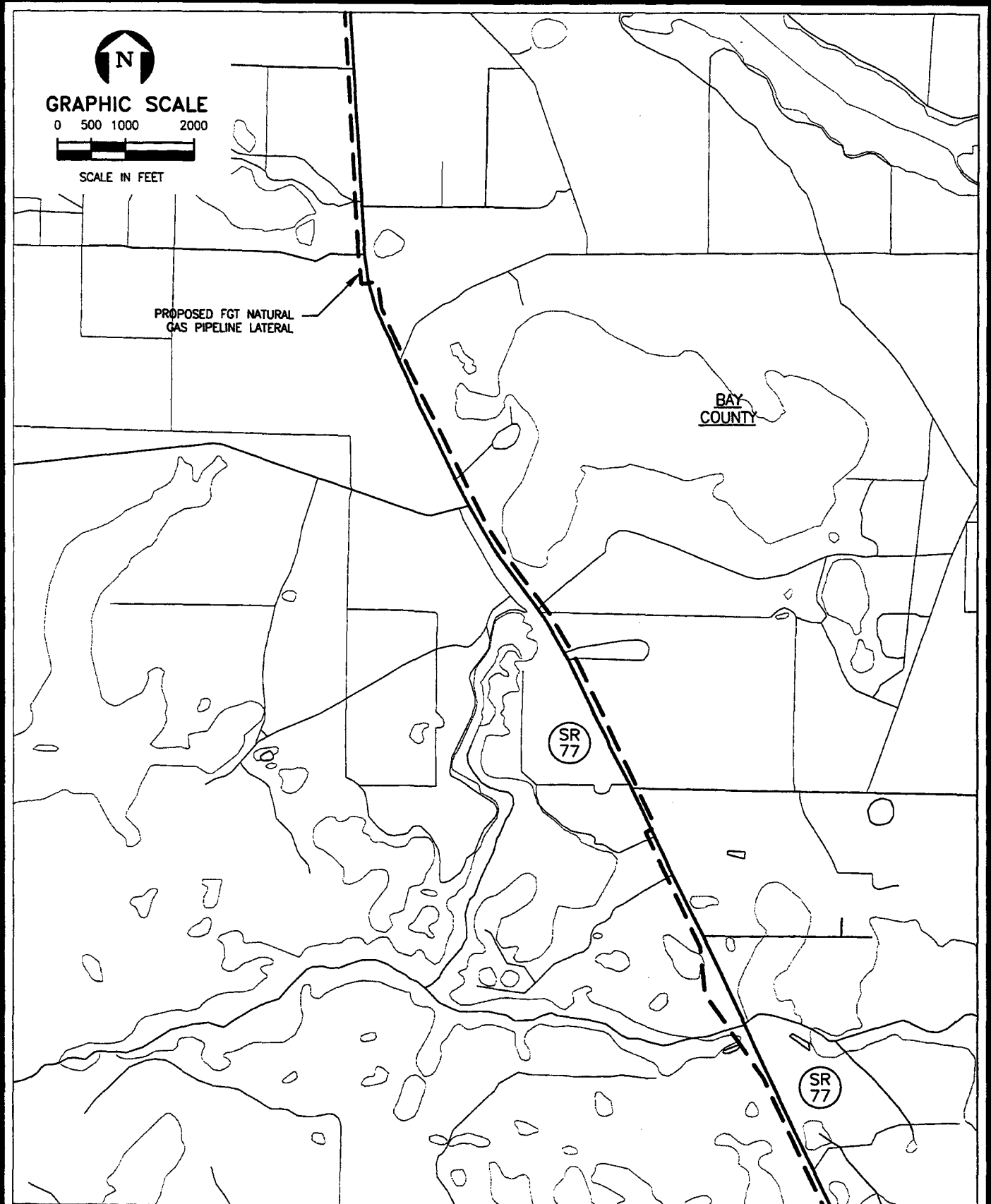


FIGURE 6.2.0-1. (PAGE 6 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodato, 1997; ECT, 1999.

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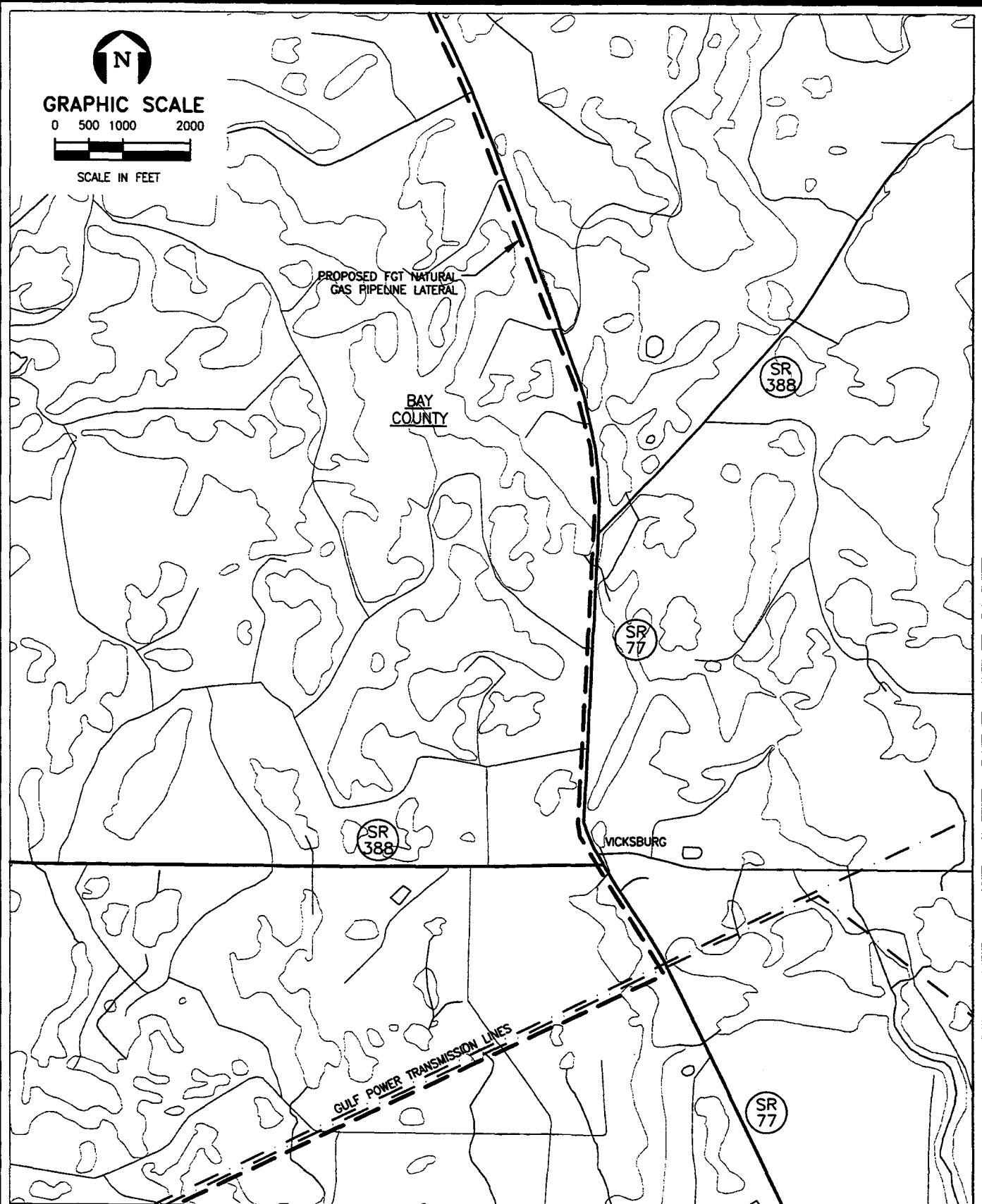


FIGURE 6.2.0-1. (PAGE 7 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodato, 1997; ECT, 1999.

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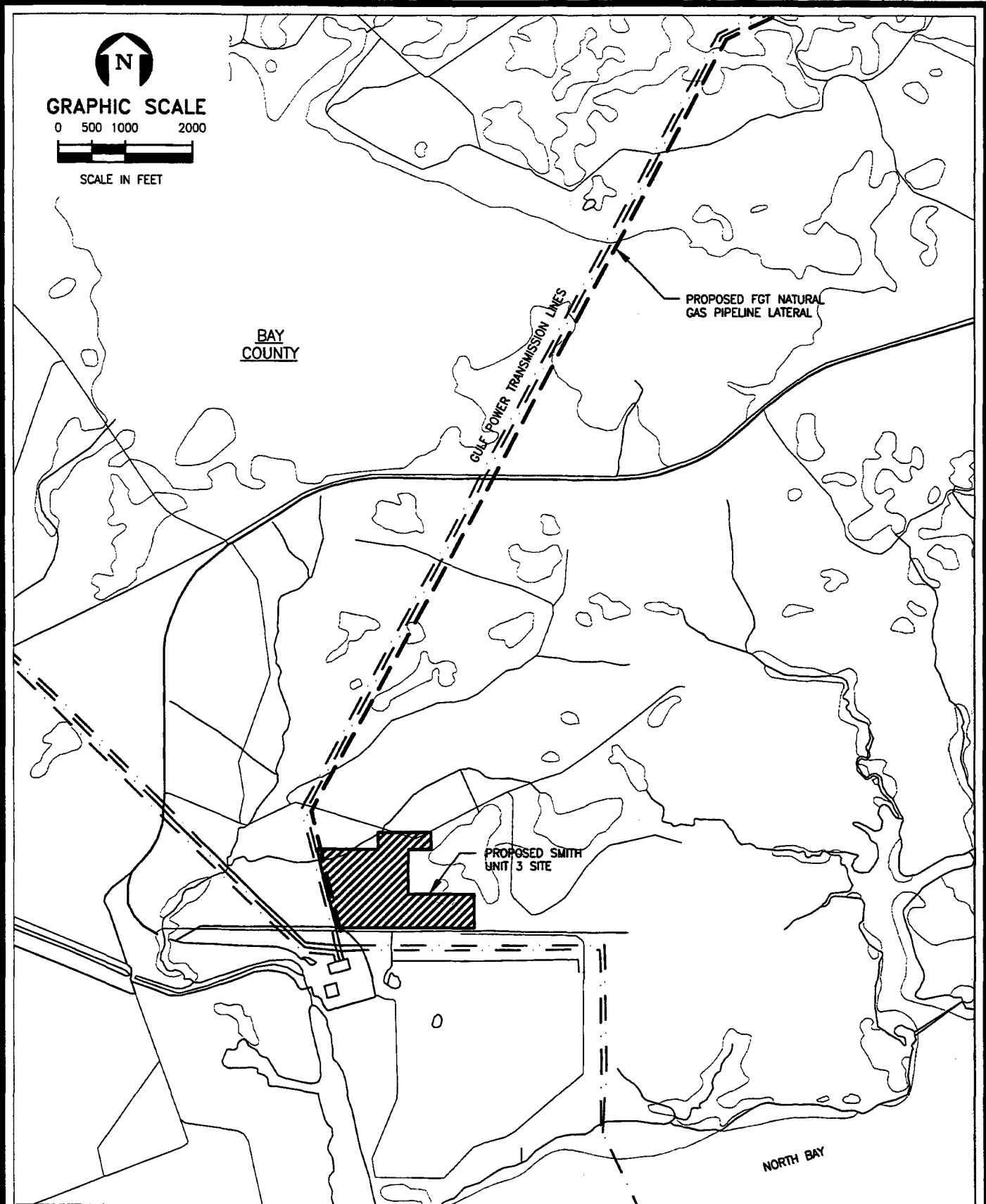


FIGURE 6.2.0-1. (PAGE 8 OF 8)
PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodato, 1997; ECT, 1999.

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Environmental Consulting & Technology, Inc.

Smith plant. The water balance diagrams (Figures 3.5.0-1 and 3.5.0-2) show schematically the various interconnections required.

No new corridors for any other linear facilities are proposed. No land use or environmental impacts for construction of these pipes are anticipated.

7.0 ECONOMIC AND SOCIAL EFFECTS OF PLANT CONSTRUCTION AND OPERATION

Construction and operation of the Smith Unit 3 Project will result in largely beneficial economic and social effects. This chapter describes the socioeconomic benefits and costs of this Project.

7.1 SOCIOECONOMIC BENEFITS

The primary benefit to the region as a result of the construction of Smith Unit 3 will be the provision of a new, clean, and reliable energy source provided to the public. As described in Chapter 1.0 of this document, Smith Unit 3 will meet the need for new electrical generation resources and meet generating reserve margin requirements. The Project will provide benefits to Bay County, nearby municipalities, and the State of Florida in terms of employment, revenues, and such sustainable practices as reuse of the existing intake waters for plant operation.

7.1.1 TAX REVENUES

The construction and operation of the Smith Unit 3 will create both direct and indirect tax benefits. Construction costs are currently estimated at \$63 million. Construction of the Project will generate significant revenues through sales tax assessments on goods purchased directly for the plant or indirectly from purchase of goods and services by workers/employees currently estimated at \$6 to \$8 million. Based on current federal multipliers (U.S. Department of Commerce, 1999) specific to Bay County, the impact of construction on industrial output is estimated to be over \$113.5 million.

7.1.2 CONSTRUCTION EMPLOYMENT

Additional construction employment, even though short term, will be a positive socioeconomic benefit to the region. As previously discussed in Section 4.6, construction employment will average 180 workers for the 21-month construction period. A peak of 325 workers will be needed for approximately 6 months.

Construction payroll and indirect costs will total approximately \$23.7 million. Approximately 75 percent of the workforce will consist of daily commuters and the remaining 25 percent will be weekly commuters. It can be anticipated that a majority of the construction wages will be generated for County residents. Another economic benefit from construction will be the use of local subcontractors and vendors to provide labor and goods. Although included in the construction workforce estimates, use of these local subcontractors and vendors will contribute to the local economy. Examples include local contractors who will be awarded the site work valued at \$1.5—\$2 million. Clean fill for the site will be purchased at nearby Bay County borrow pits and is estimated to cost up to \$1.6 million. Other local contractors expected to be used will include surveyors, concrete and soils testing companies, and suppliers of goods and services currently used at the Lansing Smith plant. Locally purchased materials will include:

- Concrete.
- Lumber.
- Welding supplies.
- Small bore piping/valves.
- Conduits/cables.
- Miscellaneous building supplies.

7.1.3 OPERATION EMPLOYMENT

The Smith Unit 3 will employ approximately 29 full-time employees. It is estimated that all employees will be hired locally. All employees will most likely reside in unincorporated Bay County or nearby municipalities. Annual operations labor payroll will total over \$1.5 million. Since it is presumed that the operations workforce will reside locally, they will pay taxes and purchase housing and other goods and services locally, providing further positive benefits to the local economy. Using federal multipliers (U.S. Department of Commerce, 1999) the indirect increase to household earnings in the community, region, and state will be over \$1.8 million. Additionally, Gulf expects approximately \$1.8 million per year to be contracted locally for maintenance services/equipment.

7.2 SOCIOECONOMIC COSTS

7.2.1 TEMPORARY EXTERNAL COSTS

The temporary external costs associated with this Project deal primarily with short-term traffic impacts due to construction. This may result in increased wear on existing roadways and cause minor traffic congestion along SR 77 during morning or evening hours when workers are arriving or departing. Temporary traffic impacts will be closely monitored, and flagmen will be employed to enhance traffic flow should conditions warrant.

Residential areas are expected to experience no impacts from this Project due to distance from the site and adequacy of existing forested vegetation to screen plant facilities. Most onsite activities will not be visible to residents in the area.

7.2.2 LONG-TERM EXTERNAL COSTS

The operational impacts resulting from Smith Unit 3 are expected to be minimal and localized. The following summarizes some of these minor potential impacts.

7.2.2.1 Aesthetics

The Project location is not near any recreational areas, parks, or scenic viewsheds. Although the plant's tallest structures (exhaust stacks) will be approximately 121 ft tall, the lack of these scenic resources and the low population density of the area will minimize aesthetic impacts. Motorists driving SR 77 will see the plant's tallest structures but the view will be short term and not incongruous with the adjacent existing Smith Units 1 and 2 facilities. Therefore, impacts to aesthetic quality of the vicinity are negligible.

7.2.2.2 Public Services/Facilities

Operation of the proposed power plant will not negatively affect essential services or facilities. While it will rely on local police and fire protection, the plant site will be equipped with its own fire protection systems, and the site will be secured with controlled, fenced access and security guards.

The number of employees working at the plant during operation is expected to be 29. This low number of employees will not materially affect provision of services, schools,

or degrade roadways. Local medical facilities are sufficient to handle staff medical emergencies.

7.2.2.3 Land Use

The conversion of the land use of the site from an Agriculture to an Industrial designation in order to accommodate the development of Smith Unit 3, is consistent with the assumptions and expectations for additional industrial lands as discussed in the Future Land Use Element of the adopted Bay County Comprehensive Plan. Future industrial acreage requirements were based on the assumptions that firms seeking industrially designated land will be distributed within the county in much the same pattern as has existed in the past, and that space requirements for industrial firms will not significantly change. Smith Unit 3 is an approximately 50-acre expansion to the existing adjacent approximately 600-acre Lansing Smith Plant.

Development of Smith Unit 3 will remove approximately 50 acres from the county's inventory of land used for silvicultural activities. According to the Future Land Use Element, the total existing silvicultural acreage in 1990 was 259,426, and no additional acreage was indicated as being needed in 1995 or 2000. The Future Land Use Element identified 813 acres designated as industrial use in 1990 with a need for 195 additional acres in 1995 and 242 additional acres between 1995 and 2000. The development of Smith Unit 3 will provide approximately 11.4 percent of the additional industrial acreage projected to be needed by 2000.

No residents will be displaced or caused an economic loss as a result of this facility being constructed. The site will not displace any scenic, recreational, or unique lands.

REFERENCES

U.S. Department of Commerce. 1999. RIMS II Multipliers for Bay County, FL. Economics and Statistics Administration, Washington, DC.

8.0 SITE AND DESIGN ALTERNATIVES

This chapter is provided to highlight the efforts of Gulf Power to minimize or mitigate the environmental impacts due to construction or operation of the Smith Unit 3 Project. Site selection and conceptual design were dictated, in large part, by the environmental suitability of various options. Some of these alternatives are discussed in the following sections.

8.1 ALTERNATIVE SITES

As part of its self-build option, Gulf evaluated four options:

- Participation in MPCo's Daniel CC Project.
- Construction of CTGs at Smith Plant.
- Construction of a CC unit at Smith Plant.
- Participation in a cogeneration project in the Pensacola area.

The evaluation process, which began in the fall of 1997, was completed in April 1998. In the final analysis, the evaluation considered options that were comparable in size to a 2-on-1, F-Class CC technology (~500 MW), and included all incremental costs associated with the installation of each alternative.

The process of selecting a site for the new generation was driven by two factors: (1) the need to be in Panama City and surrounding areas, and (2) the objective of locating close to existing power plant-related infrastructure. The results of the evaluation showed that the Smith CC unit, with the construction of a new gas pipeline, was the lowest cost alternative. Although energy savings was a major factor in the evaluation process, the primary factor that eliminated many of the options was the cost and potential environmental impacts of the transmission improvements required to support new generation at any location outside of the Panama City area. Regarding existing infrastructure, the most logical site in the Panama City area was Gulf Power's existing Lansing Smith Electric Generating Facility. This site required almost no additional transmission line work, additional surface water withdrawals, or wastewater provisions. Additionally, the site is well buffered from other land uses, residences, and area developments.

Gulf owns 600+ acres surrounding the site for Lansing Smith Units 1 and 2. The current location for the Smith Unit 3 Project represents the best available location on the property for a number of environmental and engineering reasons.

From an engineering/environmental perspective, the current location best utilizes existing infrastructure at the Smith Plant and thereby avoids additional environmental impacts.

This is manifested in the following ways:

- The chosen site is sufficiently close to the existing discharge canal which will serve as the cooling water makeup and discharge source for Unit 3. A new intake and discharge pipe will connect the canal to Unit 3 by traversing already developed power plant property. No new cooling water intake canal or discharge canal will be required, and no environmental impacts from the interconnection will occur. Any other location on the property would most likely require a longer connection to the discharge canal and would potentially impact additional natural vegetated communities and wetlands.
- The chosen site is immediately adjacent to an existing 230-kV transmission line which will allow interconnection to the existing electric grid. No new transmission corridors will be required which could impact wetlands or other natural vegetation communities.
- The chosen site is immediately adjacent to developed plant property where interconnections (potable water, sanitary, and other wastewater systems) will be made with the existing Smith Plant. No new corridors for any of these facilities will be required.
- The proposed FGT pipeline will be routed, in part, to the Unit 3 site via the existing electric transmission line corridor. Utilization of the existing transmission corridor to the Unit 3 property will minimize environmental/land use impacts associated with the proposed pipeline development.
- The proximity of the proposed site to the existing developed plant property also means that no new access roads will be required, which again minimizes potential wetland impacts.

- The proposed site is well buffered from potential future development around Gulf's property, especially to the east where residential development is proposed near Newman Bayou.

From a strictly environmental standpoint, the chosen site, compared to other locations on Gulf's property, represents a viable choice for the following reasons:

- Although the 600-acre Gulf property contains some areas with more upland habitats, the general site composition is a roughly 50-50 mix of wetlands/uplands. Placing the proposed site further from its designated location will trade off wetland impacts of the Unit 3 site with wetland impacts from the numerous additional linear facility interconnections to utilize another area of the site (discussed earlier).
- The location of Unit 3 adjacent to the Smith Plant means natural communities and wildlife habitats on Gulf's property will not be fragmented as they would if the Unit 3 site were removed from the developed area surrounding Smith Units 1 and 2.

A further alternatives analysis of the Smith site is described in the joint FDEP/USACE 404 dredge-and-fill application.

8.2 ALTERNATIVE TECHNOLOGIES AND DESIGNS

Alternative technologies and designs were considered by Gulf for the Smith Unit 3 Project for each of the following categories and are discussed in the following paragraphs.

- Alternative technologies/fuels.
- Air emission control system alternatives.
- Alternative cooling systems.
- Biological fouling control alternatives.
- Wastewater treatment/discharge alternatives.

8.2.1 ALTERNATIVE TECHNOLOGIES/FUELS

Preparation of the SES IRP requires the identification of a manageable number of generating unit alternatives to be evaluated in the generation mix analysis. For each candidate technology, inputs must be developed for the option's conceptual capital cost, design configuration, reliability data, and O&M costs. It is important to note that the information developed is not site-specific and is intended to be representative of average cost and performance data for a "generic" site.

Technology screening begins with a preliminary review of both mature and emerging technologies to identify those that are potentially suitable for installation on the SES during the planning horizon. Three technologies which had been evaluated in prior years were deleted from the list developed for the 1998 IRP. These were the intermediate load cycling coal fired, intermediate load compressed air energy storage (CAES), and peaking compressed air energy storage technologies. However, three new technologies were added, including inlet cooled combined cycle using advanced technology systems (ATS), air blown integrated gasification combined cycle (IGCC), and the topping pressurized circulating fluidized bed (PCFB). The following technologies were included for consideration in the screening process:

1. Base load pulverized coal.
2. Base load IGCC.
3. Base load PCFB.
4. Base load CC "F"-technology.
5. Base load CC "G"-technology.
6. Intermediate load low heat rate "G"-type CT.
7. Peaking CTG (3- and 6-unit sites).
8. Pumped storage hydro (PSH).
9. Inlet cooled CC with ATS technology.

In addition to a general plant description and major performance assumptions, the following information was developed for each technology under consideration:

- Heat rate and output.
- Capital cost.

- Fixed and variable O&M cost.
- Capital expenditures for maintenance.
- Emissions estimates.
- Plant life.
- Maintenance time.
- Equivalent forced outage rate (EFOR).
- Performance degradation.
- Project schedule.
- Cash flow table.

Certain information regarding Project schedule, performance degradation, emissions, EFOR and cash flow was not available for all of the technologies.

There are four categories of cost estimates. These include very conceptual, conceptual, budgetary and definitive. Below is a definition of each cost category:

Very Conceptual—The cost is as conceptual as the technology. As these technologies are developed, the costs will become more refined.

Conceptual—The technology is being developed. However, the first units have not been produced. Estimates are supplied by researchers, vendors, and governmental agencies. As these technologies are developed, the costs will become more refined.

Budgetary—This is a mature technology. There are actual costs of existing plants. The vendors offer market driven pricing and/or Southern Company Services has developed cost models.

Definitive—None of the cost information used in the technology screening process is definitive. Definitive estimates are within 5 percent of the final cost and are based on specific site and owner requirements. Definitive estimates are based on definitive scopes.

The cost models developed for mature technologies in prior years are reviewed for consistency and updated with information from ongoing projects. All cost projection dollars are based on values as of January 1, 1998. An escalation factor of 2 percent was applied for inflation on all technologies, except that the base load pulverized coal was not escalated and IGCC was escalated at 1 percent. The CC and simple cycle cost models were carefully reviewed and updated given the probability that these technologies would be chosen for near term capacity additions. Revised budgetary estimates were obtained from the vendors, and the lowest cost was incorporated in the cost model. The contingency was held to 2.5 percent for major equipment and 10 percent for the balance of plant to reflect the actual confidence in the estimate. In case of coal technologies, contingency was held to 5 percent for major equipment and 10 percent for the balance of plant.

All cost models were separated into Engineering, Procurement and Construction (EPC), site related, and owner's costs. EPC cost is equivalent in scope to what a turnkey contractor would quote for the Project. EPC cost includes the design engineering, procurement of materials and equipment, and the contractor's scope. Site cost includes land, site preparation, water treatment system, switchyard and site related engineering. Owner's cost includes Project and construction management, startup, and overheads.

Project schedules were developed for the new additions. Schedules for the remaining technologies were reviewed, but were not changed from the prior year. It should be noted that actual Project schedules would vary based on the unique requirements of the Project. Construction spending curves were expressed in percentages instead of dollar amounts to allow the flexibility to use either the EPC cost or total plant cost. Non-recoverable turbine degradation in output and heat rate was included for each technology in the technology documentation.

The nine listed technologies were reviewed and screened for reasonableness to select the final candidate technologies to be included in the generation mix process. Some technologies are eliminated when they are evaluated on an economic bus-bar analysis. The bus-bar evaluation estimates the relative cost per kilowatt-hour for the various alternatives at varying capacity factors. After this screening was completed, the following three

technologies were retained as candidates for the generation mix analysis: (1) nominal 670-MW pulverized coal unit, (2) nominal 500 MW F-class CC unit, and (3) simple cycle combustion turbine unit.

Although these technologies are used as generic unit addition candidates for the resources planning process, it is left up to the individual operating companies of the SES to ultimately determine what capacity resource to install. The process used by Gulf to ultimately select its resource addition resulted in selection of the CC technology using natural gas.

8.2.2 AIR EMISSIONS CONTROL SYSTEM ALTERNATIVES

The PSD air permitting regulations require detailed consideration of alternative means of emission control on a pollutant-by-pollutant basis. The purpose of this control technology review process, described in more detail in the PSD application (Appendix 10.2.7), is to determine the best means of control that is reasonably justifiable, or BACT. Please refer to the PSD application for a detailed discussion of the air emission control system alternatives that were considered. In summary, the use of advanced technology and clean fuel will result in very low air emissions.

8.2.3 ALTERNATIVE COOLING SYSTEMS

A power plant cooling or heat rejection system involves the transfer and/or rejection of waste heat from the condensation of the steam turbine exhaust. Optimization of the heat rejection system will minimize plant capital and operation costs, as well as potential environmental impacts of the operations. In general, five alternative plant cooling systems are available for power plant facilities involving steam turbine generating technology:

- Once-through cooling
- Cooling reservoir
- Wet cooling tower
- Dilution
- Air-cooled condenser

Once-through cooling requires the availability of large quantities of water compared to the other cooling systems because the cooling water is only used once and then discharged back into the environment, along with the waste heat it has picked up from the

condensation process. The discharge of this heat back into the initial body of water can have adverse environmental impacts due to the raising of the overall water temperature. Due to the large amount of cooling water required and the potentially adverse environmental impacts, a once-through cooling system alone was not considered to be a reasonable alternative.

A similar system to once-through cooling is a dilution system. In this system, significant amounts of cold inlet water are added downstream of the condenser to cool the hot condenser discharge before it is discharged back into the environment. This lessens the environmental impact by lowering the overall temperature of the water being discharged, but does not totally alleviate higher temperature water being discharged back into the marine environment and the adverse environmental impacts that could result from this. Additionally, this system requires a larger capital cost than a once-through system due to the additional pumps and piping required for the dilution water and requires larger initial withdrawals from the source body of water. Therefore, this system is not considered a reasonable alternative for this Project.

Cooling reservoirs require large areas of suitable land. Given the large number of acres that would be needed and the extensive earthwork that would be needed to create the reservoir, this alternative was determined to be infeasible.

An air-cooled condenser was also determined to be an unacceptable alternative. An air-cooled condenser, which uses air as the coolant instead of water, requires larger amounts of space than a cooling tower, is significantly more expensive to construct, requires a substantial amount of energy to operate, and generates a significant amount of noise when operated. This alternative was, therefore, not evaluated further.

The use of a mechanical draft wet cooling tower system utilizing the existing Smith facility once-through cooling system is the clear choice for the Smith Unit 3 Project. Cooling towers conserve precious water supplies by recycling and recirculating the water within the system (versus the much larger quantities of water needed in a once-through system). They also require modest space (versus the large acreage required for an air-

cooled condenser or a reservoir). Cooling towers generate only moderate noise (versus the elevated noise levels generated by an air-cooled condenser). Finally, by transferring the waste heat to the atmosphere instead of leaving it in the cooling water (as a once-through or dilution system), cooling towers avoid potential adverse impact on the marine environment. Utilizing the "hot" side discharge water of the existing Smith once-through cooling system, the cooling tower will not be using any additional surface water resources. The cooling tower will serve to cool this water below the existing discharge water to yield a small, positive effect on the marine environment. Therefore, for this Project the selected cooling tower system represents both a cost-effective and environmentally favorable alternative.

8.2.4 BIOLOGICAL FOULING CONTROL ALTERNATIVES

Biocide treatment of the circulating water is necessary to control biological fouling of the condenser, the associated piping, and cooling tower. Available biocides include chlorine gas, sodium hypochlorite, bromochlorination, chlorine dioxide, and ozone.

Treatment with sodium hypochlorite or hypobromite is the most widely used, accepted, and least expensive biocide treatment currently used in the power industry. Alternative biocides (e.g., chlorine gas, bromochlorination, chlorine dioxide, and ozone) involve safety issues and high operating costs and, therefore, have not gained wide acceptance for treatment of large volumes of recirculating cooling water. Sodium hypochlorite is the preferred biocide for biological fouling control in the recirculation cooling water system.

Sodium hypochlorite use will be minimized by practicing shock treatment, in which sodium hypochlorite is periodically fed to the circulating water. Through proper management of the biocide treatment program, total residual chlorine will not be discharged in the circulating water discharge (blowdown). In order to ensure this, the blowdown discharge valve will remain closed during treatment with the sodium hypochlorite. Alternative biocides are not expected to be used unless required for chlorine-resistant biofouling.

8.2.5 WASTEWATER TREATMENT/DISCHARGE ALTERNATIVES

The proposed Smith Unit 3 facility has been designed to minimize both water use and wastewater discharges. Gulf will utilize water treatment equipment specifically designed to minimize chemical usage and discharge to the environment. The service water system will be a closed loop system to again minimize water consumption. Cooling tower blowdown and small-volume process wastewater streams are the only discharge streams. Potential wastewater treatment discharge alternatives include:

- Deep well injection.
- Zero discharge

A discharge alternative to the proposed system would involve disposing of the cooling tower blowdown and other wastewaters in a deep injection well. This well would need to be of sufficient diameter and depth to reach strata that are capable of receiving the anticipated quantities of the discharge water. This potential discharge alternative would require extensive hydrogeologic studies even to demonstrate its engineering feasibility and would also be costly. Furthermore, with an injection well, there may be a permanent risk that the effluent would migrate upward or laterally and thus contaminate valuable ground water resources. Therefore, this potential alternative was not considered reasonable for further analysis.

Another alternative is to have zero discharge, although potential environmental concerns would not be eliminated. The implementation of this zero-discharge alternative would be technically feasible but extremely expensive and requires more land space (and potentially greater overall impact) than the current design. The system would involve additional equipment to concentrate the wastewater discharge to a brine, then to produce a solid material from the residual solids. The end result would be solid salts, which would require landfilling. This alternative would involve a substantial increase in both capital and operating cost. Due to the complexity, costs and transformation of liquid waste to solid waste, the zero discharge process was not considered.

9.0 COORDINATION

Various federal, state, regional, and local agencies were contacted by Gulf/Southern Company and its licensing team to provide inputs for the Smith Unit 3 Power Project. Through these contacts, Gulf obtained comments and inputs on the applicable regulatory requirements of the various agencies, and key issues to be addressed in the licensing program. These agency contacts occurred throughout the approximately 4-month period of the licensing efforts prior to submission of this SCA. Table 9.0.0-1 presents an overall listing of the agencies that were contacted regarding the Smith Unit 3 Power Project.

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts

Date	Agency	Person(s) Contacted	Type of Contact				Subject
			Meeting with	Telcon with	Letter to	Letter from	
01/08/99	FDEP (PPSA)	Hamilton S. Oven, Jr.	X				Strategy meeting
01/25/99	FDEP	Clair Fancy/Al Linero	X				Air permitting
02/17/99	NFWFMD	Larry Gordon/Alan Baker	X				Consumptive use permit
02/23/99	FDOT	Pam Day		X			Traffic counts
02/23/99	WFRPC	Lel Czeck		X			Strategic regional policy plan (SRPP)
02/25/99	WFRPC	Lel Czeck			X		Request copy of SRPP
03/02/99	FGFWFC	George Wallace		X			Listed species for the site
03/03/99	FGFWFC	George Wallace			X		Listed species for the site
03/03/99	USFWS	Gail Carmody			X		Listed species for the site
03/03/99	EPA	Greg Worley		X			Air permitting
03/04/99	Florida Division of Historic Resources	George Percy			X		Historic and archaeological resources
03/05/99	Bay County Planning Dept.	Kristen Anderson		X			Comprehensive plan status
03/09/99	Bay County Planning Dept.	Kristen Anderson	X				Socioeconomic data collection
03/10/99	WFRPC	Lel Czeck		X			North Florida hurricane study
03/10/99	FDEP	Cliff Street	X				Storm water
03/10/99	FDEP	Martin Gawronski	X				Dredge-and-fill

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts (Continued, Page 2 of 5)

Date	Agency	Person(s) Contacted	Type of Contact				Subject
			Meeting with	Telcon with	Letter to	Letter from	
03/11/99	FNAI	Jonathan Oetting				X	Listed species for the site
03/22/99	FDEP	Clair Fancy/Al Linero	X				Air permitting
03/22/99	NFWMD	Larry Gordon			X		Submitted pump test and slug test results
03/23/99	Bay County Planning Dept.	Kristen Anderson		X			Plan amendment
03/31/99	Bay County Planning Dept.	Kristen Anderson		X			Plan amendment
03/31/99	USFWS	Stan Simpkins		X			Ecological impacts of dredge/fill
04/03/99	Bay County Planning Dept.	Kristen Anderson			X		Plan amendment
04/05/99	USFWS	Gail Carmody				X	Listed species for the site
04/06/99	EPA	Greg Worley			X		Air permitting
04/07/99	Florida Division of Historic Resources	George Percy				X	Historic and archaeological resources
04/09/99	Bay County Planning Dept.	Kristen Anderson		X			Plan amendment
04/14/99	Panama City Police Dept.	Officer Mason		X			Police response
04/14/99	Bay County Sheriff's Office	Receptionist		X			Police response
04/14/99	Lynn Haven Police and Fire	Cindy		X			Police and fire response
04/14/99	Bay County Fire Department	Receptionist		X			Fire response

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts (Continued, Page 3 of 5)

Date	Agency	Person(s) Contacted	Type of Contact				Subject
			Meeting with	Telcon with	Letter to	Letter from	
04/14/99	Bay County Solid Waste Division	Receptionist		X			Steelfield Landfill
04/15/99	Bay County Planning Commission	Commission members	X				Plan amendment
04/21/99	USACE	Don Hambrick/Doug Gilmore			X		Request for wetlands jurisdiction
04/21/99	FDEP	Jason Steele/Bob Taylor			X		Request for wetlands jurisdiction
04/21/99	Bay County Chamber of Commerce	Carmel Goren		X			Bay County economic multipliers
04/22/99	USACE	Don Hambrick	X				Site visit—wetlands delineation
		Doug Gilmore	X				
04/22/99	FDEP	Jason Steele	X				Site visit—wetlands delineation
04/22/99	FGFWFC	Barbara Cerauskis				X	Listed species for the site
04/26/99	NFWFMD	Larry Gordon/Alan Baker	X				Consumptive use permit
04/27/99	USACE	Doug Gilmore		X			Wetlands permitting
04/28/99	FDEP	Richard Cantrell			X		Petition package for formal wetland jurisdictional determination
04/29/99	FDOT	Marvin Stuckey, Virgie Bowen, Jerry Campbell	X				Construction traffic

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts (Continued, Page 4 of 5)

Date	Agency	Person(s) Contacted	Type of Contact				Subject
			Meeting with	Telcon with	Letter to	Letter from	
04/30/99	FDEP	Tom Lubysinski	X				Ash reutilization
05/04/99	Bay County County Commission	County commission members	X				Plan amendment
05/05/99	US Dept. of Commerce	Paul Szczesnick			X		Bay County economic multipliers
05/11/99	FDEP	Bill Hinkley, Richard Tedder, Tom Lubysinski, Mike Kennedy, Jack McNulty	X				Ash reutilization as fill at combined cycle site
05/13/99	NMFC	Mark Thompson		X			Wetland mitigation projects
05/17/99	USFWS	Mike Brim		X			Wetland mitigation projects
05/18/99	FDEP	Ashley O'Neil, Jim Cooper, John Toby	X				Wetlands jurisdiction
05/18/99	USACE	Doug Gilmore	X				Wetlands jurisdiction
05/19/99	FDOT	Virgie Bowen, Jerry Campbell, Charles Odom	X				Construction traffic
05/19/99	NFWFMD	Alan Baker			X		Water quality data for onsite wells
05/21/99	FDEP	Bill Hinkley		X	X		Ash reutilization
05/21/99	FDEP	Mike Kennedy	X	X	X		Ash reutilization
05/23/99	FDEP	Bill Hinkley			X		Ash reutilization

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts (Continued, Page 5 of 5)

Date	Agency	Person(s) Contacted	Type of Contact				Subject
			Meeting with	Telcon with	Letter to	Letter from	
05/23/99	FDEP	Mike Kennedy	X	X	X		Ash reutilization
05/24/99	FDOT	Jerry Campbell				X	Traffic levels on SR 77
05/25/99	FDEP	Cliff Street	X				Storm water
05/26/99	USFWS	Mike Brim		X			Wetland mitigation projects
05/27/99	NWFWMD	Lawrence Gordon			X		Water use permit modification

Source: ECT, 1999.

10.0 APPENDICES

10.1 NEED PETITION

10.2 PERMIT APPLICATIONS/APPROVALS

10.2.1 LAND USE PLAN AMENDMENT

10.2.2 STORM WATER MANAGEMENT PLAN

10.2.3 BEST MANAGEMENT PRACTICES

10.2.4 USACE 404/FDEP WETLANDS PERMIT APPLICATION

10.2.5 NPDES PERMIT MODIFICATION APPLICATION

10.2.6 WATER USE PERMIT MODIFICATION APPLICATION

10.2.7 PREVENTION OF SIGNIFICANT DETERIORATION
APPLICATION

10.2.8 FEDERAL AVIATION ADMINISTRATION APPLICATION

10.3 EXISTING ZONING/LAND USE REGULATIONS

10.4 EXISTING PERMITS RELATIVE TO SMITH UNIT 3

10.4-A EXISTING INDUSTRIAL WASTEWATER PERMIT

10.4-B EXISTING WATER USE PERMIT

10.4-C NO_x COMPLIANCE PLAN

10.5 MONITORING PROGRAMS

10.5-A FDHR LETTER

10.5-B SURFACE WATER QUALITY ANALYSIS

10.5-C SOIL BORING LOGS

10.5-D WELL CONSTRUCTION LOGS

10.5-E SLUG TESTS

10.5-F SOILS ANALYSIS

10.5-G GROUND WATER MODELING REPORT

10.5-H FLY ASH TEST RESULTS

10.1 NEED PETITION

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company to
Determine Need for Proposed Electrical
Power Plant in Bay County, Florida

Docket No.: _____
Date Filed: March 15, 1999

**PETITION TO DETERMINE NEED
FOR ELECTRICAL POWER PLANT**

Gulf Power Company ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned attorneys, hereby petitions the Florida Public Service Commission ("Commission") pursuant to Section 403.519, Florida Statutes, and Rule 25-22.081, Florida Administrative Code, to determine the need for the proposed electrical power plant described herein, and to file its order making that determination with the Department of Environmental Protection ("DEP") pursuant to Section 403.507(2)(a)(2), F.S. In support thereof, Gulf states:

1. Gulf's full name and business address is:

Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780

2. The name and address of Gulf's representatives to receive communications regarding this docket are:

Jeffrey A. Stone
Russell A. Badders
Beggs & Lane
P. O. Box 12950
Pensacola, FL 32576-2950

Richard D. Melson
Hopping Green Sams & Smith, P.A.
P.O. Box 6526
Tallahassee, Florida 32314

with copies to:

Susan D. Ritenour
Assistant Secretary and Assistant Treasurer
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780

3. Gulf is a corporation with its headquarters located at 500 Bayfront Parkway, Pensacola, Florida 32501. The Company is an investor-owned utility operating under the jurisdiction of this Commission. Gulf serves approximately 350,000 customers in Northwest Florida.

4. Gulf meets its power supply needs through a combination of Gulf-owned generation, generation co-owned with sister companies, a contract for capacity with a co-generator and wholesale power purchases. As a member of the Southern electric system, Gulf can rely to some extent on system-wide reserves to meet its capacity needs. Gulf has a corresponding obligation, however, to maintain a reasonable share of those reserves.

5. By 2002, a number of factors combine to require Gulf to add generating resources to meet its customers' needs. The last 143 MW of Gulf's existing short-term firm power purchase arrangements expires at the end of 2001, leaving Gulf with a negative reserve margin on a Company-only basis. At the same time, system-wide reserve margins are declining, limiting Gulf's ability to rely on those reserves to offset its own reserve shortfall. Due to the decreasing availability and increasing cost of power purchase arrangements, Gulf cannot meet its 2002 need through additional short-term power purchases.

6. Gulf employed a competitive request for proposal ("RFP") process, in combination with an evaluation of Gulf-owned generation options, to choose the most cost-effective alternative to meet its need beginning in the year 2002. That process identified a 540 MW combined cycle generating facility, to be constructed at the existing Lansing Smith

generating plant site located in Bay County, Florida as the best alternative. The new unit, to be known as Smith Unit 3, consists of two "F" class combustion turbine/generators and two heat recovery steam generators that will power a single steam turbine/generator.

7. As indicated above, Smith Unit 3 will provide sufficient resources to enable Gulf to maintain an adequate reserve margin which, without additional new capacity, will decrease to a negative number in 2002. In addition, the construction and operation of Smith Unit 3 will replace power currently obtained through purchased power contracts totaling 143 MW which expire in 2001.

8. The Smith Unit 3 project is the most cost-effective option to meet the Gulf's generating needs. Compared to the lowest-cost alternative submitted to Gulf in response to its RFP, the Smith Unit 3 project saves approximately \$90 million (2002\$) in cumulative present worth of revenue requirements ("PWRR") over a 20-year period.

9. Pursuant to the Florida Electrical Power Plant Siting Act, Section 403.519, F.S., and Rules 25-22.080 to 25-22.081, F.A.C., the Commission has jurisdiction to determine the need for the proposed electrical power plant, applying the standards set forth in Section 403.519, F.S.

10. As authorized by Rule 25-22.080(1), F.A.C., Gulf has elected to commence this proceeding for a determination of need prior to the filing with DEP of a Site Certification Application (SCA) for the proposed electrical power plant.

11. The information supporting this petition is contained in Gulf's Need Determination Study (the "Need Study") which is attached as an exhibit to this petition and incorporated herein by reference. The Need Study contains Gulf's analysis of the need for the proposed electrical power plant and includes the information required by Rule 25-22.081, F.A.C.

12. The accompanying information demonstrates the need for the proposed electrical power plant in the proposed time frame as the most cost-effective alternative available, taking into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and other relevant matters.

(a) Smith Unit 3 will provide sufficient resources to enable Gulf to maintain an adequate reserve margin. By providing sufficient resources for Gulf to meet its reliability requirements upon termination of contract purchased power of 143 MW, the proposed plant will contribute to the reliability of the Gulf's system.

(b) The unit's location at the Smith Generating Plant also allows the unit to provide voltage support for the Eastern area of the Gulf's system at low cost, thereby contributing to the integrity of Gulf's electric system.

(c) The proposed unit will ensure that Gulf has an adequate supply of power to serve its customers' needs at a reasonable cost.

(d) The proposed unit is the most cost-effective alternative available for meeting Gulf's 2002 capacity need, saving approximately \$90 million PWRR (2002\$) over a 20-year period compared to the least cost alternative identified through the Gulf's competitive RFP process.

(e) Gulf has implemented cost-effective demand-side management programs which have resulted in significant demand and energy reductions, projected to reach 365 MW of summer peak demand reduction by 2002. Even with the demand and energy reductions from those programs, Smith Unit 3 is required to enable Gulf to reliably meet its customers' power supply needs.

13. As set forth in more detail in the Need Study, the Smith Unit 3 project has a number of advantageous features, including the following:

(a) The facility will be located at the existing Smith site which is presently connected to Gulf's load center by an existing 115 kV and 230 kV transmission system into which the new unit will connect through a 230 kV bus. No additional off-site transmission will be required to integrate the unit into the electric grid.

(b) The project will minimize environmental impacts by utilizing clean burning natural gas as the primary fuel, utilizing an air emission strategy resulting in a net reduction in NOx for the entire plant, and utilizing a closed-cycle cooling system with make-up water coming from the existing once-through cooling water discharge canal currently in use by the existing Smith Units 1 and 2.

14. Gulf has coordinated with the Commission staff to arrange a schedule which calls for the need determination hearing to commence on or about June 7, 1999.

WHEREFORE, Gulf respectfully requests that:

(1) pursuant to Rule 25-22.080(2), F.A.C., the Commission within seven days set a date no later than June 7, 1999 for commencement of a hearing on this petition;

(2) the Commission give notice of the commencement of the proceeding as required by Rule 25-22.080(3), F.A.C.; and

(3) the Commission determine that there is a need for the proposed electrical power plant described in this petition, and file its order making such determination with the DEP pursuant to Section 403.507(2)(a)2., F.S.

RESPECTFULLY SUBMITTED this 15th day of March, 1999.

By: 

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THE NEED STUDY

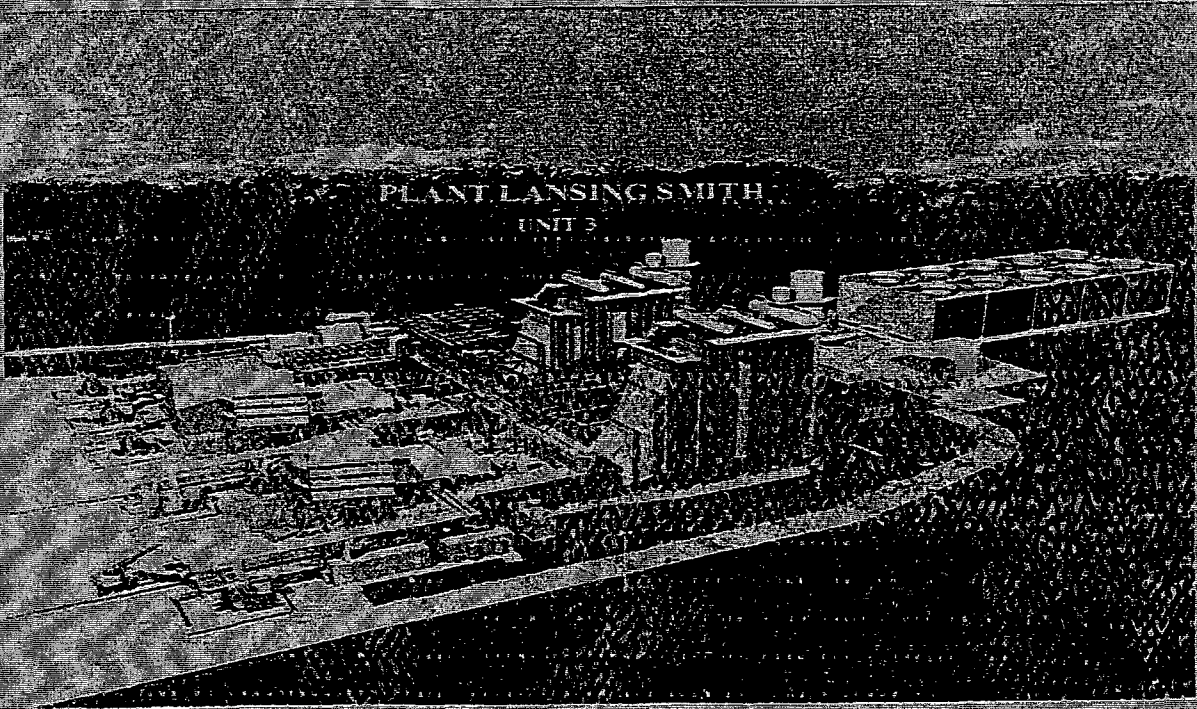
IN SUPPORT OF

GULF POWER COMPANY'S

PETITION FOR

DETERMINATION OF NEED

OF LANSING SMITH UNIT 3



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

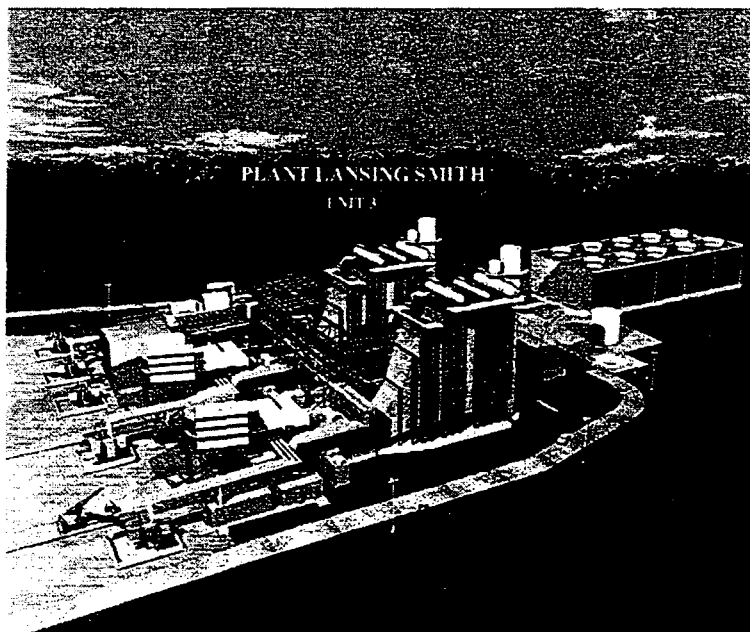
MARCH 15, 1999

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THE NEED STUDY

IN SUPPORT OF

GULF POWER COMPANY'S
PETITION FOR
DETERMINATION OF NEED
OF LANSING SMITH UNIT 3



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

MARCH 15, 1999

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1. EXECUTIVE SUMMARY

Gulf Power Company (Gulf) has determined that in order to provide reliable, cost-effective service to its customers, it must add at least 427 MW of generating resources to its system by the summer of 2002. The most cost-effective way for Gulf to meet this need is to construct a 540 MW natural gas-fired combined cycle unit at its existing Lansing Smith Electric Generating Plant. This unit will be designated as Smith Unit 3.

Smith Unit 3 is subject to the Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes. This Need Study document is being filed with the Florida Public Service Commission (FPSC) to support Gulf's petition to the FPSC for a determination of need for the project under Section 403.519, Florida Statutes.

This Need Study demonstrates that Gulf has a clear need for more capacity and that Smith Unit 3 is the most cost-effective alternative available, taking into consideration both other Gulf-constructed capacity options and options offered by third parties in response to Gulf's Request for Proposals (RFP) for power supply alternatives.

Gulf is a subsidiary of the Southern Company, which owns operating companies in Florida, Georgia, Alabama and Mississippi. As such, Gulf's planning process is part of the overall Integrated Resource Planning (IRP) process conducted for the Southern electric system (SES). As a

member of Southern, Gulf can rely to some extent on system-wide reserves to meet its capacity needs. Gulf has a corresponding obligation, however, to maintain a reasonable share of those reserves.

This Need Study is an outgrowth and continuation of Southern's annual IRP process and of Company-specific studies supporting Gulf's Revised 1998 Ten-Year Site Plan (1998 TYSP) filed with the FPSC in June, 1998. This TYSP contained detailed documentation of Gulf's existing resources, planning processes, load and fuel forecasts, other planning assumptions, and its future capacity needs.

The 1998 TYSP showed that Gulf is relying on firm purchased power contracts totaling 143 MW, along with the Company's reliance on Southern capacity resources, to meet its capacity needs through the year 2001. Due to the decreasing availability of firm power purchases, it is not feasible to replace the purchased power contracts when they expire in 2001. As shown in the 1998 TYSP, Gulf would require an additional 352 MW of capacity in 2002 in order to provide its share of Southern's 13.5% minimum reserve margin target. Subsequent updates to Gulf's planning studies show that the summer 2002 capacity shortfall has increased to 427 MW without the addition of new capacity resources. In fact, if no additional capacity is added by 2002, Gulf will have a negative reserve margin on an individual company basis.

The load forecast on which this 427 MW need is based included substantial demand reductions resulting from Gulf's

DSM programs and other conservation initiatives. These measures reduced Gulf's summer peak demand by 255 MW in 1998 and will reduce it by a total of 365 MW by the end of 2002. Due to the size of Gulf's need in 2002, Smith Unit 3 cannot be avoided or delayed further by additional DSM programs.

Gulf's planning process showed that a 500 MW class combined cycle generating unit located near Panama City (the self-build option) was the most cost-effective way of meeting this need with Gulf-constructed resources. On August 21, 1998, Gulf issued a capacity RFP to approximately 100 potential respondents to seek alternatives to the Gulf-constructed combined cycle unit. Gulf initially received four offers from three separate entities in response to this solicitation. The offers included purchases of varying terms and MW size from proposed combined cycle units, combustion turbine units, and a cogeneration facility.

After evaluating the proposals received in response to the RFP, Gulf determined that the self-build option represented by Smith Unit 3 is the most cost-effective alternative. It has a 20-year net present value (NPV) of costs (2002\$) of \$279/KW, compared to \$496/KW for the next best alternative identified through the RFP process. This amounts to a savings for Gulf's customers of at least \$90 million over those 20 years. The location of the proposed unit in the Panama City area eliminates the need for additional transmission to integrate the unit into the Northwest Florida electric grid, and the unit will provide

needed voltage support in the eastern portion of Gulf's service territory. Gulf is in the final stages of negotiating a firm natural gas supply for the unit.

Any delay in the licensing of Smith Unit 3 could adversely impact the summer 2002 in-service date. Due to Gulf's deteriorating reserve margin situation, this would leave Gulf short of needed resources during the 2002 peak summer season.

The balance of this document contains a detailed discussion of Gulf's need for capacity and the factors that led to Gulf's conclusion that Smith Unit 3 is the most cost-effective alternative available for meeting that need.

2. INTRODUCTION

2.1 DESCRIPTION OF GULF POWER COMPANY

Gulf Power Company ("Gulf" or the "Company") is a wholly-owned subsidiary of the Southern Company. Gulf serves approximately 350,000 customers in Northwest Florida. Gulf's service area is bounded by the Apalachicola River on the east and the Florida/Alabama state line on the west. Gulf's service area is shown on the system map contained in Appendix A of this Need Study.

2.2 DESCRIPTION OF EXISTING FACILITIES

2.2.1 GENERATION RESOURCES

Gulf owns and operates eleven fossil steam units, one peaking combustion turbine, and one cogeneration facility in Northwest Florida. In addition, Gulf has a 50% ownership in two coal units at Mississippi Power Company's Plant Daniel, and has a 25% ownership in Georgia Power Company's Plant Scherer Unit #3. The following is a tabulation of Gulf's current generating facilities:

TABLE 2-1**EXISTING GENERATING FACILITIES**

<u>UNIT</u>	<u>LOCATION</u>	<u>TYPE</u>	<u>FUEL</u>	<u>COMM. SERVICE DATE</u>	<u>RET. DATE</u>	<u>SUMMER NET CAPACITY IN MW</u>
Crist 1	Escambia Co.	FS	Gas	1/45	12/11	24.0
Crist 2	Escambia Co.	FS	Gas	6/49	12/11	24.0
Crist 3	Escambia Co.	FS	Gas	2/52	12/11	35.0
Crist 4	Escambia Co.	FS	Coal	7/59	12/14	78.0
Crist 5	Escambia Co.	FS	Coal	6/61	12/16	80.0
Crist 6	Escambia Co.	FS	Coal	5/70	12/15	302.0
Crist 7	Escambia Co.	FS	Coal	8/73	12/18	<u>495.0</u>
CRIST TOTAL						1,038.0
Scholz 1	Jackson Co.	FS	Coal	3/53	12/11	46.0
Scholz 2	Jackson Co.	FS	Coal	10/53	12/11	<u>46.0</u>
SCHOLZ TOTAL						92.0
Smith 1	Bay Co.	FS	Coal	6/65	12/15	162.0
Smith 2	Bay Co.	FS	Coal	6/67	12/17	192.6
Smith A	Bay Co.	CT	Oil	5/71	12/06	<u>31.6</u>
SMITH TOTAL						386.2
Pea Ridge	Escambia Co.	Cogen	Gas	5/98	12/28	14.4
GULF TERRITORIAL UNIT TOTAL						<u>1,530.6</u>
Daniel 1	Mississippi	FS	Coal	9/77	12/27	265.0
Daniel 2	Mississippi	FS	Coal	6/81	12/31	<u>265.0</u>
DANIEL TOTAL						530.0
Scherer 3	Georgia	FS	Coal	1/87	12/42	223.3
GULF OFF-SYSTEM UNIT TOTAL						<u>753.3</u>
GULF OWNED GENERATION TOTAL						<u>2,283.9</u>

As shown in Table 2-1 above, the units owned and operated by the Company within its service area provide a net summer capability totaling 1,531 megawatts. Including Gulf's ownership interests of 753 MW in Daniel Units #1 and #2 and Scherer Unit #3, Gulf has a total net summer generating capability of 2,284 MW and a total net

winter generating capability of 2,292 MW as of June 1, 1999. In addition to the Company's installed generating resources, Gulf has a contract with Solutia Corporation for 19 MW of firm capacity that will be in effect until May 31, 2005.

2.2.2 TRANSMISSION FACILITIES

Gulf owns approximately 1,426 miles of 115 kV and 230 kV transmission line. Within this transmission system, the Company has 14 points of interconnection with Alabama Power Company, Georgia Power Company, Alabama Electric Cooperative, and Florida Power Corporation. There are no additional transmission improvements required to integrate Smith Unit 3 into the Northwest Florida grid. The existing Gulf system in Northwest Florida, including generating plants, substations, transmission lines and service area, is shown on the system map designated as Appendix A.

2.3 OVERVIEW OF THE PLANNING PROCESS

The planning process for Gulf is tightly coordinated with Southern's Integrated Resource Planning (IRP) process. The Company participates in that process along with the other Southern operating companies, Alabama Power, Georgia Power, Mississippi Power, and Savannah Electric and Power.

Gulf shares in the benefits gained from planning a large system such as Southern, without the costs of a large planning staff of its own.

The capacity resource needs of Gulf and the entire Southern electric system (SES) are driven by the summer peak demand forecast and by the Southern reliability criterion of a 13.5% reserve margin target. The demand forecast used for capacity planning is a net number, which already reflects the impact of demand-side measures (DSM). Given the demand forecast and the target reserve margin, the planning process uses a computer simulation model called PROVIEW[®] to produce a listing of preferred capacity resource plans which provide sufficient capacity to reliably meet the system's needs. The best, most cost-effective plan for the entire Southern system is identified by considering the cost of the various plans on a present worth of revenue requirements (PWRR)¹ basis. The resulting system resource needs are allocated among the operating companies based on reserve requirements. Each company then performs the company-specific studies needed to choose the best way to meet its own capacity and reliability needs.

¹ Throughout this document, the analyses are conducted on a Present Worth of Revenue Requirement basis, even though the results may appear as Net Present Value (NPV).

2.4 CAPACITY ADDITIONS

Gulf's need for additional supply-side resources through 2001 will come from the reliance upon Southern system generation resources as well as purchased power. However, such purchases are only available on a short-term basis. When these arrangements expire at the end of 2001, Gulf must replace them with additional generating capacity to meet its share of system reserve margin requirements.

Beginning in 1997, Gulf performed a number of economic evaluations of potential supply options to determine the Company's most cost-effective means of meeting its 2002 capacity needs. Based on those evaluations, Gulf determined in early April, 1998, that a 500 MW class combined cycle unit at its Lansing Smith Generating Plant (Smith Unit 3) was its best internal choice for meeting the 2002 needs. This option saved over \$40 million NPV (1998 \$s) compared to the next best self-build alternative. In order to determine if other more cost-effective alternatives were available, and to comply with the Florida Public Service Commission's (FPSC) rules, Gulf issued a Request for Proposals (RFP) in August, 1998 to solicit alternatives to Gulf's construction of this combined cycle unit. After evaluating the proposals, Gulf determined that

the self-build option represented by Smith Unit 3 was the most cost-effective alternative available, providing 20-year savings of over \$90 million NPV (2002 \$s) compared to the best option resulting from the RFP process.

3. THE INTEGRATED RESOURCE PLANNING PROCESS

3.1 OVERVIEW

Gulf Power Company's resource planning process begins as a part of the Southern electric system (SES) Integrated Resource Planning (IRP) process. The Company is one of the five operating companies of the Southern Company. Together the five operating companies -- Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power -- comprise a centrally dispatched resource pool. As such, the companies coordinate resource planning for the entire system. Individually, each company provides input regarding its customers' load and energy needs in the future. These forecasts are used as input into the generation planning process to formulate overall capacity resource needs for the SES.

The SES integrated resource planning process involves a significant amount of manpower and computer resources in order to produce a least-cost, integrated demand-side and supply-side resource plan. The process examines a broad range of alternatives in order to meet the system's projected summer peak demand and energy requirements. The result of the Southern integrated resource planning process is an integrated plan that meets the needs of the system's customers in a cost-effective and reliable manner.

Gulf receives many benefits from being a part of a large system planning process. The Company comprises only

about 6.5% of the total Southern summer peak demand. Since Gulf's needs are relatively small compared to the whole system, many times the Company can meet its demand and reserve requirements by relying on temporary surpluses of capacity which are available on the Southern system. This ability to rely on the large system reserves allows Gulf to defer capacity additions until the timing is right to add a cost-effective block of capacity for Gulf's specific customer needs, as opposed to having to add smaller, more costly amounts of capacity. Another important benefit to Gulf is that it does not have to employ an entire planning staff, but can share in the utilization of the staff at Southern Company Services which performs Southern's IRP function.

3.2 INPUTS AND ASSUMPTIONS

The IRP process uses many inputs and assumptions that are ultimately fed into the analysis to develop the SES's most cost-effective capacity resource plan. These inputs and assumptions result from a number of activities that are conducted in parallel with one another in the IRP process. These activities include energy and demand forecasting, fuel price forecasting, technology screening analysis and evaluation, and the development of miscellaneous assumptions. Gulf's load forecast is discussed in Section 4 and Appendix B. The fuel price forecast used in the most recent IRP studies is discussed in Section 5. Financial

assumptions are detailed in Section 6. The following subsections discuss the Southern reserve margin criterion and the technology screening process used to identify candidate generating units.

3.2.1 RESERVE MARGIN CRITERION

One of the major assumptions in the IRP process is the Southern summer peak reserve margin target. The reserve margin target is the optimum economic point at which the system can reasonably meet its summer peak energy and demand requirements taking into account load forecast error, abnormal weather conditions, and unit-forced outage conditions. This reserve margin target is developed by comparing (1) the Customer's perceived costs of experiencing outages due to generation and (2) the costs of additional resources to eliminate those outages. Essentially this involves assessing the costs of expected unserved energy (EUE) at various reserve levels along with the costs to install generation to meet that reserve level. The optimum level of reserves is where these two parameters, combined, reach the minimum cost point. Of course, the optimum level of reserves is primarily driven by the customer's perceived cost of outages, EUE, and the cost of adding reliability through generation equipment installations.

The Southern system has, for many years, analyzed the factors that determine target reserve margin. Until 1999, the target reserve margin for the system was set at 15% on

an entire Southern basis. It is important to note that due to summer peak demand diversity among the companies of the SES, each individual operating company would be expected to maintain a 14.1% reserve margin as its share of this 15% Southern reserve margin. As a result of a 1996 re-evaluation of the customers' perceived cost of various levels of unavailable power and other factors, it was determined that the optimal target reserve margin for the SES was 13.5% beginning in 1999. This 13.5% Southern reserve margin translates into a 12.6% individual utility share. However, because of capacity supply adequacy issues that affected many utilities during the summer of 1998, and potential changes in that value customers place on not experiencing an outage, Southern is re-evaluating its target reserve margin criterion to account for this new information. After that analysis is completed later this year, there may be an adjustment to the Southern target reserve margin.

3.2.2 TECHNOLOGY ALTERNATIVES

The reasonably acceptable technology alternatives are also analyzed and screened to determine the best options to be included as candidates in the mix analysis. An overview of the SES technology screening process is contained in Appendix C. Once the technologies have been screened to identify those that will be candidates in the mix, the fixed costs of each option are scaled to a common 300 MW block

size in order to simplify modeling and put the candidates on a level playing field. This allows the mix program to select a number of technology combinations over the planning horizon without placing undue bias on any particular technology because of its size or other factors.

3.3 GENERATION MIX ANALYSIS

Once the necessary assumptions are determined the technologies are screened to the suitable candidates, and the necessary planning inputs are defined, then the generation mix analysis is initiated. The optimization tool used in the mix analysis is the PROVIEW[®] model. PROVIEW[®] uses a dynamic programming technique to develop the optimum resource mix using combinations of the generic supply-side options identified in the technology screening process. This technique allows PROVIEW[®] to evaluate, for every year, all the combinations of generation additions that satisfy the reserve margin constraint.

In performing its optimization, PROVIEW[®] calculates a net present value (NPV) for each mix of generating alternatives. This NPV includes the capital costs of the unit additions, together with the operating and maintenance costs for both the existing system and the unit additions. The program produces a report that ranks all of the different combinations by the total net present value (NPV) cost over the entire planning horizon. The leading

combinations from the program are then evaluated for reasonableness and validity. It is important to note that supply option additions produced by the PROVIEW[®] model at this stage of the analysis are for the entire Southern electric system and are reflective of the various technology candidates selected. This process produces the lowest cost resource plan for the entire SES. The additions included in that plan are then allocated, according to reserve needs, to the individual operating companies.

The Integrated Resource Planning process is a very manpower-intensive activity. In the mid-1990s, the Southern electric system decided that it would only perform a "full-blown" IRP every third year, with "updates" for the interim years. Both the full IRP process and the interim updates involve development of fuel forecasts and load and energy forecasts, since these forecasts are required for a number of business purposes in addition to resource planning. The technology assessment, however, needs to be updated only as changing conditions dictate, and typically undergoes a complete review only in connection with the full IRP process.

From a quantitative standpoint, the updates take the changes in the demand and energy forecast and perform a manual remix to assure the companies that their resource requirements are still valid, or to make the necessary resource changes. From a qualitative standpoint, changes in

the fuel forecasts and technology improvements are reviewed, and if a major change has occurred in these factors, its effect will be analyzed along with the updated mix.

3.4 RESULTS OF RECENT IRP PROCESSES

Since the decision was made to limit full IRP processes to a three-year cycle, these "full" IRP's were performed in 1995 and 1998, with updated manual mixes in the interim years.

3.4.1 1995 FULL IRP

The Southern IRP for 1995 showed the need for a mixture of combined cycle units and combustion turbines for the entire system with the first need in the year 1999.

The load forecast for Gulf in the 1995 IRP is shown in the table below. The technology screening performed for the 1995 IRP identified (1) Conventional Pulverized, Base-Load Coal, (2) Advanced E-Class Intermediate Combined Cycle, and (3) Standard and Advanced E-Class Peaking Combustion Turbines as the candidate units for all years of the mix analysis. In addition, F-Class Combustion Turbines and F-Class Combined Cycle units which provide a cost and efficiency benefit over the E-Class technology were considered to be suitable for the year 2000 and beyond.

TABLE 3-1

**GULF'S FORECASTED DEMAND
AS OF THE 1995 IRP**

<u>YEAR</u>	<u>GULF LOAD (MW)</u>
1995	1,944
1996	1,969
1997	1,985
1998	2,013
1999	2,042
2000	2,067
2001	2,093
2002	2,119
2003	2,148
2004	2,178

For Gulf, the 1995 resource plan, as described in its 1995 Ten-Year Site Plan (TYSP), indicated that the Company should construct 200 MW of combustion turbine (CT) capacity to meet its needs beginning in 1999, with an additional 100 MW of CT capacity in 2002. This plan also showed Gulf adding a 48 MW share of a system combined cycle (CC) unit in the year 2004. In total, this 1995 plan indicated that Gulf needed 300 MW of CT capacity by 2002 and an additional 48 MW of combined cycle in 2004. This is much like the mixture of CT's and CC's that formed the entire Southern IRP in 1995.

3.4.2 1996 IRP UPDATE

The 1996 IRP update, which formed the basis of Gulf's 1996 TYSP, showed an increased megawatt demand need for Gulf and a change in the preferred resource plan to meet these needs. The 1996 TYSP indicated that Gulf would purchase 180 MW of capacity beginning in 1999 and replace 80 MW of this

purchase with the installation of 200 MW of combustion turbine capacity in 2002. Once again, the Company showed a need for 300 MW of capacity by the year 2002; however, this update indicated that Gulf's intention was to meet its near term need through purchased power.

As a part of the individual utility resource requirement decision process, in 1996, Mississippi Power Company (MPCo) decided to meet its short-term needs by means of capacity purchases through the year 2000, allowing MPCo to procure smaller amounts of power until it was the optimum time to construct a cost-effective generating unit. MPCo's purchased power solicitation in 1996 resulted in a fairly large number of cost-effective offers, as well as a large amount of megawatts offered. Gulf was still a year away from needing to seek short-term power purchases to meet its 1999 needs, but viewed the results of MPCo's solicitation as very promising when considering its future prospects.

Since the 1996 IRP indicated that Southern did not have any need for units to be constructed until after the year 2001, the F-Class technology became the new assumption for combined cycle and combustion turbine unit additions. This change in technology assumption was not significant enough to warrant a new mix analysis.

3.4.3 1997 IRP UPDATE

The 1997 IRP update that formed the basis for Gulf's 1997 TYSP showed that the Company's demand had increased and

SOUTHERN reserves were lower, increasing Gulf's allocated responsibility. As a result, the Company's need for purchased power was advanced from 1999 to 1998 and increased from 180 MW to 235 MW. The Gulf demand forecast for the 1997 IRP is shown in the table below.

TABLE 3-2

GULF'S DEMAND FORECAST
AS OF THE 1997 IRP UPDATE

<u>YEAR</u>	<u>GULF DEMAND (MW)</u>
1997	2,031
1998	2,067
1999	2,102
2000	2,122
2001	2,137
2002	2,154
2003	2,175
2004	2,193

The 1997 TYSP showed the Company purchasing 235 MW beginning in 1998, growing to 335 MW in the year 2002. This plan also indicated that Gulf would install 200 MW of combustion turbine capacity to replace all but 150 MW of this capacity by summer 2003.

The following table provides a comparison of the annual incremental differences for the 1995 - 1997 resource plans for Gulf Power Company. Each of these plans was based on an allocation to Gulf of an appropriate share of the system-wide capacity need resulting from the IRP process.

TABLE 3-3

COMPARISON OF CAPACITY NEEDS
BETWEEN THE 1995, 1996, & 1997
RESOURCES PLANS

	<u>1995 PLAN (MW)</u>			<u>1996 PLAN (MW)</u>			<u>1997 PLAN (MW)</u>		
<u>YEAR</u>	CT	CC	PURCH	CT	CC	PURCH	CT	CC	PURCH
1998	0	0	0	0	0	0	0	0	235
1999	200	0	0	0	0	180	0	0	0
2000	0	0	0	0	0	0	0	0	50
2001	0	0	0	0	0	0	0	0	0
2002	100	0	0	0	0	0	0	0	50
2003	0	0	0	200	0	-80	200	0	-185
2004	0	48	0	0	0	0	0	0	0

The update performed for the 1997 IRP did reveal some changes with regard to technologies and the timing of Gulf's need based on the revised load and energy forecast. On the technology radar screen was the announcement of the design and promotion of the G-Class CT technology. The Southern technology group considered the viability of this new class of CT and determined that it was not mature enough to be considered in the 1997 update cycle. The group decided to continue to monitor its development for possible inclusion in the 1998 IRP.

3.4.4 1997 CAPACITY SOLICITATION

Based on the need shown by the 1997 IRP Update, Southern Company Services issued a solicitation for short-term purchased power on behalf of Gulf Power Company (Gulf), Alabama Power Company (APCo), and Savannah Electric and Power (SEPCo) for up to five years beginning summer of 1998.

The results of this solicitation were quite different from the 1996 MPCo solicitation in that there were far fewer cost-effective offers and a much smaller number of total megawatts offered. This was a fairly strong signal that not only were short-term purchased power offers becoming scarce, but what was available was becoming high-priced and was not cost-effective. As a result of this solicitation, SCS secured 350MW for 1998, 300MW for 1999, and 200MW for the years 2000 and 2001, with the remaining need to come from spot market firm energy and capacity purchases in the future. Gulf's share of these purchases is 178 MW in 1999 and 143 MW for 2000 and 2001.

The revelation that short-term purchased power was becoming scarce led MPCo and APCo to begin evaluating their options for capacity additions beginning in 2001. These site-specific evaluations determined that the most cost-effective capacity additions were a combined cycle plant at MPCo's existing Daniel plant near Pascagoula and a combined cycle plant at APCo's existing Barry plant near Mobile. The certification for these additions began in August of 1997.

3.4.5 1998 FULL IRP

The 1998 IRP process began in the fall of 1997 and included MPCo's and APCo's plans for constructing combined cycle units at Plants Daniel and Barry.

This study indicated that Gulf Power Company would need 120 MW of combustion turbines (CT) and 240 MW of combined

cycle (CC) capacity for the year 2002, when the Company will no longer have any purchased power agreements on which to rely. This advancement and shift in type and timing of Gulf's need was driven by a change in the system summer peak demand requirements and changes in the relative economics of combined cycle technology. The following table shows the results of the 1998 IRP for Gulf:

TABLE 3-4

**GULF'S RESOURCE NEEDS AS OUTLINED
IN THE 1998 IRP**

<u>YEAR</u>	<u>COMB. TURB.</u>	<u>COMB. CYCLE</u>	<u>PURCHASES</u>
1998	0	0	240
1999	0	0	2
2000	0	0	-15
2001	0	0	-15
2002	240	120	-178
2003	0	30	0
2004	0	30	0
2005	0	60	0
2006	60	0	0

3.5 GULF POWER COMPANY'S SPECIFIC CAPACITY NEEDS

During the latter part of 1997, it was clear that Gulf would need to add significant capacity resources by 2002. As mentioned before, the purchased power on which Gulf is currently relying for part of its resource needs will no longer be available beginning in 2002. Even with this

purchased power, Gulf's individual reserves get extremely low by 2001.

As mentioned in Section 3.4.5 above, the 1998 IRP showed Gulf's resource needs to be 120 MW of CT's and 240 MW of CC in the year 2002, which would cover Gulf's 352 MW share of the Southern reserve margin target. This amount of capacity is in the range that can be added to a system of Gulf's size in a cost-effective manner due to technology economies of scale. As a result, it became clear to Gulf that generating capacity additions would need to be explored.

The 1999 IRP Update, whose preliminary results were being distributed in late fall of 1998, indicated that because of some existing generator unit deratings and summer demand increases, Gulf had a larger capacity resource need than indicated in the 1998 IRP. Based on the 1999 Load and Energy Forecast, the new capacity need for the Company to meet its share of the Southern reserve margin target in 2002 is 427 MW. This megawatt need for Gulf further underscores that not only is a large amount of resource capacity needed, but the size of Smith Unit 3 is an appropriate and cost-effective alternative means to meet this need.

After the purchased power contracts expire, Gulf's reserve margin, using the 1999 Load and Energy Forecast, would go negative in 2002 without the addition of capacity resources. The following table shows the reserve situation

that evolves through the year 2002, absent any capacity additions:

TABLE 3-5

GULF'S RESERVES WITHOUT THE
ADDITION OF CAPACITY RESOURCES

<u>YEAR</u>	<u>PEAK DEMAND (MW)</u>	<u>STARTING CAPACITY (MW)</u>	<u>PURCH. POWER (MW)</u>	<u>ENDING CAPACITY (MW)</u>	<u>PERCENT RESERVES</u>
1999	2,175	2,123	198	2,321	6.7%
2000	2,207	2,321	-55	2,266	2.7%
2001	2,234	2,266	0	2,266	1.4%
2002	2,265	2,266	-143	2,123	-6.3%

Although Gulf is able to call on total SES reserves to reliably serve its customers through 2001, this table shows that Gulf has an obligation to add capacity in 2002 in order to avoid undue dependence on those reserves.

In order to determine the best way to meet its needs for 2002 and beyond, Gulf began site-specific analyses in late 1997. Unlike the earlier system-wide IRP studies, which had considered generic unit additions, Gulf's analysis took into account site-specific factors such as transmission system impacts, construction requirements, and the availability and cost of fuel transportation.

As discussed in Section 7, by April, 1998, Gulf's site-specific studies indicated that Smith Unit 3 was the most cost-effective self-build alternative.

This unit will be a 540 MW combined cycle unit made up of 2 - F Class combustion turbines and 1 - steam turbine of

approximately 170 MW, commonly referred to as a 2-on-1 CC unit. Because of its size and configuration, this unit is more cost-effective than a smaller combined cycle unit, that is commonly referred to as a 1-on-1 CC unit. Smith Unit 3 is also of the size that fits Gulf's needs in the 2002 through 2007 time frame without creating excessive amounts of reserves. Based on a 2002 in-service date, the reserves after the addition of Smith Unit 3 would be as shown in the following table:

TABLE 3-6

GULF'S FUTURE RESERVES BEGINNING
IN 2002 WITH THE ADDITION OF SMITH UNIT 3

<u>YEAR</u>	<u>PEAK DEMAND (MW)</u>	<u>STARTING CAPACITY (MW)</u>	<u>CAPACITY ADDITION (MW)</u>	<u>ENDING CAPACITY (MW)</u>	<u>PERCENT RESERVES</u>
2002	2,265	2,123	540	2,655	17.6%
2003	2,280	2,655	0	2,655	16.8%
2004	2,309	2,655	0	2,655	15.4%
2005	2,347	2,655	-19	2,636	12.7%
2006	2,383	2,636	0	2,636	11.0%
2007	2,425	2,636	148	2,784	15.0%
2008	2,466	2,784	0	2,784	12.9%

Table 3-6, above, demonstrates that Smith Unit 3 puts Gulf in the position of having an appropriate level of generating capacity to meet its customers' needs and maintain a suitable level of reserves for reliability purposes. As shown in Section 7, it also is a very cost-effective means of meeting these needs when compared to the other self-build options evaluated.

4. LOAD FORECAST AND DSM PROCESS

4.1 OVERVIEW

The following is a summary of Gulf Power Company's 1999 Load and Energy forecast of customers, energy sales and peak demands. The forecast horizon spans the ten-year period from 1998 through the year 2008. This is the latest in a series of annual forecasts prepared by the Marketing Services section of Gulf's Marketing and Load Management Department.

The forecast includes the estimated impact of conservation programs currently approved by the Florida Public Service Commission, as well as other conservation initiatives designed to influence patterns of demand in a manner that is mutually beneficial to both Gulf and its customers, such as Gulf's GoodCents Home program.

Gulf's annual load forecast is aggregated with those of the other Southern electric system operating companies for use in the Southern IRP process.

4.2 ASSUMPTIONS

Gulf's projections reflect the current economic outlook for its service area as provided by Regional Financial Associates (RFA), a renowned economic service provider. Gulf's forecast assumes that service area population growth will remain near that of the nation. Additionally, the projections incorporate Gulf's most recent electric price

assumptions. Natural gas prices are derived from the 1998 Southern Company Services (SCS) Fuel Panel, as described in Section 5. The following tables provide a summary of the assumptions associated with Gulf's forecast:

TABLE 4-1

**ECONOMIC SUMMARY
(1998-2008)**

GDP Growth	2.9 - 2.3%
Real Interest Rate	5.4 - 3.7%
Inflation	1.7 - 3.1%

TABLE 4-2

**AREA DEMOGRAPHIC SUMMARY
(1998-2008)**

Population Gain	161,491
Net Migration	115,420
Average Annual Population Growth	1.7%
Average Annual Labor Force Growth	1.5%
Share of Population Served	96.3%

4.3 METHODOLOGY

Gulf's total forecast employs a number of different techniques and methodologies, each applied to the task for which it is best suited. Many of the techniques take advantage of the extensive data made available through the Company's marketing efforts. These efforts are predicated

on the philosophy of knowing and understanding the needs, perceptions and motivations of Gulf's customers and actively promoting wise and efficient uses of energy which satisfy customer needs. The following provides a brief description of Gulf's forecasting methodology. A more detailed description is provided in Appendix B.

4.3.1 CUSTOMER FORECAST

4.3.1.1 RESIDENTIAL CUSTOMER FORECAST

The immediate short-term forecast (0-2 years) of customers is based primarily on projections prepared by Gulf's district personnel based upon recent historical trends in customer gains and their knowledge of locally planned construction projects from which they are able to estimate the near-term anticipated customer gains.

For the remaining forecast horizon, the Gulf Economic Model, an econometric model developed by RFA, is used in the development of residential customer projections. Projections of births, deaths, household size, and population by age groups are determined by past and projected trends. Migration is determined by economic growth relative to surrounding areas.

The forecast of residential customers is an outcome of the final section of the migration/demographic element of the model.

4.3.1.2 COMMERCIAL CUSTOMER FORECAST

As in the residential sector, the immediate short-term forecast (0-2 years) of commercial customers is prepared by Gulf's district personnel utilizing recent historical customer gains information and their knowledge of the local area economies and upcoming construction projects.

Beyond the immediate short-term period, commercial customers are forecast as a function of residential customers and total real disposable income, reflecting the growth of commercial services to meet the needs of new and existing residents.

4.3.2 ENERGY SALES FORECAST

4.3.2.1 RESIDENTIAL SALES FORECAST

The short-term (0-2 years) residential energy sales forecast is developed utilizing multiple regression analyses.

The long-term residential energy sales forecast is prepared using the Residential End-Use Energy Planning System (REEPS), a model developed for the Electric Power Research Institute (EPRI) by Cambridge Systematics, Incorporated, under Project RP1211-2. REEPS produces forecasts of appliance installations, operating efficiencies, and utilization patterns for space heating, water heating, air conditioning and cooking, as well as other major end-uses for a large number of different population segments. These segments represent households

with different demographic and dwelling characteristics. Together, the population segments reflect the full distribution of characteristics in the customer population.

The energy forecast output from REEPS reflects the continued impacts of Gulf Power's GoodCents Home program and efficiency improvements undertaken by customers as a result of Residential Energy audits, as well as conversions to higher efficiency outdoor lighting. This output is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the residential conservation programs and program features are provided in Section 4.3.4.

4.3.2.2 COMMERCIAL SALES FORECAST

The short-term (0-2 years) commercial energy sales forecast is also developed utilizing multiple regression analyses.

COMMEND, a commercial end-use model developed by the Georgia Institute of Technology through EPRI Project RP1216-06, serves as the basis for Gulf's long-term commercial energy sales forecast.

Annual building data from RFA and Gulf's most recent Commercial Market Survey provide much of the input data required for the COMMEND model. The model produces forecasts of energy use for the space heating, cooling and ventilation equipment and the lighting, water heating,

cooking, refrigeration, and other end-uses within each of 12 different business categories.

The energy forecast output from COMMEND reflects the continued impacts of Gulf Power's Commercial GoodCents building program and efficiency improvements undertaken by customers as a result of Commercial Energy Audits and Technical Assistance Audits, as well as conversions to higher efficiency outdoor lighting. The output from COMMEND is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the Commercial Conservation programs and program features are provided in Section 4.3.4.

4.3.2.3 INDUSTRIAL SALES FORECAST

The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major industrial customers, trending techniques, and multiple regression analysis. Forty-four of Gulf's largest industrial customers are interviewed to identify load changes due to equipment additions, replacements or changes in operating characteristics.

The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using multiple regression analysis.

The long-term forecast of industrial energy sales is based on econometric models of the chemical, pulp and paper, other manufacturing, and non-manufacturing sectors. The industrial forecast is further refined by accounting for expected self-generation installations. The industrial sales forecast is also adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the conservation programs and program features are provided in Section 4.3.4.

4.3.2.4 STREET LIGHTING SALES FORECAST

The forecast of monthly energy sales to street lighting customers is based on projections of the number of fixtures in service by fixture type.

The projected numbers of fixtures by fixture type are developed from analyses of recent historical fixture data to discern the patterns of fixture additions and deletions. The estimated monthly kilowatt-hour consumption for each fixture type is multiplied by the projected number of fixtures in service to produce total monthly sales for a given type of fixture. This methodology allows Gulf to explicitly evaluate the impacts of lighting programs, such as mercury vapor to high pressure sodium conversions.

4.3.2.5 WHOLESALE ENERGY FORECAST

The short-term forecast of energy sales to wholesale customers is based on interviews with these customers, as

well as recent historical data. A forecast of total monthly energy requirements at each wholesale delivery point is produced utilizing multiple regression analyses.

The long-term forecast is based on estimates of annual growth rates for each delivery point, according to future growth potential.

4.3.2.6 COMPANY USE ENERGY FORECAST

The annual forecast for Company energy usage is based on recent historical values, with appropriate adjustments to reflect short-term increases in energy requirements for anticipated new Company facilities. The monthly spreads are derived using historical relationships between monthly and annual energy usage.

4.3.3 PEAK DEMAND FORECAST

The peak demand forecast is prepared using the Hourly Electric Load Model (HELM), developed by ICF, Incorporated, for EPRI under Project RP1955-1. The model forecasts hourly electrical loads over the long-term.

HELM represents an approach designed to better capture changes in the underlying structure of electricity consumption. HELM has been designed to forecast electric utility load shapes and to analyze the impacts of factors such as alternative weather conditions, customer mix changes, fuel share changes, and demand-side programs. The HELM model provides forecasts of hourly class and system

load curves by weighting and aggregating load shapes for individual end-use components.

Model inputs include energy forecasts and load shape data for user-specified end-uses. Model outputs include hourly system and class load curves, load duration curves, monthly system and class peaks, load factors and energy requirements by season and rating period.

4.3.4 CONSERVATION PROGRAMS

Gulf has been a pacesetter in the energy efficiency market since the development and implementation of the GoodCents Home program in the mid-70's. This program brought customer awareness, understanding and expectations regarding energy efficient construction standards in Northwest Florida to levels unmatched elsewhere. Since that time, the GoodCents Home program has seen many enhancements, and has been widely accepted not only by customers, but by builders, contractors, consumers, and other electric utilities throughout the nation, providing clear evidence that selling efficiency to customers can be done successfully.

Gulf's forecasts of energy sales and peak demand reflect the continued impacts of the Company's conservation programs. These forecasts also reflect the anticipated impacts of the new programs submitted in Gulf's Demand Side Management plan filed February 22, 1995 (Docket No. 941172-EI) as approved by the FPSC. The demand and energy

reductions associated with these new programs have been updated to reflect a revised implementation schedule for the Advanced Energy Management (AEM) program in the residential sector.

The following is a listing of Gulf's conservation programs:

Residential Programs:

1. GoodCents New Home
2. Heat Pump Upgrade
3. Resistance Heat to Heat Pump Upgrade
4. Air Conditioning Upgrade
5. Residential Energy Audit
6. Residential Mail-In Audit
7. *In Concert With The Environment®*
8. Geothermal Heat Pump
9. Advanced Energy Management
10. Outdoor Lighting Conversion

Commercial Programs:

1. Commercial GoodCents Bldg.
2. Commercial Energy Audit
3. Technical Assistance Audit
4. Commercial Mail-In Audit
5. Real Time Pricing Pilot
6. Outdoor Lighting Conversion

Street Lighting Conversion

Table 4-3, below, provides estimates of the total savings (reductions in peak demand and net energy for load) resulting from Gulf's conservation programs. These estimates include the impacts of Gulf's existing programs that have been in place for several years and the anticipated impacts of Gulf's newer programs, submitted in Gulf's Demand Side Management Plan filed in 1995. These reductions are verified through on-going monitoring of Gulf's major conservation programs and reflect estimates of conservation undertaken by customers as a result of Gulf's

involvement. Conservation which has taken place without Gulf's involvement has contributed to further unquantifiable reductions in demand and net energy for load. These unquantifiable additional reductions are captured in the time series regressions in the energy forecasts and in demand model projections. Additional detail on Gulf's conservation programs is provided in Appendix B.

TABLE 4-3

CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	Summer Peak (MW)			Winter Peak (MW)			Net Energy for Load (GWH)		
	Existing	New	Total	Existing	New	Total	Existing	New	Total
1997	214	30	244	263	6	269	514	9	523
2002	253	112	365	295	128	423	573	77	650
2008	290	199	489	334	256	590	625	145	770

As indicated in this table, in 1997, Gulf's DSM programs successfully reduced summer peak demand by 244 megawatts (MW), winter peak demand by 269 MW, and net energy for load by 523 million kilowatt-hours (KWH). By the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from

1997 through 2002. These reductions are expected to grow to a total savings of 489 MW of summer peak demand, 590 MW of winter peak demand and an annual energy savings of over 770 million KWH by the year 2008.

4.3.5 RENEWABLE ENERGY

Gulf has begun implementation of a "Green Pricing" pilot program, *Solar for Schools*, to obtain funding for the installation of solar technologies in participating school facilities combined with energy conservation education of students. Initial solicitation began in September, 1996 and has resulted in participation of over 333 customers contributing \$18,171 through December, 1998. A prototype installation at a local middle school has been completed and the experience gained at this site will be used to design future *Solar for Schools* installations.

4.4 FORECAST RESULTS

The following table summarizes the major forecast results. Detailed forecast results are provided in Appendix B.

Table 4-4

History and Forecast Summary							
	1989 history	1998 history	2003 forecast	2008 forecast	CAAG 1989-1998	CAAG 1998-2003	CAAG 1998-2008
Population	662,784	810,649	891,566	960,867	2.3%	1.9%	1.7%
Residential Customers	250,038	304,413	337,784	367,016	2.2%	2.1%	1.9%
Customer Gains					54,375	33,371	62,603
KWH / Customer	13,173	14,577	14,677	14,995	1.1%	0.1%	0.3%
Energy (GWH)	3,294	4,438	4,958	5,503	3.4%	2.2%	2.2%
Commercial Customers	33,500	45,510	51,208	55,836	3.5%	2.4%	2.1%
KWH / Customer	64,761	68,379	68,275	69,507	0.6%	0.0%	0.2%
Energy (GWH)	2,169	3,112	3,496	3,881	4.1%	2.4%	2.2%
Net Energy for Load (GWH)	8,378	10,402	11,658	12,661	2.4%	2.3%	2.0%
Summer Peak Demand	1,698	2,154	2,280	2,466	2.7%	1.1%	1.4%
Winter Peak Demand	1,554	1,692	2,139	2,258	0.9%	4.8%	2.9%
Load Factor (%)	56.3%	55.1%	58.4%	58.6%			

The growth rates associated with the 1999 peak demand forecast are slightly higher than the 1998 TYSP. The summer peak demand projections for the 1999 forecast are about 31 MW higher than the 1998 TYSP forecast by 2002, the proposed in-service date of Smith Unit 3. As described in Section 3, the 1998 TYSP forecast was used to establish the need for Smith Unit 3. The additional summer peak demand projected in the most recent forecast simply underscores the need for additional capacity in 2002.

4.5 DEMAND SIDE MANAGEMENT (DSM) PROGRAM RESULTS

As shown in Table 4-3 in Section 4.3.4, by the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it

would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from 1997 through 2002. The impacts of Gulf's conservation programs are shown in Figures 4-1 through 4-3.

It should be noted that Gulf's conservation goals are currently being reviewed and revised in a separate docket and the reductions achieved as a result of these revisions may vary slightly from those included in the 1999 Forecast. However, because of the factors driving the need for additional capacity in 2002, including the expiration of purchased power contracts and dwindling reserve margins, the need for Smith Unit 3 cannot be avoided or delayed any further by additional DSM.

Figure 4-1

Gulf Power Company

History and Forecast of Summer Peak Demand

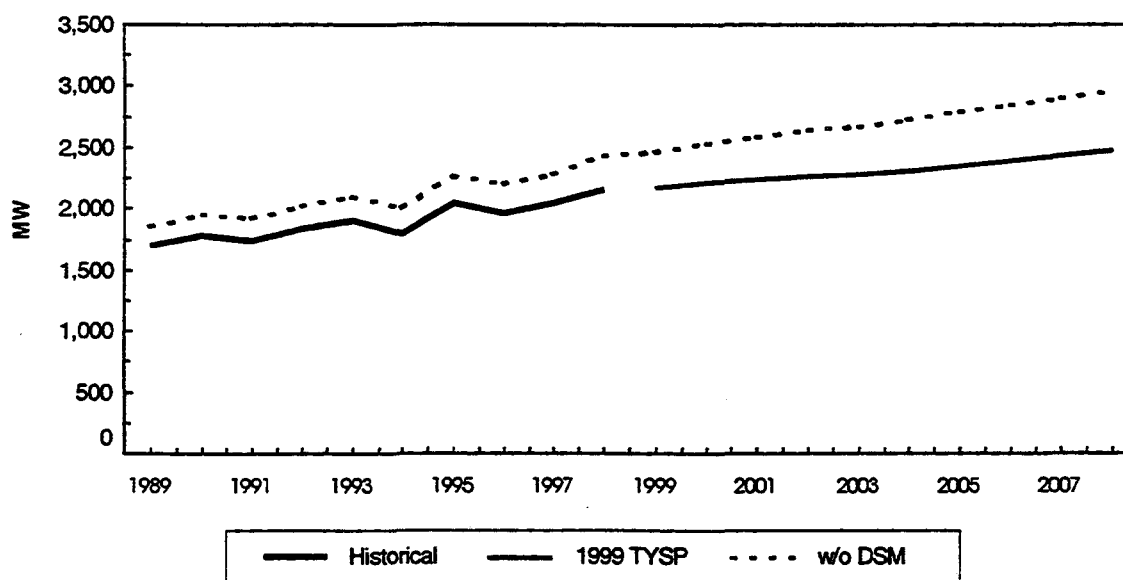


Figure 4-2
Gulf Power Company

History and Forecast of Winter Peak Demand

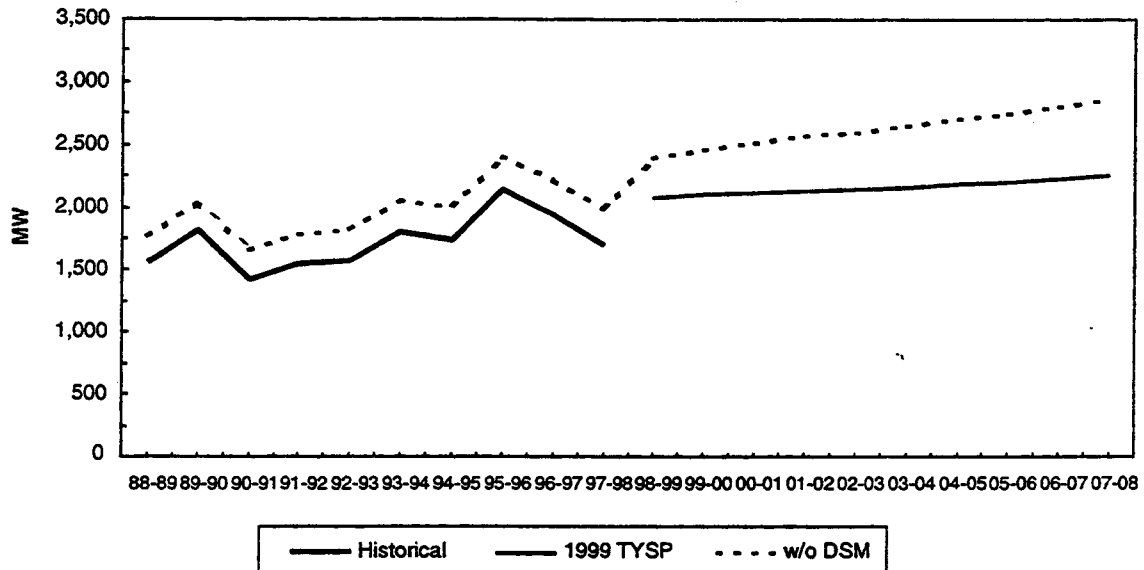
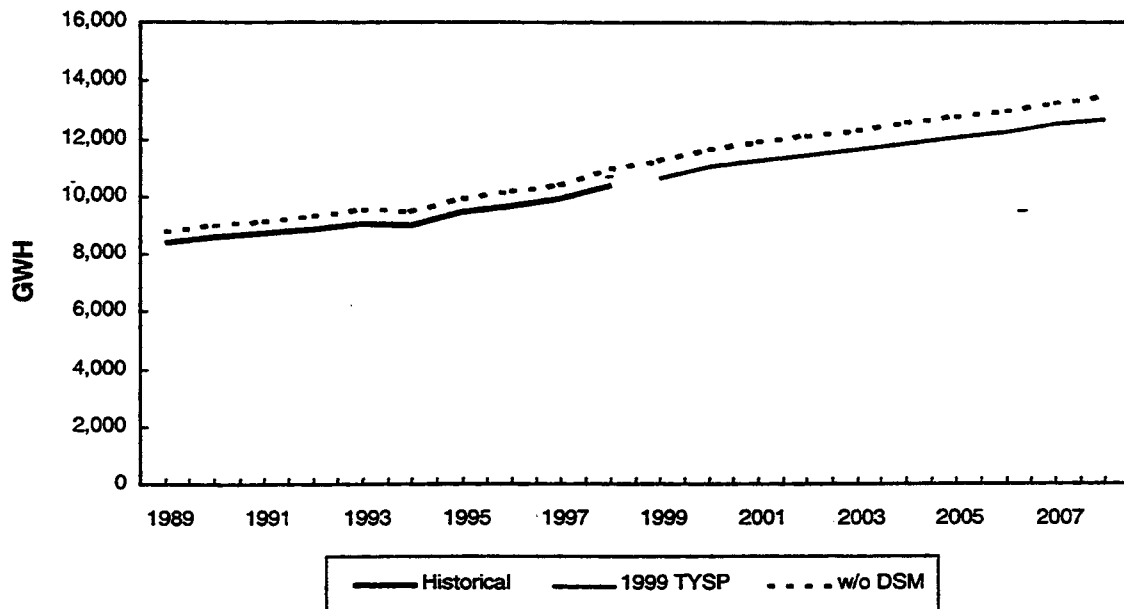


Figure 4-3
Gulf Power Company

History and Forecast of Annual Net Energy for Load



4.6 HISTORICAL FORECAST PERFORMANCE

Gulf's forecasts have traditionally been accurate. The FPSC's Review of Electric Utility 1998 Ten-Year Site Plans indicated that, of the nine reporting utilities in the state with sufficient available historical data, Gulf's average absolute percent error in retail sales forecast accuracy for the period from 1993 through 1997 was 2.5% and ranked third best in the state. Gulf's average forecast error for the same period was estimated to be an under-forecast of 1.19%, which also ranked third in the state.

5. FUEL PRICE FORECAST PROCESS

5.1 FUEL PRICE FORECASTS

Fuel price forecasts are used for a variety of purposes within the Southern electric system (SES), including such diverse uses as long-term generation planning and short-term fuel budgeting. Southern's fuel price forecasting process is designed to support these various uses.

The delivered price of any fuel consists of two components, the commodity price and the transportation cost. Commodity prices are forecast as mine-mouth prices for coal or well-head prices for natural gas. Because mine-mouth coal prices vary by source, sulfur content and Btu level, Southern prepares commodity price forecasts for 12 different coal classifications used on the Southern system. Because natural gas and oil prices do not experience the same variations, Southern prepares a single commodity price forecast for each of these fuels.

The level of detail with which transportation costs are projected depends on the purpose for which the forecast will be used. Generic transportation costs that reflect an average cost for delivery within Southern's territory are used in the delivered price forecast used for modeling generic unit additions in the Integrated Resource Planning (IRP) process. Site-specific transportation costs are developed for existing units to produce delivered price forecasts for use both in the IRP process and in fuel

budgeting. Similarly, when site-specific unit additions are under consideration, site-specific transportation costs are developed for each option.

Given the purpose of this Need Study, the following discussion will focus on the commodity price forecasts for coal and natural gas, and on the site-specific forecasts for Smith Unit 3 and the generating facilities proposed in response to Gulf's Request for Proposals (RFP).

5.2 SOUTHERN GENERIC FORECAST

Each year, Southern develops a fuel price forecast for coal, oil, and natural gas, which extends through the Company's 10-year planning horizon. This forecast is developed by a fuel panel consisting of fuel procurement managers at each of the five operating companies, with input from Southern Company Services fuel staff and outside consultants ("Fuel Panel").

The fuel price forecasting process begins with an annual Fossil Fuel Price Workshop that is held with representatives from recognized leaders in energy-related economic forecasting and transportation-related industries. Presenters at the last fuel price workshop included representatives from Resource Data International, J. D. Energy Inc., Hill and Associates, Data Resource International, Fieldston Company, and Criton Company.

During the Fossil Fuel Price Workshop, each fuel procurement representative presents their "base case"

forecast and assumptions, and high and low fuel price scenarios are discussed. A question and answer period allows for opposing views and debates on forecasts.

After the workshop, presentations by the SCS Fuel Services group reference the outside consultant forecasts and identify any major assumption differences. The Fuel Panel then consolidates both internal and external forecasts and assumptions to derive its commodity forecast for each type of fuel. The Fuel Panel's 1998 commodity price forecasts for 1.0% sulfur coal, oil, and natural gas, which were used in the economic analysis of Gulf's generating alternatives, are included in Table 5-1 below.

TABLE 5-1
SOUTHERN GENERIC FUEL PRICE FORECAST
(\$/MMBtu)

	<u>COAL</u>	<u>NAT. GAS</u>	<u>OIL</u>
1999	1.071	2.28	3.94
2000	1.080	2.28	4.06
2001	1.089	2.28	4.18
2002	1.098	2.28	4.30
2003	1.107	2.28	4.43
2004	1.115	2.28	4.58
2005	1.125	2.47	4.72
2006	1.134	2.62	4.87
2007	1.143	2.79	5.02
2008	1.152	2.96	5.18

5.3 COAL PRICE FORECAST

The information provided during the Fuel Panel meeting is used to develop the SES forecast of generic coal prices. The major influences that drive the assumptions for the coal forecast are relative expected demand for specific qualities of coal and transportation from the source. As Phase II of the Clean Air Act of 1990 approaches, the variety of suitable coal quality narrows and tends to have an upward pressure on coal commodity prices. However, as more substitution of natural gas for coal as an energy resource for new resource additions takes place, it is expected that coal prices will once again stabilize.

The generic coal price used in the IRP process is based on an average expectation of coal commodity cost combined with average transportation fees. This serves as a basis for the fuel costs associated with the pulverized coal candidate technology in the mix analyses. This generic fuel commodity price is also used with plant specific transportation fees in combination with a plant's contract coal prices to develop the existing fuel price projection for the Company's budget process.

5.4 NATURAL GAS PRICE FORECAST

The natural gas price forecast for wellhead natural gas reflects a "relaxed" view of the scarce resource theory. Past views by consultants and the U.S. Department of Energy

(DOE) would suggest that natural gas resources were rapidly declining and that reserves would be more difficult and costly to find. However, new technological innovations have resulted in a paradigm shift in the "scarce resource" theory. The new consensus is that gas resources are sufficient to meet the growing demand with moderate nominal dollar increases in price during the planning period. Dramatic improvements in producers' ability to find and develop natural gas reserves have prompted suppliers to have a bullish outlook on future markets. In the past two years, success rates in drilling offshore exploration wells have improved from 25% to 90% for most producers. In addition, new completion techniques such as horizontal drilling have increased production per well substantially. Lastly, new production methods are allowing producers to drill in very deep water at a lower cost. The result is expected to be a plentiful supply of relatively inexpensive volumes of gas in the near future.

5.5 NATURAL GAS AVAILABILITY

Assuming the construction of additional pipeline facilities, there are sufficient natural gas supplies available in the Southeastern United States to support full load operation of Smith Unit 3.

During the winter months, U.S. natural gas demand can reach 100 billion cubic feet (Bcf) per day. Unfortunately, the current maximum natural gas supplied through imports and

domestic production volumes peaks at 56 to 60 Bcf per day. In order to offset this capacity shortage, storage delivery is necessary.

Since U.S. natural gas demand in the summertime is significantly less, only about 42 to 45 Bcf per day, large end users and local distribution companies, such as Alagasco, buy extra volumes to fill huge underground gas storage fields. Typically, the markets purchase from 10 to 12 Bcf per day to fill storage during the summer months. This activity results in average gas demand reaching usage levels of 52 to 57 Bcf per day. This allows producers to operate wells at 90-95% of capacity year round.

There are indicators that during the time period 1999 and 2005, gas supply in the SES region will improve substantially. Major producers and interstate pipelines have proposed wide-scale expansion of pipelines in the Louisiana, Mississippi, and Alabama offshore areas. Suppliers forecast that an additional 2 Bcf per day will be delivered to the market by 1999. Another 4 Bcf per day should be available by the year 2005. Additionally, Canadian producers and pipelines have announced their plans to increase gas imports by 2 Bcf per day by 2000. These developments suggest that by 2005, U.S. gas supplies (specifically the SES region) should increase 15-16% above current levels. This translates into sufficient gas being available for all new gas-fired electric generation, including Smith Unit 3. It also means that average annual

gas prices should drop in the 1998 to 2000 time period as reflected in the natural gas price forecast discussed in Section 5.2 above.

5.6 SITE-SPECIFIC FUEL PROJECTIONS

Although the generic fuel forecast is useful in the IRP process for determining the preferred type of generating unit additions, it is inappropriate for use when evaluating site specific generation alternatives. For site-specific reviews, it is necessary to develop a fuel projection that specifically addresses the fuel supply that would be available to that site. This is the process that was used during both the self-build and RFP evaluations for Gulf.

The evaluations of both the RFP responses and the final self-build option were based on the gas commodity prices contained in the Fuel Panel's 1998 forecast. This provided a uniform basis for comparison. If necessary, adjustments were made to reflect any cost differences due to natural gas supply at a point other than the Henry hub, and any differences due to the specifics of the proposal, such as a commodity price adder.

To obtain site-specific costs for each alternative, transportation costs were added to the commodity forecast. In the case of the RFP respondents, the transportation adders were those quoted in the respective proposals. In the case of Gulf's self-build option, the transportation adders

reflected the rates offered in response to Gulf's September, 1998 solicitation for firm natural gas transportation.

In some cases, an RFP respondent stated that it planned to use either interruptible transportation or recallable released firm transportation, but would supply fuel oil backup. In those cases, fuel oil was assumed to be used for periods when gas transportation would likely be unavailable. The Fuel Panel's generic oil price forecast was used for this purpose, with transportation adjustments for delivery to the specific plant site.

By using the Fuel Panel's commodity price forecast in all the evaluations, SCS ensured that the competing proposals were compared on a fair, consistent basis.

6. FINANCIAL ASSUMPTIONS

The following financial assumptions were developed by Southern Company Services Financial Planning Department based on its annual assessment of regional and national economic factors. These assumptions were applied on a uniform basis in the analysis of Gulf's self-build options, the offers from respondents to Gulf's RFP, and the transmission improvements that were necessary for the alternatives. These financial factors are representative of what the Company could expect to experience when raising equity and debt at this time. Even if these assumptions turn out to be slightly different from actual rates in the near future, the relative rankings of the alternatives would not be changed.

The financial assumptions used in the evaluation processes are as follows:

Cost of Debt	7.29 %
Cost of Preferred	6.79 %
Cost of Equity	13.50 %
Percentage of Debt	45.00 %
Percentage of Preferred	10.00 %
Percentage of Equity	45.00 %
Construction Escalation	3.02 %
General Inflation	2.78 %
Ad Valorem Tax Rate	1.08 %

State Tax Rate	5.50 %
Federal Tax Rate	35.00 %
Depreciation Life	20 Years

7. SELF-BUILD OPTION SELECTION PROCESS

7.1 INITIATION OF SITE-SPECIFIC STUDIES

By the summer of 1997, it was apparent that Gulf would need to add generating resources by 2002 to reliably meet its customers' needs. This need was the result of several factors. Gulf's existing short-term power purchase agreements were scheduled to expire at the end of 2001, at which time the Company would be left with a negative reserve margin. Continuing to meet Gulf's capacity needs with new short-term power purchase options was not feasible, since such purchases were becoming not only scarce, but extremely expensive as a resource option. In addition, total SES reserve margins were declining, and Gulf could no longer rely on system-wide reserves to offset its own reserve shortfall. Two of the other operating companies in the Southern electric system, Alabama Power Company (APCo) and Mississippi Power Company (MPCo) had engaged in a study to determine their best self-build alternatives in the early part of 1997. This led to the filing for certification of APCo's Barry combined cycle unit and MPCo's Daniel combined cycle unit in August of 1997. As a member of the Southern system, Gulf was offered the opportunity to participate in the ownership of the proposed Daniel CC unit.

Based on all these circumstances, the Company in late 1997 began evaluating a number of site-specific, self-build generation options for meeting its future demand needs. The

following is a listing of the self-build alternatives that were ultimately considered in this evaluation process:

- ◆ Participation in MPCo's Daniel Combined Cycle Unit scheduled for a 2001 in-service date
- ◆ Construction of CT's at Smith Plant
- ◆ Construction of a CC unit at Smith Plant
- ◆ Participation in a cogeneration unit in the Pensacola area

The self-build evaluation process required the development of plant-specific cost and operating data for each of the alternatives. This data was then used to calculate the total 20-year net present value (NPV) of costs for each of the generating alternatives. The components of cost considered in the analysis included capital expenditures, fuel supply and transportation costs, operating and maintenance expense, transmission improvements, and system energy savings. These options were compared on both a \$/KW and total NPV basis.

7.2 SELF-BUILD UNIT SIZE

The initial self-build evaluation began by analyzing projects of comparable size to a 1-on-1, F-Class combined cycle unit, which has an output of approximately 266 MW. If a particular option being evaluated was of a different size, its characteristics were scaled either up or down to make it

comparable to the 1-on-1 CC unit. This allowed the alternatives to be evaluated on an equal basis.

This size of self-build option was initially used in the evaluation process. It became apparent that a 500 MW, F-Class, 2-on-1 combined cycle unit not only better matched the Company's demand needs, but also provided an alternative with attractive economies of scale. The major economic difference in going from a 1-on-1 to a 2-on-1 configuration is that the Company could get twice the generating capability for only about 70% in additional capital costs. Once again, some scaling was necessary to put all alternatives on equal footing in the analysis.

7.3 SIGNIFICANT COST DRIVERS

There are several significant cost drivers in the 20-year NPV cost analysis of-site-specific alternatives. These include the cost of natural gas transportation, the cost of required transmission improvements, and the amount of energy savings that result from the displacement of less efficient generation.

7.3.1 NATURAL GAS TRANSPORTATION COSTS

One of the key elements in the cost analyses was the development of natural gas (fuel) supply costs for the self-build options. As discussed in Section 5, the Southern electric system's Fuel Panel creates a forecast of generic fuel costs by type; however, a more refined and site-

specific projection must be used in the self-build analysis. Since most of the self-build options were natural gas fired alternatives, a number of different fuel assumptions were explored in the evaluation.

Natural gas commodity prices and storage costs are fairly competitive throughout the region and can be treated as basically equivalent for any of the specific sites under consideration. On the other hand, there is a great variety in the natural gas transportation rates, particularly when the cost of gas delivered into the state of Florida is compared to gas delivered outside of Florida.

The gas transportation cost for the Daniel CC unit is quite low, since the plant is located only about 5 miles away from a natural gas pipeline called the Destin Dome pipeline. This gave the option of participation in the Daniel CC a distinct fuel cost and energy savings advantage over the other self-build options. The cogeneration project, referred to in the analysis as Mulat Tower, is located near Pensacola and would receive its gas from the Koch Gas Transmission System in that area. Therefore, its transportation costs are fairly well established by existing tariffs. In contrast, there is no existing gas supply to the Smith Plant and therefore, the analyses explored a number of possible alternative supply options.

The closest natural gas pipeline to the Smith site is operated by Florida Gas Transmission (FGT) and would require the installation of approximately a 29-mile section of gas

lateral to the plant. It was assumed for purposes of this analysis that FGT would build the new lateral and Gulf could either transport the gas over FGT's system at the published tariff rate or could arrange to get release-firm gas transportation from others not using their capacity all of the time. The other alternative investigated for the Smith CC unit was the possibility of Gulf constructing its own pipeline to the Atmore, Alabama area. This new pipeline would offer the benefits of lower gas transportation costs from that area. This benefit would be impacted by the pipeline construction costs that would have to be considered in the overall economics of the option.

7.3.2 SYSTEM ENERGY SAVINGS

Another key economic factor is the amount of system energy savings associated with each alternative. System energy savings are dependent on the marginal fuel cost of the alternative. Units with lower delivered fuel prices will dispatch earlier and will run at higher capacity factors than units with higher fuel costs. In turn, these units displace a greater amount of high-priced generation from other units and maximize system energy savings. This factor tended to penalize lower efficiency combustion turbine units, as well as units with fuel purchased under currently existing gas tariff rates inside the state of Florida. The Daniel CC provided the greatest system energy savings because of its low gas transportation costs. The

energy savings of the Smith CC with the new pipeline option were slightly less than those of the Daniel unit, although the pipeline capital cost would be an offset to any savings of this option.

7.3.3 TRANSMISSION COSTS

The geographic location of the alternatives surfaced as a major factor in the cost evaluations due to the impact of location on the electric transmission system and the associated cost of needed improvements. Each of the self-build options was analyzed separately to determine any incremental transmission impacts resulting from its installation. These studies revealed that the prevailing network flows through Gulf's system are from the west to the east. As generation is added, particularly west of Gulf's service area, transmission improvements are required to reliably transport the power and provide voltage support to the Company's load centers. It was determined that capacity additions located almost anywhere except near the Panama City, Florida area had some negative impact on the transmission system. In fact, the study revealed that the further west the generation alternative was located, the greater the impact on Gulf's transmission system. The cost of overcoming these impacts was added to the overall cost of each self-build alternative in the evaluation.

7.3.4 CAPITAL AND O&M COSTS

The various options' capital and operating and maintenance costs were probably the most straight forward elements of the evaluation. It was clear that participating in a sister company project would have the least capital cost by enabling Gulf to take advantage of economies of scale. It was also clear that combustion turbines had lower capital cost and higher operating costs than the combined cycle units.

7.4 ECONOMIC EVALUATION

The economic evaluation of the self-build alternatives was approached from a total cost basis using common financial factors to develop a total net present value (NPV) for each alternative over a 20-year period. The capital costs for the units, pipeline, and transmission were calculated for each self-build alternative as a traditional present worth of revenue requirement (PWRR). The capacity costs of the cogeneration project and other fixed annual costs were treated like an expense and discounted to yield a NPV of cost. Each self-build option was modeled as an input to the entire Southern electric system to determine its effect on the total production and energy costs or savings to the system. The final result of combining these cost components was the total NPV of cost for all of the self-build options.

The evaluation process, which began the previous fall, was completed in April of 1998. As mentioned earlier, in the final analysis the evaluation considered options that were comparable in size to a 2-on-1, F-Class combined cycle technology (~540 MW) and included all incremental costs associated with the installation of each alternative.

7.5 RESULTS

The results of the evaluation showed that the Smith combined cycle unit, with the construction of a new pipeline, was the lowest cost alternative. Although energy savings was a major factor in the evaluation process, the primary factor that eliminated many of the options was the cost of the transmission improvements required to support new generation at any location outside the Panama City area. The table below provides the results of the self-build analyses which demonstrate that Smith Unit 3 is the Company's most cost-effective self-build alternative.

TABLE 7-1

<u>SELF-BUILD ALTERNATIVE</u>	<u>NET PRESENT VALUE OF COSTS (98\$ MIL)</u>
Smith Unit 3	117.1
Smith Combustion Turbine	158.5
Daniel Combined Cycle	236.7
Mulat Tower (cogeneration)	239.0

The selection of a combined cycle unit of the size of Smith Unit 3 dictated that Gulf Power follow the rules established pursuant to the Florida Electrical Power Plant Siting Act (PPSA). This included initiating a solicitation process under Rule 25-22.082 Florida Administrative Code, which must be completed prior to filing for a determination of need before the FPSC. The results of that solicitation process are covered in Section 8 of this Need Study.

8. REQUEST FOR PROPOSALS (RFP) PROCESS

8.1 OVERVIEW

Gulf began working with Southern Company Services' purchase power team early in 1998 on development of a Request for Proposals (RFP) for supply-side resources needed beginning in the summer of 2002. The Company desired a market test to determine what potential new generation option was the most cost-effective alternative for its customers. Gulf's RFP process began with the development of the RFP document, and moved through stages which included distributing the RFP, receiving proposals from respondents, initial screening of the proposals, requesting additional information from respondents, and final screening and results.

8.2 DEVELOPMENT OF THE RFP

Southern Company Services began to draft a solicitation for Gulf in February 1998, during the same time period Gulf was finalizing the study of its self-build options. The solicitation incorporated the requirements of the Commission RFP rule, such as the requirement for published notice of the respondents' sites and for Gulf's disclosure of costs for its next planned generating unit.

The RFP solicited proposals for all types of generating resources to meet all or part of a 350 - 500 MW need beginning in the summer of 2002. The RFP requested long-

term proposals lasting at least five years and specified a 50 MW minimum proposal size. The RFP advised potential respondents that resources in the Panama City area would have a significant transmission advantage. A copy of Gulf's RFP is contained in Appendix E.

8.3 DISTRIBUTION OF THE RFP

On August 21, 1998, Southern Company Services publicly issued the RFP on behalf of Gulf to approximately 100 potential respondents. As a normal course of business, Southern Company Services maintains a mailing list of developers who are active in the Southeastern United States. This list was updated for Gulf's RFP.

Additionally, Gulf published a notice of the solicitation in appropriate local and statewide newspapers and three national trade journals. All of the public notices included the name and address of the RFP contact in Birmingham as well as a schedule of critical dates for the RFP process. Gulf's objective was to attract any interested developers who may not have been on Southern Company Services' original distribution list.

8.4 PROPOSALS RECEIVED

On October 16, 1998, Southern Company Services received, on behalf of Gulf, four offers from three separate respondents. The proposals were of various terms and MW

sizes, but all offers were in the form of new generating facilities:

- ◆ A combined cycle unit in Hardee County, Florida
- ◆ A combustion turbine facility in Holmes County, Florida
- ◆ A combined cycle unit in Holmes County, Florida
- ◆ A family of cogeneration facilities in Mobile, Alabama and in Santa Rosa County, Florida

After receiving additional required information from one respondent, all offers were determined to be 'responsive' and the initial screening analysis began.

8.5 INITIAL SCREENING

In any supply side evaluation, the goal is to determine which alternative is the most cost-effective on a \$/KW basis. Although it penalizes the self-build alternative, Gulf chose to make the cost comparisons on a 20-year NPV of costs basis. Theoretically, the cost of any new generating facility constructed by Gulf would be recovered from its customers using declining revenue requirements over a thirty-year or longer time frame. A uniform 20-year analysis compresses all of those costs into a shorter timeframe, making the self-build alternative appear more expensive than what customers would really be asked to pay on a year-by-year basis.

For the initial screening in October and November, 1998, all of the proposals were modeled in PROVIEW® using only the costs contained within the offers. To facilitate this evaluation, SCS-Fuel Services provided a forecast of delivered natural gas prices for each of the facilities offered. Although the same fundamental commodity price for natural gas was used for all of the offers, there are additional site- specific variable costs of the natural gas which must be accounted for in the production cost model. To ensure the fairness of the evaluation, it is critical that the basis of the fuel forecast for the candidate unit is consistent with the fuel forecasts for generic unit additions and other competing units in the dispatch order.

To place all of the offers on equal footing, each proposal was scaled to a 600 MW size in the production cost run. This scaling method allows all offers to be compared equally, against the same base case, and it provides a consistent method of calculation on a \$/KW basis. This evaluation technique is critical to smaller projects which may have more value on a \$/KW basis, but may not meet the entire needs of the utility. Southern Company Services' goal was to evaluate the offers on an "apples to apples" basis and to eliminate any size bias in the evaluation.

Because none of the original proposals were 20-year offers, Southern Company Services allowed the PROVIEW® model to replace each offer at the end of its term with the most

appropriate generic resource addition. In Southern Company Services' experience, this technique is the best method for direct comparison of alternatives with unequal lives. When using this technique, SCS always reviews the year-by-year results to ensure that the replacement technology does not skew the results for the alternative being evaluated.

The results of the initial screening are shown below:

TABLE 8-1

INITIAL SCREENING RESULTS

Summer Rating	Proposal	Location	NPV (\$/KW)
500 MW	Combined Cycle	Holmes County, FL	273.8
486 MW	Combustion Turbine	Holmes County, FL	332.1
350 MW	A family of cogeneration facilities	Mobile, AL and Santa Rosa County, FL	432.3
532 MW	Combined Cycle	Hardee County, FL	565.2

Because this initial screening was based entirely on numbers supplied by the respondents, it was clear that Gulf Power needed to understand more about these proposals before proceeding to the final detailed evaluation. For example, the relative firmness of fuel supply was an important issue for these proposals. After conducting the initial screening analysis, formal correspondence was initiated by Southern Company Services to allow respondents to provide the additional information required.

8.6 REQUESTS FOR FURTHER INFORMATION

On November 19, 1998, letters were sent to each of the respondents asking clarifying questions that would potentially resolve any outstanding issues. Most of the uncertainty at this stage of the analysis concerned the firmness of the fuel supply, unit ratings, unit heat rates, and overall availability of the offers.

The Company wanted to make sure that all of the alternatives would have reliability and other characteristics comparable to those of its self-build option in order to make a fair assessment.

As a result of this dialogue with the respondents, the original proposals were modified and five additional proposals were made to Gulf from these participants. All of these offers were carried forward into the next phase of the evaluation.

8.7 GULF'S SELF-BUILD COSTS FOR SMITH UNIT 3

Concurrent with receipt by SCS of the RFP responses, Gulf submitted a site-specific cost estimate for Smith Unit 3. This submission did not include fuel transportation costs, which were the subject of a separate RFP issued in September, 1998, for firm natural gas service to the Lansing Smith site.

Six separate offers to build and own new pipeline facilities necessary to supply firm natural gas to the Smith

site were received on October 16, 1998. These proposals were significantly less expensive than was originally anticipated. Negotiations continue with a short list of respondents with the best offers. In addition to the solicited offers, SCS-Fuel Services developed an independent cost estimate for a Gulf self-build pipeline that was used to determine if having a third party perform this service was the least cost alternative.

8.8 DETAILED EVALUATION AND ANALYSIS RESULTS

In January 1999, a final detailed evaluation was conducted which directly compared the revised proposals to the Smith Unit 3 self-build alternative. The analysis methods for the detailed evaluation were similar to the screening analysis. Both the scaling technique and the replacement technology techniques were continued for the detailed evaluation. In addition to the generation analysis, transmission interconnection costs, system losses and transmission grid improvement costs were calculated and included for each of the supply side alternatives. Table 8-2 provides a summary of the relative ranking resulting from this detailed evaluation.

Although this detailed evaluation could have led to a list of finalists, the updated fuel cost for Smith Unit 3 really distinguished it as the best supply side alternative for Gulf's customers. As shown in the table, Smith Unit 3 produces over a \$200/KW advantage over 20 years compared to

the best external proposal. Based on these results, Gulf advised each of the respondents that its proposal was not the most cost-effective alternative.

8.9 CONCLUSION

Gulf's RFP process fully complied with both the letter and the spirit of the Florida Public Service Commission's rules governing the selection of generating capacity. Consequently, the process has confirmed that the best capacity resource alternative for Gulf's customers is Smith Unit 3. Because the size of the steam turbine exceeds 75 MW, Gulf now seeks a determination of need and certification of this unit under the Florida Electrical Power Plant Siting Act (PPSA).

TABLE 8-2

Gulf RFP Relative Ranking

<u>Rank</u>	<u>MW</u>	<u>Respondents</u>	<u>NPV Total Cost \$/KW (2002\$)</u>
1	540	Self-Build	279
2	486	Respondent B CT (20 Year Pricing)	496
3	500	Respondent B CC (10 Year Pricing)	505
4	532	Respondent C	511
5	500	Respondent B CC (7 Year Pricing)	522
6	486	Respondent B CT (10 Year Pricing)	527
7	486	Respondent B CT (7 Year Pricing)	539
8	500	Respondent B CC (20 Year Pricing)	553
9	350	Respondent A	592
10	532	Respondent C (Fixed Energy)	616

9. SUMMARY OF SMITH UNIT 3

9.1 OVERVIEW

Smith Unit 3 will be what is commonly referred to as a 2-on-1 combined cycle unit, using the General Electric "F" Class combustion turbine technology. The two combustion turbines (CT) comprising this unit will have a net generating capability of approximately 176 megawatts each in the absence of power augmentation. The exhaust gases from each of these CTs will flow through its own heat recovery steam generator (HRSG). On a combined basis, the HRSG's will produce 1,800 psig steam in sufficient quantities to power about 170 megawatts of steam turbine/generator capacity.

Smith Unit 3 will be a highly efficient, state-of-the-art combined cycle generating unit. Because the new unit will be fueled by natural gas, the environmental concerns associated with the project are minimal. Smith Unit 3 is expected to provide the customers of Gulf with many years of low cost, clean energy.

Smith Unit 3 will have a firm supply of natural gas that will come from a new pipeline installation to the Smith Plant. Currently, the Company does not have any plans to provide for a secondary fuel source for this unit because of the expected firmness of the natural gas supply. Since this new natural gas pipeline is to be built and owned by someone other than Gulf, the cost estimate does not include any major gas pipeline costs, but does include connection and metering costs.

Smith Unit 3 will be located approximately 1,000 feet north of the existing Smith Plant substation. The unit's output will reach the Company's transmission grid by means of less than 1,000 feet of 230 KV bus. The existing transmission system out of Smith Plant is sufficient to handle the unit's output.

Smith Unit 3 will have an average annual output of 521 megawatts at an efficiency of 6,741 Btu/KWH. The unit will have the capability for power augmentation by steam injection to generate up to 540 megawatts of peaking generation at a reduced efficiency of 7,139 Btu/KWH. The costs for the necessary equipment associated with the power augmentation operation are included in the estimate below.

The following is a listing of some of the specific unit characteristics:

Forced outage rate	3.4%
Scheduled maintenance outage	2 weeks/year (Ave.)
Equivalent availability	92%
Expected average capacity factor	62%
Fuel consumption (full load)	3,900 MMBtu/hour
Annual fixed O & M (98\$)	\$2.84/KW-yr.
Variable O & M (98\$)	\$1.89/mWh

9.2 PROJECTED UNIT CONSTRUCTION COSTS

The following is a breakdown of estimated installed costs for Smith Unit 3, excluding any costs associated with the

construction of the natural gas pipeline. This estimate is based on a combination of actual vendor quotes and refined engineering cost analyses and includes the costs necessary to comply with all applicable environmental regulations. With respect to most of the components that comprise the following costs, this estimate can be considered relatively firm ($\pm 10\%$).

TABLE 9-1

INSTALLED COST ESTIMATE FOR SMITH UNIT 3

<u>DESCRIPTION:</u>	<u>AMOUNT</u>
Indirects	\$ 23,661,966
Site, General	2,701,846
Steam Generator Area	36,741,570
Turbine & Generator Area	91,143,505
Fuel Facilities (metering only)	856,111
Plant Water Systems	13,443,351
Electrical Distribution & Switchyard	12,177,183
Plant Instrumentation & Controls	2,591,303
Other	<u>3,935,190</u>
TOTAL	\$187,252,025

9.3 ENVIRONMENTAL CONSIDERATIONS

Subsequent to filing the Petition for Need Determination before the Commission, the Company will file its Site Certification Application (SCA) with the Florida Department of Environmental Protection under the Florida Electrical Power Plant Siting Act (PPSA). Smith Unit 3 will be operated in compliance with all applicable federal and state environmental laws and regulations. Two principal environmental issues to be

considered are air emissions and any thermal impacts due to the discharge of cooling water from Smith Unit 3.

As mentioned above, Smith Unit 3 will be fueled by natural gas and therefore the only major air emission issue is that of NO_x. Gulf is pursuing an air emission strategy that will reduce NO_x emissions from one of the existing Smith generating units leading to a net reduction in total NO_x emissions for the entire plant. However, in an abundance of conservatism, the cost estimate used in the self-build and RFP evaluations included the capital and O&M costs of a Selective Catalytic Reduction (SCR) system for Smith Unit 3 if needed to control NO_x emissions beyond levels achieved through this strategy.

Condenser cooling for Smith Unit 3 will be accomplished by a closed-cycle cooling tower system, which will minimize cooling water withdrawals and discharge. Make-up water for the closed-cycle cooling system will be withdrawn from the existing once-through cooling water discharge canal that serves existing Smith Units 1 and 2. Blow-down from the cooling tower will be routed to the existing discharge canal, downstream of the make-up structure. The blow-down, which will be taken from the cold side of the cooling tower, will result in a slight decrease in the temperature of the cooling water of the discharge canal.

The Company believes that Smith Unit 3 will be permitted for construction and operation under the conditions and strategy that Gulf plans to propose in its SCA. From an environmental standpoint, the proposed facility will have net positive impacts.

9.4 CONSEQUENCES OF PROJECT DELAY

Beginning with the decision in April 1998 to pursue the installation of Smith unit 3, Gulf established a project timeline to pinpoint critical dates associated with the successful completion of this unit. Among the major elements in this timeline are the RFP, need determination, fuel supply negotiations, environmental permitting, equipment procurement, and unit construction. Each one of these components has a time range for its successful completion and some elements may overlap others along the timeline. Figure 9-1 represents the timeline for Smith Unit 3.

The most rigorous element in the process leading to the in-service date of Smith Unit 3, is the environmental permitting. It is estimated that the permit process will last approximately 12 to 14 months.

There are a number of elements in the timeline that can and most likely will overlap. For example, the need determination can precede and overlap the permitting, which can overlap equipment procurement. The fact that these elements overlap does not necessarily affect the other processes. However, there are some elements that can affect other elements. For instance, if the need determination were delayed or denied, the environmental permitting would not proceed until the need is resolved. Of course, there can be no construction

FIGURE 9-1

SMITH UNIT 3 - PROJECT TIMELINE

August 21, 1998	Issue Request for Proposals (RFP)
October 16, 1998	Receive proposals and begin evaluations
November 13, 1998	Initial Screening complete
December 15, 1999	Begin Detailed Screening
January 9, 1999	Select Short list for negotiations or Move forward with Self-build option.
January 15, 1999	Begin final selection process for gas supplier
February 1, 1999	Solicit vendor proposals for equipment
March 15, 1999	Lock down preliminary engineering for environmental study work for SCA
March 31, 1999	File application for need determination
June 1, 1999	File environmental Site Certification Application (SCA)
June/July, 1999	Need Determination Hearings
July 21, 1999	Land use hearings for Bay Co. site
August 25, 1999	Final decision on Need Determination
October 31, 1999	Finalize plant design
November 22, 1999	Order remaining equipment
August 1, 2000	Issue bid package for erection of the unit
September 15, 2000	Receive environmental permits
October 1, 2000	Award Erection contract
November 1, 2000	Begin site preparation and begin construction and substation work
January 15, 2002	Complete natural gas supply to plant
February 1, 2002	Begin unit testing and performance checks
May 31, 2002	Project complete

activity for the unit until the environmental permits have been approved and issued, even if the equipment were procured and located on-site.

As mentioned in Section 3.4.4, recent inquiries in the purchased power market have resulted in fewer and far more costly offers for capacity and energy. Gulf has demonstrated through the steps taken to date that its selection of Smith Unit 3 is the most cost-effective available for the Company to meet its customers' load requirements beginning in 2002. Even with some minor delays, Gulf believes that its timeline is reasonable and achievable for a summer 2002 commercial in-service date for Smith Unit 3 in order to prevent having to use this high-priced purchased power. However, if there is a delay of Smith unit 3 that prevents meeting its June, 2002 in-service date, at a minimum Gulf's customers will pay more for their electrical energy than necessary. The Company is also concerned with the possibility that without this unit's timely installation, which helps to support Southern system reserves, there are additional reliability issues that could affect customer service.

LOAD FORECAST AND DSM DETAIL

OVERVIEW

This appendix includes a detailed description of Gulf's load forecasting methodology, a detailed discussion of its conservation programs, and tables presenting Gulf's detailed forecast results.

B.1 METHODOLOGY

Gulf's total forecast employs a number of different techniques and methodologies, each applied to the task for which it is best suited. Many of the techniques take advantage of the extensive data made available through the Company's marketing efforts. These efforts are predicated on the philosophy of knowing and understanding the needs, perceptions and motivations of its customers and actively promoting wise and efficient uses of energy which satisfy customer needs. The following provides a description of Gulf's forecasting methodology.

B.1.1 CUSTOMER FORECAST

B.1.1.1 RESIDENTIAL CUSTOMER FORECAST

The immediate short-term forecast (0-2 years) of customers is based primarily on projections prepared by Gulf's district personnel. The districts remain abreast of local market and economic conditions within their service territories through direct contact with economic development agencies, developers, builders, lending institutions and other key contacts. The

projections prepared by the districts are based upon recent historical trends in customer gains and their knowledge of locally planned construction projects from which they are able to estimate the near-term anticipated customer gains. These projections are then analyzed for consistency and the incorporation of major construction projects and business developments is reviewed for completeness and accuracy. The end result is a near-term forecast of residential customers.

For the remaining forecast horizon, the Gulf Economic Model, an econometric model developed by Regional Financial Associates (RFA), is used in the development of residential customer projections. Projections of births, deaths, household size, and population by age groups are determined by past and projected trends. Migration is determined by economic growth relative to surrounding areas.

The number of households located in the eight counties in which Gulf provides service is computed by applying a household formation trend to the population by age group, and then by summing the number of households in each of five adult age categories. As indicated, there is a relationship between households, or residential customers, and the age structure of the population of the area, as well as household formation trends. The household formation trend is the product of initial year household formation rates in the Gulf service area and projected U.S. trends in household formation.

The forecast of residential customers is an outcome of the final section of the migration/demographic element of the model. The number of residential customers Gulf expects to serve is calculated by multiplying the total number of households located in Gulf's service area by the percentage of customers in these eight counties for which Gulf currently provides service.

B.1.1.2 COMMERCIAL CUSTOMER FORECAST

As in the residential sector, the immediate short-term forecast (0-2 years) of commercial customers, is prepared by Gulf's district personnel utilizing recent historical customer gains information and their knowledge of the local area economies and upcoming construction projects. A review of the assumptions, techniques and results for each district is undertaken, with special attention given to the incorporation of major commercial development projects.

Beyond the immediate short-term period, commercial customers are forecast as a function of residential customers and total real disposable income, reflecting the growth of commercial services to meet the needs of new and existing residents.

B.1.2 ENERGY SALES FORECAST

B.1.2.1 RESIDENTIAL SALES FORECAST

The short-term (0-2 years) residential energy sales forecast is developed utilizing multiple regression

analyses. Monthly class energy use per customer per billing day is estimated based upon recent historical data, expected normal weather and projected price. The model output is then multiplied by the projected number of customers and billing days by month to expand to the total residential class.

The long-term residential energy sales forecast is prepared using the Residential End-Use Energy Planning System (REEPS), a model developed for the Electric Power Research Institute (EPRI) by Cambridge Systematics, Incorporated, under Project RP1211-2. The REEPS model integrates elements of both econometric and engineering end-use approaches to energy forecasting. Market penetrations and energy consumption rates for major appliance end-uses are treated explicitly. REEPS produces forecasts of appliance installations, operating efficiencies and utilization patterns for space heating, water heating, air conditioning and cooking, as well as other major end-uses. Each of these decisions is responsive to energy prices and demand-side initiatives, as well as household/dwelling characteristics and geographical variables.

The major behavioral responses in the simulation model have been estimated statistically from an analysis of household survey data. Surveys provide the data source required to identify the responsiveness of household energy decisions to prices and other variables.

The REEPS model forecasts energy decisions for a large number of different population segments. These segments represent households with different demographic and dwelling characteristics. Together, the population segments reflect the full distribution of characteristics in the customer population. The total service area forecast of residential energy decisions is represented as the sum of the choices of various segments. This approach enhances evaluation of the distributional impacts of various demand-side initiatives.

For each of the major end-uses, REEPS forecasts equipment purchases, efficiency and utilization choices. The model distinguishes among appliance installations in new housing, retrofit installations and purchases of portable units. Within the simulation, the probability of installing a given appliance in a new dwelling depends on the operating and performance characteristics of the competing alternatives, as well as household and dwelling features. The installation probabilities for certain end-use categories are highly interdependent.

The functional form of the appliance installation models is the multinomial logit or its generalization, the nested logit. The parameters of these models quantify the sensitivity of appliance installation choices to costs and other characteristics. The magnitudes of these parameters have been estimated statistically from household survey data.

Appliance operating efficiency and utilization rates are simulated in the REEPS model as interdependent decisions. Efficiency choice is dependent on operating cost at the planned utilization rate, while actual utilization depends on operating cost given the appliance efficiency. Appliance and building standards affect efficiency directly by mandating higher levels than those otherwise expected.

The sensitivity of efficiency and utilization decisions to costs, climate, household and dwelling size, and income has been estimated from historical survey data. Energy prices, income, and household and dwelling size significantly affect space conditioning and residual energy use. Household and dwelling size also influence water heating usage. Climate significantly impacts space heating and air conditioning.

Major appliance base year unit energy consumption (UEC) estimates are based on data developed by Regional Economic Research, Inc. (RER), the current EPRI contractor, from metered appliance data or conditioned energy demand regression analysis. The latter is a technique employed in the absence of metered observations of individual appliance usage, and involves the disaggregation of total household demand for electricity into appliance specific demand functions. All of the weather sensitive UEC estimates were adjusted for Gulf Power's weather conditions.

The energy forecast output from REEPS reflects the continued impacts of Gulf Power's GoodCents Home program and

efficiency improvements undertaken by customers as a result of Residential Energy audits, as well as conversions to higher efficiency outdoor lighting. This output is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the residential conservation programs and program features are provided in Section B.1.4.

B.1.2.2 COMMERCIAL SALES FORECAST

The short-term (0-2 years) commercial energy sales forecast is also developed utilizing multiple regression analyses. Monthly class energy use per customer per billing day is estimated based upon recent historical data, expected normal weather and projected price. The model output is then multiplied by the projected number of customers and billing days by month to expand to the total commercial class.

COMMEND, a commercial end-use model developed by the Georgia Institute of Technology through EPRI Project RP1216-06, serves as the basis for Gulf's long-term commercial energy sales forecast. The COMMEND model is an extension of the capital-stock approach used in most econometric studies. This approach views the demand for energy as a product of three factors. The first of these factors is the physical stock of energy-using capital, the second factor is base year energy use, and the third is a utilization factor

representing utilization of equipment relative to the base year.

Changes in equipment utilization are modeled using short-run econometric fuel price elasticities. Fuel choice is forecast with a life-cycle cost/behavioral microsimulation submodel, and changes in equipment efficiency are determined using engineering and cost information for space heating, cooling and ventilation equipment and econometric elasticity estimates for the other end-uses (lighting, water heating, ventilation, cooking, refrigeration, and others).

Three characteristics of COMMEND distinguish it from traditional modeling approaches. First, the reliance on engineering relationships to determine future heating and cooling efficiency provides a sounder basis for forecasting long-run changes in space heating and cooling energy requirements than a pure econometric approach can supply. Second, the simulation model uses a variety of engineering data on the energy-using characteristics of commercial buildings. Third, COMMEND provides estimates of energy use detailed by end-use, fuel type and building type.

Annual building data from RFA and Gulf's most recent Commercial Market Survey provided much of the input data required for the COMMEND model. The model produces forecasts of energy use for the end-uses mentioned above, within each of the following business categories:

1. Food Stores
2. Offices
3. Retail and Personal Services
4. Public Utilities
5. Automotive Services
6. Restaurants
7. Elementary/Secondary Schools
8. Colleges/Trade Schools
9. Hospitals/Health Services
10. Hotels/Motels
11. Religious Organizations
12. Miscellaneous

The energy forecast output from COMMEND reflects the continued impacts of Gulf Power's Commercial GoodCents building program and efficiency improvements undertaken by customers as a result of Commercial Energy Audits and Technical Assistance Audits, as well as conversions to higher efficiency outdoor lighting. The output from COMMEND is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the Commercial Conservation programs and program features are provided in Section B.1.4.

B.1.2.3 INDUSTRIAL SALES FORECAST

The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major

industrial customers, trending techniques, and multiple regression analysis. Forty-four of Gulf's largest industrial customers are interviewed to identify load changes due to equipment additions, replacements or changes in operating characteristics.

The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using multiple regression analysis.

The long-term forecast of industrial energy sales is based on econometric models of the chemical, pulp and paper, other manufacturing, and non-manufacturing sectors. The industrial forecast is further refined by accounting for expected self-generation installations. The industrial sales forecast is also adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the conservation programs and program features are provided in Section B.1.4.

B.1.2.4 STREET LIGHTING SALES FORECAST

The forecast of monthly energy sales to street lighting customers is based on projections of the number of fixtures in service, for each of the following fixture types:

HIGH PRESSURE SODIUM	MERCURY VAPOR
5,400 Lumen	3,200 Lumen
8,800 Lumen	7,000 Lumen
20,000 Lumen	9,400 Lumen
25,000 Lumen	17,000 Lumen
46,000 Lumen	48,000 Lumen

The projected number of fixtures by fixture type is developed from analyses of recent historical fixture data to discern the patterns of fixture additions and deletions. The estimated monthly kilowatt-hour consumption for each fixture type is multiplied by the projected number of fixtures in service to produce total monthly sales for a given type of fixture. This methodology allows Gulf to explicitly evaluate the impacts of lighting programs, such as mercury vapor to high pressure sodium conversions.

B.1.2.5 WHOLESALE ENERGY FORECAST

The short-term forecast of energy sales to wholesale customers is based on interviews with these customers, as well as recent historical data. A forecast of total monthly energy requirements at each wholesale delivery point is produced utilizing multiple regression analyses.

The long-term forecast is based on estimates of annual growth rates for each delivery point, according to future growth potential.

B.1.2.6 COMPANY USE ENERGY FORECAST

The annual forecast for Company energy usage is based on recent historical values, with appropriate adjustments to reflect short-term increases in energy requirements for anticipated new Company facilities. The monthly spreads are derived using historical relationships between monthly and annual energy usage.

B.1.3 PEAK DEMAND FORECAST

The peak demand forecast is prepared using the Hourly Electric Load Model (HELM), developed by ICF, Incorporated, for EPRI under Project RP1955-1. The model forecasts hourly electrical loads over the long-term.

Load shape forecasts have always provided an important input to traditional system planning functions. Forecasts of the pattern of demand have acquired an added importance due to structural changes in the demand for electricity and increased utility involvement in influencing load patterns for the mutual benefit of the utility and its customers.

HELM represents an approach designed to better capture changes in the underlying structure of electricity consumption. Rapid increases in energy prices during the 1970's and early 1980's brought about changes in the efficiency of energy-using equipment. Additionally, sociodemographic and microeconomic developments have changed the composition of electricity consumption, including changes in fuel shares, housing mix, household age and size,

construction features, mix of commercial services, and mix of industrial products.

In addition to these naturally occurring structural changes, utilities have become increasingly active in offering customers options which result in modified consumption patterns. An important input to the design of such demand-side programs is an assessment of their likely impact on utility system loads.

HELM has been designed to forecast electric utility load shapes and to analyze the impacts of factors such as alternative weather conditions, customer mix changes, fuel share changes, and demand-side programs. The HELM model provides forecasts of hourly class and system load curves by weighting and aggregating load shapes for individual end-use components.

Model inputs include energy forecasts and load shape data for the user-specified end-uses. Inputs are also required to reflect new technologies, rate structures and other demand-side programs. Model outputs include hourly system and class load curves, load duration curves, monthly system and class peaks, load factors and energy requirements by season and rating period.

The methodology embedded in HELM may be referred to as a "bottom-up" approach. Class and system load shapes are calculated by aggregating the load shapes of component end-uses. The system demand for electricity in hour i is modeled as the sum of demands by each end-use in hour i :

$$L_i = \sum_{R=1}^{N_R} L_{R,i} + \sum_{C=1}^{N_C} L_{C,i} + \sum_{I=1}^{N_I} L_{I,i} + \text{Misc}_i$$

Where:

L_i = system demand for electricity in hour i ;

N_R = number of residential end-use loads;

N_C = number of commercial end-use loads;

N_I = number of industrial end-use loads;

$L_{R,i}$ = demand for electricity by residential
end-use R in hour i ;

$L_{C,i}$ = demand for electricity by commercial
end-use C in hour i ;

$L_{I,i}$ = demand for electricity by industrial
end-use I in hour i ;

Misc_i = other demands (wholesale, street lighting,
losses, company use) in hour i .

B.1.4 CONSERVATION PROGRAMS

Gulf Power Company has been a pacesetter in the energy efficiency market since the development and implementation of the GoodCents Home program in the mid-70's. This program brought customer awareness, understanding and expectations regarding energy efficient construction standards in Northwest Florida to levels unmatched elsewhere. Since that time, the GoodCents Home program has seen many enhancements,

and has been widely accepted not only by customers, but by builders, contractors, consumers, and other electric utilities throughout the nation, providing clear evidence that selling efficiency to customers can be done successfully.

Gulf's forecast of energy sales and peak demands reflect the continued impacts of the Company's conservation programs. These forecasts also reflect the anticipated impacts of the new programs submitted in Gulf's Demand Side Management plan filed February 22, 1995 (Docket No. 941172-EI) as approved by the FPSC. The demand and energy reductions associated with these new programs have been updated to reflect a revised implementation schedule for the Advanced Energy Management (AEM) program in the residential sector.

The following provides a listing of Gulf's conservation programs:

Residential Programs:

1. GoodCents New Home
2. Heat Pump Upgrade
3. Resistance Heat to Heat Pump Upgrade
4. Air Conditioning Upgrade
5. Residential Energy Audit
6. Residential Mail-In Audit
7. *In Concert With The Environment*
8. Geothermal Heat Pump
9. Advanced Energy Management
10. Outdoor Lighting Conversion

Commercial Programs:

1. Commercial GoodCents Bldg.
2. Commercial Energy Audit
3. Technical Assistance Audit
4. Commercial Mail-In Audit
5. Real Time Pricing Pilot
6. Outdoor Lighting Conversion

Street Lighting Conversion

The remainder of this section provides detailed descriptions of the conservation programs and program features in effect and estimates of reductions in peak demand and net energy for load reflected in the forecast as a result of these programs.

B.1.4.1 RESIDENTIAL CONSERVATION

In the residential sector, Gulf's GoodCents New Home program is designed to make cost effective increases in the efficiencies of the new home construction market. This is being achieved by placing greater requirements on cooling and water heating equipment efficiencies, proper HVAC sizing, increased insulation levels in walls, ceilings, and floors, and tighter restrictions on glass area and infiltration reduction practices. In addition, Gulf monitors proper quality installation of all the above energy features.

Gulf has several programs designed to make cost effective increases in efficiencies in the existing home market by requiring increased efficiency requirements on heating and cooling systems and improvements in air distribution system leakage. The A/C Upgrade program is designed to increase the efficiency of older central air conditioning units. The Heat Pump Upgrade program is designed to increase the efficiency of older heat pump units. The Resistance Heat to Heat Pump Upgrade program is

designed to replace older heating and air conditioning systems with new high efficiency heat pump systems.

Further conservation benefits are achieved in the existing home market with Gulf's Residential Energy Audit program which is designed to provide existing residential customers with cost-effective energy conserving recommendations and options that increase comfort and reduce energy operating costs. The goal of this program is to upgrade the customer's home to the GoodCents Improved Home standard by providing specific whole house recommendations. As an extension to this program, Gulf offers a Residential mail-in audit option to enhance customer participation and increase the overall program effectiveness.

In Concert With The Environment® is an environmental and energy awareness program that is being implemented in the 8th and 9th grade science classes in Gulf Power Company's service area. The program shows students how everyday energy use impacts the environment and how using energy wisely increases environmental quality. *In Concert With The Environment®* is brought to students who are already making decisions which impact the country's energy supply and the environment. Wise energy use today can best be achieved by linking environmental benefits to wise energy-use activities and by educating both present and future consumers on how to live "in concert with the environment". The program encourages participation by all household members through a take-home Energy Survey, Energy

Survey Results, and student educational handbook and is considered an extension of Gulf's Residential Audit Program.

The Residential Geothermal Heat Pump Program reduces the demand and energy requirements of new and existing residential customers through the promotion and installation of advanced and emerging geothermal systems. Geothermal heat pumps also provide significant benefits to participating customers in the form of reduced operating costs and increased comfort levels, and are superior to other available heating and cooling technologies with respect to source efficiency and environmental impacts. Gulf Power's Geothermal Heat Pump program is designed to overcome existing market barriers, specifically, lack of consumer awareness, knowledge and acceptance of this technology. The program additionally promotes efficiency levels well above current market conditions.

The Advanced Energy Management (AEM) Program provides Gulf Power's customers with a means of conveniently and automatically controlling and monitoring their energy purchases in response to prices that vary during the day and by season in relation to the Company's cost of producing or purchasing energy. The AEM System allows the customer to control more precisely the amount of electricity purchased for heating, cooling, water heating, and other selected loads; to purchase electric energy on a variable spot price rate; and to monitor at any time, and as often as desired, the use of electricity and its cost in dollars, both for the

billing period to date and on a forecast basis to the end of the period. The various components of the AEM System installed in the customer's home, as well as the components installed at Gulf Power, provide constant communication between customer and utility. The combination of the AEM System and Gulf's innovative variable rate concept will provide consumers with the opportunity to modify their usage of electricity in order to purchase energy at prices that are somewhat lower to significantly lower than standard rates a majority of the time. Further, the communication capabilities of the AEM System allow Gulf to send a critical price signal to the customer's premises during extreme peak load conditions. The signal results in a reduction attributable to predetermined thermostat and relay settings chosen by the individual participating customer. The customer's pre-programmed instructions regarding their desired comfort levels adjust electricity use for heating, cooling, water heating and other appliances automatically. Therefore, the customer's control of their electric bill is accomplished by allowing them to choose different comfort levels at different price levels in accordance with their individual lifestyles.

Additional conservation benefits are realized in the residential sector through Gulf's Outdoor Lighting program by conversion of existing, less efficient mercury vapor outdoor lighting to higher efficient high pressure sodium lighting.

B.1.4.2 COMMERCIAL/INDUSTRIAL CONSERVATION

In the commercial sector, Gulf's GoodCents Building program is designed to make cost effective increases in efficiencies in both new and existing commercial buildings with requirements resulting in energy conserving investments that address the thermal efficiency of the building envelope, interior lighting, heating and cooling equipment efficiency, and solar glass area. Additional recommendations are made, where applicable, on energy conserving options that include thermal storage, heat recovery systems, water heating heat pumps, solar applications, energy management systems, and high efficiency outdoor lighting.

The Commercial Energy Audit (EA) and Technical Assistance Audit (TAA) programs are designed to provide commercial customers with assistance in identifying cost effective energy conservation opportunities and introduce them to various technologies which will lead to improvements in the energy efficiency level of their business. The program is designed with enough flexibility to allow for a simple walk through analysis (EA) or a detailed economic evaluation of potential energy improvements through a more in-depth audit process (TAA) which includes equipment energy usage monitoring, computer energy modeling, life cycle equipment cost analysis, and feasibility studies. As an extension to this program, Gulf offers a Commercial mail-in

audit option to enhance customer participation and increase the overall program effectiveness.

Gulf's Real Time Pricing pilot program is designed to take advantage of customer price response to achieve peak demand reductions. Initial participation was limited to a maximum of 12 customers with actual demand of 2,000 KW or higher for this pilot program. In 1997 Gulf received approval to increase the participation level to a maximum of 24 customers. Customer participation is voluntary. Due to the nature of the pricing arrangement included in this program, there are some practical limitations to a customer's ability to participate. These limitations include the ability to purchase energy under a pricing plan which includes price variation and unknown future prices; the transaction costs associated with receiving, evaluating, and acting on prices received on a daily basis; customer risk management policy; and other technical/economic factors. The RTP Pilot program has been very successful and is expected to play a major role in affording Gulf Power the opportunity to meet its conservation objectives. Information gained through this program is being used to design a permanent RTP program.

B.1.4.3 STREET LIGHTING CONVERSION

Gulf's Street Lighting conversion program is designed to achieve additional conservation benefits by conversion of existing less efficient mercury vapor outdoor, street and

roadway lighting to higher efficient high pressure sodium lighting.

B.1.4.4 CONSERVATION RESULTS SUMMARY

The following Tables B-1 through B-11 provide detailed estimates of the reductions in peak demand and net energy for load resulting from Gulf's conservation programs. These reductions are verified through on-going monitoring of Gulf's major conservation programs and reflect estimates of conservation undertaken by customers as a result of Gulf Power Company's involvement. Conservation which has taken place without Gulf's involvement has contributed to further unquantifiable reductions in demand and net energy for load. These unquantifiable additional reductions are captured in the time series regressions in Gulf's energy forecasts and in the demand model projections.

Tables B-1 through B-4 reflect the total impacts of Gulf's new and existing conservation programs. The impacts of the existing programs that have been in place for several years are shown separately in Tables B-5 through B-8 and the anticipated impacts of Gulf's newer programs, submitted in Gulf's Demand Side Management Plan filed in 1995, are provided in tables B-9 through B-11.

Table B-1, below, provides the total savings in peak demand and net energy for load achieved by Gulf through its conservation programs. In 1997, Gulf's DSM programs successfully reduced summer peak demand by 244 megawatts

(MW), winter peak demand by 269 MW, and net energy for load by 523 million kilowatt-hours (KWH).

As shown in this table, by the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from 1997 through 2002. These reductions are expected to grow to a total savings of 489 MW of summer peak demand, 590 MW of winter peak demand and an annual energy savings of over 770 million KWH by the year 2008.

TABLE B-1

HISTORICAL
TOTAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	243,928	268,522	522,804,539

1999 FORECAST
TOTAL CONSERVATION PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	10,865	13,620	22,225,417
1999	30,489	36,692	30,353,374
2000	29,077	37,123	30,034,257
2001	25,943	34,501	22,988,653
2002	24,236	32,955	21,829,790
2003	23,875	32,408	21,756,342
2004	24,095	32,793	21,948,046
2005	20,322	27,386	19,861,207
2006	20,353	27,393	19,872,752
2007	17,717	23,522	18,348,712
2008	17,729	23,526	18,324,246

1999 FORECAST
TOTAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	254,793	282,143	545,029,957
1999	285,282	318,835	575,383,331
2000	314,359	355,958	605,417,587
2001	340,301	390,460	628,406,241
2002	364,536	423,414	650,236,032
2003	388,410	455,821	671,992,375
2004	412,506	488,615	693,940,422
2005	432,828	515,999	713,801,629
2006	453,180	543,392	733,674,381
2007	470,897	566,914	752,023,094
2008	488,625	590,440	770,347,340

TABLE B-2

HISTORICAL
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	106,849	163,319	271,253,667

1999 FORECAST
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	10,922	11,511	11,755,771
1999	25,804	34,591	20,028,692
2000	25,592	35,022	19,718,790
2001	24,159	33,387	18,698,570
2002	22,585	31,842	17,553,458
2003	22,162	31,295	17,469,787
2004	22,369	31,680	17,700,793
2005	18,626	26,273	15,667,821
2006	18,633	26,280	15,682,688
2007	15,993	22,409	14,159,565
2008	15,995	22,413	14,165,936

1999 FORECAST
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	117,771	174,831	283,009,439
1999	143,575	209,422	303,038,131
2000	169,167	244,444	322,756,920
2001	193,326	277,832	341,455,491
2002	215,910	309,674	359,008,948
2003	238,072	340,968	376,478,736
2004	260,442	372,649	394,179,529
2005	279,068	398,921	409,847,350
2006	297,701	425,201	425,530,038
2007	313,694	447,610	439,689,603
2008	329,689	470,023	453,855,539

TABLE B-3

HISTORICAL
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	137,080	105,203	241,038,261

1999 FORECAST
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	(58)	2,109	10,242,169
1999	4,685	2,101	10,115,326
2000	3,485	2,101	10,115,326
2001	1,784	1,114	4,092,695
2002	1,651	1,113	4,092,695
2003	1,713	1,113	4,092,695
2004	1,726	1,113	4,092,695
2005	1,696	1,113	4,092,695
2006	1,720	1,113	4,092,695
2007	1,724	1,113	4,092,695
2008	1,734	1,113	4,092,695

1999 FORECAST
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	137,022	107,312	251,280,430
1999	141,707	109,413	261,395,756
2000	145,192	111,514	271,511,082
2001	146,975	112,628	275,603,777
2002	148,626	113,740	279,696,473
2003	150,338	114,853	283,789,168
2004	152,064	115,966	287,881,864
2005	153,760	117,078	291,974,559
2006	155,479	118,191	296,067,254
2007	157,203	119,304	300,159,950
2008	158,936	120,417	304,252,645

TABLE B-4

**HISTORICAL
TOTAL OTHER DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	0	0	10,512,611

**1999 FORECAST
TOTAL OTHER DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	227,477
1999	0	0	209,356
2000	0	0	200,141
2001	0	0	197,388
2002	0	0	183,637
2003	0	0	193,860
2004	0	0	154,558
2005	0	0	100,691
2006	0	0	97,369
2007	0	0	96,452
2008	0	0	65,615

**1999 FORECAST
TOTAL OTHER DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	10,740,088
1999	0	0	10,949,444
2000	0	0	11,149,585
2001	0	0	11,346,973
2002	0	0	11,530,611
2003	0	0	11,724,471
2004	0	0	11,879,029
2005	0	0	11,979,720
2006	0	0	12,077,089
2007	0	0	12,173,541
2008	0	0	12,239,156

TABLE B-5

**HISTORICAL
TOTAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	213,772	262,789	513,626,118

**1999 FORECAST
TOTAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	9,169	6,199	14,708,361
1999	8,542	6,693	13,636,079
2000	8,034	6,646	12,920,322
2001	6,710	6,539	9,374,828
2002	6,228	6,523	8,704,575
2003	6,237	6,533	8,733,912
2004	6,211	6,507	8,642,576
2005	6,211	6,507	8,587,647
2006	6,218	6,514	8,599,192
2007	6,228	6,524	8,618,452
2008	6,231	6,527	8,593,986

**1999 FORECAST
TOTAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	222,941	268,989	528,334,480
1999	231,483	275,682	541,970,559
2000	239,517	282,328	554,890,880
2001	246,226	288,868	564,265,709
2002	252,453	295,390	572,970,285
2003	258,689	301,922	581,704,198
2004	264,901	308,430	590,346,775
2005	271,112	314,935	598,934,422
2006	277,329	321,449	607,533,614
2007	283,557	327,973	616,152,067
2008	289,787	334,500	624,746,053

TABLE B-6

HISTORICAL
RESIDENTIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	105,333	160,983	269,326,134

1999 FORECAST
RESIDENTIAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	7,273	5,968	8,941,405
1999	6,690	6,470	8,014,087
2000	6,182	6,423	7,307,545
2001	5,842	6,316	6,775,935
2002	5,360	6,300	6,119,433
2003	5,369	6,310	6,138,547
2004	5,343	6,284	6,086,513
2005	5,343	6,284	6,085,451
2006	5,350	6,291	6,100,318
2007	5,360	6,301	6,120,495
2008	5,363	6,304	6,126,866

1999 FORECAST
RESIDENTIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	112,606	166,952	278,267,540
1999	119,296	173,422	286,281,627
2000	125,478	179,845	293,589,171
2001	131,320	186,162	300,365,107
2002	136,679	192,462	306,484,539
2003	142,048	198,771	312,623,087
2004	147,392	205,056	318,709,600
2005	152,735	211,339	324,795,051
2006	158,085	217,630	330,895,369
2007	163,445	223,931	337,015,864
2008	168,808	230,235	343,142,730

TABLE B-7

HISTORICAL
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS
AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	108,439	101,806	233,787,373

1999 FORECAST
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	1,896	231	5,539,479
1999	1,852	223	5,412,636
2000	1,852	223	5,412,636
2001	868	223	2,401,505
2002	868	223	2,401,505
2003	868	223	2,401,505
2004	868	223	2,401,505
2005	868	223	2,401,505
2006	868	223	2,401,505
2007	868	223	2,401,505
2008	868	223	2,401,505

1999 FORECAST
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	110,335	102,037	239,326,852
1999	112,187	102,260	244,739,488
2000	114,039	102,483	250,152,124
2001	114,906	102,706	252,553,629
2002	115,774	102,928	254,955,135
2003	116,641	103,151	257,356,640
2004	117,509	103,374	259,758,146
2005	118,377	103,596	262,159,651
2006	119,244	103,819	264,561,156
2007	120,112	104,042	266,962,662
2008	120,979	104,265	269,364,167

TABLE B-8

HISTORICAL
OTHER EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	0	0	10,512,611

1999 FORECAST
OTHER EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	227,477
1999	0	0	209,356
2000	0	0	200,141
2001	0	0	197,388
2002	0	0	183,637
2003	0	0	193,860
2004	0	0	154,558
2005	0	0	100,691
2006	0	0	97,369
2007	0	0	96,452
2008	0	0	65,615

1999 FORECAST
OTHER EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	10,740,088
1999	0	0	10,949,444
2000	0	0	11,149,585
2001	0	0	11,346,973
2002	0	0	11,530,611
2003	0	0	11,724,471
2004	0	0	11,879,029
2005	0	0	11,979,720
2006	0	0	12,077,089
2007	0	0	12,173,541
2008	0	0	12,239,156

TABLE B-9

HISTORICAL
TOTAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	30,156	5,733	9,178,421

1999 FORECAST
TOTAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	1,696	7,421	7,517,056
1999	21,947	29,999	16,717,295
2000	21,043	30,477	17,113,935
2001	19,233	27,962	13,613,825
2002	18,008	26,432	13,125,215
2003	17,638	25,875	13,022,430
2004	17,884	26,286	13,305,470
2005	14,111	20,879	11,273,560
2006	14,135	20,879	11,273,560
2007	11,489	16,998	9,730,260
2008	11,498	16,999	9,730,260

1999 FORECAST
TOTAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	31,852	13,154	16,695,477
1999	53,799	43,153	33,412,772
2000	74,842	73,630	50,526,707
2001	94,075	101,592	64,140,532
2002	112,083	128,024	77,265,747
2003	129,721	153,899	90,288,177
2004	147,605	180,185	103,593,647
2005	161,716	201,064	114,867,207
2006	175,851	221,943	126,140,767
2007	187,340	238,941	135,871,027
2008	198,838	255,940	145,601,287

TABLE B-10

**HISTORICAL
RESIDENTIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	1,516	2,336	1,927,533

**1999 FORECAST
RESIDENTIAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	3,649	5,543	2,814,366
1999	19,114	28,121	12,014,605
2000	19,410	28,599	12,411,245
2001	18,317	27,071	11,922,635
2002	17,225	25,542	11,434,025
2003	16,793	24,985	11,331,240
2004	17,026	25,396	11,614,280
2005	13,283	19,989	9,582,370
2006	13,283	19,989	9,582,370
2007	10,633	16,108	8,039,070
2008	10,632	16,109	8,039,070

**1999 FORECAST
RESIDENTIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR**

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	5,165	7,879	4,741,899
1999	24,279	36,000	16,756,504
2000	43,689	64,599	29,167,749
2001	62,006	91,670	41,090,384
2002	79,231	117,212	52,524,409
2003	96,024	142,197	63,855,649
2004	113,050	167,593	75,469,929
2005	126,333	187,582	85,052,299
2006	139,616	207,571	94,634,669
2007	150,249	223,679	102,673,739
2008	160,881	239,788	110,712,809

TABLE B-11

HISTORICAL
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	28,641	3,397	7,250,888

1999 FORECAST
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	(1,954)	1,878	4,702,690
1999	2,833	1,878	4,702,690
2000	1,633	1,878	4,702,690
2001	916	891	1,691,190
2002	783	890	1,691,190
2003	845	890	1,691,190
2004	858	890	1,691,190
2005	828	890	1,691,190
2006	852	890	1,691,190
2007	856	890	1,691,190
2008	866	890	1,691,190

1999 FORECAST
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	26,687	5,275	11,953,578
1999	29,520	7,153	16,656,268
2000	31,153	9,031	21,358,958
2001	32,069	9,922	23,050,148
2002	32,852	10,812	24,741,338
2003	33,697	11,702	26,432,528
2004	34,555	12,592	28,123,718
2005	35,383	13,482	29,814,908
2006	36,235	14,372	31,506,098
2007	37,091	15,262	33,197,288
2008	37,957	16,152	34,888,478

B.1.5 RENEWABLE ENERGY

Gulf initiated implementation of a "Green Pricing" pilot program, *Solar for Schools*, to obtain funding for the installation of solar technologies in participating school facilities combined with energy conservation education of students. Initial solicitation began in September, 1996 and has resulted in participation of over 333 customers contributing \$18,171 through December, 1998. A prototype installation at a local middle school has been completed and the experience gained at this site will be used to design future *Solar for Schools* installations.

District heating and cooling plants are an older fundamental application of large central station heating and cooling equipment for service to multiple premises in close proximity. These systems are typically located in college or school settings as well as some military bases and industrial plants.

Within Gulf's service area there exist a number of these systems which were appropriate or seemed appropriate at the time of their installation. Current day considerations for energy pricing, operating and maintenance expenses have resulted in many of these systems becoming uneconomical and decommissioned. Future installations of district heating and cooling plants of any consequence hinge primarily upon the opportunity for optimum application of this technology. The very dispersed construction of low rise buildings which are characteristic of the building

demographics in Gulf Power's service area yield no significant opportunities for district heating and cooling that are economically viable on the planning horizon.

B.1.6 DATA SOURCES

The following data sources were utilized in the development of Gulf's projections:

1. Gulf Power Company historical billing data.
2. Gulf Power Company historical survey data.
3. Gulf Power Company historical load research data.
4. Historical weather data from NOAA and Weather Service Corp.
5. Historical data from the Florida Statistical Abstracts produced by the Bureau of Economic and Business Research, University of Florida.
6. Economic outlook including population projections, households, and other economic indicators from Regional Financial Associates. Data sources cited by RFA include the Bureau of Labor Statistics, Bureau of Economic Analysis, and the U.S. Bureau of Census.

B.1.7 DETAILED FORECAST RESULTS

The following Tables B-12 through B-17 provide the detailed forecast results.

GULF POWER COMPANY

TABLE B-12
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Rural and Residential						Commercial		
Year	Population *	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
1989	662,784	2.65	3,294	250,038	13,173	2,169	33,500	64,761
1990	677,866	2.66	3,361	255,129	13,173	2,218	33,957	65,305
1991	689,901	2.66	3,455	259,395	13,320	2,273	34,372	66,120
1992	703,860	2.65	3,597	265,374	13,553	2,369	36,009	65,796
1993	726,046	2.67	3,713	271,594	13,671	2,433	38,477	63,242
1994	747,459	2.69	3,752	278,215	13,486	2,549	39,989	63,739
1995	760,195	2.68	4,014	283,717	14,148	2,708	41,007	66,043
1996	769,246	2.67	4,160	287,752	14,457	2,809	42,381	66,271
1997	791,009	2.67	4,119	296,497	13,894	2,898	43,955	65,928
1998	810,649	2.66	4,438	304,413	14,577	3,112	45,510	68,379
1999	830,557	2.66	4,558	312,479	14,587	3,147	46,614	67,512
2000	849,054	2.65	4,692	320,074	14,658	3,273	48,150	67,980
2001	863,541	2.65	4,772	326,118	14,632	3,346	49,347	67,812
2002	877,537	2.64	4,864	331,931	14,653	3,419	50,294	67,977
2003	891,566	2.64	4,958	337,784	14,677	3,496	51,208	68,275
2004	905,608	2.64	5,057	343,661	14,715	3,572	52,130	68,528
2005	919,427	2.63	5,170	349,473	14,793	3,650	53,059	68,793
2006	933,241	2.63	5,272	355,302	14,839	3,725	53,978	69,012
2007	947,114	2.62	5,382	361,172	14,901	3,805	54,904	69,295
2008	960,867	2.62	5,503	367,016	14,995	3,881	55,836	69,507
CAAG								
89-98	2.3%	0.1%	3.4%	2.2%	1.1%	4.1%	3.5%	0.6%
98-03	1.9%	-0.2%	2.2%	2.1%	0.1%	2.4%	2.4%	0.0%
98-08	1.7%	-0.2%	2.2%	1.9%	0.3%	2.2%	2.1%	0.2%

* Historical and projected figures include portions of Escambia, Santa Rosa, Okaloosa, Bay, Walton, Washington, Holmes, and Jackson counties served by Gulf Power Company.

GULF POWER COMPANY

TABLE B-13
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Industrial			Street & Highway Lighting	Other Sales to Public Authorities	Total Sales to Ultimate Consumers
<u>Year</u>	<u>GWH</u>	<u>Average No. of Customers</u>	<u>Average KWH Consumption Per Customer</u>	<u>Railroads and Railways GWH</u>	<u>GWH</u>	<u>GWH</u>	<u>GWH</u>
1989	2,095	229	9,147,029	0	16	0	7,574
1990	2,178	247	8,817,297	0	17	0	7,774
1991	2,117	260	8,143,878	0	16	0	7,861
1992	2,179	262	8,318,456	0	16	0	8,161
1993	2,030	268	7,574,388	0	16	0	8,192
1994	1,847	280	6,596,837	0	16	0	8,164
1995	1,795	276	6,502,731	0	16	0	8,534
1996	1,808	281	6,434,470	0	17	0	8,794
1997	1,903	277	6,870,216	0	17	0	8,938
1998	1,834	263	6,971,767	0	18	0	9,401
1999	1,938	285	6,801,516	0	18	0	9,662
2000	2,029	294	6,902,869	0	18	0	10,013
2001	2,076	297	6,989,061	0	19	0	10,213
2002	2,095	300	6,982,317	0	19	0	10,396
2003	2,093	303	6,907,883	0	19	0	10,566
2004	2,091	306	6,833,259	0	19	0	10,739
2005	2,087	309	6,753,665	0	19	0	10,926
2006	2,091	312	6,703,402	0	20	0	11,108
2007	2,094	315	6,648,572	0	20	0	11,300
2008	2,071	318	6,511,389	0	20	0	11,475
CAAG							
89-98	-1.5%	1.6%	-3.0%	0.0%	1.5%	0.0%	2.4%
98-03	2.7%	2.9%	-0.2%	0.0%	1.0%	0.0%	2.4%
98-08	1.2%	1.9%	-0.7%	0.0%	0.9%	0.0%	2.0%

GULF POWER COMPANY

TABLE B-14
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)
<u>Year</u>	<u>Sales for Resale GWH</u>	<u>Utility Use & Losses GWH</u>	<u>Net Energy for Load GWH</u>	<u>Other Customers (Average No.)</u>	<u>Total No. of Customers</u>
1989	276	528	8,378	63	283,830
1990	294	545	8,612	68	289,400
1991	296	547	8,704	68	294,095
1992	299	389	8,849	74	301,719
1993	317	565	9,074	79	310,419
1994	316	487	8,967	93	318,578
1995	336	582	9,452	119	325,119
1996	347	521	9,662	157	330,571
1997	342	607	9,887	215	340,944
1998	356	645	10,402	262	350,447
1999	350	645	10,657	322	359,699
2000	361	668	11,041	352	368,870
2001	369	682	11,263	371	376,132
2002	378	694	11,468	382	382,906
2003	386	706	11,658	391	389,685
2004	393	718	11,850	400	396,496
2005	399	730	12,056	409	403,249
2006	406	743	12,257	418	410,009
2007	412	756	12,468	427	416,817
2008	418	768	12,661	436	423,605
<u>CAAG</u>					
89-98	2.9%	2.2%	2.4%	17.1%	2.4%
98-03	1.6%	1.8%	2.3%	8.3%	2.1%
98-08	1.6%	1.8%	2.0%	5.2%	1.9%

Note: Sales for Resale and Net Energy for Load include contracted energy allocated to certain customers by Southeastern Power Administration (SEPA).

GULF POWER COMPANY

TABLE B-15
History and Forecast of Summer Peak Demand - MW
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
<u>Year</u>	<u>Total</u>	<u>Wholesale</u>	<u>Retail</u>	<u>Interruptible</u>	<u>Residential Load Management</u>	<u>Residential Conservation</u>	<u>Comm/Ind Load Management</u>	<u>Comm/Ind Conservation</u>	<u>Net Firm Demand</u>
1989	1,858	60	1,799	0	0	79	0	81	1,698
1990	1,954	69	1,885	0	0	81	0	87	1,785
1991	1,923	64	1,860	0	0	83	0	92	1,748
1992	2,018	71	1,947	0	0	86	0	97	1,836
1993	2,096	76	2,021	0	0	88	0	102	1,906
1994	1,999	72	1,927	0	0	92	0	104	1,803
1995	2,265	82	2,183	0	0	96	0	122	2,048
1996	2,196	79	2,118	0	0	100	0	127	1,969
1997	2,284	75	2,208	0	0	107	0	137	2,040
1998	2,425	82	2,342	16	0	118	0	137	2,154
1999	2,460	76	2,385	29	0	144	0	142	2,175
2000	2,521	77	2,445	29	0	169	0	145	2,207
2001	2,574	78	2,496	29	0	193	0	147	2,234
2002	2,630	80	2,549	29	0	216	0	149	2,265
2003	2,668	81	2,587	29	0	238	0	150	2,280
2004	2,722	83	2,639	29	0	260	0	152	2,309
2005	2,780	84	2,696	29	0	279	0	154	2,347
2006	2,836	85	2,751	29	0	298	0	155	2,383
2007	2,896	87	2,809	29	0	314	0	157	2,425
2008	2,955	88	2,867	25	0	330	0	159	2,466
CAAG									
89-98	3.0%	3.6%	3.0%	100.0%	0.0%	4.6%	0.0%	6.0%	2.7%
98-03	1.9%	-0.2%	2.0%	12.7%	0.0%	15.1%	0.0%	1.9%	1.1%
98-08	2.0%	0.7%	2.0%	4.5%	0.0%	10.8%	0.0%	1.5%	1.4%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

NOTE 2: The forecasted interruptible amounts shown in col (5) are included here for information purposes only. The projected demands shown in column (2), column (4) and column (10) do not reflect the impacts of interruptible. Gulf treats interruptible as a supply side resource.

GULF POWER COMPANY

TABLE B-16
History and Forecast of Winter Peak Demand - MW
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
<u>Year</u>	<u>Total</u>	<u>Wholesale</u>	<u>Retail</u>	<u>Interruptible</u>	<u>Residential Load Management</u>	<u>Residential Conservation</u>	<u>Comm/Ind Load Management</u>	<u>Comm/Ind Conservation</u>	<u>Net Firm Demand</u>
88-89	1,762	56	1,706	0	0	113	0	95	1,554
89-90	2,038	57	1,980	0	0	120	0	97	1,821
90-91	1,649	50	1,600	0	0	126	0	98	1,425
91-92	1,772	60	1,712	0	0	132	0	99	1,541
92-93	1,820	61	1,759	0	0	140	0	100	1,579
93-94	2,055	72	1,983	0	0	145	0	101	1,809
94-95	1,993	71	1,922	0	0	150	0	102	1,740
95-96	2,404	82	2,322	0	0	157	0	103	2,144
96-97	2,208	80	2,127	0	0	163	0	105	1,939
97-98	1,974	61	1,913	0	0	175	0	107	1,692
98-99	2,390	76	2,314	28	0	209	0	109	2,071
99-00	2,461	77	2,384	28	0	244	0	112	2,105
00-01	2,511	78	2,433	28	0	278	0	113	2,121
01-02	2,558	80	2,478	28	0	310	0	114	2,135
02-03	2,595	81	2,513	28	0	341	0	115	2,139
03-04	2,643	83	2,560	28	0	373	0	116	2,154
04-05	2,694	84	2,610	28	0	399	0	117	2,178
05-06	2,743	85	2,658	28	0	425	0	118	2,200
06-07	2,796	87	2,709	28	0	448	0	119	2,229
07-08	2,848	88	2,760	24	0	470	0	120	2,258
CAAG									
89-98	1.3%	1.0%	1.3%	100.0%	0.0%	5.0%	0.0%	1.3%	0.9%
98-03	5.6%	5.8%	5.6%	0.0%	0.0%	14.3%	0.0%	1.4%	4.8%
98-08	3.7%	3.7%	3.7%	-1.7%	0.0%	10.4%	0.0%	1.2%	2.9%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

NOTE 2: The forecasted interruptible amounts shown in col (5) are included here for information purposes only. The projected demands shown in column (2), column (4) and column (10) do not reflect the impacts of interruptible. Gulf treats interruptible as a supply side resource.

GULF POWER COMPANY

TABLE B-17
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
<u>Year</u>	<u>Total</u>	<u>Residential Conservation</u>	<u>Comm/Ind Conservation</u>	<u>Retail</u>	<u>Wholesale</u>	<u>Utility Use & Losses</u>	<u>Net Energy for Load</u>	<u>Load Factor %</u>
1989	8,763	221	165	7,574	276	528	8,378	56.3%
1990	9,019	227	180	7,774	294	545	8,612	55.1%
1991	9,128	233	191	7,861	296	547	8,704	56.8%
1992	9,291	239	202	8,161	299	389	8,849	54.9%
1993	9,537	247	216	8,192	317	565	9,074	54.3%
1994	9,443	254	222	8,164	316	487	8,967	56.8%
1995	9,942	263	227	8,534	336	582	9,452	52.7%
1996	10,167	273	232	8,794	347	521	9,662	55.9%
1997	10,410	282	241	8,938	342	607	9,887	55.3%
1998	10,947	294	251	9,401	356	645	10,402	55.1%
1999	11,232	314	261	9,662	350	645	10,657	55.9%
2000	11,647	334	272	10,013	361	668	11,041	57.1%
2001	11,891	353	276	10,213	369	682	11,263	57.6%
2002	12,119	371	280	10,396	378	694	11,468	57.8%
2003	12,330	388	284	10,566	386	706	11,658	58.4%
2004	12,544	406	288	10,739	393	718	11,850	58.6%
2005	12,769	422	292	10,926	399	730	12,056	58.6%
2006	12,991	438	296	11,108	406	743	12,257	58.7%
2007	13,220	452	300	11,300	412	756	12,468	58.7%
2008	13,431	466	304	11,475	418	768	12,661	58.6%
CAAG								
89-98	2.5%	3.2%	4.8%	2.4%	2.9%	2.2%	2.4%	-0.2%
98-03	2.4%	5.7%	2.5%	2.4%	1.6%	1.8%	2.3%	1.1%
98-08	2.1%	4.7%	1.9%	2.0%	1.6%	1.8%	2.0%	0.6%

NOTE: Wholesale and total columns include contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA).

TECHNOLOGY SCREENING PROCESS

Preparation of the Southern electric system (SES) Integrated Resource Plan (IRP) requires the identification of a manageable number of generating unit alternatives to be evaluated in the generation mix analysis. For each candidate technology, inputs must be developed for the option's conceptual capital cost, design configuration, reliability data, and operation and maintenance costs. It is important to note that the information developed is not site-specific and is intended to be representative of average cost and performance data for a "generic" site.

The technology screening begins with a preliminary review of both mature and emerging technologies to identify those that are potentially suitable for installation on the SES during the planning horizon. Three technologies which had been evaluated in prior years were deleted from the list developed for the 1998 IRP. These were the intermediate load cycling coal fired, intermediate load compressed air energy storage (CAES), and peaking compressed air energy storage technologies. However, three new technologies were added, including inlet cooled combined cycle using ATS, air blown integrated gasification combined cycle (IGCC), and the topping pressurized circulating fluidized bed (PCFB). The following technologies were included for consideration in the screening process:

1. Base Load Pulverized Coal
1. Base Load Integrated Gasification Combined Cycle (IGCC)
3. Base Load Pressurized Fluidized-Bed Combustion (PCFB)
4. Base Load Combined Cycle, 'F' - Technology
5. Base Load Combined Cycle, 'G' - Technology
6. Intermediate Load Low Heat Rate 'G' Type CT
7. Peaking Combustion Turbine (3-Unit and 6-Unit Sites)
8. Pumped Storage Hydro (PSH)
9. Inlet Cooled Combined Cycle With ATS Technology

In addition to a general plant description and major performance assumptions, the following information was developed for each technology under consideration:

- Heat Rate and Output
- Capital Cost
- Fixed and Variable O&M Cost
- Capital Expenditures for Maintenance
- Emissions Estimates
- Plant Life
- Maintenance Time
- Equivalent Forced Outage Rate (EFOR)
- Performance Degradation
- Project Schedule
- Cash flow Table

Certain information regarding project schedule, performance degradation, emissions, EFOR and cash flow was not available for all of the technologies.

There are four categories of cost estimates. These include very conceptual, conceptual, budgetary and definitive. Below is a definition of each cost category:

Very Conceptual - The cost is as conceptual as the technology. As these technologies are developed, the costs will become more refined.

Conceptual - The technology is being developed. However, the first units have not been produced. Estimates are supplied by researchers, vendors, and governmental agencies. As these technologies are developed, the costs will become more refined.

Budgetary - This is a mature technology. There are actual costs of existing plants. The vendors offer market driven pricing and/or Southern Company Services has developed cost models.

Definitive - None of the cost information used in the technology screening process is definitive. Definitive estimates are within 5% of the final cost and are based on specific site and owner requirements. Definitive estimates are based on definitive scopes.

The cost models developed for mature technologies in prior years are reviewed for consistency and updated with information from ongoing projects. All cost projection dollars are based on values as of January 1, 1998. An escalation factor of 2% was applied for inflation for all technologies, except that the base load pulverized coal was not escalated and IGCC was escalated at 1%. The combined cycle and simple cycle cost models were carefully reviewed and updated given the probability that these technologies would be chosen for near term capacity additions. Revised budgetary estimates were obtained from the vendors, and the lowest cost was incorporated in the cost model. The contingency was held to 2.5% for major equipment and 10% for the balance of plant to reflect the actual confidence in the estimate. In case of coal technologies, contingency was held to 5% for major equipment and 10% for the balance of plant.

All cost models were separated into Engineering, Procurement and Construction (EPC), site related and owner's costs. EPC cost is equivalent in scope to what a turnkey contractor would quote for the project. EPC cost includes the design engineering, procurement of materials and equipment, and the contractor's scope. Site cost includes land, site preparation, water treatment system, switchyard and site related engineering. Owner's cost includes project and construction management, startup, and overheads.

Project schedules were developed for the new additions. Schedules for the remaining technologies were reviewed, but were not changed from the prior year. It should be noted that actual project schedules would vary based on the unique requirements of the project. Construction spending curves were expressed in percentages instead of dollar amounts to allow the flexibility to use either the EPC cost or total plant cost. Non-recoverable turbine degradation in output and heat rate was included for each technology in the technology documentation.

The nine listed technologies were reviewed and screened for reasonableness to select the final candidate technologies to be included in the generation mix process. Some technologies are eliminated when they are evaluated on an economic bus-bar analysis. The bus-bar evaluation estimates the relative cost per kilowatt-hour for the various alternatives at varying capacity factors. After this screening was completed, the following three technologies were retained as candidates for the generation mix analysis: (1) nominal 670 MW pulverized coal unit, (2) nominal 500 MW F-class combined cycle unit, and (3) simple cycle combustion turbine unit. More detailed information on these three candidate technologies is provided below.

**PULVERIZED COAL
NOMINAL 670 MW**

I. GENERAL DESCRIPTION OF THE PLANT

The major systems in the unit are based on a coal fired drum boiler operating at 2,400 psig, 1,000 deg. F. main steam temperature with a reheat temperature of 1,000 deg. F., driving a 3,600 rpm turbine-generator. Steam is condensed using circulating water that is cooled by hyperbolic natural draft cooling towers. The condensate/feedwater system utilizes four LP, three HP and one deaerating feedwater heater. A wet limestone scrubber with forced oxidation, designed for 95 % removal, is utilized for SO₂ reduction. Advanced low NO_x burners as well as a selective catalytic reduction system, designed for 80% removal, are utilized for NO_x control. A dry ash handling system is utilized for fly ash. Bottom ash is handled using hydrobins, a settling tank, and a clarifier. Both fly ash and bottom ash are either trucked away to landfill or sold.

State of Technology

This is a mature technology and currently available.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

	Net Heat Rate (Based on HHV) Btu/kWh	Net Unit Output kW
a. Peaking Condition (kW) (DB = 95° F; WB = 76° F)		
Rated	9,455	661,205
b. Annual Average (kW) (DB = 64.4° F; WB = 58° F)		
Rated	9,289	672,961
75%	9,481	506,015
50%	9,800	341,545

Basis for Heat Rate Data:

- ABB Turbine - Generator
- 8 Feedwater Heaters
- Wet Limestone Scrubber with Forced Oxidation
- Selective Catalytic Reduction System
- 2,400 psig/1,000° F/1,000° F Cycle
- 1 % Make-up and Blow-down
- Average System Weather Conditions Calculated
Based on Wet and Dry Bulb Temperature
Near Macon, GA.

III. PLANT COSTS

(with 5% contingency on
major equipment and 10% on
balance of plant)

	Per Kilowatt *	Total
EPC	\$ 840	\$555,412,000
Site	\$ 39	\$ 25,725,000
Owner's	\$ 53	\$ 34,940,000

Scope of supply on the output side extends through the switchyard to the first breaker and disconnect. Plant costs are overnight costs as of 1/1/97. This is a budget grade estimate.

* Based on the peaking rating

IV. FIXED O & M COSTS
(Based on the Peaking Rating)

\$/kW-Yr	9.92
Total	\$ 6,560,000

V. VARIABLE O & M COSTS
(Based on the Annual Average Rating and a
65% Capacity Factor)

Mills/KWH	1.65
-Total -	\$6,335,000

VI.	PLANT LIFE (yrs)	45.
VII.	MAINTENANCE TIME (weeks/yr)	4
VIII.	EQUIVALENT FORCED OUTAGE RATE	6.5
IX.	EXPENDITURE DATA AVAILABLE?	Yes
X.	PROJECT SCHEDULE AVAILABLE?	Yes
XI.	EXPECTED PLANT DEGRADATION -OUTPUT	2.04%
	HEAT RATE	2.04%
XII.	CAPITAL EXPENDITURE FOR MAINTENANCE (\$/kW-yr)	0.47

COMBINED CYCLE - 'F'
NOMINAL 500 MW

I. GENERAL DESCRIPTION OF THE PLANT

The base load combined cycle unit is a nominally rated 500 MW plant based on a power cycle utilizing two (2) nominal 170 MW advanced design industrial combustion turbine-generators with evaporative coolers, two natural circulation triple pressure heat recovery steam generators (HRSGs) with reheat sections and integral deaerators, a single condensing reheat steam turbine, a steam condenser with a mechanical draft cooling tower system for condenser cooling and associated support systems. The combustion turbines will be housed in an individual weather-proofed outdoor enclosure which includes insulation for sound attenuation and thermal protection.

State of Technology

This technology is currently available.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

	Net Heat Rate (Based on HHV) Btu/KWH	Net Unit Output kW
a. Peaking Condition (kW) (DB = 95° F; WB = 76° F)		
Rated	7,178	521,000

- b. Annual Average (kW)
(DB = 64.4° F; WB = 58° F)

Rated	6,860	517,000
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Basis for Heat Rate Data:

- (2) GE 7FA's with reheat steam turbine 1,815
psig/1,050° F/1,050° F
- Average annual based on dry low NOx control
to 9 ppm
- Evaporative cooler in use at 95° F
- 4.5" inlet / 12.0" exhaust loss on CT
(at 64° F. design point)
- 2.0% station service
- 304 ft. site elevation
- Natural gas fuel (assume natural gas
compressor not required)
- Corresponding relative humidities are 67% at 64
degrees F. dry bulb and 43% at 95 degrees F.
dry bulb temperatures
- Peak rating based on 2/1 steam to fuel
injection ratio for power augmentation

III. TOTAL PLANT COST

	Per Kilowatt *	Total
1 UNIT:		
EPC	\$ 338	\$176,211,000
Site	\$ 19	\$9,682,000
Owner's	\$ 11	\$5,987,000

2 UNITS:

EPC	\$ 325	\$338,352,000
Site	\$ 17	\$18,088,000
Owner's	\$ 11	\$11,513,000

Capital cost for gas pipeline is not included. Scope of supply on the output side extends through the switchyard to the first breaker and disconnect. The plant costs are overnight costs as of 1/1/97. This is a budget grade estimate.

* Based on the peaking rating

IV. FIXED O & M COSTS
(Based on the Peaking Rating)

1 UNIT:	\$/kW-Yr	3.66
	Total	\$1,908,000
2 UNITS:	\$/kW-Yr	2.46
	Total	\$2,561,000

V. VARIABLE O & M COSTS
(Based on the Annual Average Rating
and a 65% Capacity Factor)

1 UNIT:	Mills/KWH	1.68
	Total	\$4,934,000
2 UNITS:	Mills/KWH	1.56
	Total	\$9,209,000

VI. PLANT LIFE (yrs)	40
VII. MAINTENANCE TIME (weeks/yr)	3.0
VIII. EQUIV. FORCED OUTAGE RATE	3.44%
IX. EXPENDITURE DATA AVAILABLE?	Yes

X.	PROJECT SCHEDULE AVAILABLE?	Yes
XI.	EXPECTED PLANT DEGRADATION -OUTPUT HEAT RATE	5.89% 2.64%
XII.	CAPITAL EXPENDITURE FOR MAINTENANCE (S/kW-yr)	1.15

**SIMPLE CYCLE COMBUSTION TURBINE
NOMINAL 350 MW**

I. GENERAL DESCRIPTION OF THE PLANT

The combustion turbine plant model consists of current generation state-of-the-art, heavy duty industrial Westinghouse 501D5A nominal 120 MW units with evaporative cooler. These units utilize firing temperatures in the range of 1,950°-2,200° F. Extensive factory modularization of systems and components results in low costs for peaking applications. The plant utilizes natural gas as the primary fuel with No. 2 distillate as the back-up fuel. NOx is controlled to 25 ppm on the primary fuel through the use of water injection. The simple cycle combustion turbine plant design is based on siting three (3) nominal 120 MW simple cycle combustion turbines at one plant site.

State of Technology

This peaking plant will utilize mature technology that is commercially available at the present time.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

	Net Heat Rate (Based on HHV) Btu/KWH	Net Unit Output kW
Peaking Condition (kW) (DB = 95 Deg. F; WP = 76 Deg. F)		
Maximum Load:	11,728	364,770

Basis for Heat Rate Data:

- Natural Gas Fuel
- 95° F Dry Bulb Ambient Temperature
- 43% Relative Humidity
- Altitude is 304 Feet Above Sea Level
- Water Injection to Meet 25 ppm NOx For
Natural Gas
- 4.5" Inlet Pressure Loss
- 5" Exhaust Pressure Loss
- Performance at Base Combustor Firing Temperature
- Evaporative Cooler with 85% Effectiveness

III. TOTAL PLANT COST

(with 2.5% CT contingency and
10% for balance of plant)

	Per Kilowatt	Total
One site with three (3) Nominal 120 MW CTs		
EPC Cost	198	\$ 72,330,000
Site Cost	13	\$ 4,674,000
Owner's Cost	11	\$ 3,860,000

Capital cost for gas pipeline is not included. Scope of supply on the output side extends to the high side of the generator step-up transformer. Plant costs are overnight costs as of 1/1/97. This is a budgetary grade estimate.

IV. FIXED O & M COSTS
(Based on the Peaking Rating)

\$/kW-Yr	2.64
Total	\$ 962,000

V. VARIABLE O & M COSTS
(Based on the Peaking Rating and 300 hrs/year)

Mills/KWH	2.68
Total	\$ 293,000

VI. PLANT LIFE (yrs)	40
----------------------	----

VII. MAINTENANCE TIME (weeks/yr)	2.6
----------------------------------	-----

VIII. EQUIV. FORCED OUTAGE RATE (For periods of demand only)	3.0%
---	------

IX. EXPENDITURE DATA AVAILABLE?	Yes
---------------------------------	-----

X. PROJECT SCHEDULE AVAILABLE?	Yes
--------------------------------	-----

XI. AMBIENT TEMP. VS. CT OUTPUT AVAILABLE?	Yes
--	-----

XII. EXPECTED PLANT DEGRADATION - OUTPUT	3.13%
--	-------

HEAT RATE	1.85%
-----------	-------

XIII. CAPITAL EXPENDITURE FOR MAINTENANCE (\$/KW-YR)	0.30
--	------

LANSING SMITH GENERATING PLANT

The existing Lansing Smith Generating Plant is located on Alligator Bayou, which lies between North and West Bays north of Panama City in Bay County, Florida. The plant site consists of a total of 1,340 acres, of which only 400 acres are currently in utility use. This site has been used as an electric generation facility since June of 1965. When this site was originally purchased, it was intended to support eight coal-fired steam turbine/generating units, but because of changing conditions, only two fossil steam units and a combustion turbine are currently in service.

Smith Unit No. 1, a coal-fired steam unit with a net generating capability of 162,000 kilowatts, went into service in June, 1965. This unit is comprised of a Combustion Engineering boiler and a Westinghouse 3,600 rpm turbine/generator set. The boiler generates steam with a main steam pressure of 1,800 psig and a superheat/reheat steam temperature of 1,000/1,000 degrees Fahrenheit. Smith Unit No. 1 uses once-through salt water for its condenser cooling and a Buell Envirotech hot-side precipitator for particulate removal. This unit is a Clean Air Act (CAA) Phase II affected unit and currently burns a 1% domestic coal.

Smith Unit No. 2, a coal-fired steam unit with a net generating capability of 192,600 kilowatts, went into service in June, 1967. This unit is comprised of a

Combustion Engineering boiler and a Westinghouse 3,600 rpm turbine/generator set. The boiler generates steam with a main steam pressure of 1,800 psig and a superheat/reheat steam temperature of 1,000/1,000 degrees Fahrenheit. Smith Unit No. 2 uses once-through salt water for its condenser cooling and a Buell Envirotech hot-side precipitator for particulate removal. This unit is a CAA Phase II affected unit and currently burns a 1% domestic coal and has low-NOx burners to reduce nitrous-oxide emissions.

Smith Unit A is a Pratt & Whitney, aero-derivative combustion turbine with a net capability of 31,600 kilowatts and went into service in May of 1971. This combustion turbine unit is fueled with No. 2 fuel oil with a storage capacity of 750,000 gallons. Smith Unit A is used exclusively for peaking type service and is the only Gulf Power Company unit that is black-start capable.

The coal for Units No. 1 and No. 2 is brought into the plant by barge and unloaded by a derrick crane located on the Alligator Bayou canal. The coal stockpile at the plant typically maintains a level of approximately 30 days of combined unit nameplate ratings. Currently, there are no natural gas facilities available at the plant for generating unit consumption.

Electrically, the power generated by the plant's units is transmitted to the load centers via three 115 KV and four 230 kV transmission lines. The installation of Gulf's

planned 540 MW combined cycle unit will not necessitate any transmission system upgrades or new facilities.

Because of the site's original plan to have eight fossil steam units, there are many suitable acres for future unit expansion such as that currently planned by Gulf with its installation of Smith Unit 3. The undeveloped land on this site is mostly planted with pine trees.

APPENDIX E

The Gulf Power Company Request for Proposals (RFP) follows and appears in its original state as issued.

August 21, 1998

Mr. Generic M. Respondent
The Company Name
The Company Address
City, State ZIPCODE

RE: Request for Proposals

Dear Mr. Respondent:

Gulf Power Company has determined that it will need additional firm capacity starting as early as the summer of 2002. The Company is seeking proposals for power supply from eligible Respondents to meet the Company's requirements for electric generation capacity as described in this Request For Proposal (RFP). Location, price, and reliability of the power offered will be major factors in the purchase decision. Creative supply side electric generation alternatives that provide exceptional value and economic benefits to Gulf Power and its customers will be appropriately considered in the proposal evaluations. The attached RFP document details the requirements and specifications that Respondents should meet and also outlines the information that should be provided in a proposal.

Respondents interested in submitting proposals under this solicitation should provide six completed copies and one original of the enclosed forms in both hardcopy and electronic format (3.5" floppy diskette). Any additional information that the Respondent deems necessary to evaluate the offer should be included along with the forms. All proposals must be received no later than 5:00 p.m., on Friday, October 16, 1998 at the following address:

Director, Bulk Power Supply, 15N-8181
Southern Company Services, Inc.
600 N. 18th Street
Birmingham, AL 35203
Phone: (404) 506-7250

Any portions of offers to be treated as confidential must be so identified.

Thank you for your interest in meeting the Company's power supply needs during this period.

Sincerely,

Garey C. Rozier
Director, Bulk Power Supply

REQUEST FOR PROPOSALS

August 21, 1998

Southern Company Services, Inc. (Southern), acting as agent for Gulf Power Company (The Company, or Gulf Power), issues this request for proposals (RFP) to acquire approximately 350-500 megawatts (MW) of supply-side resources beginning in the summer of 2002. The Company invites innovative proposals of various types of electric generation, including those representing base-load, intermediate, and peaking resources. Offers proposing new electric generating facilities located near Panama City, Florida will have a transmission cost advantage.

For purposes of this solicitation, the Company is interested in long term proposals lasting at least five years. In addition to "summer only" and "year round" offers, proposals reflecting various contract periods for the same resource will be considered. The Company is particularly interested in proposals that will offer exceptional value to the Company and its customers. Respondents are encouraged to be creative in crafting offers that will meet the Company's needs.

Proposals submitted pursuant to this solicitation will be considered and evaluated against each other and against any self-build options. Transmission and ancillary service studies will be conducted as appropriate to determine the total cost impacts. A short list will then be developed reflecting those Respondents whose proposals appear to demonstrate the most value (not necessarily the lowest price). Any Respondents so selected will be contacted for negotiations that may lead to a mutually-agreeable power purchase agreement. The Company naturally reserves the right to revise the capacity needs forecast at any point during the process or negotiations; any such change may reduce, eliminate, or increase the amount of power sought.

Respondents are asked to define the firmness of the capacity offered in their proposal in one of the following categories:

- Level A: "First Call" rights on specific generating unit(s) or a system sale that is as firm as service to the Respondent's native load.
- Level B: System sale curtailable before the Respondent's native load and other wholesale obligations. (Respondent must be able to show capacity above other system needs.)
- Level C: Capacity that is backed by the Respondent's purchase(s).
- Level D: "Financially firm" (replacement cost with no liquidated damages)
- Level E: No specified generation resources

To help defray the cost for performing the evaluation of each proposal, Respondents are required to submit a check for \$8,000.00 for each proposal. Changes in the site, output, electrical characteristics (generator ratings), or technology changes (i.e. simple cycle, combined cycle, cogen, primary fuel) will require the submission of a separate proposal and payment of the fee. A change in financial terms is not considered a proposal change.

The Company reserves the right, without qualification and at its sole discretion, to reject any, all, or portions of the proposals received for any creditable reason or for failure to meet any criteria, and further reserves the right without qualification and at its sole discretion to decline to enter into a power purchase arrangement with any Respondent. Respondents should be aware, that the following (if submitted) will be classified as non-responsive and will not be considered or evaluated:

- proposals offering non-firm capacity or energy;
- demand-side proposals;
- proposals offering capacity and/or energy that is generated by facilities owned by the operating companies of the Southern Company;
- proposals involving resources that would result in increasing demand on resources owned by the operating companies of the Southern Company; or
- incomplete, or non-specific offers.

Those who submit proposals do so without recourse against the Southern Company or any of its affiliates or subsidiaries for either rejection of their proposal(s) or for failure to execute a power purchase agreement for any reason.

Tentative Solicitation Schedule

EVENT	DATE	COMMENTS
Solicitation issued	August 21, 1998	
Proposals due	October 16, 1998	Proposals must be received or hand delivered to Southern's RFP Contact by 5:00 PM
Short-list determination	December 11, 1998	If applicable
Complete negotiations	March 1, 1999	If applicable
File contract(s) for certification with state public service commission	March 31, 1999	If applicable

The Company reserves the right to revise, suspend, or terminate this schedule at their sole discretion. Any changes to the schedule will be provided as appropriate.

RFP Contact

Proposals and questions should be submitted to Southern's RFP Contact:

Garey C. Rozier
 Director, Bulk Power Supply, 15N-8181
 Southern Company Services, Inc.
 600 N. 18th Street
 Birmingham, AL 35203
 Phone: (404) 506-7250

Instructions for Completing Forms

1. All proposals should be submitted in the format shown in the RFP response form Attachment A. Additional information should be supplied (no particular format required) from the appropriate sections of Attachment B. Respondents should supply any additional information not included in these forms if such information may be needed for a thorough understanding and/or evaluation of the proposal.
2. Proposals must be signed by an officer of the Respondent.
3. A signed original and six (6) copies of the proposal forms and Respondent Questionnaire response should be submitted along with the electronic forms on a 3.5" floppy diskette. In the event of a discrepancy between the electronic forms and the hardcopy, the latter will be considered to be correct.
4. Prices and dollar figures quoted must be clearly stated as nominal for the year in which they occur. For non-nominal prices, the appropriate year for the stated dollars must be identified along with applicable escalation rates to be used for subsequent years.
5. Energy prices must be quoted as indicated in the forms as either \$/MW-hour or as heat rates to be applied to the designated published fuel index. The fuel index preferred (but not required) is the Henry Hub, as published in *Gas Daily*. Fuel transportation costs and any adjustments for energy pricing must be included in all prices.

Confidentiality

The Company will take reasonable precautions and use reasonable efforts to protect any proprietary and/or confidential information contained in an offer provided that such information is clearly identified by the Respondent as proprietary and confidential on the page on which it appears. Such information may, however, be made available under applicable state and/or federal law to regulatory commission(s), their staff(s) or other governmental agencies having an interest in these matters. The Company reserves the right to release such information to agents or contractors for the purpose of evaluating the Respondent's proposals, but such agents or contractors will be required to observe the same care with respect to disclosure as Gulf Power and Southern. Under no circumstances will the Southern Company, its subsidiaries, agents, or contractors, be liable for any damages resulting from any disclosure before, during, or after the solicitation process.

Transmission Information and Requirements

1. If power is to be provided from resources outside the Southern control area, Respondents must provide a transmission map that shows the expected contract path(s) to be used to deliver power to the Southern Company transmission system. Additionally, the map should show any site-specific electric generation resource, together with a list of control areas to be crossed. For information concerning the

Southern Company transmission systems such as: availability data on specific transmission routes, existing constraints, and interconnection points, Respondents should contact:

John E. Lucas, Manager Transmission Services
Southern Company Services, Inc.
Post Office Box 2625
Birmingham, AL 35202

2. Respondents are responsible for paying all charges and/or costs for delivering power to the Southern Company transmission system. Respondents are to include in their quotes any and all such charges.
3. The costs of any transmission upgrades to the Southern Company transmission system associated with the proposal will be considered in the evaluation. The Company will conduct transmission impact studies, as appropriate, to determine these costs. It should be noted that proposals for new electric generating facilities located near Panama City, Florida will have a significant transmission cost advantage.
4. For new facilities, Respondents are responsible for all costs related to interconnection of the facility to the Southern Company transmission network. Respondents should include all costs associated with a generator step-up transformer and synchronization to the transmission network using a Respondent supplied generator breaker. Interface between the Respondent and the company will be the high side of the Respondent supplied generator step-up transformer.

Regulatory Provisions

1. It shall be the complete and sole responsibility of the Respondent to take all necessary actions to satisfy any regulatory requirements, including but not limited to all licenses and permits that may be imposed on Respondent by any federal, state, or local law concerning the generation, sale and/or delivery of the power. The Company will cooperate with the Respondent to provide information or such other assistance, as may reasonably be necessary for the Respondent to satisfy such regulatory requirements. The Respondent shall likewise provide such information to the Company.
2. The Respondent shall be completely and solely responsible for obtaining and paying for any and all emission allowances or any other regulatory allowances, fees, or taxes that may be required for the generation, sale and/or delivery of power.
3. The proposal is subject to approval and/or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation (including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission).

4. The following regulatory requirement applies to Respondents that propose to construct electric generation facilities in the state of Florida:
Each participant in this solicitation must publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one quarter of a page and shall be published no later than ten (10) days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.
5. The Company's next planned generating unit addition, in the absence of alternate arrangements developed as a result of this solicitation, is a natural gas fired combined cycle installation of approximately 530 MW to be located in the Panama City, Bay County, Florida area. For a more detailed description of this planned unit, refer to Attachment C.

Performance Assurances

The Company will rely, in part, on this contracted power to meet the electric needs of its customers with dependable and reliable electric service. Suitable liquidated damages provisions will be required in any negotiated power purchase agreement. Performance guarantees and financial credit assurances may also be required of the Respondents, subject to negotiation, at the Company's discretion.

Minimum Requirements for Proposals

Proposals that meet these requirements will be considered responsive to this RFP. Non-responsiveness is a basis for rejecting an offer in the Company's sole discretion.

1. All forms, including both hardcopy and electronic versions, must be properly completed and returned to the RFP Contact, Garey C. Rozier, no later than 5:00 p.m. on Friday, October 16, 1998. Late or incomplete offers may be rejected in the sole discretion of the Company. Offers must remain open until at least March 31, 1999.
2. Complete information is needed to facilitate a timely evaluation. Issues that the Respondent prefers to negotiate later may be identified in the response; however, the Respondent must provide all explicit data requested on the forms. The Company may, at its sole discretion and judgment, choose to reject non-specific offers from further consideration.
3. Capacity offered must be firm. Proposals must clearly identify the firmness of the resource by the levels outlined in Attachment B. Proposals with no assurance of firmness or with no indication of the availability of actual firm resources may not be evaluated or considered.

4. Capacity offered will have the most value if fully dispatchable and available for first-call by the Southern Company system 24 hours per day and 7 days per week for the contracted period. Acceptable availability of the power when called for will be negotiated, with higher availability rates being preferred.
5. Proposal prices must include all costs that the Company will be expected to pay for the capacity and energy proposed. Attempts by the Respondent to increase prices will be grounds for rejection of the proposal.
6. No proposal less than 50 MW will be considered acceptable.

Proposal Evaluation

1. Proposals that are considered to be adequately responsive to the requirements of this RFP will be ranked and screened on price to eliminate those that are clearly not competitive before detailed modeling is performed. The majority of the evaluation will focus on price consideration. However, qualitative and non-price attributes will be considered in the overall screening process.
2. Proposals that pass the preliminary responsiveness screens will be further evaluated using appropriate production costing methods and models so that all reasonable cost impacts can be quantified.
 - a.) Preference will be given to proposals that offer shorter unit commitment notification and greater dispatch flexibility.
 - b.) Preference will be given to proposals that offer more contract flexibility features, such as call/put options, early-out provisions, and variable term pricing. The Respondent must separately identify any additional costs associated with these features.
 - c.) It is the Respondent's responsibility to submit additional information related to the proposal if such information will materially improve the quality of its offer or the Company's understanding thereof.
3. An appropriate selection of the best proposals will be chosen as a short-list for negotiations. Short-listed proposals will be evaluated against each other and with any self-build options before the Company makes any commitments regarding the resource(s) to meet its identified needs.
4. The Company reserves the right to contact Respondents to request additional information on any aspect of any proposal.

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Attachment A

Respondent's Company Name _____

Maximum Capacity (MW) _____

Minimum Capacity (MW) _____

Proposed Start Month _____

Proposed Start Year _____

Proposed End Month _____

Proposed End Year _____

Firmness Level _____ Enter Level A,B,C,D, or E (see RFP for Level descriptions)

Option Information (if Applicable)

Option Premium Price (\$/kW-month) _____

Option Strike Price (\$/kW-month) _____

Option Strike Date _____

Annual / Monthly	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price (\$/kW-month)												
Firm Fuel Delivery Adder (\$/kW-month)												
Fixed O&M (\$/kW-month)												
Guaranteed Availability (%)												
Guaranteed Dispatch Price (\$/MWh)												
OR												
Max. Heat Rate (Btu/MWh)												
Min. Heat Rate (Btu/MWh)												
Published Fuel Cost Index (Name)												
Fuel Delivery Adder (\$/MWh or \$/Mbtu)												
Other Adder (\$/MWh or \$/Mbtu)												
Variable O&M (\$/MWh)												

Annual / Monthly	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price (\$/kW-month)												
Firm Fuel Delivery Adder (\$/kW-month)												
Fixed O&M (\$/kW-month)												
Guaranteed Availability (%)												
Guaranteed Dispatch Price (\$/MWh)												
OR												
Max. Heat Rate (Btu/MWh)												
Min. Heat Rate (Btu/MWh)												
Published Fuel Cost Index (Name)												
Fuel Delivery Adder (\$/MWh or \$/Mbtu)												
Other Adder (\$/MWh or \$/Mbtu)												
Variable O&M (\$/MWh)												

Annual / Monthly	January	February	March	April	May	June	July	August	September	October	November	December
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Variable O&M (\$/MWh)												

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Guaranteed Dispatch Price (\$/MWh)												
OR												
Max. Heat Rate (Btu/MWh)												
Min. Heat Rate (Btu/MWh)												
Published Fuel Cost Index (Name)												
Fuel Delivery Adder (\$/MWh or \$/Mbtu)												
Other Adder (\$/MWh or \$/Mbtu)												
Variable O&M (\$/MWh)												

Attachment B
Respondent Questionnaire

All Respondents, as appropriate, must supply the following information:

- 1) Please provide documentation of your company's previous experience providing the proposed product.
- 2) Please provide the following financial and credit information for your company and for your parent company (if applicable):
 - Annual reports and Form 10-K for the past three years. If these documents are not available, then audited financial statements for the last three years will be accepted
 - Dunn and Bradstreet identification number
 - Credit rating of the Respondent's senior debt securities
 - Any additional documentation needed to allow the Company to determine the Respondent's financial strength and/or the strength of any corporate parents.
- 1) Present a detailed description of any security/credit instruments proposed by the Respondent to back its performance obligation.
- 2) Please describe whether or not this capacity has been offered in another RFP and under what conditions it would be released to serve this proposed sale.
- 3) Please describe the firmness category that best describes your offer and provide documentation that supports your ranking:
 - Level A:** "First call" rights on specific generating unit(s) or a system sale that is as firm as service to the Respondent's native load.
 - Level B:** System sale curtailable before the Respondent's native load and other wholesale obligations. (Respondent must be able to show capacity above other system needs.)
 - Level C:** Capacity that is backed by the Respondent's purchase(s).
 - Level D:** "Financially firm" (replacement cost with no liquidated damages)
 - Level E:** No specified generation resources
- 4) For a Level A proposal involving a specific unit, please provide the following information:
 - A. Unit name, location, and schedule for construction (if applicable)
 - B. Monthly Unit ratings
 - C. Electrical Data as required in performing load flow and stability studies
 - D. Equivalent forced outage rates (for existing units, calculated using the NERC equation for the last five years; for proposed units, as expected in operation.)
 - E. Fuel type and source (primary and secondary) and heat rate (applicable if pricing is not quoted as a firm energy price)
 - F. Guaranteed availability
 - G. Maximum and minimum operating level
 - H. Minimum run time per dispatch call
 - I. Minimum contract quantity (energy) per year (summer and winter)
 - J. Minimum down time
 - K. Start up time from cold start and from hot start

- L. Will the unit qualify for quick start capability? (less than 10 minutes)
 - M. Start up costs from cold start and from hot start
 - N. Descriptions (including models and manufacturers) of all of the major components
 - O. A detailed description of the fuel and water supplies
 - P. A thorough description of anticipated environmental impact and compliance.
- 1) For a Level A, B, or C system sale and other sales, please provide the following information:
 - A. A description of the system from which the power will be provided, including the name, location, peak hour load, the installed capacity, capacity mix and reserve projections (with and without the proposed capacity sale) during the proposal period.
 - B. An explanation of any criteria under which the supply of system power might be curtailed or interrupted and the priority of this proposed transaction relative to all other supply commitments (existing and future) of the Respondent.
 - C. For a Level A system sale, the proposed supply commitment is assumed to be at least as firm as the Respondent's service to its own native load. Please confirm this assumption. If this is not correct, please explain.
 - D. For a Level B system sale, please provide evidence of capacity available above Respondent's existing load commitments. (i.e., Current IRP documentation)
 - E. For a Level B or C system sale, please provide methodology by which the Respondent will ensure that sufficient capacity will be available to support the proposed sale.
 - 1) Please describe the transmission arrangements that have been or will be made to provide the firm transmission capacity necessary to deliver the power to the Southern Company transmission network. If transmission agreements are not in place, please describe the status of the negotiations for those arrangements.
 - 2) Please describe whether or to what extent the Respondent would assume the risk of a curtailment or interruption of transmission service.
 - 3) Please explain what will be done to rectify any shortfalls if power is not available when needed. (Describe any penalties that would be associated with failing to deliver the purchase after it has been scheduled.)
 - 4) Please describe any dispatch notice or scheduling requirements for this offer.
 - 5) Please describe any minimum requirement for the numbers of consecutive dispatch hours or a minimum energy take for the contract term?
 - 6) Please describe any other limitations on the use or availability of the power.

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Attachment C – Planned Unit Data

These following data represent generic technology assessment estimates which Gulf Power utilizes in its planning and is provided for information purposes only. These planning estimates have not been refined by site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on the Company's existing Lansing T. Smith Electric Generating Plant property in Bay County, Florida.
2. Planned Size 532 MW
3. Commercial Operation of the facility is proposed to be June 1, 2002.
4. The primary fuel is natural gas. No secondary fuel source is anticipated.
5. The estimated total direct cost is \$265,768,000 (installed 2002\$).
6. The estimated annual levelized revenue requirement is \$36,912,000 over 20 years.
7. The estimated annual value of deferral of this unit is \$55.25/kW-yr (98\$).
8. The estimated annual fixed O & M is \$1,458,000(98\$). The estimated variable O & M is \$1.85/MWH(98\$).
9. The estimated delivered fuel cost is \$ 2.42/MMBtu (98\$).
10. The following are estimates for:

Planned outage rate	5.8 %
Forced outage rate	3.2 %
Heat rate	6,527 Btu/KWH
Minimum load	284 MW
Ramp Rate	1 Hr. (Hot); 4 Hrs. (cold)
11. The estimated transmission interconnection costs associated with this unit are \$ 15 million. This unit will also have an estimated \$90 million dollars of gas lateral pipeline costs.
12. Air and water discharge permits will be required for this unit. It is the Company's plan to comply with all air and water quality standards of both the State and Federal governments.
13. The major financial assumptions in the development of these numbers were:

Construction escalation:	2.062 % per year
General escalation:	3.062 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.68 %
	10 % preferred @ 7.73 %
	45 % equity @ 13.5 %

Attachment C – Planned Unit Data

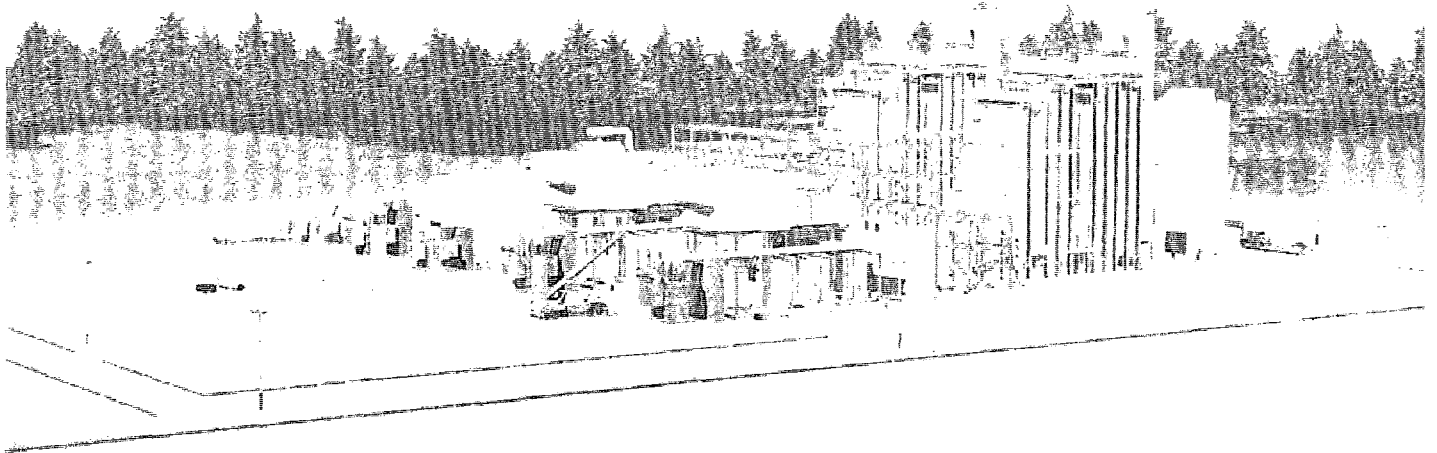
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Minimum load	284 MW
Ramp Rate	1 Hr. (Hot); 4 Hrs. (cold)
11. The estimated transmission interconnection costs associated with this unit are \$ 15 million. This unit will also have an estimated \$90 million dollars of gas lateral pipeline costs.
12. Air and water discharge permits will be required for this unit. It is the Company's plan to comply with all air and water quality standards of both the State and Federal governments.
13. The major financial assumptions in the development of these numbers were:

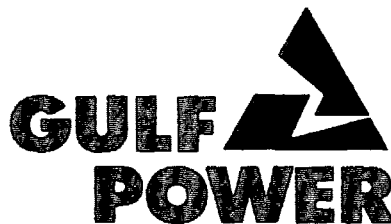
Construction escalation:	2.062 % per year
General escalation:	3.062 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.68 %
	10 % preferred @ 7.73 %
	45 % equity @ 13.5 %

GULF POWER SMITH UNIT 3 Site Certification Application



Volume 3

June 1999

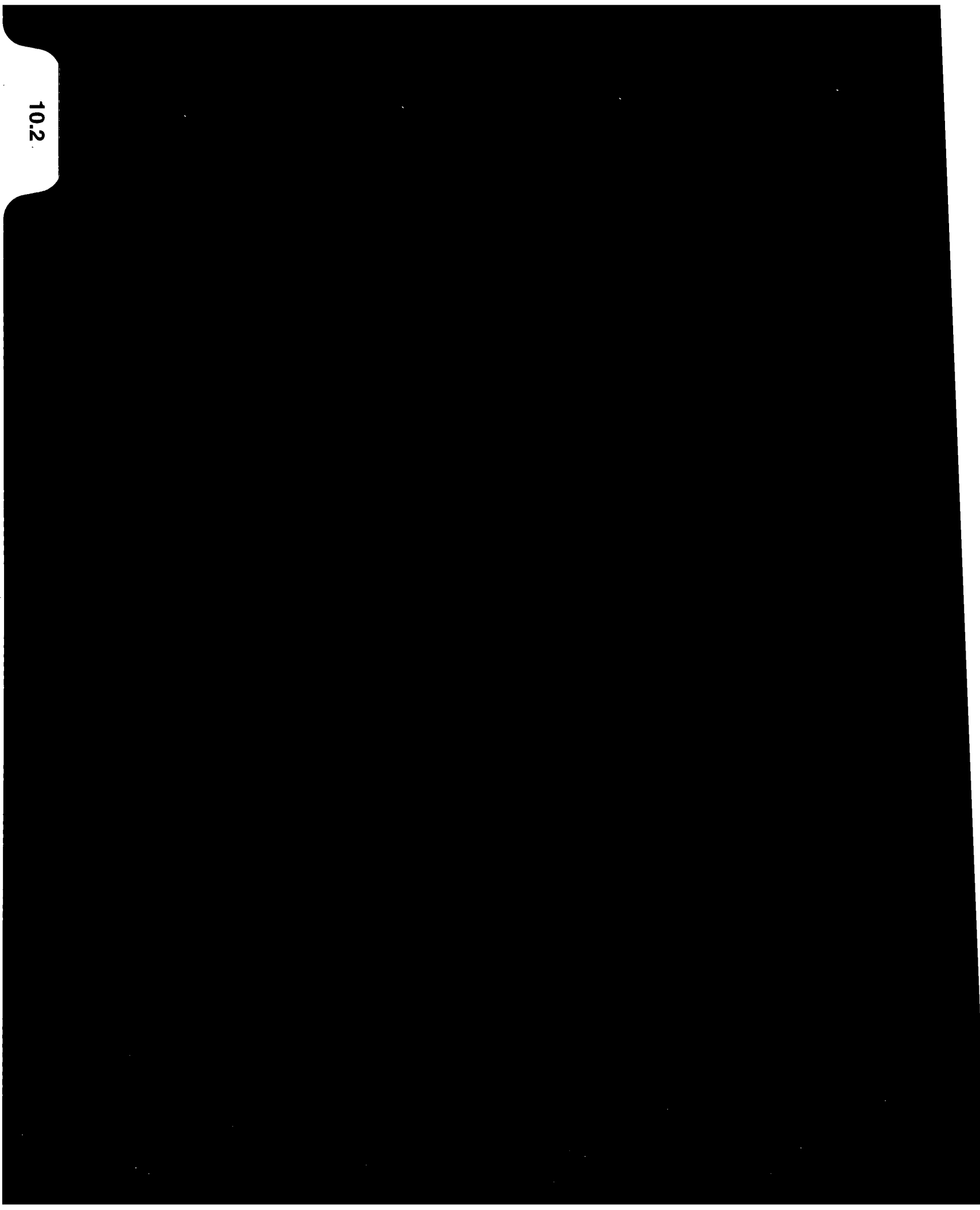


A SOUTHERN COMPANY

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Environmental Consulting & Technology, Inc.

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS



10.2 PERMIT APPLICATIONS/APPROVALS

APPENDIX 10.2.1
LAND USE PLAN AMENDMENT

**LARGE-SCALE
COMPREHENSIVE PLAN AMENDMENT
LANSING SMITH COMBINED CYCLE PROJECT
BAY COUNTY, FLORIDA**

REQUESTED BY:

**GULF POWER COMPANY
PENSACOLA, FLORIDA**

**990151-0600
April 1999**

PLAN AMENDMENT SUMMARY SHEET

Applicant: Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328
Attn: Mr. Jim Vick, Manager of Environmental Affairs
(850) 444-6311

Location: Township 2 South, Range 15 West, Section 36

Reference Number: 26636-010-000

Tax Use Code: 5500 (Timberland)

Size of Property: 50 ± acres

Current FLUM Description: Agriculture

Character District: Suburban

Adjacent Properties FLUM Designation: Agriculture to the north, east, and west
Industrial to the south (existing Lansing
Smith Plant)

Proposed FLUM Designation: Industrial

Current Use of Property: Silviculture

Plan Amendment Report Prepared By:

Environmental Consulting & Technology, Inc. (ECT)
Contact: Darren Stowe
(813) 289-9338

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1. INTRODUCTION

Gulf Power Company requests an amendment of the Bay County Comprehensive Plan – Future Land Use Map (FLUM) for 50 ± acres of land located north of the Gulf Power Company's existing Lansing Smith electrical generating power plant (Smith Units 1 and 2) as depicted on Figure 1. This request is to change the current future land use designation for this parcel from "Agriculture" to "Industrial" on the FLUM in order to allow for the construction of a new electrical power generating unit, Smith Unit 3. Gulf Power Company is currently preparing an application for authorization to construct and operate the proposed project pursuant to the Florida Electrical Power Plant Siting Act (PPSA), Sections 403.501 - .518, Florida Statutes. Figure 2 depicts the proposed site plan for Smith Unit 3.

IMAGE QUALITY

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PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

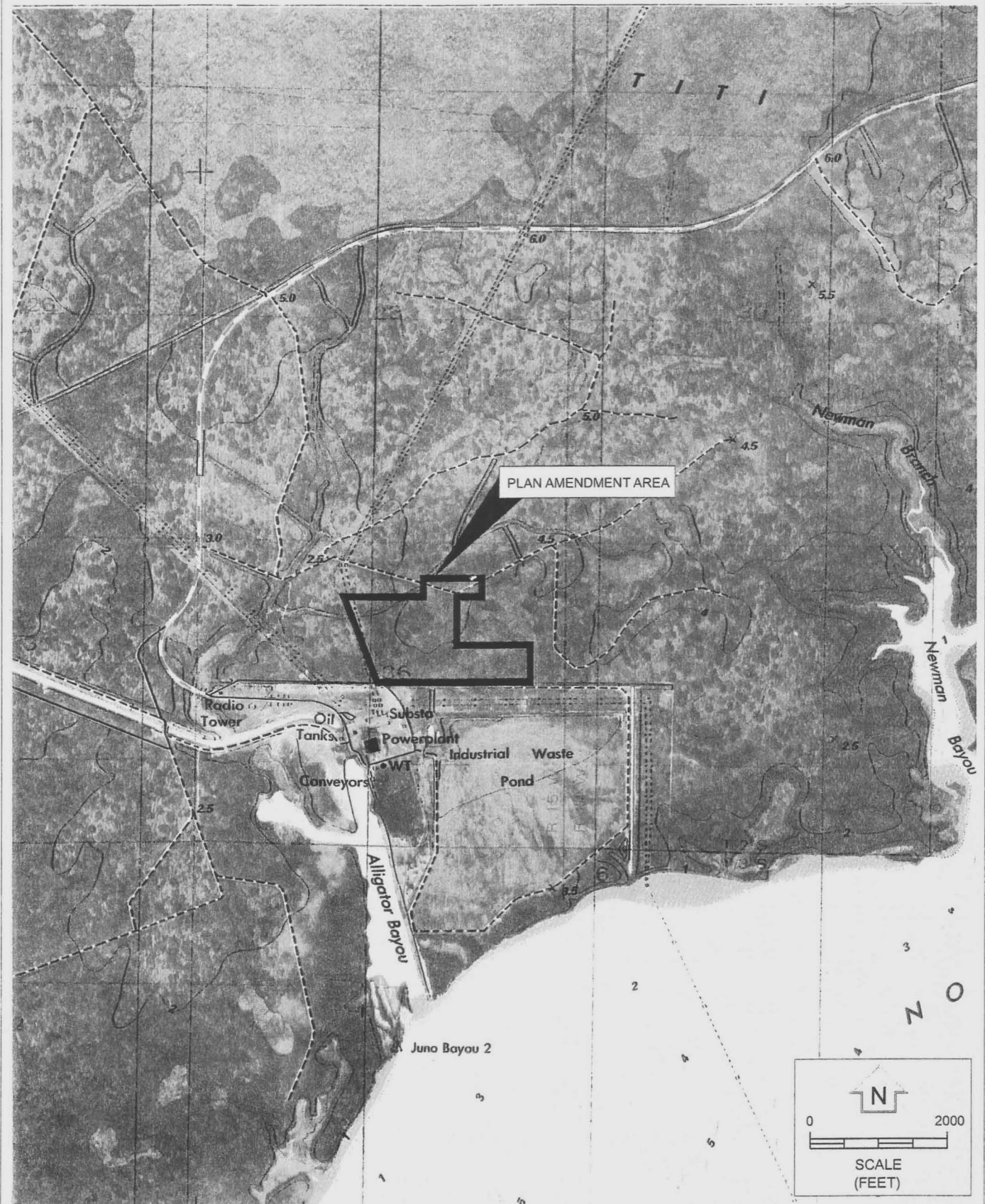


FIGURE 1.
SITE LOCATION MAP
SMITH UNIT 3 PLAN AMENDMENT
BAY COUNTY, FLORIDA

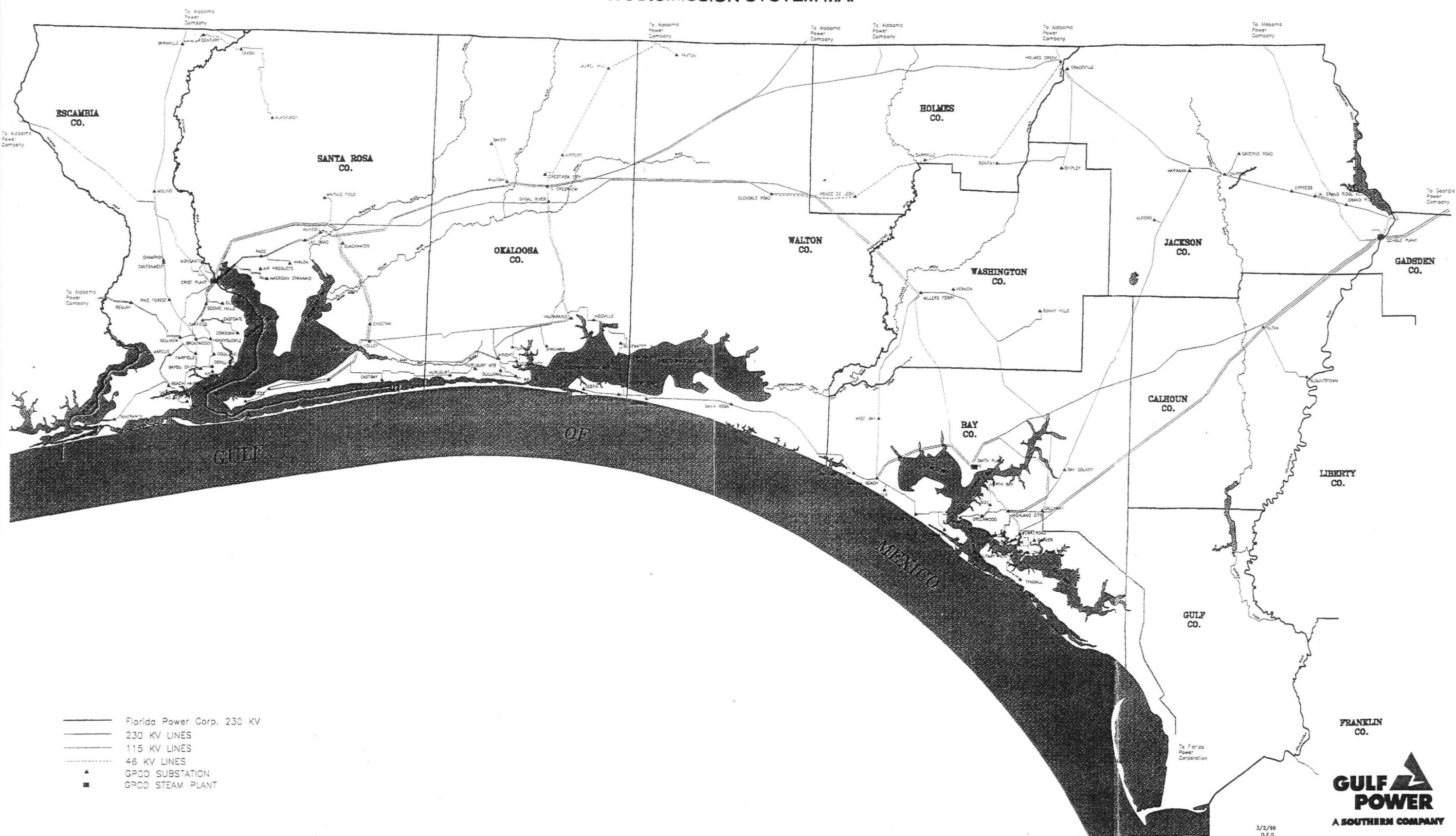
Sources: USGS Quad Map of Southport, FL., 1992; ECT, 1999.

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GULF POWER COMPANY TRANSMISSION SYSTEM MAP



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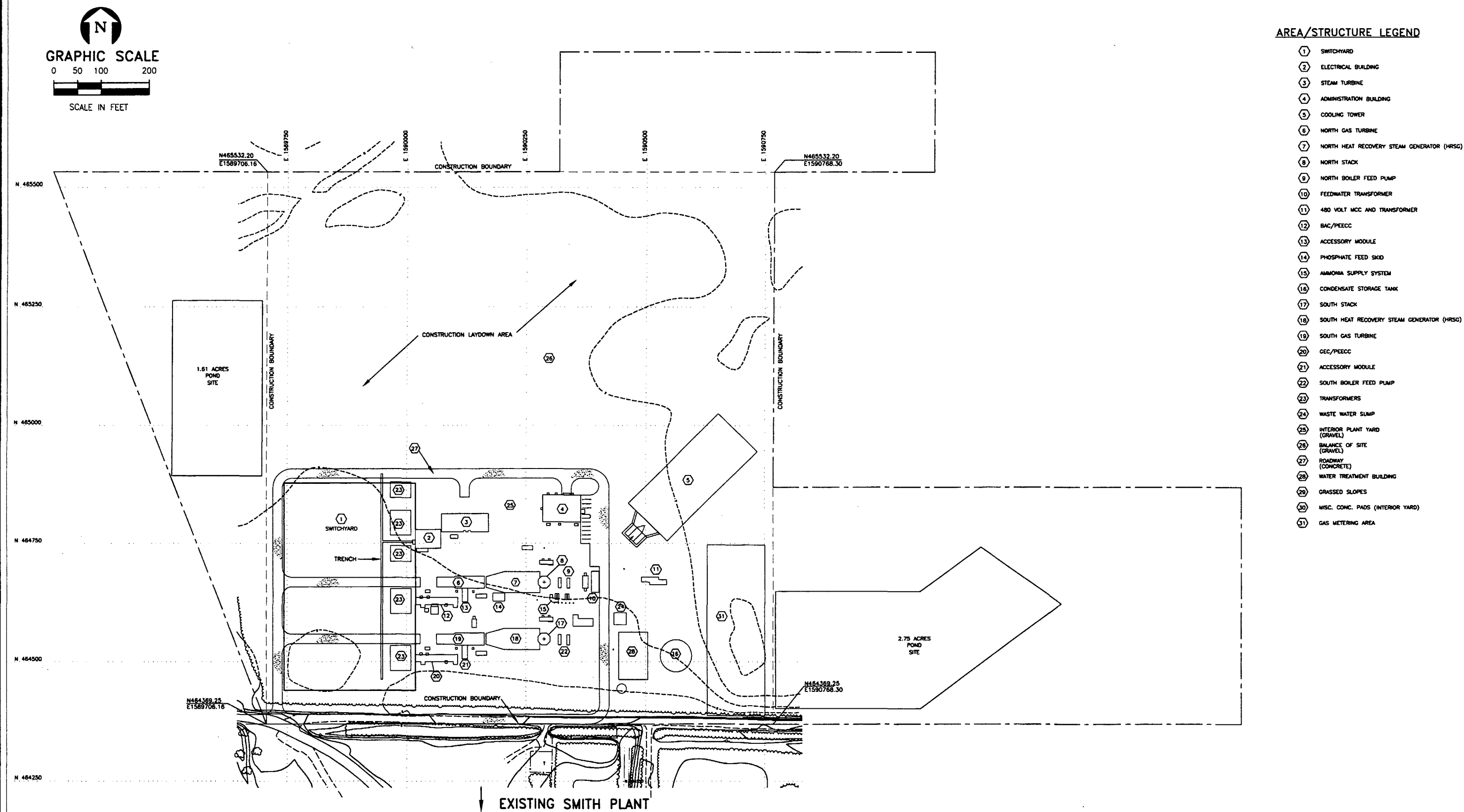


FIGURE 1.
PLOT PLAN

Sources: Gulf Power, 1999; ECT, 1999.

2. NEEDS AND JUSTIFICATION

Gulf Power Company has identified the proposed 50-acre parcel addressed by this application as the site for a new 540-megawatt (MW), natural gas-fired, "combined-cycle" electrical generating unit to be known as Smith Unit 3. The subject parcel is adjacent to Gulf Power Company's existing power plant consisting of Units 1 and 2 at the Lansing Smith Plant site, which have been in operation since the mid-1960s. Gulf Power Company currently operates 12 generating units in its service area between Pensacola, Florida and the Apalachicola River in Florida.

As part of its ongoing systemwide planning process, Gulf Power Company has determined its needs to construct and operate a new electrical power unit in the Bay County area in order to provide reliable and cost-effective electric service to the expected increase in new customers in Gulf Power Company's service area in the coming years. Gulf Power Company has recently filed a request with the Florida Public Service Commission for a determination that a need exists for the electricity to be supplied by this unit, and that the proposed Smith Unit 3 is the most cost-effective means to supply that electricity. The unit is needed to maintain an adequate reserve margin of electrical generating capacity within the Gulf Power Company service area beginning in the summer of 2002. The location of the unit in the Bay County area avoids the need to construct additional electrical transmission lines to tie the new unit into the Northwest Florida electrical transmission system because the new unit can be connected to the existing transmission lines serving the Lansing Smith plant site.

The new unit will utilize state-of-the-art electrical generating equipment, which is very efficient in its use of fuel. Air emissions will increase marginally. Total nitrogen oxide emissions will overall decrease from the combined Units 1, 2, and 3 as a result of the use of clean-burning natural gas and the installation of new emissions control systems on both the new unit and on the existing Smith Unit 1. The new unit will utilize a closed-cycle cooling system, which will minimize surface water withdrawals and discharges

while reducing overall impacts from warm water discharges from the combined Units 1, 2, and 3.

The new unit can utilize many of the existing facilities serving the Lansing Smith plant site in addition to the existing electrical transmission lines. The existing cooling water intake and discharge canal at the site will serve the new unit. Domestic and potable water facilities at the existing Lansing Smith plant site can serve the new unit. The existing site access road will be used and no offsite road improvements are needed for the unit and its 29 additional employees. The new unit will be a self-contained plant, making few demands on local public services.

The use of the proposed parcel, and its conversion from the current Agriculture to Industrial land use designation, represents a logical expansion of the site and its use for generating electricity. The site is immediately adjacent to the existing Gulf Power Company plant site, which is designated for Industrial uses. Other portions of the existing site are already committed to the existing electrical generating facilities or are not suitable for the proposed unit. The subject parcel allows connection of the new unit into existing facilities serving the site. Construction of this new unit at a different location would require the construction of new facilities that already exist at the Lansing Smith plant site. Therefore, the change in the FLUM designation from Agriculture to Industrial is entirely appropriate and justified.

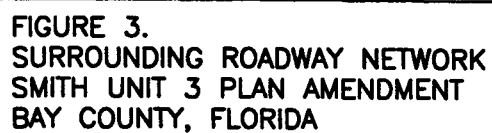
3. SITE DESCRIPTION

3.1 SITE LOCATION AND DESCRIPTION

The site of the proposed land use plan amendment is located on approximately 50 acres in Township 2 South Range 15 West Section 36 (Figure 1). The subject property is owned by Gulf Power Company. The site is located directly north of the existing Lansing Smith electric generating plant property and approximately 3,000 feet (ft) east of the southern terminus of County Road (CR) 2300 at the Lansing Smith plant entrance. The closest residential development is located approximately 2 miles to the northeast (western portion of unincorporated Southport). Figure 3 depicts the subject property's location relative to the surrounding street and thoroughfare network. The current land use designations of the subject property and abutting properties are depicted on Figure 4. The abutting properties are designated Agriculture to the east, west, and north and Industrial to the south (existing Lansing Smith plant). The property is currently planted in pine for silvicultural purposes as are the surrounding properties to the east, north, and west. The abutting property to the south is the existing site of Smith Units 1 and 2, both coal powered electrical generating units. The existing Lansing Smith unit occupies approximately 700 acres. Facilities at the existing site include Smith Units 1 and 2; coal storage and unloading area; ash pond; ash landfill; substation; and ancillary buildings.

3.2 ANALYSIS OF FACILITIES AND SERVICES

The proposed amendment area is a 50 ± acre tract located immediately north of the existing Lansing Smith plant (Units 1 and 2). The applicant, Gulf Power Company, intends to construct and operate a 540-MW combined cycle generating unit (Smith Unit 3) to be fueled by natural gas. The location of the proposed plan amendment area is adjacent to a power line transmission corridor to the west and to the existing power plant units to the south. The proposed Smith Unit 3 will share facilities with the existing units, including the discharge canal, water wells, domestic wastewater treatment plant, and transmission lines. Gulf Power Company is preparing a submittal under the Florida Electrical PPSA, known as a Site Certification Application (SCA), that will seek approval

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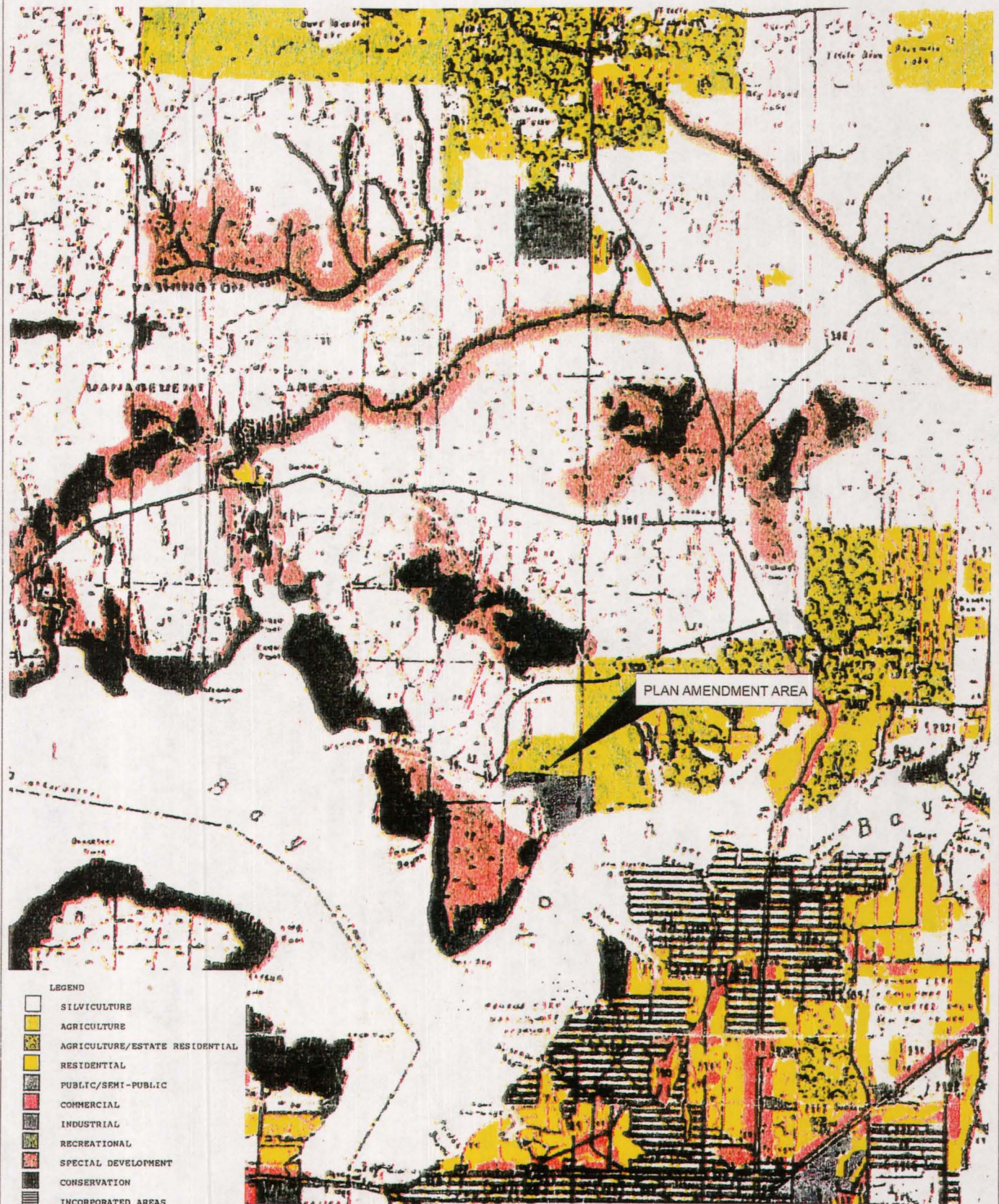


FIGURE 4.
LAND USE DESIGNATIONS
SMITH UNIT 3 PLAN AMENDMENT
BAY COUNTY, FLORIDA

Sources: Bay County Planning Dept., 1991; ECT, 1999.

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for the construction and operation of the proposed unit. The SCA will contain extensive data and analysis of the subject property and the proposed electrical generation facility. The SCA also is the primary process for permitting of the facility, including air permits, industrial wastewater permits, etc. Because of the specific nature of the proposed use of the plan amendment area, the following analysis of facilities and services and natural resources is based on the proposed development of a combined cycle electrical generating unit.

3.2.1 SANITARY SEWER

Domestic wastewater generated from the permanent employees at Smith Unit 3 will be routed to the existing wastewater treatment plant at the adjacent Lansing Smith plant. The estimated number of additional full-time employees is 29. The existing wastewater treatment plant has a maximum capacity of 3,000 gallons per day (gpd) and currently operates at an average of approximately 800 to 1,200 gpd. Based on the actual usage of the existing treatment plant, the total estimated domestic wastewater generation is estimated to be 377 gpd. Adequate domestic wastewater treatment service capacity is available to serve the proposed development. There will be no demand on public sewerage facilities.

3.2.2 POTABLE WATER

Potable water demand from the additional permanent employees at Smith Unit 3 will be supplied by permitted wells and an onsite potable water treatment system located at the Lansing Smith plant. Potable water is a portion of the overall total process water withdrawals and there is not a separate well used to meet potable water demand. The total permitted maximum withdrawal is 2,880,000 gpd and the permitted average daily withdrawal is 700,000 gpd. The 29 additional full-time employees are expected to require a maximum of 4,640 gpd. The average daily withdrawal from the permitted wells is currently approximately 500,000 to 600,000 gpd. Adequate potable water supply and treatment is available to serve the proposed development. There will be no demand on public potable water facilities.

3.2.3 SOLID WASTE

The estimated amount of solid waste to be generated per day by the 29 permanent employees at Smith Unit 3, based on the adopted per capita generation of 5.5 pounds, is 159.5 pounds. The solid waste currently generated by the existing Lansing Smith plant is transported by Waste Management to the Steelfield Landfill. Estimates by the Bay County Solid Waste Division indicate that at current landfilling rates, the landfill has an anticipated life that will last until 2032 and 80 percent capacity (the level of service [LOS] standard) will not be met until approximately 2022. The solid waste generated by the proposed plan amendment will have very limited impact on public solid waste disposal facilities.

3.2.4 DRAINAGE

The proposed plan amendment area includes area for storm water retention ponds. The size and location of the pond(s) will be addressed in the SCA. The pond(s) will be designed to meet or exceed the adopted LOS standard described in policies 1.2.3 and 1.2.4 of the drainage subelement of the Sanitary Sewer, Solid Waste, Drainage, Potable Water, and Natural Ground Water Aquifer Recharge Element of the adopted Comprehensive Plan. The Florida Department of Environmental Protection (FDEP) and the Bay County Engineering Division will review and approve the construction, design, and maintenance criteria of the drainage and storm water controls.

3.2.5 TRAFFIC CIRCULATION

All of the traffic to be generated by the proposed development will access and leave the project site from CR 2300. For a “worst-case” scenario, all of the expected new trips to be generated are assigned to the road segment from State Road (SR) 77/CR 2300 to the south approach to Bailey Bridge. The estimated number of new trips is based on an observed trip generation rate for power plants of 2.35 trips per employee. The proposed development will generate approximately 68 new daily trips. The existing, projected, and acceptable average daily traffic (ADT) and LOS are as follows:

SR 77	Existing ADT/LOS (1997)	Projected ADT/LOS (2002)	Acceptable ADT/LOS
CR 2300 South to Bailey Bridge	11,000 (B)	15,300(C) *	20,000(D)

*From CR 388 South to Bailey Bridge

The impact of the proposed amendment on the state and county road system will not degrade the existing LOS of B on this roadway segment. If the proposed Smith Unit 3 is approved, the plant is anticipated to be operational in June 2002. The anticipated ADT on SR 77 from south of CR 388 to Bailey Bridge in 2002 is approximately 15,300 and with the project traffic would be 15,368, well below the maximum acceptable LOS.

According to the Florida Department of Transportation (FDOT) District 3 personnel, the SR 77 segment from Bailey Bridge to CR 2300 is scheduled to begin project development and engineering (PD&E) studies in 2000 with right-of-way acquisition to also begin in 2000. The 4-laning of this road segment is scheduled to begin in 2005 (not in the current FDOT 5-year plan through 2004).

3.2.6 NATURAL GROUND WATER AQUIFER RECHARGE

The subject property is located within an area identified as "virtually no recharge potential" as identified by the Bay County Comprehensive Plan (Figure 5). In addition, the Northwest Florida Water Management District, as stated on page 6-63 of the adopted Comprehensive Plan, has not identified any areas in Bay County as prime ground water recharge areas. The Natural Ground Water Aquifer Recharge Element of the adopted Comprehensive Plan addresses only areas of the county with high recharge potential. The proposed project will not impact any high natural ground water aquifer recharge areas.

3.2.7 RECREATION AND OPEN SPACE

The proposed project site is not located in an area currently accessible to the public for recreation or open space opportunities. The proposed project will have no impact upon the demand for recreation and open space as it will not generate demand for such facilities nor will it reduce available recreational areas.

3.3 NATURAL RESOURCES

3.3.1 WATER WELLS AND CONES OF INFLUENCES

There are no existing water wells on the subject property. The closest water wells are located on the existing Lansing Smith plant property. Process and potable water for Smith Unit 3 will be provided from the four permitted wells. (Cooling water for the operation of the plant will be obtained from permitted surface water withdrawals). The proposed project will not adversely impact any public or private water wells.

3.3.2 BEACHES AND SHORES, INCLUDING ESTUARINE SYSTEMS

The subject property is not located on a beach or shoreline and is located approximately 1,500 ft north of Alligator Bayou and 1 mile north of North Bay. As shown on Figure 6, the property is located within the coastal zone. Figure 7 indicates that the subject property is not located in the Coastal High Hazard Area (CHHA) (defined as land lying within the Category 1 hurricane evacuation zone).

The proposed development of the plan amendment area is an electrical power generating unit, which is defined as a water-dependent use. In accordance with policy 1.8.2 of the Coastal Element of the 1990 Comprehensive Plan, water-dependent commercial/industrial uses are prioritized as follows:

1. Public use marinas;
2. Water-dependent utilities;
3. Water-dependent industries and docking facilities; and
4. Docks for water-dependent industry.

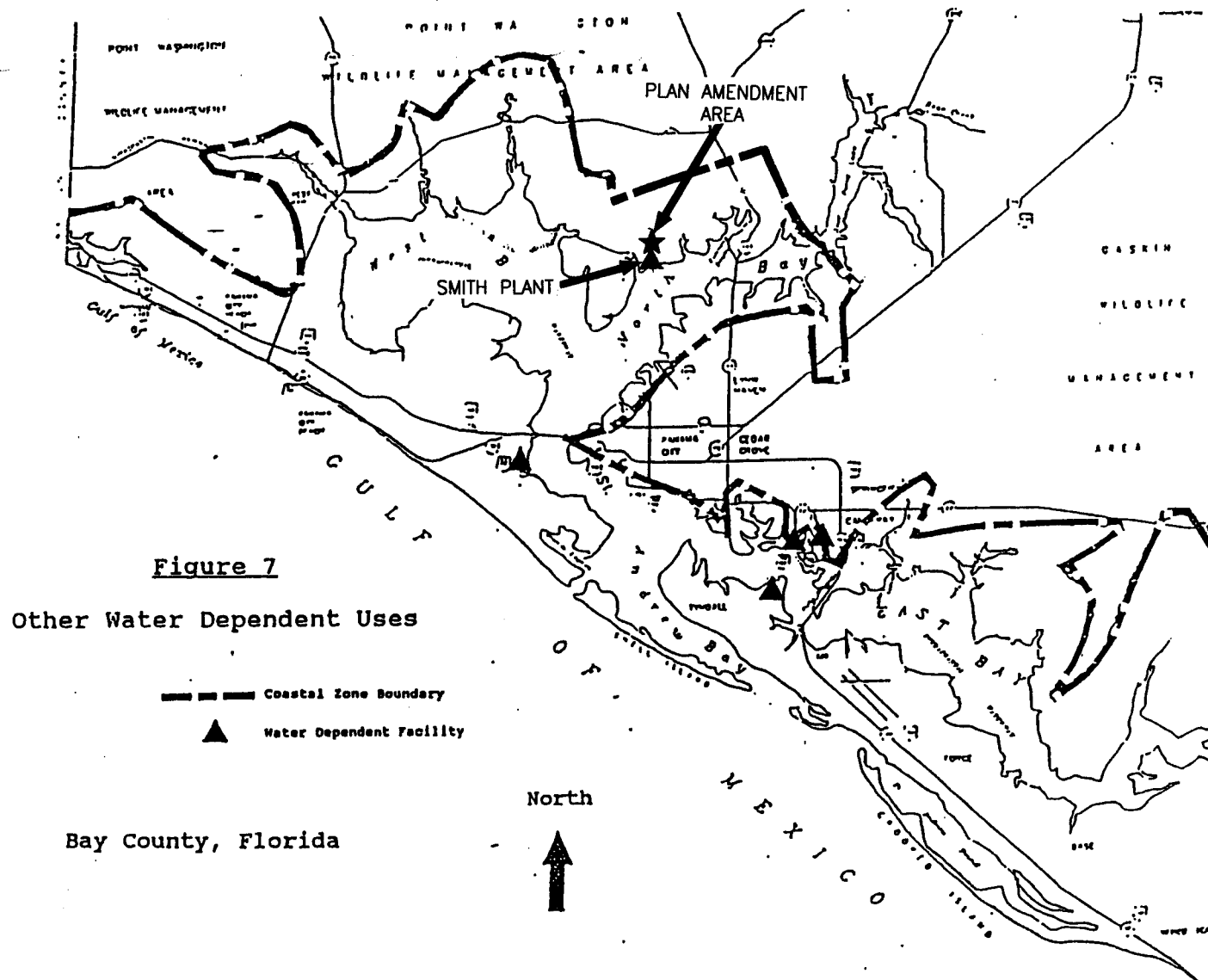


FIGURE 6.

COASTAL ZONE BOUNDARY
SMITH UNIT 3 PLAN AMENDMENT, BAY COUNTY

Source: Bay County 1990 Adopted Comprehensive Plan; ECT, 1999.

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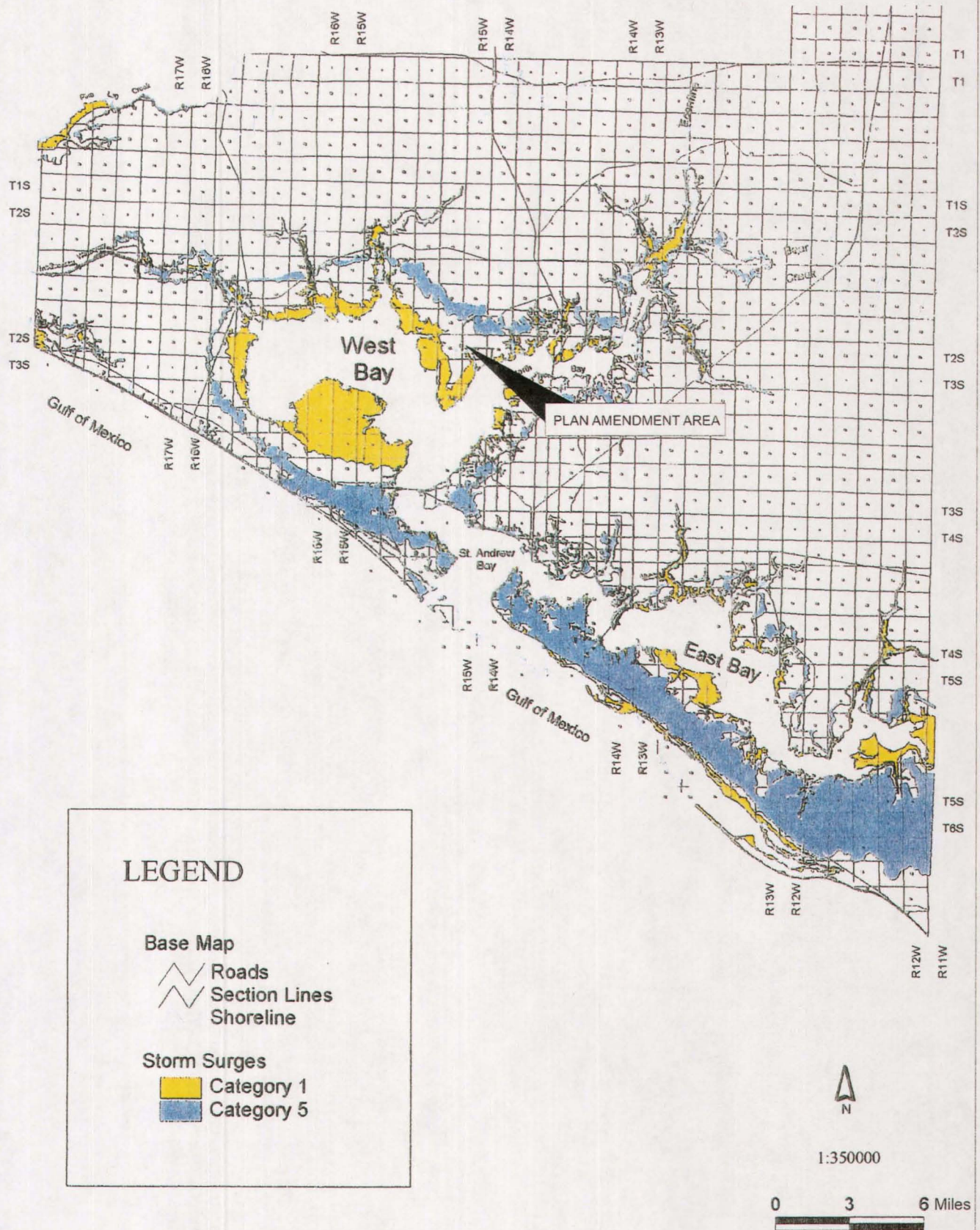


FIGURE 7.
COASTAL HIGH HAZARD AREA
SMITH UNIT 3 PLAN AMENDMENT
BAY COUNTY, FLORIDA

Sources: Bay County Comprehensive Plan, 1998; ECT, 1999.

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The proposed construction will not:

- Be built within unaltered natural habitats (the property is currently planted pine silviculture);
- Involve dredge and fill activities that disturb seagrass beds, oyster reefs, or other marine nursery areas (the nearest estuarine/marine habitat is 1,500 ft from the property);
- Discharge untreated storm water (storm water runoff will be treated in accordance with FDEP regulations);
- Involve the use of septic tanks (domestic wastewater will be treated at the existing Lansing Smith plant wastewater treatment plant);
- Impact primary dunes (there are no dunes on or within 1 mile of the proposed site);
- Involve shoreline land (the northern shore of North Bay is located approximately one mile south of the subject property); or
- Impact existing LOS for sanitary sewer, solid waste, drainage, potable water, and traffic below acceptable standards (see Section 3.2 of this report).

The operation of the unit will involve the diversion of approximately 7.5 million gallons per day (MGD) of the currently permitted 274 MGD surface water withdrawal for cooling water. After evaporation through the cooling tower, approximately 3.7 MGD will be returned to the existing discharge canal. The location of the new unit's discharge will be within the existing plant's discharge canal. Given the volume of the cooling tower blowdown (3.7 MGD) mixing with the permitted plant discharge volumes (274 MGD), the anticipated impacts to receiving water will be *de minimus*. Development of the proposed Smith Unit 3 will not adversely impact beaches, shorelines, or estuarine systems.

3.3.3 RIVER, BAYS, LAKES, FLOODPLAINS, AND HARBORS

The plan amendment area does not include any rivers, bays, lakes (surface water bodies), or harbors. As shown in Figure 8, the subject property lies completely within Flood Zone C, defined as areas of minimal flooding. The closest surface water body is Alligator

IMAGE QUALITY

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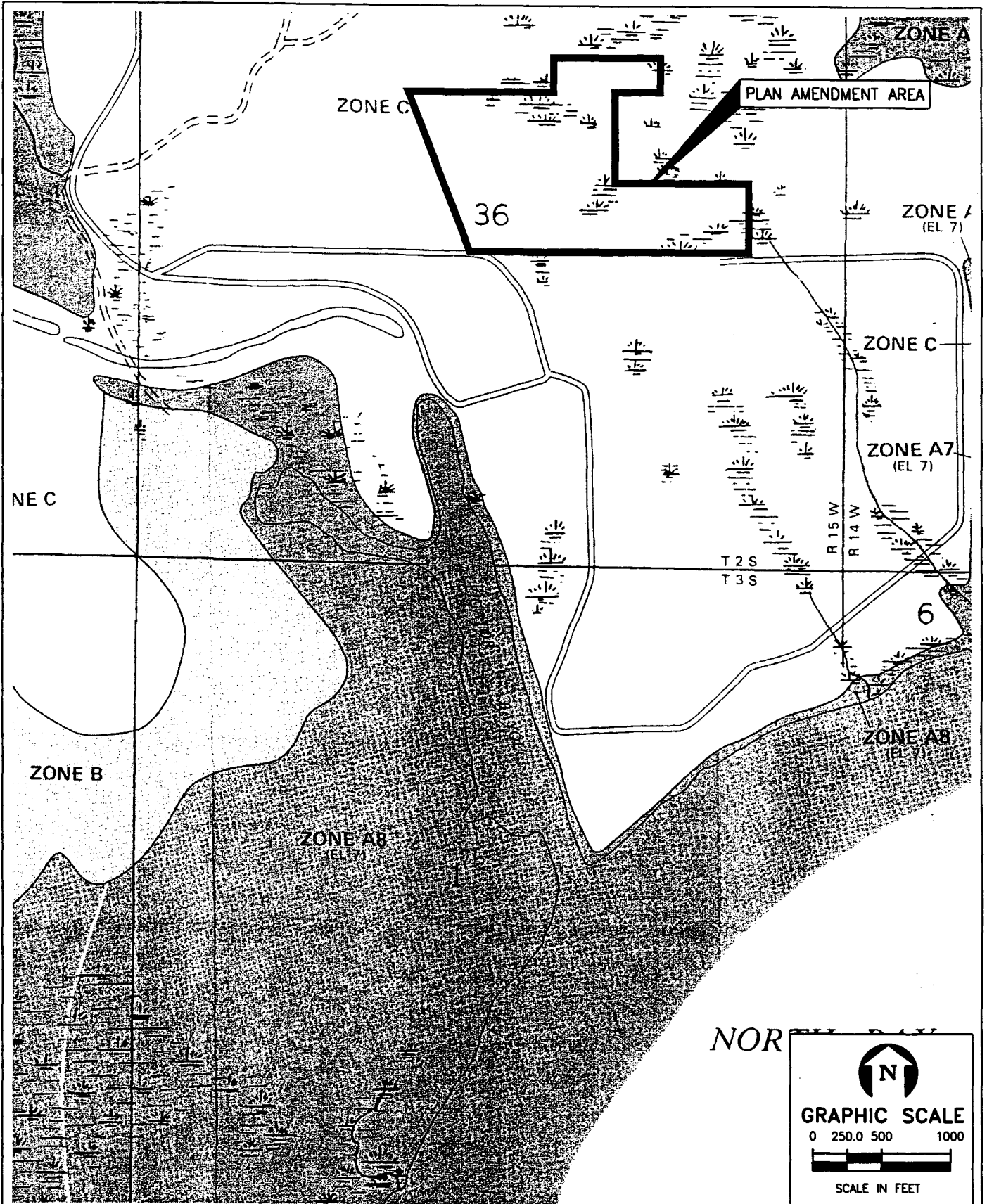


FIGURE 8.
FLOODPLAINS MAP
SMITH UNIT 3 PLAN AMENDMENT
BAY COUNTY, FLORIDA

Sources: Federal Emergency Management Agency: ECT, 1999.

Bayou, located approximately 1,500 ft to the south; and the closest bay is North Bay, located approximately 1 mile to the south. There will be no direct construction impacts to surface water bodies or North Bay. All storm water runoff will be treated to applicable FDEP regulations, domestic wastewater will be treated at the existing wastewater treatment plant, and cooling water will be thoroughly mixed with the existing discharge from Smith Units 1 and 2.

3.3.4 WETLANDS

The applicant has initiated a delineation of the wetland limits on the subject property. A qualified wetlands biologist has conducted a preliminary jurisdictional delineation of the landward extent of onsite jurisdictional wetlands by evaluating the wetland/upland vegetation, the hydrology, and the extent of hydric soils. A formal jurisdictional delineation with FDEP personnel will be completed prior to the submittal of the SCA. Figure 9 depicts the results of the initial wetland delineation, indicating approximately 12.1 acres within the portion of the site to be occupied by power generation facilities.

Gulf Power Company will prepare a dredge and fill permit application as part of the PPSA SCA. The dredge and fill application will contain a description of efforts to minimize wetland impacts and, where wetland acreage will be impacted, a mitigation plan will be proposed. Suitable lands will be identified for preservation, enhancement, and/or creation.

3.3.5 MINERALS

The 1990 adopted Conservation Element of the Comprehensive Plan indicates that large-scale development of mineral commodities has not occurred in Bay County. Figure 10 depicts the general location of mining sites in Bay County as of April 1990. No mining sites or commercially significant mineral deposits are depicted or known to occur near the subject property.

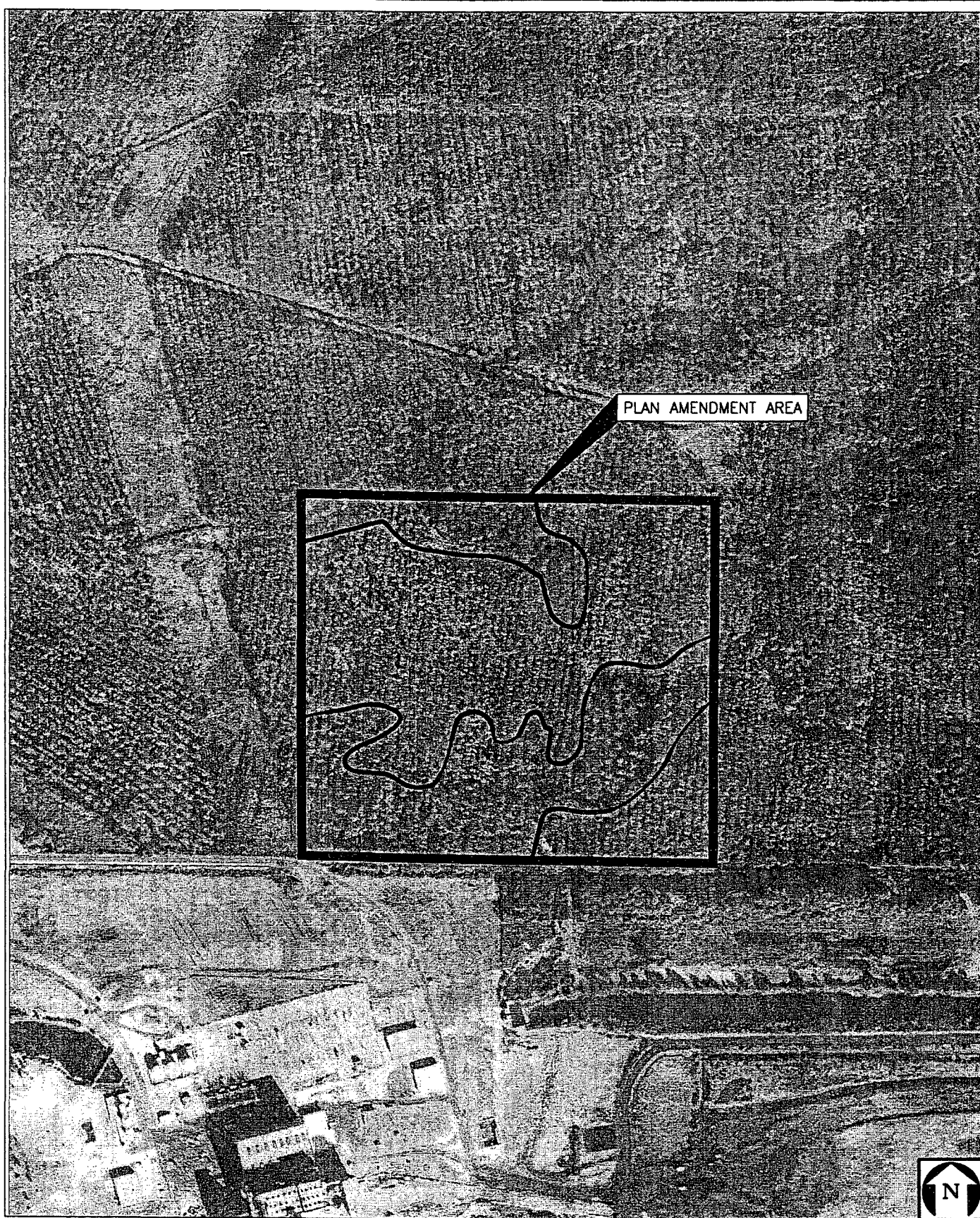


FIGURE 9.
PRELIMINARY WETLAND BOUNDARIES
SMITH UNIT 3 PLAN AMENDMENT
BAY COUNTY, FLORIDA

Sources: Bay County Aerial Photograph, FL., 1997; ECT, 1999.

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Figure 11
Location of Mines

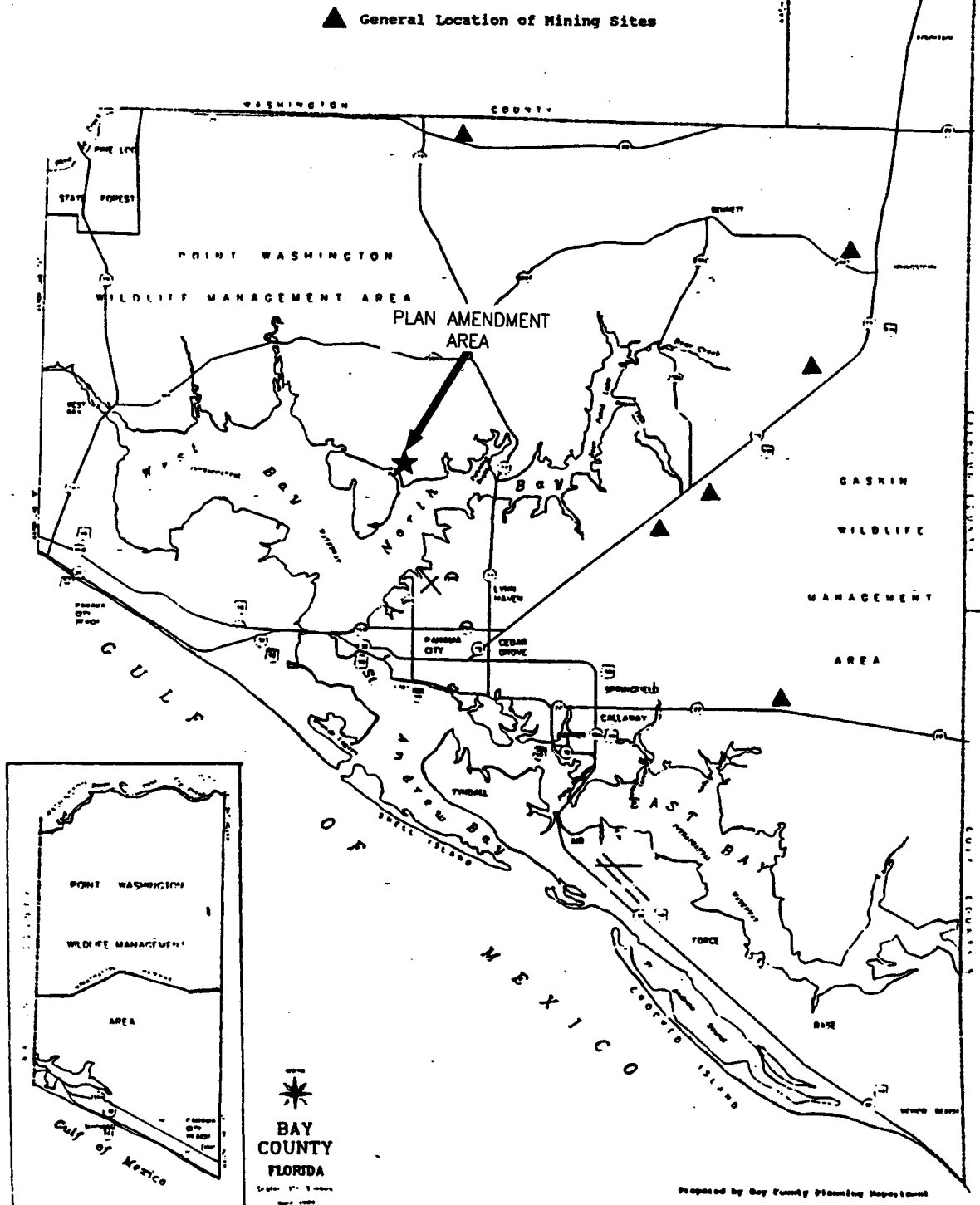


FIGURE 10.
MINING SITES
SMITH UNIT 3 PLAN AMENDMENT, BAY COUNTY

Source: Bay County 1990 Adopted Comprehensive Plan; ECT, 1999.

3.3.6 SOILS

Figure 11 is a portion of Sheet 37 of the Soil Survey of Bay County, US Geological Survey, 1984. The soil types underlying the subject property are Leon sand, Rutlege sand, and Pottsburg sand. The majority of the property is underlain by Leon sand. Limitations on development, as described in Tables 3, 10, and 11 of the soil survey are as follows:

Limitation	Leon Sand	Rutlege Sand	Pottsburg Sand
Building sites	Severe wetness	Severe wetness, Severe flooding	Severe wetness
Roads	Severe wetness	Severe ponding	Severe wetness
Shallow excavations	Severe cutbanks cave, Severe wetness	Severe cutbanks cave, Severe ponding	Severe cutbanks cave, Severe wetness

The development of Smith Unit 3 will require raising the elevation of the site to approximately match the elevation of the existing Lansing Smith plant. The backfill material brought in to raise the elevation of the site will overcome the limitations of the native soils. No septic tanks will be installed to serve the proposed development.

3.3.7 TOPOGRAPHY

Figure 1 is a portion of the USGS 7.5 minute, Southport quadrangle map. The elevations onsite and in the surrounding area are nearly level at approximately 5 ft above mean sea level. The existing topography will not present a limitation to the proposed development of the subject property.

3.3.8 NATURAL RESOURCES

The subject property supports a North Florida pine flatwoods terrestrial community (Figure 12). This community, in Bay County in general, and the subject property specifically, have been extensively logged, resulting in a low diversity of plants and a limited amount and diversity of wildlife. The planted slash pines on the subject property

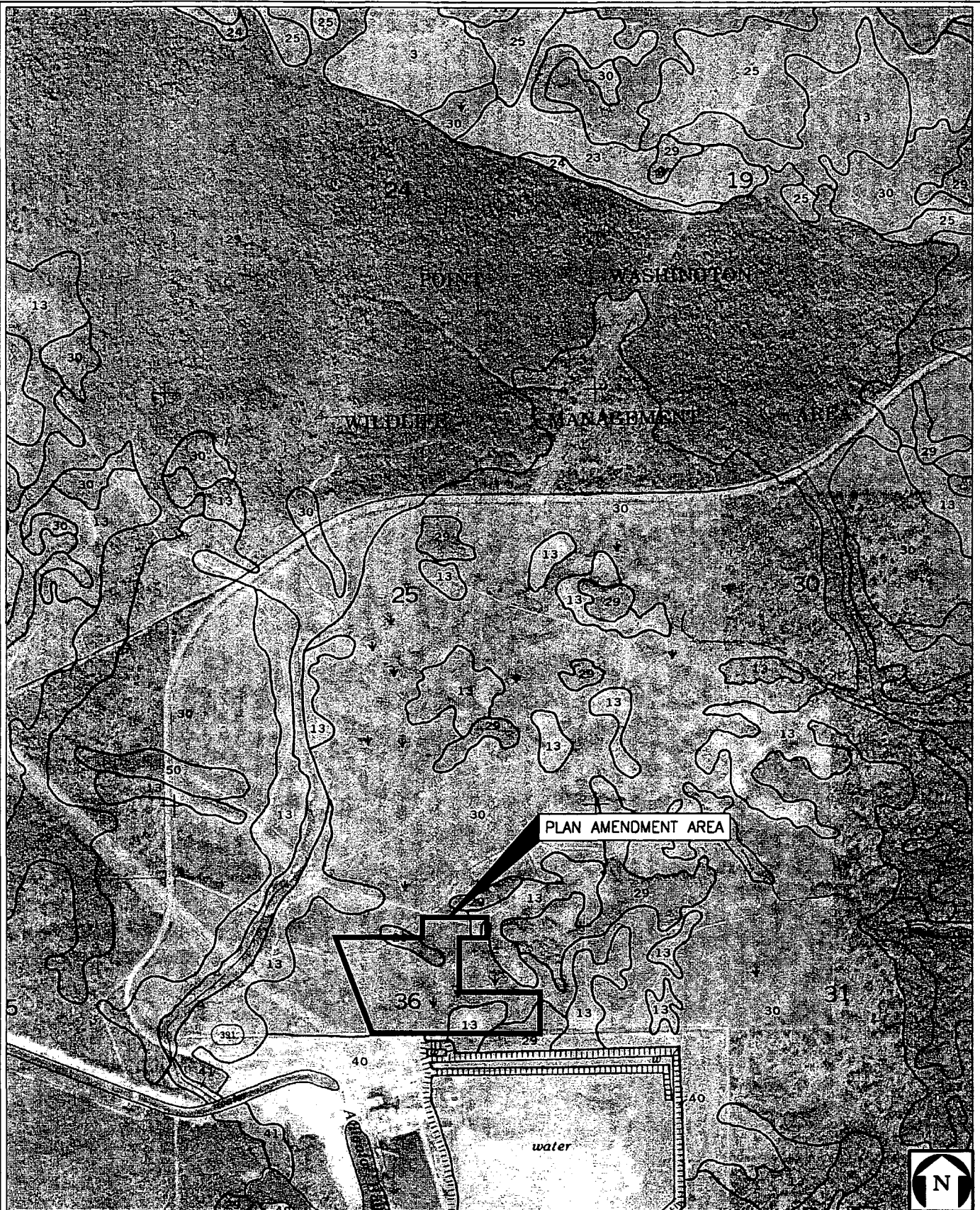


FIGURE 11.
BAY COUNTY SOIL SURVEY
SMITH UNIT 3 PLAN AMENDMENT
BAY COUNTY, FLORIDA

Sources: Bay County Soil Survey, USGS 1984; ECT, 1999.

Figure 9

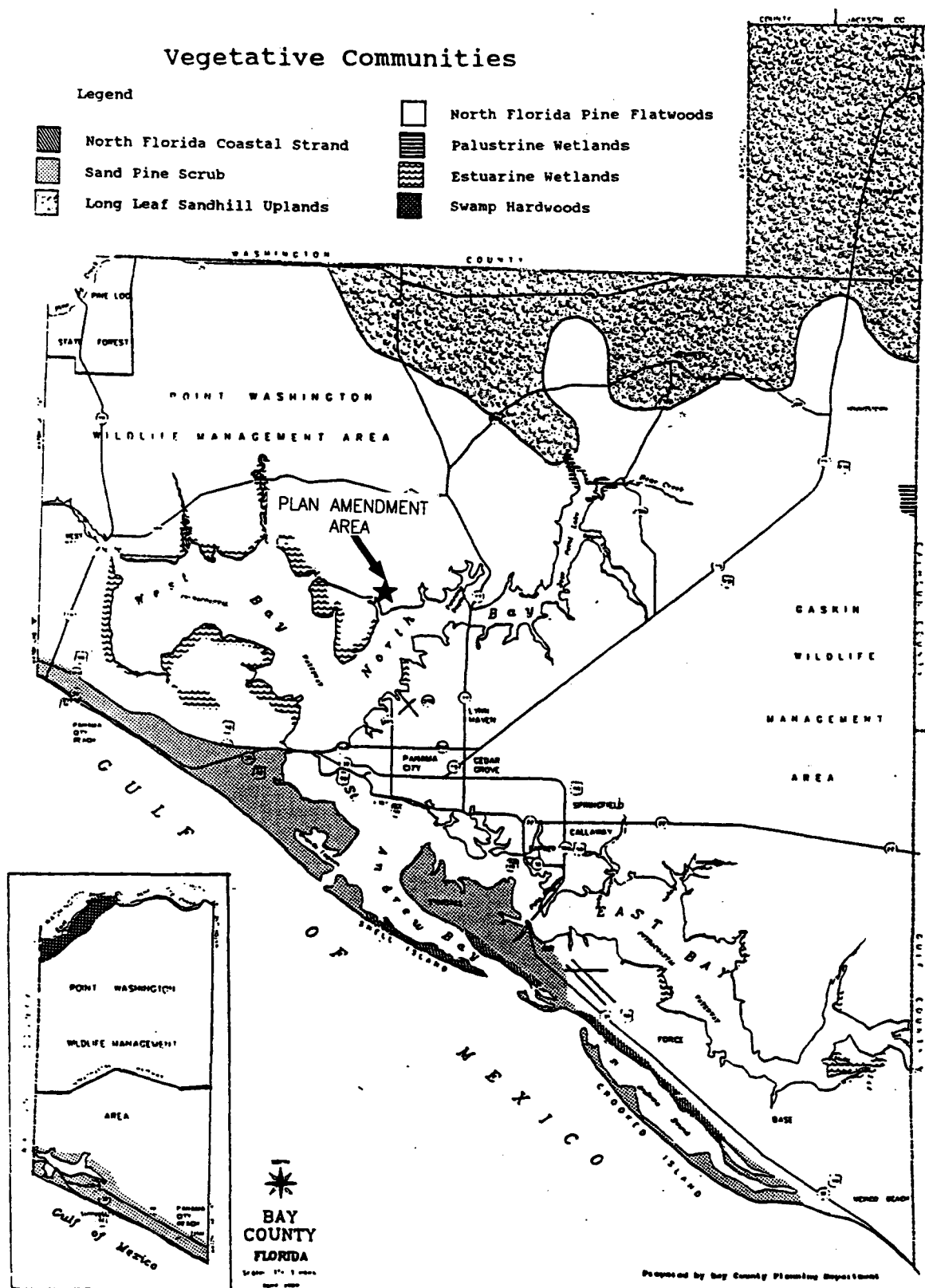


FIGURE 12.
VEGETATIVE COMMUNITIES
SMITH UNIT 3 PLAN AMENDMENT, BAY COUNTY

Source: Bay County 1990 Adopted Comprehensive Plan; ECT, 1999.

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are approximately 20 years old, as indicated on Figure 11, depicting the onsite soil types, which is based on 1978 aerial photography and which depicts the subject property and surrounding area as cleared of trees, at that time.

Figure 1 of the Conservation Element (provided as Figure 13) indicates that the subject property has not been identified as a major fish or wildlife habitat and Figure 2 of the Conservation Element (provided as Figure 14) indicates that no critical habitat areas are located on or near the property. The Strategic Regional Policy Plan (SRPP) prepared by the West Florida Regional Planning Council contains graphic locations of significant regional natural resources, including:

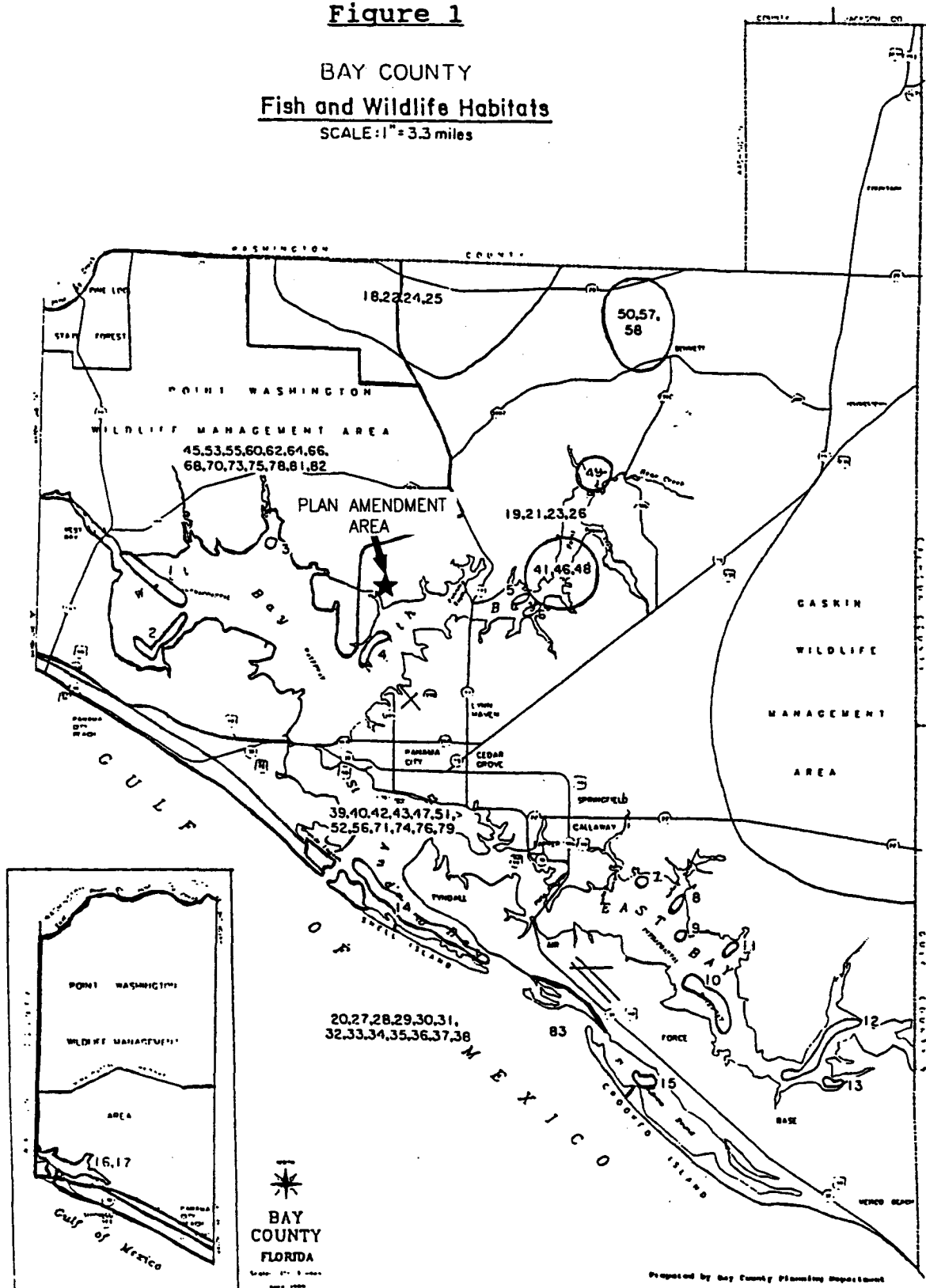
- Water resources;
- Planning and management areas;
- Wetlands;
- Significant transportation facilities;
- Natural systems (natural communities);
- Natural systems (locations of endangered, threatened, special concern and rare species of plants and animals and significant wildlife aggregation areas); and
- Strategic habitat conservation areas.

A set of these graphics is provided as Appendix A. The natural resources involvement of the subject property is identified only on the wetlands graphic. The involvement of the proposed development with wetlands is described in Section 3.4.4 of this report.

The February 1998 Draft Comprehensive Plan does indicate that the subject property is located in the proposed North Bay Ecological Management Area (EMA) and within a proposed Conservation Zone (Appendix A). EMAs are considered "Special Treatment Zones" in which extraordinary regulatory standards may be applied to protect natural resources. The proposed Conservation designation is intended to provide for conservation with appropriate use through regulations that will minimize damage to natural resources. As discussed in this section, wetlands are the only identified onsite natural resource. Wetland involvement will be minimized to the extent practicable and mitigation will be provided for unavoidable wetland impact.

Figure 1

BAY COUNTY
Fish and Wildlife Habitats
 SCALE: 1" = 3.3 miles

**FIGURE 13.**

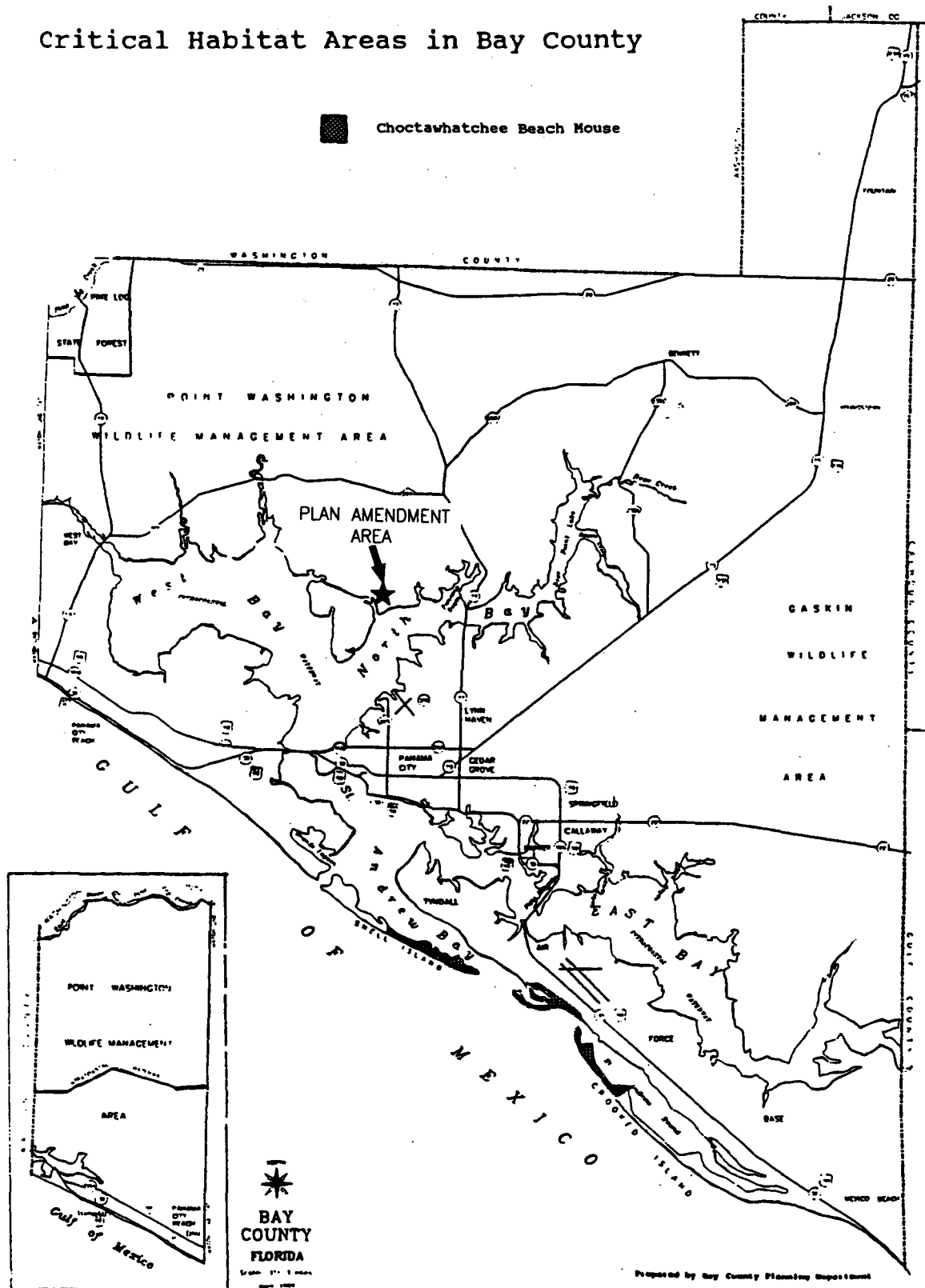
MAJOR FISH AND WILDLIFE HABITATS
SMITH UNIT 3 PLAN AMENDMENT, BAY COUNTY

Source: Bay County 1990 Adopted Comprehensive Plan; ECT, 1999.

3-20

ECT

Environmental Consulting & Technology, Inc.

Figure 2**Critical Habitat Areas in Bay County****FIGURE 14.****CRITICAL HABITAT AREAS
SMITH UNIT 3 PLAN AMENDMENT, BAY COUNTY**

Source: Bay County 1990 Adopted Comprehensive Plan; ECT, 1999.

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3.3.9 HISTORIC RESOURCES

A letter has been submitted to the State Historic Preservation Officer (SHPO) for a site-specific review of the State Division of Historic Resources Florida Master Site File for archaeological and historic resources. Figure 3 from the Future Land Use Element 1990 adopted Comprehensive Plan (provided as Figure 15) is a depiction of the generalized location of historic resources in Bay County. This figure indicates that historic resources may be located offsite near the property to the south. If required by the results of the Master Site File review, a site-specific survey of the potential for historical and archaeological resources will be undertaken. Since the subject site has been logged and replanted in pine, it is unlikely that significant historical and archaeological resources remain onsite.

3.3.10 DEER POINT LAKE WATERSHED

The proposed plan amendment area is not located within the Deer Point Lake watershed as depicted on Figure 16. The subject property is located approximately 5.5 miles southwest of the nearest boundary of the watershed. The subject property is not included in the Deer Point Lake watershed or protection zone and is located downgradient of all tributaries to the watershed.

Figure 3
Generalized Location of
Historic Resources
In Bay County

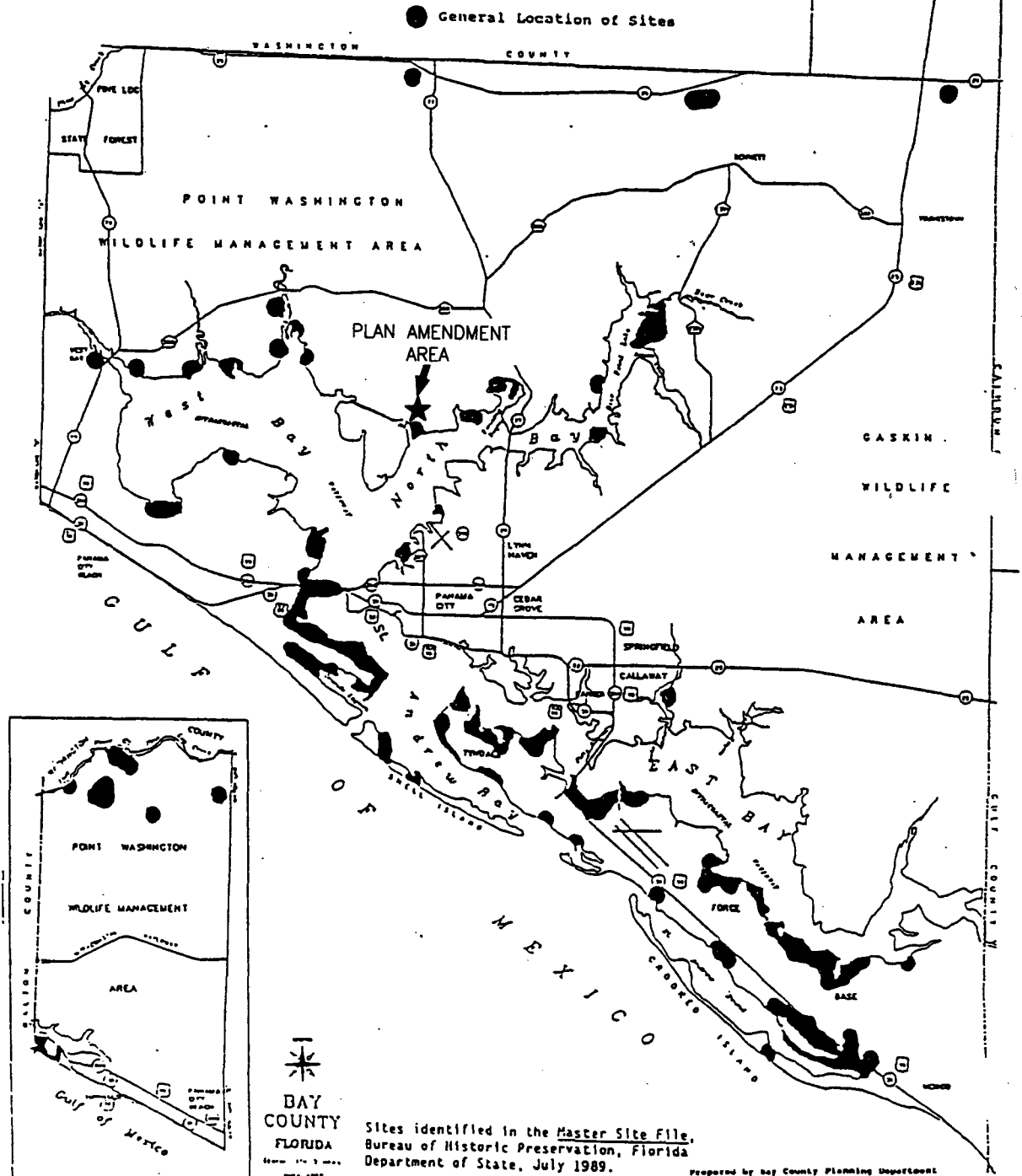


FIGURE 15.
HISTORIC RESOURCES
SMITH UNIT 3 PLAN AMENDMENT, BAY COUNTY

Source: Bay County 1990 Adopted Comprehensive Plan; ECT, 1999. 3-23

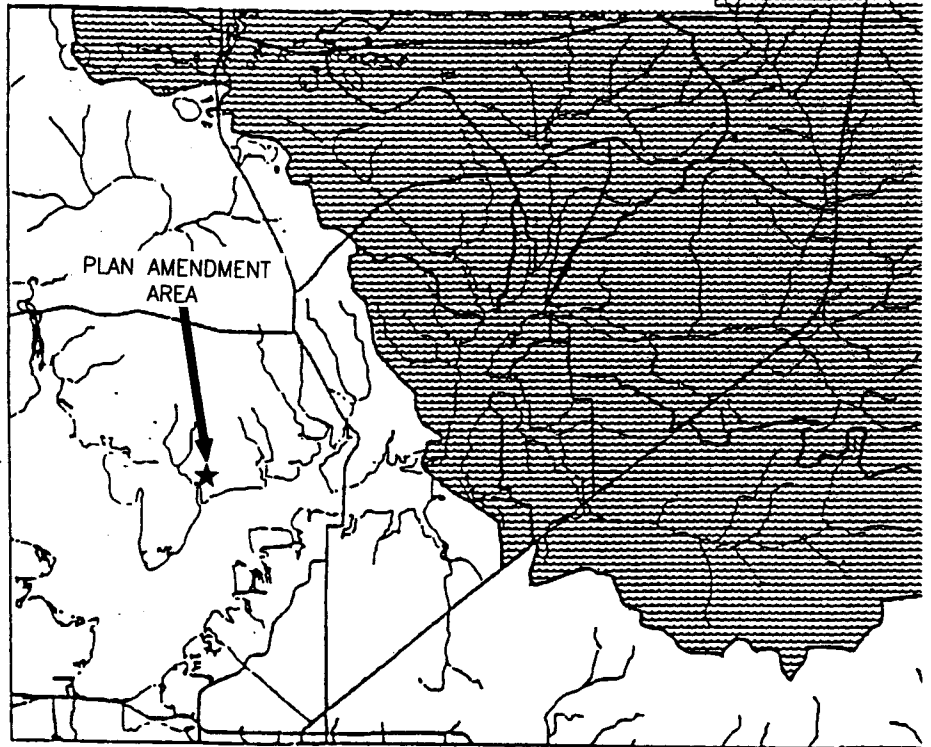
ECT
Environmental Consulting & Technology, Inc.

Figure 16

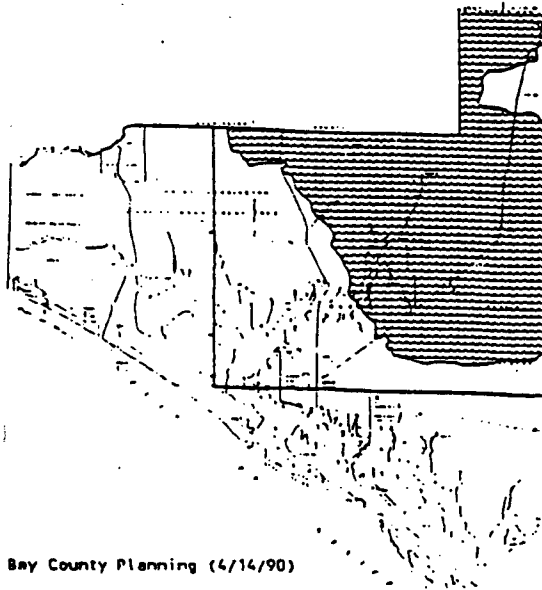
DEER POINT LAKE WATERSHED



Watershed Area



Scale 1" = 4 miles



Bay County Planning (4/14/90)

Prepared by HFWHD and the Bay County Planning Department
May 1990

1-55

FIGURE 16.

DEER POINT LAKE WATERSHED
SMITH UNIT 3 PLAN AMENDMENT, BAY COUNTY 3-24

Source: Bay County 1990 Adopted Comprehensive Plan; ECT, 1999.

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4. ANALYSIS OF SUITABILITY FOR PROPOSED USE

4.1 GROSS LAND AREA

The subject property is currently undeveloped and planted in pine for silvicultural purposes. Development of the property would remove 50 acres from the county's inventory of silvicultural land. According to Table 19 in the Future Land Use Element of the adopted 1990 Comprehensive Plan, the total existing silvicultural acreage in 1990 was 259,426, representing 55 percent of Bay County's land utilization, and no additional acreage was shown as being needed in 1995 or 2000. According to the same table, 813 acres were identified as industrial use in 1990 (0.18 percent of Bay County's land utilization) with a need for 195 additional acres by 1995 and 242 additional acres between 1995 and 2000.

The projected need for additional industrial acreage was based on the Bay County Chamber of Commerce's efforts to promote Bay County as an attractive location for new industry in order to help combat high unemployment rates experienced in the 1980s. With county government participation, the coordinated public/private sector activity has been successful in attracting new industry. The future (1995 and 2000) industrial acreage requirement of 437 was based on the assumptions that firms seeking industrially designated land will be distributed within the county in much the same pattern as has existed in the past and that acreage requirements for industrial firms will not significantly change. The expansion of the Lansing Smith plant was not foreseen in 1990, although the expansion of the plant is consistent with the assumptions and expectations for additional industrial land uses within the adopted Future Land Use Element (similar pattern of distribution and acreage requirements).

4.2 SOILS

The existing soil types and their limitations are described in Section 3.3.6. In order to develop the proposed combined cycle electrical generating unit, the elevation of the property will be raised approximately to the elevation of the existing Lansing Smith plant site. The plant structures and generating units will be built on backfill. The use of backfill will overcome the limitation of native soils.

4.3 TOPOGRAPHY

The current site is nearly level as described in Section 3.3.7. As described in Section 4.2, the proposed development will require raising the existing elevation from the present elevation to approximately match the level of the existing plant site. The rise in elevation is required to minimize the likelihood of damage from storms and to provide a stable foundation for the new unit's facilities. There are no known topographic conditions, such as sinks, that would limit development of the proposed project.

4.4 NATURAL RESOURCES

Section 3.3.8 contains a discussion of the onsite natural resources. The discussion indicates that wetlands are the only natural resource currently identified onsite or anticipated to be onsite as a result of the current and historic silvicultural activity on the subject property and within the surrounding area. A preliminary jurisdictional delineation has identified approximately 12.1 acres of FDEP jurisdictional wetlands within the area proposed for electrical generating facilities. Where practicable, impact to existing wetland areas will be avoided or minimized. Where impacts are unavoidable, the loss of wetland acreage will be mitigated through preservation, enhancement, and/or creation.

4.5 HISTORIC RESOURCES

The applicant is awaiting a response from the SHPO regarding a site-specific review of the Florida Master Site File for the presence of archaeological and historic resources. If required, a survey of the property will be conducted to evaluate the presence/absence of significant archaeological/historical resources. It is not expected that any such sites will be identified since the subject property has been disturbed and replanted.

5. ANALYSIS OF NEED FOR REDEVELOPMENT

The need for redevelopment of areas of the county is described within the Future Land Use Element of the adopted 1990 Comprehensive Plan. The areas of substandard housing were identified as the target of redevelopment. Redevelopment needs can also be indicated by the presence of nonconforming land uses. The subject property has not been identified as an area in need of redevelopment nor are there existing nonconforming land uses in proximity to the subject property.

6. ANALYSIS OF FLOOD-PRONE AREAS

The subject property is located entirely in Flood Zone C, defined as an area of minimal flooding, as shown on Flood Insurance Rate Map, Panel Number 120004 0215, as published by the Federal Emergency Management Agency (Figure 8). The proposed plan amendment area is located within the coastal zone as shown on Figure 6, although the site is not located within the CHHA. In order to minimize the likelihood of damage from coastal flooding, the existing elevation of the subject property will be raised to approximately match that of the existing Lansing Smith plant site.

7. COMPATIBILITY WITH SURROUNDING LAND USES AND THE COMPREHENSIVE PLAN

7.1 COMPATIBILITY WITH SURROUNDING LAND USES

The proposed plan amendment to the FLUM is a change from the existing "Agriculture" designation to "Industrial". An "Industrial" land use designation is located immediately south of the subject property where the existing Lansing Smith plant is located. To the east, north and west, the existing land use designation on the FLUM is "Agriculture". Except for the existing Lansing Smith plant, the surrounding area is used for silvicultural activity. No residential development is located within two miles of the proposed plan amendment area. The proposed development of the subject property is an expansion of the electrical power generating capacity of the Lansing Smith plant through the addition of Unit 3. The presence of the existing plant was part of the pattern for industrial development at the adoption of the Comprehensive Plan. The projected need for additional industrial acreage was based on the assumption of a similar future pattern of industrial development with similar acreage requirements for industrial entities. The proposed development of Smith Unit 3 is consistent with this assumption. The development of additional electrical generating capacity at the proposed site is a logical location for sharing available, existing infrastructure and as the location for meeting the projected additional acreage for industrial use. Due to the unoccupied nature of the surrounding "Agriculture" land use designation and the abundance of land used for silviculture (no additional acreage is projected to be required), the proposed change in land use to "Industrial" is compatible with existing development patterns.

7.2 COMPATIBILITY WITH THE 1990 ADOPTED COMPREHENSIVE PLAN

Future Land Use Element

Goal	1	Provide for economic growth and development while maintaining adopted levels of services (LOS) and providing protection for the environment.
Objective	1.1	All new and existing land uses shall be adequately served by facilities and service at the LOS established in the Comprehensive Plan.

Policy 1.1.1 All development orders shall be conditioned upon the availability of public service facilities at the adopted LOS.

The proposed development of the plan amendment area is not expected to require upgrades or improvements to existing public services or facilities. The proposed Smith Unit 3 will utilize non-public sanitary sewer and potable water infrastructure already available or permitted for the existing Lansing Smith plant. The number of full-time employees at Smith Unit 3 will not generate vehicle trips or solid waste that would adversely impact existing facilities. Drainage facilities to address water quality and water quantity requirements will be provided onsite. The project will not increase the demand for parks or recreation lands.

Objective 1.2 Ensure the availability of suitable land for utility facilities necessary to support proposed development by designating 3000 acres in land use categories on the FLUM on which utility facilities may be located.

Policy 1.2.3 Region-serving facilities shall be located in areas designated as "industrial" or "public/semi-public" on the FLUM.

Smith Unit 3 is being proposed for construction in order to provide reliable electric service to the expected increase in new customers within the service area of the Gulf Power Company. Smith Unit 3 will be a region-serving facility. Since the existing Lansing Smith plant with Units Nos. 1 and 2 is designated Industrial on the FLUM, it is logical that Smith Unit 3 would be designated as Industrial.

Objective 1.7 By 1995, achieve an increase in employment as compared to 1985 levels.

Policy 1.7.1 The County shall prepare an Economic Element for this Plan by 1991, which shall include an economic analysis of the county in order to determine additional commercial and industrial land requirements.

Please refer to comments contained in the economic element (p.7-14).

Goal 2 Identify and protect the archaeological and historic resources of Bay County, including structures of architectural significance.

Objective 2.2 By 1992, Bay County shall develop and implement procedures for protection of historically and archaeologically significant sites and structures within its jurisdiction.

Policy 2.2.5 Coordinate with review and compliance procedures for environment altering projects, such as Developments of Regional Impact, to identify and protect historical and archaeological resources.

The applicant has submitted a letter to the SHPO requesting a review of the Florida Master Site File. In the event that a site-specific survey is recommended, such a survey will be conducted to identify any significant historical or archaeological resources. The disturbed and replanted nature of the subject property suggests that significant archaeological or historical resources will not be found onsite.

Goal 3 Protect and conserve Bay County's natural resources as described in Bay County's Comprehensive Growth Management Plan.

Objective 3.1 Provide a framework for protecting Bay County's natural resources form negative consequences of growth and development meeting the standards in this Plan.

Policy 3.1.2 Develop and implement a process for land development permitting to ensure that all required state and land permits are applied for and received prior to start of construction.

The proposed development of the plan amendment area requires review through the Florida Electrical PPSA. Both the planning and permitting requirements for the electrical power generating unit will be thoroughly reviewed by federal, state, and local agencies. All permits will be approved prior to the initiation of construction.

Objective 3.2 Land development regulations adopted in 1990 will include restrictions for development in areas of steep-sided sinks or other topographical constraints and areas with soils that have limitations for development.

Policy 3.2.1 Development permit applications for sites in areas identified on the soils map included as part of the FLUM series as belonging to a soil association that poses moderate to severe limitations to development shall provide a detailed soils analysis that indicates the soils suitability for use of septic tanks and absorption fields and building and road construction. Development shall be clustered on portions of the site posing the fewest restrictions and specific construction considerations, based on the requirements of the soils found on the site, shall be utilized.

- Policy 3.2.3** **Coordinate with the Soil Conservation Service to consider soil and topographic suitability of land when developing land use ordinances and when reviewing request for variances of adopted land use ordinance.**

The proposed development of the plan amendment area will not be undertaken until sufficient geotechnical investigations are conducted to provide information for site design. It is anticipated that backfill will be added to portions of the subject property to an elevation similar to that of the existing Lansing Smith plant. There are no known topographical constraints to development of the subject site and the addition of fill will overcome the limitations of the native soils. No septic tanks will be installed to serve the proposed development.

Traffic Circulation Element

- Goal 1** **Provide a safe and efficient transportation system to accommodate current and future land use patterns and to maintain adopted traffic circulation LOS standards.**
- Objective 1.1** **Maintain the LOS standards contained in Policy 1.1.1.**
- Policy 1.1.1** **The following peak hour minimum acceptable operating LOS standards are adopted for the Bay County road system, consistent with the Florida Department of Transportation (FDOT) policy.**

Peak Hour LOS Standards

Roadway Type	Transportation Planning Areas		
	Existing Urbanized Areas	Transitioning Urbanized Areas	Rural Areas
Principal arterials	D	C	C
Minor arterial and other	E	D	D

The proposed Smith Unit 3 traffic generated by 29 full-time employees, 18 on the day shift, will access the property from County Road (CR) 2300. This road provides access and egress to the Lansing Smith plant, to a branch of the Gulf Coast Community College, and to several residences. It is not anticipated that the additional traffic generated by the operation of Smith Unit 3 will result in unacceptable LOS standards on CR 2300 or SR 77. Both roads currently operate at an acceptable LOS.

SANITARY SEWER SUBELEMENT

- | | | |
|------------------|--------------|---|
| Goal | 1 | Sanitary sewer facilities shall be provided in a manner that protects ground and surface water quality and promotes orderly and compact growth. |
| Objective | 1.2 | Sanitary sewer facilities shall not be provided outside of the existing and potential service areas... |
| Policy | 1.2.5 | By 1990, land development regulations will include provisions for adequate operation and maintenance of package plants consistent with the requirements of Chapter 17-6, Florida Administrative Code (F.A.C.). |

The proposed development of the plan amendment area will utilize the existing, permitted domestic wastewater treatment plant at the Lansing Smith plant to treat the domestic wastewater generated by the additional employees. The existing treatment plant is in compliance with the provisions of Chapter 62-600, F.A.C. (formerly Chapter 17-6, F.A.C.).

DRAINAGE SUBELEMENT

- | | | |
|---------------|--------------|--|
| Goal | 1 | Provide adequate storm water management including reasonable protection from flooding, protection of the quality of receiving waters, and protection of investments in existing facilities. |
| Policy | 1.2.3 | The county hereby adopts a minimum countywide water quality LOS standard. |
| Policy | 1.2.4 | The county hereby adopts a minimum countywide water quality LOS standard. |
| Policy | 1.2.5 | No approvals for development shall be issued for new development, which would not comply with the adopted LOS. |

Development of the plan amendment area will include the provision of onsite drainage ponds that will provide both storm water runoff water quality treatment and water quantity storage/retention. The onsite drainage facilities will meet adopted LOS standards, including the water quality standards.

- | | | |
|------------------|------------|---|
| Objective | 1.3 | By 1991, storm water management regulations will be incorporated into the Bay County land development regulations. |
|------------------|------------|---|

- Policy 1.3.1 Storm water management regulations will prohibit the alterations of existing drainage features unless such alterations will not create adverse impact in the form of decreased performance for upstream and downstream areas. The evaluation of adverse impacts shall be by acceptable engineering methodologies and shall consider storage volume, conveyance, water quality, and maintenance. Storm water management regulations shall require that future development utilize the storm water master plan as a basis for design.**

There are no existing surface water bodies, rivers, or tributary creeks located within the plan amendment area. The onsite drainage improvements, i.e., storm water ponds, to be constructed onsite will not adversely impact upstream or downstream drainage features. The design of the storm water ponds will meet all applicable federal, state and local requirements. Offsite areas will be allowed drainage around the site through existing conveyance systems.

- Policy 1.3.2 Storm water management regulations will:**
- (a) Require that new developments provide storm water management systems that meet quality and quantity levels of service defined in drainage policies 1.2.3 and 1.2.4. . . .**
 - (b) Require that appropriate storm water engineering, design and construction standards for onsite systems are provided and utilized;**
 - (c) Require that erosion and sediment controls are used during development;**
 - (d) Require that periodic inspection and maintenance of onsite systems is provided by the owner, unless the system is accepted by the county for maintenance;**
 - (e) Require that buffer zone requirements for areas adjacent to natural drainage features are developed;**
 - (f) Provide for new commercial, industrial, public, and residential developments to integrate their storm water management systems into their project's landscaping, open space, or recreational areas and to require the maintenance of 10% of the building lot's native vegetation in order to absorb storm water runoff; and**
 - (g) Include provisions to prevent the creation of breeding areas for disease-carrying vectors, such as mosquitoes.**

The development of storm water ponds within the plan amendment area will meet water quality and water quantity LOS standards. Erosion and sediment controls will be used during construction activities to protect wetlands and downstream receiving waters. Maintenance of the completed ponds will be the responsibility of Gulf Power Company. A majority of the subject property is planted slash pine with natural vegetation restricted to isolated wetlands. The storm water ponds will be incorporated into open spaces and/or landscaped areas and may be located adjacent to wetlands to ensure maintenance of hydroperiods. To the extent practicable, native vegetation will be retained. Design of the storm water ponds will be such that provisions to prevent the creation of breeding areas can be incorporated.

POTABLE WATER SUBELEMENT

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| Goal | 1 | To provide high quality potable water in adequate quantity to meet the adopted level of service in such a manner that encourages orderly and compact growth. |
| Objective | 1.1 | By 1991, Bay County will implement procedures to ensure that potable water will be provided as needed and where needed to correct existing deficiencies and to serve future development occurring within potable water service areas. Adopted potable water service areas will be shown on the Future Land Use Map Series. |

The proposed development of the plan amendment area will utilize potable water from permitted wells at the Lansing Smith plant. There will be sufficient permitted ground water withdrawal to supply the proposed Smith Unit 3 with potable water. The development of Smith Unit 3 will not use public potable water service.

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|------------------|--------------|--|
| Objective | 1.2 | Bay County shall implement measures to conserve and to protect potable water resources and to reduce the per capita consumption rate of potable water by 15 percent by the year 1995. |
| Policy | 1.2.2 | Bay County shall require use of water conservation devices in all new development. Water conservation devices shall include water saving water closets and flow restricting shower heads and faucets. |

The proposed development of the plan amendment area will utilize water conservation devices and techniques.

AQUIFER RECHARGE SUBELEMENT

- | | | |
|------------------|--------------|---|
| Goal | 1 | To provide protection to those areas of Bay County with high recharge potential to the Floridan aquifer. |
| Objective | 1.1 | By 1991, Bay County will restrict land uses in the area of high recharge potential in order to preserve the quality of water which may recharge the Floridan aquifer. |
| Policy | 1.1.1 | Land development regulations adopted by the county shall prohibit land uses that may discharge substances that could infiltrate and degrade the ground water in the area of high recharge potential. |

As depicted on Figure 5, the plan amendment area is not located in an area of high recharge potential to the Floridan aquifer.

COASTAL MANAGEMENT ELEMENT

- | | | |
|------------------|--------------|--|
| Goal | 1 | Protect, conserve, and restore coastal area resources and plan for development activities. |
| Objective | 1.1 | Prohibit development of unaltered natural habitats in the coastal area unless a portion of the development site is left in its original condition. |
| Policy | 1.1.2 | Areas containing endangered or threatened species habitat and unique natural areas such as those designated in the Florida Natural Areas Inventory shall not be developed for any use that would cause loss of viability of the community or habitat. |

The majority of the plan amendment area has been altered for silvicultural activities (planted pine). The only unaltered natural areas onsite are isolated wetlands. No habitat for endangered or threatened plant or animal species has been found onsite.

- | | | |
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| Objective | 1.3 | Reduce discharge of untreated storm water from all sources into surface waters, including wetlands and estuaries. |
| Policy | 1.3.4. | The storm water management plan shall prohibit use of wetlands and other waterbodies as sediment traps during development. Sediment traps shall be constructed onsite to prevent escape of sediments to waterbodies. |

There currently are no surface water bodies located onsite. The onsite wetlands will not be used as sediment traps during or after development. The storm water ponds will be designed to prevent downstream migration of sediments.

Policy 1.3.6 Require all new sewage treatment plants, industries and other facilities that discharge waste products to dispose of effluent via land spreading, spray irrigation, recycling or other means that avoid direct discharge into surface waters without advanced treatment.

The domestic wastewater generated from the proposed Smith Unit 3 will be treated by the existing domestic wastewater treatment plant at the Lansing Smith plant. The effluent from the treatment plant is routed to the existing ash pond which discharges intermittently in response to a design storm event. Industrial wastewater for the new plant will be recycled into the closed-loop cooling system. The cooling towers associated with Smith Unit 3 will use 7.5 million gallons per day (MGD) of surface water from the existing Lansing Smith plant discharge canal, which has a permitted surface water withdrawal of 274 MGD for the two existing units. The cooling system blowdown water, approximately 3.7 MGD, will be routed back to the discharge canal where it will mix with the discharge water from the existing Smith Units 1 and 2. The impact of the blowdown water volume to downstream surface waters will be negligible and in compliance with applicable water quality standards.

Objective 1.9 Development or redevelopment in the coastal area shall occur only if adequate infrastructure to maintain the adopted level of service is in place by the time of project completion to serve the proposed development.

Policy 1.9.1 Coastal area levels of service shall be consistent with those adopted in the sanitary sewer, solid waste, drainage, potable water, and natural ground water aquifer recharge element; the traffic circulation element; and the capital improvements element.

Development of Smith Unit 3 will meet all LOS standards as determined by a concurrency review at the time that an application for developmental approval is submitted. Sanitary sewer and potable water service will be provided by permitted onsite facilities at the Lansing Smith plant. Solid waste generation and traffic generation will not adversely impact existing LOS standards. The development of the subject property will include the provision of storm water ponds that will meet water quality and water quantity LOS standards. The plan amendment is not located in a high natural ground water aquifer recharge area.

Policy 1.9.4 Development approvals for projects for which adequate sewer capacity is not available prior to development completion shall be conditioned upon provision of domestic waste treatment facilities that meet Florida Department of Environmental Regulation standards. The development shall be required to connect to central sewer service within 1 year of availability.

The existing wastewater treatment plant at the Smith Plant meets FDEP regulatory requirements. This plant will provide treatment for the domestic wastewater generated at Smith Unit 3.

1.9.7 Development approvals, including those in the coastal area, shall be reviewed by the Panama City Urban Area Metropolitan Planning Organization and/or the Department of Transportation for their impact on the level of service of the existing roadway network. Developments that will generate sufficient additional traffic to cause the adopted level of service standard for that roadway to be exceeded shall be denied until improvements required to maintain the adopted level of service standard are complete.

The additional employment from the development of Smith Unit 3 will not generate sufficient additional traffic to impact the existing LOS on CR 2300 or SR 77. Traffic impacts will be evaluated during the state site certification process.

Policy 1.9.10 Storm water facilities shall be constructed to meet or exceed the standards set forth by the Florida Department of Environmental Regulation and the comprehensive storm water management plan.

The storm water ponds to be constructed as part of the Smith Unit 3 will meet the LOS standards established by the Comprehensive Plan and the requirements of FDEP.

Objective 1.12 Protect historically significant resources in the coastal area of Bay County, including structures that are significant examples of the architectural design of their period.

The SHPO has been sent a letter requesting a site-specific review of the Florida Master Site File for the presence of significant historical and archaeological resources. If recommended, a survey of the plan amendment area will be conducted. The disturbed and replanted nature of the subject property suggest that significant archeological or historical resources will not be found onsite.

CONSERVATION ELEMENT

- Goal 1 Protect, manage, and conserve the natural resources of Bay County to achieve their continued best use for the current and future citizens of the county.**
- Objective 1.1 Prevent degradation of surface water quality below water quality classifications designated by the Department of Natural Resources and the Department of Environmental Regulation.**

The storm water runoff generated by development of the plan amendment area will be treated to the LOS standards established by the Comprehensive Plan and will meet the requirements of FDEP. The only other surface water discharge from Smith Unit 3 will be the blowdown water from the cooling tower. This 3.7 MGD discharge will co-mingle with approximately 274 MGD of cooling water discharged from Smith Units 1 and 2. The treated storm water and the co-mingled blowdown discharge will not significantly degrade the surface water quality of downstream receiving waters to below the existing water quality classifications.

- Objective 1.4 Meet or exceed minimum air quality standards established by regulatory agencies.**
- Policy 1.4.3 Require industrial land uses to be located where the impacts on air quality in residential and conservation land use areas do not cause or contribute to an ambient concentration that exceeds the standards established in Chapter 17-2, F.A.C.**

The location of Smith Unit 3 is at least 2 miles from existing residential development. The design of the unit, the cleaner burning natural gas fuel, and the air pollution prevention equipment will prevent exceedances of current air quality standards.

- Objective 1.9 Protect plant and animal species designated as endangered, threatened, and species of special concern and unique vegetative communities in the county.**

Policy 1.9.2 Endangered or threatened species habitats and unique natural areas, as identified by the Florida Natural Areas Inventory, shall be considered environmentally sensitive. Prior to development in these sections, the development site shall be inventoried for the presence of environmentally sensitive habitats. The results of this survey, as well as mitigation measures for protection of these features if found, shall be submitted as part of land development permit applications submitted for the project.

No endangered or threatened plant or animal habitats have been found onsite. The majority of the property has been used for silvicultural purposes. Only isolated wetlands have been left relatively undisturbed. It is not anticipated that environmentally sensitive habitats will be found onsite.

Objective 1.10 Maintain the current complement of fisheries, wildlife, wildlife habitat, marine habitat, and vegetative communities through conservation of diverse and viable habitats.

Policy 1.10.7 All development other than individual single-family residential construction that is not part of a larger common plan of development shall preserve a minimum of 10 percent of its area as open space landscaped with native species in accordance with a County Landscape Ordinance. Land development regulations shall provide incentives, such as density bonuses or increased lot coverage ratios, for the use of native species in required plantings.

To the extent practicable, the onsite isolated wetlands will be incorporated into the development of Smith Unit 3. These wetlands are the only areas of unaltered native species. Landscaping will use native species to meet county landscape ordinance requirements.

CAPITAL IMPROVEMENTS ELEMENT

Goal 1 Provide public facilities to meet existing deficiencies and maintain adopted LOS standards as identified in the Comprehensive Plan.

Objective 1.5 Development orders or permits shall be issued consistent with the provision of needed capital improvements and adopted LOS standards.

Policy 1.5.1 No later than December 1, 1990, the county shall not issue a development order or permit that results in the reduction in the

LOS adopted in the Bay County Comprehensive Plan.

The proposed development of Smith Unit 3 will be reviewed for concurrency with adopted LOS standards when an application for development approval is submitted. The proposed development will meet LOS standards.

ECONOMIC ELEMENT

- Goal 1 Provide a diversified and stable economy that is compatible with planned growth and quality of life objectives and that provides maximum legitimate employment opportunities for all segments of the Bay County population.**
- Objective 1.1 Increase employment opportunities for Bay County residents.**

The construction of Smith Unit 3 will provide up to 325 construction-related jobs and will provide 29 full-time jobs when the unit is operational.

- Objective 1.3 Ensure that sufficient developable land is allocated for future agricultural, commercial, industrial, and recreational land uses to meet the needs projected for future growth in all sectors of the county's economy on the FLUM adopted by the County.**
- Policy 1.3.1 In identifying suitable lands for commercial and industrial growth, the following factors shall be utilized:**
- Close proximity to principal arterials;**
 - Access to required utilities, including water, sewer, electricity, gas, and telephone. Provisions for the extension of these utilities required by new commercial or industrial development by the private sector shall be made in the Future Land Use Element of this Plan;**
 - Access to rail facilities, if appropriate;**
 - Minimizing negative impacts to the natural environment and adjacent land uses through the use of buffers, such as natural vegetation.**

The plan amendment area is located approximately 5 miles from SR 77, a principal arterial directly accessed by CR 2300. Access to required utilities is primarily from the existing Lansing Smith plant. Rail access is not applicable to Smith Unit 3, which is a water-dependent utility accessible to Alligator Bayou through the existing Lansing Smith plant. Surrounding land uses are silvicultural activities to the east, north, and west, and the existing Lansing Smith plant to the south. The applicant controls 571 additional acres located east, north, and west of the property and no development is proposed for this area, now in planted pine. To the extent practicable, impacts to the onsite wetlands, the remaining natural environment within the plan amendment area, will be minimized.

7.3 COMPATIBILITY WITH THE PROPOSED BAY COUNTY COMPREHENSIVE PLAN (FEBRUARY 1998 VERSION)

ECONOMIC DEVELOPMENT

- | | | |
|------------------|---------------|--|
| Objective | 2.1 | Ensure an adequate supply of land designated for commercial and industrial use on the FLUM. |
| Policy | 2.1.1. | The County will designate land for commercial and industrial uses on the FLUM. |
| Policy | 2.1.2 | General criteria for the designation of industrial land uses on the FLUM include: |

1. Existing industrial or commerce parks;

The subject property is located adjacent to an existing Industrial designation (existing Lansing Smith plant).

2. Availability of public or private utilities;

Proposed development of the subject property will utilize the existing domestic wastewater treatment plant at the Lansing Smith plant and will use potable water from the existing and permitted water wells. Neither public sewer service nor public water supply will be used to serve the plan amendment area.

3. Proximity to major highway access and/or rail access;

The plan amendment area is located approximately 5 miles from SR 77, a major arterial roadway. Access to SR 77 is by CR 2300, which primarily is used by employees, visitors and vendors of the existing Lansing Smith plant.

4. Potential to create nuisances such as fumes, noise, odor, dust, traffic, etc;

The proposed development will not create a nuisance to surrounding land uses, which are silviculture, undeveloped land, and the existing Lansing Smith plant. The closest residential development is located over 2 miles northeast of the plan amendment area.

5. For water dependent industry, access to deep water channels; and

The proposed electrical power generating development (Smith Unit 3) is a water dependent use. Access to a deep-water channel is available from Alligator Bayou.

6. Minimal impact on locally significant environmental resources.

The majority of the plan amendment area is planted pine and the only locally significant environmental resource identified onsite is the presence of wetlands. The site planning process will avoid wetland impacts to the extent practicable and any unavoidable wetland impacts will be mitigated through preservation, enhancement or creation.

Policy 2.1.4 Industrial or commerce parks may be located in urban, suburban, or rural service areas when level of service standards are met.

The plan amendment area is identified as within a suburban planning area. The proposed development of the subject site will meet level of service standards for sanitary sewer and potable water by using private permitted facilities at the Lansing Smith plant; for drainage, by constructing storm water ponds for water quality and quantity in accordance with FDEP regulations; and for solid waste and transportation, due to the minimal impact to the existing Steelfield landfill and on the existing LOS of SR 77.

Objective 2.4 Promote the growth and development of existing industrial and commerce parks.

- Policy 2.4.1** New industrial growth shall be encouraged to use existing or underutilized industrial or commerce parks unless circumstances exist that would preclude such location.
- Policy 2.4.2** Where possible, new industrial growth should occur in publicly funded industrial or commerce parks in order to recapture public investment.
- Policy 2.4.3** The Board shall not approve amendments to the FLUM that will create industrial land outside of existing industrial or commerce parks unless it can be demonstrated that a bonafide need exists for such industrial land use.

Section 2 of this plan amendment application addresses the need and justification for constructing Smith Unit 3. Siting this additional electrical power generating unit adjacent to the existing Lansing Smith plant is an efficient and logical planning choice due to the ability to use existing infrastructure such as wastewater treatment, ground water withdrawal wells, transmission lines, cooling water withdrawal and shared discharge points. The proposed use of the plan amendment area is located within a suburban area and is an expansion of an existing industrial use, following a pattern of existing industrial development.

- Objective 2.11** Establish a procedure to “fast track” large-scale land use plan amendments to this plan that will be instrumental to the attraction, retention or expansion of business enterprise.
- Policy 2.11.1** The attraction, expansion, or retention of businesses that create new jobs is hereby declared to be in the public interest of Bay County. As means of furthering this interest the Board will participate in the “expedited permitting” process as described in Chapter 97-28, Laws of Florida.

The proposed expansion of the existing Lansing Smith plant is in the public interest of Bay County. Approximately 29 new jobs will be created once the unit is operational and up to 325 temporary jobs will be created during construction of Smith Unit 3.

FUTURE LAND USE ELEMENT

- Objective 3.3** Establish and maintain criteria for the designation of land use categories identified in Policy 3.2.4.
- Policy 3.3.1** Criteria for designating land use categories on the FLUM and attendant standards for development shall be as shown on Table 3A.
Agriculture = Allowable use – self-contained industrial.

Intensity – no more than 25% impervious area
Industrial = Designation criteria: Existing industrial or commerce parks, proximity to major highway access and/or rail access, availability of public or private utilities, potential to create for water dependent industry access to deep water channels, minimal impact on locally significant environmental resources.

Allowable uses = DOR Property Use Code Table 4000 through 4900

Intensity = No more than 80% impervious area

Development restrictions = Should not be located near residential areas. New industrial development to be located in existing industrial or commerce parks unless otherwise determined necessary by the Board.

The existing Agriculture designation (1990 adopted Comprehensive Plan) does not accommodate the proposed industrial use. It is possible that text changes in the allowable uses incorporated in the draft 1998 Comprehensive Plan would allow for the development of Smith Unit 3 as a self-contained industrial use. The site plan provided as Figure 2 depicts an intensity of less than 25 percent impervious area. Due to the proposed timing of the approval of the construction and operation of Smith Unit 3 this separate plan amendment application has been prepared. The existing Lansing Smith plant is designated industrial and its Department of Revenue (DOR) property code is 9100. The appropriate Standard Industrial Code (SIC) is 4911, power generation, (a subset of SIC code 4900). The proposed use of the plan amendment area is an expansion of the existing electrical power generating facility within the existing Industrial land use designation. The extension of this designation to the plan amendment area is consistent with prior Bay County interpretations of land use and property use codes. The plan amendment area is located at least 2 miles from the nearest residential area.

TRANSPORTATION ELEMENT

Objective 4.4 Establish access control corridors to provide safe and convenient movement to and from Urban Service Area so as to enhance managed growth and the overall development of commerce in Bay County.

- Policy 4.4.1** The following arterial roads are hereby designated as “Access Control Corridors”.
- 2.** State Road 77, Washington County line to the intersection of State Road 77 and County Road 2300. LOS D

The majority of the permanent employees at Smith Unit 3 are anticipated to live within the Panama City/Panama City Beach area and will, therefore, access CR 2300 from SR 77 from the south.

INFRASTRUCTURE ELEMENT

- Objective 5B.8** Establish wastewater LOS standards for purposes of estimating future needs and issuing development orders.
- Policy 5B.8.1** For areas where central sewer service is not available concurrency requirements may be met by the issuance of an “Onsite Sewage Disposal” (septic tank) permit pursuant to Chapter 10D-6, F.A.C.

The proposed Smith Unit 3 will utilize the domestic wastewater treatment capability at the existing Lansing Smith plant. The proposed use within the plan amendment area will meet concurrency requirements relative to wastewater treatment.

- Objective 5C.2** Provide potable water from Deer Point Reservoir using the County’s systems to replace existing community service level water wells. (Public Purpose: Reduce consumption of limited ground water resources).

Potable water will be provided to the proposed development from four existing and permitted wells at the Lansing Smith plant site.

- Objective 5E.10** Establish specific provisions in the Land Use Code for the regulation of storm water runoff.
- Policy 5E.10.1** *Ecosystem Management Zones:* Treatment to OFW standards may be required for areas within designated EMAs.
- Objective 5E.12** Ensure that State water quality standards are maintained or improved as a result of the County’s storm water management programs.
- Policy 5E.12.1** The County will not permit any new development that will cause degradation of State water quality standards.

The storm water ponds will be designed in accordance with FDEP regulations. Both stormwater treatment (water quality) and storm water storage (water quantity) will be provided onsite. State water quality standards will be met.

CONSERVATION ELEMENT

Objective 6.2 Identify and designate locally significant natural resources.

Policy 6.2.1 Locally significant natural resources are as follows:

- 4. Designated Ecosystem Management Areas (EMAs).**
- 5. Designated habitat conservation areas.**
- 7. Ground water resources**
- 8. Wetlands.**
- 9. Flood zones.**
- 12. Selected trees and vegetation.**
- 13. Threatened and endangered species.**

The plan amendment area is located within the proposed North Bay EMA. The other onsite locally significant natural resource is the presence of wetlands. The plan amendment area is not a designated habitat conservation area, is located outside of Zone A, is not characterized by an unaltered natural state and is not unique habitat for threatened and endangered species. No new ground water withdrawal wells will be located onsite. Any ground water withdrawal requirements will be from permitted wells.

Objective 6.5 Maintain or improve estuarine water quality consistent with state water quality standards.

Policy 6.5.1 The County will maintain or improve estuarine water quality by:

- 5. Restricting development in designated EMAs.**

The plan amendment area is located within the proposed North Bay EMA. Storm water treatment will be provided onsite and blowdown water from the cooling tower will be thoroughly mixed with the existing discharge from Smith Units 1 and 2. Estuarine water quality should not be adversely impacted by the proposed development.

Policy 5C.2.1 The Board will strive to make potable water available from the county system on a wholesale basis to areas currently served by community level water wells when determined to be financially feasible.

- Objective 5C.6** Make certain that all water distribution systems are designed and constructed in conformance with professionally accepted standards.
- Policy 5C.6.4** In areas where central water service is not available private potable water wells may be installed consistent with applicable regulations.

Central water service is not available to the plan amendment area. The proposed Smith Unit 3 will utilize potable water from permitted wells serving the existing Lansing Smith plant site.

- Objective 5C.10** Protect ground water resources from contamination and/or overuse.
- Policy 5C.10.3** All community level potable water wells will be evaluated to determine possible effects on ground water resources.

The proposed development of Smith Unit 3 will use water from permitted wells serving the existing Lansing Smith plant.

- Objective 5C.11** Establish level of service standards for purposes of estimating consumptive demands and issuing development orders.
- Policy 5C.11.1** 3. For areas where central water service is not available concurrency requirements can be satisfied by private, individual water wells.

The proposed development of the subject property will meet the concurrency requirements through use of permitted wells.

- Objective 5E.9** Ensure that storm water runoff is no greater after a development project than before the project.
- Objective 5E.10** Establish specific provisions in the Land Use Code for the regulation of storm water runoff.
- Policy 5E.10.1** 6. Require evaluation of flooding that may be caused by the development of vacant land adjacent to existing developed areas...
7. Require that best available engineering practices be used for the design and construction of storm water control facilities based on the following level of service standards:

The onsite drainage improvements (storm water treatment and storage ponds) will be designed, permitted and constructed in accordance with applicable federal, state and local regulations.

- Objective 6.7 Conserve and manage natural resources on a systemwide basis rather than piecemeal.**
- Policy 6.7.1 The County will use designated EMAs as a means for the conservation of natural systems.**

The plan amendment area has been altered through its use for silviculture. Nearly the entire site was logged as depicted in the aerial photograph that serves as the base map for the Soil Survey (Figure 11).

- Policy 6.7.2 EMAs are considered "Special Treatment Zones" in which extraordinary regulatory standards may be applied to protect natural resources.**
- Policy 6.7.4 The following development standards will apply in designated EMAs:**
- 1. The requirements of this policy shall apply unless: (1) it can be demonstrated that no locally significant resources exist on a parcel of land subject to development, or; (2) a developer can design and construct a development project such that locally significant environmental resources are preserved, or impact minimized.**
 - 2. All storm water runoff will be treated to OFW standards or greater**
 - 3. Any new point source discharges of sewage effluent are prohibited.**
 - 5. Development will be undertaken so as to avoid activities that would destroy wetlands or the natural functions of wetlands.**
 - 6. No building or structure can be located closer than 30 feet from any DEP wetland jurisdictional line. All native vegetation, if any exists, will be preserved within the 30-foot setback area.**
 - 7. No development will be permitted that can reasonably be expected to cause short or long term violations of state water quality standards.**

The plan amendment area is currently used for silviculture (planted slash pine). The onsite wetlands are isolated systems without connection to larger regional wetland systems such as Jacksons Titi or Newman Bayou. To the extent practicable, development of Smith Unit 3 will minimize impact to the onsite wetlands. There will be no new point source discharges of sewage effluent since domestic wastewater will be treated at the existing treatment plant at the Lansing Smith plant. The proposed project would not be expected to produce wastewater streams that could cause violations of state water quality standards.

Policy 6.7.6 The County will encourage and support the preservation and acquisition of lands within EMAs for mitigation or mitigation banking purposes.

For unavoidable impacts to wetlands, the applicant will provide mitigation through preservation, enhancement and/or creation.

Objective 6.11 Protect and conserve wetlands and the natural functions of wetlands

Policy 6.11.1 For purpose of this plan the term “wetlands” means the same as defined at s. 376.016(17), F.S.

Policy 6.11.2 Dredge and fill activities in wetlands will be governed by applicable federal and state regulatory requirements.

Policy 6.11.3 The County will employ the following measures to protect and conserve wetlands:

- 1. Wetlands will be delineated and depicted on all site plans included in Applications for Development Approval.**
- 2. Developers will design and construct development projects so as to avoid activities that would destroy wetlands or the natural functions of wetlands.**
- 3. Wetland setbacks will be required by EMAs as specified in policy 6.7.4.**
- 4. Wetland crossings that connect dry upland areas are permissible provided the natural water flow between wetlands is not interrupted.**
- 5. In the event that a lot or parcel of property is rendered totally undevelopable by avoidance of wetlands the property may be developed when: (1) disturbance of wetland is the minimum necessary to build an allowable use, and (2) mitigation is provided as allowed by applicable law.**

Development of the plan amendment area will be designed to minimize the amount of wetlands impacts to the extent practicable. Unavoidable wetland impacts will be mitigated through preservation, enhancement and/or creation. The development of the property will require the preparation, submittal and approval of a dredge and fill permit to be reviewed jointly by FDEP and the US Army Corps of Engineers (USACE).

Objective 6.13 Reduce the potential risk to lives and property from flooding by using hazard mitigation strategies and special building construction practices.

The plan amendment area is not located in the flood zone.

Objective 6.16 Protect and conserve selected trees and important vegetative communities.

Policy 6.16.3 Developers of land within Critical Habitat Areas will be required to preserve those vegetative communities that are critical to continuation of the habitat.

The plan amendment area is not located in a Critical Habitat Area. The natural state of the subject property has been altered by silvicultural practices.

Objective 6.17 Identify and classify areas to be designated for conservation purposes on the FLUM.

Policy 6.17.3 The Conservation designation is intended to provide for conservation with appropriate use through regulations that will minimize damage to natural resources. Areas or resources to be designated as Conservation include:
1. EMAs

The plan amendment area is located within the proposed North Bay EMA. The subject property is depicted as a proposed Conservation area (Appendix A). The only locally significant natural resource identified onsite is isolated wetlands. To the extent practicable, impact to these wetlands will be minimized.

Objective 6.18 Provide landowners with beneficial use of their property when environmental restrictions cause the loss of full development potential through use of innovative and flexible development strategies.

- Policy 6.18.1** On lots or parcels where locally significant environmental resources exist and resulting development restrictions apply, owners or developers may use, or be required to use, the following innovative land development techniques.
- 4. Clustering.**
 - 5. Density transfers.**
 - 6. Mitigation.**

Where impacts to wetlands, the only locally significant environmental resource identified onsite, are unavoidable, mitigation will be used. Mitigation might consist of preservation, enhancement and/or creation.

COASTAL MANAGEMENT ELEMENT

- Objective 7.1** Define and establish the "Coastal Planning Area".
- Policy 7.1.1** The "Coastal Planning Area" will be all land and water areas seaward of the landward section line of those sections of land which contain the Category 5 hurricane evacuation zone (Map 7A).

The plan amendment area is located within the Coastal Planning Area.

- Objective 7.3** Maintain or improve estuarine water quality by identifying potential sources of pollution, regulating such sources of pollution, and constructing capital improvements to reduce or eliminate known pollution sources.
- Policy 7.3.1** Major threats to estuarine water quality include the following:
- 1. Wastewater treatment plant point source discharge.**
 - 2. Uncontrolled and untreated storm water runoff.**
 - 3. Hazardous substance spills.**
 - 6. Unregulated dredge and fill activities.**
- Policy 7.3.2** The Board will maintain or improve estuarine water quality by:
- 4. Requiring treatment of storm water runoff and correcting existing storm water deficiencies**
 - 6. Coordinating with regulatory agencies having jurisdiction over dredge and fill activities toward ensuring that any such activities are conducted in an acceptable manner.**

Development of the plan amendment area will require preparation, submittal and approval of permits for storm water facilities construction and operation (FDEP review and approval) and for dredge and fill activities (FDEP and USACE review). A new point source discharge for treatment of domestic wastewater will not be required since the wastewater treatment plant at the existing Lansing Smith plant will be used. The construction of Smith Unit 3 will include appropriate containment structures and containment areas at hazardous materials and hazardous waste storage/accumulation areas.

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|------------------|--------------|---|
| Objective | 7.5 | Institute beachfront construction standards that will protect coastal resources and minimize the potential for damage caused by coastal storms. |
| Policy | 7.5.1 | ...Other development undertaken within 1,500 feet of the Coastal Construction Control Line (CCCL) must be undertaken in compliance with the Coastal Zone Protection Act (s. 161.55, F.S.). |

The plan amendment is not located within 1,500 feet of the CCCL.

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|------------------|--------------|--|
| Objective | 7.6 | Define and establish the “Coastal High-Hazard Area” (CHHA). |
| Policy | 7.6.1 | The CHHA will be all land area lying within the Category 1 hurricane evacuation zone (Map 7A). |
| Objective | 7.11 | Maintain development review procedure that will promote the protection of coastal historic resources. |

The plan amendment area is not located within the CHHA.

- | | | |
|---------------|---------------|--|
| Policy | 7.11.1 | The County will use the State Master Site File to identify those areas where historic resources may be present. Developers of property within these areas must either demonstrate that no such historic resources are present or provide a protection plan to show how historic resources will be preserved, protected or reused. |
|---------------|---------------|--|

A letter requesting a review of the State Master Site File has been sent to the SHPO. If required, a detailed survey of the property will be conducted to identify any significant historical or archaeological resources. The disturbed and replanted nature of the subject property suggest that significant archaeological or historical resources will not be found.

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|------------------|---------------|--|
| Objective | 7.13 | Development or redevelopment in the coastal area of Bay County shall occur only if adequate infrastructure to maintain the adopted LOS is in place by the time of project completion to serve the proposed development. |
| Policy | 7.13.1 | Coastal area LOSs shall be consistent with those adopted in the Capital Improvements Element. |

Development of the plan amendment area will not impact the LOS standards for potable water or sanitary sewer due to the use of existing and permitted facilities at the Lansing Smith plant. Solid waste generation at Smith Unit 3 will have a negligible impact on the capacity of the Steelfield landfill. Water quality and water quantity LOS standards relative to storm water runoff will be met. The traffic generated by the anticipated number of employees (18 on the largest, daytime shift) will not adversely impact the LOS standard of SR 77. Adequate land for open space and recreation currently exist in Bay County and the proposed development will not impact the need for open space or recreational lands.

- | | | |
|---------------|---------------|--|
| Policy | 7.13.4 | Development approvals for projects for which adequate sewer capacity is not available prior to development completion shall be conditioned upon provision of domestic waste treatment facilities, which meet FDEP standards. The development shall be required to connect to central sewer service within one year of availability. |
|---------------|---------------|--|

Domestic wastewater treatment generated from Smith Unit 3 will be provided by the permitted treatment plant at the Lansing Smith plant. Should public sewer service become available, the applicant will connect during the applicable time period.

CAPITAL IMPROVEMENTS ELEMENT

- Objective 11.4** Establish procedures for the coordination of land use decisions with the financial capability of the County to provide public facilities and services.
- Policy 11.4.2** The Board will use the Future Land Use Element of this plan and attendant land use controls to direct growth into those areas where services and facilities can be provided in an efficient and effective manner.
- Policy 11.4.3** All applications for development approval will be evaluated with regard to the availability of facilities and services required to accommodate the proposed development.

The proposed development of the plan amendment area will not require the upgrade of public infrastructure including sanitary sewer or potable water treatment capacity, solid waste landfill capacity, land for parks or recreation or roads. Storm water treatment and storage will be provided onsite.

- Objective 11.7** Make certain that developers bear a proportionate cost of providing facilities or facility improvements for any infrastructure necessitated by their development projects.
- Policy 11.7.1** Developers will be required to construct or install any infrastructure improvements such as roads, water and sewer lines, storm water retention, etc. that may be required as a result of their development project.
- Policy 11.7.2** Developers will be required to pay for upgrades or improvements to existing offsite facilities such as roads, drainage, water and sewer lines, pump stations, etc. when such improvements are required to maintain LOS standards.

The proposed development of the plan amendment area is not expected to require any upgrades or improvements to existing offsite public facilities. Onsite drainage to address water quality and water quantity requirements will be provided. All onsite facilities will be constructed, maintained and paid for by the Gulf Power Company.

- Objective 11.9** Establish and maintain a "Concurrency Management System" to make certain that public facilities and services needed to support development will be available concurrent with the impacts of such development.
- Policy 11.9.1** The concurrency requirements of this element shall apply to roads, sanitary sewer, solid waste, drainage, potable water, and parks and recreation. All ADAs shall be reviewed to ensure that LOS standards are maintained and minimum concurrency requirements are met.

The proposed development will meet all minimum concurrency requirements prior to development approval.

8. LAND NEEDED TO ACCOMMODATE PROJECTED INDUSTRIAL USE

The proposed amendment would add an additional 50± acres of industrially designated land to the FLUM. According to Table 19 in the Future Land Use Element of the adopted 1990 Comprehensive Plan, 813 acres were identified as industrial use in 1990. Between 1990 and 1995, Table 19 indicates a need for 195 additional acres of industrially designated land and between 1995 and 2000, another 242 acres will be required. The requested change to Industrial will meet approximately 20.7 percent of the projected need for industrial land use designations for the planning period 1995 to 2000.

The projected need for additional industrial acreage was based on the Bay County Chamber of Commerce's efforts to promote Bay County as an attractive location for new industry in order to help combat high unemployment rates experienced in the 1980s. With county government participation, the coordinated public/private sector activity has been successful in attracting new industry. The future (1995 and 2000) industrial acreage requirement of 437 was based on the assumption that firms seeking industrially designated land will be distributed within the county in much the same pattern as has existed in the past and that acreage requirements for industrial firms will not significantly change.

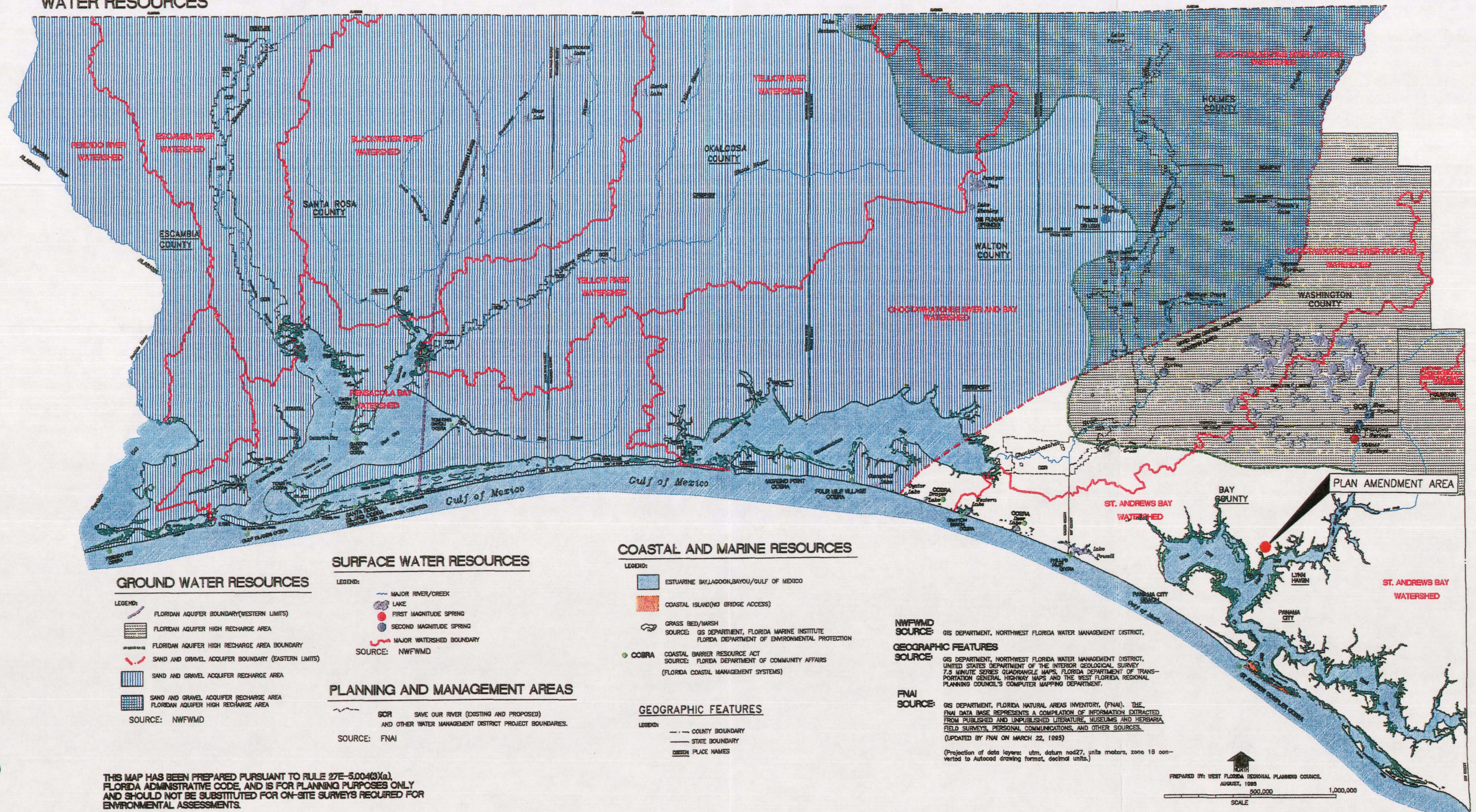
The proposed amendment of the FLUM from Agriculture to Industrial is requested to accommodate an expansion of the existing Lansing Smith plant. The proposed Smith Unit 3 cannot be sited on the existing plant property site because of existing electrical generating facilities and support buildings (warehouse and administration). The expansion of the Lansing Smith plant was not foreseen in 1990, although the expansion of the plant is consistent with the assumptions within the adopted Future Land Use Element (similar pattern of distribution and acreage requirements).

APPENDIX A

**WEST FLORIDA REGIONAL PLANNING COUNCIL, STRATEGIC
REGIONAL POLICY PLAN, AND BAY COUNTY 1990 ADOPTED
COMPREHENSIVE PLAN FIGURES**

WEST FLORIDA REGION SIGNIFICANT NATURAL RESOURCES WATER RESOURCES

MAP 1

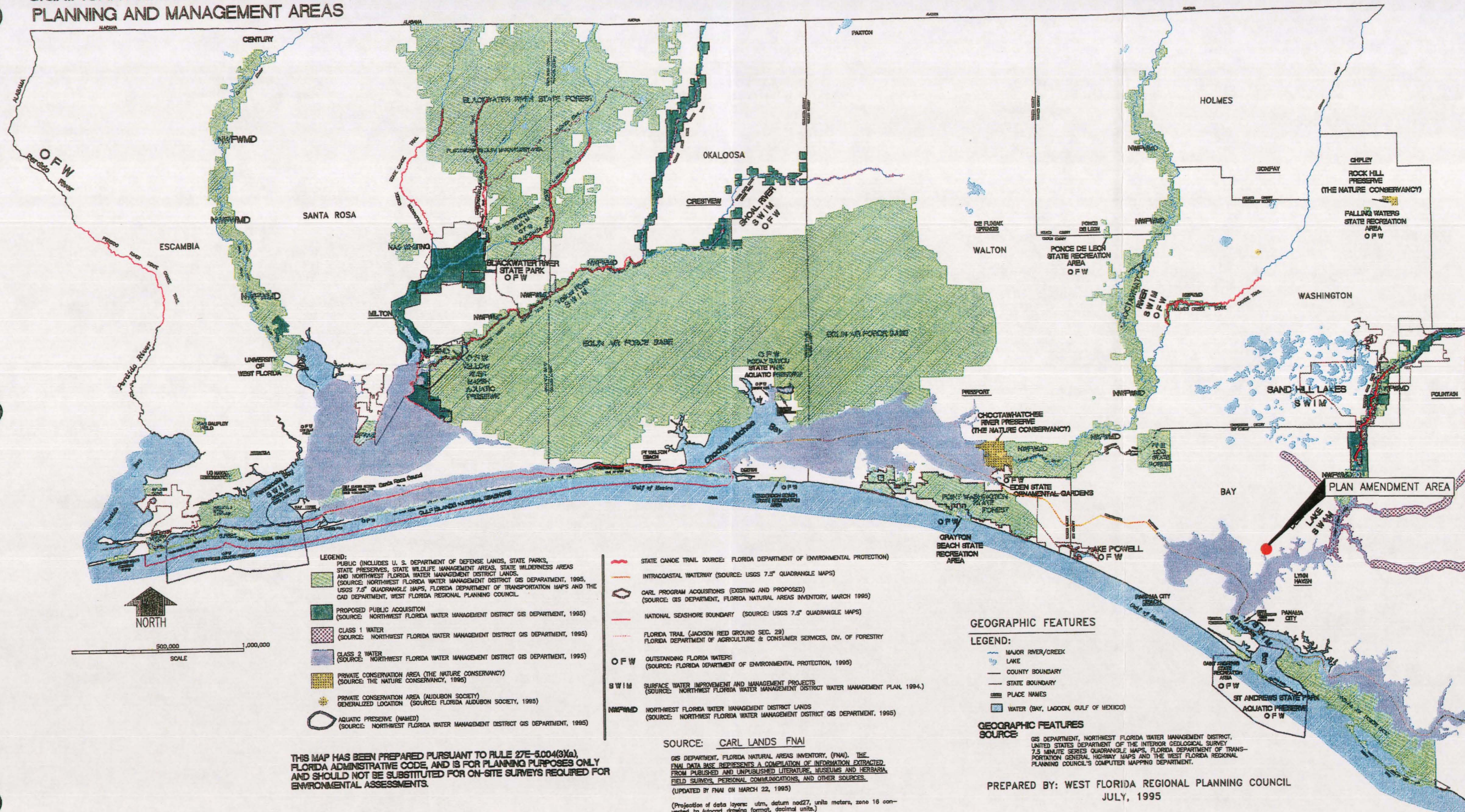


THIS MAP HAS BEEN PREPARED PURSUANT TO RULE 27E-5.004(3)(a), FLORIDA ADMINISTRATIVE CODE, AND IS FOR PLANNING PURPOSES ONLY AND SHOULD NOT BE SUBSTITUTED FOR ON-SITE SURVEYS REQUIRED FOR ENVIRONMENTAL ASSESSMENTS.

Adopted 7/15/96
IV-97

WEST FLORIDA REGION SIGNIFICANT NATURAL RESOURCES PLANNING AND MANAGEMENT AREAS

MAP 2



Adopted 7/15/96

IV-98

WEST FLORIDA REGION
SIGNIFICANT NATURAL RESOURCES
WETLANDS

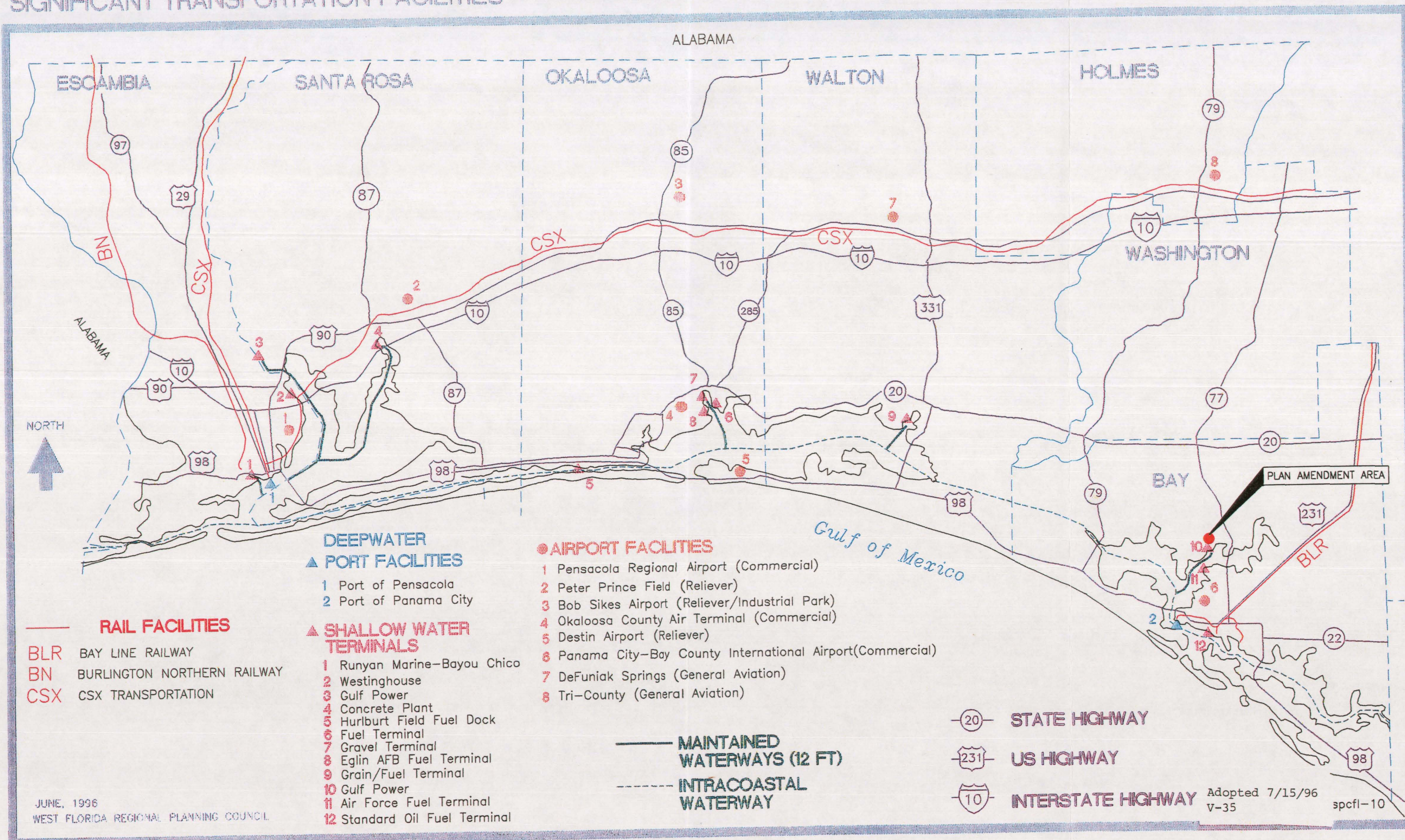
MAP 3



Adopted 7/15/96
IV-99

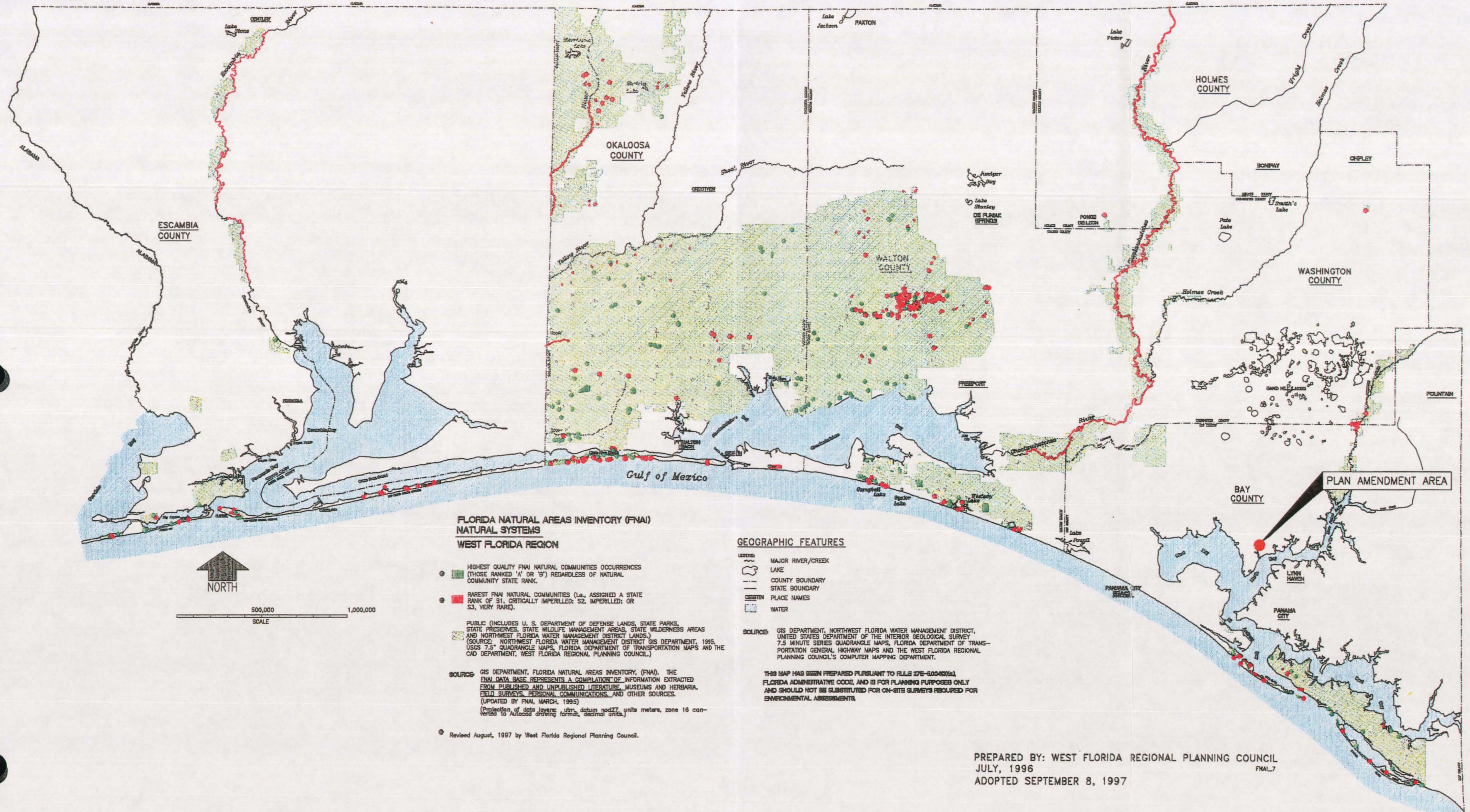
WEST FLORIDA REGION SIGNIFICANT TRANSPORTATION FACILITIES

MAP 4



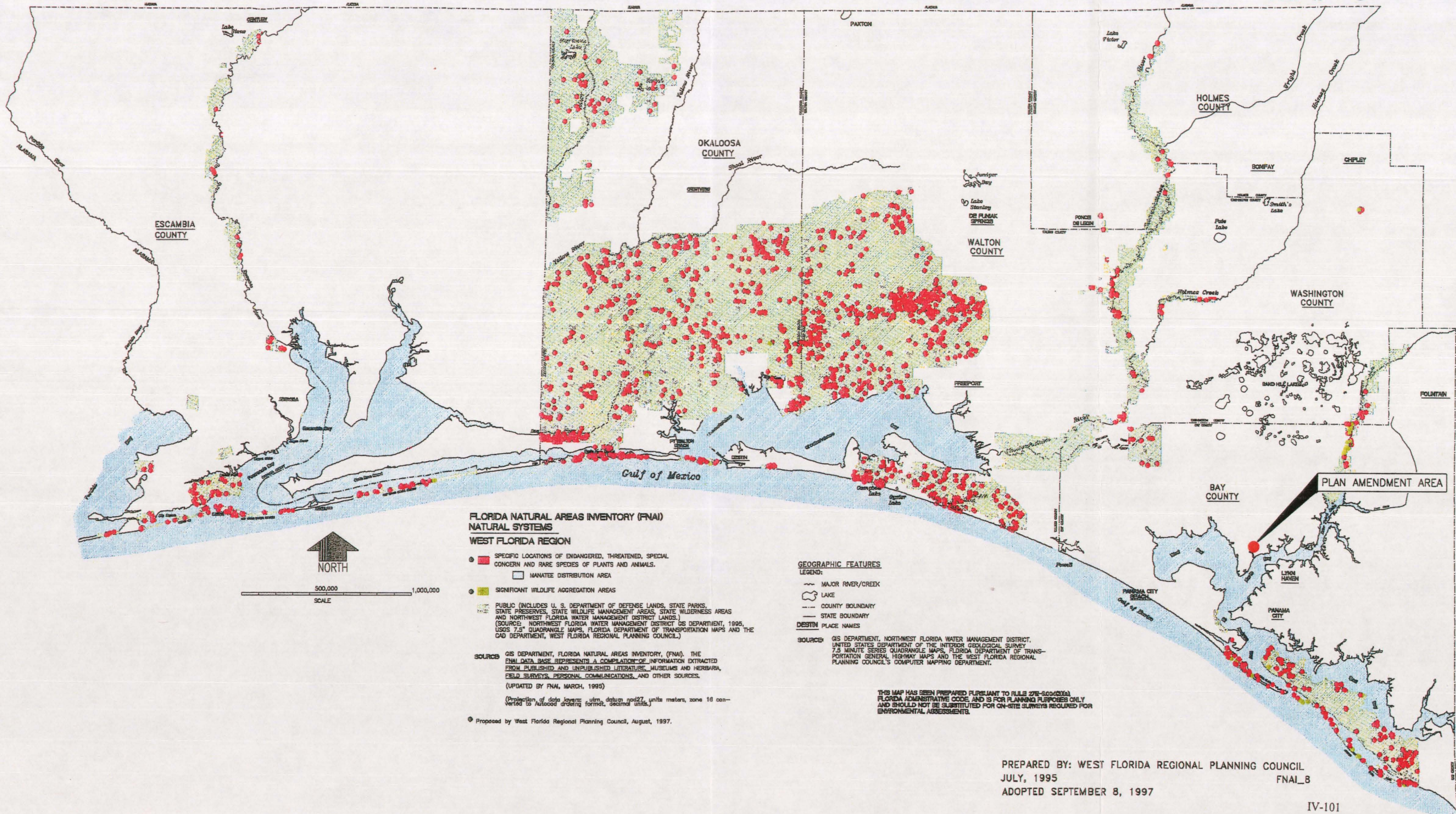
FLORIDA NATURAL AREAS INVENTORY (FNAI)
NATURAL SYSTEMS
WEST FLORIDA REGION

MAP 5

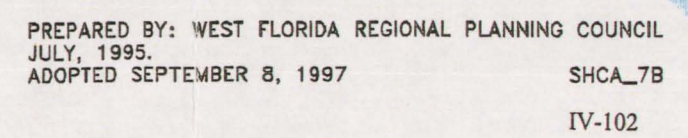


FLORIDA NATURAL AREAS INVENTORY (FNAI)
NATURAL SYSTEMS
WEST FLORIDA REGION

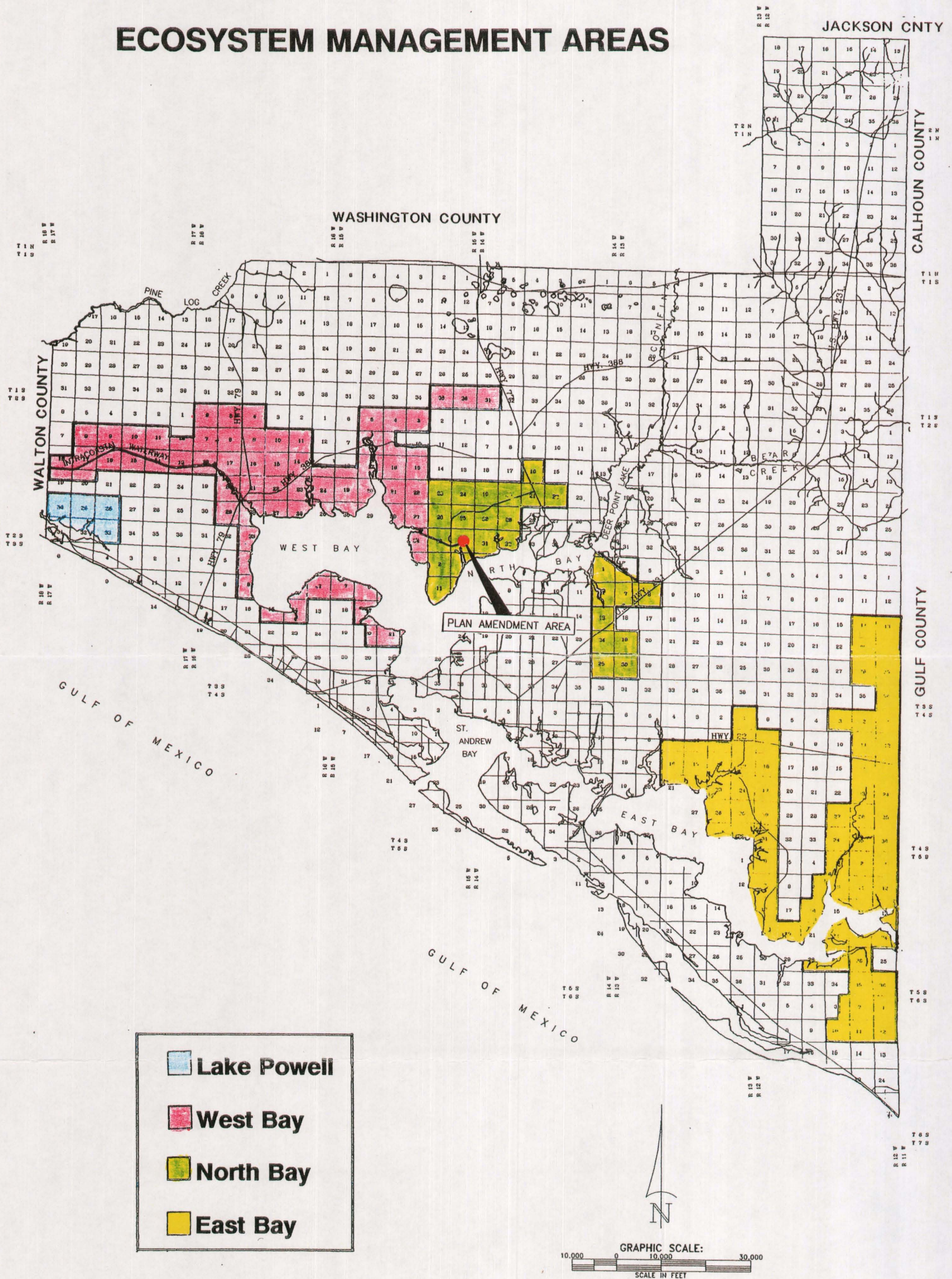
MAP 6



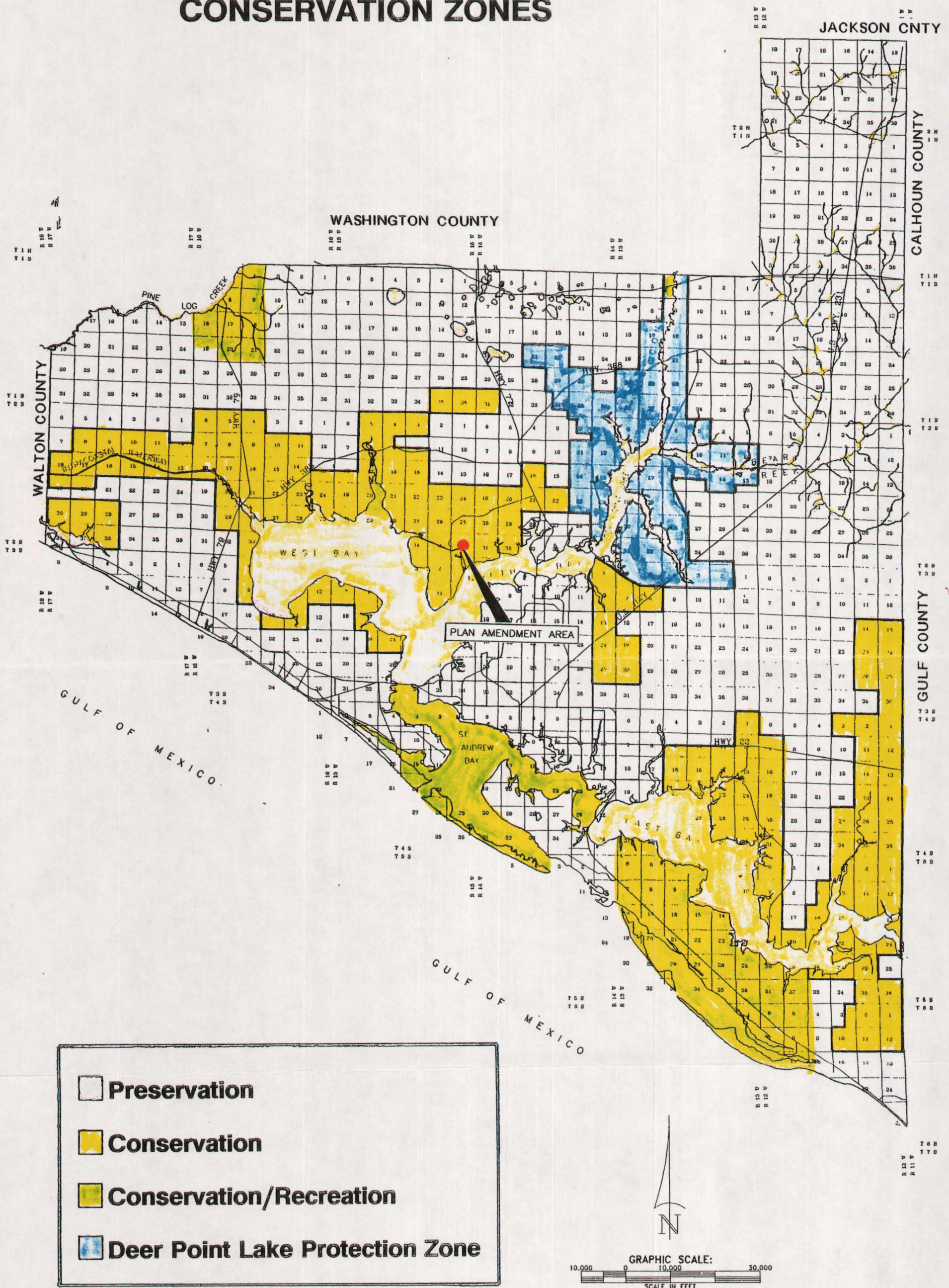
MAP 7



ECOSYSTEM MANAGEMENT AREAS



CONSERVATION ZONES



HEADING 2010: CHARTING OUR COURSE BAY COUNTY COMPREHENSIVE PLAN



Prepared by Department of Development Services
Planning Division
January, 1998
Base Map by Bay County GIS

APPENDIX 10.2.2
STORM WATER MANAGEMENT PLAN

STORM WATER MANAGEMENT PLAN

Prepared for:

**GULF POWER COMPANY
Pensacola, Florida**

Prepared by:

ECT

Environmental Consulting & Technology, Inc.

***3701 Northwest 98th Street
Gainesville, Florida 32606***

ECT No. 990151-0500

June 1999

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ATTACHMENT—STORM WATER CALCULATIONS

LIST OF FIGURES

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1.0 INTRODUCTION

This storm water management plan (SWMP) describes measures that will be implemented to control storm water runoff on the site of the Gulf Power Smith Unit 3 Project located in Bay County, Florida (Figure 1). The SWMP includes storm water control measures that will be implemented during both construction and operation periods.

1.1 PROJECT DESCRIPTION

The Smith Unit 3 Plant will be a natural gas-fired combined cycle, electric generating facility with an operating capacity of 574 megawatts. The plant will be constructed on a 50.1-acre site located within the property boundary of the existing Lansing Smith Generating Plant in Bay County, Florida. The Project site is at the end of County Road 2300, west of State Road 77 and northwest of Panama City (see Figure 2).

1.2 SITE DESCRIPTION

The 50.1-acre site has an approximate ground surface elevation of 5 to 8 feet National Geodetic Vertical Datum (ft-NGVD) as shown in Figure 1. This undeveloped site is located north of the existing facility and will utilize some of the existing infrastructure, such as transmission lines and roads. Approximately 32.7 acres of the site area will be cleared for the new plant construction.

Portions of the site consist of poorly drained soils with standing water and wetland systems. Upland areas have been modified by silvicultural practices with rills and planted pines. The site generally drains to the southwest to natural wetland systems.

The site will be elevated by fill material to achieve surface drainage and to prevent flooding in the facility area. Two storm water management ponds will be located in the northwest and southeast portions of the site. The ponds will be further described within the SWMP.

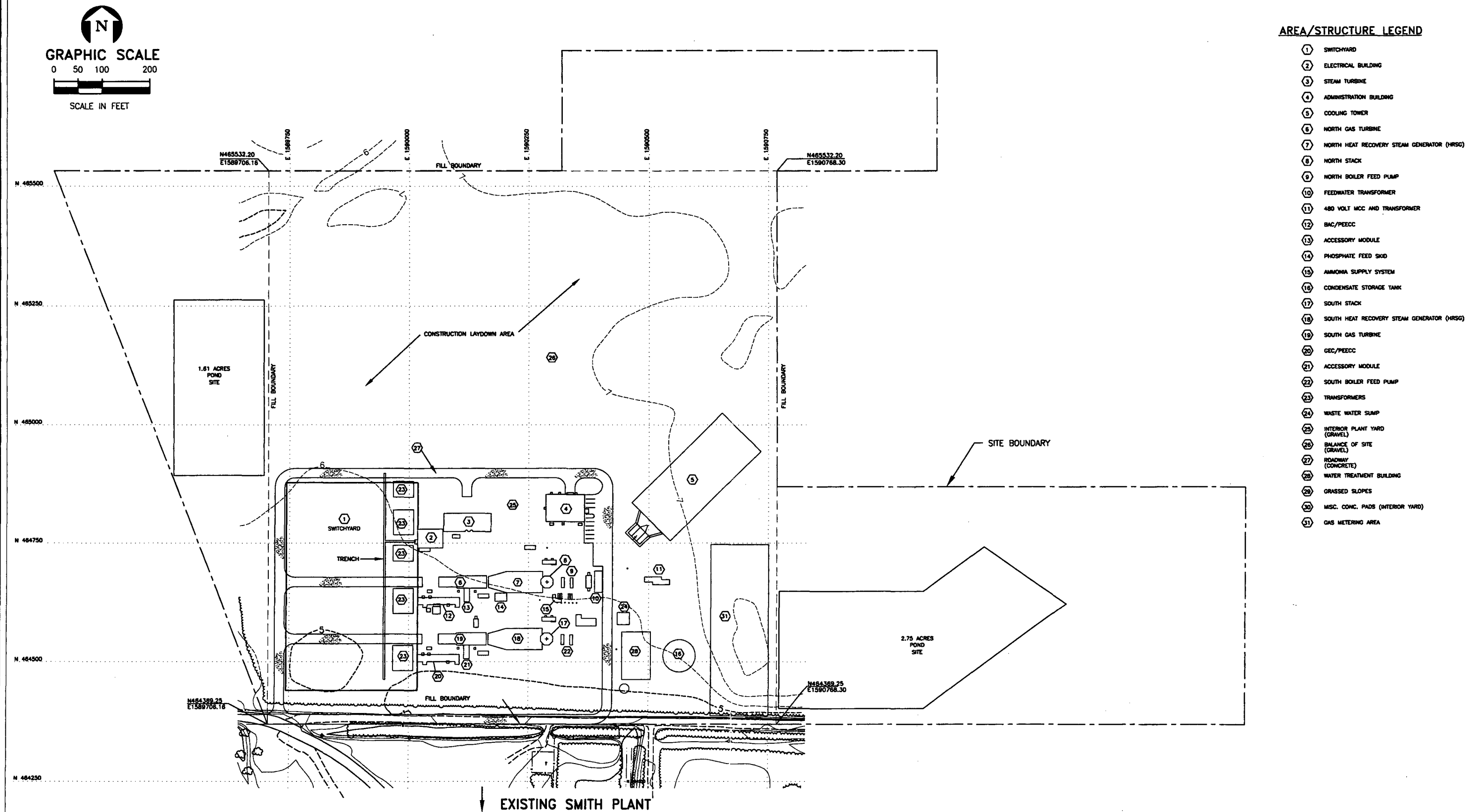


FIGURE 1.

PLOT PLAN

Sources: Gulf Power, 1999; ECT, 1999.

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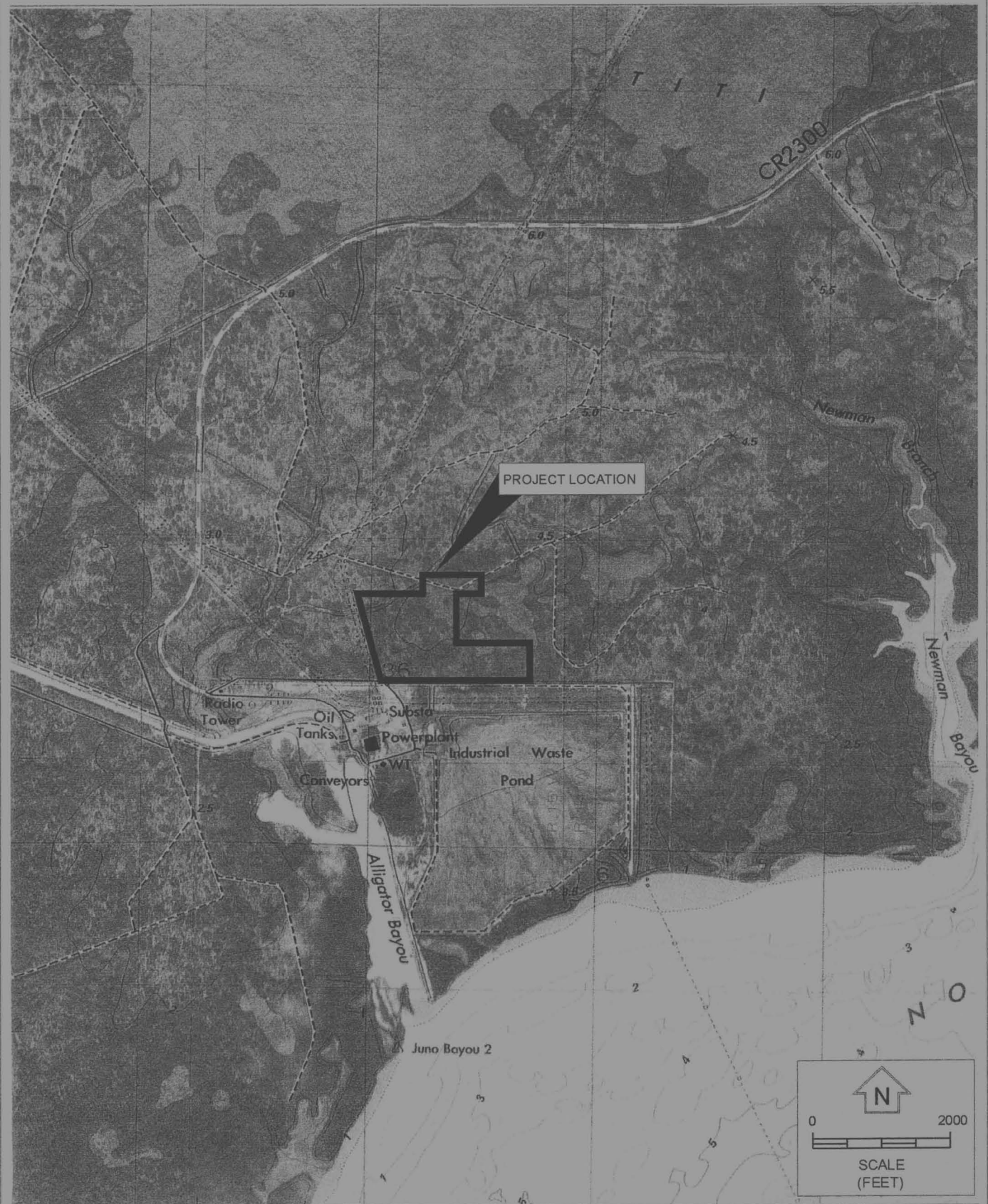


FIGURE 2.

SITE LOCATION MAP

Sources: USGS topo map of Southport, FL, 1992; ECT 1999.

Poor Original

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2.0 DESIGN CRITERIA

Storm water control measures used on the new plant are designed to comply with requirements of local, state, and federal regulations. Storm water runoff calculations, runoff volumes, peak discharges, and control structures were determined or designed using methods described in Chapter 62-25, Florida Administrative Code, and Section 7.03.00 of the Bay County regulations.

2.1 SITE GRADING

The site will be filled and graded to provide a finished surface for construction of structures and associated facilities, including roadways, parking areas, construction laydown areas, storm water detention basins, and conveyances. The grading will provide adequate drainage for all buildings, structures, and working areas.

Site drainage will be accomplished by gravity flow, utilizing a surface drainage system consisting of mild surface slopes, drainage ditches, swales, and culverts. First floor elevations will be above the 100-year flood elevation of 7 ft-NGVD. The site will generally be graded to elevations of 10 ft-NGVD or higher. Figure 3 shows the site grading plan and Figure 4 shows the cross sections of the site according to the site grading.

2.2 ROADS AND PARKING AREAS

A roadway system will provide access to various portions of the site. It includes permanent, paved roads or driveways with minimum 20-ft-wide paved surfaces. During construction, roadways will be surfaced with aggregate.

Parking will be provided adjacent to the administration building in addition to the existing lots in the Smith Plant site.

Approximately 87,680 square feet (ft²) of impervious surface will be used for roads and parking. These surfaces will be sloped to collect and drain storm water to one of the two wet detention ponds.

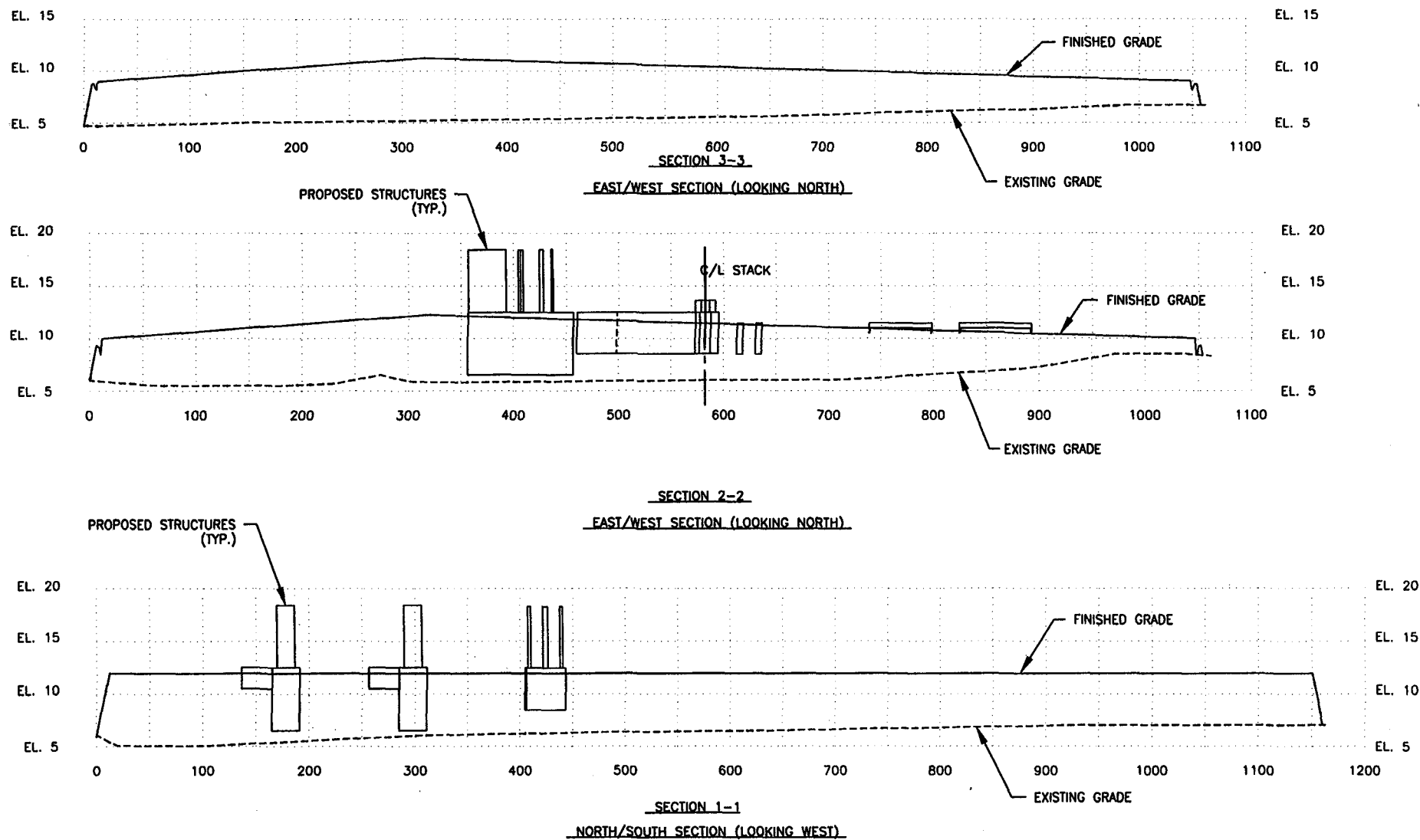


FIGURE 4.
GRADING PLAN PROFILES

Source: SCS, 1999.

ECT
Environmental Consulting & Technology, Inc.

2.3 OTHER PERVIOUS AND IMPERVIOUS AREAS

As calculated from the site layout plan, approximately 10.33 acres of the site will be impervious surface, inclusive of the normal pool wet area of the ponds. These surfaces include transformers, concrete pads, buildings, and associated facilities. Pervious areas that will be part of the improved area (approximately 22.37 acres) will either be grassed or landscaped.

2.4 DRAINAGE DITCHES AND SWALES

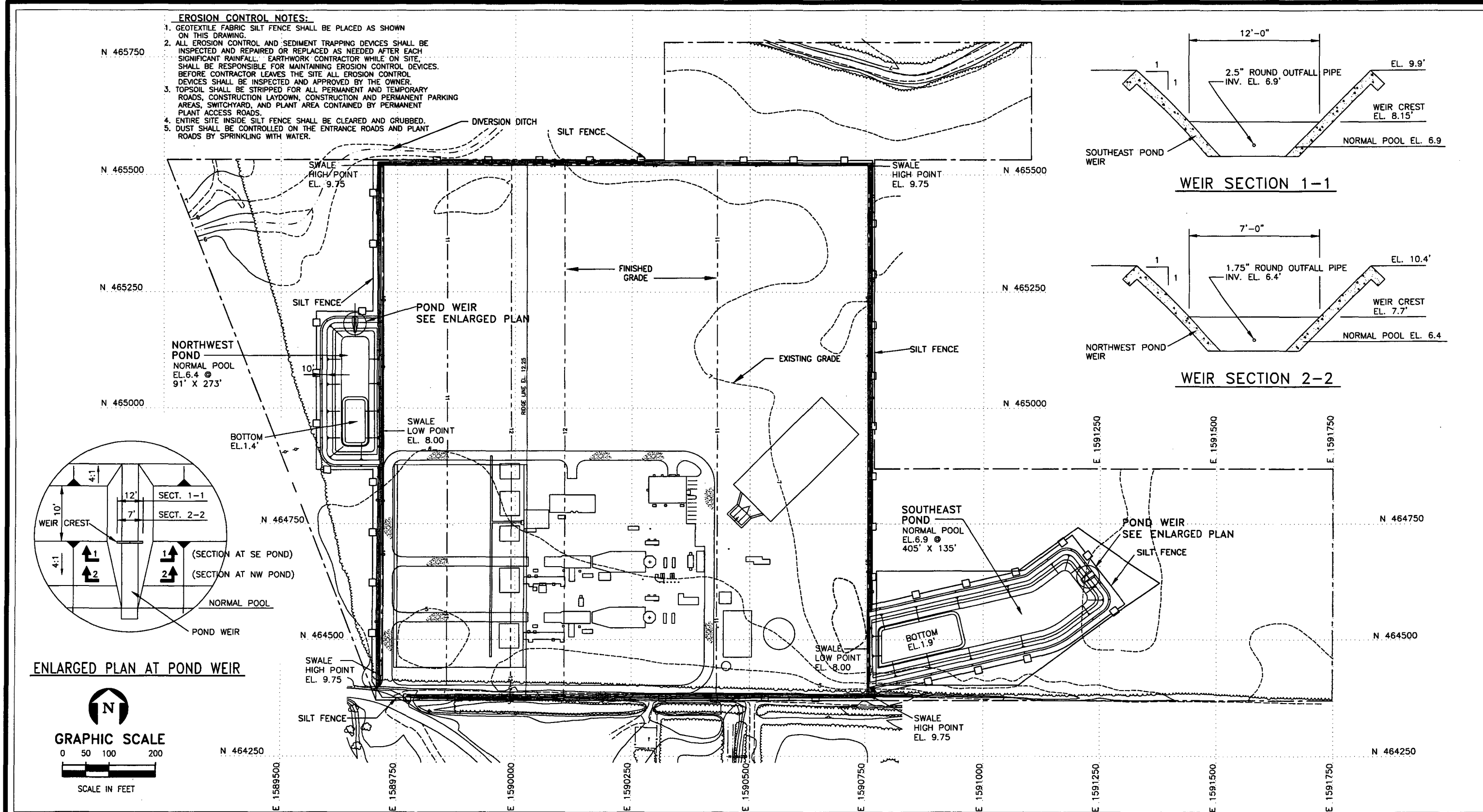
Collection systems which will convey runoff to the wet detention ponds are designed for the 100-year, 24-hour capacity. Side slopes will be a maximum of 3 horizontal to 1 vertical, and longitudinal slopes of 0.3 percent or greater. Since the site will be elevated with well drained fill material, ditch elevations will be above water table elevations. Ditches and swales will be grassed and included in the plant's normal maintenance program.

2.5 CULVERTS

Drainage culverts will be installed at road crossings and embankments. Culverts will be either reinforced concrete or high-density polyethylene pipe or equivalent. Culverts within the collection system for the wet detention ponds will be designed for the 100-year, 24-hour storm capacity for a headwater elevation below the roadway base course. All culverts will be designed to support AASHTO HS20 and construction equipment traffic loads.

2.6 DETENTION BASIN

Two wet detention basins will be constructed to provide water quality treatment and attenuation of site storm water runoff. A 1.25-acre pond (as measured at the normal pool elevation) will be located in the southeast section of the site, collecting runoff from approximately 22.56 acres. Another 0.56-acre pond will be located in the northwest section of the site, collecting runoff from approximately 10.14 acres of site area. The locations and configurations of the detention ponds are shown in Figure 5.



The detention basins will be excavated to have a permanent pool volume in excess of the 14-day residence time during the wet season (June through October) to assure adequate sedimentation and water quality treatment of storm water runoff. Under normal conditions, the permanent pool elevations of the ponds will be 6.4 and 6.9 ft-NGVD for the northwest and southeast ponds, respectively. A small orifice in the outlet structure of the ponds will be used as a bleed down device to recover detention and water quality treatment volume. The bleed down device will recover 50 percent of the detention volume within the first 60 hours following the rainfall event. The bleed down orifice at the southeast pond will be 2.5 inches in diameter with an invert elevation of 6.9 ft-NGVD. The bleed down orifice at the northwest pond will be 1.75 inches in diameter with an invert elevation of 6.4 ft-NGVD.

For the 25-year, 24-hour storm, the ponds will attenuate the peak flows to below the predevelopment rates through the outlet control structures. Discharges will be directed to the existing wetland systems adjacent to the site. The following table summarizes the predevelopment and postdevelopment runoff calculations:

Parameters	Predevelopment	Postdevelopment
Northwest pond peak flow	58 cfs	46 cfs
Southeast pond peak flow	128 cfs	68 cfs
Northwest pond peak water level	—	8.54 ft-NGVD
Southeast pond peak water level	—	8.98 ft-NGVD

Note: cfs = cubic feet per second.

The storm water detention ponds will serve as sedimentation basins during construction. The detention ponds will be constructed to allow suspended solids or loose sediments to be settled to the bottom. They will be maintained for proper operation following construction.

Supporting calculations for the wet detention systems are located in the attachment to this SWMP.

2.7 DIVERSION OF OFFSITE DRAINAGE

There is an existing small, intermittent drainage that cuts through the northwestern corner of the construction site. The proposed grading plan will potentially impede the existing drainage pattern in this area. To provide conveyance of the storm water drainage previously carried by this system, a diversion ditch will be excavated around the northwestern corner of the construction site. The diversion ditch, shown in Figure 5, will be of similar width and depth as the existing channel, in order to minimize the alteration of discharge hydrograph.

2.8 EROSION CONTROL

During construction, site erosion will be controlled by maintaining finished surface slopes to less than 1 percent. Silt fencing and straw bale barriers will be used to prevent sedimentation along the perimeter of the site. Surfaces will be vegetated to prevent sediment loss and ditches will be stabilized, as necessary. These generalized measures are shown on Figure 5.

3.0 STORM WATER MANAGEMENT PLAN AND PRACTICES

The storm water management plan for the Smith Unit 3 Project is shown in Figure 5, including site layout, general arrangement of equipment and facilities, arrangement and locations of storm water runoff control structures, locations of storm water runoff outfall structures, and offsite storm water runoff receiving areas. Control practices for storm water during both construction and operational periods are described below.

3.1 CONSTRUCTION PHASE STORM WATER CONTROL MEASURES AND PRACTICES

During construction of the Smith Unit 3, a combination of silt fencing, straw bale sediment barriers, and the storm water detention basins will be used to control erosion on the site and to reduce the potential for transport of eroded sediment offsite. All grading will be accomplished in phases, with each graded area seeded and mulched after construction of the Smith Unit 3 Project is complete.

A portion of the storm water detention basins will be constructed in the initial phase of site preparation to serve as sedimentation basins. Subsequently, the drainage ditch system will be constructed to convey storm water to the detention/sedimentation basins to remove suspended solids from runoff.

Movement of sediment off graded areas will initially be controlled by the use of silt fences that will provide continuous silt barriers on the downgradient sides of all actively graded areas. Interception of runoff by drainage ditches established early in the construction phase will allow removal of sediment by straw bale fences, with subsequent conveyance of runoff to the storm water detention basins.

To isolate runoff from materials storage areas, appropriate containment such as earth berms will be provided. Runoff from these areas will be treated by onsite wastewater treatment facilities.

Site dewatering flows during construction are expected to be minimal, and they will be routed through the drainage ditch system to the detention basins for treatment before off-site discharge. A silt fence/straw bale barrier will be used for initial removal of sediment from dewatering flows as they enter the drainage ditch system to minimize sedimentation impacts on detention basin storage volume during construction. Available capacity of the detention pond will be monitored during dewatering activity to assure that adequate capacity remains available to provide detention for the 25-year, 24-hour design storm event.

Sediment collected in ditches, secondary detention/sedimentation basins, and the primary detention basin will be monitored and removed periodically as needed to maintain ditch and basin capacity. Sediment removed from these facilities will be disposed onsite for landscaping applications.

3.2 OPERATING PHASE STORM WATER CONTROL MEASURES AND PRACTICES

The Smith Unit 3 drainage ditch system will be constructed to intercept all onsite runoff from the developed site area under design storm conditions and convey it to the storm water detention basins. The detention basins will be sized to retain and treat the runoff volume that results from 1.0 inch of runoff from the site area. In addition, the basin will be sized to serve as a detention basin to control rate of runoff from a 25-year, 24-hour storm event in accordance with design requirements of Bay County. Storm water runoff will be drained by gravity to the wet detention basins.

ATTACHMENT

SMITH UNIT 3 PLANT STORM WATER CALCULATIONS

Pond Sizing/Treatment Volumes

Southeast Pond: Treatment required for 1 inch of runoff from the contributing area

$$Area_{SE} = \left(\frac{742.14' \times 1,162.95'}{43,560 \frac{ft^2}{ac}} \right) + 2.75 \text{ acres} = 22.56 \text{ acres}$$

Note: 2.75 acres allowed for the pond site.

$$Volume_{SE} = 22.56 \text{ acres} \times \frac{43,560 \text{ ft}^2}{\text{acre}} \times 1'' \text{ runoff} \times \frac{1'}{12''}$$

$$Volume_{SE} = 81,893 \text{ ft}^3$$

Treatment volume may be stored in 1.5-ft depth above the normal pool. Therefore, minimum pond size required at the normal pool is:

$$Area_{SE} = \frac{81,893 \text{ ft}^3}{1.5' \text{ max. depth}} = 54,595 \text{ ft}^2 \text{ or } 1.25 \text{ acres}$$

Maintaining a 3:1 length to width ratio will make the pond the following dimensions at the normal pool:

$$x = \text{width}$$

$$Area = 3(x)(x) = 3x^2$$

$$54,595 = 3x^2$$

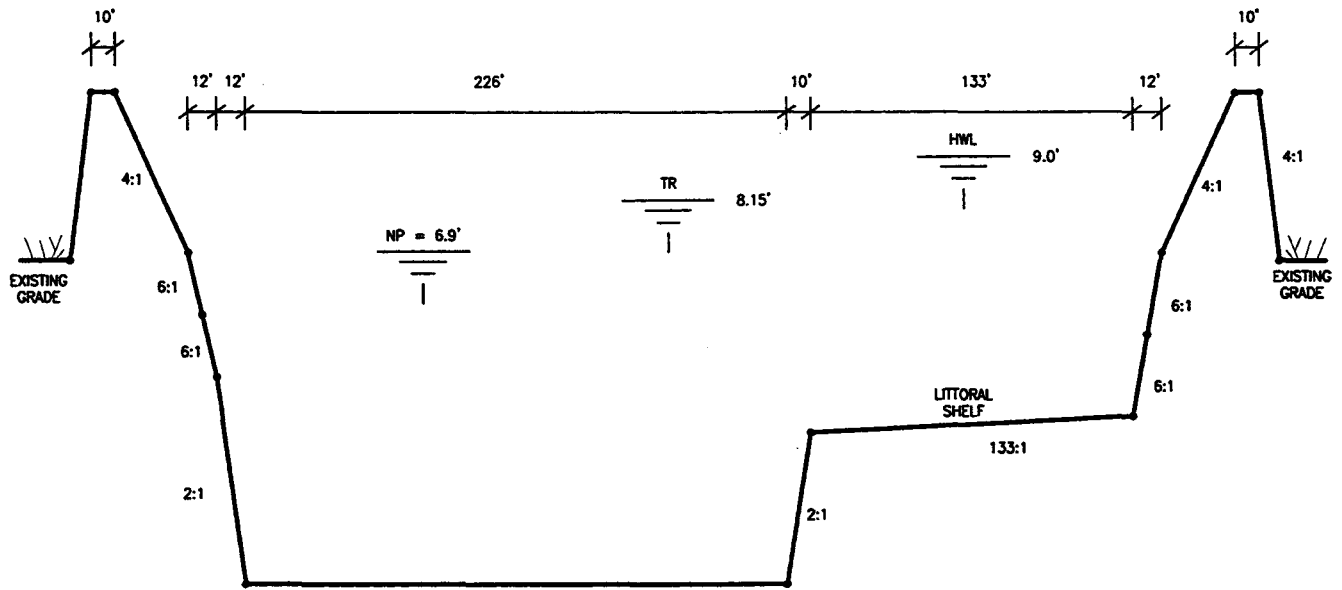
$$x = 135 \text{ feet}$$

$$\text{length} = 405 \text{ feet}$$

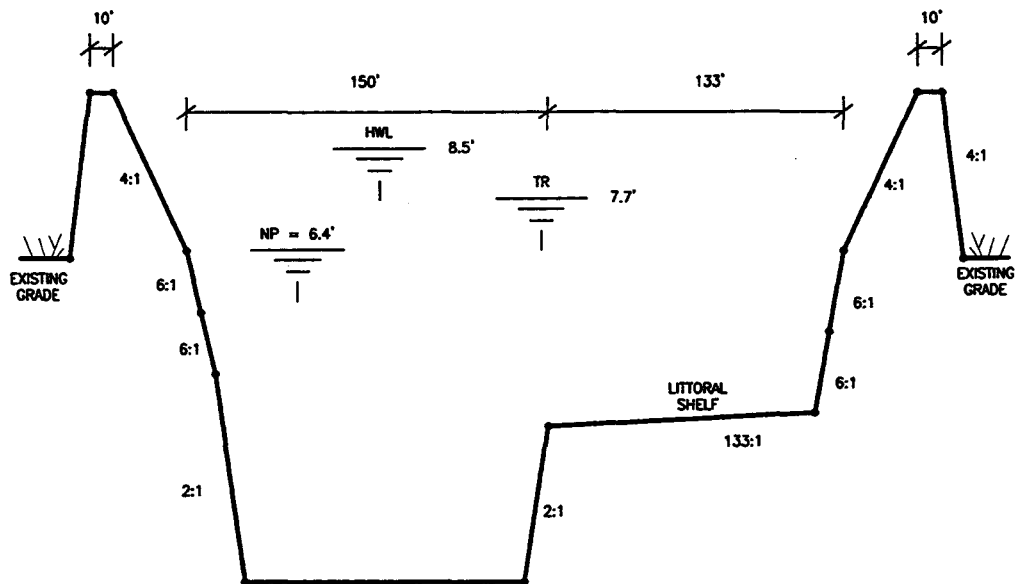
See (A) of Figure A-1.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



(A) SOUTHEAST POND



(B) NORTHWEST POND

FIGURE A-1.
TYPICAL POND SECTIONS

Source: ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

Northwest Pond:

$$Area_{NW} = \left(\frac{320' \times 1,162.95'}{43,560 \frac{ft^2}{ac}} \right) + 1.60 \text{ acres} = 10.14 \text{ acres}$$

Note: 1.60 acres allowed for the northeast pond site.

$$Volume_{NW} = 10.14 \text{ acres} \times \frac{43,560 \text{ ft}^2}{\text{acre}} \times 1'' \text{ runoff} \times \frac{1'}{12''}$$

$$Volume_{NW} = 36,808 \text{ ft}^3$$

$$Area_{NW @ \text{normal pool}} = \frac{36,808 \text{ ft}^3}{1.5' \text{ max. depth}} = 24,539 \text{ ft}^2 \text{ or } 0.56 \text{ acres}$$

$$Area = 3 (\text{width})^2 = 24,539 \text{ ft}^2$$

$$\text{width} = 91 \text{ feet}$$

$$\text{length} = 273 \text{ feet}$$

See (B) of Figure A-1.

Normal Water Level Determination

Seven monitoring wells were installed to measure the surficial aquifer system. Fluctuations were observed through measurements of the well. Normal pool elevations for the ponds are estimated to be approximately 0.4 feet below the ground surface for the pond locations. This would result in normal pool elevations of 6.4 ft (northwest pond) and 6.9 ft (southeast pond) (refer to SCA Section 2.3.2).

Permanent Pool Volumes:

Method I: 3.83 percent of annual average runoff.

Rainfall = 65.81 inches (Source: NCDC, 1999¹).

$$\text{Runoff} = \frac{(P - 0.2 [S])^2}{(P + 0.8 [S])}$$

$P = \text{rainfall all (inches)}.$

$S = \text{Potential max retention (inches)}.$

$$S = \frac{1,000}{CN} - 10$$

$CN = \text{curve number}.$

CN Estimation:

Pervious surface—grass cover, imported fill CN = 61

Impervious—concrete, building, gravel, road CN = 98

Southeast Pond:

	Area (ac)	CN	A × CN
Pond at NP	1.25	100	125.00
Impervious	4.80	98	470.40
Pervious	16.51	61	1,007.11
	22.56		1,602.51

$$CN = \frac{1,602.51}{22.56} = 71$$

$$S = \frac{1,000}{71} - 10 = 4.1$$

Northwest Pond:

	Area (ac)	CN	A × CN
Pond at NP	0.56	100	56.00
Impervious	3.72	98	364.56
Pervious	5.86	61	357.46
	10.14		778.02

¹ National Climatic Data Center (NCDC). 1999. Meteorological data on Apalachicola and Pensacola, Florida. Online. www.epa.gov.

$$CN = \frac{778.02}{10.14} = 78$$

$$S = \frac{1,000}{78} - 10 = 2.8$$

$$Runoff_{SE} = \frac{(65.81 - 0.2 [4.1])^2}{(65.81 + 0.8 [4.1])} = 61.1''$$

$$PPV_{SE} = (0.0383)(61.1'')(3,630) = 8,495 \text{ ft}^3$$

$$Runoff_{NW} = \frac{(65.81 - 0.2 [2.8])^2}{(65.81 + 0.8 [2.8])} = 62.6''$$

$$PPV_{SE} = (0.0383)(62.6'')(3,630) = 8,703 \text{ ft}^3$$

Method II = (2'' [impervious area] + 0.5'' [pervious area]) (3,680)

$PPV_{SE} = (2'' [6.05 \text{ acres}] + 0.5'' [16.51]) (3,630) = 73,889 \text{ ft}^3$

$PPV_{NW} = (2'' [4.28 \text{ acres}] + 0.5'' [5.86 \text{ acres}]) (3,680) = 41,709 \text{ ft}^3$

Method III = 14-day residence time (wet season June to October)

DA = drainage area.

WS = wet season.

R = wet season rainfall (32.64'').

RT = residence time (14 days).

$$CF = \left(\frac{12 \text{ inches}}{1 \text{ ft}} \right)$$

C = 0.95 impervious; 0.15 pervious.

$$PPV = \frac{(DA)(C)(R)(RT)}{(WS)(CF)}$$

$$PPV_{SE} = \frac{(6.05)(0.95)(32.64'')(14)}{(153)(12)} + \frac{(16.51)(0.15)(32.64'')(14)}{(153)(12)}$$

$$PPV_{SE} = 1.43 + 0.62 = 2.05 \text{ acre-foot} \rightarrow 89,298 \text{ ft}^3$$

$$PPV_{NW} = \frac{(4.28)(0.95)(32.64'')(14)}{(153)(12)} + \frac{(5.86)(0.15)(32.64'')(14)}{(153)(12)}$$

$$PPV_{SE} = 1.01 + 0.22 = 1.23 \text{ acre-foot} \rightarrow 53,614 \text{ ft}^3$$

Therefore, use:

$$PPV_{SE} = 89,298 \text{ ft}^3 \text{ or } 2.05 \text{ ac-ft}$$

$$PPV_{NW} = 53,614 \text{ ft}^3 \text{ or } 1.23 \text{ ac-ft}$$

Existing conditions

***** Basin Summary - PRE *****

Basin Name:	NW	SE
Group Name:	BASE	BASE
Node Name:	NWPOND	SEPOND
Hydrograph Type:	UH	UH
Unit Hydrograph:	UH256	UH256
Peaking Factor:	256.00	256.00
Spec Time Inc (min):	1.33	1.33
Comp Time Inc (min):	1.33	1.33
Rainfall File:	SCSIII	SCSIII
Rainfall Amount (in):	11.00	11.00
Storm Duration (hr):	24.00	24.00
Status:	ONSITE	ONSITE
Time of Conc. (min):	10.00	10.00
Lag Time (hr):	0.00	0.00
Area (acres):	10.14	22.56
Vol of Unit Hyd (in):	1.00	1.00
Curve Number:	77.00	77.00
DCIA (%):	0.00	0.00
Time Max (hrs):	12.27	12.27
Flow Max (cfs):	57.70	128.37
Runoff Volume (in):	8.08	8.08
Runoff Volume (cf):	297382	661631

Stormwater analysis of the two wet detention ponds

Inflow (cfs)	Node Name	Group Name	Max Time Max Outflow Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Inflow (cfs)	Max Time Max Outflow
12.37	NWPOND	BASE	12.37	8.54	10.00	0.0126	33110.94	12.33	49.84
0.00	OUTFALL	BASE	0.00	6.00	0.00	0.0000	0.00	12.48	109.62
68.12	SEPOND	BASE	12.56	8.98	10.00	0.0176	66303.85	12.42	77.09

□□ Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.11) [1]
 Copyright 1995, Streamline Technologies, Inc.

Stormwater analysis of the two wet detention ponds

***** Link Maximum Conditions - 25YR

□(Time units - hours)

Link	Group	Max Time	Max Flow	Max Delta Q	Max Time	Max US Stage	Max Time	
Max DS Stage	Name	Flow	(cfs)	(cfs)	U/S Stage	(ft) D/S Stage	(ft)	
O-NW	BASE	12.37	0.12	0.00	12.37	8.54	0.00	6.00
O-SE	BASE	12.56	0.24	0.00	12.56	8.98	0.00	6.00
W-NW	BASE	12.37	46.15	0.83	12.37	8.54	0.00	6.00
W-SE	BASE	12.56	67.89	1.49	12.56	8.98	0.00	6.00

Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.11) [4]
Copyright 1995, Streamline Technologies, Inc.

GP Smith Plant

***** Input Report *****

-----Class: Weir-----

Name: W-SE From Node: SEPOND
Group: BASE To Node: OUTFALL
Count: 1

Type: Horiz Flow: Both Geometry: Rectangular

Span(in): 144
Rise(in): 36
Invert(ft): 8.15
Control Elev(ft): 8.15
TABLE
Bottom Clip(in): 0
Top Clip(in): 0
Weir Discharge Coef: 3
Orifice Discharge Coef: 0.6

-----Class: Simulation-----

C:\ICPR2\GP\25YR

Execution: Both

Header: Stormwater analysis of the two wet detention ponds

-----HYDRAULICS-----HYDROLOGY-----

Max Delta Z (ft): 1
Delta Z Factor: 0.01 Override Defaults: No
Time Step Optimizer: 0
Drop Structure Optimizer: 0
Sim Start Time(hrs): 0
Sim End Time(hrs): 100
Min Calc Time(sec): 30
Max Calc Time(sec): 300
To Hour: PInc(min): To Hour: PInc(min):
9 15 9 15
22 5 30 5
200 15 50 30

-----GROUP SELECTIONS-----

+ BASE [05/24/99]

GP Smith Plant

***** Input Report *****

-----Class: Weir-----

Name: O-SE From Node: SEPOND
Group: BASE To Node: OUTFALL
Count: 1

Type: Horiz Flow: Both Geometry: Circular

Span(in): 2.5
Rise(in): 2.5
Invert(ft): 6.9
Control Elev(ft): 6.9
TABLE
Bottom Clip(in): 0
Top Clip(in): 0
Weir Discharge Coef: 3
Orifice Discharge Coef: 0.6

-----Class: Weir-----

Name: W-NW From Node: NWPOND
Group: BASE To Node: OUTFALL
Count: 1

Type: Horiz Flow: Both Geometry: Rectangular

Span(in): 84
Rise(in): 36
Invert(ft): 7.7
Control Elev(ft): 7.7
TABLE
Bottom Clip(in): 0
Top Clip(in): 0
Weir Discharge Coef: 3
Orifice Discharge Coef: 0.6

Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.11) [2]
Copyright 1995, Streamline Technologies, Inc.

GP Smith Plant

***** Input Report *****

-----Class: Basin-----
Basin: SE Node: SEPOND Status: On Site Type: SCS Unit Hydr
Group: BASE
Unit Hydrograph: UH256 Peak Factor: 256
Rainfall File: SCSIII Storm Duration(hrs): 24
Rainfall Amount(in): 11
Area(ac): 22.56 Concentration Time(min): 26
Curve #: 71 Lag Time(hrs): 0
DCIA(%): 0

-----Class: Weir-----
Name: O-NW From Node: NWPOND
Group: BASE To Node: OUTFALL
Count: 1

Type: Horiz Flow: Both Geometry: Circular

Span(in): 1.75
Rise(in): 1.75
Invert(ft): 6.4
Control Elev(ft): 6.4
TABLE
Bottom Clip(in): 0
Top Clip(in): 0
Weir Discharge Coef: 3
Orifice Discharge Coef: 0.6

□□ Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.11) [1]
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GP Smith Plant

***** Input Report *****

-----Class: Node-----
Name: NWPOND Base Flow(cfs): 0 Init Stage(ft): 6.4
Group: BASE Length(ft): 0 Warn Stage(ft): 10
Comment:

Stage(ft)	Area(ac)
4.4	0.383
6.4	0.5703
7.4	0.6739
10.4	0.9009

-----Class: Node-----
Name: OUTFALL Base Flow(cfs): 0 Init Stage(ft): 6
Group: BASE Length(ft): 0 Warn Stage(ft): 0
Comment:

Time(hrs)	Stage(ft)
0	6
200	6

-----Class: Node-----
Name: SEPOND Base Flow(cfs): 0 Init Stage(ft): 6.9
Group: BASE Length(ft): 0 Warn Stage(ft): 10
Comment:

Stage(ft)	Area(ac)
4.9	0.9709
6.9	1.2552
7.9	1.4072
9.9	1.6203
10.9	1.7312

-----Class: Basin-----
Basin: NW Node: NWPOND Status: On Site Type: SCS Unit Hydr
Group: BASE
Unit Hydrograph: UH256 Peak Factor: 256
Rainfall File: SCSIII Storm Duration(hrs): 24
Rainfall Amount(in): 11
Area(ac): 10.14 Concentration Time(min): 15
Curve #: 78 Lag Time(hrs): 0
DCIA(%): 0

Stormwater analysis of the two wet detention ponds

***** Node Time Series by Time - 25YR *****

		Inflow					Link	
Node Name	Stage (ft)	Surface Ar.(ac)	Base Q (cfs)	Onsite (cfs)	Offsite (cfs)	Bndry Q (cfs)	Link Q (cfs)	Outflow
*** Group: BASE		Time	83.647:	3 days	11 hours	38 minutes	49 seconds	
NWPOND	7.14	0.65	0.00	0.00	0.00	0.00	0.00	0.07
OUTFALL	6.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00
SEPOND	7.62	1.36	0.00	0.00	0.00	0.00	0.00	0.14
*** Group: BASE		Time	83.897:	3 days	11 hours	53 minutes	49 seconds	
NWPOND	7.13	0.65	0.00	0.00	0.00	0.00	0.00	0.07
OUTFALL	6.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00
SEPOND	7.62	1.36	0.00	0.00	0.00	0.00	0.00	0.14
*** Group: BASE		Time	84.147:	3 days	12 hours	8 minutes	49 seconds	
NWPOND	7.13	0.65	0.00	0.00	0.00	0.00	0.00	0.07
OUTFALL	6.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00
SEPOND	7.62	1.36	0.00	0.00	0.00	0.00	0.00	0.14
*** Group: BASE		Time	84.397:	3 days	12 hours	23 minutes	49 seconds	
NWPOND	7.13	0.65	0.00	0.00	0.00	0.00	0.00	0.07
OUTFALL	6.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00
SEPOND	7.61	1.36	0.00	0.00	0.00	0.00	0.00	0.14
*** Group: BASE		Time	84.647:	3 days	12 hours	38 minutes	49 seconds	
NWPOND	7.13	0.65	0.00	0.00	0.00	0.00	0.00	0.07
OUTFALL	6.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00
SEPOND	7.61	1.36	0.00	0.00	0.00	0.00	0.00	0.14
*** Group: BASE		Time	84.897:	3 days	12 hours	53 minutes	49 seconds	
NWPOND	7.13	0.65	0.00	0.00	0.00	0.00	0.00	0.07
OUTFALL	6.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00
SEPOND	7.61	1.36	0.00	0.00	0.00	0.00	0.00	0.14
*** Group: BASE		Time	85.147:	3 days	13 hours	8 minutes	49 seconds	
NWPOND	7.12	0.65	0.00	0.00	0.00	0.00	0.00	0.07
OUTFALL	6.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00
SEPOND	7.61	1.36	0.00	0.00	0.00	0.00	0.00	0.14
*** Group: BASE		Time	85.397:	3 days	13 hours	23 minutes	49 seconds	
NWPOND	7.12	0.65	0.00	0.00	0.00	0.00	0.00	0.07
OUTFALL	6.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00
SEPOND	7.60	1.36	0.00	0.00	0.00	0.00	0.00	0.14

APPENDIX 10.2.3
BEST MANAGEMENT PRACTICES

DRAFT

**STORM WATER POLLUTION PREVENTION PLAN
&
BEST MANAGEMENT PRACTICES
POLLUTION PREVENTION (BMP3) PLAN**

**GULF POWER COMPANY
LANSING SMITH ELECTRIC GENERATING PLANT
BAY COUNTY, FLORIDA**

**REVISED
MARCH 1999**

CURRENT REVISION DATE

This SWPPP/BMP3 Plan will be revised periodically if there have been changes in design, construction, operations, or maintenance which has a significant effect on the potential for the discharge of pollutants to surface water of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. In addition, modifications to the SWPPP/BMP3 Plan incorporated to improve the effectiveness of the plan will also be included. The table below is to be used in order to document any changes or updates made to the SWPPP/BMP3 Plan.

[illegible]

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CERTIFICATION

Owner's Certification

I certify under penalty of law that this document and all appendices, attachments and enclosures were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment for knowing of violations.

Signature: _____

Title: _____

Certification Date: _____

1.0 INTRODUCTION

1.1 Background

All facilities covered by the National Pollutant Discharge Elimination System (NPDES) Multi-Sector General Permit for Storm Water Discharges Associated with Industrial Activities issued by the U.S. Environmental Protection Agency (USEPA) must develop and implement a Storm Water Pollution Prevention Plan (SWPPP). The requirements of the Final NPDES Multi-Sector Permit for Storm Water Discharges Associated with Industrial Activity, were first published by the USEPA in the *Federal Register* on September 29, 1995 (60 FR 50804) under authorization of the Code of Federal Regulations (CFR) at 40 CFR 122.28. In addition, FDEP Rule 62-620, Florida Administrative Code, requires facilities covered by NPDES permits to develop and implement a Best Management Pollution Prevention Plan (BMP3), incorporating the requirements of 40 CFR § 125, Subpart K. Both requirements are applicable for Florida facilities including Gulf Power Company's (GPC) electric generating plants. The intent of the SWPPP/BMP3 Plan is to evaluate potential pollution sources at the site and to select and implement appropriate measures known as Best Management Practices (BMPs) to prevent or control the discharge of pollutants in storm water runoff.

NPDES Permit Number FL0002267 was issued to GPC on April 17, 1998 for operation of Units 1 and 2 of the Lansing Smith Electric Generating Plant, under Section 403.0885, Florida Statutes and FDEP Rule 62-620, Florida Administrative Code. Under this permit the facility is required to develop and implement a Best Management Practices Pollution Prevention (BMP3) Plan directed toward reducing pollutants of concern which discharge or could discharge, to surface waters. The BMP3 Plan will address all activities which could or do contribute pollutants, as defined in the permit, to the surface water discharge, including storm water, water and waste treatment, and plant ancillary activities.

Due to the similarity of components required for the NPDES permits as described above, GPC has incorporated the requirements for both the SWPPP and BMP3 Plan into this joint document for the Lansing Smith Electric Generating Plant.

Information used to prepare this joint document was received from GPC and Lansing Smith Electric Generating Plant (Plant Smith) personnel and from Plant Smith's existing Storm Water Pollution Prevention Plan dated March 1993. Detailed site observations were conducted by representatives of Gulf Coast Environmental & Engineering, Inc. (GCE&E) accompanied by GPC personnel. This joint document has been prepared pursuant to the requirements and provisions of GPC's NPDES Permit No. FL0002267, Part VII, Section C and the facility's NPDES Multi-Sector Storm Water General Permit No. FLR05C162. Copies of both permits issued to Lansing Smith Electric Generating Plant are included in this plan as Appendix A.

1.2 Objectives

The pollution prevention approach adopted in the general permit focuses on two major objectives associated with industrial activities from the facility: 1) identifying sources of pollution potentially affecting the quality of storm water, water and waste treatment, and plant ancillary activities; and 2) describing and ensuring implementation of practices to minimize and control pollutants in storm water and wastewater discharges and providing a mechanism for compliance with the terms and conditions of the NPDES General Permit. To meet these objectives and the permit requirements, this joint document will:

- Present a Pollution Prevention Team of qualified personnel who will be responsible for assisting in the development, implementation, maintenance, and revision of the SWPPP/BMP3 Plan (Section 2.0)
- Summarize findings from the initial assessment of potential on-site storm water pollution sources (Section 3.0)
- Identify the appropriate BMPs and controls (Section 4.0)

- Implement the BMPs and controls (Section 5.0)
- Institute evaluation and monitoring of the SWPPP/BMP3 Plan to verify that it is properly implemented in accordance with the terms and conditions of the permit (Section 6.0)

1.3 Storm Water Pollution Prevention Plan/BMP3 Plan Format

In general, this joint plan format is organized to correspond to the multi-sector permit requirements in the order addressed in the USEPA Manual entitled "Storm Water Management for Industrial Activities: Developing Pollution Prevention Plans and Best Management Practices" (Manual). The reader is encouraged to review the Plant Smith SWPPP/BMP3 Plan jointly with the Manual. The Manual may assist the reader in understanding and implementing the SWPPP/BMP3 Plan. The SWPPP/BMP3 Plan is meant to be a foundation for GPC and Plant Smith personnel to build upon to create an effective storm water pollution prevention program. As conditions and practices at Plant Smith change to accommodate pollution prevention activities, sections of this document shall be revised accordingly. The format for this SWPPP/BMP3 Plan is designed to easily accommodate these changes. Details on implementation and evaluation activities required for the SWPPP/BMP3 Plan are included in Sections 5.0 and 6.0, respectively.

1.4 Impacts to Endangered Species

The NPDES Multi-Sector General Permit requires a certification regarding the presence and assessment of potential impacts to endangered species (as listed pursuant to the Federal Endangered Species Act (ESA) in areas receiving storm water discharges authorized under the NPDES Multi-Sector General Permit. A list of species and their locations which are contained in Addendum H of the NPDES Multi-Sector General Permit was reviewed. A determination was made whether the species listed are in proximity to the storm water discharges at the site and if so, whether there is any likely adverse effect upon the species.

Addendum H of the NPDES Multi-Sector Permit lists several species as potentially being found in Bay County, Florida. An endangered species survey was conducted which included a review of information on the relative abundance and distribution of the species and an on-site field survey to determine the presence or absence of the species and/or their habitat. The conclusion of the survey indicated that no known endangered or threatened species are located within a one-mile radius of the site and therefore, the discharge of storm water runoff that will be within the NPDES permit limitations and monitoring requirements established for these wastewaters will have no adverse impacts to endangered or threatened species or their habitat.

1.5 Impacts to Historic Sites

The NPDES Multi-Sector General Permit requires an indication concerning the applicability of and compliance with a written historic preservation agreement that may exist with respect to any historic sites listed on the National Historic Register that may be subject to adverse impacts from storm water discharges.

A review of historic sites in the area was conducted. The conclusion of the review indicated that no historical sites are located within a one-mile radius of the site and therefore, the discharge of storm water runoff that will be within NPDES permit limitations and monitoring requirements established for these wastewaters will have no adverse impacts to historic sites.

1.6 Statement of Company Policy

Gulf Power Company is committed to the goals of this SWPPP/BMP3 Plan program in order to prevent or minimize the potential for the discharge or release of pollutants to waters of the state. The primary objective of this joint plan is to ensure that preventative measures and procedures are in place to prevent any spill of oil or other regulated substances from reaching navigable

waters or adjoining shorelines. An assessment of operations of the facility is included herein as they have the potential for discharge of oil or other regulated substances. Where such a potential exists: (a) employees will be adequately trained to reduce the number of human errors that often causes spills; (b) inspection procedures will be implemented; (c) when appropriate, pollution prevention equipment will be installed and maintained; and (d) secondary containment, if practicable, will be provided to contain any material that may be spilled. The joint SWPPP/BMP3 Plan contained herein is designed to familiarize plant personnel with areas of potential spills, the procedures used to report a spill, and the methods and procedures used to inspect equipment so that the risk of an accidental spill is reduced.

2.0 PLANNING AND ORGANIZATION

2.1 Pollution Prevention Team/Best Management Practices Committee

As part of the development and implementation of the Plant Smith SWPPP/BMP3 Plan, a Pollution Prevention Team has been formed. A member roster listing the individuals, their phone numbers, and responsibilities, has been prepared and is included as Table 1.

The Pollution Prevention Team includes a corporate representative and the on-site team leader. The corporate representative is Ms. Rachel Terry, Environmental Affairs Specialist, with Gulf Power Company. The on-site team leader will be the plant Environmental Coordinator.

As delineated in the USEPA Manual, the Pollution Prevention Team is responsible for the following:

- Implementing all Multi-Sector General permit and pollution prevention plan requirements
- Defining and agreeing upon an appropriate set of goals for the facility's storm water management program
- Being aware of any changes that are made in plant operations to determine whether any changes must be made to the SWPPP/BMP3 Plan
- Maintaining a clear line of communication with plant management to ensure a cooperative partnership

The Pollution Prevention Team will gather at regularly scheduled meetings. If Plant Smith personnel notice potential sources of pollutants or have ideas to help reduce storm water

pollution, they should discuss them with any team member. The active participation of all Plant Smith personnel in helping identify and eliminate potential storm water pollution sources is vital to the success of this SWPPP/BMP3 Plan.

2.2 Existing Environmental Management Programs

Provisions of existing environmental management plans for Plant Smith should be coordinated to improve consistency between plans. Applicable plans which should be reviewed may include the following:

- Oil Spill Prevention Control and Countermeasures Plan
- Oil Spill Contingency Plan
- OSHA Emergency Action Plan

The SWPPP/BMP3 Plan has been prepared to be a comprehensive stand-alone document, but coordination of relevant portions of these plans should be considered. Revisions to the SWPPP/BMP3 Plan should be considered as other plans are reviewed and revised.

3.0 POLLUTANT SOURCE ASSESSMENT

3.1 Site Location

The Lansing Smith Electric Generating Plant is located on County Road 2300 in Bay County, Florida, west of the City of Southport on the peninsula between North Bay and West Bay, on the east bank of Alligator Bayou. The plant is accessed from State Highway 77 and thence from County Road 2300 to the Lansing Smith entrance gate. The plant address is 6804 Highway 2300, Southport, Florida 32409. The plant mailing address is P.O. Box 1210, Lynn Haven, Florida 32444. A site location map showing Plant Smith and the surrounding areas is presented as Figure 1. The plant is surrounded by undeveloped planted pine plantation dotted with small lakes and wetlands.

3.2 Site Description

Plant Smith encompasses approximately 1,230 acres and employs about 90 people. On this plant site there are three generating units that have a combined generating capacity of 390 megawatts (mw). The generating units are supported by a number of facilities which are described below.

Plant Smith started operation in May 1965. The plant consists of two coal-fired steam driven generating units and a peaking unit powered by an oil fired combustion turbine. The following is a table summarizing the characteristics of the generating units:

<u>Unit</u>	<u>Capacity (mw)</u>	<u>Fuel</u>	<u>Commercial In-service Date</u>
1	163	Coal	June 1965
2	192	Coal	June 1967
A	35	Oil	May 1971
Net-System Peak Hour Capacity	390		

The two primary generating units use electrostatic precipitators for air emission control and are cooled by a once-through cooling water system. Non-contact, once-through cooling water is

withdrawn from Alligator Bayou and discharged through a canal to Warren Bayou (West Bay of St. Andrew Bay). The peaking unit has no air emission control system and is internally cooled.

Other significant facilities supporting the electric generating units on the Plant Smith site include the following:

- Coal unloading and storage facilities
- Ash-handling and disposal facilities
- Bulk liquid storage facilities
- Storm water management system
- Wastewater management systems

Other facilities that support power generation at Plant Smith include the following:

- Three warehouse buildings
- Switchyard
- Contractor staging area
- Maintenance and storage shops
- Fire training area
- Parking lots
- Domestic water and wastewater facilities
- Demineralizer facilities and
- Miscellaneous other facilities

A SWPPP/BMP3 Plan pollutant source assessment for these facilities was conducted on May 10, 1999 by representatives of GCE&E accompanied by GPC personnel. Figure 2 has been prepared to satisfy U.S. EPA's permit requirements outlined in the plan named above. The above facilities and the following additional information are presented on Figure 2:

- All USEPA and FDEP permitted outfalls and storm water discharges
- Drainage areas of each storm water outfall
- Significant structural storm water pollution control measures
- Names of receiving waters
- Locations of exposed significant materials
- Location of past spills and leaks

Locations of high-risk, waste-generating areas and activities

The topography of Plant Smith does not significantly impact storm water management. The plant is located east of Alligator Bayou on the banks of North Bay slightly above sea level on relatively level ground.

On-site storm water runoff is controlled using a variety of structural methods. These methods include: storm drain systems, concrete swales, curbed roadways, ditches, roof drains, and pump stations. The individual drainage basins for Plant Smith are shown on Figure 2. In general, storm water that is not diverted to the Plant's ash pond and recycled to the ash sluice system is discharged through the outfalls shown on Figure 2, and ultimately, to West Bay. Storm water management practices associated with the facility operations are discussed below in Section 3.3.

All treated and untreated wastewater (except once-through cooling water and emergency overflow from the main yard sump) from the operation of Units 1 and 2 is discharged to the ash pond.

Wastewater streams that discharge to the ash pond include boiler blowdown, water treatment filter backwash, air preheater wash, ash and pyrite sluice, coal pile runoff, yard runoff, treated metal cleaning waste, treated demineralizer regeneration waste, treated domestic wastewater, and other minor process and non-process waste streams.

Demineralizer regeneration waste is neutralized and allowed to settle in a retention pond prior to discharge to the ash pond. Metal cleaning waste is neutralized in pipe and is chemically precipitated and allowed to settle in a retention pond prior to discharge to the ash pond. Domestic wastewater receives secondary treatment in an extended aeration package treatment plant prior to discharge to the ash pond.

3.3 Materials Inventory

In accordance with permit requirements, an inventory of materials that may have been or are exposed to rain water was conducted. The following items have been prepared to satisfy the permit requirements:

- A list of significant materials that have been exposed to storm water in the past three years with a focus on areas where materials are stored, processed, transported, or transferred
- A summary of methods and locations of on-site storage and disposal
- A description of materials management practices employed to minimize contact of the materials with storm water runoff
- A discussion of existing structural and non-structural control measures used to reduce pollutants in storm water runoff
- A discussion of existing treatment for storm water runoff

Some significant materials which have been exposed to storm water in the past three years are listed on Table 2. The locations of these exposed significant materials which may be potential pollutant sources are shown on Figure 2. Appendix A contains a list of on-site chemicals, which, if exposed to precipitation, could potentially pollute storm water.

Methods and locations of on-site storage and the associated materials management practices (loading and unloading) employed to minimize the contact of these materials with storm water is presented in the following subsections. A narrative description of the associated existing storm water structural and non-structural control measures, as well as treatment of the associated storm water runoff, is also included in the same subsections.

3.3.1 Outdoor Material Storage Areas

There are five types of outdoor material storage areas at Plant Smith including: coal storage area, ash storage ponds and landfill, bulk liquid storage facilities, solid waste storage areas, and a construction materials storage area. Four of these five types of material storage areas are exposed to direct storm water contact. The materials in the bulk liquid storage facilities are generally unexposed. The location of outdoor material storage areas is shown on Figure 2.

The following text describes the methods of material storage and management and the associated storm water control and treatment measures for each type of storage area. Best management practices for these areas are discussed in Section 4.0.

3.3.1.1 Coal Storage Area

Approximately 18 acres of the Plant Smith site are occupied by facilities and equipment for unloading and storage of coal. The coal unloading facility is located adjacent to the coal barge docks in Alligator Bayou. The coal storage area (coal pile) is located immediately east of the coal unloading facility. The locations of these facilities are shown on Figure 2.

Storm water contacting the coal pile drains to the perimeter of the storage area. In general, runoff is controlled by concrete swales and coal berms. On the north side of the coal unloader, runoff drains to a concrete swale on the eastern side of the plant road. This swale drains to a sump which discharges to the ash pond and is treated as wastewater. Runoff to the north is intercepted by a coal berm where it appears to percolate to groundwater. Runoff from the east side of the coal pile drains to a concrete perimeter swale back to a pump station located in the southeast corner of the coal storage area. Runoff from the south and southwest also appears to drain towards this pump station as well. This pump station discharges to the ash pond.

3.3.1.2 Ash Storage Ponds and Landfill

Ash storage and disposal facilities for Plant Smith include the ash storage pond and an ash landfill. The ash storage pond and the associated discharge to the recycle canal are covered by a NPDES permit. Currently, use of the ash pond for disposal is alternated between several diked areas within the pond. After an area is filled, the ash is removed and placed in the on-site landfill. Clean runoff from the capped and grassed landfill drains to perimeter swales and then to a culvert located in the southeast corner of the landfill area. Additionally, there is a stormwater detention pond located in the southwest corner of the landfill. Water in this pond is pumped to the ash storage pond. An

emergency overflow structure was observed during the site visit. There were no indications that the water level in the pond has ever reached the spillway on this structure. The ash pond and landfill are shown on Figure 2.

3.3.1.3 Bulk Liquid Storage Facilities

Plant Smith stores almost all liquid chemicals and petroleum products used at the Plant site in above ground storage tanks (AST). There are 9 outdoor ASTs located across the site. In general, ASTs contain petroleum products for fuel and lubrication, and chemicals for water treatment. The locations and contents of these ASTs are shown on Figure 2.

All AST areas have secondary containment systems which, if properly maintained, will isolate the stored material and any storm water within the containment area from the surrounding areas and ultimately from surface waters. Storm waters collected in the containment areas are generally allowed to evaporate, or are drained by operations personnel. The liquid sodium hydroxide (caustic) and sulfuric acid installation south of the demineralization facility are stored in horizontal ASTs with secondary containment. Laboratory personnel have the responsibility for testing and draining storm water from these containments. In that same area, adjacent to the vehicle maintenance facility, a diesel fuel dispensing station also has secondary containment.

Secondary containment has been installed at the combustion turbine oil unloading area. Plant Smith also has a Spill Prevention and Countermeasure Plan and the associated equipment to reduce risk associated with spills and leaks.

3.3.1.4 Solid Waste Storage Areas

Solid waste generated from the Plant is placed into solid waste containers located around the plant site at locations shown on Figure 2. Some containers are uncovered and therefore storm water does come in contact with the refuse placed in them. Drainage from each of these dumpsters could flow

towards local catch basins or other storm water management structures for conveyance to a storm water outfall.

During the site reconnaissance, there did not appear to be evidence that dumpster drainage affects storm water quality. Further evaluation will be completed as part of the implementation of baseline BMPs. Recommendations will be based on the findings of the evaluation.

3.3.1.5 Construction Material Storage Areas

Scrap metal and construction materials appear to be stored in the contractor lay down area behind the main plant building. Scrap metal generated on-site is either placed on the ground or into roll off storage containers located around the site as shown in Figure 2.

During the site reconnaissance, there did not appear to be evidence that construction materials and scrap metal storage area drainage affects storm water quality. Further evaluation will be completed as part of the implementation of baseline BMPs. Recommendations will be based on the findings of the evaluation.

3.3.2 Indoor Material Storage Areas

There are a number of buildings where materials are stored indoors at Plant Smith. These areas include the main building, three warehouses, maintenance building, and oil house. These storage areas shelter materials from storm water exposure. The materials in these four locations generally appear to be stored in a manner to reduce the risk associated with spills and leaks. More detailed inspections will be conducted to assess conditions of each area as part of the BMP implementation program. The greatest risk associated with management of the materials stored indoors is initial loading and unloading or transfer of materials between storage and use locations. Additionally, there is a risk of non-stormwater discharge from building sumps if material spills or leaks occur.

A detailed inventory of materials used and stored on site will be developed as part of the BMP implementation program. Development of BMPs associated with management of individual materials stored indoors will be included in Section 4.0.

3.3.3 Loading and Unloading Areas

The loading and unloading of materials between vehicles and facilities discussed in Sections 3.3.1 (Outdoor Material Storage Areas) and 3.3.2 (Indoor Material Storage Areas) occurs at multiple locations. The loading and unloading areas are grouped as follows:

- Coal unloading dock
- Ash handling and disposal facilities
- Outdoor bulk liquid storage facilities
- Outdoor solid waste metal storage areas
- Contractor staging area
- Packaged goods storage areas

The following sections describe materials management for these areas. The locations where these activities occur are shown on Figure 2. Best management practices for these areas are discussed in Section 4.0.

3.3.3.1 Coal Unloading Dock

Coal delivered to Plant Smith arrives in open-top barges which are docked in Alligator Bayou for unloading. Unloading is accomplished by one stationary crane located adjacent to the bayou. Buckets of coal are transferred between the barges and a feed hopper by this manually operated crane. Coal is then conveyed either to the coal pile or to the plant. Given the nature of the operation, some coal may be lost from the bucket between the barge and the hopper, and distributed around the unloader or in Alligator Bayou between the barge and the seawall. However, current practices and equipment are designed to minimize these occurrences.

3.3.3.2 Ash Handling and Disposal Facilities

Ash is transferred from the plant using a sluice piping system. Exposure of ash materials to storm water is minimized due to the method of transfer between the point of generation and the ash storage pond.

3.3.3.3 Outdoor Bulk Liquid Storage Facilities

Liquid chemicals and petroleum products are stored outdoors predominantly in ASTs. There are five unloading areas on the Plant site where these products are transferred to ASTs; or in the case of the chlorination plant, placed in the storage area in one-ton pressurized cylinders. These five locations are identified on Figure 2 and described as follows:

- Diesel fuel unloading and sludge and waste oil loading adjacent to the ASTs west of the switch yard
- Chlorine cylinder unloading at the chlorination plant
- Chemical product unloading south of the main building on the southeast corner of the plant road. Chemicals unloaded at this facility include sulfuric acid, 50-percent sodium hydroxide (caustic)
- Petroleum product unloading, including diesel fuel, adjacent to the chemical unloading area
- Diesel fuel unloading behind the fire pump house south of the main building

The condition of these unloading areas varies from location to location. General materials management practices require that the contractor unloading the material be accompanied by Plant personnel who will witness the entire unloading operation. The contractor is responsible for providing equipment associated with their delivery vehicles to eliminate exposure of the materials

to storm water on the Plant site. Truck to Plant offloading equipment varies from location to location. Again, the unloading area for combustion turbine diesel fuel has secondary containment in place.

3.3.3.4 Outdoor Solid Waste/Scrap Metal Storage Areas

Transfer of solid waste and recoverable materials between the point of generation and temporary storage locations is done predominantly for refuse and scrap metal. Generally there is one location on site where materials are transferred. This area is east of the main building near the contractor staging area and the Number 3 Warehouse.

Good housekeeping is typically practiced for transfer of trash and scrap metal placed in containers to minimize exposure to storm water.

3.3.3.5 Contractor Staging Area

During the site visit, significant contractor activity was observed on the plant site. A concentration of construction trailers and material storage, both new and used, was present east of the main building. Loading and unloading, as well as storage of materials in this area, could expose the materials to storm water. Runoff from this area appears to drain east to the road and then north beyond the perimeter fence to a drainage ditch. Although these contractors are only temporarily on site, improved materials practices and temporary structural BMPs should be considered to reduce material exposure to runoff. Further evaluation of these measures is included as a BMP for Plant Smith.

3.3.3.6 Packaged Goods Storage Areas

A variety of materials delivered to the Plant are covered in this category. Packaged goods are defined as any material which is delivered from the manufacturer pre-packaged and stored on-site in that package. Locations where packaged goods may be stored include the following:

- Three warehouses
- Vehicle maintenance building
- Chlorination plant
- Main building

There is limited risk associated with exposure of materials to storm water during loading or unloading of these materials from these particular areas.

3.3.4 Other Support Areas

Other support areas, such as the fire training area, car wash, and parking lots, were visited during the site reconnaissance. At this time, no additional BMPs are required for these areas.

3.4 History of Past Spills and Leaks

This SWPPP/BMP3 Plan must list any significant spills and/or leaks that may have occurred at the Plant over the past three years. "Significant spills" have been identified by the U.S. EPA as the release within a 24-hour period of toxic or hazardous substances in excess of reportable quantities under Section 311 of the Clean Water Act and/or Section 102 of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Reportable quantities are predefined amounts of substances in pounds, gallons, or other units and are listed in 40 CFR 117 and 40 CFR 302. Releases are defined to include any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing of a substance into the environment.

The NPDES Multi-Sector General Permit requires that any significant spills/leaks that have occurred during the three-year period prior to the date of the submittal of the NOI to be covered by this permit be identified in the SWPPP. Table 3 is included in this Plan to summarize spills and/or leaks which occurred during this three-year period. One spill occurred on July 31, 1995, when an underground fiberglass pipeline associated with the plant's used oil storage tank ruptured spilling approximately 853 gallons of used oil. The spill was properly managed and reported to FDEP. An Initial Remedial Action (IRA) Report was filed with FDEP. A Site Rehabilitation Completion Order for the spill incident was approved and final from FDEP on 2-26-96.

3.5 Non-Storm Water Discharges

The Multi-Sector General Permit requires that the Storm Water Pollution Prevention Plan list any non-storm water discharges that may exist at the Plant. On May 10, 1999, two representatives of GPC and GCE&E conducted a field investigation of the plant site in order to evaluate each storm water outfall and/or drainage area for the presence of non-stormwater discharges. The method used to make this determination was a visual inspection of the site. The results of this evaluation are supported by Plant Smith personnel who conduct daily inspections of the facility site. Table 4 is included in this SWPPP/BMP3 Plan to summarize non-storm water discharges at Plant Smith, and/or to act as an official certification that non-storm water discharges that may have existed have been eliminated. One storm water outfall has been identified. No non-storm water discharges were observed to occur at this outfall. Table 4 of this SWPPP/BMP3 Plan contains GPC's certification that non-storm water discharges, which are not otherwise identified above and/or duly authorized by the NPDES Multi-Sector General Permit, are not present at the facility.

There are five permitted wastewater discharges covered by the NPDES Wastewater Permit. Wastewater discharges include condenser cooling water, boiler blowdown, air preheater washwater, fly and bottom ash sluice, miscellaneous minor process streams, and emergency overflows from the main plant sump and the recycle canal. Outfalls associated with these discharges are shown on Figure 2. These outfalls are regularly tested as required by the NPDES permits.

Presented is a summary of the outfalls listed in the state and federal permits:

<u>Outfall Number</u>	<u>Outfall Name</u>
D001	Main Plant Discharge Canal
D015	Metal Cleaning Wastes
D01C	Ash Recycle System
D00D	Main Yard Sump Overflow
D01A	Treated Domestic Wastewater

Sanitary wastewater generated at the plant site is treated in the domestic wastewater treatment plant. Septic tanks are in use for the Administrative Building and the Coal Unloading facility. These septic tanks each have their own drainfields for disposal of effluent via percolation to groundwater.

3.6 Existing Storm Water Monitoring Data

Sampling has been conducted at Plant Smith. Details of the sampling events, sampling procedures, and copies of laboratory test results will be added to the SWPPP/BMP3 Plan.

3.7 Storm Water Sampling and Analysis Plan

In accordance with the storm water discharge monitoring requirements for steam electric power generating facilities contained in the NPDES Multi-Sector General Permit, Plant Smith is required to collect quarterly grab samples for total recoverable iron during the second and fourth years of permit coverage. However, since year two has already passed, monitoring will only be required in year four (October 1, 1998, through September 30, 1999). Quantative analytical data for total recoverable iron must be collected and submitted within three months of the conclusion of each year to the U.S. EPA as required by the NPDES Multi-Sector General Permit.

Sampling Locations and Schedule

Plant Smith personnel will collect a storm water sample at the outfall location on a quarterly basis during the fourth year of permit coverage.

Sample Types and Sampling Protocol

The storm water samples will be collected in accordance with the storm water sampling requirements of the NPDES Multi-Sector General Permit. Specifically, the representative samples must be collected as grab samples for total recoverable iron during the first 30 minutes of storm water discharge through a designated outfall.

Representative Storm Event

The storm water samples will be collected from the discharge at the designated outfalls that results from a regulatory-defined storm event. The storm water sampling regulations of the NPDES Multi-Sector General Permit require that storm water samples be collected from the discharge resulting from a storm event that is greater than 0.1 inches in magnitude and that occurs at least 72 hours following the most recent, previously measurable storm event that had a rainfall magnitude greater than 0.1 inches.

Storm Water Sample Containers

All containers for sample collection (grab samples) will be provided by the contract laboratory. All containers must be prepared in accordance with good laboratory practice and made chemically clean pursuant to the sample collection and sample container requirements of the applicable U.S. EPA-approved analytical methods for the respective analyses to be conducted. Any required preservatives will be added to the designated sample containers by the laboratory prior to the sampling event. Additional or redundant sample containers should be considered as a contingency for breakage or inadvertent contamination prior to/during sample collection. Only containers provided by the laboratory for each respective type of analysis should be substituted in the field.

Storm Water Sample Labels

Proper labeling of all sampling containers is required. The following information will be included on each sample label:

- Sample identification label
- Date

- Time
- Location (Outfall #)
- Facility (Lansing-Smith)
- Full name of sample collector
- Contract laboratory
- Analysis to be performed

Marking of labels and containers should be performed in a dry area prior to the onset of sampling during a “wet weather” event to prevent loss of legibility due to smearing. Labels and containers should be marked using permanent, indelible ink.

Sample Handling, Transport, and Chain-of-Custody Documentation

Following collection, the storm water grab samples must be placed and stored on wet ice in ice chests to maintain a temperature of 4°C during transport of samples to the contract laboratory.

Designated personnel will be responsible for the storm water samples throughout the sampling period and will coordinate transportation of the samples to the contract laboratory for analyses. An appropriate chain-of-custody form detailing the analytical requirements must be filled out by the designated responsible personnel and must accompany the samples to the contract laboratory.

When transferring possession of samples, for each change of possession, the transferor and the recipient must sign and record the date and time on the chain-of-custody form. In general, custody transfers can be made for individual samples or samples as a group. The number of custody transfers should be kept to a minimum. A standardized chain-of-custody form will be used that is designated to “prompt” the user(s) to complete all required sample collection and transport information including the following:

- Sample type and number of containers
- Sample source location description
- Full name of person collecting the samples
- Date and time of collection for each sample
- Laboratory analysis required/requested, and
- Full name and signature of each transferor and recipient, along with date and time for every custody transfer from sample collection through receipt by the contract laboratory.

Observing proper chain-of-custody procedures, designated personnel will provide oversight of transportation of all samples to the analytical laboratory. All samples must be properly labeled and packaged in ice chests (on wet ice at a temperature of 4°C) and delivered to the contract laboratory office for transfer of custody and sample “log-in”.

Laboratory Analysis

GPC will contract with a commercial analytical laboratory with demonstrated experience and expertise with environmental media for the analyses of the storm water samples. The contracted laboratory will receive custody of the samples following transport to the laboratory by designated, responsible personnel. The laboratory will “log-in” and account for all collected and transported samples and will retain custody through sample analyses, data validation, and reporting of analytical results. The contract laboratory must perform all analyses in accordance with the applicable U.S. EPA-approved analytical method for each parameter for which testing is required by the NPDES Multi-Sector General Permit for the Plant Smith storm water discharges.

The laboratory analytical methods to be used must be in accordance with the requirements of the NPDES program as specified at 40 CFR 136, Guidelines Establishing Test Procedures for the Analysis of Pollutants. The contract laboratory must implement and adhere to all applicable and appropriate laboratory quality assurance/quality control (QA/QC) procedures in accordance with good laboratory practice and with the specific requirements of the respective U.S. EPA-approved analytical methods (approved pursuant to 40 CFR 136).

Quarterly Visual Examinations of Storm Water Quality

All facilities must conduct and document quarterly visual examinations of storm water discharges. Examinations will be conducted in each of the following periods for the purpose of visually inspecting storm water quality associated with storm water runoff from the facility: *January through March; April through June; July through September; and October through December.*

Examinations are to be made of samples collected within the first 30 minutes (or as soon thereafter as practical, but not to exceed one hour) of when the runoff begins discharging. The examinations shall document observations of color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution. The examination must be conducted in a well lit area. No analytical tests are required to be performed on the samples. All such samples are to be collected from the discharge resulting from a storm event that is greater than 0.1 inches in magnitude and that occurs at least 72 hours from the previously measurable (greater than 0.1 inch rainfall) storm event.

Visual examination reports must be maintained onsite in the SWPPP/BMP3 Plan. The report must include the examination date and time, examination personnel, the nature of the discharge (i.e., runoff), visual quality of the storm water discharge (including observations of color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution), and probable sources of any observed storm water contamination. An example Storm Water Sampling Report is included in Table 9.

If Plant Smith personnel are unable to collect samples over the course of the monitoring period as a result of adverse climatic conditions, Plant Smith personnel must document the reason for not performing the visual examination and retain this documentation onsite with the records of the visual examination. Adverse weather conditions which may prohibit the collection of samples include weather conditions that create dangerous conditions for personnel (such as local flooding, high winds, hurricane, tornadoes, electrical storms, etc.) or otherwise make the collection of samples impracticable (drought).

3.8 Site Assessment Summary

The Multi-Sector General Permit requires that a narrative description of the potential pollutant sources associated with the assessment be presented with a discussion of the pollutants of concern. The previous subsections in Section 3.0 satisfy the permit requirements. These subsections addressed site characteristics, facility characteristics, and the Plant Smith materials which may be exposed to rainwater. Furthermore, discussions concerning materials storage and existing management practices which reduce material exposure to rainwater, direct storm water away from contaminated areas, and/or collect it for on-site treatment were presented. The conditions described in the previous subsections are representative of information reviewed and field observations made during preparation of this revised SWPPP/BMP3 Plan. A discussion of BMPs for the plant areas and pollutants of concern are addressed in Section 4.0.

4.0 BEST MANAGEMENT PRACTICES

This section describes recommended storm water management controls to be carried out under this SWPPP/BMP3 Plan. Several general recommendations to reduce storm water contact with materials present at the Plant were formulated based on observations and information collected during the Plant visit. The general recommendations are presented for the eight baseline BMP categories required by the permit. Priority BMPs for identified potential sources of pollutants will be developed from site observations. The priority BMPs will be included as Section 4.2. The following recommendations are intended to augment the best management practices already being practiced at the Plant.

4.1 Baseline BMPs

The baseline BMPs include: good housekeeping, preventive maintenance, spill prevention response, sediment and erosion control, management of runoff, visual inspections, employee training, recordkeeping and reporting. Discussions concerning employee training, recordkeeping, reporting, plan review, and modifications are presented in Sections 5.0 and 6.0.

4.1.1 Good Housekeeping

Potential storm water pollution can be limited if everyone helps by practicing good housekeeping. This will be a Plant-wide effort to maintain a clean site. General housekeeping methods and practices are described below:

- Improve operation and maintenance of equipment and processes
- Implement careful material storage practices
- Maintain up-to-date material inventory
 - Identify all chemical substances present in the workplace
 - Label all containers showing name and type of substance, stock number, etc.
- Schedule routine cleanup operations

- Maintain well-organized work areas
- Train employees about good housekeeping practices

4.1.2 Preventive Maintenance

Facilities and equipment at Plant Smith need to be maintained in good working condition to prevent storm water pollution. The catch basin and drop inlet grates, culvert entrances, concrete ditches, and other storm water control features should be periodically inspected. Accumulated sediment or debris such as paper and leaves should be removed. Obvious signs of potential pollution, e.g., oil on the water surface, should be reported. Storm water facilities should be cleaned as needed to remove possible accumulations of oil, fuels, and solid debris. All pumping and other mechanical equipment should be tested and maintained routinely. The water and cleaning materials used for this should be disposed of properly and not allowed to flow off-site.

All Plant preventative maintenance activities should be documented, including the following information:

- The date the maintenance was performed
- An estimate of the quantity of pollutant materials removed from the site
- Solid and liquid waste recycling, reduction, or disposal methods
- Locations of disposal facilities
- Any further action required

Disposal manifests must be kept on file if a hazardous waste was involved. Records of work performed under the Preventative Maintenance Program should be documented and placed in Appendix D.

4.1.3 Spill Prevention and Response

Spills may occur anywhere on the property indoors or outdoors, especially at the outdoor AST areas or at loading or unloading areas around the Plant. If a spill occurs anywhere on the plant

site, it can potentially enter the storm drain system and pollute storm water runoff. The best way to handle a spill is to prevent it from happening. This can be accomplished by doing the following:

- Keeping all containment vessels of hazardous materials in secondary spill containment structures
- Clearly marking the hazardous materials that require special handling, storage, use, and disposal
- Training personnel in the proper procedures for handling hazardous materials and the location of Material Safety Data Sheet (MSDS)
- Inspecting all chemical and petroleum related storage areas to be sure there are no signs of leaks or the potential of a leak to occur because of a corroded containment vessel
- Using proper filling procedures for tanks and equipment that minimize spills
- Substituting less or non-toxic materials for toxic materials.

If a spill of a reportable quantity of hazardous material is released, the Plant personnel should respond in accordance with the Plant Smith Emergency Action Plan (EAP). The "reportable quantity" varies for different hazardous materials. A complete list of the quantities can be found in the USEPA Title III, List of Lists, January 1992. If the quantity or type of material is unknown or not listed, but the quantity is estimated to be at least one pound, the release should be reported. If a spill of hazardous materials occurs, the EAP outlines the specific procedures to follow and the people to be notified during such an event.

4.1.4 Sediment and Erosion Control

The Plant's land surface is relatively stable. The grassed, graveled, fabriform covered areas, and paved areas appear to be in good condition and do not appear to produce excessive eroded sediments which can pollute storm water. Existing vegetated areas will be maintained along the intake canal area to prevent erosion and facilitate natural filtration of suspended solids in storm

water runoff. However, should erosion affecting storm water management systems occur on the property, remedial action to stop the erosion should be taken. This could involve planting new grass, adding more gravel to an exposed soil surface, or patching or repaving deteriorated fabriform covered or paved surfaces. If construction activity occurs on site, sediment and erosion control must be implemented and monitored.

4.1.5 Management of Runoff

Runoff at Plant Smith is generally well managed using a number of stormwater management techniques. Improved management at the source to reduce pollutant exposure, as well as traditional methods to divert runoff from surface water outfalls should be routinely evaluated. Visual inspections of material storage areas and loading and unloading facilities during rain events should be conducted with the intent of identifying exposed materials and potential improvements for management of runoff.

4.1.6 Visual Inspections

In addition to preventive maintenance inspections, visual inspections will be conducted regularly of all areas which contain potential pollutant sources. Routine visual inspections are to verify and ensure that key elements of the SWPPP/BMP3 Plan are in place and are effective. Although the visual inspections are not intended to be exhaustive, they will be used on a quarterly basis by the plant Environmental Coordinator or a designated representative to observe and verify the effectiveness of the selected management practices in preventing the contamination of storm water from the site.

All secondary containment structures for outdoor storage of significant materials (e.g. C.T. diesel fuel storage tanks) will be inspected for damage to structural integrity and for any evidence of leakage or residual contamination to storm water. All storm water conveyances and drains will be inspected for evidence of any malfunction or damage that may interfere with the conveyance of storm water. The entire site will be inspected for evidence of spills.

Visual inspections will be thoroughly documented by a designated Plant Smith representative. A checklist designed to facilitate quarterly inspections is included in Table 8 (Record of Quarterly BMP Inspections) of the SWPPP/BMP3 Plan. Deficiencies noted during the inspections should be corrected using Plant Smith's Work Order System. A listing of the completed Work Orders should be kept on file in Appendix C. Inspection forms and Work Orders are required to be kept for three years. Section 6.1 Annual Site Compliance Evaluation describes inspection requirements in greater detail. These requirements should be considered while conducting quarterly inspections.

4.2 Priority BMPs

This section of the Plan identifies areas and practices that have a high potential for polluting storm water runoff. Based on the initial work for the SWPPP/BMP3 Plan, BMPs have been outlined for the coal unloading and storage area, bulk liquid storage facilities, solid waste storage areas, contractor staging area, packaged goods storage areas, and the fire training area. Table 5 contains BMPs to address these potential sources. Additional BMPs and schedules for implementation will be added as the SWPPP/BMP3 Plan is implemented. Prioritization of BMPs will also be undertaken by the Pollution Prevention Team. An extra column to note dates of completed work is included in Table 5 to record actual implementation.

5.0 POLLUTION PREVENTION PLAN IMPLEMENTATION

5.1 Implementing Appropriate Controls

Based on the assessment of the potential pollutant sources at the plant, this SWPPP/BMP3 Plan includes in Section 4.0 a summary of appropriate storm water management measures (BMPs) which will be implemented and maintained. Implementation of the approved BMPs should be scheduled by GPC as determined appropriate. These schedules will be developed following prioritization of the storm water management BMPs considering the hierarchy of the classifications included in the Manual. This hierarchy is shown below with example BMPs.

Storm Water Management Hierarchy

Example BMPs

Source Reduction

Preventive maintenance
Spill prevention
Chemical substitution
Housekeeping
Training
Materials management practices

Containment/Diversion

Segregating the activity of concern
Covering the activity
Berming the activity
Diverting flow to grassed area
Dust control

Recycling

Enhanced recycling

Treatment

Oil/water separator
Vegetated swale
Storm water detention pond
Re-vegetation of intake canal to prevent erosion

To implement the plan, specific individuals, including representatives from the Pollution Prevention Team, will be delegated the responsibility for implementing and/or monitoring implementation of BMPs. Performing non-structural BMPs, like good housekeeping, will be everybody's responsibility. As with other activities, appropriate approvals should be obtained based on the implementation schedule and strategy prior to implementation.

Reporting progress of implementation for the individual BMPs or the overall BMP program is discussed in Section 6.2. Additional BMPs and progress with existing BMPs should be added to this plan by revising Table 5 Best Management Practices Log.

5.2 Employee Training

In accordance with permit requirements, an employee training program is necessary to inform all personnel about prevention of storm water pollution. The training topics should address health and safety, hazard communications, spill and leak response, good housekeeping, and materials management practices. Specific ideas included in EPA's Manual, and presented below should be a guideline to develop the employee training program. A preliminary training program is outlined in Table 6.

The goals of the training program are to teach personnel, at all levels of responsibility, the components and goals of the SWPPP/BMP3 Plan. Furthermore, it should create an overall sensitivity to pollution prevention concerns. Open discussions should be encouraged to further the importance and enhance the training program. In addition, the effectiveness of the training program should be evaluated routinely to verify that information has been communicated effectively to the employees.

5.2.1 Spill Prevention Response

Discuss spill prevention and response procedures or plans in the training program in order to ensure that all plant employees, not just those on the spill response teams, are aware of what to do if a spill occurs. Specifically, all employees involved in the industrial activities of your facility should be trained about the following measures:

- Identifying potential spill areas and drainage routes, including information on past spills and causes
- Reporting spills to appropriate individuals, without penalty (e.g., employees should be provided "amnesty" when they report such instances)
- Specify material handling procedures and storage requirements
- Implementing spill response procedures

On-site contractors and temporary personnel should also be informed of the plant operations and design features in order to help prevent accidental discharges or spills from occurring.

5.2.2 Good Housekeeping

Teach facility personnel how to maintain a clean and orderly work environment. Emphasize these points in the good housekeeping portion of your training program:

- Require regular vacuuming and/or sweeping
- Promptly clean up spilled materials to prevent polluted runoff
- Identify places where brooms, vacuums, sorbents, foams, neutralizing agents, and other good housekeeping and spill response equipment are located
- Display signs reminding employees of the importance and procedures of good housekeeping

- Discuss updated procedures and report on the progress of practicing good housekeeping at every meeting
- Provide instruction on securing drums and containers and frequently checking for leaks and spills
- Outline a regular schedule for housekeeping activities to allow you to determine that the job is being done

5.2.3 Materials Management Practices

The following items should be emphasized regarding materials management practices:

- Neatly organize materials for storage
- Identify all toxic and hazardous substances stored, handled, and produced on site
- Discuss handling procedures for these materials

5.2.4 Tools for a Successful Training Program

Training tools that can be included in the facility's training program include:

- Employee handbooks
- Videos and slide presentations
- Drills
- Routine employee meetings (mandatory attendance)
- Bulletin boards
- Suggestion boxes
- Newsletters
- Environmental excellence awards or other employee incentive programs

5.2.5 Training Frequency

Frequency of training should take into account the complexity of the plant's operations and the nature of the staff. The pollution prevention team will determine the frequency and who should

attend. Documentation of attendance should be placed in Appendix B of this plan. Table 7 is a sample copy of an attendance sheet.

6.0 POLLUTION PREVENTION PLAN EVALUATION

6.1 Annual Site Compliance Evaluation

The permit requires that qualified personnel conduct site compliance evaluations at least once a year. The annual site compliance evaluations are comprehensive inspections beyond the scope of the periodic inspections discussed above. These inspections will be performed by the Pollution Prevention Team. They should be accompanied by other employees who are familiar with Plant Smith's industrial operations and the goals and requirements of the SWPPP/BMP3 Plan. This annual evaluation will provide a basis for evaluating the overall effectiveness of the SWPPP/BMP3 Plan.

As part of the compliance evaluation, the general permit requires the following activities to be carried out:

- Inspect storm water drainage areas for evidence of pollutants entering the drainage system
- Evaluate the effectiveness of BMPs to reduce pollutant loadings and whether additional measures are needed
- Observe structural measures, sediment controls, and other storm water BMPs to ensure proper operation
- Revise the plan as needed within two weeks of inspection and implement any necessary changes within 12 weeks of the inspection
- Prepare a report summarizing inspection results and follow-up actions, identifying the date of inspection and who conducted the inspection
- Identify any incidence of non-compliance or certify that the facility is in compliance with the plan
- Have the report signed by the plant Environmental Coordinator or a duly authorized representative responsible for the environmental matters of Plant Smith

In order to carry out the above outlined activities, the following site-specific activities will be completed:

- Review the Plant Smith SWPPP/BMP3 Plan and outline a list of those items which are part of material handling, storage, and transfer areas covered by the Plan. These areas are described in Section 3.3
- List all equipment and containment of these areas covered in the plan
- Review the plant's operations for the past year to determine if any more areas should be included in the original plan, or if any existing areas were modified so as to require plan modification
- Conduct an inspection to determine if all storm water pollution prevention measures are accurately identified in the plan and if they are in place and working properly
- Document findings as described above and in Sections 5.3. Any incidents of non-compliance must be documented in an inspection report using the Inspection Report Form included as Table 8. Signed, completed reports shall be filed in Appendix C with the monthly inspection reports
- Modify the Plant Smith SWPPP/BMP3 Plan as necessary. Plan Revision procedures are described below in Section 6.3

6.2 Recordkeeping and Reporting

Plant Smith will record and maintain records of spills, leaks, inspections, and maintenance activities for at least one year after the permit expires in accordance with the Multi-Sector General permit requirements. Recordkeeping and internal reporting represents good operating practices because they can increase the efficiency of the facility and the effectiveness of BMPs.

The records should include the following as appropriate:

- The date and time of the incident, the weather conditions, duration, cause, environmental problems, response procedures, parties notified; recommended revisions of the BMPs program; Operating procedures and/or equipment needed to prevent reoccurrence.
- Formal written reports using forms presented as Tables 8 and 9 or other appropriate format. Reports similar to those required by Plant Smith Oil Spill Prevention Control and Countermeasures Plan (SPCCP) may be used. Reporting of spills and other discharges shall be done in accordance with 40 CFR 117.3 and 40 CFR 302.4. If a spill or leak occurs, the Oil Spill Contingency Plan outlined in the oil SPCCP should be used to notify the appropriate plant personnel.
- Recordkeeping and reporting of maintenance activities. As described above in Section 5.3, the Plant's Work Order System should be used for correcting deficiencies including maintenance activities. A log of all maintenance activities should be included in Appendix D of the SWPPP/BMP3 Plan.,

6.3 Plan Review and Modifications

The permit requires that the SWPPP/BMP3 Plan be amended if there have been changes in construction, operations, or maintenance. In addition, modifications to the SWPPP/BMP3 Plan incorporated to improve the effectiveness of the plan should also be included. The SWPPP/BMP3 Plan should be revised where needed, and revisions should be noted on the Inspection Report Form, following the month of the revision.

Ms. Rachel Terry, corporate representative, or a designated GPC employee, will have the responsibility for revising the plan so that it reflects current conditions at the Plant, and for documenting these revisions to reflect the Plant's efforts to control pollution from storm water runoff. Pages of the SWPPP/BMP3 Plan which are superseded by revised pages should be filed in Appendix E.

With these objectives in mind, the following steps should be taken when revising this Plan:

- All new material should be typed on a new page and inserted in the appropriate location in this Plan. Each new page should be typed in the same format as other SWPPP/BMP3 Plan pages and be signed and dated by the Plan designated representative in the footer at the bottom of the page entitled:

"Implemented by: _____"
Name Date

- When pages of the plan are revised due to changes in existing conditions at the Plant, the entire page should be replaced. New pages must be typed in the same format as other SWPPP/BMP3 Plan pages and be signed and dated by the Plan designated representative in the footer at the bottom of the page entitled:

"Implemented by: _____"
Name Date

- Those pages that are being replaced must be signed and dated by the SWPPP/BMP3 Plan designated representative in the footer at the bottom of the page entitled:

"Revised by: _____"
Name Date

and placed in Appendix F of this Plan. These will serve as the historical record of efforts made to reduce storm water pollution at the Plant.

- The Annual Site Compliance Report must note all Plan revisions which have taken place during the preceding year.

TABLES

Table 1: Pollution Prevention Team Member Roster - Plant Smith

Corporate Representative: Rachel Terry		Title: Environmental Affairs Specialist	
		Office Phone: (850) 444-6127	
Responsibilities:			
Coordinate all stage of plan development and implementation; attend team meetings; participate in employee training program; review Inspection Reports and Site Compliance Evaluation Annual Report; ensure reports are submitted; and update storm water pollution prevention plan.			
On-Site Team Leader: Tracy Reeder		Title: Plant Smith Environmental Coordinator	
		Office Phone:	
Responsibilities:			
Implement SWAP; conduct/oversee inspections and prepare reports; spill prevention and accountability; attend team meetings; coordinate employee training program; keep all records.			
Members:			
<u>(1) Chris Alexander</u>		Title: Assistant Laboratoryman	
		Office Phone: (850) 265-2185	
<u>(2) Bobby Brock</u>		Title: Control Center Supervisor	
		Office Phone: (850)) 265-2185	
<u>(3)</u>		Title:	
		Office Phone:	
Responsibilities:			
Carry out existing and proposed best management practices; attend team meetings; participate in employee training programs.			

Implemented by: _____
Name Date

Revised by: _____
Name Date

Table 2: Description of Exposed Significant Material - Plant Smith

Instruction: Describe significant materials that were exposed to storm water during the past three years and/or are currently exposed.					
Description of Exposed Significant Material	Periods of Exposure	Quantity Exposed (Units)	Location (as indicated on site map)	Method of Storage or Disposal (e.g., pile, drum, tank)	Description of Material Management Practice (e.g., pile covered, drum sealed)
Scrap Metal - aluminum - copper wire - iron and steel	Every rain	Unknown; varies	Contractor staging area	Varies	Varies
Trash	Every rain	Unknown; varies	East of main building	Box containers	Box containers without covers
Construction Materials	Every rain	Unknown; varies	Coal Pile Area	Varies	Varies

Implemented by: _____
Name Date

Revised by: Stan Houston 09/26/96
Name Date

Table 3: List of Significant Spills and Leaks - Plant Smith

Instruction: Record below all significant spills and significant leaks of toxic or hazardous pollutants that have occurred at the facility in the three years prior to coverage of the permit.						
Date (Month/Day/Year)	Spill or Leak (S/L)	Location (as indicated on site map)	Type of Material	Amount of Material Recovered	Material Exposed to Storm Water (Y/N)	Preventive Measures Taken (add additional sheets if necessary)
07/31/95	S/L	East Hyd. House (850 GAL.)	Used Oil	Est. 400 GAL.	N	RAP submitted and approved by DEP
						NFA requested and approved.
						Spill containment catch basins and
						removed by Contractor with vacuum
						trucks. IRA submitted Sept. 21, 1995.
						Notice of successful remediation
						received Feb. 26, 1996.

Implemented by: _____
Name Date

Revised by: Stan Houston 09/26/96
Name Date

[illegible]

Revised by: _____
Name Date

Table 5: Best Management Practices Log - Plant Smith

Instructions: List all identified actual and potential storm water pollution sources and describe exiting management practices and proposed BMPs with implementation schedule.			
Potential Pollution Sources	Best Management Practice	Implementation Schedule	Date Work Completed
Coal unloading and storage area	Dock area - evaluated area drainage; developed BMPs to eliminate storm water related discharge to Alligator Bayou	Concrete curb added from seawall	1st Quarter 1995 Completed 04/95
	Coal pile - evaluate storm water management; develop BMPs to eliminate potential for discharge to surface water	Inspected 09/26/96	Completed
Bulk liquid storage and unloading areas	Sulfuric acid/caustic storage area - evaluate improved storage method including containment; develop structural BMPs All AST facilities - 1) perform condition survey of ASTs, containment structures, unloading facilities, and ancillary equipment. 2) inspect surrounding areas for evidence of material exposure to runoff. 3) develop structural BMPs	Covered by state required monthly AST inspections	Secondary containment completed 02/95
Solid waste storage areas	Scrap metal storage - inspect containers and surrounding areas for evidence of material exposure to run off; develop BMPs as necessary	Inspected 09/26/96	No runoff
	Dumpster - inspect containers and surrounding areas for evidence of material exposure to runoff; develop BMPs as necessary	Inspected 09/26/96	No runoff
Packaged goods storage areas	All areas - evaluate materials management practice-loading/unloading and material transfer; develop BMPs as necessary.	Inspected 09/26/96	No runoff
Fire training area	Evaluate impact of training activity and drainage from area on storm water runoff quality; develop BMPs as necessary	Inspected 09/26/96	No further evaluation
Contractor staging area	Evaluate impact of materials management and storage practices; develop BMPs as necessary		New catch basins installed 11-94
Car wash facility	Evaluate car wash area drainage and material exposure to storm water; develop BMPs as necessary	Inspected 09/26/96	No runoff problem
Main building sumps	Evaluate main building operations and materials management practices	TBD	
	Identify all materials which may be included as unauthorized non-storm water discharges in building sumps which discharge to surface waters		All sumps discharge to ash pond

Implemented by: _____
Name Date

Revised by: _____
Name Date

Table 5: Best Management Practices Log - Plant Smith - Continued

Instructions: List all identified actual and potential storm water pollution sources and describe exiting management practices and proposed BMPs with implementation schedule.			
Potential Pollution Sources	Best Management Practice	Implementation Schedule	Date Work Completed
General	Inventory - all materials on site Update SWPPP/BMP3 Plan by adding material inventory		

Note:

⁽¹⁾ TBD - To be determined

Implemented by: _____
Name Date

Revised by: _____
Name Date

Table 5: Best Management Practices Log -Plant Smith - Continued

Instructions: List all identified actual and potential storm water pollution sources and describe exiting management practices and proposed BMPs with implementation schedule.			
Potential Pollution Sources	Best Management Practice	Implementation Schedule	Date Work Completed
General	Building sumps which discharge to surface waters inventory - all materials on site Update SWPPP by adding material inventory		

Note:

⁽¹⁾ TBD - To be determined

Sludge Tank	Added concrete floor and a "Piggy Back Sump" for additional containment.	Done	Feb. 1997
Coal Pipe Containment	Re-contoured the existing slopes and stabilized to prevent erosion with grass seed and erosion control matting.	Done	April 1997
Recycle Structure	Added soil and spray seeded areas of high traffic.	Done	April 1997
Coal Pile Sump	Converting controls to sonic level sensor and added a visual red flash high level alarm light.	Done	Nov. 1997

Page ____ of ____

Implemented by: _____
Name Date

Revised by: _____
Name Date

Table 6: Employee Training Program - Plant Smith

Instructions: Describe the employee training program for your facility below. The program should, at a minimum, address spill prevention and response, good housekeeping, and material management practices. Provide a schedule for the training program and list the employees who will attend training sessions.			
Training Topics	Brief Description of Scheduled Training Program/Materials (e.g., film, seminar, staff meeting)	Proposed Frequency of Training (e.g., once per quarter)	Attendees
Spill Prevention and Response and Hazardous Communications	Discuss and/or review the procedures in the Emergency Action Plan and SPCCP. Distribute copies of the SWPPP	TBD ⁽¹⁾	TBD
Good Housekeeping	Discuss new procedures and/or review present plans to maintain good housekeeping practices	TBD	TBD
Material Management Practices	Discuss new procedures and/or review present plans to maintain good material management practices	TBD	TBD
Health and Safety	Discuss new procedures and/or review present Health and Safety procedures.	TBD	TBD
Other Topics			
Best Practices Video	Professionally developed film on stormwater BMPS's and regulation	Annually	All employees

Note:

⁽¹⁾ TBD - To be determined

Implemented by: _____
Name Date

Revised by: Stan Houston 09/26/96
Name Date

[illegible]

Table 8: Inspection Report Form - Plant Smith

Purpose: Other	Date of Inspection: 09/26/96	Inspection By: Stan Houston
Explanation: Annual Site Compliance Inspection		
Weather Conditions: Cloudy - Light Rain		
<p>Inspection Comments:</p> <ol style="list-style-type: none"> 1. Review Smith SWPP and modified to incorporate changes, operations and maintenance. Updated appropriate sections to reflect changes in responsible personnel. 2. Inspected stormwater drainage. <ul style="list-style-type: none"> Main Yard Sump Coal Pile Perimeter (run off ditches) Coal Pile East & West Sumps Unloading Wharf Area Unloader Cable lay-down area Contractor Staging Area Fire Fighting Training Area Recycle Structure Warehouse #2 Switchyard Trash Dumpsters Caustic/Acid, Lighter Oil Unloading Area 3. BMP Review <ul style="list-style-type: none"> Confirmed that stormwater runoff point has been corrected at coal unloading dock area - concrete curbing installed. All above ground tanks, except CT oil storage tanks have secondary containment. Noted that scrap metal is now stored in dumpster in coal pile area - not in contractor staging area. Catch basins in contractor staging area appears to be handling collection of stormwater properly - no problems noted. Inspected car wash - no need for development of BMP at this time - runoff not a problem. <p>Items for evaluation:</p> <ol style="list-style-type: none"> 1. Erosion of coal and dirt into Alligator Bayou on west side of coal pile area -- need to determine proper remedy. 2. Fire training area -- evaluate if additional containment area needed around training pit. <p>As a result of this inspection, changes in the storm water pollution prevention plan will ____ will not ____ be undertaken</p>		

Table 8: Inspection Report Form - Plant Smith

Purpose: Monthly/Other	Date of Inspection: 12/17/97	Inspection By: Stan Houston Rachel Allen
Explanation: Annual Storm Water Inspection		
Weather Conditions: Sunny 45°		
<p>Inspection Comments:</p> <ul style="list-style-type: none"> • Reviewed any significant spills or leaks. None noted, no reportable spills for 1997. • Reviewed plan for any changes. • Updated table with storm water BMP's for 1997. • Performed plant inspection and walk-arounds and noted the following items for 1998: <ul style="list-style-type: none"> • Removed coal that was pushed past pile boundary road and re-grade and seed. • Investigate possible repair alternatives for repairs of the west slope of the discharge canal due to erosion. • Investigate potential solutions to containing oil/water spray during fire training activities. Clean any contaminated material currently present. 		
<p>As a result of this inspection, changes in the storm water pollution prevention plan will _____ will not _____ be undertaken</p>		

STORM WATER SAMPLING REPORT

Facility Name: _____ Facility Location: _____
 Sample Collected By: _____ Date Sample Collected: _____
 Sample Analyzed By: _____

Time Storm Began: _____ am/pm Time Storm Ended: _____ am/pm
Time Sample Collected: _____ am/pm
Total Rainfall Measurement for Storm: _____ inches
Duration from the end of the previous measurable storm and this storm: _____ days/hours
Total volume of rainfall during storm event ^a: _____ gallons

Outfall _____: Location: _____

[illegible]

^a can be estimated by:

Drainage area (acres) x Rainfall Depth (inches) x % Imperviousness of Outfall Drainage Area x 27,150.

FIGURES

**APPENDIX A
FACILITY INFORMATION SUMMARY**

APPENDIX B
EMPLOYEE TRAINING - COMPLETED FORMS

APPENDIX C
COMPLETED INSPECTION FORMS

APPENDIX D
MAINTENANCE ACTIVITY LOG

APPENDIX E
LETTERS OF CONCURRENCE FROM REGULATORY AGENCIES

APPENDIX 10.2.4
USACE 404/FDEP WETLANDS
PERMIT APPLICATION

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

Joint Application for Works in the Waters of Florida

Department of the Army (Corps/Florida Department of Environmental Protection (DEP)/
Water Management District (WMD)

Corps Application Number (official use only)	DEP Application Number (official use only)
--	--

Type or Print Legibly

1. Applicant's Name and Address

Name Vick, James O., Manager of Environmental Affairs, Gulf Power Company
Last Name, First Name (if individual); Corporate Name; Name of Govt. Agency
Street 1 Energy Place
City Pensacola State: Florida Zip: 32520-0328
Telephone (850) 444-6311 (Day) (850) 444-6311 (Night)

2. Name, Address, Zip Code, Telephone Number and Title of Applicant's Authorized Agent

Name Simpson, Philip W., Project Manager
Last Name, First Name

Corporate Name; Name of Govt. Agency Environmental Consulting & Technology, Inc.
Street 3701 Northwest 98th Street
City Gainesville State Florida Zip 32606
Telephone (352) 332-0444 (Day) (352) 332-0444 (Night)

3. Name of Waterway at Work Site: Alligator Bayou is the closest waterway to work site

4. Street, Road or Other Location of Work Southern terminus of County Road 2300

Incorporated City or Town Lynn Haven
Section 36 Township - 2 South Range 15 West
Section N/A Township - N/A Range N/A
Section N/A Township - N/A Range N/A
County(ies) Bay

Coordinates in Center of Project:

Latitude 30 ° 16 ' 15 West " Longitude 85 ° 42 ' 05 North "
Lot N/A Block N/A Subd N/A Plat Bk N/A Pg N/A

Federal Projects Only:

x y

Directions to Locale Site: Go along State Road 77 to County Road 2300 and then head south

5. Names, Addresses, and Zip Codes of Adjacent Property Owners Whose Property Also Adjoins the Water (Excluding Applicant). Show Numbers or Names of These Owners on Plan Views. If More Than Six (6) Owners Adjoin the Project, You May Be Required to Publish a Public Notice for the DEP.

- | | |
|-----------------------------|----|
| 1. St. Joe Paper Company | 2. |
| Post Office Box 908 | |
| Port St. Joe, Florida 32457 | |

3.

4.

5.

6.

DEPARTMENT OF
ENVIRONMENTAL PROTECTION

JUN 18 1999

SITING COORDINATION

6. Proposed Use (Check one or more as applicable) Private: Single Family ☐ Multi-Family ☐
Public ☐ Commercial ☐ New Work ☐ Alteration of Existing Works ☐ Maintenance ☐ Other ☒ (Explain):
Regulated electric utility

7. Desired Permit Duration (see Fee Schedule): 5 Yr. ☒ 10 Yr ☐ Other (Specify)

8. General Permit or Exemption Requested:

DEP General Permit FAC Rule 17-312. N/A DEP Exemption FAC Rule 17-312. N/A Section 403. N/A FS.

9. Total Extent of Work in Jurisdictional Open Waters or Wetlands: (Use additional sheets and provide complete breakdown of each category if more space is needed.)

a. Within Corps Jurisdiction:

Fill: 662,112 Sq. Ft. 15.2 Acres 171,487 Cu. Yds
Excavation: 7,000 Sq. Ft. 0.16 Acres 1,036 Cu. Yds.

b. Within DEP Jurisdiction:

Fill: 662,112 Sq. Ft. 15.2 Acres 171,487 Cu. Yds.
Excavation: 7,000 Sq. Ft. 0.16 Acres 1,036 Cu. Yds.
Excavation Waterward of MHW N/A cu. yds (information needed for DEP)

c. DEP Jurisdictional Area Severed (Area Landward of Fill Structures which will be Severed):

N/A Sq. Ft. N/A Acres

d. DEP Jurisdictional Area Created (New Excavation from Uplands, Exclusive of Mitigation):

79,518 Sq. Ft. 1.8 Acres

e. Docks, Piers, and Over Water Structures: N/A

Total Number of Slips:		Total Number of Mooring Pilings:		
Length	Width	Height above MHW		
Length	Width	Height above MHW		
Number of Finger Piers		Length	Width	Height
Number of Finger Piers		Length	Width	Height
Total area of structure over waters & wetlands		sq. ft.		
Use of structure				

Will the docking facility provide: N/A No Yes Number

Live-aboard Slips ☐ ☐

Fueling Facilities ☐ ☐

Sewage Pump-out Facilities ☐ ☐

Other Supplies or Services Required for Boating
(Excluding refreshments, bait and tackle) ☐ ☐

f. Seawall length: N/A ft. Seawall material: N/A
Riprap revetment length: N/A ft. Slope N/A H: V Toe width
Riprap at toe of seawall length N/A ft. Slope N/A H: V Toe width
Size of riprap: N/A

Type of riprap or seawall material: N/A

g. Other (See item 10).

10. Description of Work (be specific; use additional sheets as necessary).

Gulf Power Company has to construct a new 574 megawatt electric power generating plant to be known as Smith Unit 3. A more detailed description of the proposed project is provided in Appendix A.

11. Turbidity, Erosion, and Sedimentation Controls Proposed:

Prior to the initiation of construction activities, silt fencing or straw bales will be placed along the outside edge of the construction area boundaries. Silt fencing and straw bales will be used to control transport of sediment. Sod and/or matting will be used to stabilize disturbed areas and ditch bottoms/side slopes to limit erosion potential. Finished slopes will be gradual in order to limit velocities which may promote erosion.

12. Date Activity is Proposed to Commence August 1, 2000 to be Completed June 1, 2002
Total Time Required to Construct 22 months

13. Previous Applications for this Project have been: N/A DEP No. Corps no.
A. Denied (date)
B. issued (date)
C Other (please explain)

Differentiate between existing work and proposed work on the drawings.

14. Certification. Application is hereby made for a permit or permits to authorize the activities described herein.

A. I Certify That: (Please check appropriate space)

1. I am the record owner ☒; lessee ☐, or the record easement holder ☐ of the property on which the proposed project is to be undertaken, as described in the attached legal document.

2. I am not ☐ the record owner, lessee or record easement holder of the property on which the proposed project is to be undertaken, as described in the attached legal document, but I will have, before undertaking the proposed work the requisite property interest. (Please explain what the interest will be and how it will be acquired.)

Attach legal description of property or copy of deed to the property on which project is to occur (must be provided).

See Appendix B

B. I understand I may have to provide any additional information/data that may be necessary to provide reasonable assurance or evidence that the proposed project will comply with the applicable State Water Quality Standards or other environmental standards both before construction and after the project is completed.

C In addition, I agree to provide entry to the project site for inspectors with proper identification or documents as required by law from the environmental agencies for the purpose of inspecting the site. Further, I agree to provide entry to the project site for such inspectors to monitor permitted work, if a permit is granted.

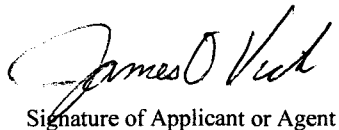
D. This is a Joint Application and is not a Joint Permit. I hereby acknowledge the obligation and responsibility for obtaining all of the required state federal or local permits before commencement of construction. I also understand that before commencement of this proposed project, I must be granted separate permits or authorizations from the U.S. Corps of Engineers, the U.S. Coast

Guard, the Department of Environmental Protection and the Delegated Water Management District (where applicable), as necessary.

E. I am familiar with the information contained in this application, and that to the best of my knowledge and belief, such information is true, complete and accurate, I further certify that I possess the authority to undertake the proposed activities or am acting as the duly

authorized agent of the applicant. I understand that knowingly making any false statement or representation in this application is a violation of Section 403.161, ES. and Chapter 837, FS.

Mr. James O. Vick
Typed/Printed Name of Applicant or Agent


Signature of Applicant or Agent

6/17/99
Date

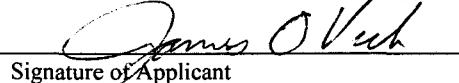
Manager of Environmental Affairs, Gulf Power Company
(Corporate Title if applicable)

AN AGENT MAY SIGN ABOVE IF APPLICANT COMPLETES THE FOLLOWING:

I hereby designate and authorize the agent listed above to act on *my* behalf as my agent in the processing of this permit application and to furnish on request, supplemental information in support of the application.

NA

Typed/Printed Name of Applicant


Signature of Applicant

Date 6/17/99

(Corporate Title if applicable)

15. For your Information: Section 370.034, Florida Statutes, requires that all dredge and fill equipment owned, used, leased, rented or operated in the state shall be registered with the Department of Natural Resources. Before selecting your contractor or equipment you may wish to determine if this requirement has been met. For further information, contact the Chief of the Bureau of Saltwater Licenses and Permits, Department of Natural Resources, 3900 Commonwealth Blvd, Tallahassee- Florida 32399. Telephone No. (904) 487-3122. This Is not a requirement for a permit from the Department of Environmental Regulation.

18 U.S.C. Section 1001 provides that, Whoever, in any manner within the jurisdiction of any department or agency of The United States knowingly and willfully falsifies, conceals, or covers up by any trick, scheme, or device a material fact or makes any false, fictitious or fraudulent statements or representations or makes or uses any false writing or document knowing same to contain any false, fictitious or fraudulent statement or entry, shall be fined not more than \$10,000 or imprisoned not more than five years, or both.

16. Please submit this completed form, with attached drawings and the complete DEP processing fee to the appropriate DEP or Delegated WMD office with jurisdiction over the project site.

Drawings will be provided soon after surveys have been completed at the site.

APPENDIX A
DESCRIPTION OF WORK

EXECUTIVE SUMMARY

Gulf Power Company (Gulf) plans to construct, own, and operate a new electric power generating plant in Bay County, Florida. The Smith Unit 3 Project (Smith Unit 3 or the Project) will be capable of producing up to 574 megawatts (MW) of electricity using state-of-the-art technology and clean, natural gas fuel.

Gulf, which is a wholly-owned subsidiary of Southern Company, serves approximately 350,000 customers in northwest Florida. Gulf has determined that in order to continue providing reliable, cost-effective service to its customers, it must add at least 427 MW of new generating resources to its system by summer of 2002. The most cost-effective means to meet this need is construction of Smith Unit 3 at Gulf's existing Lansing Smith Electric Generating Plant north of Panama City, Florida.

On March 15, 1999, Gulf filed a petition with the Florida Public Service Commission to demonstrate that the Project is needed to meet the growing demand for power in the Florida panhandle. The need petition shows that the Project will be a reliable, cost-effective, and environmentally friendly power generation resource in Florida.

ES.1 THE SITE CERTIFICATION APPLICATION

The licensing of electrical power plants in Florida requires compliance with applicable federal, state, and local laws, regulations, and ordinances. The most comprehensive state law governing the licensing of the Smith Unit 3 Project is the Florida Electrical Power Plant Siting Act (FEPPSA). The FEPPSA establishes the State's policy to balance the need for new power plant facilities with the potential effects of the facility's construction and operation on human health, welfare, and environmental resources of the state. To implement this policy, the FEPPSA establishes a centrally coordinated permitting process. The FEPPSA proceedings are initiated when the applicant files a site certification application (SCA) with the Florida Department of Environmental Protection (FDEP), which administers and coordinates the process with affected agencies, governmental entities, other parties, and the applicant. The process concludes with the approval or certification of the power plant by the Governor and Cabinet, sitting as the Siting Board.

The FDEP procedures for implementing the FEPPSA are contained in Chapter 62-17, Florida Administrative Code (F.A.C.). In this case, the SCA for the Project has been prepared in compliance with the requirements contained in the FDEP *Instruction Guide For Certification Applications* (FDEP Form 62-1.211[1], F.A.C.). The SCA demonstrates that the Project will comply with all applicable laws, regulations, and standards.

ES.2 SITE AND VICINITY CHARACTERISTICS

The proposed site for the Project is located at Gulf's existing Lansing Smith Plant in central Bay County, northwest of Panama City (T2S, R15W, Section 36). The site is owned by Gulf, as is all the surrounding property to the site.

Figures ES-1 and ES-2 show the location of the Project within the State of Florida and within Bay County, respectively. Figure ES-3 shows the location of the proposed 50.1-acre site relative to the existing Smith Plant. The site is located at the end of County Road (CR) 2300 which connects to State Road (SR) 77.

The site is currently in silvicultural operations, with planted pine dominating the site. The existing Smith plant is an industrial land use, but otherwise the surrounding vicinity is rural and in a natural state. No residential development is found within a 2-mile radius.

ZONING AND LAND USE REGULATIONS

The Project site is currently located in the Agricultural land use classification as depicted on Bay County's 1990 Adopted Comprehensive Plan Future Land Use Map (FLUM). Power plants are not an allowable use in this land use designation.

To be consistent with the adopted comprehensive plan, Gulf has submitted a large-scale plan amendment application to change the FLUM from Agriculture to Industrial. The Industrial category will allow for development of the Project and will be consistent with the existing designation for the adjacent Lansing Smith Plant (Units 1 and 2). The plan amendment was submitted in May 1999 and is expected to be adopted in Fall 1999.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



Source: ECT, 1999.

ES-3

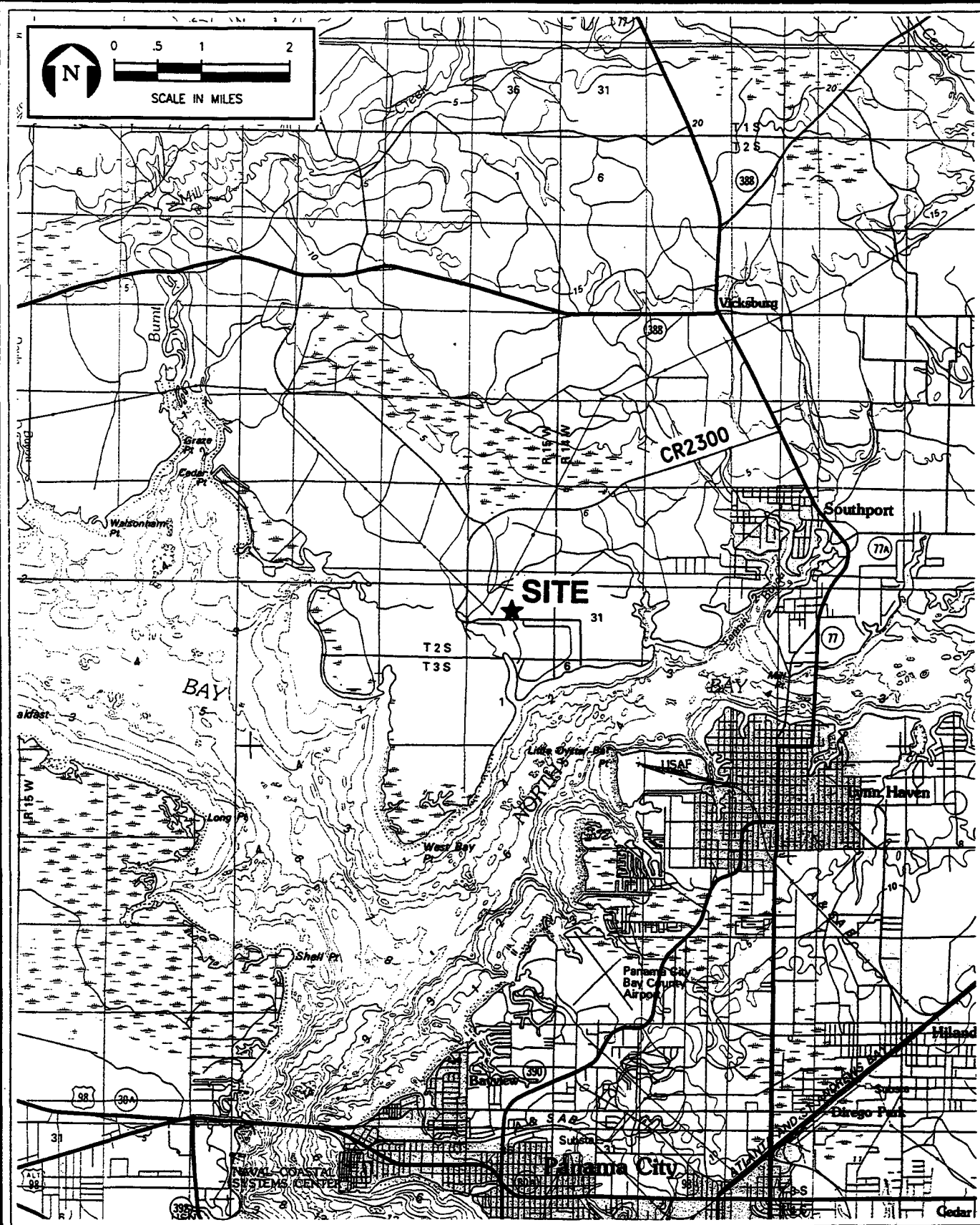


FIGURE ES-2.
SITE LOCATION WITHIN BAY COUNTY

Sources: USGS 30x60-minute topo map: Panama City, FL, 1981.

ECT
Environmental Consulting & Technology, Inc.

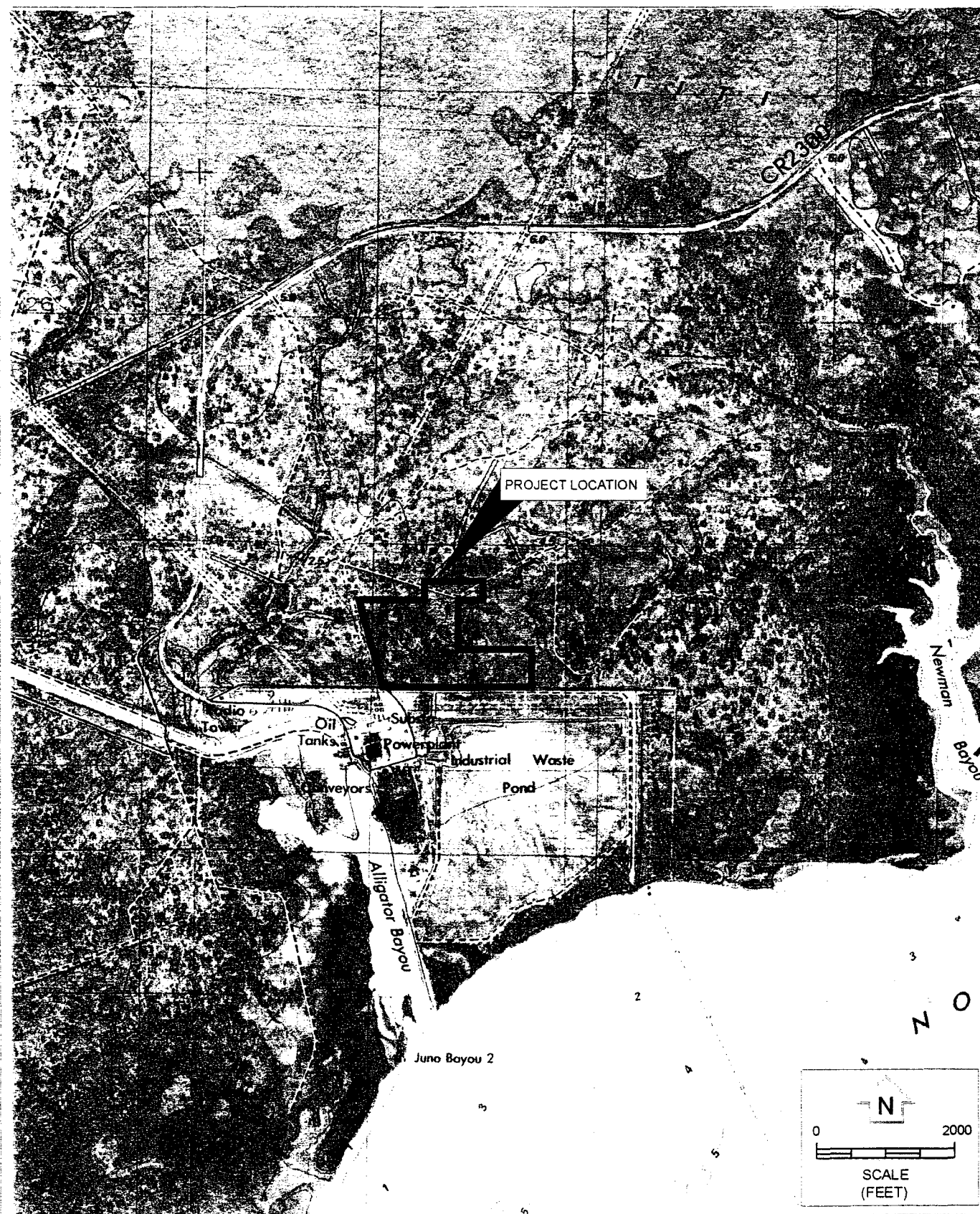


FIGURE ES-3.

PROJECT SITE LOCATION RELATIVE TO
LANSING SMITH PLANT

Sources: USGS topo map of Southport, Fl., 1992; ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

In Bay County, zoning is consistent with the land use plan designations. Therefore, when the FLUM is approved, so will the corresponding zoning for the site.

No sensitive natural resource, scenic, or cultural lands are located on the proposed site. No known archaeological or historic resources are located on the site.

GEOLOGICAL FEATURES

The Project site is located on the Pamlico Terrace in an area of low relief between elevation 5 and 8 feet above mean sea level. The site is underlain by a thick sequence of Tertiary-age sediments that generally dip to the southwest. Formations range from the Pleistocene marine terraces (loose, permeable silts and sands) that extend to 20 feet below land surface, to the Bruce Creek Limestone formation (a limestone dominated by macrofossils) that is approximately 300 feet thick.

No geologic faults have been mapped for the site; therefore, faults pose no hazard to site development. Karst development and sinkhole potential are low. Geotechnical investigations performed on the site indicate it can be safely used for the intended Project, providing standard engineering practices are employed.

GROUND WATER

The Smith Unit 3 Project is located in the Econfinia Creek Basin. Four hydrogeologic units define the regional system:

- The surficial aquifer system.
- The intermediate system.
- The Floridan aquifer system.
- The sub-Floridan confining unit.

The Floridan aquifer system provides over 90 percent of the ground water supplies for northwest Florida. The surficial aquifer system is of poor quality and is only used for irrigation and surface water recharge.

SURFACE WATER

There are numerous fresh water wetlands intermixed with the pine plantations of the site vicinity. No natural lakes, ponds, streams, or rivers are found on the site. Most of these wetlands drain to the southwest or west, eventually to West Bay.

The marine environment of St. Andrew Bay is the major surface water feature in the site vicinity. This system has been well studied by Gulf and others. Currently, the Lansing Smith Plant uses surface water from North Bay for once-through cooling at Units 1 and 2. The cooling water is ultimately discharged through a nearly 2-mile-long canal to West Bay, where the thermal mixing zone occurs. The current discharge meets all applicable water quality standards for the Bay which is a Class II water.

ECOLOGICAL FEATURES

Approximately 95 percent of the site is vegetated. Wetlands cover approximately 50 percent of the site but most of these are wet, planted pine plantations. Cypress-titi swamps represent the higher quality wetlands found onsite.

No unique habitats are found onsite. No listed wildlife species were observed onsite and none are likely to depend on the site's resources for their habitat needs. Four listed plant species were found onsite, one of which, the panhandle spiderlily, is endangered. Several specimens of this rare plant were observed in wetlands onsite and offsite.

Existing stresses to terrestrial systems include the presence of the existing Lansing Smith units, logging practices, and prescribed burning. Existing stresses to the marine systems include storm water runoff, pollution from non-point sources, and the thermal discharge of the existing Lansing Smith cooling system.

AIR RESOURCES AND NOISE

Climate in the site vicinity is characteristic of the upper Gulf Coast with mild winters and summer heat, tempered by breezes off the Gulf of Mexico. Prevailing winds are from the north.

The Smith Unit 3 site is located in an area that has been classified as attainment for all criteria air pollutants, which means the site meets all applicable state and federal air standards. The only major air emissions sources in the area are the Smith Units 1 and 2 and a few industrial facilities around St. Andrew Bay.

Ambient noise at the proposed site is dominated by the day-to-day operations of Smith Units 1 and 2. Noise surveys performed by Gulf indicate noise levels around the property boundary currently fall well below the Bay County noise code.

ES.3 PROJECT DESCRIPTION

The Smith Unit 3 Project will utilize state-of-the-art combined cycle (CC) design concepts and equipment to achieve a high level of efficiency in electrical power production. The Project will employ two General Electric Model PG 7241 (FA) gas turbine units which have a proven operating record around the world. These machines will utilize the latest developments in dry low-nitrogen oxides (NO_x) combustion technology to achieve low emissions.

Each combustion turbine generator (CTG) will exhaust into a heat recovery steam generator (HRSG), which will produce steam-generated electricity to supplement the CTGs. Typical plant operation is expected to produce 519 MW when operating at full load. When Gulf employs power augmentation, the unit will be capable of generating up to 574 MW.

Cooling of Smith Unit 3 will feature a creative and environmentally sound combination of utilizing existing Smith Units 1 and 2 cooling water discharge with a cooling tower. This means the Project will actually use hot water from the existing cooling system and discharge cooler water back to the existing discharge canal. The average annual water requirements for this cooling system will be approximately 7.5 million gallons per day (MGD) obtained from the existing 274 MGD hot water discharge from Units 1 and 2.

Other uses of the existing Lansing Smith infrastructure will include the uses of ground water from Gulf's onsite wells, use of the existing domestic wastewater treatment pack-

age plant, use of existing electric transmission and road access, and use of the existing potable water system.

Air pollution control equipment utilizing clean-burning natural gas as a fuel and low-NO_x burners will benefit the air quality in the region. Use of low-sulfur natural gas will limit emissions of particulate matter including particulate matter less than or equal to 10 micrometers diameter. Carbon monoxide and volatile organic compound emissions will be controlled by the use of advanced combustion equipment and operational practices. Dry low-NO_x combustors and low-NO_x burner technology will abate NO_x emissions. Sulfur dioxide and sulfuric acid mist emissions will be controlled by the use of low-sulfur natural gas. Drift eliminators will be employed to limit cooling tower drift to no more than 0.001 percent of the circulating water.

Gulf will require a natural gas supply to the site via a new pipeline lateral. However, Gulf will not own, build, or operate the pipeline. A gas pipeline route will be permitted and licensed separately by the supplier.

No new electric transmission line corridors are required to place Smith Unit 3 into service. A 1,000-foot wire bus connecting Smith Unit 3 to the existing Lansing Smith 230-kilovolt (kV) substation will be constructed across already developed plant property. Smith Unit 3 will require replacement of existing conductors (wires) on approximately 20 miles of existing Gulf 115-kV transmission lines in the Panama City vicinity. However, no new right-of-way, access roads, structures, dredging, or filling will be required for these upgrades. No environmental or land use impacts are anticipated from these upgrades.

ES.4 IMPACTS OF PROJECT CONSTRUCTION

The Smith Unit 3 Project will be located on a 50.1-acre site with development occurring on 32.7 acres of that total. Construction activities will include clearing, grading, development of storm water ponds, power plant construction, final grading, and landscaping.

No explosives will be used in the construction of the facility. Construction impacts will be reduced by use of existing access roads to the site and the Lansing Smith barging terminal for delivery and offloading heavy equipment. Gulf is also proposing use of benign fly ash from the existing Lansing Smith Plant as a fill substitute to help reduce the volume of fill and corresponding truck traffic to the site. Trash and construction debris will be removed or recycled by a licensed contractor.

Construction impacts to surface water systems (including wetlands) will be minimized by developing a drainage plan to allow postconstruction drainage to match preconstruction drainage. Storm water basins will be used to minimize offsite runoff and sedimentation. Best management practices (BMPs) employed for Smith Units 1 and 2 will be modified to include Smith Unit 3 and to protect potential offsite aquatic resources.

Construction impacts on ground water resources are expected to be short term and minimal. Any site dewatering will include the use of storm water ponds to collect and treat the water before recharge or discharge. Construction will not impact any drinking water supplies or other uses of the Floridan aquifer.

Approximately 15.2 acres of wetlands will be impacted during construction. Gulf is submitting a joint FDEP/U.S. Army Corps of Engineers dredge-and-fill application to quantify these impacts. The application will contain a proposed mitigation plan for these lost resources. The remaining acreage (17.4) will be left as natural, vegetated communities (e.g., pine plantation and wetlands). Construction will have minimal impacts on flora and fauna. No impacts to regional populations of any listed species are expected. The panhandle spiderlily (a state-endangered plant) is proposed to be relocated out of construction areas to nearby undisturbed wetlands.

The socioeconomic impacts are largely beneficial. A maximum construction workforce of 325 people will be required, the great majority coming from the Panama City/Bay County area. An average of 180 employees will be used over the 21-month construction period. Construction payroll is expected to total over \$18.4 million, and the impact of

construction on industrial output in Bay County is estimated to be \$113.5 million. Numerous local contractors and vendors will be utilized.

Although traffic on SR 77 and CR 2300 will increase over the construction period due to construction employees and hauling fill to the site, levels are not expected to exceed existing level of service (LOS) on any access road (primarily SR 77) to the site. Gulf is further reducing traffic impacts by spreading out fill hauling over a longer period than the construction period, and by stockpiling fill at the existing Lansing Smith property. This will dilute the truck trips required per day to and from local borrow pits. Gulf is also proposing use of benign fly ash as an alternative fill material which will be used in combination with imported clean fill. Use of fly ash could reduce truck hauling by over 50 percent.

Existing services (schools, fire, police, medical, etc.) in Bay County and nearby communities are adequate to meet short-term demands of construction.

Noise will be generated during construction which will exceed ambient levels. However, noise will be below Bay County standards at Gulf's property boundary. The nearest residential receptor is nearly 2 miles away and will not be affected by construction noise.

ES.5 IMPACTS OF PROJECT OPERATION

Overall, the Project will be a highly efficient and environmentally clean method of producing electrical power. Two positive benefits will be produced over the existing Lansing Smith Generating Facility. First, the reuse of cooling water discharge will mean no additional surface water requirements for once-through cooling will be needed. With the use of the cooling tower, the net impact of operation of Smith Unit 3 will be no increase in the temperature of the existing discharge and a reduction in the discharge volume. Consequently, the heat rejection rate will be reduced by 1.3 percent which will slightly reduce the thermal impacts on the receiving waters of West Bay.

A second major benefit of Smith Unit 3 operations will be a net reduction in NO_x emissions from Lansing Smith due to installation of low-NO_x burner technology and a burner

management system on Smith Unit 1. This results in a significant increase in electrical generating capacity with no increase in NO_x emissions.

The limited use of ground water for process water needs at the Lansing Smith site including Smith Unit 3 will not adversely affect the surficial aquifer or Floridan aquifer at the site. No impacts to existing water supplies or water wells are expected.

During operations, the storm water management plan and BMPs will protect adjacent areas from any storm water runoff impacts. Solid wastes generated will be disposed offsite by licensed contractors.

The best available control technology and PSD review required for Smith Unit 3 will ensure emissions of air-borne pollutants will be minimized. The Project will not cause or contribute to any violation of ambient air quality standards or PSD increments. Secondary air impacts will be negligible. Types and concentrations of air pollutants will not adversely affect soil or vegetation.

No significant ecological effects are anticipated from plant operation. The plant will not affect regional plant and wildlife populations.

Noise impacts will be minimal and confined to the near-plant limits. Noise levels are calculated to be well below Bay County standards.

Existing infrastructure and facilities in Bay County will be sufficient to handle the relatively small increase in operational workforce (29). This workforce will most likely reside locally, but impacts to roads, schools, police, fire, and medical services will be negligible.

Socioeconomic benefits of the Project will be positive. In addition to providing additional inexpensive and reliable electricity to rate payers in Florida, the Project will generate approximately \$1.5 million in additional payroll to Bay County residents. Much of this money will be spent on goods and services. Additionally, Gulf expects to contract \$1.8

million per year to local suppliers of maintenance services/supplies. Traffic generated by the 29 employees will be insignificant on SR 77 and CR 2300. Existing LOSs will not be impacted on area roadways.

ES.6 ALTERNATIVES

The site selected for Smith Unit 3 was driven by the need to be in or close to Panama City and the objective to minimize environmental impacts by locating near existing power plant infrastructure. Smith Unit 3 accomplishes these needs.

The extensive technology and project alternatives analysis performed by Gulf showed that a CC unit located at Gulf's Lansing Smith site using natural gas fuel was the best and lowest cost alternative.

Location at the existing Smith Generating site maximizes use of existing power plant infrastructure (cooling discharge canal, wastewater, potable water, electric transmission, and roads). The site was located on Gulf's property at Lansing Smith to best utilize these infrastructure requirements and minimize onsite environmental impacts. The proposed location, while impacting some wetlands, will avoid wetland impacts associated with longer, interconnecting facility corridors if the site were further from the existing facilities on available Smith property. Moving the site elsewhere would also have the potential to fragment natural communities and wildlife habitat onsite.

ES.7 CONCLUSIONS

In summary, the Project will provide needed low-cost electrical power for Gulf Power rate payers, while minimizing the potential impacts of power generation. The Project will comply with all applicable land use and environmental regulations. The Project should be approved by the Siting Board because it meets pressing local and state needs for electrical power in an environmentally sound manner.

ATTACHMENT B
LEGAL DESCRIPTION OF PROJECT SITE



NORTHWEST ENGINEERING, INC.
Consulting Engineers & Land Surveyors

DESCRIPTION OF PROPOSED PLANT SITE

A PARCEL OF LAND LYING IN AND BEING A PART OF SECTION 36, TOWNSHIP 2 SOUTH, RANGE 15 WEST, BAY COUNTY, FLORIDA, BEING MORE PARTICULARLY DESCRIBED AS FOLLOWS:

COMMENCING AT THE WEST $\frac{1}{4}$ CORNER OF SECTION 36, TOWNSHIP 2 SOUTH, RANGE 15 WEST, BAY COUNTY, FLORIDA; THENCE RUN EAST A DISTANCE OF 2,574.69 FEET TO THE POINT OF BEGINNING OF THE HEREIN DESCRIBED PARCEL OF LAND; THENCE NORTH $21^{\circ} 09' 12''$ WEST A DISTANCE OF 1,176.18 FEET TO A $\frac{1}{4}$ INCH DIAMETER IRON PIPE (LB 5122); THENCE NORTH $89^{\circ} 59' 45''$ EAST A DISTANCE OF 1,062.13 FEET TO A $\frac{1}{4}$ INCH DIAMETER IRON PIPE (LB 5122); THENCE NORTH $00^{\circ} 00' 03''$ WEST A DISTANCE OF 249.99 FEET TO A $\frac{1}{4}$ INCH DIAMETER IRON PIPE (LB 5122); THENCE NORTH $89^{\circ} 59' 44''$ EAST A DISTANCE OF 784.04 FEET TO A $\frac{1}{4}$ INCH IRON PIPE (LB 5122); THENCE SOUTH $00^{\circ} 00' 02''$ WEST A DISTANCE OF 250.01 FEET TO A $\frac{1}{4}$ INCH IRON PIPE (LB 5122); THENCE SOUTH $89^{\circ} 59' 52''$ WEST A DISTANCE OF 334.02 FEET TO A 1" DIAMETER IRON ROD; THENCE SOUTH $00^{\circ} 00' 10''$ EAST A DISTANCE OF 662.93 FEET TO A $\frac{1}{4}$ INCH DIAMETER IRON ROD (LB 5122); THENCE EAST A DISTANCE OF 979.97 FEET A $\frac{1}{4}$ INCH IRON PIPE (LB 5122); THENCE SOUTH $00^{\circ} 00' 02''$ WEST A DISTANCE OF 500.00 FEET TO A $\frac{1}{4}$ INCH IRON PIPE (LB 5122); THENCE SOUTH $89^{\circ} 59' 42''$ WEST A DISTANCE OF 2,042.14 FEET TO A FOUND STEEL SPINDLE IN AN ASPHALT ROAD; THENCE NORTH $21^{\circ} 09' 12''$ WEST A DISTANCE OF 70.86 FEET TO THE POINT OF BEGINNING OF THE HEREIN DESCRIBED PARCEL.

SAID PARCEL CONTAINING 50.12 ACRES, MORE OR LESS.

APPENDIX 10.2.5
NPDES PERMIT MODIFICATION
APPLICATION



WASTEWATER PERMIT APPLICATION FORM 1 GENERAL INFORMATION

DESCRIPTION OF PERMIT APPLICATION FORMS

Form 1 - General information. This booklet includes general information on applying for a permit to operate a domestic or industrial wastewater facility. **Form 1 is required for all permit applications.**

Form 2 - Specific information. This group of forms includes the specific information required for the type of wastewater facility for which a permit is needed. Select the appropriate form(s) to be submitted with Form 1.

Form 2A - Domestic Wastewater Facilities.

Form 2B - Concentrated Animal Feeding Operations and Aquatic Animal Production Facilities.

Form 2CS -Industrial Wastewater Facilities (discharging process wastewater to surface waters).

Form 2CG -Industrial Wastewater Facilities (discharging process wastewater to ground water).

Form 2ES -Industrial Wastewater Facilities (discharging non-process wastewater to surface waters).

Form 2EG -Industrial Facilities (discharging non-process wastewater to ground water).

Form 2F - Stormwater Discharges to Surface Waters from Industrial or Domestic Facilities

Form 2CR -Non-Discharging/Closed Loop Recycle System.

SECTION A - GENERAL INSTRUCTIONS

Who Must Apply:

Persons who are or are going to discharge wastewater to waters of Florida or the United States must file for and be granted a permit under Sections 403.087, 403.088, or 403.0885, Florida Statutes (F.S.). There are severe penalties for discharging without a permit.

There are some exceptions to this requirement. Discharges of domestic sewage from vessels and discharges from properly operating marine engines are not required to have a permit under the laws listed above. However, discharges of rubbish, trash, garbage or other such materials discharged overboard do require permits. Vessels operated in a capacity other than as a means of transportation are required to have a permit if they are discharging to waters. These types include vessels used as an energy or mining facility, a storage facility, a seafood processing facility, or a anchored facility for the purpose of mineral or oil exploration or development.

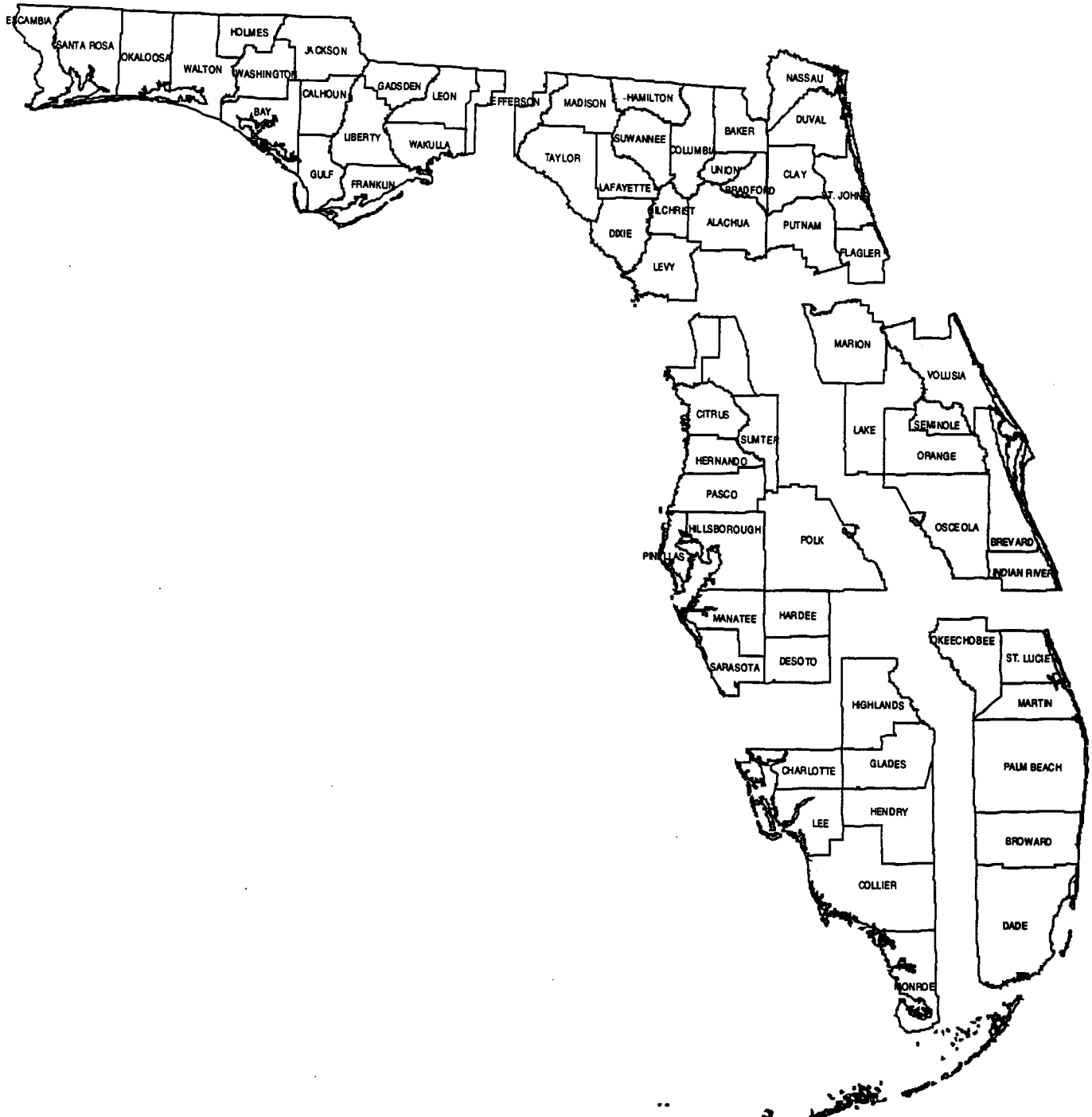
The introduction of sewage, industrial wastes, or other pollutants into a domestic wastewater treatment facility does not need a permit under Sections 403.087, 403.088 or 403.0885, F.S. Persons discharging to permitted wastewater treatment facilities must comply all applicable pretreatment standards. If a person has a plan or an agreement to switch from direct discharge into waters of the state to discharge to a domestic treatment facility, it does not relieve the person from obtaining a permit for the discharge until such time as the connection is made and the discharge is stopped.

Most discharges from agricultural and silvicultural activities to waters of the state do not require a permit under Sections 403.087, 403.088, or 403.0885, F.S. However, permits under those sections are required for discharges from concentrated animal feeding operations, concentrated aquatic animal production facilities, activities associated with approved aquaculture projects, and silvicultural point sources.

Where to Apply:

Permit applications must be filed with the Department of Environmental Protection (DEP) district office shown in Figure 1 for the county in which the wastewater facility is located, except for permit applications for steam electrical generating power plants which are filed with the DEP office in Tallahassee. DEP offices are located at

Figure 1. State Map Showing DEP District Offices



NORTHWEST DISTRICT

160 Government Center, Ste 308
Pensacola, Florida 32501-5794
Phone No. (850) 444-8300

Northwest District Branch Office

2353 Jenks Avenue
Panama City, Florida 32405
Phone No. (850) 872-4375

Northwest District Branch Office

2815 Remington Green Circle
Tallahassee, Florida 32308
Phone No. (850) 488-3704

SOUTHWEST DISTRICT

3804 Coconut Palm Drive
Tampa, Florida 33618-8318
Phone No. (813) 744-6100

SOUTH DISTRICT OFFICE

2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901
Phone No. (941) 332-6975

South District Branch Office

11400 Overseas Highway, Suite 123
Marathon, Florida 33050
Phone No. (305) 289-2310

NORTHEAST DISTRICT

7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256-7577
Phone No. (904) 448-4300

Northeast District Branch Office

5700 Southwest 34 Street, Suite 1204
Gainesville, Florida 32608
Phone No. (352) 955-2095

CENTRAL DISTRICT

3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Phone No. (407) 894-7555

SOUTHEAST DISTRICT

400 North Congress Avenue
West Palm Beach, Florida 33401
Phone No. (561) 681-6600

Southeast District Branch Office

1801 Southeast Hillmoor Drive, Suite C-204
Port St. Lucie, Florida 34952
Phone No. (561) 871-7662

When to Apply:

Applications must be filed with the appropriate DEP office 180 days before your current permit expires or 180 days before startup of a new or modified facility. If the submitted application is for a new facility or for a modification of an existing facility, the information required for describing the construction must be filed at least 90 days before construction begins. The DEP encourages applicants to file the materials describing the construction of a new facility or the modification of an existing facility as early as possible to avoid problems with delays in startup or facility redesign to achieve effluent limitations.

Federal regulations provide that a new source in the NPDES program may not be constructed or started to be constructed before the issuance of an operation permit. Because of this regulation, a permit application for a new source may need to be submitted well in advance of the required 180 days.

Fees:

Application fees are listed in Section 62-4.050, Florida Administrative Code (F.A.C.). An application will not be processed until the application fee has been paid. If the DEP determines that a permit should be issued for less than five years duration, the application fee will be pro rated.

If a permit is issued for a surface water discharge, the permittee will be assessed a regulatory and surveillance program fee annually. Those fees are listed in Section 62-4.052, F.A.C. Failure to pay the annual fee may result in revocation of the permit.

Availability of Information to the Public:

Information contained in these applications forms will, upon request, be made available to the public for inspection and copying. However, you may request confidential treatment for certain information which you may submit to supplement the information requested on these forms. Section 620.302, F.A.C., and 40 CFR 2 provide set forth the procedures for making the claim. No information on Forms 1 and 2A through 2EG may be claimed as confidential.

Completion of Forms:

Unless otherwise specified in instructions to the forms, each item in each form must be answered. To indicate that each item has been considered, enter "NA", for not applicable, if a particular item does not fit the circumstances or characteristics of your facility or activity.

If you have previously submitted information to the DEP which answers a question, you may either repeat the information in the space provided or attach a copy of the previous submission. DO NOT WRITE "ON FILE". Some items in the form require narrative explanation. If more space is necessary to answer a question, attach a separate sheet entitled "Additional Information."

SECTION B - FORM 1 LINE-BY-LINE INSTRUCTIONS

This form must be completed by all applicants.

Completing This Form:

Please type or print in the underlined areas only. Some items have a limited number of spaces or characters so that your response may be entered into a computer program. Please do not exceed this maximum number with your response. Abbreviate if necessary to stay within the number of characters allowed for each item. Use one space for breaks between words, but not for punctuation marks unless they are needed to clarify your response.

Item I

Space is provided at the upper right hand corner of Form 1 for insertion of your Facility Identification Number. If you have an existing facility, enter your identification number. If you don't know your identification number, please contact the appropriate DEP office which will provide you with your number. If your facility is new (not yet constructed), leave this item blank.

Item II

Answer each question to determine which supplementary forms you need to fill out. Be sure to check the glossary in Section C of these instructions for the legal definitions of any words you are not certain of their meaning.

If you answer "no" to every question, then you may not need a permit. However, you should call the appropriate district office to determine if you have made a correct determination. If you answer "yes" to any question, then you must complete and file the supplementary form by the deadline listed in Section A along with this form.

Item III

Enter the facility's official or legal name. Do not use a colloquial name.

Item IV

Give the name, title, and work telephone number of a person who is thoroughly familiar with the operation of the facility, with the facts reported in this application, and who can be contacted by reviewing offices if necessary.

Item V

Give the complete mailing address of the office where correspondence should be sent. This often is not the address used to designate the location of the facility or activity.

Item VI

Give the address or location of the facility identified in Item III of this form. If the facility lacks a street name or route number, give the most accurate alternative geographic information (for example, section number or quarter section number from county records or at intersection of Rts 426 and 22).

Item VII

List four, in descending order of significance, 4-digit standard industrial classification (SIC) codes which best describe your facility in terms of the principal products or services you produce or provide. Also, specify each classification in words. These classifications may differ from the SIC codes describing the operation generating the discharge from the facility.

SIC code numbers are descriptions which may be found in the "Standard Industrial Classification Manual" prepared by the Executive Office of the President, Office of Management and Budget, which is available from the Government Printing Office, Washington, D.C. Your local library may have a copy of this publication which you may use. Use the current edition of the manual. If you have any questions concerning the appropriate SIC code for your facility, please contact the appropriate DEP district office.

Item VIII-A

Give the name, as it is legally referred to, of the person, firm, public organization, or any other entity which operates the facility described in this application. This may or may not be the same name as the facility. The operator of the facility is the legal entity which controls the facility's operation rather than the plant or site manager. Do not use a colloquial name.

Item VIII-B

Indicate whether the entity which operates the facility also owns it by marking the appropriate box.

Item VIII-C

Enter the appropriate letter to indicate the legal status of the operator of the facility. Indicate "public" for a facility solely owned by a local government, such as a city, town, county, etc.

Items VIII-D through H

Enter the telephone number and address of the operator identified in Item VIII-A.

Item IX

Indicate whether the facility is located on Indian Lands.

Item X

Give the number of each presently effective wastewater permit issued to the facility listed in this application. List relevant federal, state, and local permits. DO NOT LIST ALL YOUR PERMITS. LIST ONLY CURRENT ENVIRONMENTAL PERMITS RELATING TO THIS PROJECT.

Item XI

Provide a topographic map or maps of the area extending at least to one mile beyond the property boundaries of the facility which clearly show the following:

The legal boundaries of the facility;

The location and serial number of each of your existing and proposed intake and discharge structures;

All hazardous waste management facilities;

Each well where you inject fluids underground; and

All springs and surface water bodies in the area, plus all drinking water wells within 1/4 mile of the facility which are identified in the public record or otherwise known to you.

If an intake or discharge structure, hazardous waste disposal site, or injection well associated with the facility is located more than one mile from the plant, include it on the map, if possible. If not, attach additional sheets describing the location of the structure, disposal site, or well, and identify the U.S. Geological Survey (or other) map corresponding to the location.

On each map, include the map scale, a meridian arrow showing north, and latitude and longitude at the nearest whole second. On all maps of rivers, show the direction of the current, and in tidal waters, show the directions of the ebb and flow tides. Use a 7-1/2 minute series map published by the U.S. Geological Survey. If a 7-1/2 minute series map has not been published for your facility site, then you may use a 15 minute series map from the U.S. Geological Survey. If neither a 7-1/2 nor 15 minute series map has been published for your facility site, use a plat map or other appropriate map, including all the requested information; in this case, briefly describe land uses in the map area (for example, residential, commercial).

You may trace your map from a geological survey chart, or other map meeting the above specifications. If you do, your map should bear a note showing the number or title of the map or chart from which it was traced. Include the names of nearby towns, water bodies, and other prominent points.

You may obtain a topographic map from:

Eastern Mapping Center
National Cartographic Information Center
U.S. Geological Survey
536 National Center
Reston, VA 22092

Item XII

Briefly describe the nature of your business (for example, products produced or services provided).

Item XIII

Section 403.161, F.S., provides severe penalties for submitting false information on this application form or any reports or records required by a permit, if issued. There are both civil and criminal penalties, in addition to the revocation of the permit.

Rule 62-620.305, F.A.C., requires that the application and any reports required by the permit, if issued, to be signed as follows:

- A. For a corporation, by a responsible corporate officer as described in Rule 62-620.305, F.A.C.;
- B. For partnership or sole proprietorship, by a general partner or the proprietor, respectively; or
- C. For a municipality, state, federal or other public facility, by a principal executive officer or elected official.

SECTION C - GLOSSARY

NOTE: This Glossary includes terms used in the instructions and in Forms 1, 2A through 2EG. If you have any questions concerning the meaning of any of these terms, please contact your DEP district office.

Aliquot means a sample of specified volume used to make up a total composite sample.

Animal Feeding Operation means a lot or facility (other than an aquatic animal production facility) where the following conditions are met:

A. Animals (other than aquatic animals) have been, are, or will be stabled or confined and fed or maintained for a total of 45 days or more in any 12 month period; and

B. Crops, vegetation, forage growth, or post-harvest residues are not sustained in the normal growing season over any portion of the lot or facility.

Two or more animal feeding operations under common ownership are a single animal feeding operation if they adjoin each other or if they use a common area or system for the disposal of wastes.

Animal Unit means a unit of measurement for any animal feeding operation calculated by adding the following number:
The number of slaughter and feeder cattle multiplied by 1.0; plus the number of mature dairy cattle multiplied by 1.4; plus the number of swine weighing over 25 kilograms (approximately 55 pounds) multiplied by 0.4; plus the number of sheep multiplied by 0.1; plus the number of horses multiplied by 2.0.

Application means the approved DEP standard forms for applying for a permit, including any approved additions, revisions, or modifications to the forms. Approved forms are numbered, Form 62-620.910, and have an effective date of October 1, 1994, or later.

Aquifer means a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

Best Management Practices (BMP) means schedules of activities, prohibitions of practices, maintenance procedures, and other management practices to prevent or reduce the pollution of waters of the United States. BMPs include treatment requirements, operation procedures, and practices to control plant site runoff, spillage or leaks, sludge or waste disposal, or drainage from raw material storage.

Biological Monitoring Test means any test which include the use of aquatic algal, invertebrate, or vertebrate species to measure acute or chronic toxicity, and any biological or chemical measure of bioaccumulation.

Bypass means the intentional diversion of wastes from any portion of a treatment facility.

Concentrated Animal Feeding Operation means an animal feeding operation which meets the criteria set forth in Chapter 62-670, F.A.C.

Concentrated Aquatic Animal Production Facility means a hatchery, fish farm, or other facility which contains, grows or hold aquatic animals as set forth in Chapter 62-660, F.A.C.

Contact Cooling Water means water used to reduce temperature which comes into contact with a raw material, intermediate product, waste product other than heat, or finished product.

CWA means the Clean Water Act as amended, 33 U.S.C. 1251 et seq.

Dike means any embankment or ridge of either natural or manmade materials used to prevent the movement of liquids, sludges, solids, or other materials.

Discharge (of a Pollutant) means any addition of any pollutant or combination of pollutants to waters of the State from any point source; or any addition of any pollutant or combination of pollutants to the marine waters of the State from any point source other than a vessel or other floating craft which is being used as a means of transportation.

This definition includes discharges into waters of the State from surface runoff which is collected or channelled by man; discharges through pipes, sewers, or other conveyances owned by the State, a municipality, or other person which do not lead to POTWs; and discharges through pipes, sewers, or other conveyances, leading into privately owned treatment works. This term does not include an addition of pollutants by any indirect discharge.

Effluent Limitation mean any restriction imposed by the DEP on quantities, discharge rates, and concentrations of pollutants which are discharged from point sources into waters of the State.

Effluent Limitation Guideline means a regulation published under Section 304(b) of the Clean Water Act to adopt or revise effluent limitations.

EPA means the United States Environmental Protection Agency.

Existing Source or Existing Discharger means any source which is not a new source or a new discharger.

Facility or wastewater facility means any facility which can reasonably be expected to be a source of pollution and includes any or all of the following: a collection and transmission system, a wastewater treatment works, a reuse or disposal system, and a residuals management facility.

Ground Water means water below the land surface in a zone of saturation.

Indirect Discharger means an industrial discharger introducing pollutants to a publicly owned treatment works.

Injection Well mean a well into which fluids are injected.

MGD means millions of gallons per day.

Municipality means a city, village, town, borough, county, district, association, or other public body created by or under State law and have jurisdiction over disposal of sewage, industrial wastes, or other wastes.

National Pollutant Discharge Elimination System (NPDES) means the national program for issuing, modifying, revoking and reissuing, termination, monitoring and enforcing permits and imposing and enforcing pretreatment requirements, under Sections 307, 318, 402, and 405 of the CWA. The term includes a State program which has been authorized by EPA under 40 CFR Part 123.

New Discharger mean any building, structure, facility, or installation: (A) from which there is or may be a new or additional discharge of pollutants at a site at which on October 18, 1972, it had never discharged pollutants; (B) which has never received a finally effective NPDES permit for discharges at that site; and (C) which is not a "new source." This definition includes an indirect discharger which commences discharging into water of the State. It also includes any existing mobile point source, such as an offshore oil drilling rig, seafood processing vessel, or aggregate plant that begins discharging at a location for which it does not have an existing permit.

New Source means any building, structure, facility, or installation from which there is or may be a discharge of pollutants, the construction of which commenced: (A) after promulgation of standards of performance under Section 306 of the CWA which are applicable to such source; or (B) after proposal of standards of performance in accordance with Section 306 of CWA which are applicable to such source, but only if the standards are promulgated in accordance with Section 306 within 120 days of their proposal.

Non-Contact Cooling Water means water used to reduce temperature which does not come into direct contact with any raw material, intermediate produce, waste product (other than heat), or finished product.

Off-Site means any site which is not "on-site."

On-Site means on the same or geographically contiguous property which may be divided by public or private right(s)-of-way, provided the entrance and exit between the properties is at a cross-roads intersection, and access is by crossing as opposed to going along, the right(s)-of-way. Non-contiguous properties owned by the same person, but connected by a right-of-way which the person controls and to which the public does not have access, is also considered on-site property.

Operator means the person responsible for the overall operation of a facility.

Outfall means a point source.

Owner means the person who owns a facility or part of a facility.

Permit means an authorization, license, or equivalent control document issued by the State to implement the requirements of 40 CFR 122, 123, and 124 and Chapter 403, F.S.

Point Source means any discernible, confined, and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, vessel or other floating craft from which pollutants are or may be discharged. This term does not include return flows from irrigated agriculture.

Pollutant means dredged spoil, solid waste, incinerator residue, filter backwash, sewage, garbage, sewage sludge, munitions, chemical waste, biological materials, radioactive materials (except those regulated under the Atomic Energy Act of 1954, as amended), heat, wrecked or discarded equipment, rocks, sand, cellar dirt and industrial, municipal, and agriculture waste discharged into water. It does NOT mean: (A) sewage from vessels; or (B) water, gas, or other material which is injected into a well to facilitate production of oil or gas, or water derived in association with oil and gas production and disposed of in a well, if the well used either to facilitate production or for disposal purposes is approved by authority of the State in which the well is located, and if the State determines that the injection or disposal will not result in the degradation of ground or surface water resources.

Privately Owned Treatment Works means any device or system which is used to treat domestic wastewater from any facility which is not a POTW.

Process Wastewater means any water which, during manufacturing or processing, comes into direct contact with or results from the production or use of any raw material, intermediate product, finished product, byproduct, or waste product.

Publicly Owned Treatment Works (POTW) means any device or system used in the treatment (including recycling and reclamation) of domestic sewage or industrial wastes of a liquid nature which is owned by a State or municipality. This definition includes any sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment.

Residuals means the solid, semisolid, or liquid residue generated during the treatment of domestic wastewater. Not included are solids removed from pump stations and lift stations, and screenings and grit removed from the headworks of domestic wastewater treatment facilities. Also not included are other solids removed prior to treatment of the residuals to meet the stabilization standards of Chapter 62-640, F.A.C., or ash generated during the incineration of residuals.

Sewage From Vessels means human body wastes and the wastes from toilets and other receptacles intended to receive or retain body wastes that are discharged from vessels and regulated under Section 312 of the CWA.

Sewage Sludge means residuals.

Silvicultural Point Source means any discernable, confined and discrete conveyance related to rock crushing, gravel washing, log sorting, or log storage facilities which are operated in connection with silvicultural activities and from which pollutants are discharged into water of the State.

Storm Water Runoff means water discharged as a result of rain, snow, or other precipitation.

Surface Impoundment or Impoundment means a facility or part of a facility which is a natural topographic depression, manmade excavation, or diked area formed primarily of earthen materials (although it may be lined with manmade materials), which is designed to hold an accumulation of liquid wastes or wastes containing free liquids, and which is not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

Toxic Pollutant means any pollutant listed as toxic under Section 307(a)(1) of the CWA.

Upset means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

Waters of the State means the waters defined in Section 403.031, F.S., and including waters of the United States to the seaward boundaries of the State.



WASTEWATER PERMIT APPLICATION FORM 1 GENERAL INFORMATION

I IDENTIFICATION NUMBER:

Facility ID FL0002267

II CHARACTERISTICS:

INSTRUCTIONS: Complete the questions below to determine whether you need to submit any permit application forms to the Department of Environmental Protection. If you answer "yes" to any questions, you must submit this form and the supplemental form listed in the parenthesis following the question. Mark "X" in the blank in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if you activity is excluded from permit requirements. See Section B of the instructions. See also, Section C of the instructions for definitions of the terms used here.

SPECIFIC QUESTIONS	YES	NO	FORM ATTACHED
A. Is this facility a domestic wastewater facility which results in a discharge to surface or ground waters?		X	
B. Does or will this facility (either existing or proposed) include a concentrated animal feeding operation or aquatic animal production facility which results in a discharge to waters?		X	
C. Does or will this facility (other than those describe in A. or B.) discharge process wastewater, or non-process wastewater regulated by effluent guidelines or new source performance standards, to surface waters?	X		X
D. Does or will this facility (other than those described in A. or B.) discharge process wastewater to ground waters?		*X	
E. Does or will this facility discharge non-process wastewater, not regulated by effluent guidelines or new source performance standards, to surface waters?		X	
F. Does or will this facility discharge non-process wastewater to ground waters?		X	
G. Does or will this facility discharge stormwater to surface waters?		X	
H. Is this facility a non-discharging/closed loop recycle system?		X	

III NAME OF FACILITY: (40 characters and spaces)

Smith Electric Generating Plant

***NOTE:** This application is for a modification to existing permit FL0002267. The modification involves Smith 3, a new generating unit to be added to the Plant Smith site. The modification does not involve a discharge to groundwater.

IV FACILITY CONTACT: (A. 30 characters and spaces)

A. Name and Title (Last, first, & title)	B. Phone (area code & no.)
Terry, Rachel A. Env. Affairs Spec.	850.444.6127

V FACILITY MAILING ADDRESS: (A. 30 characters and spaces; B. 25 characters and spaces)

A. Street or P.O. Box: One Energy Place		
B. City or Town: Pensacola	State: FL	Zip Code: 32520

VI FACILITY LOCATION: (A. 30 characters and spaces; B. 24 characters and spaces; C. 3 spaces (if known); D. 25 characters and spaces; E. 2 spaces; F. 9 spaces)

A. Street, Route or Other Specific Identifier:		
B. County Name: Bay	C. County Code (if known): 03	
D. City or Town: Southport	E. State: FL	F. Zip Code: 32409

VII SIC CODES: (4-digit, in order of priority)

1. Code #: 4911	(Specify) Elec Gen Plt	2. Code #: NA	(Specify) NA
3. Code #: NA	(Specify) NA	4. Code #: NA	(Specify) NA

VIII OPERATOR INFORMATION: (A. 40 characters and spaces; B. 1 character; C. 1 character (if other, specify); D. 12 characters; E. 30 characters and spaces; F. 25 characters and spaces; G. 2 characters; H. 9 characters)

A. Name: Gulf Power Company		B. Is the name in VIII A. the owner? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	
C. Status of Operator: F = Federal; S = State; P = Private; O = Other; M = Public (other than F or S)	(code) P	(specify) Electric Util	D. Phone No.: 850.444.6311
E. Street or P. O. Box: One Energy Place			
F. City or Town: Pensacola		G. State: FL	H. Zip Code: 32520

IX INDIAN LAND: Is the facility located on Indian lands?☐ Yes☒ No

X EXISTING ENVIRONMENTAL PERMITS:

A. NPDES Permit No.	B. UIC Permit No.	C. Other (specify)	D. Other (specify)
FL0002267	NA	NA	NA

XI MAP: Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers and other surface water bodies in the map area. See instructions for precise requirements. See attached site map.

XII NATURE OF BUSINESS (provide a brief description)

See Attached description.

XIII CERTIFICATION (see instructions)

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

Robert G. Moore

A. Name (type or print)

Robert G. Moore

B. Signature

Vice President of Power Generation and
Official Title (type or print) Transmission

5/27/99

C. Date Signed

XII. NATURE OF BUSINESS

Gulf Power Company currently generates electricity with 2 coal fired units and an oil-fired combustion turbine at the Lansing Smith facility. A third unit is planned to be added to the facility that will be a natural gas-fired combined cycle unit with a maximum generating capacity of 574 MW (Smith Unit 3). Unit 3 will utilize a cooling tower that will withdraw makeup water from the once through cooling water in the existing discharge canal currently used for Units 1 and 2.

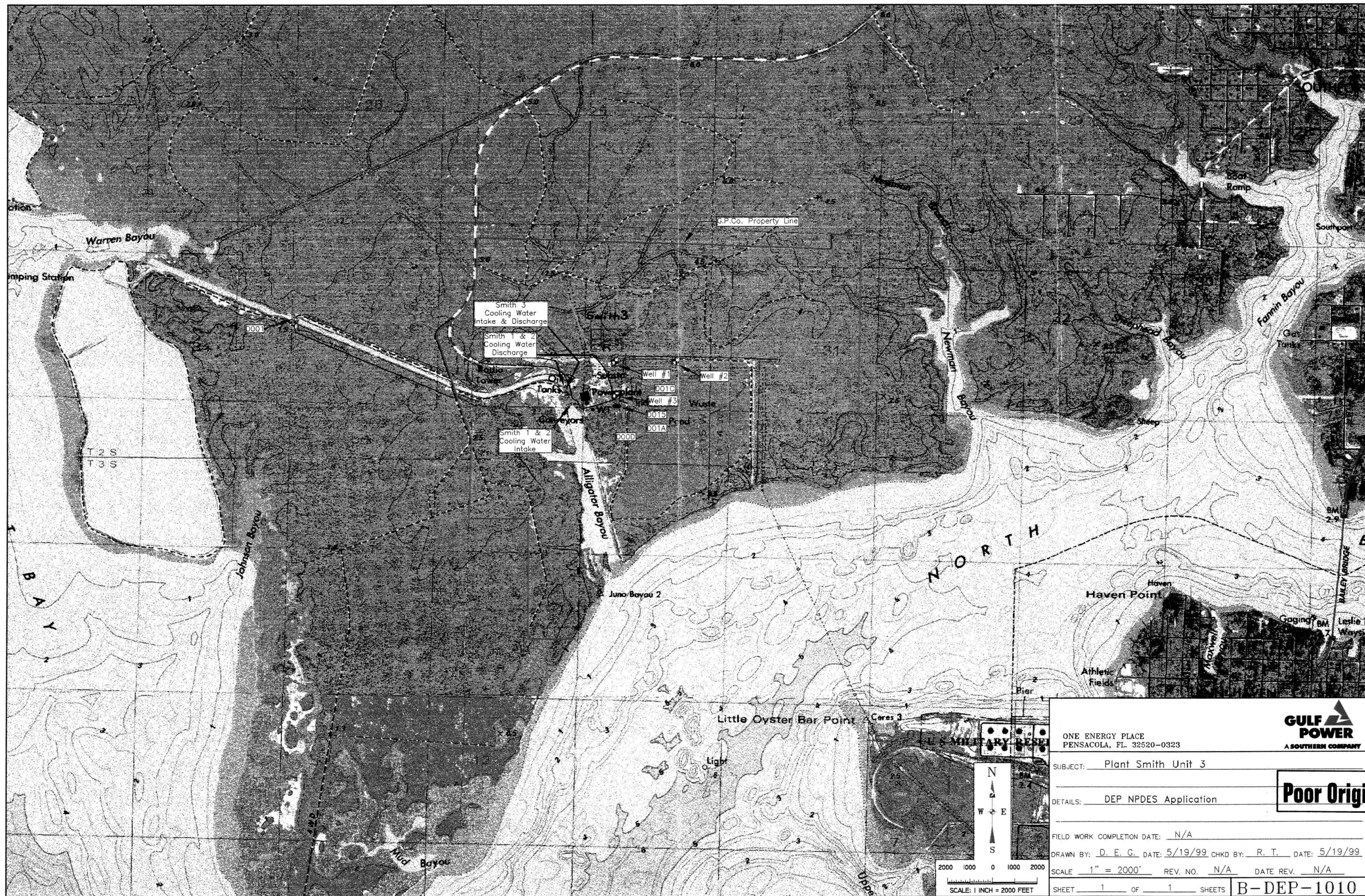
The cooling tower will operate at 2 cycles of concentration prior to the water being returned to the discharge canal. The blowdown from the cooling tower will be discharged from the cold side of the cooling tower such that the cooling tower blowdown temperature will be lower than the water in the Units 1 and 2 discharge canal. As a result, there will be a slight reduction in the total heat rejection rate of the existing once-through system. Domestic waste from Smith Unit 3 will be routed to an existing on-site permitted domestic treatment facility which already has adequate capacity. Therefore, this modification will not require modifications to existing permit limits for that internal outfall.


Gulf is submitting this NPDES modification request to include the addition of the new unit. The application addresses only those outfalls that will be modified as a result of the expansion. These include:

- Addition of a new internal discharge (D017 - the cooling tower blowdown that will discharge to the existing Smith Units 1 and 2 discharge tunnel).
- Modifications to discharge D001 when Unit 3 is operating at 100-percent capacity that include flow reduction because of cooling tower makeup water withdrawal and water quality changes because of cooling tower blowdown recycling to the discharge canal.

Please note that Smith Units 1 and 2 outfalls that will not be modified by the Smith Unit 3 expansion and are already permitted under NPDES Permit Number F10002267 have not been repeated in this application.

**SMITH NPDES MODIFICATION
FORM 1 :ITEM XI - SITE TOPOGRAPHIC MAP**



 GULF POWER A SOUTHERN COMPANY	
ONE ENERGY PLACE PENSACOLA, FL. 32520-0323	
SUBJECT: <u>Plant Smith Unit 3</u>	
DETAILS: <u>DEP NPDES Application</u>	
FIELD WORK COMPLETION DATE: <u>N/A</u>	
DRAWN BY: <u>D. E. G.</u> DATE: <u>5/19/99</u> CHKD BY: <u>R. T.</u> DATE: <u>5/19/99</u>	
SCALE <u>1" = 2000'</u> REV. NO. <u>N/A</u> DATE REV. <u>N/A</u>	
SHEET <u>1</u> OF <u>1</u> SHEETS B-DEP-1010	

Poor Original

ATTACHMENT TO NPDES PERMIT APPLICATION

ANTIDegradation Demonstration

The expansion of Gulf Power's Lansing Plant by the addition of Unit 3 will result in a modification to the water balance and effluent discharge currently permitted for the facility (Permit FL0002267). The expansion will include the addition of a cooling tower that will withdraw makeup water from the existing once-through cooling discharge effluent for Units 1 and 2. Approximately 5,200 gallons per minute (gpm) will be withdrawn from the existing 190,000-gpm cooling water discharge and approximately 2,600 gpm of cooling tower blowdown (two cycles of concentration) will be returned to the existing discharge canal. The cooling tower blowdown will be discharged from the cold side of the cooling tower such that the temperature of the blowdown will be lower than the temperature of the existing once-through cooling water. Since less water will be ultimately discharged through the discharge canal to West Bay (approximately 2,500 gpm will be lost to evaporation from the Smith 3 cooling tower), there will be a net reduction of the total heat rejection rate of approximately 1.3 percent.

In addition to makeup water from the existing discharge, some of the plant process water will be routed to the cooling tower for reuse. This includes demineralizer (17 gpm [89 gpm during power augmentation]), condensate polisher (2.2 gpm), evaporative coolers (9.0 gpm), and clean building drains (78 gpm). The water quality at Outfall D001, including the addition of the cooling tower blowdown to the existing discharge, is projected to either meet water quality standards or will be below method detection limits for those parameters that have numeric water quality standards.

A site certification application (SCA) has been submitted to the state that addresses the impacts of the modification to the discharge as well as all other potential impacts of construction and operation of Unit 3. Details addressing the need for the project and benefits are also provided in the SCA. However, to comply with Chapter 62-4.242, Florida Administrative Code (F.A.C.), the following summary is provided to address the factors

identified in determining whether the proposed discharge is necessary or desirable under federal standards and under circumstances that are clearly in the public interest:

- As determined in the policies set forth in Rules 62-302.100 and 62-302.300, the power plant is important and beneficial to the public health, safety, and welfare of the region by providing electric power to a growing region. Gulf has determined that, to provide reliable, cost-effective service to its customers, it must add at least 427 megawatts (MW) of generating resources to its system by the summer of 2002. The most cost-effective way for Gulf to meet this need is to construct a 574-MW natural gas-fired combined cycle (CC) unit at its existing Lansing Smith Electric Generating Plant north of Panama City, Bay County, Florida. Smith Unit 3 is subject to the Florida Electrical Power Plant Siting Act (FEPPSA), Chapter 403, Part II, Florida Statutes. On March 15, 1999, Gulf filed a petition with the Florida Public Service Commission (FPSC) for a Determination of Need for this Project under Section 403.519, Florida Statutes.
- The effects of the existing thermal discharges from the Smith facility have been studied extensively over the last two decades, including an extensive study by Law Environmental, Inc. (1993), that concluded “. . . substantial damage to the aquatic life and/or vegetation of Warren Bayou and West Bay was not evidenced by this study and that beneficial uses assigned to these waters were maintained.” Also, a continuing monitoring program being conducted by SCS (1998) that began in 1993 concluded that, based on “. . . Biological Integrity Test and Laboratory Effluent Toxicity Tests . . . no toxicity problems have been indicated to exist, and the biological integrity of West Bay appears to remain intact.” Since the heat rejection rate will be reduced by up to 1.3 percent and the water quality is projected to comply with water quality standards (or will be below the method detection limit), the effluent will not adversely affect conservation of fish and wildlife, including endangered or threatened species or their habitats.
- Since the proposed modification will slightly reduce the temperature effects of the existing Units 1 and 2 discharge, it will not adversely affect the fish-

ing or water-based recreational values or marine productivity in the vicinity of the proposed discharge.

- The proposed modification to the discharge is not inconsistent with any applicable surface water improvement and management plan.

In addition to the factors previously listed, the following alternatives for the discharge from the proposed facility modification were considered and rejected as not economically or technically feasible:

- Reuse of domestic reclaimed water is not feasible since a source of reuse water is not available or planned. The cooling tower makeup water will use the existing thermal effluent, and internal process streams will be routed to the cooling tower for reuse to the extent practical.
- The use of another discharge location and the use of land application or reuse of the cooling tower blowdown are not practical. The use of the existing discharge canal, which requires no modification, will result in the least disturbance and best source for receiving, diluting, and discharging the effluent.

In addition to the information provided that specifically address the antidegradation permitting requirements details in Chapter 62-4.242, Table 1 is presented to provide the water quality characteristics of the makeup water, the blowdown, and the combined effluent at the point of discharge (Outfall D001) for both normal operating conditions and under power augmentation. The table illustrates that there will be a negligible increase in some of the water quality parameters caused by concentration because of evaporation in the cooling tower (approximately 1.3 percent) and all applicable water quality standards or permit limits will continue to be met in the receiving waters.

For the reasons stated herein that show no significant impacts to water quality and because all requirements of Chapter 62-4.242 have been addressed, an antidegradation determination is appropriate.

Table 1. Water Quality Parameters of the Gulf Smith Unit 3 Cooling Water

Parameter	Makeup Water (Normal)	Makeup Water (Augmentation)	Blowdown (Normal)	Blowdown (Augmentation)	POD (D001) (Normal)	POD (D001) (Augmentation)	Class II Marine Standards†
Flow (gpm)	5,120	5,048	2,587	2,587	187,467	187,539	—
Calcium (mg/L)	172	172	343	346	174	174	—
Magnesium (mg/L)	583	583	1,154	1,139	591	591	—
Sodium (mg/L)	5,416	5,416	10,955	10,809	5,493	5,491	—
Total cations (mg/L)	6,171	6,171	12,452	12,294	6,258	6,256	—
Biocarbonate (mg/L)	65	65	135	152	66	66	—
Sulfate (mg/L)	2,801	2,801	5,544	5,470	2,839	2,838	—
Chloride (mg/L)	8,730	8,730	17,275	17,043	8,848	8,845	—
Phosphate (mg/L)	0	0	0.09	0.09	<0.01	<0.01	—
Total anions (mg/L)	11,596	11,596	22,954	22,665	11,755	11,751	—
pH (units)	7.98	7.98	7.97	7.91	7.98	7.98	6.5 to 8.5
Silica (mg/L)	0.00	0.00	0.5	1.9	0.007	0.026	—
TSS (mg/L)	6.5	6.5	13.8	13.7	6.6	6.6	—
Temperature (°F)	86	86	86	86	86	86	—
Oil and grease (mg/L)	0.00	0.00	0.00	0.00	0.00	0.00	≤5.0
Antimony (mg/L)*	<0.02	<0.02	<0.04	<0.04	<0.02	<0.02	≤4.3
Arsenic (mg/L)*	<0.01	<0.01	<0.01	<0.01	<0.02	<0.02	<0.05
Beryllium (mg/L)*	<0.04	<0.04	<0.08	<0.08	<0.04	<0.04	≤0.00013
Cadmium (mg/L)*	<0.005	<0.005	<0.01	<0.01	<0.005	<0.005	≤0.0093
Chromium (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.05
Lead (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.0056
Nickel (mg/L)*	<0.04	<0.04	<0.08	<0.08	<0.04	<0.04	≤0.0083

Table 1. Water Quality Parameters of the Gulf Smith Unit 3 Cooling Water (Continued, Page 2 of 2)

Parameter	Makeup Water (Normal)	Makeup Water (Augmentation)	Blowdown (Normal)	Blowdown (Augmentation)	POD (D001) (Normal)	POD (D001) (Augmentation)	Class II Marine Standards
Selenium (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.071
Silver (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	—
Thallium (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.0063
Zinc (mg/L)*	<0.02	<0.02	<0.04	<0.04	<0.02	<0.02	≤0.086
Mercury (mg/L)*	<0.0002	<0.0002	<0.0004	<0.0004	<0.000	<0.0002	<0.000025
Copper (mg/L)*	<0.002	<0.002	<0.04	<0.04	<0.02	<0.02	<.0029
Cyanide (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤1.0

* Because of two cycles of concentration, the concentration will approximately double in the blowdown. Input from process streams to the cooling tower are expected to be below detection limits for these parameters. Values shown as less than (“<”) are below the detection limits.

† Pursuant to the facility’s NPDES permit, “the actual limit shall be the water quality standard set forth in F.A.C. 62-302.530 for Class II waters...or the concentration of the intake cooling water, whichever is greater.”

Sources: Gulf, 1999.
ECT, 1999.



WASTEWATER APPLICATION FORM 2CS

PERMIT TO DISCHARGE PROCESS WASTEWATER
FROM NEW OR EXISTING
INDUSTRIAL WASTEWATER FACILITIES
TO SURFACE WATER

INSTRUCTIONS - FORM 2CS

This form must be completed by all applicants who check "yes" to Item II-C in DEP Form 62-620.910(1).

Public Availability of Submitted Information.

You may not claim as confidential any information required by this form or DEP Form 62-620.910(1), whether the information is reported on the forms or in an attachment. This information will be made available to the public upon request. Any information you submit to the Department which goes beyond that required by this form or DEP Form 62-620.910(1) you may claim as confidential, but claims for information which is effluent data will be denied. If you do not assert a claim of confidentiality at the time of submitting the information, the Department may make the information public without further notice to you. Claims of confidentiality must be in accordance with Rule 62-620.302, Florida Administrative Code.

Completeness

Your application will not be considered complete unless you answer every question on this form (DEP Form 62-620.910(5)) and on Form 1 (DEP Form 62-620.910(1)). If an item does not apply to you, enter "NA" (for "not applicable") to show that you considered the question. Also, you may need a Plan of Study (POS) to develop Water Quality Effluent Limitations (WQBEL) required by Rule 62-650, F.A.C. Please contact the Department for information.

Follow-up Requirements (for New or Substantially Modified Facilities)

Although you are now required to submit estimated data on this form, please note that no later than six months after you begin discharging from the proposed or substantially modified facility, you must complete and submit items VII and VIII of this Form 2CS (DEP Form 62-620.910(5)). However, you need not complete those portions of Item V requiring test which you have already performed under the discharge monitoring requirements of your permit.

Definitions

All significant terms used in these instructions and in the form are defined in the glossary found in the General Instructions which accompany Form 1.

DEP ID Number

If you are applying for a renewal of an existing permit or for a substantial revision to an existing permit, fill in your DEP Identification Number at the top of each page of Form 2CS. You may copy this number directly from Item 1 of Form 1. If you are applying for a permit for a proposed facility, leave the DEP Identification Number blank. The Department will assign a number.

Item I

You may use the map you provided for Item XI of Form 1 to determine the latitude and longitude of each of your discharge locations.

Item II

Describe the design of each outfall, including construction materials used or to be used.

Item III

Describe the surface water body which will be or is receiving effluent from the wastewater facility.

Item IV

A. The line drawing should show generally the route taken by water in your facility from intake to discharge. Show all operations contributing wastewater, including process and production areas, sanitary flows, cooling water, and stormwater runoff. You may group similar operations into a single unit, labeled to correspond to the more detailed listing in Item III B. The water balance should show average flows. Show all significant losses of water to products, atmosphere, and discharge. You should use actual measurements whenever available; otherwise, use your best estimate.

B. List all sources of wastewater to each discharge point. Operations may be described in general terms (for example, "dye-making reactor" or "distillation tower"). You may estimate the flow contributed by each source if no data are available. For stormwater discharges you may estimate the average flow, but you must indicate the rainfall event upon which the estimate is based and the method of estimation. For each treatment unit, indicate its size, flow rate, and retention time, and describe the ultimate disposal of any solid or liquid wastes not discharged. Treatment units should be listed in order and you should select the proper code from Table 2CS-1 to fill in column 3-b for each treatment unit. Insert "XX" into column 3-b if no code corresponds to a treatment unit you list.

C. A discharge is intermittent unless it occurs without interruption during the operating hours of the facility, except for infrequent shut-downs for maintenance, process changes, or other similar activities. A discharge is seasonal if it occurs only during certain parts of the year. Fill in every applicable column in this item for each source of intermittent or seasonal discharges. Base your answers on actual data whenever available; otherwise, provide your best estimate. Report the highest daily value for flow rate and total volume in the "Max. Daily" columns (columns 4-a and 4-b). Report the average of all daily values measured during days when the discharge occurred within the last year in the "Long Term Avg." columns (columns 4-a and 4-b).

Item V

"Production" in this question refers to those goods which the proposed, substantially modified, or existing facility will produce or is producing, not to "wastewater" production. This information is only necessary where production-based new source performance standards (NSPS) or effluent guidelines apply to your facility. Your estimated production figures should be based on a realistic projection of actual daily production level (not design capacity) for each of the first three operating years of the facility. This estimate must be a long-term-average estimate (e.g., average production on an annual basis). If production will vary depending on long-term shifts in operating schedule or capacity, you may report alternate production estimates and the basis for the alternate estimates.

A. All NSPS and effluent guidelines promulgated by EPA appear in the Federal Register and are published annually in 40 CFR Subchapter N. A guideline applies to you if you have any operations contributing process wastewater in any subcategory covered by a BPT, BCT, or BAT guideline. If you are unsure whether you are covered by a promulgated NSPS or effluent guideline, check with your DEP district office (*Figure 1 in the Form 1 instructions*). You must check "yes" if an applicable NSPS or effluent guideline has been promulgated, even if the guideline limitations are being contested in court. If you believe that a promulgated NSPS or effluent guideline has been remanded for reconsideration by a court and does not apply to your operations, you may check "no."

B. An NSPS or effluent guideline is expressed in terms of production (*or other measure of operation*) if the limitation is expressed as mass of pollutant per operational parameter: for example, "pounds of BOD per cubic foot of logs from which bark is removed," or "pounds of TSS per megawatt hour of electrical energy consumed by smelting furnace." An example of a guideline not expressed in terms of a measure of operation is one which limits the concentration of pollutants.

C. This item must be completed only if you checked "yes" to Item V-B. The production information requested here is necessary to apply effluent guidelines to your facility and you cannot claim it as confidential. However, you do not have to indicate how the reported information was calculated. Report quantities in the units of measurement used in the applicable NSPS or effluent guideline. The production figures provided must be based on actual daily production and not on design capacity or on predictions of future operations. To obtain alternate limits under Rule 62-620.620(2)(b)3., F.A.C., you must define your maximum production capability and demonstrate to the Department that your actual production is substantially below maximum production capability and that there is a reasonable potential for an increase above actual production during the duration of the permit.

Item VI

- A. If you check "yes" to this question, complete all parts of the chart, or attach a copy of any previous submission you have made to the Department containing the same information.
- B. You are not required to submit a description of future pollution control projects if you do not wish to or if none is planned.

Item VII (A, B, C, and D, including Tables VII-A, VII-B, and VII-C)

This item requires you to collect and report data on the pollutants discharged from each of your discharge points. Each part of this item addresses a different set of pollutants and must be completed in accordance with the specific instructions for that part. The following general instructions apply to the entire item.

General Instructions

Part A requires you to report at least one analysis for each pollutant listed. Parts B and C require you to report analytical data in two ways. For some pollutants, you may be required to mark "X" in the "Testing Required" column (*column 2-a, Part C*), and test (*sample and analyze*) and report the levels of the pollutants in your discharge whether or not you expect them to be present in your discharge. For all other, you must mark "X" in either the "Believe Present" column or the "Believe Absent" column (*columns 2-a or 2-b, Part B, and Columns 2-b or 2-c, Part C*) based on your best estimate, and test for those which you believe to be present. (*See specific instructions on the form and below for Parts A through D.*) Base your determination that a pollutant is present in or absent from your discharge on your knowledge of your raw materials, maintenance chemicals, intermediate and final products and by-products, and any previous analyses known to you of your effluent or similar effluent. (*For example, if you manufacture pesticides, you should expect those pesticides to be present in contaminated stormwater runoff.*) If you would expect a pollutant to be present solely as a result of its presence in your intake water, you must mark "Believe Present" but you are not required to analyze for that pollutant. Instead, mark an "X" in the "Intake" column.

A. Reporting

All levels must be reported as concentration and as total mass. You may report some or all of the required data by attaching separate sheets of paper instead of filling out pages VII-1 to VII-10 if the separate sheets contain all the required information in a format which is consistent with pages VII-1 to VII-10 in spacing and in identification of pollutants and columns. (*For example, the data systems used in your GC/MS analysis may be able to print data in the proper format.*) Use the following abbreviations in the columns headed "Units" (*column 3, Part A, and Column 4, Parts B and C*).

Concentration
ppm - parts per million
mg/l - milligrams per liter
ppb - parts per billion
µg/l - micrograms per liter

Mass
lbs - pounds
ton - tons (English tons)
mg - milligrams
g - grams
kg - kilograms
T - tonnes (metric tons)

All reporting of values for metals must be in terms of "total recoverable metal," unless (1) an applicable, promulgated effluent limitation or standard specifies the limitation for the metal in dissolved, valent, or total form; or (2) all approved analytical methods for the metal inherently measure only its dissolved form (e.g., hexavalent chromium). If you measure only one daily value, complete only "Max. Daily Values" columns and insert "1" into the "Number of Analyses" column (*columns 2-a and 2-d, Part A, and column 3-a, 3-d, Parts B and C*). The Department may require you to conduct additional analyses to further characterize your discharges. For composite sample, the daily value is the total mass or average concentration found in a composite sample taken over the operating hours of the facility during a 24-hour period; for grab samples, the daily value is the arithmetic or flow-weighted total mass or average concentration found in a series of at least

four grab samples taken over the operating hours of the facility during a 24-hour period. If you measure more than one daily value for a pollutant and those values are representative of your waste stream, you must report them. You must describe your method of testing and data analysis. You also must determine the average of all values within the last year and report the concentration and mass under the "Long Term Avg. Values" columns (*column 2-c, Part A, and column 3-c, Parts B and C*), and the total number of daily values under the "Number of Analyses" columns (*column 2-d, Part A, and columns 3-d, Parts B and C*). Also determine the average of all daily values taken during each calendar month, and report the highest average under the "Max. 30-day Values" columns (*column 2-c, Part A, and column 3-b, Parts B and C*).

B. Sampling

The collection of the samples for the reported analyses should be supervised by a person experienced in performing sampling of industrial wastewater. Any specific requirements contained in the applicable analytical methods should be followed for sample containers, sample preservation, holding times, the collection of duplicate samples, etc. The time when you sample should be representative of your normal operation, to the extent feasible, with all processes which contribute wastewater in normal operation, and with your treatment system operating properly with no system upsets. Samples should be collected from the center of the flow channel, where turbulence is at a maximum, at a site specified in your present permit, or at any site adequate for the collection of a representative sample. Sampling for metals that are hardness-dependent shall also include sampling for hardness.

For pH, temperature, cyanide, total phenols, residual chlorine, oil and grease, and fecal coliform, grab samples must be used. For all other pollutants 24-hour composite samples must be used. However, a minimum of one grab sample may be taken for effluents from holding ponds, or other impoundments with a retention period of greater than 24 hours. For stormwater discharges a minimum of one to four grab samples may be taken, depending on the duration of the discharge. One grab must be taken in the first hour (*or less*) of discharge, with one additional grab (*up to a minimum of four*) taken in each succeeding hour of discharge for discharges lasting four or more hours. The Department may waive composite sampling for any discharge point for which you demonstrate that use of an automatic sampler is infeasible and that a minimum of four grab samples will be representative of your discharge.

Grab and composite samples¹ are defined as follows:

Grab sample: An individual sample or at least 100 milliliters collected at a randomly-selected time over a period not exceeding 15 minutes.

¹Sampling requirements are periodically reviewed in light of recent research on testing methods. Upon completion of the review, changes to sampling requirements may be made. Before starting any required sampling or submitting past sampling to the Department, be sure that you have a current copy of 40 CFR Part 136 or Chapter 160, Florida Administrative Code.

Composite sample: A combination of at least 8 sample aliquots of a least 100 milliliters, collected at periodic intervals during the operating hours of a facility over a 24-hour period. The composite must be flow proportional; either the time interval between each aliquot or the volume of each aliquot must be proportional to either the stream flow at the time of sampling or the total stream flow since the collection of the previous aliquot. Aliquots may be collected manually or automatically. For GC/MS Volatile Organic Analysis (VOA), aliquots must be combined in the laboratory immediately before analysis. Four (4) (*rather than eight*) aliquots or grab samples should be collected for VOA. These four samples should be collected during actual hours of discharge over a 24-hour period and need not be flow proportioned. Only one analysis is required.

Data from samples taken in the past may be used if all data requirement are met; sampling was done no more than three years before submission; and all data are representative of the present discharge. Among the factors which would cause the data to be unrepresentative are significant changes in production level; changes in raw materials, processes, or final products; and changes in wastewater treatment. When EPA promulgates new analytical methods in 40 CFR Part 136, EPA will provide information as to when you should use the new methods to generate data on your discharges. The Department may promulgate new methods in Chapter 160, Florida Administrative Code, with the date when the new methods are to be used. Always be sure you have current copies of these two documents before you take samples or submit sampling data to the Department. If you have submitted data from past sampling, the Department may request additional information, including current quantitative data, if it is determined to be necessary to assess your discharges.

C. Analysis

You must use test methods promulgated in 40 CFR Part 136 or Chapter 160, Florida Administrative Code; however, if none has been promulgated for a particular pollutant, you may use any suitable method for measuring the level of the pollutant in your discharge if you submit a description of the method or a reference to a published method. Your description should include the sample holding time, preservation techniques, and the quality control measures which you used. If you have two or more substantially identical discharge points, you may request permission from the Department to sample and analyze only one point and submit the results of the analysis for other substantially identical points. If your request is granted by the Department, or a separate sheet attached to the application form identify which point you did test, and describe why the other points you did not test are substantially identical to the point which you did test.

D. Reporting of Intake Data

You are not required to report data under the "Intake" columns unless you wish to demonstrate your eligibility for a "net" effluent limitation for one or more pollutants, that is, an effluent limitation adjusted by subtracting the average level of the pollutant(s) present in your intake water. To demonstrate your eligibility, under the "Intake" columns report the average of the results of analyses on your intake water (*If your water is treated before use, test the water after it is treated.*), and discuss the requirements for a new limitation with the appropriate district office.

Part VII-A

Part VII-A must be completed by all applicants for all discharge points including discharges of non-contact cooling water or storm runoff. However, at your request, the Department may waive the requirement to test for one or more of these pollutants, upon a determination that available information is adequate to support issuance of the permit with less stringent reporting requirements for these pollutants. Use composite samples for all pollutants in this Part, except use grab samples for pH and temperature. See the discussion in General Instructions to item *VII* for definitions of the columns in Part A. The "Long Term Avg. Values" column (*column 2-c*) and "Max. 30-day Values" column (*column 2-b*) are not compulsory but should be filled out if data are available.

Part VII-B

Part VII-B must be completed by all applicants for all discharge points, including points containing only non-contact cooling water or storm runoff. You must report quantitative data if the pollutant(s) in question is limited in an effluent limitation either directly or indirectly but expressly through a limitation on an indicator (*e.g., use of TSS as an indicator to control the discharge of iron and aluminum*). For other discharged pollutants you must provide quantitative data or explain their presence in your discharge. The Department will consider a request to eliminate the requirement to test for pollutants for an industrial category or subcategory. Your request must be supported by data representative of the industrial category or subcategory in question. The data must demonstrate that individual testing for each applicant is unnecessary, because the facilities in the category or subcategory discharge substantially identical levels of the pollutant or discharge the pollutant uniformly at sufficiently low levels. Use composite samples for all pollutants you analyze for in this part, except use grab samples for residual chlorine, oil and grease, and fecal coliform. The "Long Term Avg. Values" column (*column 2-c*) and "Max. 30-day Values" column (*column 2-b*) are not compulsory but should be filled out if data are available.

Part VII-C

Table 2CS-2 at the end of these instructions lists 34 primary industry categories. For each discharge point, if any of your processes which contribute wastewater falls into one of those categories, you must mark "X" in "Testing Required" column (*column 2-a*) and test for (1) all of the toxic metals, cyanide, and total phenols; and (2) the organic toxic pollutants contained in Table 2CS-3 as applicable to your category. The organic toxic pollutants are listed by GC/MS fractions on pages VII-4 to VII-10 in Part VII-C. The inclusion of total phenols in Part VII-C is not intended to classify total phenols as a toxic pollutant. When you determine which industry category you are in to find your testing requirements, you are not determining your category for any other purpose and you are not giving up your right to challenge your inclusion in that category before your permit is issued. For all other cases (*secondary industries, non-process wastewater discharge points, and GC/MS fractions that are not required*), you must mark "X" in either the "Believed Present" column or the "Believed Absent" column for each pollutant.

You must report quantitative data as follows:

For every pollutant you know or have reason to believe is present in your discharge in concentrations of 10 ppb or greater;

For acrolein; acrylonitrile; 2,4 dinitrophenol; and 2-methyl-4,6 dinitrophenol where you expect these four pollutants to be discharged in concentrations of 100 ppb or greater; and

For every pollutant expected to be discharged in concentrations less than the thresholds specified above. For pollutants in this last category, in lieu of quantitative data, you may briefly describe the reasons the pollutant is expected to be discharged.

You are required to mark "Testing Required" for dioxin if you use or manufacture one of the following compounds:

- (a) 2,4,5-trichlorophenoxy acetic acid, (2,4,5-T);
- (b) 2-(2,4,5-trichlorophenoxy) propanoic acid, (Silvex, 2,4,5-TP);
- (c) 2-(2,4,5-trichlorophenoxy) ethyl 2,2-dichloropropionate, (Erbon);
- (d) 0,0-dimethyl 0-(2,4,5-trichlorophenyl) phosphorothioate, (Ronnell);
- (e) 2,4,5-trichlorophenol, (TCP); or
- (f) hexachlorophene, (HCP).

If you mark "testing Required" or "Believed Present," you must perform a screening analysis for dioxin, using gas chromatography with an electron capture detector. A TCDD standard for quantitation is not required. Describe the results of this analysis in the space provided: for example, "no measurable baseline deflection at the retention time of TCDD" or "a measurable peak within the tolerances of the retention time of TCDD." The Department may require you to perform a quantitative analysis if you report a quantitative analysis if you report a positive result.

Part VII-D

List any pollutants in Table 2CS-3 that you believe to be present and explain why you believe them to be present. No analysis is required, but if you have analytical data, you must report it. For discharges of the hazardous substances listed in Table 2CS-4, you may be exempt from the reporting requirements of section 311 of the Clean Water Act. Please contact the Department for information.

Item VIII

This requirement applies to current use or manufacture of a toxic pollutant as an intermediate or final product or by-product. The Department may waive or modify the requirement if you demonstrate that it would be unduly burdensome to identify each toxic pollutant and the Department has adequate information to issue your permit. You may not claim this information as confidential; however, you do not have to distinguish between use or production of the pollutants or list the amounts.

Item IX

This item is self explanatory.

Item X

This item is self explanatory.

Item XI

This item is self explanatory.

Item XII

There are severe penalties for submitting false information on this application form. Chapter 62-620, Florida Administrative Code, requires, in addition to the certification provided by a professional engineer, a certification from the owner or responsible authority of the facility as follows:

A. For a corporation: by a responsible corporate official. For purposes of this section, a responsible corporate official means (1) a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision-making functions for the corporation; or (2) the manager of one or more manufacturing, production or operating facilities employing more than 250 person or have gross annual sales or expenditures exceeding \$25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

B. For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or

C. For a municipality, State, Federal, or other public agency: by either a principal executive officer or ranking elected official. A principal executive officer includes the chief executive officer of the agency or a senior executive officer having the responsibility for the overall operations of a principal geographic unit of the agency, for example, a regional or district administrator.

**TABLE 2CS-1
CODES FOR TREATMENT UNITS**

PHYSICAL TREATMENT PROCESSES			
1-A	Ammonia Stripping	1-N	Microstraining
1-B	Dialysis	1-O	Mixing
1-C	Diatomaceous Earth Filtration	1-P	Moving Bed Filters
1-D	Distillation	1-Q	Multimedia Filtration
1-E	Electrodialysis	1-R	Rapid Sand Filtration
1-F	Evaporation	1-S	Reverse Osmosis (Hyperfiltration)
1-G	Flocculation	1-T	Screening
1-H	Flotation	1-U	Sedimentation (Settling)
1-I	Foam Fractionation	1-V	Slow Sand Filtration
1-J	Freezing	1-W	Solvent Extraction
1-K	Gas-Phase Separation	1-X	Sorption
1-L	Grinding (Comminutors)	1-Y	Percolation Pond
1-M	Grit Removal		
CHEMICAL TREATMENT PROCESSES			
2-A	Carbon Adsorption	2-G	Disinfection (<i>Ozone</i>)
2-B	Chemical Oxidation	2-H	Disinfection (<i>Other</i>)
2-C	Chemical Precipitation	2-I	Electrochemical Treatment
2-D	Coagulation	2-J	Ion Exchange
2-E	Dechlorination	2-K	Neutralization
2-F	Disinfection (<i>Chlorine</i>)	2-L	Reduction
BIOLOGICAL TREATMENT PROCESSES			
3-A	Activated Sludge	3-E	Pre-Aeration
3-B	Aerated Lagoons	3-F	Spray Irrigation/Land Application

Table 2CS-1, Codes for Treatment Units contd.

3-C	Anaerobic Treatment	3-G	Stabilization Ponds
3-D	Nitrification-Denitrification	3-H	Trickling Filter
OTHER PROCESSES			
4-A	Discharge to Surface Water	4-C	Reuse/Recycle of Treated Effluent
4-B	Ocean Discharge Through Outfall	4-D	Underground Injection
SLUDGE TREATMENT AND DISPOSAL PROCESSES			
5-A	Aerobic Digestion	5-M	Heat Drying
5-B	Anaerobic Digestion	5-N	Heat Treatment
5-C	Belt Filtration	5-O	Incineration
5-D	Centrifugation	5-P	Land Application
5-E	Chemical Conditioning	5-Q	Landfill
5-F	Chlorine Treatment	5-R	Pressure Filtration
5-G	Composting	5-S	Pyrolysis
5-H	Drying Beds	5-T	Sludge Lagoons
5-I	Elutriation	5-U	Vacuum Filtration
5-J	Flotation Thickening	5-V	Vibration
5-K	Freezing	5-W	Wet Oxidation
5-L	Gravity Thickening		

TABLE 2CS-2
TESTING REQUIREMENTS FOR ORGANIC TOXIC POLLUTANTS INDUSTRY CATEGORY

INDUSTRY CATEGORY	GC/MS FRACTION ¹			
	Volatile	Acid	Basic/Neutral	Pesticide
Adhesives and sealants	X	X	X	
Aluminum forming	X	X	X	
Auto and other laundries	X	X	X	X
Battery manufacturing	X		X	
Coal mining	X	X	X	X

Table 2CS-2, Testing Requirements for Organic Toxic Pollutants Industry Category contd.

Coil coating	X	X	X	
Copper forming	X	X	X	
Electric and electronic compounds	X	X	X	X
Electroplating	X	X	X	
Explosives manufacturing		X	X	
Foundries	X	X	X	
Gum and wood chemicals	X	X	X	X
Inorganic chemicals manufacturing	X	X	X	
Iron and steel manufacturing	X	X	X	
Leather tanning and finishing	X	X	X	X
Mechanical products manufacturing	X	X	X	
Nonferrous metals manufacturing	X	X	X	X
Ore mining	X	X	X	X
Organic chemicals manufacturing	X	X	X	X
Paint and ink formulation	X	X	X	X
Pesticides	X	X	X	X
Petroleum refining	X	X	X	X
Pharmaceutical preparations	X	X	X	
Photographic equipment and supplies	X	X	X	X
Plastic and synthetic materials manufacturing	X	X	X	X
Plastic processing	X			
Porcelain enameling	X		X	X
Printing and publishing	X	X	X	X
Pulp and paperboard mills	X	X	X	X
Rubber processing	X	X	X	
Soap and detergent manufacturing	X	X	X	
Steam electric power plants	X	X	X	
Textile mills	X	X	X	X
Timber products processing	X	X	X	X

¹The pollutants in each fraction are listed in Item VII-C. X = Testing required.

TABLE 2CS-3
TOXIC POLLUTANTS AND HAZARDOUS SUBSTANCES
REQUIRED TO BE IDENTIFIED BY APPLICANTS
IF EXPECTED TO BE PRESENT

<u>Toxic Pollutant</u>	<u>Hazardous Substances</u>	<u>Hazardous Substances</u>
Asbestos	2,2 Dichloropropionic acid	Monomethyl amine
	Dichlorvos	Naled
<u>Hazardous Substances</u>	Diethyl amine	Naphthenic acid
Acetaldehyde	Dimethyl amine	Nitrotoluene
Allyl alcohol	Dintrobenzene	Parathion
Allylchloride	Diquat	Phenolsulfonate
Amyl acetate	Disulfoton	Phosgene
Aniline	Diuron	Propargite
Benzonitrile	Epichlorohydrin	Propylene oxide
Benzyl chloride	Ethion	Pyrethrins
Butyl acetate	Ethylene diamine	Quinoline
Butylamine	Formaldehyde	Resorcinol
Captan	Furfural	Strontium
Carbaryl	Guthion	Strychnine
Carbofuran	Isoprene	2,4,5-T (2,4,5-Trichlorophenoxyacetic acid)
Carbon disulfide	Isopropanolamine	TDE (Terochlorodiphenyl ethane)
Chlopyrifos	dodecylbenzenesulfonate	2,4,5-TP [2-(2,4,5-Trichlorophenoxy)propanoic acid]
Coumpahos	Kelthane	Trichlorofon
Cresol	Kepone	Triethanolamine dodecylbenzenesulfonate
Crotonaldehyde	Malathion	Triethylamine
Cyclohexane	Mercaptodimethur	Uranium
2,4-D (2,4-Dichlorophenoxyacetic acid)	Methoxychlor	Vanadium
Diazinon	Methyl mercaptan	Vinyl acetate
Dicamba	Methyl methacrylate	Xylene
Dichlobenil	Methyl parathion	Xylenol
Dichlone	Mevinphos	Zirconium
	Mexacarbate	
	Monoethyl amine	

**TABLE 2CS-4
HAZARDOUS SUBSTANCES**

1. Acetaldehyde	49. Arsenic trisulfide	97. Cupric nitrate
2. Acetic acid	50. Barium cyanide	98. Cupric oxalate
3. Acetic anhydride	51. Benzene	99. Cupric sulfate
4. Acetone cyanohydrin	52. Benzoic acid	100. Cupric sulfate ammoniated
5. Acetyl bromide	53. Benzonitrile	101. Cupric tartrate
6. Acetyl chloride	54. Benzoyl chloride	102. Cyanogen chloride
7. Acrolein	55. Benzyl chloride	103. Cyclohexane
8. Acrylonitrile	56. Beryllium chloride	104. 2,4-D acid (2,4- Dichlorophenoxyacetic acid)
9. Adipic acid	57. Beryllium fluoride	105. 2,4-D esters (2,4- Dichlorophenoxyacetic acid esters)
10. Aldrin	58. Beryllium nitrate	106. DDT
11. Allyl alcohol	59. Butylacetate	107. Diazinon
12. Allyl chloride	60. n-Butylphthalate	108. Dicamba
13. Aluminum sulfate	61. Butylamine	109. Dichlobenil
14. Ammonia	62. Butyric acid	110. Dichlone
15. Ammonium acetate	63. Cadmium acetate	111. Dichlorobenzene
16. Ammonium benzoate	64. Cadmium bromide	112. Dichloropropane
17. Ammonium bicarbonate	65. Cadmium chloride	113. Dichloropropene
18. Ammonium bichromate	66. Calcium arsenate	114. Dichloropropene-Dichloropropane mix
19. Ammonium bifluoride	67. Calcium arsenite	115. 2,2-Dichloropropionic acid
20. Ammonium bisulfite	68. Calcium carbide	116. Dichlorvos
21. Ammonium carbamate	69. Calcium chromate	117. Dieldrin
22. Ammonium carbonate	70. Calcium cyanide	118. Diethylamine
23. Ammonium chloride	71. Calcium dodecylbenzenesulfonate	119. Dimethylamine
24. Ammonium chromate	72. Calcium hypochlorite	120. Dinitrobenzene
25. Ammonium citrate	73. Captan	121. Dinitrophenol
26. Ammonium fluoroborate	74. Carbaryl	122. Dinitrotoluene
27. Ammonium fluoride	75. Carbofuran	123. Diquat
28. Ammonium hydroxide	76. Carbon disulfide	124. Disulfoton
29. Ammonium oxalate	77. Carbon tetrachloride	125. Diuron
30. Ammonium silicofluoride	78. Chlordane	126. Dodecylbenzenesulfonic acid
31. Ammonium sulfamate	79. Chlorine	127. Endosulfan
32. Ammonium sulfide	80. Chlorobenzene	128. Endrin
33. Ammonium sulfite	81. Chloroform	129. Epichlorohydrin
34. Ammonium tartrate	82. Chlorpyrifos	130. Ethion
35. Ammonium thiocyanate	83. Chlorosulfonic acid	131. Ethylbenzene
36. Ammonium thiosulfate	84. Chromic acetate	132. Ethylenediamine
37. Amyl acetate	85. Chromic acid	133. Ethylene dibromide
38. Aniline	86. Chromic sulfate	134. Ethylene dichloride
39. Antimony pentachloride	87. Chromous chloride	135. Ethylene Diaminetetracetic acid (EDTA)
40. Antimony potassium tartrate	88. Cobaltous bromide	136. Ferric ammonium citrate
41. Antimony tribromide	89. Cobaltous formate	137. Ferric ammonium oxalate
42. Antimony trichloride	90. Cobaltous sulfamate	138. Ferric chloride
43. Antimony trifluoride	91. Coumaphos	139. Ferric fluoride
44. Antimony trioxide	92. Cresol	140. Ferric nitrate
45. Arsenic disulfide	93. Crotonaldehyde	
46. Arsenic pentoxide	94. Cupric acetate	
47. Arsenic trichloride	95. Cupric acetoarsenite	
48. Arsenic trioxide	96. Cupric chloride	

HAZARDOUS SUBSTANCES (contd.)

141. Ferric sulfate
142. Ferrous ammonium sulfate
143. Ferrous chloride
144. Ferrous sulfate
145. Formaldehyde
146. Formic acid
147. Fumaric acid
148. Furfural
149. Guthion
150. Heptachlor
151. Hexachlorocyclopentadiene
152. Hydrochloric acid
153. Hydrofluoric acid
154. Hydrogen cyanide
155. Hydrogen sulfide
156. Isoprene
157. Isopropanolamine
dodecylbenzenesulfonate
158. Kelthane
159. Kepone
160. Lead acetate
161. Lead arsenate
162. Lead chloride
163. Lead fluoborate
164. Lead fluorite
165. Lead iodide
166. Lead nitrate
167. Lead stearate
168. Lead sulfate
169. Lead sulfide
170. Lead thiocyanate
171. Lindane
172. Lithium chromate
173. Malathion
174. Maleic acid
175. Maleic anhydride
176. Mercaptodimethur
177. Mercuric cyanide
178. Mercuric nitrate
179. Mercuric sulfate
180. Mercuric thiocyanate
181. Mercurous nitrate
182. Methoxychlor
183. Methyl mercaptan
184. Methyl methacrylate
185. Methyl parathion
186. Mevinphos
187. Mexacarbate
188. Monoethylamine
189. Monomethylamine
190. Naled
191. Naphthalene
192. Naphthenic acid
193. Nickel ammonium sulfate
194. Nickel chloride
195. Nickel hydroxide
196. Nickel nitrate
197. Nickel sulfate
198. Nitric acid
199. Nitrobenzene
200. Nitrogen dioxide
201. Nitrophenil
202. Nitrotoluene
203. Paraformaldehyde
204. Parathion
205. Pentachlorophenol
206. Phenol
207. Phosgene
208. Phosphoric acid
209. Phosphorus
210. Phosphorus oxychloride
211. Phosphorus pentasulfide
212. Phosphorus trichloride
213. Polychlorinated biphenyls (PCB)
214. Potassium arsenate
215. Potassium arsenite
216. Potassium bichromate
217. Potassium chromate
218. Potassium cyanide
219. Potassium hydroxide
220. Potassium permanganate
221. Propargite
222. Propionic acid
223. Propionic anhydride
224. Propylene oxide
225. Pyrethrins
226. Quinoline
227. Resorcinol
228. Selenium oxide
229. Silver nitrate
230. Sodium
231. Sodium arsenate
232. Sodium arsenite
233. Sodium bichromate
234. Sodium bifluoride
235. Sodium bisulfite
236. Sodium chromate
237. Sodium cyanide
238. Sodium dodecylbenzenesulfonate
239. Sodium fluoride
240. Sodium hydrosulfide
241. Sodium hydroxide
242. Sodium hypochlorite
243. Sodium methylate
244. Sodium nitrate
245. Sodium phosphate (dibasic)
246. Sodium phosphate (tribasic)
247. Sodium selenite
248. Strontium chromate
249. Strychnine
250. Styrene
251. Sulfuric acid
252. Sulfur monochloride
253. 2,4,5-T acid (2,4,5-Trichlorophenoxy acetic acid)
254. 2,4,5-T amines (2,4,5-Trichlorophenoxy acetic acid amines)
255. 2,4,5-T esters (2,4,5-Trichlorophenoxy acetic acid esters)
256. 2,4,5-T salts (2,4,5-Trichlorophenoxy acetic acid salts)
257. 2,4,5-TP acid (2,4,5-Trichlorophenoxy propanoic acid)
258. 2,4,5-TP acid esters (2,4,5-Trichlorophenoxy propanoic acid esters)
259. TDE (Tetrachlorodiphenyl ethane)
260. Tetraethyl lead
261. Tetraethyl pyrophosphate
262. Thallium sulfate
263. Toluene
264. Toxaphene
265. Trichlorofon
266. Trichloroethylene
267. Trichlorophenol
268. Triethanolamine
dodecylbenzenesulfonate
269. Triethylamine
270. Trimethylamine
271. Uranyl acetate
272. Uranyl nitrate
273. Vanadium pentoxide
274. Vanadyl sulfate
275. Vinyl acetate
276. Vinylidene chloride
277. Xylene
278. Xylenol
279. Zinc acetate
280. Zinc ammonium chloride

HAZARDOUS SUBSTANCES (contd.)

281. Zinc borate
282. Zinc bromide
283. Zinc carbonate
284. Zinc chloride
285. Zinc cyanide
286. Zinc fluoride

287. Zinc formate
288. Zinc hydrosulfite
289. Zinc nitrate
290. Zinc phenolsulfonate
291. Zinc phosphide
292. Zinc silcofluoride

293. Zinc sulfate
294. Zirconium nitrate
295. Zirconium potassium fluoride
296. Zirconium sulfate
297. Zirconium tetrachloride

FORM 2CS



WASTEWATER APPLICATION FOR PERMIT TO DISCHARGE PROCESS WASTEWATER FROM NEW OR EXISTING INDUSTRIAL WASTEWATER FACILITIES TO SURFACE WATERS

Facility I.D. Number: FL0002267

Please print or type information in the appropriate areas.

I OUTFALL LOCATION For each outfall, list the X,Y coordinates and the name of the receiving water.
(latitude/longitude to the nearest 15 seconds)

A. Outfall No. (List)	B. Latitude			C. Longitude			D. Name of Receiving Water
	Deg.	Min.	Sec.	Deg.	Min.	Sec.	
D001	30	16	23.87	85	43	15.52	West Bay
D015	30	16	04.47	85	41	49.61	Internal Outfall
D01C	30	16	12.34	85	41	53.16	Internal Outfall
D00D	30	16	04.42	85	42	03.11	Alligator Bayou
D01A	30	16	01.34	85	41	49.09	Internal Outfall
*D017	30	16	09.76	85	42	06.28	Internal Outfall to existing discharge canal

II OUTFALL DESIGN

A. Outfall No. (List)	B. Design Configuration and Construction Materials	C. Distance from shore	D. Diameter	E. Elevation of Discharge Invert (MSL)	F. Receiving Water Depth at POD (MSL)
D001	Man made canal	NA	200' wide	NA	NA
D015	Metal cleaning waste treatment pond	Internal	Outfall	to Ash Pond	
D01C	Parshall Flume / Concrete	Internal	Outfall	to D001	
D00D	Main Yard Sump		12"		6'
D01A	Domestic Waste Plant	Internal	Outfall	to Ash Pond	
*D017	Metal Pipe	NA	24"	to be determined	about 6'

*NOTE: D017 is the number for proposed new internal outfall for Smith 3.

III RECEIVING WATER INFORMATION

For each surface water that will receive effluent, supply the following information:

A. Name of Receiving Water	B. Check One		C. Classification (See Ch. 62-302, F.A.C.)	D. Type of Receiving Water (canal, river, lake, etc.)
	Fresh	Salt or Brackish		
West Bay		X	Class II	Bay

E. Minimum 7-day 10-year low flow of the receiving water at each outfall (if appropriate). **NA**

F. Identify and describe the flow of effluent from each outfall to a major body of water. A suitably marked map or aerial photograph may be used. **The new proposed internal Outfall D017 will discharge to the existing canal. D001 will continue to discharge as previously permitted through the discharge canal to West Bay (see Figure in Form 1).**

G. Do you request a mixing zone under Rule 62-4.244, F.A.C.? If yes, for what parameters or pollutants? **No**

IV FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

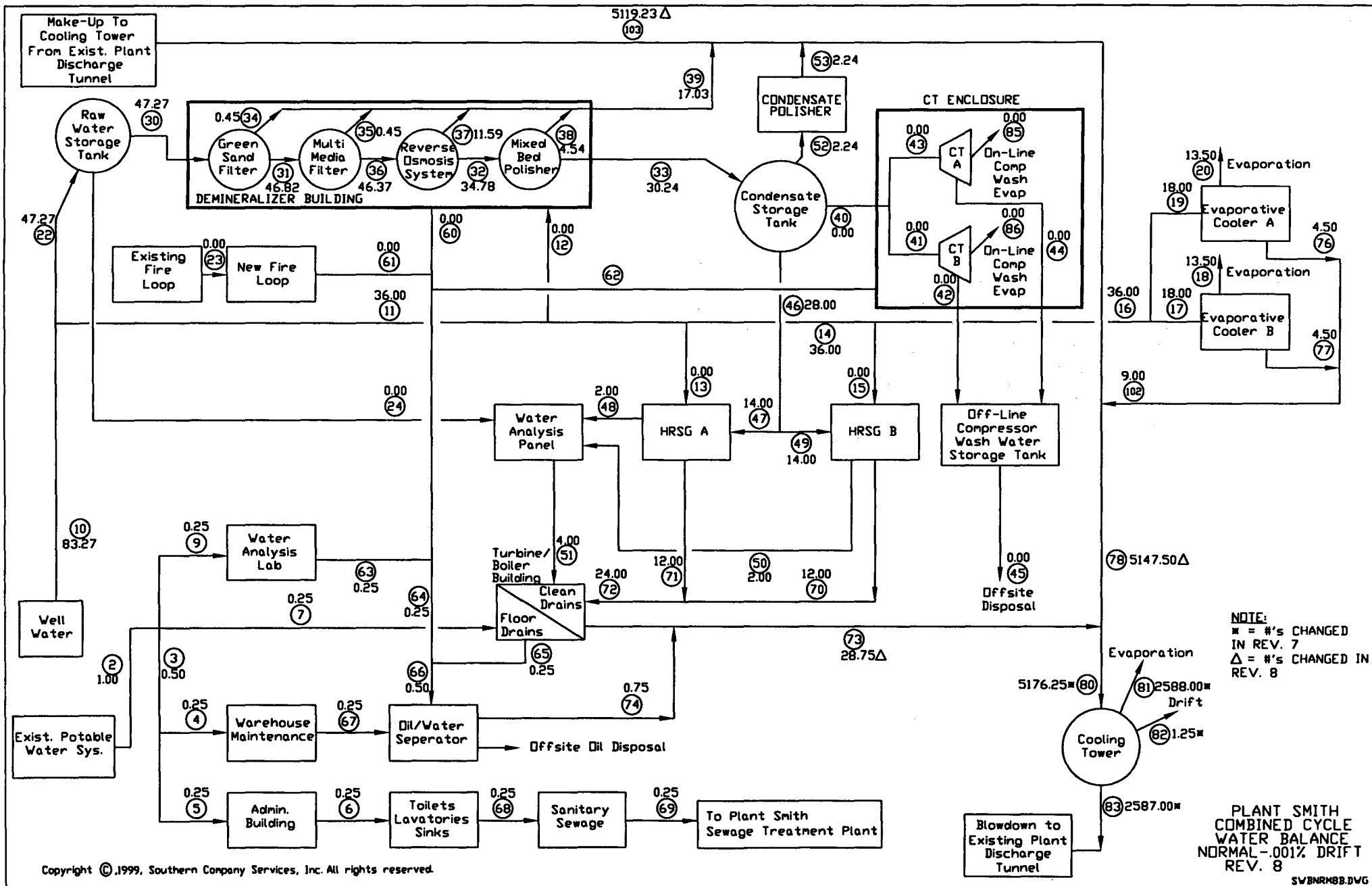
B. For each outfall, provide a description of:

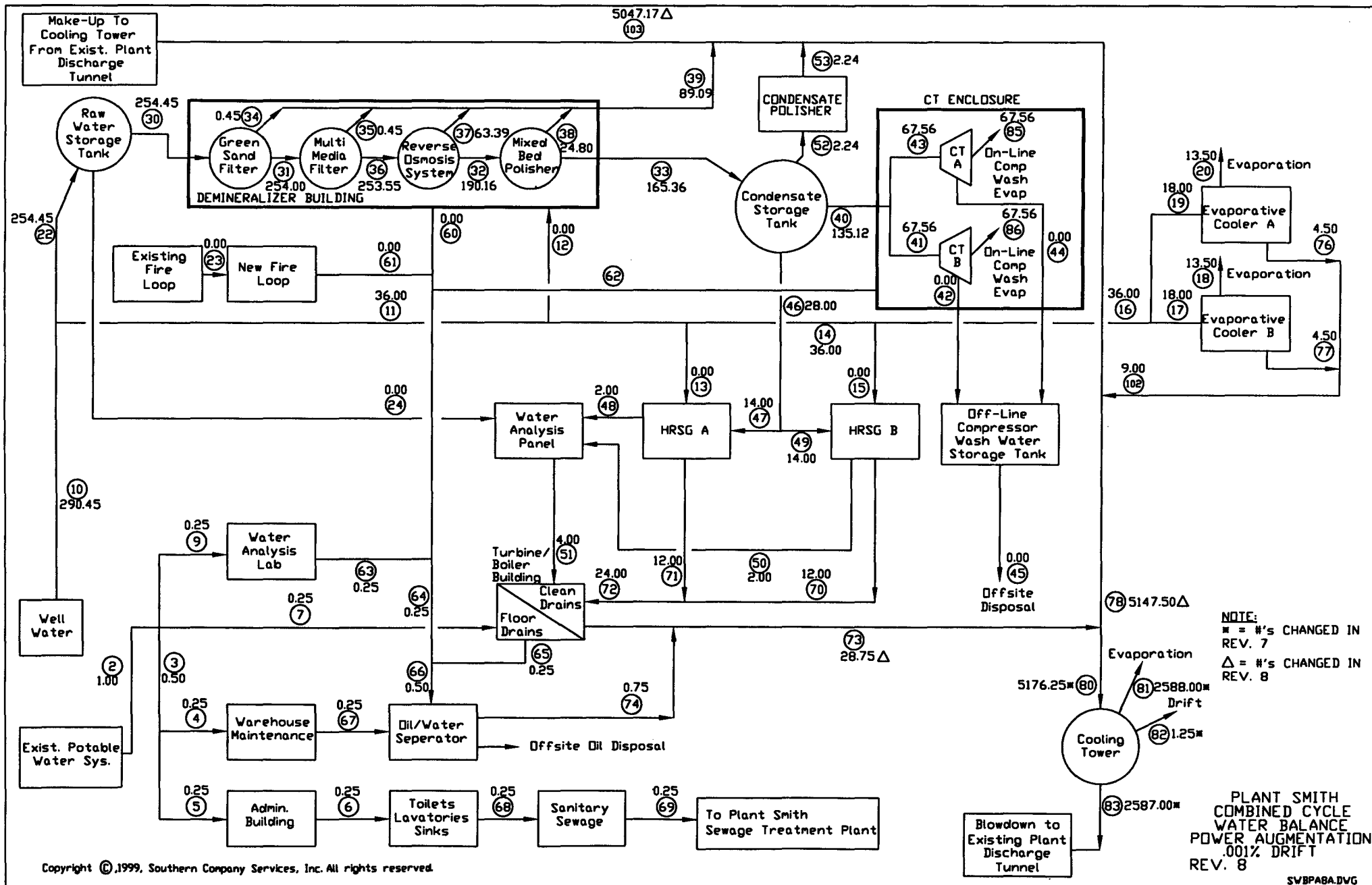
1. All operations contributing wastewater to the effluent; including process wastewater, sanitary wastewater, cooling water, and stormwater runoff;
2. The average flow contributed by each operation; and
3. The treatment received by the wastewater.

Use the space on the next page. Continue on additional sheets, if necessary.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.





General Notes: Includes only those outfalls that will be modified by the addition of Smith 3.
 *As described in the existing Smith NPDES permit, once-through cooling water flow for Units 1 and 2 is 274 MGD. Cooling tower evaporation for Smith Unit 3 will reduce the final discharge at D001 to approximately 270 MGD.
 †Demineralizer flow increases to 89 gpm during power augmentation.

- C. Except for storm runoff, leaks, or spills, are any of the discharges described in Items II-A or B intermittent or seasonal?
☐ Yes (complete the following table) ☒ No (go to D. below)

(1) Outfall # (List)	(2) Operation(s) Contributing Flow (List)	(3) Frequency		(4) Flow					
		(a) Days per Week (specify avg.)	(b) Months per Yr. (specify avg.)	(a) Flow Rate (in mgd)		(b) Total Volume (specify with units)		(c) Duration (in days)	
				Long Term Avg.	Max. Daily	Long Term Avg.	Max. Daily		

- D. Describe practices to be followed to ensure adequate wastewater treatment during emergencies such as power loss and equipment failures causing shutdown of pollution abatement equipment of the proposed/permitted facilities. **See attached description.**
- E. List the method(s) and location(s) of flow measurement. **Pump logs for the once-through cooling water and the cooling tower blowdown discharge.**

V PRODUCTION

- A. Does an effluent guideline limitation promulgated by EPA under Section 304 of the Clean Water Act apply to your facility?
☒ Yes (complete Item V-B) ☐ No (go to Section VI)
- B. Are the limitations in the applicable guideline expressed in terms of production (or other measure of operation)?
☐ Yes (complete Item V-C) ☒ No (go to Section VI)
- C. If you answered "yes" to Item V-B, list the quantity which represents an actual measurement of your level of production, expressed in the terms and units used in the applicable effluent guideline, and indicate the affected outfalls.

1. AVERAGE DAILY PRODUCTION			2. Affected Outfalls (list outfall nos.)
a. Quantity per Day	b. Units of Measure	c. Operation, Product, Materials, Etc. (specify)	

SECTION IV-D (page 2CS-19): Describe practices to be followed to ensure adequate wastewater treatment during emergencies such as power loss and equipment failures causing shutdown of pollution equipment of the proposed/permitted facilities.

The only wastewater treatment process associated with the requested NPDES modification will be the mixing of the cooling tower blowdown (D017) with the existing once-through cooling water from Smith Units 1 and 2. Should Unit 3 go off-line, there will be discharge from internal Outfall D017. All other internal waste streams will stop should the plant go off-line.

VI IMPROVEMENTS

A. Are you now required by any Federal, State or local authority to meet any implementation schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement order, enforcement compliance schedule letter, stipulations, court orders, and grant or loan conditions.

☐ Yes (complete the following table) ☒ No (go to Item VI-B)

1. Identification of Condition, Agreement, Etc.	2. Affected Outfalls		3. Brief Description of Project	4. Final Compliance Date	
	a. No.	b. Source of Discharge		a. Required	B. Projected

B. OPTIONAL: You may attach additional sheets describing any additional water pollution control programs (or other environmental projects which may affect your discharges) you now have underway or which you plan. Indicate whether each program is now underway or planned, and indicate your actual or planned schedules for construction.

☐ Mark "X" if description of additional control programs is attached.

VII INTAKE AND EFFLUENT CHARACTERISTICS

A, B, & C: See instructions before proceeding--Complete one set of tables for each outfall -- Annotate the outfall number in the space provided. NOTE: Tables VII-A, VII-B, and VII-C are included on separate sheets number VII-1 through VII-9.

D. Use the space below to list any of the pollutants listed in Table 2CS-3 of the instructions, which you know or have reason to believe is discharged or may be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it to be present and report any analytical data in your possession.

1. Pollutant	2. Source	1. Pollutant	2. Source
None			

PLEASE PRINT OR TYPE ONLY: You may report some or all of this information on separate sheets (use the same format) instead of completing these pages. SEE INSTRUCTIONS.

VII INTAKE AND EFFLUENT CHARACTERISTICS

PART A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. Pollutant	2. Effluent						3. Units		4. Intake (optional)			
	a. Max. Daily Value		b. Max. 30-day Value		c. Annual Avg. Value		d. No. of Analyses	a. Concen- tration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
a. Carbonaceous Biochemical Oxygen Demand (CBOD ₅)	<2.0	<4,600					1	mg/L	lb/day	<2.0	<4600	1
b. Chemical Oxygen Demand (COD)	NA for salt water	NA for salt water										
c. Total Organic Carbon (TOC)	6.7	15,000					1	mg/L	lb/day	6.8	16000	1
d. Total Suspended Solids (TSS)	6.6	14,900					1	mg/L	lb/day	7.7	18000	1
e. Total Nitrogen (as N)	0.15	340					1	mg/L	lb/day	0.11	250	1
f. Total Phosphorus (as P)	<0.05	<113					1	mg/L	lb/day	<0.050	<110	1
g. Ammonia (as N)	<0.05	<113					1	mg/L	lb/day	<0.050	<110	1
f. Flow - actual or projected	Value	270*	Value		Value		12	MGD	NA	Value	254.4	12
g. Flow - design	Value		Value		Value					Value		
h. Specific Conductivity	Value	39,000	Value		Value			µmhos/cm		Value	38000	
i. Temperature (winter)	Value	30.8	Value		Value		6	°C		Value	18.0	
j. Temperature (summer)	Value	38.9	Value		Value		6	°C		Value	27.7	
k. pH	Min.	7.5	Max.	8.0	Min.	Max.	12	STANDARD UNITS				

PART B - Mark "X" in column 2a for each pollutant you know or have reason to believe is present. Mark "X" in column 2b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. Pollutant and CAS No. (if available)	2. Mark "X"		3. Effluent							4. Units		5. Intake (optional)		
	a. be- lieved present	b. be- lieved absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concen- tration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
			(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
a. Bromide (24959-67-9)	X		49	110,000					1	mg/L	lb/day	48	110,000	1
b. Chlorine, Total Residual		X	<0.05	<113					12	mg/L	lb/day	<.05	<113	12
c. Color	X		20	NA					1	mg/L	lb/day	25	NA	1
d. Fecal Coliform	X		300	NA					1	mg/L	lb/day	90	NA	1
e. Fluoride (16984-48-8)	X		0.72	1,600					1	mg/L	lb/day	0.69	1600	1
f. Nitrate-Nitrite (as N)		X	<0.50	<110					1	mg/L	lb/day	<.05	<110	1

Note: The values in Parts A and B (plus dioxin) for this requested modification are based on discharge values provided in the original NPDES application. Values for Part C are provided from a sample of the existing discharge taken on March 25, 1999. The values incorporate the addition of the cooling tower blowdown (internal discharge D017) to provide the estimated values at the POD (Outfall D001).

*The discharge flow for full operation of Units 1, 2, and 3 will be 270 MGD. If Unit 3 is off-line with the cooling tower shutdown discharge flow for Units 1 and 2 will revert to the original discharge flow of 274 MGD.

1. Pollutant and CAS No. (if available)	2. Mark "X"		3. Effluent						4. Units		5. Intake (optional)			
	a. be- lieved present	b. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avrg. Value (if available)		d. No. of Analyses	a. Con- centration	b. Mass	a. Long Term Average Value		b. No. of Analyses
			(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
g. Nitrogen, Total Organic (as N)	X		0.15	340					1	mg/L	lb/day	0.11	250	1
h. Oil and Grease		X	<1.0	<2,300					1	mg/L	lb/day	<1.0	<2300	1
i. Phosphorus, Total (as P) (7723-14-0)		X	<0.05	<110					1	mg/L	lb/day	<0.05	<110	1
j. Radioactivity														
(1) Alpha, Total		X	<2.0	NA					1	pCi/L	NA	250+/-130	NA	1
(2) Beta, Total		X	150 ±370	NA					1	pCi/L	NA	430+/-200	NA	1
(3) Radium, Total		X	<3.4	NA					1	pCi/L	NA	<3.4	NA	1
(4) Radium 226, Total		X	<0.6	NA					1	pCi/L	NA	<0.6	NA	1
k. Sulfate (as SO ₄) (14808-79-8)	X		2,812	6,335,000					1	mg/L	lb/day	2000	4600000	1
l. Sulfide (as S)		X	<0.04	<91					1	mg/L	lb/day	<0.040	<91	1
m. Sulfite (as SO ₃) 14265-45-3)	X		1.5	3,380					1	mg/L	lb/day	2.2	5000	1
n. Surfactants		X	<0.10	<225					1	mg/L	lb/day	<0.10	<230	1
o. Aluminum, Total (7429-90-5)	X		0.23	518					1	mg/L	lb/day	0.14	320	1
p. Barium, Total (7440-39-3)		X	<0.01	<23					1	mg/L	lb/day	<0.010	<23	1
q. Boron, Total (7440-42-8)	X		3.1	6,984					1	mg/L	lb/day	3.0	6800	1
r. Cobalt, Total (7440-48-4)		X	<0.01	<23					1	mg/L	lb/day	<0.01	<23	1
s. Iron, Total (7439-89-6)	X		0.17	383					1	mg/L	lb/day	0.24	550	1
t. Magnesium, Total (7439-95-4)	X		960	2,160,000					1	mg/L	lb/day	900	2000000	1
u. Molybdenum, Total (7439-98-7)		X	<0.01	<23					1	mg/L	lb/day	<0.010	<23	1
v. Manganese, Total (7439-96-5)		X	<0.01	<23					1	mg/L	lb/day	<0.010	<23	1
w. Tin, Total (7440-31-5)		X	<0.25	<563					1	mg/L	lb/day	<0.25	<570	1
x. Titanium, Total (7440-32-6)		X	<0.10	<225					1	mg/L	lb/day	<0.10	<230	1

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2a for all GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2a (secondary industries, non-process wastewater outfalls, and non-required GC/MS fractions), mark "X" in column 2b for each pollutant you know or have reason to believe is present. Mark "X" in column 2c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4-dinitrophenol, or 2-methyl-4,6-dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (all 7 pages) for each outfall. See instructions for additional details and requirements.

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent							4. Units		5. Intake (optional)		
	a. testing required	b. be- lieved present	c. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Con- cen- tration	b. Mass	A. Long Term Average Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)	X			<0.02	<45					1	mg/L	lb/day	<0.02	<45	1
2M. Arsenic, Total (7723-14-0)	X			<0.01	<23					1	mg/L	lb/day	<0.01	<23	1
3M. Beryllium, Total (7440-41-7)	X			<0.004	<9					1	mg/L	lb/day	<0.004	<9	1
4M. Cadmium, Total (7440-43-9)	X			<0.005	<11					1	mg/L	lb/day	<0.0050	<11	1
5M. Chromium, Total (7440-47-3)	X			<0.01	<23					1	mg/L	lb/day	<0.010	<23	1
6M. Copper, Total (7440-50-8)	X			<0.002	<4.5					1	mg/L	lb/day	0.004	45	1
7M. Lead, Total (7439-92-1)	X			<0.01	<23					1	mg/L	lb/day	<0.01	<23	1
8M. Mercury, Total (7439-97-6)	X			<0.0002	<0.45					1	mg/L	lb/day	<0.00020	<0.46	1
9M. Nickel, Total (7440-02-0)	X			<0.04	<90					1	mg/L	lb/day	0.025	57	1
10M. Selenium, Total (7782-49-2)	X			<0.01	<23					1	mg/L	lb/day	<0.01	<23	1
11M. Silver, Total (7440-22-4)	X			<0.01	<23					1	mg/L	lb/day	<0.010	<23	1
12M. Thallium, Total (7440-28-0)	X			<0.01	<23					1	mg/L	lb/day	<0.010	<23	1
13M. Zinc, Total (7440-66-6)	X			<0.02	<45					1	mg/L	lb/day	<0.020	<46	1
14M. Cyanide, Total (57-12-5)	X			<0.01	<23					1	mg/L	lb/day	<0.010	<23	1
15M. Phenols, Total	X			<0.10	<225					1	mg/L	lb/day	<0.010	<23	1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)	X			<0.005	<11					1	mg/L	lb/day	<0.0050	<0.011	1

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Average Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION - VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)	X			<100	<225					1	µg/L	lb/day	<100	<230	1
2V. Acrylonitrile (107-13-1)	X			<100	<225					1	µg/L	lb/day	<100	<230	1
3V. Benzene (71-43-2)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
4V. Bis (Chloromethyl) Ether (542-88-1)			X	NA						1	µg/L	lb/day	NA		1
5V. Bromoform (75-25-2)	X			78	176					1	µg/L	lb/day	110	248	1
6V. Carbon Tetrachloride (56-23-5)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
7V. Chlorobenzene (108-90-7)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
8V. Chlorodi-bromomethane (124-48-1)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
9V. Chloroethane (75-00-3)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
10V. 2-Chloro-ethylvinyl Ether (110-75-8)	X			<50	<113					1	µg/L	lb/day	<50	<110	1
11V. Chloroform (67-66-3)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
12V. Dichloro-bromomethane (75-27-4)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
13V. Dichloro-difluoromethane (75-71-8)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
14V. 1,1-Dichloroethane (75-34-3)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
15V. 1,2-Dichloroethane (107-06-2)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
16V. 1,1-Dichloroethylene (75-35-4)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
17V. 1,2-Dichloropropane (78-87-5)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
18V. 1,3-Dichloropropylene (542-75-6)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
19V. Ethylbenzene (100-41-4)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
20V. Methyl Bromide (74-83-9)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
21V. Methyl Chloride (74-87-3)	X			<10	<23					1	µg/L	lb/day	<10	<23	1

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. be- lieved present	c. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Con- centration	b. Mass	a. Long Term Average Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION - VOLATILE COMPOUNDS (continued)															
22V. Methylene Chloride (75-98-2)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
23V. 1,1,2,2-Tetra- chloroethane (79-34-5)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
24V. Tetrachloroethylene (127-18-4)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
25V. Toluene (108-88-3)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
26V. 1,2-Trans- Dichloroethylene (156-60-5)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
27V. 1,1,1-Trichloroethane (71-55-6)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
28V. 1,1,2-Trichloroethane (79-00-5)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
29V. Trichloroethylene (79-01-6)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
30V. Trichloro-fluoromethane (75-69-4)	X			<5.0	<11.3					1	µg/L	lb/day	<5.0	<11	1
31V. Vinyl Chloride (75-01-4)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
GC/MS FRACTION - ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
2A. 2,4-Dichlorophenol (120-83-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
3A. 2,4-Dimethylphenol (105-67-9)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
4A. 4,6-Dinitro-O-Cresol (534-52-1)	X			<50	<113					1	µg/L	lb/day	<50	<110	1
5A. 2,4-Dinitrophenol (51-28-5)	X			<50	<113					1	µg/L	lb/day	<50	<110	1
6A. 2-Nitrophenol (88-75-5)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
7A. 4-Nitrophenol (100-02-7)	X			<50	<113					1	µg/L	lb/day	<50	<110	1

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent							4. Units		5. Intake (optional)		
	a. Testing Required	b. Believed Present	c. Believed Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avrg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avrg. Value		b. No of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS Fraction - Acid Compounds Contd.															
8A. P-Chloro-M-Cresol (59-50-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
9A. Pentachlorophenol (87-86-5)	X			<50	<113					1	µg/L	lb/day	<50	<110	1
10A. Phenol (108-95-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
11A. 2,4,5-Trichloro-phenol (88-06-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
GC/MS Fraction - Base/Neutral Compounds															
1B. Acenaphthene (83-32-9)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
2B. Acenaphthylene (208-96-8)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
3B. Anthracene (120-12-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
4B. Benzidine (92-87-5)	X			<80	<180					1	µg/L	lb/day	<80	<180	1
5B. Benzo (a) Anthracene (56-55-3)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
6B. Benzo (a) Pyrene (50-32-8)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
7B. 3,4-Benzo-fluoranthene (205-99-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
8B. Benzo (ghi) Perylene (191-24-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
9B. Benzo (k) Fluoranthene (207-08-9)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
10B. Bis (2-Chloroethoxy) Methane (111-91-1)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
11B. Bis (2-Chloroethyl) Ether (111-44-4)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
12B. Bis (2-Chloroisopropyl) Ether (102-60-1)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
13B. Bis (2-Ethylhexyl) Phthalate (117-81-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent								4. Units		5. Intake (optional)		
	a. Testing Required	b. Believed Present	c. Believed Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses	
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass		
GC/MS Fraction - Base/Neutral Compounds Contd.																
14B. 4-Bromophenyl Phenyl Ether (101-55-3)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
15B Butyl Benzyl Phthalate (85-68-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
16B. 2-Chloronaphthalene (91-58-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
17B. 4-Chlorophenyl Phenyl Ether (7005-72-3)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
18B. Chrysene (218-01-9)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
19B. Dibenzo (a,h) Anthracene (53-70-3)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
20B. 1,2-Dichlorobenzene (95-50-1)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
21B. 1,3-Dichlorobenzene (541-73-1)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
22B. 1,4-Dichlorobenzene (106-46-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
23B. 3,3'-Dichlorobenzidine (92-94-1)	X			<20	<45					1	µg/L	lb/day	<20	<46	1	
24B. Diethyl Phthalate (84-66-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
25B. Dimethyl Phthalate (131-11-3)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
26B. Di-N-Butyl Phthalate (84-74-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
27B. 2,4-Dinitrotoluene (121-14-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
28B. 2,6-Dinitrotoluene (606-20-2)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	
29B. Di-N-Octyl Phthalate (117-84-0)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1	

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent							4. Units		5. Intake (optional)		
	a. Testing Required	b. Be-lieved Present	c. Be-lieved Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS Fraction - Acid Compounds Contd.															
30B. 1,2-Diphenylhydrazine (as Azobenzene) (122-66-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
31B. Fluoranthene (206-44-0)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
32B. Fluorene (86-73-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
33B. Hexachlorobenzene (118-74-1)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
34B. Hexachlorobutadiene (87-68-3)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
35B. Hexachlorocyclopentadiene (77-47-4)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
36B. Hexachloroethane (67-72-1)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
37B. Indeno (1,2,3-cd) Pyrene (193-39-5)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
38B. Isophorone (78-59-1)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
39B. Naphthalene (91-20-3)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
40B. Nitrobenzene (98-95-9)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
41B. N-Nitrosodimethylamine (62-75-9)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
42B. N-Nitrosodi-N-Propylamine (621-64-7)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
43B. N-Nitro-sodiphenylamine (86-30-6)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
44B. Phenanthrene (85-01-8)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
45B. Pyrene (129-00-0)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1
46B. 1,2,4-Trichlorobenzene (120-82-1)	X			<10	<22.5					1	µg/L	lb/day	<10	<23	1

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent								4. Units		5. Intake (optional)		
	a. Testing Required	b. Believed Present	c. Believed Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses	
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass		
GC/MS Fraction - Pesticides																
1P. Aldrin (309-00-2)			X													
2P. -BHC (319-84-6)			X													
3P. -BHC (319-85-7)			X													
4P. -BHC (58-89-9)			X													
5P. -BHC (319-86-8)			X													
6P. Chlordane (57-74-9)			X													
7P. 4,4'-DDT (50-29-3)			X													
8P. 4,4'-DDE (72-55-9)			X													
9P. 4,4'-DDD (72-54-8)			X													
10P. Dieldrin (60-57-1)			X													
11P. -Endosulfan (115-29-7)			X													
12P. -Endosulfan (115-29-7)			X													
13P. Endosulfan Sulfate (1031-07-8)			X													
14P. Endrin (72-20-8)			X													
15P. Endrin Aldehyde (7421-92-4)			X													
16P. Heptachlor (76-44-8)			X													
17P. Heptachlor Epoxide (1024-57-3)			X													
18P. PCB-1242 (53469-21-9)			X													
19P. PCB-1254 (11097-69-1)			X													
20P. PCB-1221 (11104-28-2)			X													
21P. PCB-1232 (11141-16-5)			X													
22P. PCB-1248 (12672-29-6)			X													
23P. PCB-1260 (11096-82-5)			X													

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent								4. Units		5. Intake (optional)			
	a. Testing Required	b. Be- lieved Present	c. Be- lieved Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses		
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass			
GC/MS Fraction - Pesticides																	
24P. PCB-1016 (12674-11-2)			X														
25P. Toxaphene (8001-35-2)			X														

PLEASE PRINT OR TYPE ONLY: You may report some or all of this information on separate sheets (use the same format) instead of completing these pages. SEE INSTRUCTIONS.

VII INTAKE AND EFFLUENT CHARACTERISTICS

PART A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. Pollutant	2. Effluent						3. Units		4. Intake (optional)			
	a. Max. Daily Value		b. Max. 30-day Value		c. Annual Avg. Value		d. No. of Analyses	a. Concen- tration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
a. Carbonaceous Biochemical Oxygen Demand (CBOD ₅)	<5	<156					1	mg/L	lb/day			
b. Chemical Oxygen Demand (COD)	NA	—						mg/L	lb/day			
c. Total Organic Carbon (TOC)	13.4	418					1	mg/L	lb/day			
d. Total Suspended Solids (TSS)	13.7	427					1	mg/L	lb/day			
e. Total Nitrogen (as N)	0.30	9.5					1	mg/L	lb/day			
f. Total Phosphorus (as P)	<0.13	<4.1					1	mg/L	lb/day			
g. Ammonia (as N)	<0.10	<3.2					1	mg/L	lb/day			
f. Flow - actual or projected	Value 3.7		Value		Value		projected	MGD	NA	Value		
g. Flow - design	Value		Value		Value					Value		
h. Specific Conductivity	Value 44,466		Value		Value			µmhos/cm		Value		
i. Temperature (winter)	Value		Value		Value			°C		Value		
j. Temperature (summer)	Value		Value		Value 30		Projected	°C		Value		
k. pH	Min. 7	Max.8.5	Min.	Max.			12	STANDARD UNITS				

PART B - Mark "X" in column 2a for each pollutant you know or have reason to believe is present. Mark "X" in column 2b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. Pollutant and CAS No. (if available)	2. Mark "X"		3. Effluent							4. Units		5. Intake (optional)		
	a. be- lieved present	b. be- lieved absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concen- tration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
			(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
a. Bromide (24959-67-9)	X		98	3,057					1	mg/L	lb/day	See intake	data for	D001.
b. Chlorine, Total Residual*		X	<0.05	<1.56					12	mg/L	lb/day	See intake	data for	D001.
c. Color	X		NA	NA					1	mg/L	lb/day	See intake	data for	D001.
d. Fecal Coliform	X		300	NA					1	mg/L	lb/day	See intake	data for	D001.
e. Fluoride (16984-48-8)	X		1.44	44.9					1	mg/L	lb/day	See intake	data for	D001.
f. Nitrate-Nitrite (as N)	X		<1.0	<31					1	mg/L	lb/day	See intake	data for	D001.

*During chlorination, the cooling tower blowdown valve will remain closed until the chlorine has been allowed to dissipate.

Note: The water quality values provided were calculated by doubling the concentrations of the D017 intake water (which is taken from Smith discharge canal) because of the two cycles of concentration in the cooling tower and adding the contribution from operation of the combined cycle unit. The added contributions from operation of the combined cycle have been estimated to be: total nitrogen (0.14 lb/day), total phosphorus (0.94 lb/day), ammonia (0.14 lb/day), sulfate (143 lb/day), sulfite (0.54 lb/day), and iron (0.0022 lb/day). Total suspended solids and conductivity values are engineering estimates of the cooling tower blowdown quality. See the table of data submitted for D001 for column 5 intake values.

1. Pollutant and CAS No. (if available)	2. Mark "X"		3. Effluent							4. Units		5. Intake (optional)		
	a. be- lieved present	b. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Con- centration	b. Mass	a. Long Term Average Value		b. No. of Analyses
			(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
g. Nitrogen, Total Organic (as N)	X		0.304	9.5					1	mg/L	lb/day	See intake	data for	D001.
h. Oil and Grease		X	<2.0	<6.2					1	mg/L	lb/day	See intake	data for	D001.
i. Phosphorus, Total (as P) (7723-14-0)	X		<0.13	<4.05					1	mg/L	lb/day	See intake	data for	D001.
j. Radioactivity														
(1) Alpha, Total		X	<2.0	NA					1	pCi/L	NA	See intake	data for	D001.
(2) Beta, Total		X	150 ±370	NA					1	pCi/L	NA	See intake	data for	D001.
(3) Radium, Total		X	<3.4	NA					1	pCi/L	NA	See intake	data for	D001.
(4) Radium 226, Total		X	<0.6	NA					1	pCi/L	NA	See intake	data for	D001.
k. Sulfate (as SO ₄) (14808-79-8)	X		5,544	172,917					1	mg/L	lb/day	See intake	data for	D001.
l. Sulfide (as S)		X	<0.08	<2.5					1	mg/L	lb/day	See intake	data for	D001.
m. Sulfite (as SO ₃) 14265-45-3)	X		1.517	47.3					1	mg/L	lb/day	See intake	data for	D001.
n. Surfactants		X	<0.20	<6.23					1	mg/L	lb/day	See intake	data for	D001.
o. Aluminum, Total (7429-90-5)	X		0.46	14.3					1	mg/L	lb/day	See intake	data for	D001.
p. Barium, Total (7440-39-3)		X	<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
q. Boron, Total (7440-42-8)	X		6.2	193					1	mg/L	lb/day	See intake	data for	D001.
r. Cobalt, Total (7440-48-4)		X	<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
s. Iron, Total (7439-89-6)	X		0.34	10.6					1	mg/L	lb/day	See intake	data for	D001.
t. Magnesium, Total (7439-95-4)	X		960	29,942					1	mg/L	lb/day	See intake	data for	D001.
u. Molybdenum, Total (7439-98-7)		X	<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
v. Manganese, Total (7439-96-5)		X	<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
w. Tin, Total (7440-31-5)		X	<0.50	<15.6					1	mg/L	lb/day	See intake	data for	D001.
x. Titanium, Total (7440-32-6)		X	<0.10	<3.1					1	mg/L	lb/day	See intake	data for	D001.

PART C - If you are in primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2a for all GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2a (secondary industries, non-process wastewater outfalls, and non-required GC/MS fractions), mark "X" in column 2b for each pollutant you know or have reason to believe is present. Mark "X" in column 2c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4-dinitrophenol, or 2-methyl-4,6-dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (all 7 pages) for each outfall. See instructions for additional details and requirements.

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. be- lieved present	c. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concen- tration	b. Mass	a. Long Term Average Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)	X			<0.04	<1.25					1	mg/L	lb/day	See intake	data for	D001.
2M. Arsenic, Total (7723-14-0)	X			<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
3M. Beryllium, Total (7440-41-7)	X			<0.008	<0.25					1	mg/L	lb/day	See intake	data for	D001.
4M. Cadmium, Total (7440-43-9)	X			<0.01	<0.31					1	mg/L	lb/day	See intake	data for	D001.
5M. Chromium, Total (7440-47-3)	X			<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
6M. Copper, Total (7440-50-8)	X			<0.004	<0.12					1	mg/L	lb/day	See intake	data for	D001.
7M. Lead, Total (7439-92-1)	X			<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
8M. Mercury, Total (7439-97-6)	X			<0.0004	<0.012					1	mg/L	lb/day	See intake	data for	D001.
9M. Nickel, Total (7440-02-0)	X			<0.04	<1.25					1	mg/L	lb/day	See intake	data for	D001.
10M. Selenium, Total (7782-49-2)	X			<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
11M. Silver, Total (7440-22-4)	X			<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
12M. Thallium, Total (7440-28-0)	X			<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
13M. Zinc, Total (7440-66-6)	X			<0.04	<1.25					1	mg/L	lb/day	See intake	data for	D001.
14M. Cyanide, Total (57-12-5)	X			<0.02	<0.62					1	mg/L	lb/day	See intake	data for	D001.
15M. Phenols, Total	X			<0.20	<6.2					1	mg/L	lb/day	See intake	data for	D001.
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)	X			<0.01	<0.31					1	mg/L	lb/day	See intake	data for	D001.

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent						4. Units			5. Intake (optional)		
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Average Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION - VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)	X			<200	<6.23					1	µg/L	lb/day	See intake	data for	D001.
2V. Acrylonitrile (107-13-1)	X			<200	<6.23					1	µg/L	lb/day	See intake	data for	D001.
3V. Benzene (71-43-2)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
4V. Bis (Chloromethyl) Ether (542-88-1)	X			NA	—					1	µg/L	lb/day	See intake	data for	D001.
5V. Bromoform (75-25-2)	X			156	4.87					1	µg/L	lb/day	See intake	data for	D001.
6V. Carbon Tetrachloride (56-23-5)	X			<10	<0.31					1	µg/L	lb/day	See intake	data for	D001.
7V. Chlorobenzene (108-90-7)	X			<10	<0.31					1	µg/L	lb/day	See intake	data for	D001.
8V. Chlorodi-bromomethane (124-48-1)	X			<10	<0.31					1	µg/L	lb/day	See intake	data for	D001.
9V. Chloroethane (75-00-3)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
10V. 2-Chloro-ethylvinyl Ether (110-75-8)	X			<100	<3.1					1	µg/L	lb/day	See intake	data for	D001.
11V. Chloroform (67-66-3)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
12V. Dichloro-bromomethane (75-27-4)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
13V. Dichloro-difluoromethane (75-71-8)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
14V. 1,1-Dichloroethane (75-34-3)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
15V. 1,2-Dichloroethane (107-06-2)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
16V. 1,1-Dichloroethylene (75-35-4)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
17V. 1,2-Dichloropropane (78-87-5)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
18V. 1,3-Dichloropropylene (542-75-6)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
19V. Ethylbenzene (100-41-4)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
20V. Methyl Bromide (74-83-9)	X			<20.0	<0.62					1	µg/L	lb/day	See intake	data for	D001.
21V. Methyl Chloride (74-87-3)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Average Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION - VOLATILE COMPOUNDS (continued)															
22V. Methylene Chloride (75-98-2)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
23V. 1,1,2,2-Tetrachloroethane (79-34-5)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
24V. Tetrachloroethylene (127-18-4)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
25V. Toluene (108-88-3)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
26V. 1,2-Trans-Dichloroethylene (156-60-5)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
27V. 1,1,1-Trichloroethane (71-55-6)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
28V. 1,1,2-Trichloroethane (79-00-5)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
29V. Trichloroethylene (79-01-6)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
30V. Trichloro-fluoromethane (75-69-4)	X			<10.0	<0.31					1	µg/L	lb/day	See intake	data for	D001.
31V. Vinyl Chloride (75-01-4)	X			<20.0	<0.62					1	µg/L	lb/day	See intake	data for	D001.
GC/MS FRACTION - ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)	X			<20.0	<0.62					1	µg/L	lb/day	See intake	data for	D001.
2A. 2,4-Dichlorophenol (120-83-2)	X			<20.0	<0.62					1	µg/L	lb/day	See intake	data for	D001.
3A. 2,4-Dimethylphenol (105-67-9)	X			<20.0	<0.62					1	µg/L	lb/day	See intake	data for	D001.
4A. 4,6-Dinitro-O-Cresol (534-52-1)	X			<100	<3.1					1	µg/L	lb/day	See intake	data for	D001.
5A. 2,4-Dinitrophenol (51-28-5)	X			<100	<3.1					1	µg/L	lb/day	See intake	data for	D001.
6A. 2-Nitrophenol (88-75-5)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
7A. 4-Nitrophenol (100-02-7)	X			<100	<3.1					1	µg/L	lb/day	See intake	data for	D001.

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent							4. Units		5. Intake (optional)		
	a. Testing Required	b. Be-lieved Present	c. Be-lieved Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS Fraction - Acid Compounds Contd.															
8A. P-Chloro-M-Cresol (59-50-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
9A. Pentachlorophenol (87-86-5)	X			<100	<3.1					1	µg/L	lb/day	See intake	data for	D001.
10A. Phenol (108-95-2)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
11A. 2,4,5-Trichloro-phenol (88-06-2)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
GC/MS Fraction - Base/Neutral Compounds															
1B. Acenaphthene (83-32-9)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
2B. Acenaphthylene (208-96-8)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
3B. Anthracene (120-12-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
4B. Benzidine (92-87-5)	X			<160	<5.0					1	µg/L	lb/day	See intake	data for	D001.
5B. Benzo (a) Anthracene (56-55-3)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
6B. Benzo (a) Pyrene (50-32-8)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
7B. 3,4-Benzo-fluoranthene (205-99-2)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
8B. Benzo (ghi) Perylene (191-24-2)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
9B. Benzo (k) Fluoranthene (207-08-9)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
10B. Bis (2-Chloroethoxy) Methane (111-91-1)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
11B. Bis (2-Chloroethyl) Ether (111-44-4)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
12B. Bis (2_Chloroisopropyl) Ether (102-60-1)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
13B. Bis (2-Ethylhexyl) Phthalate (117-81-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent								4. Units		5. Intake (optional)		
	a. Testing Required	b. Believed Present	c. Believed Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses	
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass		
GC/MS Fraction - Base/Neutral Compounds Contd.																
14B. 4-Bromophenyl Phenyl Ether (101-55-3)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
15B Butyl Benzyl Phthalate (85-68-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
16B. 2-Chloronaphthalene (91-58-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
17B. 4-Chlorophenyl Phenyl Ether (7005-72-3)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
18B. Chrysene (218-01-9)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
19B. Dibenzo (a,h) Anthracene (53-70-3)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
20B. 1,2-Dichlorobenzene (95-50-1)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
21B. 1,3-Dichlorobenzene (541-73-1)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
22B. 1,4-Dichlorobenzene (106-46-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
23B. 3,3'-Dichlorobenzidine (92-94-1)	X			<40	<1.25					1	µg/L	lb/day	See intake	data for	D001.	
24B. Diethyl Phthalate (84-66-2)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
25B. Dimethyl Phthalate (131-11-3)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
26B. Di-N-Butyl Phthalate (84-74-2)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
27B. 2,4-Dinitrotoluene (121-14-2)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
28B. 2,6-Dinitrotoluene (606-20-2)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	
29B. Di-N-Octyl Phthalate (117-84-0)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.	

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent							4. Units		5. Intake (optional)		
	a. Testing Required	b. Believed Present	c. Believed Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS Fraction - Acid Compounds Contd.															
30B. 1,2-Diphenylhydrazine (as Azobenzene) (122-66-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
31B. Fluoranthene (206-44-0)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
32B. Fluorene (86-73-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
33B. Hexachlorobenzene (118-74-1)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
34B. Hexachlorobutadiene (87-68-3)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
35B. Hexachlorocyclopentadiene (77-47-4)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
36B. Hexachloroethane (67-72-1)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
37B. Indeno (1,2,3-cd) Pyrene (193-39-5)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
38B. Isophorone (78-59-1)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
39B. Naphthalene (91-20-3)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
40B. Nitrobenzene (98-95-9)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
41B. N-Nitrosodimethylamine (62-75-9)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
42B. N-Nitrosodi-N-Propylamine (621-64-7)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
43B. N-Nitro-sodiphenylamine (86-30-6)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
44B. Phenanthrene (85-01-8)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
45B. Pyrene (129-00-0)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.
46B. 1,2,4-Trichlorobenzene (120-82-1)	X			<20	<0.62					1	µg/L	lb/day	See intake	data for	D001.

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent								4. Units		5. Intake (optional)			
	a. Testing Required	b. Be- lieved Present	c. Be- lieved Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses		
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass			
GC/MS Fraction - Pesticides																	
1P. Aldrin (309-00-2)			X														
2P. -BHC (319-84-6)			X														
3P. -BHC (319-85-7)			X														
4P. -BHC (58-89-9)			X														
5P. -BHC (319-86-8)			X														
6P. Chlordane (57-74-9)			X														
7P. 4,4'-DDT (50-29-3)			X														
8P. 4,4'-DDE (72-55-9)			X														
9P. 4,4'-DDD (72-54-8)			X														
10P. Dieldrin (60-57-1)			X														
11P. -Endosulfan (115-29-7)			X														
12P. -Endosulfan (115-29-7)			X														
13P. Endosulfan Sulfate (1031-07-8)			X														
14P. Endrin (72-20-8)			X														
15P. Endrin Aldehyde (7421-92-4)			X														
16P. Heptachlor (76-44-8)			X														
17P. Heptachlor Epoxide (1024-57-3)			X														
18P. PCB-1242 (53469-21-9)			X														
19P. PCB-1254 (11097-69-1)			X														
20P. PCB-1221 (11104-28-2)			X														
21P. PCB-1232 (11141-16-5)			X														
22P. PCB-1248 (12672-29-6)			X														
23P. PCB-1260 (11096-82-5)			X														

1. Pollutant and CAS Number (if available)	2. Mark "X"			3. Effluent								4. Units		5. Intake (optional)		
	a. Testing Required	b. Be- lieved Present	c. Be- lieved Absent	a. Maximum Daily Value		b. Max. 30-Day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No of Analyses	
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass		
GC/MS Fraction - Pesticides																
24P. PCB-1016 (12674-11-2)			X													
25P. Toxaphene (8001-35-2)			X													

VIII POTENTIAL DISCHARGES NOT COVERED BY ANALYSIS

Is any pollutant listed in Item VII-C a substance or a component of a substance which you currently use or manufacture as an intermediate or final product or by-product?

YES (list all such pollutants below) X NO (go to IX)

IX BIOLOGICAL TOXICITY TESTING DATA

Do you have any knowledge or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharges or on a receiving water in relation to your discharge within the last 3 years?

X YES (identify the test(s) and describe their purposes below) NO (go to Section X)

Each summer (beginning in 1993), Gulf conducts a 96-hour static screening toxicity test on effluent from Plant Smith. The testing, which has been for informational purposes only, has shown no evidence of toxicity.

X CONTRACT ANALYSIS INFORMATION

Were any of the analyses reported in Item VII performed by a contract laboratory or consulting firm?

X YES (list the name, address, telephone number, and certification number of, and pollutants analyzed by each such laboratory or firm below)

NO (go to Section XI)

A. Name	B. Address	C. Telephone (area code & no.)	D. Pollutants Analyzed (list)
Savannah Laboratories & Environmental Services, Inc. Florida DHRS Certification Nos. E87089, E81055, DEP CQAP No. 890142G	900 Lakeside Drive Mobile, Alabama 36693	334-666-6633	All parameters analyzed by Savannah except for pH, TRC, and temperature. pH and TRC and temperature based on historical data. NOTE: For this modification application, some 1995 data were used.

XI CONNECTION TO REGIONAL POTW

A. Indicate the relationship between this project and area regional planning for wastewater treatment. List steps to be taken for this industrial wastewater facility to become part of an area-wide wastewater treatment system.

Wastewater treatment is done on-site. Since Plant Smith is in a remote, rural area and there are no POTW's in the area to connect to.

XII-A CERTIFICATIONS FOR NEW OR MODIFIED FACILITIES

This is to certify the engineering features of this pollution control project have been designed by me and found to be in conformity with sound engineering principles, applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules of the Department. It is also agreed that the undersigned, if authorized by the owner, will furnish the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Gulf Power Company

Company Name

Address Gulf Power Company

One Energy Place

Pensacola, Florida 32520-0328

Florida Registration No.: PE 52786

Telephone No.: (850) 429-2381

Date 05/28/1999

Signature

Gregory N. Terry

Name (please type)

(Affix Seal)

Poor Original

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Robert G. Moore Vice President of Power Generation and

Name & Official Title (Please type or print) Transmission

(850) 444-6383

Telephone No. (area code & No.)

Robert G. Moore

Signature

5/27/99

Date Signed

XII-B CERTIFICATIONS FOR PERMIT RENEWALS

This is to certify the engineering features of this pollution control project have been examined by me and found to be in conformity with sound engineering principles, applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules of the Department.

Signature

Company Name

Address

Name (please type)

(Affix Seal)

Florida Registration No.:

Telephone No.:

Date

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Name & Official Title (Please type or print)

Signature

Telephone No. (area code & No.)

Date Signed

APPENDIX 10.2.6
WATER USE PERMIT
MODIFICATION APPLICATION



May 27, 1999

Mr. Lawrence A. Gordon, P.G.
Associate Hydrologist
ATTN: Consumptive Use - Division of Resource Regulation
Northwest Florida Water Management District
81 Water Management Drive
Havana, Florida 32333

**RE: Consumptive Use Permit Modification for Plant Lansing Smith, Southport,
Florida**

Dear Mr. Gordon:

Enclosed please find the application for a modification to the existing consumptive use permit number S850073-System, for surface water (North Bay) and groundwater (Floridan Aquifer) at Plant Lansing Smith. This document includes extensive groundwater modeling utilizing two models entitled MODFLOW and SHARP. The calibration of the MODFLOW model was previously discussed with the District at our last meeting.

The current permitted amount that is allowed to be withdrawn from the Floridan Aquifer is 0.7 million gallons per day (MGD). We are currently proposing to increase consumptive uses of groundwater to a total of 1.2 MGD. As illustrated in our modeling report, this consumptive rate does not adversely affect adjacent well operators and does not cause a significant impact to the Floridan Aquifer.

In a previous submittal on March 22, 1999 we submitted slug test results and also pump test results for the surficial aquifer at Plant Smith. As illustrated by that data, the surficial aquifer is unsuitable for our water needs at this plant.

Well #4, which is currently included in our existing permit, is scheduled to be installed in October 1999. The proposed location of the new well, as indicated on the enclosed well location map, approximately 8000 feet north of the existing plant site. The new well site will be on our transmission corridor and adjacent to County road 2300. We have provided notification to the adjacent property owner, St. Joe Paper Company (Arvida), and they did not have any objections to the installation and operation of this well. As discussed in the modeling report (enclosed), and as discussed in our meetings, the installation and operation of this well will help Gulf Power Company (Gulf) meet the future demand for power in Northwest Florida.

Mr. Larry Gordon, P.G.
May 27, 1999
Page 2

In reference to surface water withdrawals, the permit application includes no increases for the next five years. We are currently permitting a new combined cycle generating unit which will utilize once-through cooling water already covered by our consumptive use permit. This is one of the conservation measures that we have undertaken at Gulf. In addition, we currently re-circulate water from our on-site ash pond to reduce consumptive usage of groundwater.

If you should have any questions regarding this permit application, please feel free to give me a call at (850) 444-6573.

Sincerely,



Richard "Mike" Markey, P.G.
Environmental Affairs

Enclosures

Cc: Gulf Power Company
Rachel Allen Terry
John Chappell
Kim Flowers
Doug Helms
Stan Houston, P.E.
Joe Neese
Tom Turk
Jim Vick

SCS - Birmingham
Steve Bearce, P.G.

NWFWMD
Alan Baker



CONSUMPTIVE USE PERMIT

District Use Only

Application for Other Uses

CUPA #: _____

Color: White

Northwest Florida Water Management District
Route 1, Box 3099, Havana, FL 32333-9700 (850) 539-5999 (Suncom) 771-2080

SECTION I - INSTRUCTIONS TO THE APPLICANT

1. Type or print in INK.
2. Please submit TWO (2) COPIES of this application and all other submitted materials (letters, etc.).
3. A checklist is provided on page 6.

SECTION II - GENERAL INFORMATION

1. TYPE OF APPLICATION:

☐ New (Proposed) ☐ Unpermitted (Existing) ☒ Modification ☒ Renewal

2. WATER USE PERMIT NUMBER (if application is for renewal or modification): S850072

3. APPLICANT (Complete legal name in which permit should be issued)

NAME: Gulf Power Company - Plant Lansing Smith

ADDRESS: One Energy Place

CITY, STATE, ZIP: Pensacola, FL 32520-0328

DAY PHONE: 850.444.6127 NIGHT PHONE: 850.887.7680 (emergency pager)

Applicant is: ☒ Owner ☐ Lessee ☐ Other (explain) _____

4. AGENT OR CONSULTANT Address all correspondence to the person below? ☒ Yes ☐ No

NAME: Rachel A. Terry / Gulf Power Company

ADDRESS: One Energy Place

CITY, STATE, ZIP: Pensacola, FL 32520-0328

DAY PHONE: 850.444.6127 NIGHT PHONE: 850.887.7480 (emergency pager)

5. OWNER (IF OTHER THAN APPLICANT)

NAME: _____

ADDRESS: _____

CITY, STATE, ZIP: _____

DAY PHONE: _____ NIGHT PHONE: _____

SECTION III - PROPERTY CONTROL

Is the PROPERTY AT THE WITHDRAWAL POINT(S) owned or leased?

☒ Owned ☐ Leased

If leased, specify expiration date and whether it is renewable.

Lease Expiration Date: _____ Renewable? ☐ Yes ☐ No

If requested, a copy of the current lease (signed by the property owner) detailing the lease arrangement and the duration of the lease must be submitted.

SECTION IV - CLASSIFICATION

Check applicable classification:

- | | |
|---|--|
| <input type="checkbox"/> Aesthetic Use
<input type="checkbox"/> Aquifer Remediation
<input type="checkbox"/> Commercial
<input type="checkbox"/> Dewatering
<input type="checkbox"/> Diversion and Impoundment
(into Non-District Facilities)
<input type="checkbox"/> Domestic Use
<input type="checkbox"/> Essential Use
<input type="checkbox"/> Heating and/or Cooling
<input type="checkbox"/> Industrial Use | <input type="checkbox"/> Mining
<input type="checkbox"/> Navigation
<input type="checkbox"/> Other Outside Use
<input type="checkbox"/> Perishable Food Processing
<input checked="" type="checkbox"/> Power Production

<input type="checkbox"/> Sanitation Use
<input type="checkbox"/> Soil Flooding
<input type="checkbox"/> Water Based Recreation Use
<input type="checkbox"/> Other (explain): _____ |
|---|--|

Power production includes minor domestic and drinking water uses.

SECTION V - CONSUMPTIVE WATER USE INFORMATION

1. ANNUAL WATER USE

WATER USAGE	PRESENT (GPD)	PROJECTED 5 YEARS (GPD)	PROJECTED 7 YEARS (GPD)	PROJECTED 10 YEARS (GPD)
AVERAGE DAILY RATE (ADR)	700,000	1,200,000	1,250,000	1,440,000
MAXIMUM DAILY RATE (MDR)	2,880,000	2,880,000	3,600,000	3,600,000
MAXIMUM MONTHLY RATE (MMR)	21,700,000	37,200,000	38,750,000	44,640,000

MGPD = Million Gallons Per Day

2. USE OF RECYCLED AND/OR RECLAIMED WATER

- A. Is **RECYCLED RUNOFF WATER** (e.g., rainfall runoff) being utilized? ☒ Yes ☐ No
 If yes, please describe use, including average daily, maximum daily, and maximum monthly volumes.

See Attachment A

- B. Is **RECLAIMED WATER** (treated wastewater) being utilized? ☒ Yes ☐ No
 If yes, complete Items 1 - 3 below.

1. Has approval been received from the Department of Environmental Protection for all existing and proposed reuse projects? ☒ Yes ☐ No

2. Volumes of any **RECLAIMED WATER** storage ponds on site:
 * As of December 1998. This volume can decrease as ash is deposited in the pond.
 * See Attachment A.

Pond ID	Storage Volume (gal)
Ash Pond	43,837,000*

3. RECLAIMED WATER sources and volumes provided (attach additional sheets if necessary).

VOLUME OF RECLAIMED WATER PROVIDED (MGD)		RECLAIMED WATER SOURCES		
		WASTEWATER UTILITY NAME: (on-site)	WASTEWATER UTILITY NAME:	WASTEWATER UTILITY NAME:
		1. N/A domestic plant		3.
PRESENT	AVERAGE	Approx. 3,000 GPD		
5 YEAR	AVERAGE	Approx. 3,000 GPD		
7 YEAR	AVERAGE			
10 YEAR	AVERAGE			
LEVEL OF TREATMENT		Secondary Treatment		

N/A = Not Applicable

SECTION VI - REQUESTED WITHDRAWAL AMOUNTS

1. APPLYING FOR GROUND WATER? ☒ Yes ☐ No

A. Total GROUND WATER amount requested (APPLY FOR TOTAL SYSTEM USAGE):

- (1) Average Daily Rate of Withdrawal (ADR) 1,200,000 Gallons Per Day*
- (2) Maximum Daily Rate of Withdrawal (MDR) 2,880,000 Gallons Per Day**
- (3) Maximum Monthly Rate of Withdrawal (MMR) 37,200,000 Gallons Per Month
- (4) Number of **Consecutive** Days MDR is to be pumped. 3 Days (Typically 3 days)
per week

* Total yearly water use divided by 365 days.

** Maximum amount of water requested per 24 hours - cannot exceed system pump capacity.

B. WITHDRAWAL FACILITY

- (1) Total Number of Existing Wells in Use: 3
- (2) Total Number of Existing Wells not in Use: 0
- (3) Total Number of Proposed Wells: 1 (well to be installed prior to 12/1/99)

NOTE: This well is already covered by the existing Consumptive Use Permit.

2. APPLYING FOR SURFACE WATER? ☒ Yes ☐ No

A. Total SURFACE WATER amount requested (APPLY FOR TOTAL SYSTEM USAGE):

- (1) Average Daily Rate of Withdrawal (ADR) 274,000,000 Gallons Per Day*
- (2) Maximum Daily Rate of Withdrawal (MDR) 274,000,000 Gallons Per Day**
- (3) Maximum Monthly Rate of Withdrawal (MMR) 8,494,000,000 Gallons Per Month
- (4) Number of **Consecutive** Days MDR is to be pumped. 7 Days (Typically 3 days)
per week

* Total yearly water use divided by 365 days.

** Maximum amount of water requested per 24 hours - cannot exceed system pump capacity.

B. WITHDRAWAL FACILITY

- (1) Total Number of Existing Withdrawal Facilities: 4
- (2) Total Number of Proposed Withdrawal Facilities: 0
- (3) Name of Creek, Stream, River, Lake, or Impoundment: North Bay via Alligator Bayou

3. Provide calculations that support the requested average daily rate (ADR), maximum daily rate (MDR), and maximum monthly rate (MMR) of withdrawals (site references, metered reports, attach additional sheets if necessary):

(ADR): Groundwater: current needs = 0.7MGPD (annual average daily). Ground-
water needs in 2001 will be 1MGD, with an increase 1.2MGD by 2003 through the
end of the permit. Existing and new requirements = 1.2MGD. Surface Water:

47,400 GPM X 1440 min/day = 273,024,000 (assume 274MGD).

(MDR): Groundwater: 4 wells X 500 gal./min. X 1440 min./day = 2,880,000GPD

Surface Water: 4 intake pumps X 47,400 gal./min. X 1440 min./day =

273,024MGD (assume 274MGD).

(MMR): Groundwater: 1,200,000GPD X 31 days/month = 37.2MGD

Surface Water: 274MGD X 31 = 8494MGD.

SECTION VII - FACILITY INFORMATION

1. GROUND WATER WITHDRAWAL TABLE (Please complete each item)

I. D. NUMBER	FLORIDA UNIQUE I. D. NUMBER *	DIAMETER (INCHES)	TOTAL DEPTH	CASED DEPTH	PUMP GPM	PUMP H. P.	PROPOSED EXISTING?	AQUIFER SYSTEM	FLOW METER YES/NO?	SECTION AND 1/4 SECTION	TOWNSHIP	RANGE
LSGP #1	N/A	18"	370'	(1) 148'	500	50	E	FL	N	SE/4 S 36	25	15W
LSGP #2	N/A	18"	307	(2) 95'	500	50	E	FL	N	SE/4 S 36	25	15W
LSGP #3	N/A	14"	400	(3) 150'	500	50	E	FL	N	SE/4 S 36	25	15W
LSGP #4	N/A	18"	300'	100'	500	50	P**	FL	N	NE/4 S 25	25	15W

* If available. FL = Floridan Aquifer (1) open hole 148-370' (2) open hole 95-307' (3) open hole 150-400' **Well #4 already covered by existing permit.
 2. SURFACE WATER WITHDRAWAL TABLE (Please complete each item) N/A=Not Available.

I. D. NUMBER	INTAKE DIAMETER	PUMP GPM	PUMP H. P.	PROPOSED EXISTING?	WATER SOURCE?	VOLUME (AC/FT) OF POND/LAKE Bay	FLOW METER YES/NO?	SECTION AND 1/4 SECTION	TOWNSHIP	RANGE	LATITUDE	LONGITUDE
LSGP 1A/NB	11'8"	47400	50	Exist.	North Bay	86426	No	SW/4 S 36	2S	15W	30°16'05"	85°42'05"
LSGP 1B/NB	11'8"	47400	50	Exist.	North Bay	86426	No	SW/4 S 36	2S	15W	30°16'05"	85°42'05"
LSGP 2A/NB	11'8"	47400	50	Exist.	North Bay	86426	No	SW/4 S 36	2S	15W	30°16'05"	85°42'05"
LSGP 2B/NB	11'8"	47400	50	Exist.	North Bay	86426	No	SW/4 S 36	2S	15W	30°16'05"	85°42'05"
NB = North Bay												

SECTION VIII - SITE WITHDRAWAL INFORMATION

1. WITHDRAWAL LOCATION **Lansing Smith Electric Generating Plant**
4300 County Road 2300, Southport, FL 32409

ADDRESS: _____

COUNTY, UNIT, BLOCK, LOT: Bay

2. Number of acres: 1383.47 Owned _____ Leased _____

3. Describe the facility(ies) to which water is supplied: Electric generating plant

4. If the application is for a multiple well system, a well 4 inches or larger in diameter, or a surface water withdrawal, then submit a United States Geological Survey 7 - 1/2 minute topographic quad map (or copy) that delineates the following items:

A. Name of the quad map used (Example: QUINCY QUAD). Southport Quad.

B. Property boundaries. See attached map

SECTION VIII - SITE WITHDRAWAL INFORMATION (CONTINUED)

- C. Approximate location of all existing AND proposed wells and/or surface water withdrawal pumps - with identification numbers (e.g. Well #1, Pump #1, etc.).
 - D. Surface water management ponds used for withdrawal.
 - E. Potential impacts to wetlands MAY require the submittal of a recent aerial map having a minimum scale of 1" = 2,000 feet.
5. Provide the dimensions and volumes (acre-feet) of all surface water ponds/lakes used for withdrawal purposes (e.g. surface acreage x average pond depth = acre-feet).

SECTION IX - MODIFICATION AND PERMIT COMPLIANCE

If this application is for a modification, please describe the modification requested and the reason the modification is necessary. For modification and renewal requests, describe the applicant's compliance with EACH of the conditions of the existing permit:

MODIFICATION DESCRIPTION: Gulf Power Company proposes to increase water use
from 0.7 MGD to 1.2MGD by the end of the anticipated permit period (5 years).

PERMIT CONDITION COMPLIANCE: Gulf Power Company has been in compliance with (1)
all permitted water usage requirements/limitations and, (2) significant saline
water intrusion has not occurred at the site. Usage requirements for the
current permit are: average/maximum groundwater use of 700,000/2,880,000GPD
and surface water withdrawals of less than the permit average and maximum of
264,600,000GPD and 274,000,000GPD.

SECTION X - IMPACTS

Please attach a detailed description of the anticipated impacts on the resource and on existing legal users which could be impacted by the proposed use. The District shall require any other necessary information in accordance with the provisions of Section 40A-2.101(3), Florida Administrative Code and Chapter 373.223, Florida Statutes. **See attached modeling and report (Attachment B)**

SECTION XI - CONSERVATION

Provide a description of present and planned activities undertaken to conserve water and minimize off-site surface water runoff (attach additional sheets if necessary): Water is recycled from the on-site
ash pond for a variety of uses such as: washing precipitators, backup water
supply for the fire protection system, sluicing ash from the plant to the ash
pond, controlling fugitive emissions (dust control) on plant roads, equipment
seal water, and for general equipment wash down water. See Attachment C.

SECTION XII - APPLICANT CERTIFICATION

I hereby certify that the information contained herein is true and accurate and that I have legal authority to undertake the activities described herein and execute this application.

Further, I authorize Rachel A. Terry to act as my agent for permit application coordination.

SECTION XII - APPLICANT CERTIFICATION (CONTINUED)

James O. Vach
APPLICANT SIGNATURE

5/27/99
DATE

I hereby certify that I am the authorized agent of the applicant.

Nachel Terry
AGENT SIGNATURE

5-27-99
DATE

I hereby certify that the applicant has sufficient legal control of the property described in this application.

James O. Vach
PROPERTY OWNER SIGNATURE

5/27/99
DATE

APPLICANT CHECKLIST

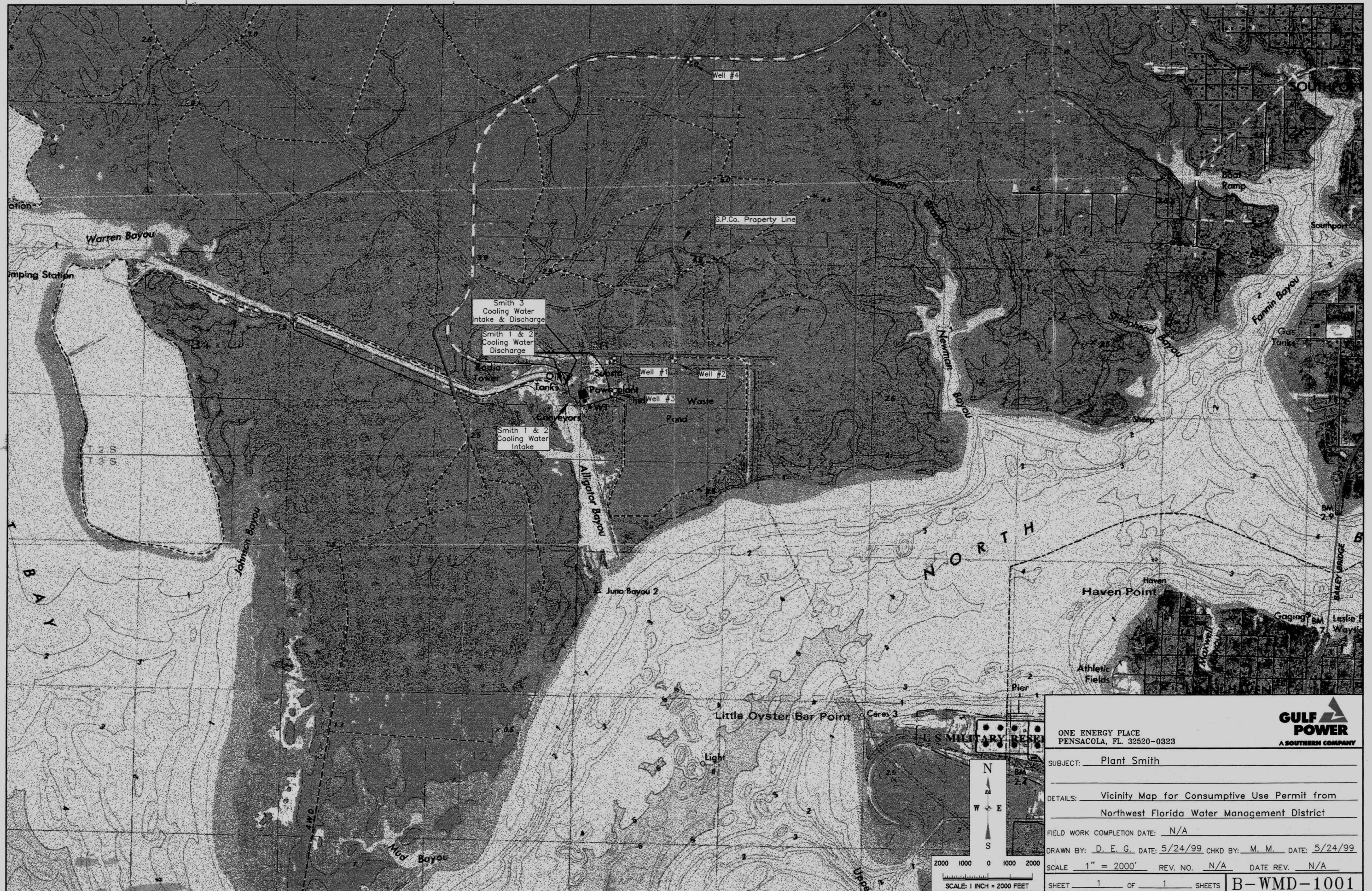
1. Appropriate permit processing fee (check only) ☒ Attached*
2. Complete legal name was provided in Section II ☒ Provided
3. Copy of legal description (deed, lease) See Attachment D ☒ Attached ☐ N/A
4. S. C. S. conservation plan ☐ Attached ☐ Pending ☒ N/A
5. S. C. S. irrigation and water management plan ☐ Attached ☐ Pending ☒ N/A
6. U. S. G. S. 7 - 1/2 minute topographic map ☒ Attached
7. Description of anticipated impact(s) ☒ Attached
8. For aquifer remediation projects, enclose the summary of the remedial action plan ☐ Attached ☒ N/A
9. Two (2) copies of all materials ☒ Attached

* All permit processing fees are non-refundable and are based upon the average daily withdrawal rate (ADR). To determine one's permit processing fee - compare the requested ADR amount(s) of Section VI to the matrix below:

AVERAGE DAILY WITHDRAWAL RATES (ADR) GALLONS	PROCESSING FEE
Less than 25,000 gallons per day, average	\$ 100.00
25,000 to 99,999 gallons per day, average	\$ 250.00
100,000 to 499,999 gallons per day, average	\$ 500.00
500,000 to 999,999 gallons per day, average	\$ 1,000.00
1,000,000 to 1,999,999 gallons per day, average	\$ 2,000.00
2,000,000 gallons or more per day, average	\$ 3,000.00
Permit Transfer	\$ 50.00
Temporary Permit (in addition to the fees identified above)	\$ 50.00

Please address all correspondence to the following address:

NORTHWEST FLORIDA WATER MANAGEMENT DISTRICT
ATTN: Consumptive Use - Division of Resource Regulation
Route 1, Box 3099
Havana, Florida 32333-9700
Telephone: (850) 539-5999
Suncom: (850) 771-2080



ONE ENERGY PLACE
PENSACOLA, FL 32520-0323



SUBJECT: Plant Smith

DETAILS: Vicinity Map for Consumptive Use Permit from
Northwest Florida Water Management District

FIELD WORK COMPLETION DATE: N/A

DRAWN BY: D. E. G. DATE: 5/24/99 CHKD BY: M. M. DATE: 5/24/99

SCALE: 1" = 2000' REV. NO. N/A DATE REV. N/A

SHEET 1 OF 1 SHEETS B-WMD-1001

ATTACHMENT A
DESCRIPTION OF RECYCLED STORMWATER
AND RECLAIMED WATER USAGE

SECTION V – CONSUMPTIVE WATER USE INFORMATION

2. USE OF RECYCLE AND/OR RECLAIMED WATER

A. Is RECYCLED RUNOFF WATER (e.g. rainfall runoff) being utilized? YES

Rainfall runoff from the Smith Plant site is collected in a series of stormwater sumps and transferred to an on-site ash pond. This pond is used for the storage of ash generated from the combustion of coal in the power plant. Water from the ash pond is utilized in a recycle system which sluices ash from the plant to the pond.

B. Is RECLAIMED WATER being utilized? YES

Treated effluent from an on-site 3,000 GPD capacity domestic wastewater treatment plant is discharged into the same ash pond mentioned in paragraph 2.A above. This domestic plant is permitted as internal Outfall D01A in the Smith NPDES Permit FL0002267. The ash pond is permitted as Outfall D01C.

**ATTACHMENT B
MODFLOW AND SHARP
MODELING REPORT**

**REPORT ATTACHED IN
ATTACHMENT 10.5-G, APPENDIX 10.5**

**ATTACHMENT C
FURTHER DESCRIPTION OF
WATER CONSERVATION EFFORTS**

SECTION XI (Continued):

As described in Section V (and Attachment A), stormwater from the industrial portions of our site is collected and sent to the ash pond. This water is then used in a recycle system which transfers ash from the plant to the ash pond. Water from the ash pond is also used for a variety of plant operation tasks as described previously in this section. In addition, water drained from the boilers is routed to the ash pond for re-use.

The proposed combined cycle electric generating unit at Plant Smith is designed to conserve water. It will utilize non-contact cooling water which is already covered in our existing consumptive use permit. As a result, there will not be a need for any additional surface water withdrawal from North Bay. The proposed combined cycle unit will involve collecting approximately 5,150 gallons per minute from the existing discharge canal for Smith Units 1 and 2. This water will be utilized as makeup cooling water for the combined cycle operation.

ATTACHMENT D
COPY OF LEGAL DESCRIPTION
WARRANTY DEED

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

THIS DEED was made this 5th day of July, A. D. 1961, between ST. JOE PAPER COMPANY, a corporation created and existing under the laws of the State of Florida, with principal office at Jacksonville, Florida, party of the first part, and GULF POWER COMPANY, a corporation created and existing under the laws of the State of Maine, with principal office at Pensacola, Florida, party of the second part:

WITNESSETH: That the said party of the first part, for and in consideration of the sum of Ten Dollars and other valuable considerations to it in hand paid, the receipt whereof is hereby acknowledged, has granted, bargained, sold, aliened, remised, released, conveyed and confirmed, and by these presents doth grant, bargain, sell, alien, remise, release, convey and confirm unto the said party of the second part, and its successors and assigns, forever; subject to letter dated June 30, 1961, from Gulf Power Company to St. Joe Paper Company. *OK*

A. (300-foot strip of land)

A strip of land three hundred feet (300') wide, being one hundred fifty feet (150') on each side of a centerline and a continuation thereof, through, over and across the following lands in Bay County, Florida, to-wit:

The South Half ($S\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$), and the Northeast Quarter ($NE\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Thirty-six (36); the Southeast Quarter ($SE\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$), the West Half ($W\frac{1}{2}$) of the Southeast Quarter ($SE\frac{1}{4}$), the South Half ($S\frac{1}{2}$) of the Northeast Quarter ($NE\frac{1}{4}$), and the Northeast Quarter ($NE\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$) of Section Twenty-five (25); the Southeast Quarter ($SE\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$) of Section Twenty-four (24), all being in Township Two (2) South, Range Fifteen (15) West; the West Half ($W\frac{1}{2}$) of the Southwest Quarter ($SW\frac{1}{4}$), the Northeast Quarter ($NE\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$), the South Half ($S\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$), the Northeast Quarter ($NE\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$), and the Northwest Quarter ($NW\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$) of Section Nineteen (19); the Southeast Quarter ($SE\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$), the South Half ($S\frac{1}{2}$) of the Southeast Quarter ($SE\frac{1}{4}$), and the Northeast Quarter ($NE\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$) of Section Eighteen (18); the West Half ($W\frac{1}{2}$) of the Southwest Quarter ($SW\frac{1}{4}$), the Northeast Quarter ($NE\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$), the Northwest Quarter ($NW\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$), the Southwest Quarter ($SW\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$) of Northeast Quarter ($NE\frac{1}{4}$), the East Half ($E\frac{1}{2}$) of the Southwest Quarter ($SW\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$), and the Southeast Quarter ($SE\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$) of Section Seventeen (17); that part of the Southwest Quarter ($SW\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$) lying West of State Highway No. 77 in Section Sixteen (16), all being in Township Two (2) South, Range Fourteen (14) West.

FILED

1961 JUL 14 PM 4:19

ERUICE COLLINS
CLERK, BAY COUNTY
JACKSONVILLE, FLORIDA

Said centerline across the above described land being described as follows, to-wit:

Begin at a point on the South boundary of the South Half ($S\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Thirty-six (36), Township Two (2) South, Range Fifteen (15) West, determined as follows: From the Southwest Corner of the Northwest Quarter ($NW\frac{1}{4}$) of said Section Thirty-six (36), run East along the South boundary thereof a distance of One Thousand Eight Hundred Fifty-four and Twenty-eight One Hundredths feet (1854.28'), to POINT OF BEGINNING of said centerline; from said point of beginning run North 46 degrees 04 minutes West a distance of Seven Hundred Forty and Two Tenths feet (740.2') to an angle point in said South Half ($S\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) of said Section Thirty-six (36), from said angle point run North 27 degrees 20 minutes East across Sections Thirty-six, Twenty-five and Twenty-four (36, 25 & 24), Township Two (2) South, Range Fifteen (15) West, and Sections Nineteen and Eighteen (19 & 18), Township Two (2) South, Range Fourteen (14) West, a distance of Fourteen Thousand Four Hundred Forty-four and One Tenth feet (14,444.1') to an angle point in said Section Eighteen (18), from said angle point run North 64 degrees 08 minutes East across Sections Eighteen, Seventeen and Sixteen (18, 17 & 16), Township Two (2) South, Range Fourteen (14) West a distance of Eight Thousand Eight Hundred Forty-six and Two Tenths feet (8846.2') to State Highway No. 77 in said Section Sixteen (16).

This three hundred foot (300') wide right-of-way comprises one hundred sixty-five and five tenths (165.5) acres.

B. (100-foot strip of land)

A strip of land one hundred feet (100') wide, being fifty feet (50') on each side of a centerline and a continuation thereof, through, over and across the following lands in Bay County, Florida, to-wit:

The South Half ($S\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) and the Northwest Quarter ($NW\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Thirty-six (36); the Northeast Quarter ($NE\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$) of Section Thirty-five (35); the South Half ($S\frac{1}{2}$) of the Southeast Quarter ($SE\frac{1}{4}$), the Northwest Quarter ($NW\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$), the North Half ($N\frac{1}{2}$) of the Southwest Quarter ($SW\frac{1}{4}$), the South Half ($S\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) and the Northwest Quarter ($NW\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Twenty-six (26); the East Half ($E\frac{1}{2}$) of the Northeast Quarter ($NE\frac{1}{4}$) and the Northwest Quarter ($NW\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$) of Section Twenty-seven (27); the South Half ($S\frac{1}{2}$) of the Southeast Quarter ($SE\frac{1}{4}$), the Northwest Quarter ($NW\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$), the East Half ($E\frac{1}{2}$) of the Southwest Quarter ($SW\frac{1}{4}$), the Northwest Quarter ($NW\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$), and the Southwest Quarter ($SW\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Twenty-two (22); the East Half ($E\frac{1}{2}$) of the Northeast Quarter ($NE\frac{1}{4}$) and the Northwest Quarter ($NW\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$) of Section Twenty-one (21); the Southwest Quarter ($SW\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$) and the South Half ($S\frac{1}{2}$) of the Southwest Quarter ($SW\frac{1}{4}$) of Section Sixteen (16); the South Half ($S\frac{1}{2}$) of the Southeast Quarter ($SE\frac{1}{4}$) and the Southeast Quarter ($SE\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$) of Section Seventeen (17); the North Half ($N\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Twenty (20); the North Half ($N\frac{1}{2}$) of the Northeast Quarter ($NE\frac{1}{4}$) and the Northwest Quarter ($NW\frac{1}{4}$) of Section

Nineteen (19), all being in Township Two (2) South, Range Fifteen (15) West; the South Half ($S\frac{1}{2}$) of the Northeast Quarter ($NE\frac{1}{4}$), the South Half ($S\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) and the Northwest Quarter ($NW\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$) of Section Twenty-four (24); the Southeast Quarter ($SE\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$), the North Half ($N\frac{1}{2}$) of the Southeast Quarter ($SE\frac{1}{4}$), the East Half ($E\frac{1}{2}$) of the Southwest Quarter ($SW\frac{1}{4}$) and the Southwest Quarter ($SW\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$) of Section Twenty-three (23); the Southeast Quarter ($SE\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$) of Section Twenty-two (22); the North Half ($N\frac{1}{2}$) of the Northeast Quarter ($NE\frac{1}{4}$), the East Half ($E\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) and the Southwest Quarter ($SW\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Twenty-seven (27); the Original Government Lots 3 and 4 North of Bay, Lot 2 South of Bay and Fractional Southwest Quarter ($SW\frac{1}{4}$) of Section Twenty-eight (28); the East Half ($E\frac{1}{2}$) of the Southeast Quarter ($SE\frac{1}{4}$), the Southwest Quarter ($SW\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$) and the Southeast Quarter ($SE\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$) of Section Twenty-nine (29); the Northwest Quarter ($NW\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$), the North Half ($N\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) and the Southwest Quarter ($SW\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Thirty-two (32); the Southeast Quarter ($SE\frac{1}{4}$) of the Northeast Quarter ($NE\frac{1}{4}$), the East Half ($E\frac{1}{2}$) of the Southeast Quarter ($SE\frac{1}{4}$) and the Southwest Quarter ($SW\frac{1}{4}$) of the Southeast Quarter ($SE\frac{1}{4}$) of Section Thirty-one (31), all being in Township Two (2) South, Range Sixteen (16) West; the West Half ($W\frac{1}{2}$) of the Northeast Quarter ($NE\frac{1}{4}$), the East Half ($E\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$), the North Half ($N\frac{1}{2}$) of the Southwest Quarter ($SW\frac{1}{4}$) and the Southwest Quarter ($SW\frac{1}{4}$) of the Southwest Quarter ($SW\frac{1}{4}$) of Section Six (6); the Northwest Quarter ($NW\frac{1}{4}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Seven (7), all being in Township Three (3) South, Range Sixteen (16) West.

Said centerline across the above described land being described as follows, to-wit:

Begin at a point on the South boundary of the South Half ($S\frac{1}{2}$) of the Northwest Quarter ($NW\frac{1}{4}$) of Section Thirty-six (36), Township Two (2) South, Range Fifteen (15) West, determined as follows: From the Southwest Corner of the Northwest Quarter ($NW\frac{1}{4}$) of said Section Thirty-six (36), run East along South boundary thereof a distance of One Thousand Five Hundred Seventy and Three One Hundredths feet (1570.03') to POINT OF BEGINNING of said centerline, from said point of beginning run North 46 degrees 04 minutes West across Sections Thirty-six, Thirty-five, Twenty-six, Twenty-seven, Twenty-two, Twenty-one, and Sixteen (36, 35, 26, 27, 22, 21 & 16) all being in Township Two (2) South, Range Fifteen (15) West a distance of Nineteen Thousand Four Hundred Forty-four feet (19,444') to an angle point in said Section Sixteen (16), from said angle point run North 88 degrees 07 minutes West across Sections Sixteen and Seventeen (16 & 17), Township Two (2) South, Range Fifteen (15) West a distance of Four Thousand Two Hundred Ninety-three and Nine Tenths feet (4293.9') to an angle point in said Section Seventeen (17), from said angle point run South 77 degrees 44 minutes West across Sections Seventeen, Twenty and Nineteen (17, 20 & 19) all being in Township Two (2) South, Range Fifteen (15) West, and Sections Twenty-four and Twenty-three (24 & 23), Township Two (2) South, Range Sixteen (16) West, a distance of Seventeen Thousand One Hundred Sixty-five feet (17,165') to an angle point in said Section Twenty-three (23), from said angle point run South 64 degrees 42 minutes West across Sections Twenty-three, Twenty-two, Twenty-seven, Twenty-eight, Twenty-nine and Thirty-two (23, 22, 27, 28, 29 and 32), all

being in Township Two (2) South, Range Sixteen (16) West a distance of Twenty-one Thousand Five Hundred Ninety feet (21,590') to an angle point in said Section Thirty-two (32), from said angle point run South 30 degrees 18 minutes West across Sections Thirty-two and Thirty-one (32 & 31), Township Two (2) South, Range Sixteen (16) West and Sections Six and Seven (6 & 7), Township Three (3) South, Range Sixteen (16) West a distance of Eleven Thousand Twenty-nine and One Tenth feet (11,029.1') to the North boundary of the Laguna Beach Substation of Gulf Power Company in said Section Seven (7).

This one hundred foot (100') wide right-of-way comprises one hundred sixty-five and sixty-four hundredths (165.64) acres.

For use by the party of the second part, its successors and assigns, for the purpose of constructing, operating and maintaining electric transmission lines and all telegraph and telephone lines, towers, poles and appliances necessary or convenient in connection therewith from time to time upon, over and across the lands herein described, and for all counter-poise wires or other counter-poise conductors over, under and upon the lands herein described; for the transmission of electric energy over, upon and across the lands herein described, including specifically but without limiting the generality of the foregoing the right to set and maintain poles and anchors for electric transmission lines, and the necessary appurtenances for such lines over and across said lands; and with the right to install, maintain and use anchors and guy wires on land adjacent to said strips of land, only where necessary at the angle points.

TOGETHER with all the tenements, hereditaments and appurtenances, with every privilege, right, title, interest and estate, reversion, remainder and easement thereto belonging or in anywise appertaining; TO HAVE AND TO HOLD the same in fee simple, forever.

AND the said party of the first part does hereby specially warrant the title to said land and will defend the same against the lawful claims of all persons claiming by, through or under the party of the first part, but not otherwise.

It is agreed between the parties hereto that the party of the first part shall have the right of ingress, egress and regress, over, across and upon the lands above described in carrying on forestry and silva-culture work on its lands adjoining the lands above described, so long as such passage over the lands above described by the servants, agents and employees of the party of the first part shall not interfere with the use of the lands by party of the second part in its business of constructing, maintaining and operating electric power lines upon and over said lands. The party of the first part reserves the right to construct and maintain fences on, over and across the lands herein conveyed. This right, however, shall not interfere with the rights of party of the second part as owner of the fee simple title of the lands herein conveyed or the use thereof by party of the second part, and all rights as the fee simple owner thereof, and for the purposes herein shown. This will give the party of the second part the right to cross and place gates in, as desired by party of the second part, any fences constructed by party of the first part across the lands herein conveyed.

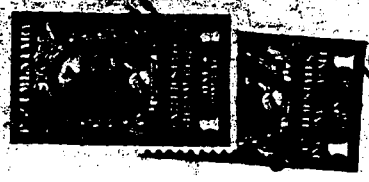
And the said party of the first part does hereby further reserve unto itself and its successors and assigns all of the oil, gas, sulphur and other minerals that might be in or under the lands hereinabove described and herein and hereby conveyed, together with the full right to explore for, mine, produce and remove said minerals from the said pieces or parcels of land in any manner not inconsistent with or that might interfere with the use by the party of the second part of the said pieces or parcels of land for the purposes conveyed. This shall not interfere with the right of the party of the second part to use the lands herein conveyed for the purposes herein set forth, that is to say, for all

purposes of its business of constructing, maintaining and operating electric power lines, and otherwise the uses as hereinbefore shown.

It is further agreed that the party of the second part shall not have the right to sell nor convey the lands above described nor any part thereof (except to an electric utility) until it shall have first offered the said land or such part thereof to the party of the first part, naming the terms of any proposed sale. The party of the first part shall have thirty days to accept or reject such terms. The sale price, however, shall not exceed the prevailing price of lands of similar character in the area where located. The offer of sale shall be by registered mail addressed to party of the first part at Tallahassee, Florida.

If, in falling, any part of a tree outside the rights of way could come within five (5) feet of any part of any electric transmission line on the lands above described, such tree is defined as a danger tree for the purposes of this instrument. It is agreed that from time to time the party of the second part, its successors or assigns, shall designate the trees which are or which may become danger trees as defined herein, and the party of the first part shall have the right to cut and remove said trees at its own cost under the supervision of the party of the second part, its successors or assigns, and trees so cut shall be the property of the party of the first part. The party of the first part shall cut and remove such danger trees within ninety (90) days after they shall have been designated as such by the party of the second part, its successors or assigns, and the party of the first part shall have been notified of such designation by written notice mailed by the party of the second part, its successors or assigns, addressed to party of the first part at Tallahassee, Florida. Upon failure of the party of the first part to cut and remove such trees within said period of time, the party of the second part, its successors or assigns, may proceed to cut the same.

WITNESS WHEREOF, the said party of the first part has
caused these presents to be signed in its name by its Vice
President, and its corporate seal to be affixed, attested by its Secretary
the day and year first above written.



ST. JOE PAPER COMPANY

By R. C. Brent Jr.
Vice President



Irene Walsh
Secretary

Signed, Sealed and Delivered
in our Presence:

John Beall
C. L. Clark



STATE OF FLORIDA,
COUNTY OF DUVAL

I HEREBY CERTIFY, That on this 8th day of July,
A. D. 1961, before me personally appeared R. C. Brent, Jr.
Vice
and Irene Walsh, respectively President and
Secretary, of St. Joe Paper Company, a corpor-
ation under the laws of the State of Florida, to me known to be
the individuals and officers described in and who executed the
foragoing conveyance to Gulf Power Company, and severally acknowledged
the execution thereof to be their free act and deed as such officers
thereunto duly authorized; and that the official seal of said cor-
poration is duly affixed thereto, and the said conveyance is the
act and deed of said corporation.

WITNESS my hand and official seal, on this the day and year
last aforesaid.

Juanita Driggers
Notary Public, State of Florida
at large.

DUVAL COUNTY, FLORIDA
JUL 14 1961
4:14 PM
Filed for record and duly recorded. Book and
page noted above. John Collins, Clerk,
County Court.

My commission expires:

APPENDIX 10.2.7
PREVENTION OF SIGNIFICANT
DETERIORATION APPLICATION

**PREVENTION OF SIGNIFICANT
DETERIORATION
APPLICATION**

SMITH UNIT 3

Prepared for:

**GULF POWER COMPANY
Pensacola, Florida**

Prepared by:

ECT

Environmental Consulting & Technology, Inc.

***3701 Northwest 98th Street
Gainesville, Florida 32606***

ECT No. 990151-0300

June 1999

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Gulf Power Company (Gulf) is planning to construct and operate a natural gas-fired combustion turbine generator (CTG)-based combined cycle (CC) unit at its existing Lansing Smith Electric Generating Plant. This new unit, designated Smith Unit 3, will have a nominal generating capacity of 540 megawatts (MW). At average annual site conditions with duct burner (DB) firing, Unit 3 will generate 566 MW. At summer peaking site conditions with DB firing and steam power augmentation, Unit 3 will generate 574 MW. The existing Lansing Smith Electric Generating Plant is located in Bay County northwest of Panama City. The existing Lansing Smith facility includes: (a) two coal-fired electric generating units having nominal generating capacities of 175 MW (Unit 1) and 205 MW (Unit 2); (b) one No. 2 fuel oil-fired combustion turbine having a nominal generating capacity of 40 MW; and (c) ancillary supporting equipment and processes including coal handling and storage. The proposed Smith Unit 3 is being licensed under the Florida Electrical Power Plant Siting Act.

Operation of the proposed project will result in the emission of air contaminants. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This report, including the required permit application forms and supporting documentation included in the appendices, constitutes Gulf's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, F.A.C.

Smith Unit 3 will be located in an attainment area and will have potential emissions of a regulated pollutant in excess of 100 tons per year (tpy). Consequently, Smith Unit 3 qualifies as a new major facility and is subject to the prevention of significant deterioration (PSD) new source review (NSR) requirements of Rule 62-212.400, F.A.C. Therefore, this report and application is also submitted to satisfy the permitting requirements

contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and a summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes national and state air quality standards and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 describes the PSD NSR review procedures.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (dispersion modeling methodology) and 7.0 (dispersion modeling results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of Smith Unit 3 and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.

Attachments A through D provide the FDEP Application for Air Permit—Title V Source, CTG vendor information, emission rate calculations, and NO_x netting analysis, respectively. All dispersion modeling input and output files for the ambient impact analysis are provided in diskette format in Attachment E.

1.2 SUMMARY

Smith Unit 3 will consist of two nominal 170-MW General Electric (GE) PG7241 (FA) CTGs, two heat recovery steam generators (HRSGs) equipped with supplemental DBs, and one nominal 200-MW steam turbine generator (STG); i.e., a 2-on-1 configuration. At average annual site conditions with DB firing, Unit 3 will generate 566 MW. At summer peaking site conditions with DB firing and steam power augmentation, Unit 3 will generate 574 MW. Ancillary equipment includes a mechanical draft cooling tower and water treatment and storage facilities. The CTGs will be fired exclusively with pipeline-quality

natural gas containing no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf).

The planned construction start date for Smith Unit 3 is November 1, 2000. Smith Unit 3 projected date for the facility to begin commercial operation is May 31, 2002, following initial equipment startup and completion of required performance testing.

Based on an evaluation of anticipated worst-case annual operating scenarios, Smith Unit 3 will have the potential to emit 757 tpy of nitrogen oxides (NO_x), 701 tpy of carbon monoxide (CO), 253 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM/PM₁₀), 105 tpy of sulfur dioxide (SO₂), and 93 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, Smith Unit 3 will potentially emit 12 tpy of sulfuric acid (H₂SO₄) mist. Due to the contemporaneous installation of low-NO_x burners and an improved burner management system for Lansing Smith Unit No. 1, a federally enforceable NO_x emissions cap of 3,587 tpy, using continuous emissions monitoring systems (CEMS) to demonstrate compliance, for Smith Units 1 and 3 is requested to achieve a net reduction of 9 tpy in NO_x emissions from the Lansing Smith Plant following construction of Smith Unit 3. No increases in emissions of CO, VOC, or PM/PM₁₀ are expected due to the installation of low-NO_x burners for Unit 1. A detailed NO_x netting analysis and a discussion of CO, VOC, and PM/PM₁₀ emissions associated with Unit 1 low-NO_x burner installation are provided in Attachment D. Based on these annual emission rate potentials, CO, VOC, PM/PM₁₀, SO₂, and H₂SO₄ mist emissions are subject to PSD review.

As presented in this report, the analyses required for this permit application resulted in the following conclusions:

- The use of good combustion practices and clean fuels is considered to be BACT for PM/PM₁₀. The CTGs and DBs will utilize the latest burner technologies to maximize combustion efficiency and minimize PM/PM₁₀ emission rates, and will be fired exclusively with pipeline-quality natural gas.

- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOC for the CTGs and DBs. At base load operation without DB firing, the CTG/HRSG CO exhaust concentration is projected to be 13 parts per million by dry volume (ppmvd) at 15 percent oxygen. At base load operation with DB firing and without steam power augmentation, the CTG/HRSG CO exhaust concentration is projected to be 16 ppmvd at 15 percent oxygen. At base load operation with DB firing and with steam power augmentation, the CTG/HRSG CO exhaust concentration is projected to be 23 ppmvd at 15 percent oxygen for 1,000 hours per year (hr/yr). At base load operation without DB firing, the CTG/HRSG VOC exhaust concentration is projected to be 3 ppmvd at 15 percent oxygen. At base load operation with DB firing and without steam power augmentation, the CTG/HRSG VOC exhaust concentration is projected to be 4 ppmvd at 15 percent oxygen. At base load operation with DB firing and with steam power augmentation, the CTG/HRSG VOC exhaust concentration is projected to be 6 ppmvd at 15 percent oxygen for 1,000 hr/yr. These concentrations are consistent with prior FDEP BACT determinations for CTG/HRSG units; e.g., City of Tallahassee Purdom Unit 8, Lakeland Utilities McIntosh Unit 5, and Santa Rose Energy. Cost effectiveness of a CO oxidation catalyst control system was determined to be \$1,567 per ton of CO. Installation of a CO oxidation catalyst control system is considered to be economically unreasonable.
- BACT for SO₂ and H₂SO₄ mist will be achieved through the exclusive use of low-sulfur, pipeline-quality natural gas.
- Smith Unit 3 is projected to emit CO, PM/PM₁₀, SO₂, and H₂SO₄ mist in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants, with the exception of PM₁₀. Accordingly, Smith Unit 3 qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants except PM₁₀. Representative, current quality-

assured ambient PM₁₀ data collected by FDEP at a monitoring site located in Panama City, Bay County, was used to satisfy the PSD preconstruction ambient air monitoring requirements for PM₁₀.

- With the exception of PM₁₀, the ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.259(259), F.A.C. Accordingly, a multi-source interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class II increment consumption was required for PM₁₀ only.
- Based on refined dispersion modeling, Smith Unit 3 will not cause nor contribute to a violation of any NAAQS, Florida ambient air quality standards (AAQS), or PSD increment for Class I or Class II areas.
- Modeling of H₂SO₄ mist emissions shows that maximum project impacts will be well below FDEP's draft ambient reference concentrations.
- The ambient impact analysis also demonstrates that project impacts will be well below levels that are detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Bradwell Bay Wilderness Area) is located approximately 125 kilometers (km) southeast of the Smith Unit 3 site. Air quality and visibility impacts on this Class I area will be negligible.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The proposed Smith Unit 3 will be located in Bay County approximately 13 km (8 miles) northwest of Panama City. The approximately 50-acre plant site is bordered on the south by the existing Lansing Smith Generating Plant property, on the west by a Gulf electric transmission line corridor, and on the north and east by undeveloped property owned by Gulf. Figure 2-1 shows the location of Smith Unit 3 within the state of Florida. The project site location and surroundings are provided in Figure 2-2. Figure 2-3 provides portions of a U.S. Geological Survey (USGS) topographical map showing the project site location relative to local landmarks.

Major components of Smith Unit 3 include:

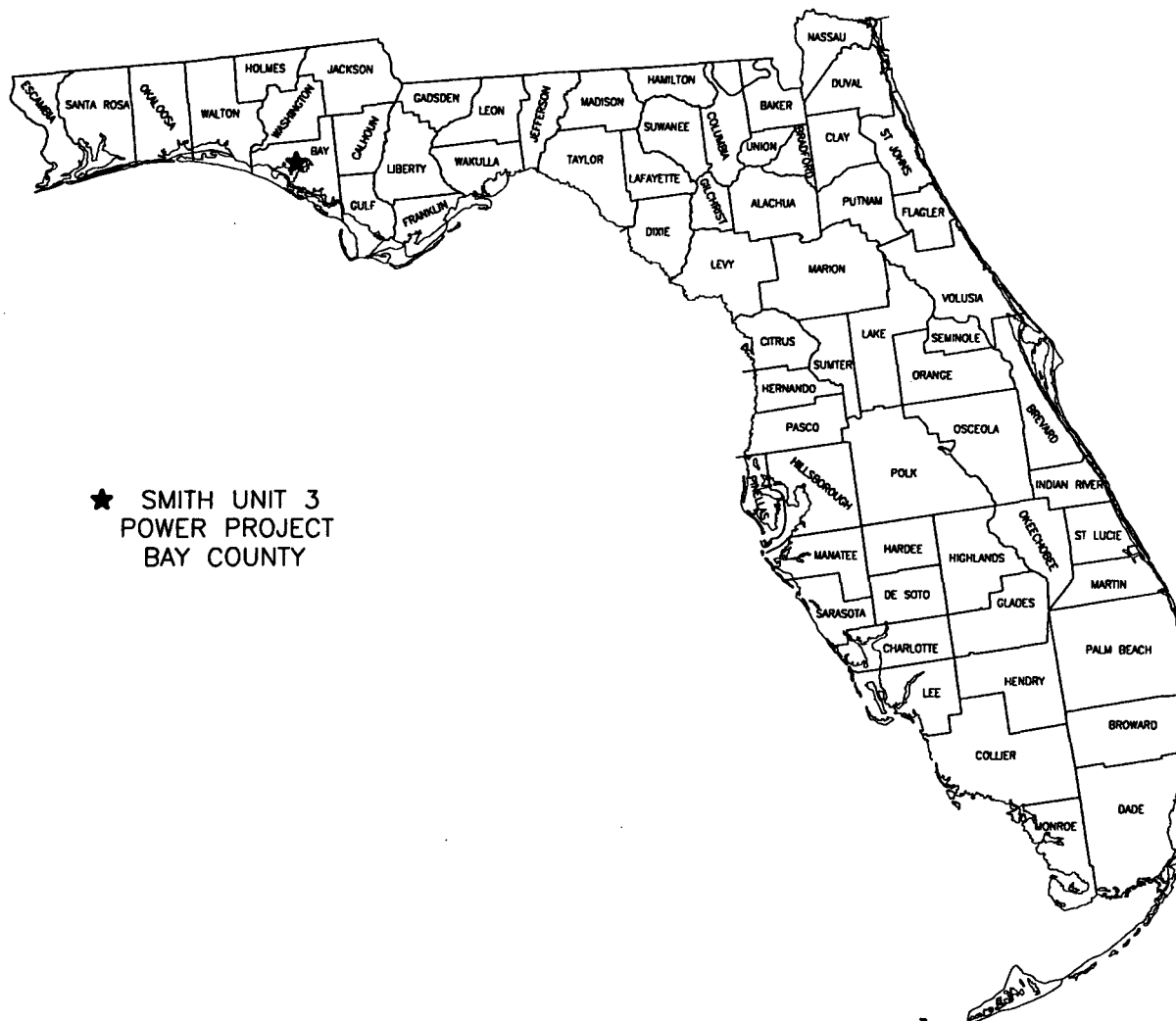
1. The base CC generating plant, consisting of two F-class CTG/HRSG units and one STG; i.e., a 2-on-1 configuration.
2. Mechanical draft cooling tower.
3. Ancillary equipment, including raw and demineralized water storage tanks.

The CTGs will be GE PG7241 (FA) units. The two CTGs will have provisions for steam power augmentation and will each be capable of producing a nominal 170 MW of electricity. The two HRSG units, which will be equipped with supplemental DBs, will furnish steam to the STG for the additional generation of electricity. The STG will be capable of generating an additional nominal 200 MW of power for an overall nominal generation capacity of 540 MW. At average annual site conditions with DB firing, Unit 3 will generate 566 MW. At summer peaking site conditions with DB firing and steam power augmentation, Unit 3 will generate 574 MW. The CTGs and DBs will be fired exclusively with pipeline quality natural gas.

Smith Unit 3 will be capable of continuous operation at base load for up to 8,760 hr/yr. The CTGs will normally operate between 50- and 100-percent load, with commensurate STG

IMAGE QUALITY

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PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



★ SMITH UNIT 3
POWER PROJECT
BAY COUNTY

FIGURE 2-1.

SITE LOCATION WITHIN THE STATE OF FLORIDA

Source: ECT, 1999.

ECT

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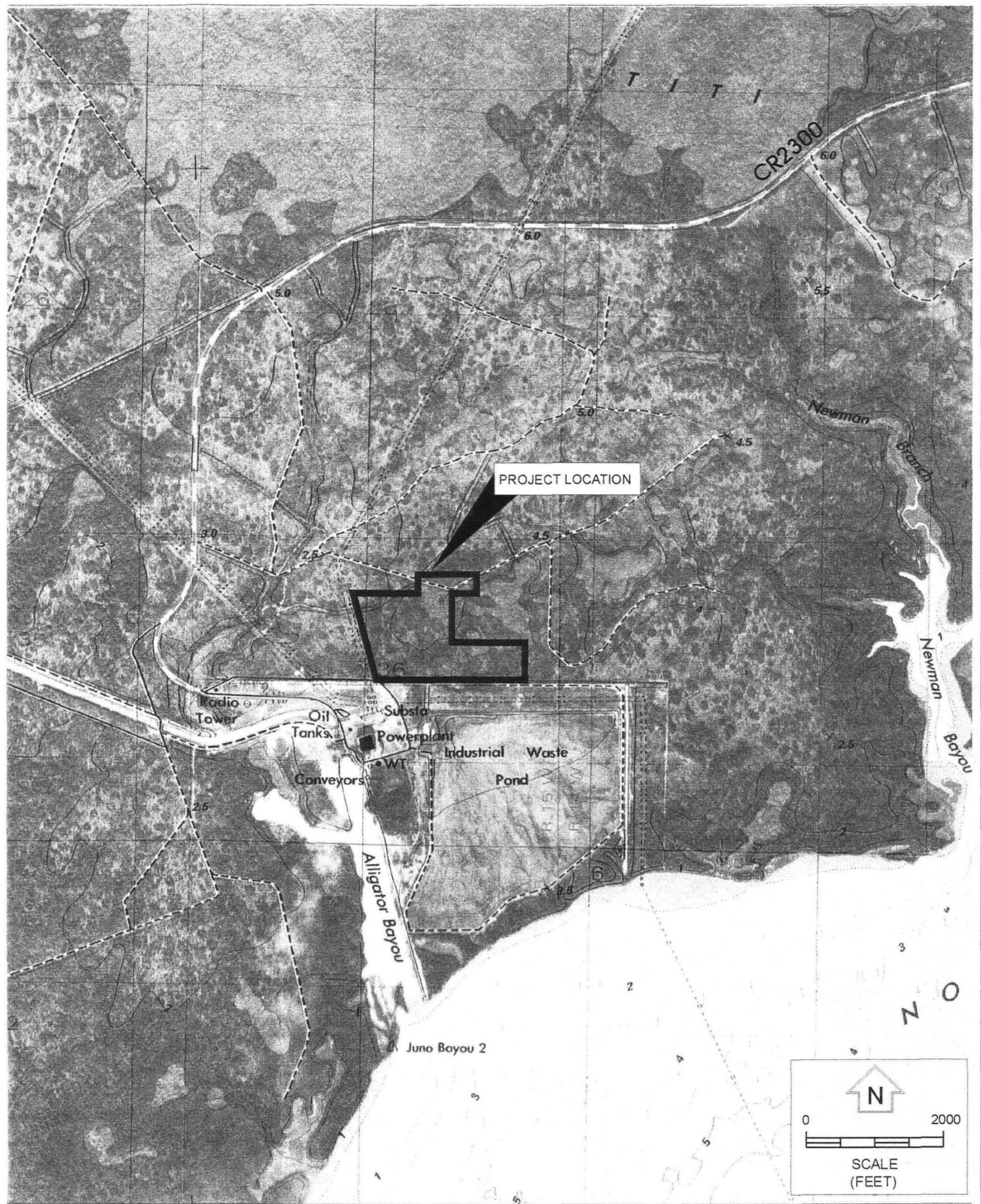


FIGURE 2-2.

PROJECT SITE LOCATION AND SURROUNDINGS

Sources: USGS topo map of Southport, FL, 1992; ECT, 1999.

ECT

Environmental Consulting & Technology, Inc.

load. Neither CTG will be designed to operate in simple cycle mode (i.e., bypassing the HRSG).

Combustion of natural gas in the CTGs and DBs will result in emissions of particulate matter (PM/PM₁₀), SO₂, NO_x, CO, VOCs, and H₂SO₄ mist. Cooling tower operation will result in PM/PM₁₀ emissions due to drift losses.

Emission control systems proposed for the CTG/HRSG units include the use of dry low-NO_x combustors for control of NO_x; good combustion practices for abatement of CO and VOCs; and exclusive use of clean, low-sulfur, low-ash natural gas to minimize PM/PM₁₀, SO₂, and H₂SO₄ mist emissions. Drift eliminators will be utilized to control PM/PM₁₀ emissions from the mechanical draft cooling tower.

A plot plan showing facility property lines, major process equipment and structures, and all emission points is presented in Figure 2-4. Primary access to the plant will be provided by County Road (CR) 2300 which terminates at the existing power plant entrance. CR 2300 connects to State Road (SR) 77 to the north. The entrance will have security gates to control site access. The entire site perimeter will be fenced or include natural barriers at the property boundary.

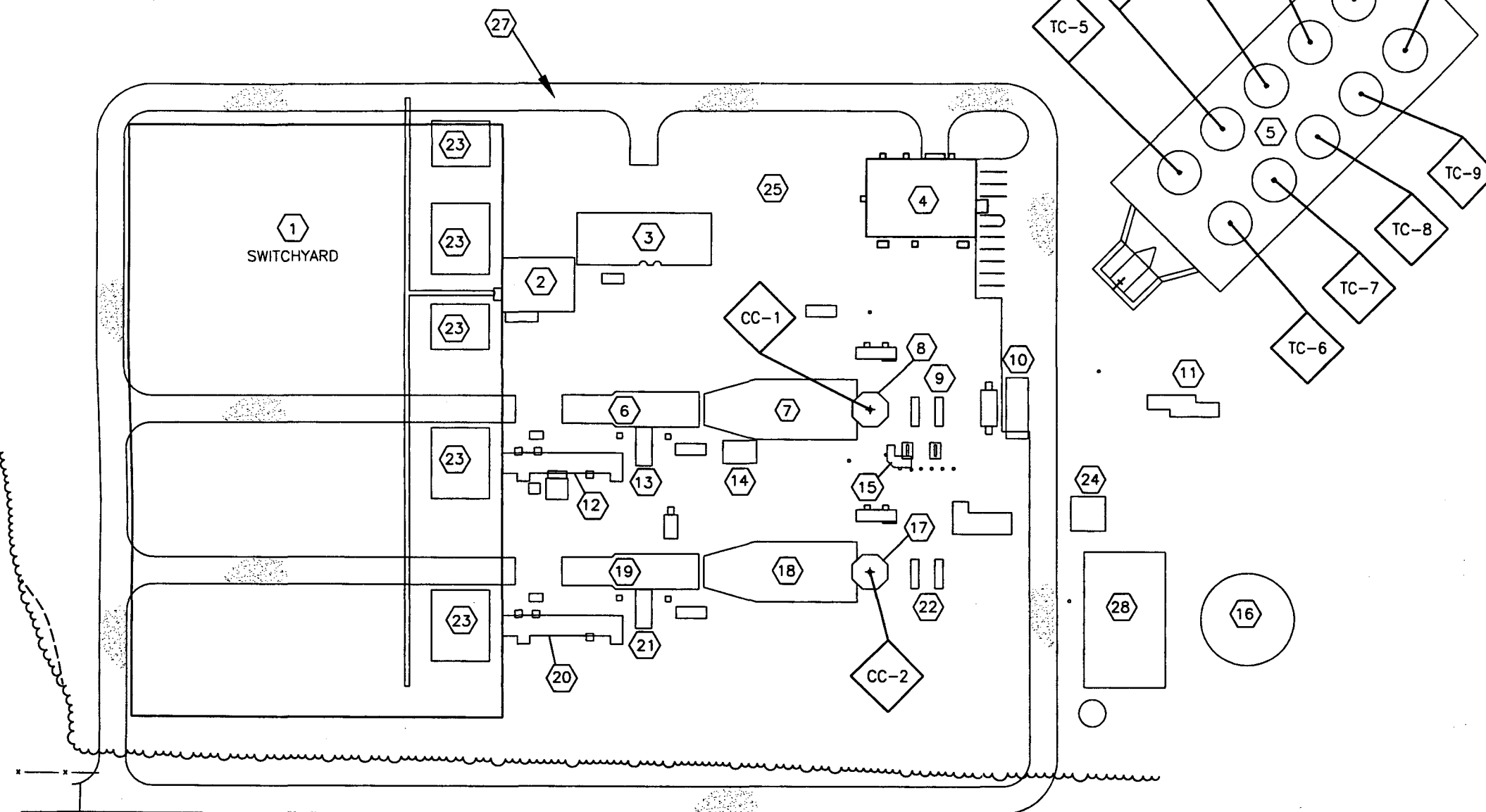
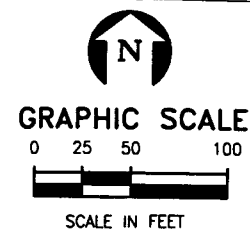
2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed Smith Unit 3 natural gas-fired CC facility will include two nominal 170-MW CTGs, two HRSGs with supplemental DBs, and one nominal 200-MW STG. At average annual site conditions with DB firing, Unit 3 will generate 566 MW. At summer peaking site conditions with DB firing and steam power augmentation, Unit 3 will generate 574 MW. A process flow diagram of Smith Unit 3 is presented in Figure 2-5.

CTGs are heat engines that convert latent fuel energy into work using compressed hot gas as the working medium. CTGs deliver mechanical output by means of a rotating shaft which is used to drive an electrical generator, thereby converting a portion of the engine's

IMAGE QUALITY

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PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



AREA /STRUCTURE LEGEND

NAME	SIZE (SQ. FEET)
CC-1 EMISSION POINT	
1 SWITCHYARD	120,346.68
2 ELECTRICAL BUILDING	2,351.44
3 STEAM TURBINE	3,768.28
4 ADMINISTRATION BUILDING	4,586.67
5 COOLING TOWER	33,178.27
6 NORTH GAS TURBINE	2,412.20
7 NORTH HEAT RECOVERY STEAM GENERATOR (HRSG)	4,617.73
8 NORTH STACK	534.43
9 NORTH BOILER FEED PUMP	258.02
10 FEEDWATER TRANSFORMER	720.00
11 480 VOLT MCC AND TRANSFORMER	664.06
12 BAC/PEECC	1,427.18
13 ACCESSORY MODULE	335.50
14 PHOSPHATE FEED SKID	425.00
15 AMMONIA SUPPLY SYSTEM	181.91
16 CONDENSATE STORAGE TANK	3,631.68
17 SOUTH STACK	534.43
18 SOUTH HEAT RECOVERY STEAM GENERATOR (HRSG)	4,617.73
19 SOUTH GAS TURBINE	2,412.20
20 GEC/PEECC	1,427.18
21 ACCESSORY MODULE	335.50
22 SOUTH BOILER FEED PUMP	258.02
23 TRANSFORMERS	9,541.24
24 WASTE WATER SUMP	325.13
25 INTERIOR PLANT YARD (GRAVEL)	76,418.62
26 BALANCE OF SITE (GRAVEL)	814,224.3
27 ROADWAY (CONCRETE)	87,682.38
28 WATER TREATMENT BUILDING	6,000.00
29 GRASSED SLOPES	50,000.00
30 MISC. CONC. PADS (INTERIOR YARD)	2,000.00

FIGURE 2-4.

SMITH UNIT 3 PLOT PLAN

Source: ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

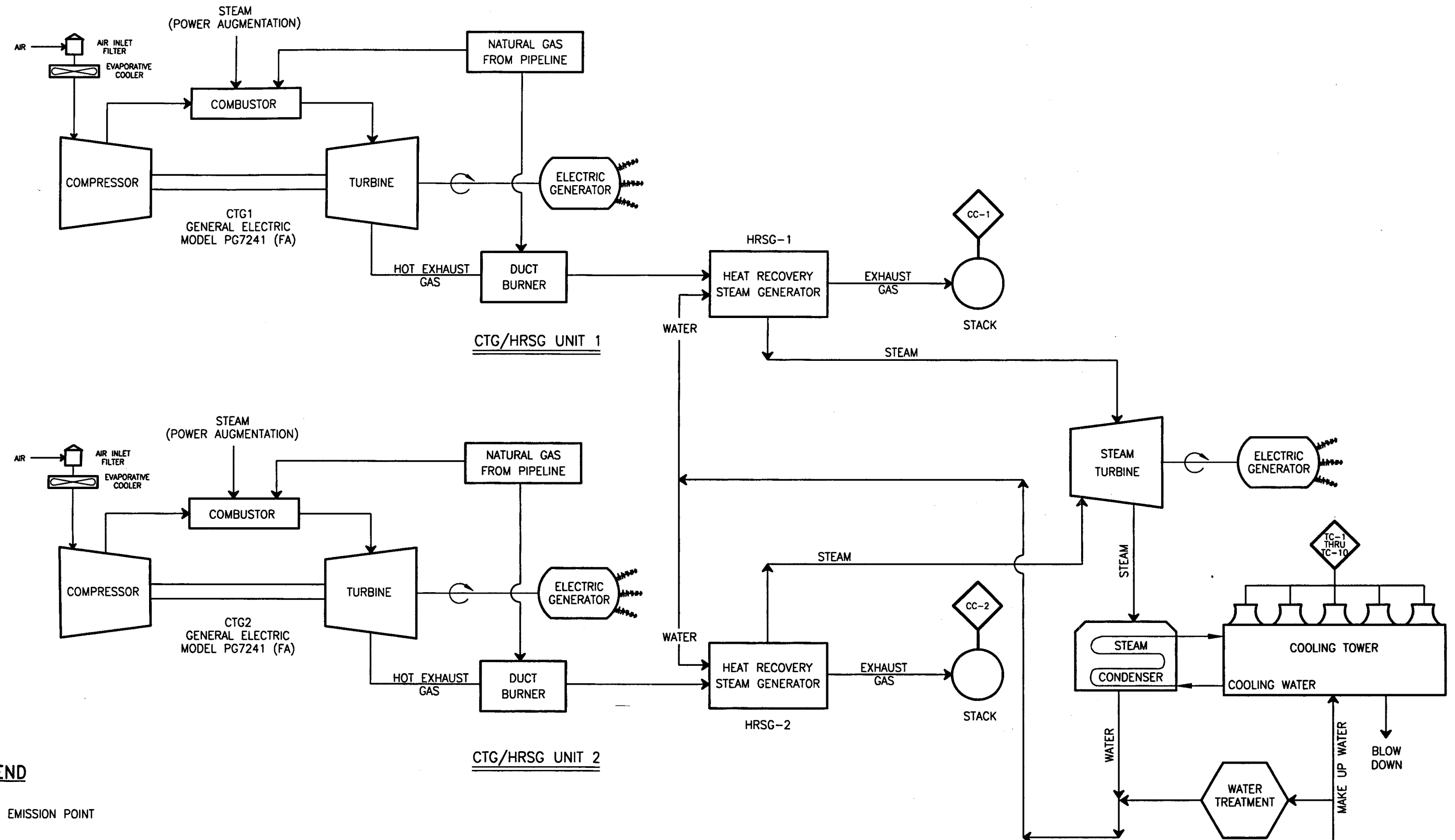


FIGURE 2-5.
PROCESS FLOW DIAGRAM

Source: ECT, 1999.

mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CTG compressor. The CTG compressor increases the pressure of the combustion air stream and also raises its temperature. During warm days when the ambient air temperature exceeds 65 degrees Fahrenheit (°F), the turbine inlet ambient air is cooled by an evaporative cooler, thus providing denser air for combustion and improving the power output. The compressed combustion air is then combined with natural gas fuel and burned in the CTG's high-pressure combustor to produce hot exhaust gases. These high pressure, hot gases next expand and turn the CTG's turbine to produce rotary shaft power which is used to drive an electric generator as well as the CTG combustion air compressor. The CTGs will also utilize steam power augmentation to increase power production during periods of peak demand.

The hot exhaust gases from the CTGs next flow to the HRSGs for the production of steam. Each CTG will use an HRSG to recover exhaust heat from the CTG and produce steam to power the STG. The STG, in turn, will drive an electric generator having a nominal generation capacity of 170 MW. The two HRSGs include supplemental DB firing for the production of additional steam during peak demand periods. The DBs, which will be fired exclusively with natural gas, each have a nominal heat input rating of 275 million British thermal units per hour (MMBtu/hr), lower heating value (LHV). Following reuse of the CTG exhaust waste heat by the HRSGs, the exhaust gases are discharged to the atmosphere.

Normal operation is expected to consist of both CTG/HRSG units operating at base load. Alternate operating modes include reduced load (i.e., between 50 and 100 percent of base load) operation for one or both of the CTG/HRSG units depending on power demands, use of inlet air evaporative cooling under high ambient temperature conditions, and supplemental HRSG DB firing and steam power augmentation during peak demand periods. The CTGs will not be designed with bypass stacks and will operate only in the CC mode. The CTG/HRSG units are designed for continuous operation (i.e., 8,760 hr/yr) and may operate at up to a 100 percent annual capacity factor.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to startup, shutdown, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CTG hot, warm, and cold start-up and shutdown periods may last for more than 2 hours in a 24-hour period, the following periods of excess emissions above the 2-hour per 24-hour limit are requested for the Smith Unit 3 CTGs: (a) up to 1 hour per start-up during hot start-up to CC operation, (b) up to 2 hours per start-up during warm start-up to CC operation, (c) up to 4 hours per start-up during cold start-up to CC operation, and (d) up to 4 hours per shutdown during shutdowns from CC operation. Hot start-up is defined as a startup to CC operation following a complete shutdown lasting less than or equal to 8 hours. Warm start-up is defined as a startup to CC operation following a complete shutdown lasting between 8 and 48 hours. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. CTG start-up is defined as that period of time from initiation of CTG firing unit until the unit reaches steady-state load operation. Steady-state operation is reached when the CTG reaches minimum load (i.e., 50 percent load) and the steam turbine is declared available for load changes.

The CTGs and DBs will utilize dry low-NO_x combustion technology to control NO_x air emissions. The exclusive use of low-sulfur natural gas in the CTGs and DBs will minimize PM/PM₁₀, SO₂, and H₂SO₄ mist air emissions. High efficiency combustion practices will be employed to control CO and VOC emissions. The mechanical draft cooling tower will be equipped with drift eliminators achieving a drift loss rate of no more than 0.001 percent.

2.3 EMISSION AND STACK PARAMETERS

Table 2-1 provides maximum hourly criteria pollutant CTG/HRSG emission rates. Maximum hourly noncriteria pollutant (i.e., H₂SO₄ mist) emission rates are summarized in Table 2-2. The highest hourly emission rates for each pollutant are prescribed, taking

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	PM/PM ₁₀ *		SO ₂		NO _x		CO		VOC		Pb	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	0†	20.8	2.62	12.7	1.60	78.7	9.91	78.7	9.91	10.2	1.29	Neg.	Neg.
	65‡	20.9	2.63	11.9	1.50	82.9	10.45	75.4	9.49	9.8	1.23	Neg.	Neg.
	95**	21.5	2.65	12.4	1.57	113.3	14.28	116.6	14.69	16.8	2.12	Neg.	Neg.
75	0	19.8	2.50	9.3	1.18	56.1	7.07	46.2	5.82	5.2	0.66	Neg.	Neg.
	65	19.8	2.50	8.6	1.09	51.7	6.51	42.9	5.41	5.2	0.65	Neg.	Neg.
	95	19.8	2.50	8.2	1.04	49.5	6.24	40.7	5.13	4.2	0.53	Neg.	Neg.
50	0	19.8	2.50	7.4	0.94	44.0	5.54	37.4	4.71	4.4	0.55	Neg.	Neg.
	65	19.8	2.50	6.9	0.87	41.8	5.27	35.2	4.44	4.4	0.55	Neg.	Neg.
	95	19.8	2.50	6.6	0.83	39.6	4.99	34.1	4.30	5.0	0.63	Neg.	Neg.

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible.

* Excludes H₂SO₄ mist.

† Emission rates include supplemental duct burner firing.

‡ Emission rates include use of evaporative cooler and supplemental duct burner firing.

** Emission rates include use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table 2-2. Maximum Noncriteria Pollutant Emission Rates for Three Loads and Four Ambient Temperatures (Per CTG/HRSG Unit)

Unit Load (%)	Ambient Temperature (°F)	<u>H₂SO₄ mist</u>	
		lb/hr	g/s
100	0*	1.46	0.184
	65†	1.36	0.172
	95*‡	1.43	0.180
75	0	1.07	0.135
	65	0.99	0.125
	95*	0.94	0.119
50	0	0.85	0.108
	65	0.80	0.100
	95*	0.76	0.095

* Emission rates include supplemental duct burner firing.

† Emission rates include use of evaporative cooler and supplemental duct burner firing.

‡ Emission rates include use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.

into account load and ambient temperature to develop maximum hourly emission estimates for each CTG/HRSG unit.

Maximum hourly emission rates for SO₂ and H₂SO₄ mist, in units of pounds per hour (lb/hr), are projected to occur for operations at low ambient temperature (i.e., 0°F), CTG baseload, and DB firing. For PM/PM₁₀, NO_x, CO, and VOCs, maximum hourly mass emission rates are projected to occur at 95°F, CTG baseload with steam power augmentation, and DB firing. The bases for these emission rates are provided in Attachment C.

Table 2-3 presents projected maximum annualized criteria and noncriteria emissions for Smith Unit 3. The maximum annualized rates were conservatively estimated for each CTG/HRSG unit assuming 7,760 hr/yr at 65°F, CTG baseload with DB firing and 1,000 hr/yr at 95°F, CTG baseload with steam power augmentation and DB firing.

Annual emission rate estimates for the mechanical draft cooling tower and total Smith Unit 3 annual emissions are shown in Table 2-3. Details of the annualized emission calculations are also included in Attachment C. Stack parameters for the natural gas-fired CTG/HRSG units are provided in Table 2-4.

Table 2-3. Maximum Annualized Emission Rates in tpy for Smith Unit 3

Pollutant	CTG/HRSG Units	Cooling Tower	Unit 3 Totals
NO _x	757	N/A	757
CO	701	N/A	701
PM/PM ₁₀ *	184	80	264
SO ₂	105	N/A	105
VOC	93	N/A	93
H ₂ SO ₄ mist	12	N/A	12

Note: N/A = not applicable.

*Excludes H₂SO₄ mist.

Sources: ECT, 1999.
GE, 1999
Gulf Power, 1999.

Table 2-4. Stack Parameters for Three Unit Loads and Three Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	0*	121	36.7	190	361	81.5	24.8	16.8	5.11
	65†	121	36.7	186	359	74.2	22.6	16.8	5.11
	95‡	121	36.7	170	350	73.3	22.3	16.8	5.11
75	0	121	36.7	170	350	62.6	19.1	16.8	5.11
	65	121	36.7	166	348	58.7	17.9	16.8	5.11
	95	121	36.7	180	355	58.1	17.7	16.8	5.11
50	0	121	36.7	159	344	50.2	15.3	16.8	5.11
	65	121	36.7	155	341	47.6	14.5	16.8	5.11
	95	121	36.7	173	351	47.9	14.6	16.8	5.11

Note: m = meter.
K = Kelvin.
m/sec = meter per second.

*Stack parameters reflect supplemental duct burner firing.

†Stack parameters reflect use of evaporative cooler and supplemental duct burner firing.

‡Stack parameters reflect use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments, the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS; reference Section 62-204.240, F.A.C. Table 3-1 presents the current national and Florida AAQS.

Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The proposed Smith Unit 3 is located in Bay County approximately 13 km northwest of Panama City. Bay County is presently designated in 40 CFR §81.310 as better than national standards (for total suspended particulates [TSPs] and SO₂), unclassifiable/attainment (for CO), unclassifiable or better than national standards (for nitrogen dioxide [NO₂]), and not designated (for lead). 40 CFR §81.310 also indicates that the 1-hour ozone standard is not applicable. Bay County is designated attainment (for ozone, SO₂, CO, and NO₂) and unclassifiable (for PM₁₀ and lead) by Section 62-204.340, F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

Smith Unit 3 will be located in Bay County. As noted above, Bay County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, Smith Unit 3 is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

Table 3-1. National and Florida Air Quality Standards (micrograms per cubic meter [$\mu\text{g}/\text{m}^3$] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards		Florida Standards
		Primary	Secondary	
SO ₂ (ppmv)	3-hour ¹		0.5	0.5
	24-hour ¹	0.14		0.1
	Annual ²	0.030		0.02
SO ₂	3-hour ¹			1,300
	24-hour ¹			260
	Annual ²			60
PM ₁₀ ¹³	24-hour ³	150	150	
	Annual ⁴	50	50	
PM ₁₀	24-hour ⁵			150
	Annual ⁶			50
PM _{2.5} ^{11,12}	24-hour ⁷	65	65	
	Annual ⁸	15	15	
CO (ppmv)	1-hour ¹	35		35
	8-hour ¹	9		9
CO	1-hour ¹			40,000
	8-hour ¹			10,000
Ozone (ppmv)	1-hour ⁹			0.12
	8-hour ^{10,11}	0.08	0.08	
NO ₂ (ppmv)	Annual ²	0.053	0.053	0.05
	Annual ²			100
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

¹ Not to be exceeded more than once per calendar year.² Arithmetic mean.³ Standard attained when the 99th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.⁴ Arithmetic mean, as determined by 40 CFR 50, Appendix N.⁵ Not to be exceeded more than once per year, as determined by 40 CFR 50, Appendix K.⁶ Standard attained when the expected annual arithmetic mean is less than or equal to the standard, as determined by 40 CFR 50, Appendix K.⁷ Standard attained when the 98th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.⁸ Arithmetic mean, as determined by 40 CFR 50, Appendix N.⁹ Standard attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H.¹⁰ Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard, as determined by 40 CFR 50, Appendix I.¹¹ The U.S. Court of Appeals for the District of Columbia Circuit (Circuit Court) held that these standards are not enforceable. American Trucking Association v. U.S.E.P.A., 1999 WL300618 (Circuit Court).¹² The Circuit Court may vacate standards following briefing. Id.¹³ The Circuit Court held PM₁₀ standards vacated upon promulgation of effective PM_{2.5} standards.

Sources: 40 CFR 50.

Section 62-204.240, F.A.C.

3.3 PSD NSR APPLICABILITY

CTG-CC, such as the proposed Smith Unit 3, are considered by FDEP to fall within the Section 62-212.400, Table 212.400-1, F.A.C., Major Facility Category of "fossil-fuel-fired steam electric plants." Accordingly, new CTG-CC plants of more than 250 MMBtu/hr heat input, with potential emissions of 100 tpy or more of any regulated pollutant, and located in an attainment area are classified as *new major facilities* subject to PSD NSR.

The proposed Smith Unit 3 will have a heat input greater than 250 MMBtu/hr, will be located in an attainment area, and will have potential emissions of a regulated pollutant in excess of 100 tpy. Therefore, Smith Unit 3 qualifies as a new major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants which are emitted at or above the specified PSD significant emission rate levels. Due to the contemporaneous installation of low-NO_x burners and an improved burner management system for Lansing Smith Unit No. 1, a federally enforceable NO_x emissions cap of 3,587 tpy, using CEMS to demonstrate compliance, for Smith Units 1 and 3 is requested to achieve a net reduction of 9 tpy in NO_x emissions from the Lansing Smith Plant following construction of Smith Unit 3. No increases in emissions of CO, VOC, or PM/PM₁₀ are expected due to the installation of low-NO_x burners for Unit 1. There are no other creditable contemporaneous emission rate increases or decreases that have occurred at the Lansing Smith Plant within the last 5 years. Comparisons of estimated potential annual emission rates for Smith Unit 3 and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of PM, PM₁₀, SO₂, CO, and H₂SO₄ mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Detailed emission rate estimates for Smith Unit 3 are provided in Attachment C.

Table 3-2. Projected Emissions Compared to PSD Significant Emission Rates

Pollutant	Projected Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO _x	-9	40	No
CO	701	100	Yes
PM	264	25	Yes
PM ₁₀	264	15	Yes
SO ₂	105	40	Yes
Ozone/VOC	93	40	Yes
Lead	Negligible	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Not Present	3	No
H ₂ SO ₄ mist	12	7	Yes
Total reduced sulfur (including hydrogen sulfide)	Not Present	10	No
Reduced sulfur compounds (in- cluding hydrogen sulfide)	Not Present	10	No
Municipal waste combustor acid gases (measured as SO ₂ and hydrogen chloride)	Not Present	40	No
Municipal waste combustor met- als (measured as PM)	Not Present	15	No
Municipal waste combustor or- ganics (measured as total tetra- through octa- chlorinated dibenzo-p- dioxins and dibenzofurans)	Not Present	3.5 × 10 ⁻⁶	No

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 1999.

4.0 PSD NSR REQUIREMENTS

4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(5)(c), F.A.C., an analysis of BACT is required for each pollutant which is emitted by the proposed Smith Unit 3 in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(42), F.A.C., BACT is "an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation. Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results."

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant which exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units involved in a major modification or a new major source that emit or increase emissions of the applicable pollutants must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

BACT is defined in terms of a numerical emissions limit unless determined to be infeasible. This numerical emissions limit can be based on the application of air pollution control equipment; specific production processes, methods, systems, or techniques; fuel cleaning; or combustion techniques. BACT limitations may not exceed any applicable federal new source performance standard (NSPS) or national emission standard for hazardous air pollutants (NESHAPs), or any other emission limitation established by state regulations.

BACT analyses are conducted using the *top-down* analysis approach, which was outlined in a December 1, 1987, memorandum from Craig Potter, EPA Assistant Administrator, to EPA Regional Administrators on the subject of "Improving New Source Review (NSR) Implementation." Using the top-down methodology, available control technology alternatives are identified based on knowledge of the particular industry of the applicant and previous control technology permitting decisions for other identical or similar sources. These alternatives are rank ordered by stringency into a control technology hierarchy. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts, and to assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is not applicable, or is technically or economically infeasible, it is rejected as BACT, and the next most stringent alternative is then considered. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the pollutant in question emitted from the particular facility under consideration.

4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those that the source would potentially

emit in significant amounts; i.e., those that exceed the PSD significant emission rate thresholds shown in Table 3-2.

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

Rule 62-212.400(2)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility shall be exempt from the monitoring requirements of Rule 62-212.400(5)(f) and (g), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the source or modification would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400, Table 212.400-3, F.A.C. (see Table 4-1). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to the proposed Smith Unit 3 is discussed in Section 8.0.

4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). The FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220(4), F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA *Guideline on Air Quality Models* as published

Table 4-1. PSD *De Minimis* Ambient Impact Levels

Averaging Time	Pollutant	Significance Level ($\mu\text{g}/\text{m}^3$)
Annual	NO ₂	14
Quarterly	Lead	0.1
24-Hour	PM ₁₀	10
	SO ₂	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Hydrogen sulfide	0.2
NA	Ozone	100 tpy of VOC emissions

Source: Section 62-212.400, Table 212.400-3, F.A.C.

in Appendix W to 40 CFR Part 51. Criteria pollutants may be exempt from the full source impact analysis if the net increase in impacts due to the new source or modification is below the appropriate Rule 62-210.200(259), F.A.C., significant impact level, as presented in Table 4-2.

Ozone is one pollutant for which a source impact analysis is not normally required. Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone generally are applied to entire urban areas.

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

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality *baseline concentration* level for SO₂ and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 2,024 hectares [ha] [5,000 acres], and national parks larger than 2,428 ha [6,000 acres]) or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA

Table 4-2. Significant Impact Levels

Pollutant	Averaging Period	Concentration ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	1
	24-Hour	5
	3-Hour	25
PM ₁₀	Annual	1
	24-Hour	5
NO ₂	Annual	1
CO	8-Hour	500
	1-Hour	2,000
Lead	Quarterly	0.03

Source: Rule 62-210.200(260), F.A.C.

then promulgated, as regulations, the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated PSD increments for NO₂; the effective date of the new regulation was October 17, 1989. However, the baseline date for NO₂ increment consumption was set at March 28, 1988, for Florida; new major sources or modifications constructed after this date will consume NO₂ increment.

On June 3, 1993, EPA promulgated PSD increments for PM₁₀; the effective date of the new regulation was June 3, 1994. The increments for PM₁₀ replace the original PM increments which were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM₁₀ increments. Revised NAAQS for PM, which includes a revised NAAQS for PM₁₀ and a new NAAQS for particulate matter less than or equal to 2.5 micrometers (PM_{2.5}), became effective on September 16, 1997. The new NAAQS for PM_{2.5} has been recently remanded to EPA and is not currently effective. In addition, due to the significant technical difficulties that exist with respect to PM_{2.5} monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for PM_{2.5} is administratively impracticable at this time for State permitting authorities. Accordingly, EPA has advised that PM₁₀ may be used as a surrogate for PM_{2.5} in meeting NSR requirements until these difficulties are resolved.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 4-3.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, *baseline concentration* means the ambient concentration level that exists in the baseline area at the

Table 4-3. PSD Allowable Increments ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Time	Class		
		I	II	III
PM ₁₀	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
SO ₂	Annual arithmetic mean	2	20	40
	24-Hour maximum*	5	91	182
	3-Hour maximum*	25	512	700
NO ₂	Annual arithmetic mean	2.5	25	50

* Maximum concentration not to be exceeded more than once per year at any one location.

Source: Section 62-204.260, F.A.C.

time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

1. The actual emissions representative of sources in existence on the applicable minor source baseline date.
2. The allowable emissions of major stationary sources which commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.

The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s); i.e., allowed increment consumption:

1. Actual emissions from any major stationary source on which construction commenced after the major source baseline date.
2. Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration *change* attributable to emission sources that affect increment. *Major source baseline date* means January 6, 1975, for PM (TSP/PM₁₀) and SO₂ and February 8, 1988, for NO₂. *Minor source baseline date* means the earliest date after the trigger date, on which the first complete application (in Florida, December 27, 1977, for PM/PM₁₀ and SO₂; and March 28, 1988 for NO_x) was submitted by a major stationary source or major modification subject to the requirements of 40 CFR §52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM₁₀) and SO₂ and February 8, 1988, for NO₂.

The ambient impact analysis for Smith Unit 3 is provided in Sections 6.0 (methodology) and 7.0 (results).

4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(5)(e), F.A.C., requires additional impact analyses for three areas: (1) associated growth, (2) soils and vegetation impact, and (3) visibility impairment. The level of analysis for each area should be commensurate with the scope of Smith Unit 3. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

1. A projection of the associated industrial, commercial, and residential growth that will occur in the area.
2. An estimate of the air pollution emissions generated by the permanent associated growth.
3. An air quality analysis based on the associated growth emission estimates and the emissions expected to be generated directly by the new source or modification.

The soils and vegetation analysis is typically conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria pollutants below the NAAQS will not result in harmful effects. Sensitive vegetation and emissions of toxic air pollutants could necessitate a more extensive assessment of potential adverse effects on soils and vegetation.

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of Smith Unit 3.

The additional impact analyses for the Smith Unit 3 is provided in Section 9.0.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method as previously described in Section 4.1. The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, post-process stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information which were used to identify control alternatives include:

- EPA reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information System database.
- EPA NSR web site.
- EPA Control Technology Center (CTC) web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- Environmental Consulting & Technology, Inc. (ECT), experience for similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the draft *EPA NSR Workshop Manual* (EPA, 1990a). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (EPA, 1996). Specific factors used in estimating capital and annual operating costs are summarized in Table 5-1.

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
<u>Direct Capital Costs</u>	
Sales tax	0.06 x purchased equipment cost
Freight	0.05 x purchased equipment cost
Foundations and supports	0.08 x purchased equipment cost
Handling and erection	0.14 x purchased equipment cost
Electrical	0.04 x purchased equipment cost
Piping	0.02 x purchased equipment cost
Insulation	0.01 x purchased equipment cost
Painting	0.01 x purchased equipment cost
<u>Indirect Capital Costs</u>	
Engineering	0.10 x purchased equipment cost
Construction and field expenses	0.05 x purchased equipment cost
Contractor fees	0.10 x purchased equipment cost
Start-up	0.02 x purchased equipment cost
Performance testing	0.01 x purchased equipment cost
Contingencies	0.03 x purchased equipment cost
<u>Direct Annual Operating Costs</u>	
Supervisor labor	0.15 x total operator labor cost
Maintenance labor	1.10 x operator labor direct wage
Maintenance materials	1.00 x total maintenance labor cost
<u>Indirect Annual Operating Costs</u>	
Overhead	0.60 x total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 x total capital investment
Property taxes	0.01 x total capital investment
Insurance	0.01 x total capital investment

Source: EPA, 1996.

The fifth and final step is the selection of a BACT emission limitation or a design, equipment, work practice, operational standard, or combination thereof, corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

As indicated in Section 3.3, Table 3-2, projected annual emission rates of CO, VOC, PM/PM₁₀, SO₂, and H₂SO₄ mist for Smith Unit 3 exceed the PSD significance rates and, therefore, are subject to BACT analysis. Control technology analyses using the five-step top-down BACT method are provided in Sections 5.3, 5.4, and 5.5 for combustion products (PM/PM₁₀), products of incomplete combustion (CO and VOC), and acid gases (SO₂, and H₂SO₄ mist), respectively.

5.2 FEDERAL AND FLORIDA EMISSION STANDARDS

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR Part 60), NESHAP (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

On the federal level, emissions from gas turbines are regulated by NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the LHV of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated base load at International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines which sell more than one-third of their potential electric output to any

utility power distribution system. The Smith Unit 3 CTGs qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO₂ emission limitations of NSPS 40 CFR 60, Subpart GG, § 60.332(a)(1) and § 60.333, respectively.

The Smith Unit 3 DBs each have a rated heat input greater than 250 MMBtu/hr and, therefore, are subject to the requirements of NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*. Specifically, emissions from the DBs are limited to no more than 0.03 lb PM/MMBtu per §60.42a(a)(1); 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity per §60.42a(b); 0.20 lb SO₂/MMBtu (30-day rolling average) per §60.43a(b)(2); and 1.6 lb NO_x/MW-hr (30-day rolling average) per §60.43a(d)(1). The proposed Smith Unit 3 has no applicable NESHAP requirements.

FDEP emission standards for stationary sources are contained in Chapters 62-296, F.A.C., *Stationary Sources—Emission Standards*. Chapter 62-296, F.A.C., contains general emission standards for sources emitting PM (Section 62-296.320, F.A.C.) which are not applicable to Smith Unit 3 but are applicable to the Lansing Smith facility. Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through 62-296.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTGs. Rule 62-296.405(2) contains visible emissions, PM, SO₂, and NO_x limitations for new fossil fuel steam generators with more than 250 MMBtu/hr heat input which are applicable to the Smith Unit 3 DBs. For each air contaminant, Rule 62-296.405(2) references Rule 62-204.800(7) and 40 CFR Subpart Da. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subpart Da.

Emission standards applicable to sources located in nonattainment areas are contained in Sections 62-296.500 (for ozone nonattainment and maintenance areas) and 62-296.700, F.A.C. (for PM nonattainment and maintenance areas). Because Smith Unit 3 will be lo-

cated in Bay County, Florida, and because this county is designated attainment for all criteria pollutants, these emission standards are not applicable. Finally, Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines*, and Subpart Da, *Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*, are applicable to the Smith Unit 3 CTGs and DBs, respectively. There are no applicable NESHAP requirements.

Applicable federal and state emission standards are summarized in Tables 5-2 and 5-3, respectively. Detailed calculations of NSPS Subpart GG NO_x limitations are provided in Attachment C. BACT emission limitations proposed for Smith Unit 3 are all more stringent than the applicable federal and state standards cited in these tables.

5.3 BACT ANALYSIS FOR PM/PM₁₀

PM/PM₁₀ emissions resulting from the combustion of natural gas are due to oxidation of ash and sulfur contained in the fuel. Due to its low ash and sulfur content, natural gas combustion generates inherently low PM/PM₁₀ emissions.

5.3.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies used for controlling PM/PM₁₀ include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large (greater than 10 microns) size particles. Particles generated from natural gas combustion are typically less than 1.0 micron in size. ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a

Table 5-2. Federal Emission Limitations

NSPS Subpart GG, Stationary Gas Turbines

<u>Pollutant</u>	<u>Emission Limitation</u>
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NO _x	STD = 0.0075 x (14.4/Y) + F
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where: STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate in kilojoules per watt hour at manufacturer's rated load, or actual measured heat rate based on LHV of fuel as measured at actual peak load. Y cannot exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen per:

FBN = fuel bound nitrogen.

<u>FBN</u> <u>(weight percent)</u>	<u>F</u> <u>(NO_x - volume percent)</u>
N ≤ 0.015	0
0.015 < N ≤ 0.1	0.04 x N
0.1 < N ≤ 0.25	0.004 + 0.0067 x (N-0.1)
N > 0.25	0.005

where: N = nitrogen content of fuel; percent by weight.

SO₂ = ≤0.015 percent by volume at 15 percent oxygen and on a dry basis; or fuel sulfur content ≤0.8 weight percent.

NSPS Subpart Da, Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.

<u>Pollutant</u>	<u>Emission Limitation</u>
NO _x	1.6 lb/MW-hr (gross output)
SO ₂	0.20 lb/MMBtu
PM	0.03 lb/MMBtu
Opacity	20 percent

Sources: 40 CFR 60, Subparts Da and GG.

Table 5-3. Florida Emission Limitations

Pollutant	Emission Limitation
General Visible Emissions Standard Rule 62-296.320(4)(b)1., F.A.C.	
• Visible emissions	< 20 percent opacity (averaged over a 6-minute period)

Source: Chapter 62-296, F.A.C.

negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95 percent for particles smaller than 2.5 microns in size.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft²). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

Wet scrubbers remove PM from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrub-

ber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

While all of these post-process technologies would be technically feasible for controlling PM/PM₁₀ emissions from CTGs and DBs, none of the above described control equipment have been applied to natural gas-fired CTGs and DBs because exhaust gas PM concentrations are inherently low. CTGs operate with a significant amount of excess air which generates large exhaust gas flow rates. The Smith Unit 3 CTGs and DBs will be fired exclusively with natural gas. Combustion of natural gas will generate low PM emissions in comparison to other fuels due to the low ash and sulfur content of natural gas. The minor PM emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM concentrations. The estimated maximum PM/PM₁₀ exhaust concentration from each CTG/DB unit is approximately 0.004 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

PM emissions will also occur due to cooling tower operation. Smith Unit 3 will include a 10-cell, induced draft counterflow cooling tower. Because of direct contact between the cooling water and ambient air, a small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large size water droplets (e.g., greater than 200 microns) constitute the majority of the drift released. These large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential PM emissions because of the fine PM formed by crystallization of the dissolved solids contained in the droplet.

The only feasible technology for controlling PM from cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. Drift eliminator configurations include herringbone (blade-type), wave form, and cellular (honeycomb) designs. Drift eliminator materials of construction include ceramics, fiber reinforced cement, metal, plastic, and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

Factors affecting cooling tower PM emission rates include drift droplet loss rate (expressed as a percent of recirculating cooling water flow rate), concentration of dissolved solids in the recirculating cooling water, and the recirculating cooling water flow rate (i.e., size of the tower).

PM emissions from the Smith Unit 3 cooling tower will be controlled using high efficiency drift eliminators achieving a drift loss rate of no more than 0.001 percent of the cooling tower recirculating water flow.

5.3.2 PROPOSED BACT EMISSION LIMITATIONS

BACT PM/PM₁₀ limits obtained from the RBLC database for natural gas-fired CTGs are provided in Table 5-4. Recent Florida BACT determinations for natural gas-fired CTGs are shown in Table 5-5. All determinations are based on the use of clean fuels and good combustion practice. Table 5-6 provides RBLC database PM BACT determinations for cooling towers. A recent Florida BACT determination for cooling towers is the determination of 0.002 percent drift loss rate made for the City of Tallahassee Purdom Unit 8.

Because post-process stack controls for PM/PM₁₀ are not appropriate for natural gas-fired CTGs and DBs, the use of good combustion practices and clean fuels is considered to be BACT. The Smith Unit 3 CTGs and DBs will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM₁₀ emission rates. Combustion efficiency, defined as the percentage of fuel that is completely oxidized in the combustion

Table 5-4. RBLC PM Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
			Issuance	Update					
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	2.5 LBS/HR (GAS)	EFFICIENT OPERATION OF THE COMBUSTION TURBINE	BACT-PSD
AL-0109	SOUTHERN NATURAL GAS	AUBURN	3/2/98	4/24/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	10.95 TPY	FUEL SPEC: NATURAL GAS	BACT-PSD
AL-0110	SOUTHERN NATURAL GAS	WARD	3/4/98	4/24/98	2-9160 HP GE MODEL M53002G NATURAL GAS TURBINES	9160 HP	10.95 TPY	FUEL SPEC: NATURAL GAS	BACT-PSD
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	4.3 LB/DAY	NATURAL GAS, AIR INTAKE COOLER, VENTING THE LUBE OIL VENT INTO THE EXHAUST STREAM OF THE TURBINE FOR OXIDATION	LAER
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT		0.012 LB/MMBTU	LUBE OIL VENT COALESCE, OPACITY LIMIT APPLIES TO LUBE OIL VENTS.	LAER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25.8 LB/H	FUEL SPEC: NATURAL GAS FIRED	OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	9.9 T/YR		OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	9.9 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	12.4 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	12.4 T/YR		OTHER
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAN	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	0.006 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	18 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	19 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOW	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	15.4 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	0.0065 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	5 LB/H	GOOD COMBUSTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	34066	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	7 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	47793	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE, GAS	1214 MMBTU/H	0.0136 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	7 LB/HR AT 20 F	FUEL SPEC: LOW SULFUR FUELS	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	0.006 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	0.0064 LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	18 LB/HR	CLEAN FUEL	BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	5 LBS/HR		BACT-PSD
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	92 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION	BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	18.3 LB/HR	NO CONTROL CLEAN FUEL	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	5 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSH	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.0023 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	0.006 LB/MMBTU	TURBINE DESIGN	BACT-PSD
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	0.006 LB/MMBTU	TURBINE DESIGN	OTHER
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	SEE P2 DESC.	COMBUSTION AIR FILTERS, GOOD COMBUSTION PRAC. AND MAINT.	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE P2	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW			BACT-PSD
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	5.3 LBS/HR	HIGH COMBUSTION EFFICIENCY	BACT-PSD
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	30.6 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE COMBUSTOR	BACT-PSD
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	0.004 LB/MMBTU GAS (BASE)	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL	BACT-OTHER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	0.004 LB/MMBTU, GAS	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL	BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	33816	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	0.0062 LB/MMBTU	COMBUSTION CONTROLS	BACT-OTHER
NY-0048	KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	11/5/92	9/13/94	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COUR	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.035 LB/MMBTU	FUEL SPEC: USE OF NATURAL GAS	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	380 MMBTU/HR	8 LB/HR		BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	0.0015 % OF FLOW	TWO STAGE MIST ELIMINATOR TO RESTRICT DRIFT.	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	12 LB/HR	GOOD COMBUSTION PRACTICES, FUEL SPEC: USE OF NG/LPG.	BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	35339	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	59 LB/HR	GOOD COMBUSTION PRACTICES, FUEL SPEC: USE OF NG/LPG.	BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	0.005 LB/MMBTU, GAS		BACT-PSD
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	45 LBS/HR	FUEL SPEC: LOW ASH CONTENT FUELS	BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT.GAS FIRED (3 - 1 SPARE) AND 2 BOILERS	54.6 MM BTU/HR TURBINES	3.79 TPY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK	BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	34456	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	52 TPY	INTERNAL COMBUSTION CONTROLS	BACT
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6000 HRS/YR	96.3 TPY	USE OF CLEAN LOW ASH FUEL	BACT/NSPS
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6000 HRS/YR	96.3 TPY	USE OF CLEAN LOW ASH FUEL	BACT/NSPS

Source: RBLC 1999.

Table 5-5. Florida BACT PM Emission Limitation Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size		PM Emission Limit		Control Technology
		MW	MMBtu/hr	lb/hr	lb/MMBtu	
08/17/92	Orlando Cogeneration, L.P.	79	857	9.0	0.01	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,214	10.5	0.0134	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	367	(9.0)	0.0245	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	869	(8.7)	0.0100	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,615	9.0	(0.0056)	Combustion design and clean fuels
09/28/93	Florida Gas Transmission	N/A	32	0.64	N/A	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,755	17.0	0.013	Combustion design and clean fuels
02/25/94	Florida Power Corp. Polk County Site	235	1,510	9.0	0.006	Combustion design and clean fuels
03/07/95	Orange Cogeneration, L.P.	39	388	5.0	(0.013)	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	403	5.0	0.0065	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	971	7.0	(0.0072)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		7.0		Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,468	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,174	—	—	Combustion design and clean fuels
09/29/98	Florida Power Corporation Hines Energy Center	165	1,757	15.6	(0.0089)	Combustion design and clean fuels
11/25/98	Florida Power & Light Fort Myers Repowering	170	1,760	—	—	Combustion design and clean fuels
12/04/98	Santa Rosa Energy LLC	167	1,780	—	—	Combustion design and clean fuels

Note: () = calculated values.

Source: FDEP, 1999.

Table 5-6. RBLC PM Summary - Cooling Towers

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate	Emission Limits	Control System Description	Basis
			Issuance	Last Update					
CA-0713	TEXACO REFINING AND MARKETING, INC.	BAKERSFIELD	1/19/96	11/23/96	COOLING TOWER	18,000 GAL PER MIN	30.2 LB/DAY	CELLULAR TYPE DRIFT ELIMINATOR	BACT-OTHER
FL-0050	FLORIDA POWER CORPORATION	CRYSTAL RIVER	8/30/90	5/14/93	COOLING TOWER, 4 EACH	735,000 G/M SALT WATER	0.004 % OF CIRCULATION WATER	DRIFT ELIMINATOR	BACT-PSD
NJ-0016	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	9/4/92	8/8/94	COOLING TOWER, MECHANICAL DRAFT	27,000,000 LB/H H2O RECIRC.	0.909 LB/HR	DRIFT ELIMINATOR	BACT-PSD
NJ-0019	CROWN/VISTA ENERGY PROJECT (CVEP)	WEST DEPTFORD	10/1/93	8/31/94	COOLING TOWER (2)		5.9 LB/HR	DRIFT ELIMINATOR	BACT-PSD

Source: RBLC, 1999.

process, is projected to be greater than 99 percent. The CTGs and DBs will be fired exclusively with natural gas. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM₁₀ concentrations and consistent with recent FDEP BACT determinations for CTGs, a visible emissions limit of 10 percent opacity is proposed as a surrogate BACT limit for PM/PM₁₀.

5.4 BACT ANALYSIS FOR CO AND VOC

CO and VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO and VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of CO and VOC will generally increase during turbine partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam for NO_x control will also result in an increase in CO and VOC emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO and VOC emission rates. Emissions of NO_x and CO/VOC are inversely related; i.e., decreasing NO_x emissions will result in an increase in CO and VOC emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in NO_x and CO/VOC formation in order to develop units which achieve acceptable emission levels for all three pollutants.

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO and VOCs from gas turbines and duct burners: (1) combustion process design and (2) oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTGs, approximately 99 percent, CO and VOC emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOCs to carbon dioxide (CO₂) and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO and VOCs up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F; higher temperatures on the order of 900°F are needed to oxidize VOCs. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 percent for CO. VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using an oxidation catalyst control system is 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOCs. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been

oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be technically feasible for combustion devices that are fired with fuels containing appreciable amounts of sulfur.

Technical Feasibility

Both CTG combustor design and oxidation catalyst control systems are considered to be technically feasible for the Smith Unit 3 CTGs and DBs. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO and VOC are provided in the following sections.

5.4.2 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO and VOC emissions.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs and DBs fired with natural gas.

Because CO and VOC emission rates from CTGs and DBs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements; i.e., below the defined PSD significant impact levels for CO and negligible reductions in ambient VOC levels. The location of Smith Unit 3 (Bay County, Florida) is classified attainment for all criteria pollutants. From an air quality perspective, the only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. The catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2 . Dispersion modeling of CO emissions

from Smith Unit 3 indicate that maximum CO impacts, without oxidation catalyst, will be insignificant.

The application of oxidation catalyst technology to a gas turbine will result in an increase in back pressure on the CTG due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for the Smith Unit 3 CTGs is projected to have a pressure drop across the catalyst bed of approximately 1.0 inch of water (H₂O). This pressure drop will result in a 0.2 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 2,978,400 kilowatt-hours (kwh) (10,163 MMBtu) per year at base load (170-MW) operation and 100 percent capacity factor per CTG. This energy penalty is equivalent to the use of 19.4 million cubic feet (ft³) of natural gas annually based on a natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft³) for both CTGs. The lost power generation energy penalty, based on a power cost of \$0.0186/kwh, is \$110,975 per year for both CTGs.

5.4.3 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors previously summarized in Table 5-1 and project-specific economic factors provided in Table 5-7. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 5-8 and 5-9.

The base case Smith Unit 3 (i.e., for both CTG/HRSG units) annual CO emission rate is 701.3 tpy. The controlled annual CO emission rate, based on an 80 percent control efficiency, is 140.3 tpy. Base case and controlled CO emission rates are summarized in Table 5-10.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be \$1,567 per ton of CO removed. Based on the high control costs, use of oxidation catalyst

Table 5-7. Economic Cost Factors

Factor	Units	Value
Interest rate	%	8.51
Control system life	Years	15
Oxidation catalyst life	Years	3
Electricity cost	\$/kwh	0.01863
Labor costs (base rates)	\$/hour	
Operator		24.50
Maintenance		24.50

Sources: ECT, 1999.
Gulf, 1999.

Table 5-8. Capital Costs for Oxidation Catalyst System, Two CTGs

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Purchased equipment	1,457,778	A
Sales tax	87,467	0.06 x A
Freight	72,889	0.05 x A
Installation		
Foundations and supports	129,451	0.08 x A
Handling and erection	226,539	0.14 x A
Electrical	64,725	0.04 x A
Piping	32,363	0.02 x A
Insulation for ductwork	16,181	0.01 x A
Painting	16,181	0.01 x A
Subtotal Installation Cost	485,440	
Subtotal Direct Costs	2,103,573	
<u>Indirect Costs</u>		
Engineering	161,813	0.10 x A
Construction and field expenses	80,907	0.05 x A
Contractor fees	161,813	0.10 x A
Startup	32,363	0.02 x A
Performance test	16,181	0.01 x A
Contingency	48,544	0.03 x A
Subtotal Indirect Costs	501,621	
TOTAL CAPITAL INVESTMENT	2,605,195	(TCI)

Source: ECT, 1999.

Table 5-9. Annual Operating Costs for Oxidation Catalyst System, Two CTGs

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Catalyst costs		
Replacement (materials and labor)	1,568,000	
Credit for used catalyst	(192,000)	
Subtotal Catalyst Costs	1,376,000	
Annualized Catalyst Costs	538,855	
Energy Penalties		
Turbine backpressure	110,975	
Subtotal Direct Costs	649,830	(TDC)
<u>Indirect Costs</u>		
Administrative charges	52,104	0.02 x TCI
Property taxes	26,052	0.01 x TCI
Insurance	26,052	0.01 x TCI
Capital recovery	124,974	
Subtotal Indirect Costs	229,182	
TOTAL ANNUAL COST	879,012	

Sources: ECT, 1999.
Gulf, 1999.

Table 5-10. Summary of CO BACT Analysis

Control Option	Emission Impacts		Emission Reduction (tpy)	Economic Impacts			Energy Impacts Increase Over Baseline (MMBtu/yr)	Environmental Impacts	
	Emission Rates			Installed Capital Cost (\$)	Total Annualized Cost (\$/yr)	Cost Effectiveness Over Baseline (\$/ton)		Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
	(lb/hr)	(tpy)							
Oxidation catalyst	32.0	140.3	561.1		879,012	1,567	20,326	Y	Y
Baseline	160.1	701.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) CTGs, 100-percent load for 7,760 hr/yr with duct burner firing at 59°F ambient temperature and 1,000 hr/yr with duct burner firing and steam power augmentation at 95°F ambient temperature.

Sources: GE, 1999.
ECT, 1999.

technology to control CO emissions is not considered to be economically feasible. Results of the oxidation catalyst economic analysis are summarized in Table 5-10.

5.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO and VOCs from CTGs and DBs is typically required only for facilities located in CO and/or ozone nonattainment areas. BACT CO and VOC limits obtained from the RBLC database for natural gas-fired CTGs are provided in Tables 5-11 and 5-12, respectively. FDEP gas turbine CO BACT determinations for the past 5 years range from 9 to 30 ppmvd with an average CO limit of 26 ppmvd. Of the 15 recent FDEP CO BACT determinations for CTGs, 13 determinations established a limit of 20 ppmvd or higher. A summary of FDEP CO and VOC BACT determinations for natural gas-fired combustion turbines for the previous 5 years is provided in Table 5-13 and 5-14.

The use of oxidation catalysts will, as previously noted, result in excessive H₂SO₄ mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H₂SO₄ mist emissions will also occur, on a smaller scale, from CTGs and DBs fired with natural gas. Because CO emission rates from CTGs and DBs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality, i.e., well below the defined PSD significant impact levels for CO.

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs. These control techniques have been considered by FDEP to represent BACT for CO and VOCs for all CTG projects permitted within the past 5 years. CO and VOC emissions from the CTG/HRSG units at base load with or without steam power augmentation, and without duct burner firing, will be less than or equal to 13 and 3 ppmvd at 15 percent oxygen, respectively. With duct burner firing and no steam power augmentation, CO and VOC emissions from the CTG/HRSG units at base load will be less than or equal to 16 and 4 ppmvd at 15 percent

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

Table 5-11. RBLC CO Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate	Emission Limit	Control System Description	Control Efficiency	Basis
			Issuance	Update						
AL-0074	FLORIDA GAS TRANSMISSION COMPANY	MOBILE	8/5/93	5/12/94	TURBINE, NATURAL GAS	12800 BHP	0.42 GM/HP-HR	AIR-TO-FUEL RATIO CONTROL, DRY COMBUSTION CONTROLS		BACT-PSD
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	28 PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES		BACT-PSD
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		BACT-PSD
AZ-0011	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		BACT-PSD
AZ-0012	EL PASO NATURAL GAS		10/18/91	7/20/94	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	60 PPM @ 15% O2	LEAN BURN		BACT-PSD
CA-0418	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	8/4/93	TURBINE, GAS-FIRED	47.64 MMBTU/H	7.74 PPM @ 15% O2	HIGH TEMPERATURE OXIDATION CATALYST	80	BACT-PSD
CA-0463	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	5/31/92	TURBINE, GAS FIRED, SOLAR MODEL H	5500 HP	7.74 PPM @ 15% O2	HIGH TEMP OXIDATION CATALYST	80	BACT-PSD
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)		10 PPM @ 15% O2	OXIDATION CATALYST	75	BACT-OTHER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	22.4 PPM @ 15% O2			BACT-PSD
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #2, GE FRAME 6	33 MW	250 T/YR, LESS THAN	CO CATALYST		OTHER
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAN	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	30 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWE	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	30 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	30 PPMVD	GOOD COMBUSTION		BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	49 LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	34066	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	40 LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE, GAS	1214 MMBTU/H	15 PPMVD	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0102	PANDA-KATHLEEN, L.P.	LAKELAND	6/1/95	5/20/96	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	25 PPM @ 15% O2	COMBUSTION CONTROLS STANDARD ONLY APPLIES TO GE CT		BACT-PSD
FL-0109	KEY WEST CITY ELECTRIC SYSTEM	KEY WEST	9/28/95	5/31/96	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	20 PPM @ 15% O2 FULL LD	GOOD COMBUSTION		BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS		BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	10 PPMVD	COMPLETE COMBUSTION		BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	12 LBS/HR	GOOD COMBUSTION; 10 PPMVD AT 15% OXYGEN.		BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	40 LBS/HR	GOOD COMBUSTION; 40 PPMVD AT 15% OXYGEN.		BACT-PSD
LA-0079	ENRON LOUISIANA ENERGY COMPANY	EUNICE	8/5/91	10/30/91	TURBINE, GAS, 2	39.1 MMBTU/H	60 PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS		BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSRG, GAS COGEN	338 MM BTU/HR TURBINE	165.9 LB/HR	COMBUSTION CONTROL		BACT
LA-0089	FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE	3/2/95	4/17/95	TURBINE/HRSRG, GAS COGENERATION	450 MM BTU/HR	25.8 LB/HR	PROPER OPERATION		BACT-PSD
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	972.4 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	BATON ROUGE	3/7/97	4/28/97	TURBINE/HRSRG, GAS COGENERATION	450 MM BTU/HR	70 LB/HR	COMBUSTION DESIGN AND CONSTRUCTION.		BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	198.6 LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE		BACT-PSD
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL GAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-OTHER
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	20 PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
MI-0206	KALAMAZOO POWER LIMITED	COMSTOCK	12/3/91	3/23/94	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1805.9 MMBTU/H	20 PPMV	DRY LOW NOX TURBINES		BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	59 LB/HR	COMBUSTION CONTROL		BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.0055 LB/MMBTU	CATALYTIC OXIDATION	80	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHI	33329	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN		BACT-OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	1.8 PPMVD	OXIDATION CATALYST		OTHER
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11257 HP	50 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	ENGINE, GAS-FIRED, RECIPROCATING	1000 HP	2.5 G/B-HP-H	CLEAN/LEAN BURN TECHNOLOGY		BACT-PSD
NM-0022	MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	CARLSBAD	1/11/95	4/26/95	TURBINES, NATURAL GAS (2)	5500 HP	13.2 LBS/HR	LEAN-PREMIEX COMBUSTION TECHNOLOGY.	66	BACT-PSD
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	27.6 PPM @ 15% O2			BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES		BACT-PSD
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	27 LBS/HR	DRY LOW-NOX TECHNOLOGY, PROPER AIR-FUEL RATIO.		BACT-PSD
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	152.5 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR		BACT-PSD
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	TURBINE, NATURAL GAS FIRED	240 MW	4 PPM @ 15% O2			LAER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	10 PPM	COMBUSTION CONTROLS		BACT-OTHER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	25 PPM	COMBUSTION CONTROL		BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	3 PPM	OXIDATION CATALYST		BACT-OTHER
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	11/24/92	9/13/94	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133 MMBTU/HR (EACH)	13 PPM	COMBUSTION CONTROLS		BACT-OTHER
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	GE LM-5000 GAS TURBINE	550 MMBTU/HR	92 LB/HR TEMP > 20F	NO CONTROLS		BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.015 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS		OTHER
OR-0010	PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	34485	8/6/97	TURBINES, NATURAL GAS (2)	1720 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
OR-0011	HERMISTON GENERATING CO.	HERMISTON	4/1/94	5/1/95	TURBINES, NATURAL GAS (2)	1696 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	110 T/YR	OXIDATION CATALYST	90	OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	9/23/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	3.1 PPM @ 15% O2	OXIDATION CATALYST 16 PPM @ 15% O2 FOR NO. 2 OIL.	80	OTHER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	50 PPMV@15%O2	GOOD COMBUSTION		BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	33 PPMVD	COMBUSTION CONTROLS		BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	100 PPMVD AT MIN. LOAD	COMBUSTION CONTROLS.		BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1380 MMBTU/H EACH	11 PPM @ 15% O2, GAS			BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	33450	5/31/92	TURBINE, GAS, 2	49 MMBTU/H	0.114 LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-OTHER
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	23 LBS/HR	GOOD COMBUSTION PRACTICES		BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	300 TPY	INTERNAL COMBUSTION CONTROLS		BACT
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6000 HRS/YR	96 TPY	GOOD COMBUSTION OPERATING PRACTICES		BACT/NSPS
WA-0027	SUMAS ENERGY INC.	SUMAS	6/25/91	8/1/91	TURBINE, NATURAL GAS	88 MW	6 PPM @ 15% O2	CO CATALYST	80	BACT-PSD
							Minimum	1.8 PPM		
							Maximum	60.0 PPM		
							Average	21.9 PPM		

Source: RBLC 1999.

Table 5-12. RBLC VOC Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate	Emission Limit	Control System Description	Control Efficiency	Basis
			Issuance	Update						
CA-0788	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	8 LB/HR	NATURAL GAS AS PRIMARY FUEL		LAER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	16.7 LB/H			OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	26.7 T/YR			OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	35.2 T/YR			OTHER
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	1.6 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWE	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	1 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35 MW	7 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	10 PPMVD	GOOD COMBUSTION		BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE, GAS	1214 MMBTU/H	6 LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	7 PPMVW	GOOD COMBUSTION PRACTICES		BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	0.003 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	6 PPMVD	COMPLETE COMBUSTION		BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG. GAS COGEN	338 MM BTU/HR TURBINE	3.6 LB/HR COMBINED	COMBUSTION CONTROLS, FUEL SELECTION		BACT
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	2 LB/HR	COMBUSTION CONTROL		BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHI	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.0046 LB/MMBTU	TURBINE DESIGN		OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	4 PPMOV	TURBINE DESIGN		BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11257 HP	25 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE P2	GOOD COMBUSTION PRACTICES		BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW				BACT-PSD
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	3/8/96	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	0.0045 LB/MMBTU	OXIDATION CATALYST		BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.1 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS		OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	105 PPM @ 15% O2	OXIDATION CATALYST	50	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	4.4 LB/HR	GOOD COMBUSTION PRACTICES		BACT-OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	9/23/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	4 PPM @ 15% O2	OXIDATION CATALYST WHEN FIRING NO. 2 OIL EMISSION LI	12	LAER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/28/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	25 PPMV@15%O2	GOOD COMBUSTION		BACT-OTHER
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	5 PPM @ 15% O2			BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	7/31/91	5/31/92	TURBINE, GAS, 2	49 MMBTU/H	0.016 LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-OTHER
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	10 LBS/HR	GOOD COMBUSTION PRACTICES		BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	77.86 LBS/DAY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK		LAER
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	38 TPY	INTERNAL COMBUSTION CONTROLS		BACT
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	5 PPMVD	COMBUSTION CONTROLS		BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	8 PPMVD	COMBUSTION CONTROL		BACT-PSD

Source: RBLC 1999.

Table 5-13. Florida BACT CO Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	30	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	15	Good combustion
02/21/94	Polk Power Partners	84	25	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	25	Good combustion
07/20/94	Pasco Cogen, Limited	42	28	Good combustion
03/07/95	Orange Cogeneration, L.P.	39	30	Good combustion
06/01/95	Panda-Kathleen	75	25	Good combustion
09/28/95	City of Key West	23	20	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
09/29/98	Florida Power Corporation Hines Energy Complex	165	25	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	12	Good combustion
12/04/98	Santa Rosa Energy, LLC	167	9	Good combustion
			24 (with duct burner)	Good combustion

Note: () = calculated values.

Source: FDEP, 1999.

Table 5-14. Florida BACT VOC Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40		Good combustion
04/09/93	Kissimmee Utility Authority	80		Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184		Good combustion
02/25/94	Florida Power Corp. Polk County Site	235		Good combustion
07/20/94	Pasco Cogen, Limited	42	28	Good combustion
03/07/95	Orange Cogeneration, L.P.	39	10	Good combustion
06/01/95	Panda-Kathleen	75		Good combustion
09/28/95	City of Key West	23		Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		Good combustion
05/98	City of Tallahassee Purdom Unit 8	160		Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	4	Good combustion
09/29/98	Florida Power Corporation Hines Energy Complex	165	7	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	1.4	Good combustion
12/04/98	Santa Rosa Energy, LLC	167	1.4	Good combustion
			84 (with duct burner)	Good combustion

Note: () = calculated values.

Source: FDEP, 1999.

oxygen, respectively. With duct burner firing and steam power augmentation, CO and VOC emissions from the CTG/HRSG units at base load will be less than or equal to 23 and 6 ppmvd as 15 percent oxygen, respectively. This latter operating condition, however, will occur for no more than 1,000 hr/yr. These CO and VOC emissions are consistent with recent FDEP BACT determinations for CTG/HRSG units; e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5. CO and VOC BACT emission limits proposed for Smith Unit 3 are summarized in Table 5-15.

5.5 BACT ANALYSIS FOR SO₂ AND H₂SO₄ MIST

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

Technologies employed to control SO₂ and H₂SO₄ mist emissions from combustion sources consist of fuel treatment and post-combustion add-on controls; i.e., flue gas desulfurization (FGD) systems.

Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas containing sulfur compounds (e.g., hydrogen sulfide), a variety of technologies are available to remove these sulfur compounds to acceptable levels. Desulfurization of natural gas is performed by the fuel supplier prior to distribution by pipeline.

Flue Gas Desulfurization

FGD systems remove SO₂ from exhaust streams by utilizing an alkaline reagent to form sulfite and sulfate salts. The reaction of SO₂ with the alkaline chemical can be performed using either a wet- or dry-contact system. FGD wet scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. In a dry FGD system, an alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO₂

Table 5-15. Proposed CO and VOC BACT Emission Limits

Emission Source	<u>Proposed CO and VOC BACT Emission Limits*</u>	
	ppmvd at 15 percent oxygen	lb/hr
GE PG7241 (FA) CTGs and DBs (Per CTG/HRSG Unit)		
A. With or Without Steam Power Augmentation, Without Duct Burner Firing		
CO	13	58
VOC	3	7
B. With Duct Burner Firing, Without Steam Power Augmentation		
CO	16	79
VOC	4	10
C. With Duct Burner Firing and Steam Power Augmentation		
CO	23	117
VOC	6	17

*Maximum rates for each operating scenario.

Sources: ECT, 1999.
 GE, 1999.
 Gulf, 1999.

are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment.

Technical Feasibility

Treatment of natural gas to remove sulfur compounds is conducted by the fuel supplier, when necessary, prior to distribution by pipeline. Accordingly, additional fuel treatment by end users is considered technically infeasible because the natural gas sulfur content has already been reduced to very low levels.

There have been no applications of FGD technology to natural gas-fired CTGs or DBs due to the low sulfur content of natural gas. The Smith Unit 3 CTGs and DBs will be fired exclusively with natural gas. The sulfur content of natural gas is more than 100 times lower than the fuels (e.g., coal) employed in boilers utilizing FGD systems. In addition, CTGs operate with a significant amount of excess air which generates high exhaust gas flow rates. Because FGD SO₂ removal efficiency decreases with decreasing inlet SO₂ concentration, application of a FGD system to a CTG/HRSG exhaust stream will result in unreasonably low SO₂ removal efficiencies. Due to low SO₂ exhaust stream concentrations, FGD technology is not considered to be technically feasible for CTGs or DBs because removal efficiencies would be unreasonably low. Similarly, use of mist eliminators to control H₂SO₄ mist emissions is not technically feasible due to the very low CTG and DB H₂SO₄ mist exhaust concentrations. For example, the Smith Unit 3 CTGs and DBs will have a H₂SO₄ mist exhaust concentration of 0.0002 grains per actual cubic foot at 100 percent load, 0°F operating conditions per CTG/HRSG unit.

5.5.2 PROPOSED BACT EMISSION LIMITATIONS

Because post-combustion SO₂ and H₂SO₄ mist controls are not applicable, use of low sulfur fuel is considered to represent BACT for the Smith Unit 3 CTGs and DBs. Natural gas utilized at Smith Unit 3 will be pipeline-quality. Emissions of H₂SO₄ mist were estimated based on a 7.5 percent conversion rate of SO₂ to H₂SO₄ mist. BACT for SO₂ and H₂SO₄ mist for Smith Unit 3 is the use of pipeline quality natural gas.

5.6 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Control technologies proposed as BACT for each pollutant subject to review are summarized in Table 5-16. Specific proposed BACT emission limits for each pollutant are summarized in Table 5-16.

Table 5-16. Summary of BACT Control Technologies

Pollutant	Control Technology
A. GE PG7241 (FA) CTGs and DBs	
PM/PM ₁₀	<ul style="list-style-type: none"> • Exclusive use of low-ash and low-sulfur natural gas • Efficient combustion
CO and VOC	<ul style="list-style-type: none"> • Efficient combustion
SO ₂ /H ₂ SO ₄ mist	<ul style="list-style-type: none"> • Exclusive use of low-sulfur natural gas
B. Cooling Tower	
PM/PM ₁₀	<ul style="list-style-type: none"> • Efficient mist eliminators

Source: ECT, 1999.

Table 5-17. Summary of Proposed BACT Emission Limits

Emission Source	Pollutant	<u>Proposed BACT Emission Limits*</u>	
		(ppmvd) †	(lb/hr)
GE PG7241 (FA) CTGs and DBs (Per CTG/HRSG Unit)			
A. All Operating Scenarios			
	PM/PM ₁₀		10% opacity
	SO ₂		Pipeline quality natural gas
	H ₂ SO ₄ mist		Pipeline quality natural gas
B. With or Without Steam Power Augmentation, Without Duct Burner Firing			
	CO	13	58
	VOC	3	7
C. With Duct Burner Firing, Without Steam Power Augmentation			
	CO	16	79
	VOC	4	10
D. With Duct Burner Firing and Steam Power Augmentation			
	CO	23	117
	VOC	6	17

2.1.1.1.1 Cooling Tower

PM/PM ₁₀	Drift eliminators
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*Maximum rates for each operating scenario.

†Corrected to 15 percent oxygen.

Sources: ECT, 1999.
 GE, 1999.
 Gulf, 1999.

6.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

The approach used to analyze the potential impacts of the proposed facility, as described in detail in the following sections, was developed in accordance with accepted regulatory agency practice. Guidance contained in EPA manuals and users' guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, Smith Unit 3 will have the potential to emit 757 tpy NO_x; 701 tpy of CO; 253 tpy of PM/PM₁₀; 105 tpy of SO₂; 93 tpy of VOCs; and 12 tpy of H₂SO₄ mist. Due to the contemporaneous installation of low-NO_x burners and an improved burner management system for Lansing Smith Unit No. 1, a federally enforceable NO_x emissions cap of 3,587 tpy, using CEMS to demonstrate compliance, for Smith Units 1 and 3 is requested to achieve a net reduction of 9 tpy in NO_x emissions from the Lansing Smith Plant following construction of Smith Unit 3. Accordingly, total annual Lansing Smith Plant NO_x emissions will be decreased from historical levels following installation of Unit 3. A comparison of estimated potential annual emission rates for Smith Unit 3 and the PSD significant emission rate thresholds was previously provided in Table 3-2. As shown in that table, potential emissions of PM, PM₁₀, SO₂, CO, VOC, and H₂SO₄ mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR air quality impact analysis requirements of Rule 62-212. 400(5)(d), F.A.C.

The ambient impact analysis addresses PM, PM₁₀, SO₂, CO, and H₂SO₄ mist. Modeled impacts of H₂SO₄ mist were compared to FDEP's 8- and 24-hour draft ambient reference concentrations (ARCs) for this pollutant. Because VOCs contribute to the formation of ground-level ozone and because ozone modeling is conducted on a regional scale, modeling of VOC emissions resulting from the operation of Smith Unit 3 was not conducted.

6.3 MODEL SELECTION AND USE

For this study, air quality models were applied at two levels. The first, or screening, level provided conservative estimates of impacts from the cogeneration units. The purposes of the screening modeling were to:

- Eliminate the need for more sophisticated analysis in situations with low predicted impacts and no threat to any standard.
- Provide information to guide the more rigorous refined analysis, including the operating mode (load and ambient temperature) which caused the highest ambient impact for each criteria pollutant.

The second, or refined, level encompassed a more detailed treatment of atmospheric processes. Refined modeling required more detailed and precise input data, but is presumed to have provided more accurate estimates of source impacts.

6.3.1 SCREENING MODELS

For screening purposes, the SCREEN3 model, Version 96043, is recommended and was used in this analysis. SCREEN3 is a simple model that calculates 1-hour average concentrations over a range of pre-defined worst-case meteorological conditions. SCREEN3 also includes algorithms to assess building wake downwash. SCREEN3 also includes algorithms for analyzing concentrations on simple and complex terrain.

The proposed CTG/HRSG units may operate under a variety of operating scenarios. These scenarios include different loads, ambient air temperatures, and the use of evaporative coolers, supplemental duct burner firing, and steam power augmentation. Plume dispersion and, therefore, ground-level impacts, will be affected by these different operating scenarios because emission rates, exit temperatures, and exhaust gas velocities will change. Each of the operating scenarios was evaluated for each pollutant of concern to identify the scenario which caused the highest impact. These worst-case operating scenarios were then subsequently evaluated using the refined ISC dispersion model. The two CTG/HRSG stacks were collocated for screening modeling purposes since: (1) the two

point sources will emit the same pollutant(s); (2) they both will have identical stack heights, volumetric flow rates, and stack gas exit temperatures; and (3) the stacks are situated relatively close to each other. A nominal emission rate of 10.0 grams per second (g/s) was used for all SCREEN3 model runs. The SCREEN3 model results were then adjusted to reflect maximum emission rates for each operating case; i.e., model results were multiplied by the ratio of maximum emission rates (in g/s) to 10.0 g/s. Screening modeling results are summarized in Section 7.0, Table 7-1 through 7-5. These tables show, for each operating scenario and pollutant evaluated, the SCREEN3 unadjusted 1-hour average maximum impact, emission rate adjustment ratio, and the adjusted SCREEN3 1-hour average maximum impact.

6.3.2 REFINED MODELS

The most recent regulatory version of the Industrial Source Complex (ISC) models (EPA, 1998) is recommended and was used in this analysis for refined modeling. The ISC3 models are steady-state Gaussian plume models that can be used to assess air quality impacts over simple terrain from a wide variety of sources. The ISC3 models are capable of calculating concentrations for averaging times ranging from 1 hour to annual. For this study, the ISC3 short-term (ISCST3, Version 98356) model was used to calculate short-term ambient impacts with averaging times between 1 and 24 hours as well as long-term annual averages.

Procedures applicable to the ISCST3 dispersion model specified in EPA's *Guideline for Air Quality Models* (GAQM) were followed in conducting the refined dispersion modeling. The GAQM is codified in Appendix W of 40 CFR Part 51. In particular, the ISCST3 model control pathway MODELOPT keyword parameters DFAULT, CONC, RURAL, and NOCMPL were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC, RURAL, and NOCMPL parameters specify calculation of concentrations, use of rural dispersion, and suppression of complex terrain calculations, respectively. As previously mentioned, the ISCST3 model was also used to determine annual average impact predictions, in ad-

dition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword. Conservatively, no consideration was given to pollutant exponential decay.

6.4 DISPERSION OPTION SELECTION

Area characteristics in the vicinity of proposed emission sources are important in determining model selection and use. One important consideration is whether the area is rural or urban, since dispersion rates differ between these two classifications. In general, urban areas cause greater rates of dispersion because of increased turbulent mixing and buoyancy-induced mixing. This is due to the combination of greater surface roughness caused by more buildings and structures and greater amount of heat released from concrete and similar surfaces. EPA guidance provides two procedures to determine whether the character of an area is predominantly urban or rural. One procedure is based on land use typing and the other is based on population density. The land use typing method utilizes the work of Auer (Auer, 1978) and is preferred by EPA and FDEP because it is meteorologically oriented. In other words, the land use factors employed in making a rural/urban designation are also factors that have a direct effect on atmospheric dispersion. These factors include building types, extent of vegetated surface area and water surface area, types of industry and commerce, etc. Auer recommends that these land use factors be considered within 3 km of the source to be modeled to determine urban or rural classifications. The Auer land use typing method was used for the ambient impact analysis.

The Auer technique recognizes four primary land use types: industrial (I), commercial (C), residential (R), and agricultural (A). Practically all industrial and commercial areas come under the heading of urban while the agricultural areas are considered rural. However, those portions of generally industrial and commercial areas that are heavily vegetated can be considered rural in character. In the case of residential areas, the delineation between urban and rural is not as clear. For residential areas, Auer subdivides this land use type into four groupings based on building structures and associated vegetation. Accurate classification of the residential areas into proper groupings is important to determine the most appropriate land use classification for the study area.

USGS 7.5-minute series topographic maps for the area were used to identify the land use types within a 3-km radius area of the proposed site. Based on this analysis, more than 50 percent of the land use surrounding the plant was determined to be rural under the Auer land use classification technique. Therefore, rural dispersion coefficients and mixing heights were used for the Ambient Impact Analysis.

6.5 TERRAIN CONSIDERATION

The GAQM defines *flat terrain* as terrain equal to the elevation of the stack base, *simple terrain* as terrain lower than the height of the stack top, and *complex terrain* as terrain above the height of the plume center line (for screening modeling, *complex terrain* is terrain above the height of the stack top). Terrain above the height of the stack top but below the height of the plume center line is defined as *intermediate terrain*.

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of the proposed Smith Unit 3 (i.e., within an approximate 10-km radius). Base elevation of the site is approximately 10 feet above mean sea level (ft-msl). Highest elevations in the vicinity of the site are approximately 20 ft-msl. Site base elevation plus CTG/HRSG stack height (i.e., 10 + 125) is 135 ft-msl. Accordingly, terrain in the vicinity of the site would be classified as ranging from *flat* to *simple terrain*. Due to the minimal amount of terrain elevation differences in the vicinity, assignment of receptor terrain elevations was not conducted; i.e., all receptors were assumed to be at the same elevation as the CTG/HRSG stack base for modeling purposes.

6.6 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

The CAA Amendments of 1990 require the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds good engineering practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated fi-

nal stack height regulations (40 CFR 51). GEP stack height is defined as the highest of 65 meters, or a height established by applying the formula:

$$H_g = H + 1.5 L$$

where: H_g = GEP stack height.

H = height of the structure or nearby structure.

L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While GEP stack height regulations require that stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The stack height proposed for the CTG/HRSG units (125 ft) is less than the *de minimis* GEP height of 65 meters (213 ft) and, therefore, complies with the EPA promulgated final stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height which can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. The ISC dispersion models contain two algorithms that assess the effect of building downwash; these algorithms are referred to as the Huber-Snyder and Schulman-Scire methods. The following steps are employed in determining the effects of building downwash:

- A determination is made as to whether a particular stack is located in the area of influence of a building (i.e., within five times the lesser of the building's height or projected width). If the stack is not within this area, it will not be subject to downwash from that building.

- If a stack is within a building's area of influence, a determination is made as to whether it will be subject to downwash based on the heights of the stack and building. If the stack height to building height ratio is equal to or greater than 2.5, the stack will not be subject to downwash from that building.
- If both conditions in Items 1 and 2 are satisfied (a stack is within the area of influence of a building and has a stack height to building height ratio of less than 2.5), the stack will be subject to building downwash. The determination is then made as to whether the Huber-Snyder or Schulman-Scire downwash method applies. If the stack height is less than or equal to the building height plus one-half the lesser of the building height or width, the Schulman-Scire method is used. Conversely, if the stack height is greater than this criterion, the Huber-Snyder method is employed.
- The ISCST3 downwash input data consists of an array of 36 wind direction-specific building heights and projected widths for each stack. LB is defined as the lesser of the height and projected width of the building. For directionally dependent building downwash, wake effects are assumed to occur if a stack is situated within a rectangle composed of two lines perpendicular to the wind direction, one line at 5 LB downwind of the building and the other at 2 LB upwind of the building, and by two lines parallel to the wind, each at 0.5 LB away from the side of the building.

For the ambient impact analysis, the complex downwash analysis described above was performed using the current version of EPA's Building Profile Input Program (BPIP—Version 95086). The EPA BPIP program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. Dimensions of the building/structures evaluated for wake effects are shown in Table 6-1; the locations of these buildings/structures were previously provided on Figure 2-2. BPIP output consists of an

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions		
	<u>Width</u> (meter)	<u>Length</u> (meter)	<u>Height</u> (meter)
Heat Recovery Steam Generators	18.3	30.5	33.5
Cooling Tower	34.7	81.4	17.4

Sources: ECT, 1999.
Gulf, 1999.

array of 36 direction-specific (10 to 360°) building heights and projected building widths for each stack suitable for use as input to the ISCST3 model.

6.7 RECEPTOR GRIDS

Receptors were placed at locations considered to be *ambient air*, which is defined as “that portion of the atmosphere, external to buildings, to which the general public has access.” The entire perimeter of the plant site, excluding natural barriers, will be fenced; therefore, the nearest locations of general public access are at the facility property lines.

Consistent with GAQM recommendations, the ambient impact analysis utilized the following receptor grids:

- Fence Line Receptors: Receptors placed on the site boundary spaced 100 meters apart.
- Near-Field Discrete Receptors: Cartesian receptors placed at 100-meter spacings from the site to the first near-field polar receptor ring
- Near-Field Polar Receptors: Receptor rings (with 36 receptors per ring at 10° intervals) starting from the site and extending to 2.9 km at 100-meter spacings.
- Mid-Field Polar Receptors: Receptor rings (with 36 receptors per ring at 10° intervals) starting 3 km from the site and extending to 5 km at 250-meter spacings.
- Far-Field Polar Receptors: Receptor rings (with 36 receptors per ring at 10° intervals) starting 5.5 km from the site and extending to 10 km at 500-meter spacings.

Each polar receptor ring was offset 5° from the previous ring to improve the spatial distribution.

A graphical representation of the receptor grids (out to a distance of 3 km) is provided in Figure 6-1. A depiction of the receptor grids (from 3 to 10 km) is shown in Figure 6-2.

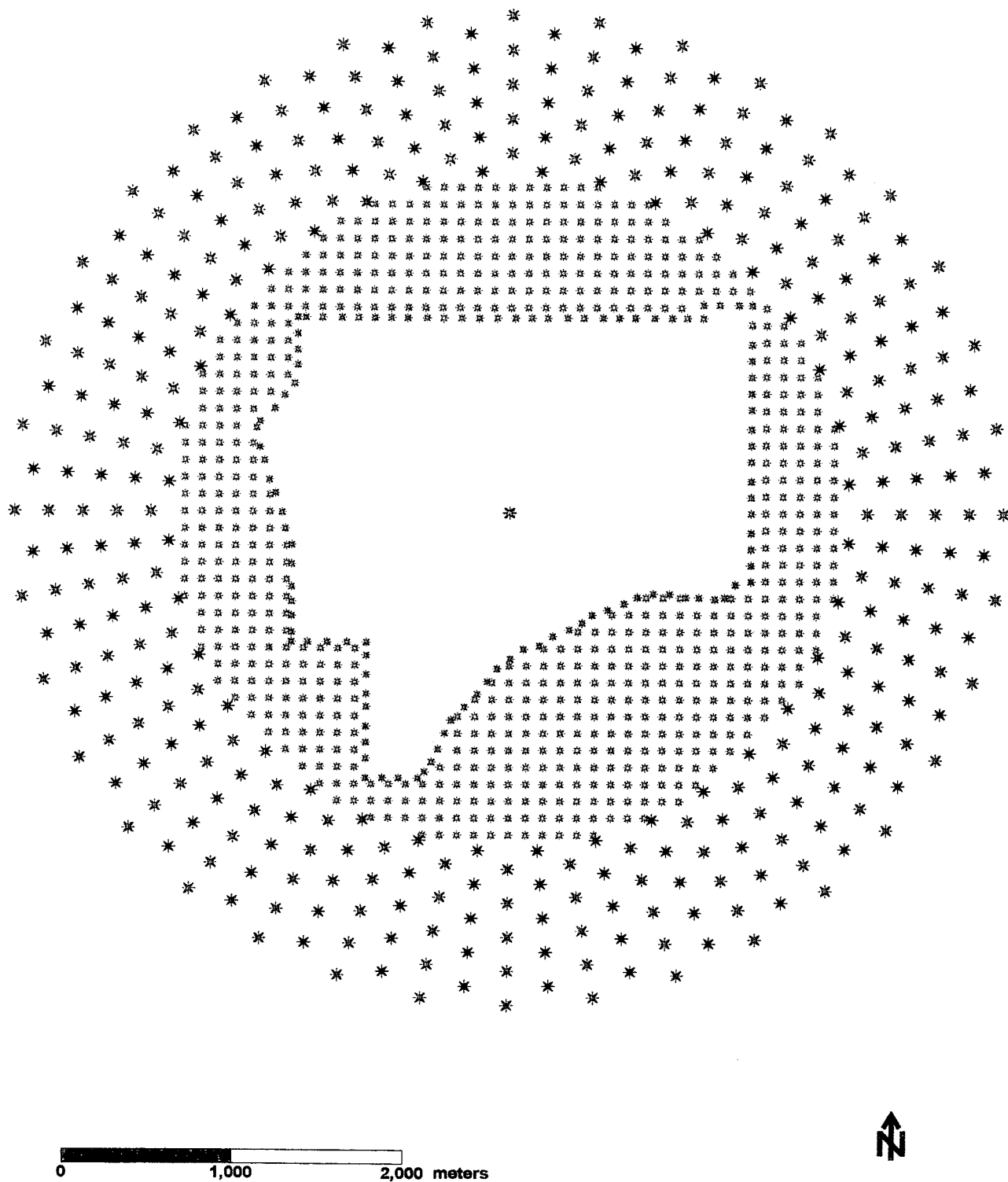


FIGURE 6-1.

RECEPTOR LOCATIONS (WITHIN 1 KM)

Source: ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

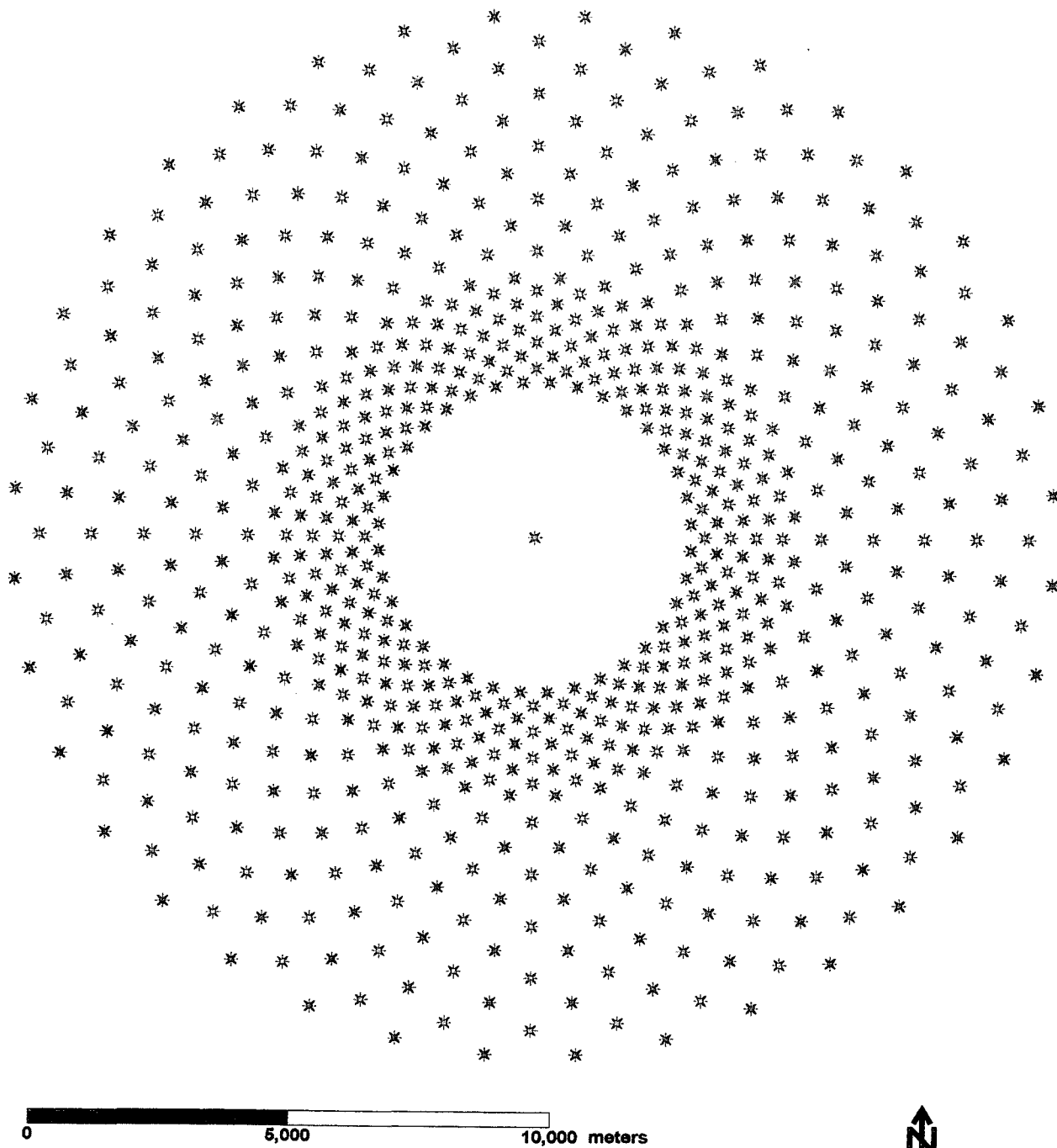


FIGURE 6-2.

RECEPTOR LOCATIONS (FROM 3 TO 10 KM)

Source: ECT, 1999.

ECT

Environmental Consulting & Technology, Inc.

6.8 METEOROLOGICAL DATA

Detailed meteorological data are needed for modeling with the ISC dispersion models. The ISCST3 model requires a preprocessed data file compiled from hourly surface observations and concurrent twice-daily rawinsonde soundings (i.e., mixing height data).

There are no onsite surface or upper meteorological stations. The nearest offsite surface meteorological station is located at the Apalachicola Municipal Airport approximately 88 km (55 miles) southeast of Smith Unit 3 site. The nearest offsite upper air meteorological station is also located at the Apalachicola Municipal Airport. The surface meteorological station at Pensacola Regional Airport is located approximately 145 km (90 miles) west, northwest of Smith Unit 3 site.

Short-Term Meteorological Data

Consistent with the GAQM and FDEP guidance, 5 consecutive years of the most recent, readily available, representative meteorological data were processed for the ambient impact analysis. For Bay County, FDEP recommends use of Pensacola and Apalachicola surface and Apalachicola upper air meteorological data in conducting the air quality analyses. As recommended by FDEP, 1986 and 1987 Pensacola surface (Pensacola Regional Airport—Station No. 13899), 1988 through 1990 Apalachicola surface (Apalachicola Municipal Airport—Station No. 12832), and 1986 through 1990 Apalachicola upper air meteorological data were used in the Ambient Impact Analysis.

The surface and mixing height data for each of the 5 years were processed using the current version of EPA's PCRAMMET (Version 95300) meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model. PCRAMMET input files consist of the surface and mixing height files as obtained from the EPA SCRAM website. The mixing height file for each year must include mixing height records for December 31 of the year preceding the year of record and for January 1 of the year following the year of record. If records for these 2 days are un-

available, duplicate mixing height records are used with the year, month, and day changed appropriately.

In addition to the surface and mixing height meteorological data files, PCRAMMET requires input with respect to: (a) the use of dry or wet deposition calculations; (b) output filename; (c) output file type (UNFORM or ASCII); (d) surface data format (CD144, SAMSON, or SCRAM); and (e) latitude, longitude, and time zone of the surface meteorological station. In processing the Apalachicola and Pensacola meteorological data, the NONE deposition option was selected, ASCII output file chosen, and the SCRAM surface data format utilized. As obtained from the EPA SCRAM web site, Apalachicola surface station latitude and longitude coordinates (in decimal degrees) are 29.733 and 85.033, respectively. The Pensacola surface station latitude and longitude coordinates (in decimal degrees) are 30.467 and 87.200, respectively. The Apalachicola and Pensacola surface stations are located in time zones 5 and 6, respectively.

Actual anemometer height for the Apalachicola surface station, obtained from the National Climatic Data Center (NCDC), is 30 ft (9.1 meters) for the time period of interest (i.e., 1988 through 1990). Actual anemometer height for the Pensacola surface station is 22 ft (6.7 meters) for the time period of interest (i.e., 1986 and 1987).

Processing of the Apalachicola and Pensacola station meteorological data did not require any data replacement or substitution.

6.9 MODELED EMISSION INVENTORY

6.9.1 ON-PROPERTY SOURCES

On-property emission sources addressed in the ambient impact analysis consisted of the two CTG/HRSG units and the mechanical draft cooling tower.

Emission rates and stack parameters for the CTG/HRSG units were previously presented in Tables 2-1 through 2-4. Model input parameters for the mechanical draft cooling tower

include a PM/PM₁₀ emission rate of 15.7 lb/hr (1.98 g/s), stack height of 57 ft (17.4 meters), equivalent stack diameter of 104.4 ft (31.8 meters), exhaust temperature of 68°F (293 Kelvin), and an exhaust velocity of 22.9 feet per second (7.0 meters per second).

6.9.2 OFF-PROPERTY SOURCES

As will be discussed in Section 7.0, maximum air quality impacts are projected to be below the PSD significant impact levels for all pollutants defined in Rule 62-210.200(259), F.A.C., with the exception of PM/PM₁₀. Accordingly, a full, multi-source interactive assessment of PM₁₀ NAAQS attainment and PSD Class II increment consumption was not required for Smith Unit 3.

An inventory of PM/PM₁₀ emission sources within approximately 75 km of Smith Unit 3 was obtained from FDEP. A summary of the FDEP off-property PM₁₀ emission sources is provided on Table 6-2.

Off-property PM/PM₁₀ emission sources included in the dispersion modeling analysis for the Smith Unit 3 consisted of all emission sources listed on Table 6-2 located within 53 km of the project site; i.e., within the 2.2-km area of impact (AOI) distance plus 50 km, having data available for modeling purposes. Smith Units 1 and 2 are ducted to a common stack. Emission source data for Smith Units 1 and 2 and the existing combustion turbine were revised to reflect current data as obtained from Gulf's Title V permit application and recent stack test data. A summary of the modeled off-property PM/PM₁₀ emission sources is provided on Table 6-3.

Table 6-2. FDEP Off-Property PM₁₀ Emission Inventory

Company Name	EU ID	UTM Coordinates (km)		Distance From Unit 3 (km)	Relative Coordinates		PM Emission Rates			Stack Parameters			
		Northing (km)	Easting (km)		Y (m)	X (m)	(lb/hr)	(g/s)	(tpy)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
ALABAMA ELECTRIC COOPERATIVE	1	3,383.5	575.1	61.1	-34,500	50,400			2.40	7.6	824.8	64.61	0.30
ANDERSON COLUMBIA CO INC #6	1	3,362.8	648.8	27.1	-13,780	-23,290	18.000	2.268	27.00	9.8	435.9	21.03	1.22
ANDERSON COLUMBIA CO., INC.	1	3,401.2	672.1	70.0	-52,190	-46,620	14.360	1.809	7.98	7.0	366.5	29.59	1.16
ANDERSON COLUMBIA COMPANY, INC.	1	3,404.5	677.0	75.7	-55,500	-51,500	38.590	4.862	40.13	10.7	322.0		1.31
ANDERSON MATERIALS CO., INC.	1	3,401.3	672.3	70.2	-52,250	-46,810			49.00				
ARIZONA CHEMICAL COMPANY	14	3,335.4	633.1	15.6	13,600	-7,600	17.500	2.205	76.65	30.5	510.9	22.55	1.22
ARIZONA CHEMICAL COMPANY	15	3,335.4	633.1	15.6	13,600	-7,600	17.500	2.205	76.65	30.5	466.5	17.37	1.22
ARIZONA CHEMICAL COMPANY	19	3,335.4	633.1	15.6	13,600	-7,600	0.073	0.009	0.32	6.1	298.2		6.71
ARIZONA CHEMICAL COMPANY	28	3,335.4	633.1	15.6	13,600	-7,600				5.2	298.2	5.70	0.99
ARIZONA CHEMICAL COMPANY	30	3,335.4	633.1	15.6	13,600	-7,600							
BAXTER'S ASPHALT & CONCRETE, INC. DBA DO	1	3,392.9	673.9	65.4	-43,930	-48,420			0.30				
BAY COUNTY ENERGY SYSTEMS, INC.	1	3,348.9	644.0	18.5	100	-18,500	6.800	0.857	29.55	38.1	477.6	17.37	1.37
BAY COUNTY ENERGY SYSTEMS, INC.	2	3,348.9	644.0	18.5	100	-18,500	6.800	0.857	29.80	38.1	497.0	17.37	1.37
COASTAL METALS, INC.	1	3,338.7	630.8	11.6	10,300	-5,300							
COUCH CONSTRUCTION, L.P.	1	3,338.8	630.1	11.2	10,230	-4,570			0.03				
COUCH CONSTRUCTION, L.P.	2	3,360.3	573.1	53.6	-11,300	52,400	8.170	1.029	8.50	6.1	366.5	15.30	1.19
COUCH CONSTRUCTION, L.P.	3	3,360.3	573.1	53.6	-11,300	52,400							
COUCH CONSTRUCTION, L.P.	1	3,400.7	577.2	70.8	-51,670	48,330	7.340	0.925	32.15	18.3	338.7	24.69	1.07
COUCH CONSTRUCTION, L.P.	3	3,400.7	577.2	70.8	-51,670	48,330			1.80				
COUCH, INCORPORATED	1	3,401.4	580.6	69.0	-52,400	44,900				11.9	303.2	2.74	0.40
COX BUILDING CORPORATION	1	3,342.3	613.0	14.2	6,700	12,500				15.2	303.2	25.60	0.15
EAGLE RECYCLING, INC.	1	3,333.9	669.1	46.2	15,120	-43,640	3.800	0.479	16.80	9.1		12.92	0.91
EB PIPE COATING INC.	1	3,339.1	622.1	10.5	9,900	3,400				3.7	305.4	33.01	0.43
EB PIPE COATING INC.	2	3,339.1	622.1	10.5	9,900	3,400				4.0	305.4	56.72	0.34
EB PIPE COATING INC.	3	3,339.1	622.1	10.5	9,900	3,400				4.9	305.4	31.61	0.46
EB PIPE COATING INC.	4	3,339.1	622.1	10.5	9,900	3,400				5.8	305.4	15.33	0.69
EB PIPE COATING INC.	5	3,339.1	622.1	10.5	9,900	3,400				4.0	305.4	32.34	0.30
EB PIPE COATING INC.	6	3,339.1	622.1	10.5	9,900	3,400				7.9	305.4	19.23	0.56
EB PIPE COATING INC.	7	3,339.1	622.1	10.5	9,900	3,400					305.4		
EWELL INDUSTRIES, INC.	1	3,345.5	605.2	20.6	3,500	20,300				12.2	303.2	25.60	0.15
EWELL INDUSTRIES, INC.	2	3,345.5	605.2	20.6	3,500	20,300							
EWELL INDUSTRIES, INC.	1	3,359.9	585.5	41.5	-10,940	40,030				18.9	303.2	25.60	0.15
FLORIDA ASPHALT PAVING COMPANY	1	3,338.3	631.4	12.2	10,700	-5,900	14.400	1.814	28.80	7.0	302.6	9.14	1.86
FLORIDA ASPHALT PAVING COMPANY	1	3,399.8	624.4	50.8	-50,800	1,100	10.000	1.260	43.80	11.0	435.9	22.25	1.16
FLORIDA COAST PAPER COMPANY, L.L.C.	2	3,299.0	662.8	62.4	50,000	-37,300	10.290	1.297	45.10	33.8	352.6	19.81	1.22
FLORIDA COAST PAPER COMPANY, L.L.C.	3	3,299.0	662.8	62.4	50,000	-37,300	10.290	1.297	45.1	33.5	352.6	18.29	1.22
FLORIDA COAST PAPER COMPANY, L.L.C.	4	3,299.0	662.8	62.4	50,000	-37,300	10.290	1.297	45.10	33.8	352.6	20.73	1.22
FLORIDA COAST PAPER COMPANY, L.L.C.	5	3,299.0	662.8	62.4	50,000	-37,300			1.63				
FLORIDA COAST PAPER COMPANY, L.L.C.	17	3,299.0	662.8	62.4	50,000	-37,300	25.670	3.234	112.43	12.2	355.4	1.22	0.76
FLORIDA COAST PAPER COMPANY, L.L.C.	18	3,299.0	662.8	62.4	50,000	-37,300	25.670	3.234	112.43	12.2	355.4	1.22	0.76
FLORIDA COAST PAPER COMPANY, L.L.C.	21	3,299.0	662.8	62.4	50,000	-37,300	5.000	0.630	21.90	38.1	360.4	7.62	1.07
FLORIDA COAST PAPER COMPANY, L.L.C.	22	3,299.0	662.8	62.4	50,000	-37,300	37.500	4.725	164.25	38.1	460.9	14.63	2.56
FLORIDA COAST PAPER COMPANY, L.L.C.	23	3,299.0	662.8	62.4	50,000	-37,300	5.000	0.630	21.90	38.1	355.4		1.07
FLORIDA COAST PAPER COMPANY, L.L.C.	24	3,299.0	662.8	62.4	50,000	-37,300	37.500	4.725	164.25	38.1	394.3	2.74	2.56
FLORIDA COAST PAPER COMPANY, L.L.C.	25	3,299.0	662.8	62.4	50,000	-37,300	88.200	11.113	386.32	51.8	343.2	10.06	4.27
FLORIDA COAST PAPER COMPANY, L.L.C.	26	3,299.0	662.8	62.4	50,000	-37,300	152.380	19.200	667.42	57.9	444.3	14.63	2.68
FLORIDA COAST PAPER COMPANY, L.L.C.	27	3,299.0	662.8	62.4	50,000	-37,300	19.900	2.507	87.20	30.5	367.6	2.13	2.38
FLORIDA COAST PAPER COMPANY, L.L.C.	31	3,299.0	662.8	62.4	50,000	-37,300				19.8	303.2	71.62	0.09
FLORIDA COAST PAPER COMPANY, L.L.C.	35	3,299.0	662.8	62.4	50,000	-37,300				33.5	352.6	18.29	1.22
FLORIDA COAST PAPER COMPANY, L.L.C.	36	3,299.0	662.8	62.4	50,000	-37,300	0.690	0.087	0.54				

Table 6-2. FDEP Off-Property PM₁₀ Emission Inventory (Page 2 of 2)

Company Name	EU ID	UTM Coordinates (km)		Distance From Unit 3 (km)	Relative Coordinates		PM Emission Rates			Stack Parameters			
		Northing (km)	Easting (km)		Y (m)	X (m)	(lb/hr)	(g/s)	(tpy)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
FLORIDA GAS TRANSMISSION CO.	6	3,394.2	610.6	47.6	-45,200	14,900	0.080	0.010	0.35	15.2	560.9	71.01	0.37
FLORIDA GAS TRANSMISSION CO.	7	3,394.2	610.6	47.6	-45,200	14,900							
FLORIDA MINING & MATERIALS	1	3,339.5	629.0	10.1	9,510	-3,500				20.7	303.2	0.30	1.04
FLORIDA MINING & MATERIALS	2	3,339.5	629.0	10.1	9,510	-3,500				20.7	303.2	0.30	1.04
FLORIDA MINING & MATERIALS	3	3,339.5	629.0	10.1	9,510	-3,500				12.5	303.2	1.83	0.49
FLORIDA MINING & MATERIALS	1	3,342.3	613.0	14.2	6,700	12,500							
FLORIDA MINING & MATERIALS	2	3,342.3	613.0	14.2	6,700	12,500							
FLORIDA MINING & MATERIALS CONCRETE	1	3,299.5	662.9	62.0	49,490	-37,410				13.7	305.4	13.41	0.18
FLORIDA MINING & MATERIALS CONCRETE	2	3,299.5	662.9	62.0	49,490	-37,410	10.000	1.260	0.13				
G.A.C. CONTRACTORS INC.	1	3,343.7	634.9	10.8	5,300	-9,400	35.430	4.464	44.29	7.6	327.6	11.28	1.22
GRANGER ASPHALT PAVING, INC.	1	3,340.3	628.1	9.1	8,720	-2,590	8.300	1.046	15.10	8.5	405.4	2.44	3.05
GULF COAST CREMATORY SERVICE	1	3,343.9	634.3	10.2	5,100	-8,800				6.1	588.7	3.35	0.61
GULF POWER COMPANY	1	3,349.1	625.2	0.3	-100	300	176.800	22.277	774.00	61.0	399.8	19.51	5.49
GULF POWER COMPANY	1	3,349.1	625.2	0.3	-100	300	176.800	22.277	774.00	61.0	399.8	19.51	5.49
GULF POWER COMPANY	2	3,349.1	625.2	0.3	-100	300	204.200	25.729	894.40	61.0	399.8	19.51	5.49
GULF POWER COMPANY	2	3,349.1	625.2	0.3	-100	300	204.200	25.729	894.40	61.0	399.8	19.51	5.49
GULF POWER COMPANY	3	3,349.1	625.2	0.3	-100	300	33.090	4.169	144.80	7.6	922.0	124.05	1.52
HUMANE SOCIETY OF BAY COUNTY.	1	3,338.8	630.7	11.4	10,200	-5,200	0.600	0.076	2.63	4.9	669.3	8.23	0.52
JERKINS, INCORPORATED	1	3,383.7	635.6	36.2	-34,720	-10,070	0.148	0.019	0.65	4.6	298.2	2.13	0.37
LOUISIANA PACIFIC CORP	1	3,355.2	608.8	17.8	-6,160	16,700	8.400	1.058	36.79	15.5	344.3	14.93	0.91
LOUISIANA PACIFIC CORP	2	3,355.2	608.8	17.8	-6,160	16,700							
PARTHENON PRINTS	1	3,343.5	627.5	5.9	5,500	-2,000				10.7	322.0	85.95	0.46
PERDUE FARMS INCORPORATED	2	3,399.3	590.1	61.5	-50,300	35,400	0.530	0.067	1.66		508.2		
PERDUE FARMS INCORPORATED	3	3,399.3	590.1	61.5	-50,300	35,400	0.190	0.024	0.58		508.2		
PERDUE FARMS INCORPORATED	4	3,399.3	590.1	61.5	-50,300	35,400	0.260	0.033	0.80		508.2		
PERDUE FARMS INCORPORATED	5	3,399.3	590.1	61.5	-50,300	35,400	0.130	0.016	0.42		508.2		
PERDUE FARMS INCORPORATED	6	3,399.3	590.1	61.5	-50,300	35,400	16.000	2.016	41.60	44.2	305.4	19.81	0.88
PERDUE FARMS INCORPORATED	7	3,399.3	590.1	61.5	-50,300	35,400	16.000	2.016	41.60	44.2	305.4	23.47	0.88
PERDUE FARMS INCORPORATED	8	3,399.3	590.1	61.5	-50,300	35,400							
PREMIER REFRACTORIES, INC.	2	3,302.8	664.7	60.6	46,200	-39,200	9.490	1.196	41.57	21.6	463.7	3.05	1.83
PREMIER REFRACTORIES, INC.	3	3,302.8	664.7	60.6	46,200	-39,200	11.060	1.394	48.45	36.6	300.4	8.23	0.52
PREMIER REFRACTORIES, INC.	6	3,302.8	664.7	60.6	46,200	-39,200	9.490	1.196	41.57	19.5	449.8	4.57	1.83
PREMIER REFRACTORIES, INC.	7	3,302.8	664.7	60.6	46,200	-39,200	9.490	1.196	41.57	19.5	439.3	5.49	1.83
PREMIER REFRACTORIES, INC.	8	3,302.8	664.7	60.6	46,200	-39,200	10.380	1.308	45.47	20.1	338.7	7.01	1.22
PREMIER REFRACTORIES, INC.	9	3,302.8	664.7	60.6	46,200	-39,200	0.190	0.024	0.82	15.2	355.4	14.51	0.21
SIKES CONCRETE PIPE CO	4	3,339.3	630.9	11.1	9,700	-5,400				11.0	303.2	12.80	0.15
SIKES CONCRETE PIPE CO.	1	3,338.7	630.7	11.5	10,300	-5,200				9.8	303.2	12.80	0.15
STEPHEN MILEY	1	3,373.2	581.1	50.6	-24,210	44,410	16.000	2.016	32.20				
STONE CONTAINER CORPORATION	1	3,335.1	632.8	15.7	13,900	-7,300	112.500	14.175	472.50	70.1	435.9	23.44	2.77
STONE CONTAINER CORPORATION	4	3,335.1	632.8	15.7	13,900	-7,300	29.830	3.759	130.66	18.3	348.7	6.71	2.04
STONE CONTAINER CORPORATION	5	3,335.1	632.8	15.7	13,900	-7,300	32.300	4.070	141.91	19.8	352.6	4.57	0.88
STONE CONTAINER CORPORATION	15	3,335.1	632.8	15.7	13,900	-7,300	109.500	13.797	479.61	62.8	327.0	23.16	2.38
STONE CONTAINER CORPORATION	16	3,335.1	632.8	15.7	13,900	-7,300	86.600	10.912	379.30	62.8	324.8	24.99	2.38
STONE CONTAINER CORPORATION	19	3,335.1	632.8	15.7	13,900	-7,300	112.500	14.175	492.75	70.1	435.9	23.16	2.77
STONE CONTAINER CORPORATION	20	3,335.1	632.8	15.7	13,900	-7,300	28.520	3.594	130.10	73.1	338.7	4.27	1.80
STONE CONTAINER CORPORATION	21	3,335.1	632.8	15.7	13,900	-7,300	29.710	3.743	130.10	73.1	338.7	3.96	1.80
STONE CONTAINER CORPORATION	30	3,335.1	632.8	15.7	13,900	-7,300			24.00		293.7		
SYLVACHEM CORPORATION	2	3,299.6	661.9	61.3	49,380	-36,350	0.986	0.124	4.32	16.5	515.9	14.02	1.22
SYLVACHEM CORPORATION	5	3,299.6	661.9	61.3	49,380	-36,350	7.000	0.882	30.66	6.1	310.9	25.60	0.30
SYLVACHEM CORPORATION	6	3,299.6	661.9	61.3	49,380	-36,350	12.800	1.613	55.26	9.1	302.6	0.91	1.52
SYLVACHEM CORPORATION	15	3,299.6	661.9	61.3	49,380	-36,350							
TEXTURED COATINGS OF AMERICA, INC.	1	3,338.5	631.3	12.0	10,500	-5,800	0.004	0.001	0.00	6.1	294.3	7.01	0.82
TRIANGLE CONSTRUCTION ROAD BUILDING INC.	1	3,347.0	638.8	13.4	2,000	-13,300	7.370	0.929	11.50	10.7	349.8	14.02	1.01
UNITED STATES AIR FORCE	9	3,326.8	635.6	24.4	22,200	-10,100	0.700	0.088	1.02	6.1	549.8	2.13	0.21
WHITE CONSTRUCTION COMPANY	1	3,403.5	579.5	61.6	-54,500	-28,700	6.990	0.881	30.62	10.7	449.8	32.92	1.10
WHITE CONSTRUCTION COMPANY	2	3,403.5	579.5	61.6	-54,500	-28,700							
WHITE CONSTRUCTION COMPANY, INC.	1	3,397.5	633.9	49.2	-48,470	-8,430			2.40		298.2		
WHITE CONSTRUCTION COMPANY, INC.	2	3,397.5	633.9	49.2	-48,470	-8,430			1.10				
WHITE CONSTRUCTION COMPANY, INC.	3	3,397.5	633.9	49.2	-48,470	-8,430			9.00				
WHITE CONSTRUCTION COMPANY, INC.	1	3,400.5	579.5	69.1	-51,500	46,000	12.810	1.614	55.90	7.0	410.9	29.08	1.16
WHITE CONSTRUCTION COMPANY, INC.	3	3,400.5	579.5	69.1	-51,500	46,000					298.2		

Source: FDEP, 1999.

Table 6-3. FDEP Off-Property PM₁₀ Emission Inventory - Modeled Emission Sources

Company Name	ISC ID	EU ID	UTM Coordinates (km)		Distance From Smith Unit 3 (km)	PM Emission Rates		Stack Parameters			
			Easting (km)	Northing (km)		(lb/hr)	(g/s)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
GULF POWER COMPANY	1	3	625.2	3,349.1	0.3	33.090	4.169	10.1	922.0	36.90	4.20
GULF POWER COMPANY	2	1	625.2	3,349.1	0.3	381.746	48.100	60.7	441.0	31.30	5.49
GRANGER ASPHALT PAVING, INC.	6	1	628.1	3,340.3	9.1	8.300	1.046	8.5	405.4	2.44	3.05
G.A.C. CONTRACTORS INC.	7	1	634.9	3,343.7	10.8	35.430	4.464	7.6	327.6	11.28	1.22
HUMANE SOCIETY OF BAY COUNTY.	8	1	630.7	3,338.8	11.4	0.600	0.076	4.9	669.3	8.23	0.52
TEXTURED COATINGS OF AMERICA, INC.	9	1	631.3	3,338.5	12.0	0.004	0.001	6.1	294.3	7.01	0.82
FLORIDA ASPHALT PAVING COMPANY	10	1	631.4	3,338.3	12.2	14.400	1.814	7.0	302.6	9.14	1.86
TRIANGLE CONSTRUCTION ROAD BUILDING INC.	11	1	638.8	3,347.0	13.4	7.370	0.929	10.7	349.8	14.02	1.01
ARIZONA CHEMICAL COMPANY	12	19	633.1	3,335.4	15.6	0.073	0.009	6.1	298.2	0.01	6.71
ARIZONA CHEMICAL COMPANY	13	14	633.1	3,335.4	15.6	17.500	2.205	30.5	510.9	22.55	1.22
ARIZONA CHEMICAL COMPANY	14	15	633.1	3,335.4	15.6	17.500	2.205	30.5	466.5	17.37	1.22
STONE CONTAINER CORPORATION	15	20	632.8	3,335.1	15.7	28.520	3.594	73.1	338.7	4.27	1.80
STONE CONTAINER CORPORATION	16	21	632.8	3,335.1	15.7	29.710	3.743	73.1	338.7	3.96	1.80
STONE CONTAINER CORPORATION	17	4	632.8	3,335.1	15.7	29.830	3.759	18.3	348.7	6.71	2.04
STONE CONTAINER CORPORATION	18	5	632.8	3,335.1	15.7	32.300	4.070	19.8	352.6	4.57	0.88
STONE CONTAINER CORPORATION	19	16	632.8	3,335.1	15.7	86.600	10.912	62.8	324.8	24.99	2.38
STONE CONTAINER CORPORATION	20	15	632.8	3,335.1	15.7	109.500	13.797	62.8	327.0	23.16	2.38
STONE CONTAINER CORPORATION	21	1	632.8	3,335.1	15.7	112.500	14.175	70.1	435.9	23.44	2.77
STONE CONTAINER CORPORATION	22	19	632.8	3,335.1	15.7	112.500	14.175	70.1	435.9	23.16	2.77
LOUISIANA PACIFIC CORP	23	1	608.8	3,355.2	17.8	8.400	1.058	15.5	344.3	14.93	0.91
BAY COUNTY ENERGY SYSTEMS, INC.	24	1	644.0	3,348.9	18.5	6.800	0.857	38.1	477.6	17.37	1.37
BAY COUNTY ENERGY SYSTEMS, INC.	25	2	644.0	3,348.9	18.5	6.800	0.857	38.1	497.0	17.37	1.37
UNITED STATES AIR FORCE	26	9	635.6	3,326.8	24.4	0.700	0.088	6.1	549.8	2.13	0.21
ANDERSON COLUMBIA CO INC #6	27	1	648.8	3,362.8	27.1	18.000	2.268	9.8	435.9	21.03	1.22
JERKINS, INCORPORATED	28	1	635.6	3,383.7	36.2	0.148	0.019	4.6	298.2	2.13	0.37
EAGLE RECYCLING, INC.	29	1	669.1	3,333.9	46.2	3.800	0.479	9.1	255.4	12.92	0.91
FLORIDA GAS TRANSMISSION CO.	30	6	610.6	3,394.2	47.6	0.080	0.010	15.2	560.9	71.01	0.37
FLORIDA ASPHALT PAVING COMPANY	32	1	624.4	3,399.8	50.8	10.000	1.260	11.0	435.9	22.25	1.16
COUCH CONSTRUCTION, L.P.	33	2	573.1	3,360.3	53.6	8.170	1.029	6.1	366.5	15.30	1.19

Sources: FDEP, 1999.
Gulf, 1999.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 SCREENING ANALYSIS

The SCREEN3 dispersion model was used to assess each of the 14 CTG operating cases; i.e., a matrix of three CTG loads (100-, 75-, and 50-percent); three ambient temperatures (0, 65, and 95°F); and optional use of evaporative cooling, duct burner firing, and steam power augmentation, for each pollutant subject to PSD review (SO₂, PM/PM₁₀, CO, and H₂SO₄ mist). The worst-case operating mode identified by the SCREEN3 model for each pollutant was then carried forward to the refined modeling for further analysis.

SCREEN3 model runs employed the specific stack exit temperature and exhaust gas velocity appropriate for each operating case. A nominal emission rate of 1.0 g/s was used for each case; model results were then scaled to reflect the maximum emission rates for each pollutant. Because the SCREEN3 model is a single-source model, the scaling procedure was based on maximum emissions from both CTGs. SCREEN3 model options used include rural dispersion, building downwash, full meteorology, and automated receptors extending from 725 (distance to the nearest boundary) to 10,000 meters.

SCREEN3 model maximum 1-hour impacts for each CTG operating case are provided on Tables 7-1 through 7-4 for SO₂, PM/PM₁₀, CO, and H₂SO₄ mist, respectively. These tables indicate, for each operating case, the maximum emission rate for both CTGs, SCREEN3 model results based on a nominal 1.0 g/s emission rate, emission rate scaling factor, scaled SCREEN3 model result, and location of maximum impact.

As shown in Tables 7-1, 7-3, and 7-4, the maximum impacts for SO₂, CO, and H₂SO₄ mist all occurred for Case 11 (100 percent load, 95°F ambient temperature, evaporative cooling, duct burner firing, and steam power augmentation). For PM/PM₁₀, the maximum SCREEN3 impact occurred for Case 14 (50 percent load and 95°F ambient temperature). These worst-case operating cases were then analyzed using the refined ISCST3 dispersion model.

Table 7-1. SCREEN3 Model Results - SO₂ Impacts, Two CTG/HRSGs

Case	CTG Fuel	Operating Scenario	Down-wash	Load (%)	Ambient Temperature (°F)	SCREEN3 Emission Rate (g/sec)	SCREEN3 Maximum Impact (µg/m ³)	Sulfur Dioxide			Down Wind Distance (m)
								Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (µg/m ³)	
1	Natural Gas	CTG	Yes	100	0	1.0	3.32	2.92	2.92	9.71	725
2	Natural Gas	CTG + DB	Yes	100	0	1.0	3.33	3.20	3.20	10.65	725
3	Natural Gas	CTG	Yes	75	0	1.0	3.82	2.35	2.35	8.98	725
4	Natural Gas	CTG	Yes	50	0	1.0	4.26	1.87	1.87	7.98	725
5	Natural Gas	CTG + EC	Yes	100	65	1.0	3.89	2.68	2.68	10.44	725
6	Natural Gas	CTG + EC + DB	Yes	100	65	1.0	3.91	2.99	2.99	11.68	725
7	Natural Gas	CTG	Yes	75	65	1.0	4.48	2.18	2.18	9.75	725
8	Natural Gas	CTG	Yes	50	65	1.0	5.15	1.75	1.75	8.99	725
9	Natural Gas	CTG + EC	Yes	100	95	1.0	4.46	2.53	2.53	11.30	725
10	Natural Gas	CTG + EC + PA	Yes	100	95	1.0	4.44	2.68	2.68	11.89	725
11	Natural Gas	CTG+ EC + PA + DB	Yes	100	95	1.0	4.43	3.13	3.13	13.89	725
12	Natural Gas	CTG + EC + DB	Yes	100	95	1.0	4.36	3.00	3.00	13.07	725
13	Natural Gas	CTG	Yes	75	95	1.0	4.67	2.07	2.07	9.67	725
14	Natural Gas	CTG	Yes	50	95	1.0	5.76	1.66	1.66	9.57	725
Maximum										13.89	

Note: Case producing the highest impact is shown in bold type.

CTG = combustion turbine generator.

EC = evaporative cooler.

DB = duct burner.

PA = power augmentation.

Source: ECT, 1999.

Table 7-2. SCREEN3 Model Results - PM/PM₁₀ Impacts, Two CTG/HRSGs

Case	CTG Fuel	Operating Scenario	Down-wash	Load (%)	Ambient Temperature (°F)	SCREEN3 Emission Rate (g/sec)	SCREEN3 Maximum Impact (µg/m ³)	PM/PM ₁₀			Down Wind Distance (m)
								Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (µg/m ³)	
1	Natural Gas	CTG	Yes	100	0	1.0	3.32	4.99	4.99	16.59	725
2	Natural Gas	CTG + DB	Yes	100	0	1.0	3.33	5.24	5.24	17.44	725
3	Natural Gas	CTG	Yes	75	0	1.0	3.82	4.99	4.99	19.05	725
4	Natural Gas	CTG	Yes	50	0	1.0	4.26	4.99	4.99	21.25	725
5	Natural Gas	CTG + EC	Yes	100	65	1.0	3.89	4.99	4.99	19.42	725
6	Natural Gas	CTG + EC + DB	Yes	100	65	1.0	3.91	5.27	5.27	20.58	725
7	Natural Gas	CTG	Yes	75	65	1.0	4.48	4.99	4.99	22.34	725
8	Natural Gas	CTG	Yes	50	65	1.0	5.15	4.99	4.99	25.69	725
9	Natural Gas	CTG + EC	Yes	100	95	1.0	4.46	4.99	4.99	22.24	725
10	Natural Gas	CTG + EC + PA	Yes	100	95	1.0	4.44	4.99	4.99	22.16	725
11	Natural Gas	CTG+ EC + PA + DB	Yes	100	95	1.0	4.43	5.41	5.41	23.96	725
12	Natural Gas	CTG + EC + DB	Yes	100	95	1.0	4.36	5.29	5.29	23.06	725
13	Natural Gas	CTG	Yes	75	95	1.0	4.67	4.99	4.99	23.31	725
14	Natural Gas	CTG	Yes	50	95	1.0	5.76	4.99	4.99	28.76	725
										Max.	28.76

Note: Case producing the highest impact is shown in bold type.

CTG = combustion turbine generator.

EC = evaporative cooler.

DB = duct burner.

PA = power augmentation.

Source: ECT, 1999.

Table 7-3. SCREEN3 Model Results - CO Impacts, Two CTG/HRSGs

Case	CTG Fuel	Operating Scenario	Down-wash	Load (%)	Ambient Temperature (°F)	SCREEN3 Emission Rate (g/sec)	SCREEN3 Maximum Impact (µg/m³)	Carbon Monoxide			Down Wind Distance (m)
								Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (µg/m³)	
1	Natural Gas	CTG	Yes	100	0	1.0	3.32	14.69	14.69	48.83	725
2	Natural Gas	CTG + DB	Yes	100	0	1.0	3.33	19.82	19.82	65.96	725
3	Natural Gas	CTG	Yes	75	0	1.0	3.82	11.64	11.64	44.45	725
4	Natural Gas	CTG	Yes	50	0	1.0	4.26	9.42	9.42	40.14	725
5	Natural Gas	CTG + EC	Yes	100	65	1.0	3.89	13.31	13.31	51.80	725
6	Natural Gas	CTG + EC + DB	Yes	100	65	1.0	3.91	18.99	18.99	74.21	725
7	Natural Gas	CTG	Yes	75	65	1.0	4.48	10.81	10.81	48.40	725
8	Natural Gas	CTG	Yes	50	65	1.0	5.15	8.87	8.87	45.67	725
9	Natural Gas	CTG + EC	Yes	100	95	1.0	4.46	12.47	12.47	55.61	725
10	Natural Gas	CTG + EC + PA	Yes	100	95	1.0	4.44	12.47	12.47	55.40	725
11	Natural Gas	CTG+ EC + PA + DB	Yes	100	95	1.0	4.43	29.38	29.38	130.26	725
12	Natural Gas	CTG + EC + DB	Yes	100	95	1.0	4.36	18.46	18.46	80.42	725
13	Natural Gas	CTG	Yes	75	95	1.0	4.67	10.26	10.26	47.92	725
14	Natural Gas	CTG	Yes	50	95	1.0	5.76	8.59	8.59	49.52	725
Max.										130.26	

Note: Case producing the highest impact is shown in bold type.

CTG = combustion turbine generator.

EC = evaporative cooler.

DB = duct burner.

PA = power augmentation.

Source: ECT, 1999.

Table 7-4. SCREEN3 Model Results - H₂SO₄ Impacts, Two CTG/HRSGs

Case	CTG Fuel	Operating Scenario	Down-wash	Load (%)	Ambient Temperature (°F)	SCREEN3 Emission Rate (g/sec)	SCREEN3 Maximum Impact (µg/m ³)	Sulfuric Acid Mist			Down Wind Distance (m)
								Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (µg/m ³)	
1	Natural Gas	CTG	Yes	100	0	1.0	3.32	0.336	0.34	1.12	725
2	Natural Gas	CTG + DB	Yes	100	0	1.0	3.33	0.368	0.37	1.22	725
3	Natural Gas	CTG	Yes	75	0	1.0	3.82	0.270	0.27	1.03	725
4	Natural Gas	CTG	Yes	50	0	1.0	4.26	0.215	0.22	0.92	725
5	Natural Gas	CTG + EC	Yes	100	65	1.0	3.89	0.308	0.31	1.20	725
6	Natural Gas	CTG + EC + DB	Yes	100	65	1.0	3.91	0.343	0.34	1.34	725
7	Natural Gas	CTG	Yes	75	65	1.0	4.48	0.250	0.25	1.12	725
8	Natural Gas	CTG	Yes	50	65	1.0	5.15	0.200	0.20	1.03	725
9	Natural Gas	CTG + EC	Yes	100	95	1.0	4.46	0.291	0.29	1.30	725
10	Natural Gas	CTG + EC + PA	Yes	100	95	1.0	4.44	0.307	0.31	1.37	725
11	Natural Gas	CTG+ EC + PA + DB	Yes	100	95	1.0	4.43	0.36	0.36	1.59	725
12	Natural Gas	CTG + EC + DB	Yes	100	95	1.0	4.36	0.345	0.34	1.50	725
13	Natural Gas	CTG	Yes	75	95	1.0	4.67	0.238	0.24	1.11	725
14	Natural Gas	CTG	Yes	50	95	1.0	5.76	0.191	0.19	1.10	725
Max.										1.59	

Note: Case producing the highest impact is shown in bold type.

CTG = combustion turbine generator.

EC = evaporative cooler.

DB = duct burner.

PA = power augmentation.

Source: ECT, 1999.

7.2 MAXIMUM FACILITY IMPACTS AND SIGNIFICANT IMPACT AREAS

The refined ISCST model was used to model the operating cases identified by the SCREEN3 model to cause maximum impacts. ISCST3 model results for each year of meteorology evaluated (1986—1990) are summarized on Table 7-5 (annual SO₂ impacts), Table 7-6 (3-hour SO₂ impacts), Table 7-7 (24-hour SO₂ impacts), Table 7-8 (annual PM/PM₁₀ impacts), Table 7-9 (24-hour PM/PM₁₀ impacts), Table 7-10 (1-hour CO impacts), and Table 7-11 (8-hour CO impacts).

Tables 7-5 through 7-11 demonstrate that Smith Unit 3 impacts, for all pollutants and all averaging times, are below the PSD significant impact levels previously shown in Table 4-2 with the exception of PM₁₀. A summary of maximum Smith Unit 3 impacts and PSD significant impact levels is provided on Table 7-12.

7.3 NAAQS ANALYSIS

An assessment of Smith Unit 3 impacts, together with other sources within 54 km, was performed for comparison to the annual and 24-hour average PM₁₀ NAAQS. The modeled emission inventory included the two Smith Unit 3 CTG/HRSG units (operating under Case 14 conditions) and cooling tower, and all other sources contained in the FDEP PM emission inventory retrieval that are located within 54 km of the Smith Unit 3 site. Conservatively, the PM emission rates provided by FDEP were assumed to be equal to PM₁₀ emission rates.

The receptor grids for the refined NAAQS analysis consisted of the fence line and natural barrier receptors, and near-field grid receptors consistent with the approximate 2.4 km AOI; i.e., the grid extended from Smith Unit 3 site out to 2.4 km. The results of the annual and 24-hour average PM₁₀ NAAQS modeling are provided on Tables 7-13 and 7-14, respectively. This table demonstrates that Smith Unit 3 emission source impacts, together with all other off-property PM emission sources and including background, are well below the annual and 24-hour average PM₁₀ NAAQS.

Table 7-5. ISCST3 Model Results - Maximum Annual Average SO₂ Impacts

Maximum Annual Impacts	1986	1987	1988	1989	1990
Unadjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ¹	0.37	0.39	0.41	0.37	0.60
Emission Rate Scaling Factor ²	0.1566	0.1566	0.1566	0.1566	0.1566
Adjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ³	0.06	0.06	0.06	0.06	0.09
PSD Significant Impact ($\mu\text{g}/\text{m}^3$)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	5.7	6.2	6.4	5.8	9.3
Receptor UTM Easting (m)	625,500.0	625,761.4	623,278.5	623,520.1	623,278.5
Receptor UTM Northing (m)	3,346,300.0	3,346,011.5	3,350,864.0	3,350,980.0	3,350,864.0
Distance From Grid Origin (m)	2,700	3,000	2,900	2,800	2,900
Direction From Grid Origin (Vector °)	180	175	310	315	310

¹ Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

² Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

³ Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-6. ISCST3 Model Results - Maximum 24-Hour Average SO₂ Impacts

Maximum 24-Hour Impacts	1986	1987	1988	1989	1990
Unadjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ¹	10.85	8.73	4.21	4.45	6.35
Emission Rate Scaling Factor ²	0.1566	0.1566	0.1566	0.1566	0.1566
Adjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ³	1.70	1.37	0.66	0.70	0.99
PSD Significant Impact ($\mu\text{g}/\text{m}^3$)	5.0	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	34.0	27.3	13.2	13.9	19.9
PSD <i>de minimis</i> Ambient Impact Threshold ($\mu\text{g}/\text{m}^3$)	13.0	13.0	13.0	13.0	13.0
Exceed PSD <i>de minimis</i> Ambient Impact (Y/N)	N	N	N	N	N
Percent of PSD <i>de minimis</i> Ambient Impact (%)	13.1	10.5	5.1	5.4	7.6
Receptor UTM Easting (m)	625,714.2	625,104.6	626,991.3	623,228.7	623,206.4
Receptor UTM Northing (m)	3,350,143.0	3,350,143.0	3,346,870.3	3,349,786.8	3,350,606.0
Distance From Grid Origin (m)	1,163	1,209	2,600	2,404	2,800
Direction From Grid Origin (Vector °)	11	341	145	289	305
Date of Maximum Impact	2/26/86	4/14/87	11/28/88	5/18/89	5/26/90
Julian Date of Maximum Impact	57	104	333	138	146

¹ Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

² Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

³ Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-7. ISCST3 Model Results - Maximum 3-Hour Average SO₂ Impacts

Maximum 3-Hour Impacts	1986	1987	1988	1989	1990
Unadjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ¹	48.76	41.82	16.84	18.76	18.18
Emission Rate Scaling Factor ²	0.1566	0.1566	0.1566	0.1566	0.1566
Adjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ³	7.64	6.55	2.64	2.94	2.85
PSD Significant Impact ($\mu\text{g}/\text{m}^3$)	25.0	25.0	25.0	25.0	25.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	30.5	26.2	10.5	11.8	11.4
Receptor UTM Easting (m)	625,009.4	625,104.6	623,431.9	623,944.4	626,438.2
Receptor UTM Northing (m)	3,350,143.0	3,350,143.0	3,349,364.8	3,350,555.8	3,348,523.8
Distance From Grid Origin (m)	1,244	1,209	2,100	2,200	1,052
Direction From Grid Origin (Vector °)	337	341	280	315	117
Date of Maximum Impact	3/13/86	4/14/87	8/13/88	7/26/89	10/25/90
Julian Date of Maximum Impact	72	104	226	207	298
Ending Hour of Maximum Impact	0300	1200	1200	1500	2100

¹ Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

² Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

³ Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-8. ISCST3 Model Results - Maximum Annual Average PM/PM₁₀ Impacts

Maximum Annual Impacts	1986	1987	1988	1989	1990
ISCST3 Impact ($\mu\text{g}/\text{m}^3$)	0.38	0.33	0.32	0.28	0.47
PSD Significant Impact ($\mu\text{g}/\text{m}^3$)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	38.0	33.0	32.0	28.0	47.0
Receptor UTM Easting (m)	626,228.6	625,923.8	623,891.3	623,944.4	623,891.3
Receptor UTM Northing (m)	3,350,143.0	3,350,143.0	3,350,349.8	3,350,555.8	3,350,349.8
Distance From Grid Origin (m)	1,355	1,219	2,100	2,200	2,100
Direction From Grid Origin (Vector °)	33	20	310	315	310

Source: ECT, 1999.

Table 7-9. ISCST3 Model Results - Maximum 24-Hour Average PM/PM₁₀ Impacts

Maximum 24-Hour Impacts	1986	1987	1988	1989	1990
ISCST3 Impact ($\mu\text{g}/\text{m}^3$)	13.44	8.13	6.06	3.43	4.68
PSD Significant Impact ($\mu\text{g}/\text{m}^3$)	5.0	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Y/N)	Y	Y	Y	N	N
Percent of PSD Significant Impact (%)	268.8	162.6	121.2	68.6	93.6
PSD <i>de minimis</i> Ambient Impact Threshold ($\mu\text{g}/\text{m}^3$)	10.0	10.0	10.0	10.0	10.0
Exceed PSD <i>de minimis</i> Ambient Impact (Y/N)*	Y	N	N	N	N
Percent of PSD <i>de minimis</i> Ambient Impact (%)*	134.4	81.3	60.6	34.3	46.8
Receptor UTM Easting (m)	625,800.0	625,828.5	625,923.8	625,900.0	623,370.2
Receptor UTM Northing (m)	3,350,200.0	330,143.0	3,350,143.0	3,350,300.0	3,350,491.3
Distance From Grid Origin (m)	1,237	3,018,857	1,219	1,360	2,600
Direction From Grid Origin (Vector °)	14	180	20	17	305
Date of Maximum Impact	2/26/86	1/29/87	6/9/88	5/18/89	5/26/90
Julian Date of Maximum Impact	57	29	161	138	146

*An "exceedance" of the *de minimis* ambient impact threshold simply requires that more refined modeling be performed.

Source: ECT, 1999.

Table 7-10. ISCST3 Model Results - Maximum 1-Hour Average CO Impacts

Maximum 1-Hour Impacts	1986	1987	1988	1989	1990
Unadjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ¹	74.51	75.68	35.29	34.43	51.00
Emission Rate Scaling Factor ²	1.47	1.47	1.47	1.47	1.47
Adjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ³	109.47	111.19	51.85	50.58	74.93
PSD Significant Impact ($\mu\text{g}/\text{m}^3$)	2,000.0	2,000.0	2,000.0	2,000.0	2,000.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	5.5	5.6	2.6	2.5	3.7
Receptor UTM Easting (m)	625,009.4	625,419.0	625,752.3	626,171.5	624,238.3
Receptor UTM Northing (m)	3,350,143.0	3,350,143.0	3,348,275.8	3,348,466.5	3,349,756.0
Distance From Grid Origin (m)	1,244	1,146	767	858	1,471
Direction From Grid Origin (Vector °)	337	356	161	128	301
Date of Maximum Impact	3/13/86	2/2/87	7/2/88	11/16/89	2/5/90
Julian Date of Maximum Impact	72	33	184	320	36
Ending Hour of Maximum Impact	0300	0500	2200	0600	2400

¹ Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

² Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

³ Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-11. ISCST3 Model Results - Maximum 8-Hour Average CO Impacts

Maximum 8-Hour Impacts	1986	1987	1988	1989	1990
Unadjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ¹	21.83	26.12	11.24	10.20	12.64
Emission Rate Scaling Factor ²	1.47	1.47	1.47	1.47	1.47
Adjusted ISCST3 Impact ($\mu\text{g}/\text{m}^3$) ³	32.07	38.38	16.52	14.98	18.57
PSD Significant Impact ($\mu\text{g}/\text{m}^3$)	500.0	500.0	500.0	500.0	500.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	6.4	7.7	3.3	3.0	3.7
PSD <i>de minimis</i> Ambient Impact Threshold ($\mu\text{g}/\text{m}^3$)	575.0	575.0	575.0	575.0	575.0
Exceed PSD <i>de minimis</i> Ambient Impact (Y/N)	N	N	N	N	N
Percent of PSD <i>de minimis</i> Ambient Impact (%)	5.6	6.7	2.9	2.6	3.2
Receptor UTM Easting (m)	624,895.1	625,104.6	627,691.6	623,944.4	623,738.1
Receptor UTM Northing (m)	3,350,143.0	3,350,143.0	3,348,808.3	3,350,555.8	3,350,478.5
Distance From Grid Origin (m)	1,293	1,209	2,200	2,200	2,300
Direction From Grid Origin (Vector °)	332	341	95	315	310
Date of Maximum Impact	3/12/86	4/14/87	11/5/88	6/1/89	6/12/90
Julian Date of Maximum Impact	71	104	310	153	164
Ending Hour of Maximum Impact	2400	1600	1600	1600	1600

¹ Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

² Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

³ Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-12. Smith Unit 3 Emission Sources—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu\text{g}/\text{m}^3$)	Significant Impact ($\mu\text{g}/\text{m}^3$)
CO	8-hour	38.4	500
	1-hour	111.2	2,000
PM/PM ₁₀	Annual	0.5	1.0
	24-hour	13.4	5.0
SO ₂	Annual	0.1	1.0
	24-hour	1.7	5.0
	3-hour	7.6	25.0

Source: ECT, 1999.

Table 7-13. ISCST3 Model Results - Maximum Annual Average PM₁₀ Impacts; NAAQS Analysis

Maximum Annual Impacts	1986	1987	1988	1989	1990
ISCST3 Impact (µg/m ³)	0.96	0.93	1.02	1.13	1.27
Background (µg/m ³)	28.0	28.0	28.0	28.0	28.0
Total Impact (µg/m ³)	29.0	28.93	29.20	29.13	29.27
NAAQS (µg/m ³)	50.0	50.0	50.0	50.0	50.0
Exceed NAAQS (Y/N)	N	N	N	N	N
Percent of NAAQS (%)	57.9	57.9	58.0	58.3	58.5
Receptor UTM Easting (m)	625,500.0	625,709.2	627,197.1	625,290.8	623,738.1
Receptor UTM Northing (m)	3,346,700.0	3,346,609.3	3,347,303.0	3,346,609.3	3,350,478.5
Distance From Grid Origin (m)	2,300	2,400	2,400	2,400	2,300
Direction From Grid Origin (Vector °)	180	175	135	185	310

Source: ECT, 1999.

Table 7-14. ISCST3 Model Results - High, Second Highest 24-Hour Average PM₁₀ Impacts; NAAQS Analysis

High, Second Highest 24-Hour Impacts	1986	1987	1988	1989	1990
ISCST3 Impact ($\mu\text{g}/\text{m}^3$)	8.2	7.3	7.9	9.1	7.9
Background ($\mu\text{g}/\text{m}^3$)	73.0	73.0	73.0	73.0	73.0
Total Impact ($\mu\text{g}/\text{m}^3$)	81.2	80.30	80.85	82.10	80.90
NAAQS ($\mu\text{g}/\text{m}^3$)	150.0	150.0	150.0	150.0	150.0
Exceed NAAQS (Y/N)	N	N	N	N	N
Percent of NAAQS (%)	54.1	53.5	53.9	54.7	53.9
Receptor UTM Easting (m)	625,800.0	626,038.1	626,038.1	626,800.0	626,038.1
Receptor UTM Northing (m)	3,350,200.0	3,350,143.0	3,350,143.0	3,350,200.0	3,350,143.0
Distance From Grid Origin (m)	1,237	1,263	1,263	1,237	1,263
Direction From Grid Origin (Vector °)	14	25	25	14	25
Date of Maximum Impact	6/30/86	8/4/87	5/4/88	1/8/89	1/24/90
Julian Date of Maximum Impact	181	216	125	8	24

Source: ECT, 1999.

The NAAQS impact analyses was conducted using conservative premises for background PM₁₀ levels, off-property source PM₁₀ emission rates, and Smith Unit 3 cooling tower PM₁₀ emission rates. The *highest* 24-hour and annual average PM₁₀ values obtained from the FDEP PM₁₀ monitoring site located in Panama City, Bay County for 1997 and 1998 were used as background. This approach results in an over-estimation of total impacts due to “double-counting”; i.e., a portion of the FDEP monitored ambient PM₁₀ data would be expected to have been caused by the same PM₁₀ emission sources which are also included in the modeled emission inventory. As noted above, all PM emission rates provided by FDEP for the off-property sources were conservatively assumed to be equal to PM₁₀ emission rates.

More significantly, Smith Unit 3 cooling tower PM₁₀ emission rates were estimated using EPA AP-42 procedures. As noted, and emphasized in AP-42, these emission estimation procedures result in “conservatively high” PM₁₀ emission rates. Analysis of the dispersion model PM₁₀ results shows that the Smith Unit 3 cooling tower was one of the principal contributors to the highest impacts. With respect to 24-hour average PM₁₀ impacts, Smith Unit 3 cooling tower emissions were responsible for approximately 55 percent of the total impact. For maximum annual average PM₁₀ impacts, Smith Unit 3 cooling tower emissions contributed approximately 25 percent of the total impact. Note that PM₁₀ emissions from the primary Smith Unit 3 emission sources, the two CTG/HRSG units, result in maximum PM₁₀ impacts which are well below the PSD significant impact levels.

Because of the conservative approach used in conducting the air quality analysis for PM₁₀ NAAQS impacts, there is reasonable assurance that Smith Unit 3 will not cause nor contribute to an exceedance of the PM₁₀ NAAQS.

7.4 PSD CLASS II INCREMENT ANALYSIS

An assessment of Smith Unit 3 impacts, together with other sources within 54 km, was performed for comparison to the annual and 24-hour average PSD Class II PM₁₀ increments. The modeled emission inventory included the two Smith Unit 3 CTG/HRSG units

(operating under Case 14 conditions) and cooling tower, and all other sources contained in the FDEP PM emission inventory retrieval that are located within 54 km of Smith Unit 3 site. The FDEP PM₁₀ emission inventory did not identify the specific emission sources which consume PSD PM₁₀ increment. Conservatively, *all* off-property PM₁₀ emission sources located within 54 km of Smith Unit 3 site were assumed to consume PSD increment. In addition, the PM emission rates provided by FDEP were conservatively assumed to be equal to PM₁₀ emission rates.

The receptor grids for the refined PSD Class II PM₁₀ increment analysis consisted of the fence line receptors, and near-field grid receptors consistent with the approximate 2.4 km AOI; i.e., the grid extended from Smith Unit 3 site out to 2.4 km. The results of the 24-hour and annual average PSD Class II PM₁₀ increment modeling are provided in Table 7-15 and 7-16, respectively. These tables demonstrate that maximum Smith Unit 3 impacts, together with all other PSD PM₁₀ increment consuming emission sources, are below the 24-hour and annual average PSD Class II PM₁₀ increments.

Similar to the NAAQS air quality analysis, the assessment of PSD Class II PM₁₀ increment consumption was conducted using several conservative premises. As noted above, *all* off-property PM emission sources were assumed to consume PSD PM₁₀ increment. In addition, the PM emission rates provided by FDEP for the off-property sources were assumed to be equal to PM₁₀ emission rates. The same conservatively high PM₁₀ emission rates used for Smith Unit 3 cooling tower in the NAAQS analysis were also used in the PSD Class II PM₁₀ increment consumption analysis. Accordingly, the Smith Unit 3 cooling tower was also one of the principal contributors to PSD Class II PM₁₀ increment consumption; i.e., accounting for approximately 57 and 26 percent of the total impact for the 24-hour and annual averaging periods, respectively.

Because of the conservative approach used in conducting the air quality analysis for PM₁₀ PSD Class II increment consumption, there is reasonable assurance that Smith Unit 3 will not cause nor contribute to an exceedance of the PSD Class II PM₁₀ increments.

Table 7-15. ISCST3 Model Results - Maximum Annual PM₁₀ Impacts; PSD Class II Increment Analysis

Maximum Annual Impacts	1986	1987	1988	1989	1990
ISCST3 Impact ($\mu\text{g}/\text{m}^3$)	0.96	0.93	1.02	1.13	1.27
PSD Class II Increment ($\mu\text{g}/\text{m}^3$)	17.0	17.0	17.0	17.0	17.0
Exceed PSD Class II Increment (Y/N)	N	N	N	N	N
Percent of PSD Class II Increment (%)	5.6	5.5	6.0	6.6	7.5
Receptor UTM Easting (m)	625,500.0	625,709.2	627,197.1	625,290.8	623,738.1
Receptor UTM Northing (m)	3,346,700.0	3,346,609.3	3,347,303.0	3,346,609.3	3,350,478.5
Distance From Grid Origin (m)	2,300	2,400	2,400	2,400	2,300
Direction From Grid Origin (Vector °)	180	175	135	185	310

Source: ECT, 1999.

Table 7-16. ISCST3 Model Results - High, Second Highest 24-Hour Average PM₁₀ Impacts; PSD Class II Increment Analysis

High, Second Highest 24-Hour Impacts	1986	1987	1988	1989	1990
ISCST3 Impact ($\mu\text{g}/\text{m}^3$)	8.2	7.3	7.9	9.1	7.9
PSD Class II Increment ($\mu\text{g}/\text{m}^3$)	30.0	30.0	30.0	30.0	30.0
Exceed PSD Class II Increment (Y/N)	N	N	N	N	N
Percent of PSD Class II Increment (%)	27.3	24.3	26.2	30.3	26.3
Receptor UTM Easting (m)	625,800.0	626,038.1	626,038.1	626,800.0	626,038.1
Receptor UTM Northing (m)	3,350,200.0	3,350,143.0	3,350,143.0	3,350,200.0	3,350,143.0
Distance From Grid Origin (m)	1,237	1,263	1,263	1,237	1,263
Direction From Grid Origin (Vector °)	14	25	25	14	25
Date of Maximum Impact	6/30/86	8/4/87	5/4/88	1/8/89	1/24/90
Julian Date of Maximum Impact	181	216	125	8	24

Source: ECT, 1999.

7.5 SULFURIC ACID MIST

The maximum 1-hour average SCREEN3 model impact was $1.59 \mu\text{g}/\text{m}^3$ for H_2SO_4 mist. Recommended EPA (EPA, 1992) multiplying factors for converting 1-hour averages to 8- and 24-hour averages are 0.7 and 0.4, respectively. Use of these factors yields maximum 8- and 24-hour average H_2SO_4 mist impacts of 1.11 and $0.64 \mu\text{g}/\text{m}^3$, respectively. These impacts are well below the FDEP draft ARCs for H_2SO_4 mist of 10.0 and $2.4 \mu\text{g}/\text{m}^3$ for 8- and 24-hour average periods, respectively. A summary of Smith Unit 3 H_2SO_4 impacts and the FDEP draft ARC levels is provided on Table 7-17.

7.6 CONCLUSIONS

Comprehensive dispersion modeling using the SCREEN3 and refined ISCST3 models demonstrates that Smith Unit 3 emission sources will result in ambient air quality impacts that are:

- Below the PSD significant impact levels for all pollutants and all averaging periods with the exception of PM_{10} .
- Below the PSD *de-minimis* ambient impact levels for all pollutants and all averaging periods with the exception of PM_{10} .
- Below the FDEP draft ARCs for H_2SO_4 mist.

Comprehensive dispersion modeling using the refined ISCST3 model demonstrates that Project emission sources, together with all off-property PM emission sources located within 54 km of Smith Unit 3 site and including background concentrations, will result in ambient air quality impacts that are:

- Below the NAAQS for PM_{10} ; and
- Below the PSD Class II increment for PM_{10} .

Table 7-17. Summary of Worst-Case Estimates of H₂SO₄ Mist Impacts Compared to FDEP Ambient Reference Concentrations

Pollutant	Averaging Time	Maximum Impact (µg/m ³)	Ambient Reference Concentration (µg/m ³)
H ₂ SO ₄ mist	8-hour	1.11	10
	24-hour	0.64	2.4

Source: ECT, 1999.

Based on the conservative nature of the air quality analysis, there is reasonable assurance that Smith Unit 3 will:

- Not cause nor contribute to an exceedance of any NAAQS or Florida AAQS.
- Not cause nor contribute to an exceedance of any PSD Class I or Class II increment.
- Not cause nor contribute to an exceedance of any FDEP draft ARC.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest FDEP ambient air monitoring station is located in Panama City, Bay County, approximately 13 km southeast of the Smith Unit 3 site. The FDEP monitoring station at Panama City monitors PM_{10} . The nearest FDEP stations that monitor SO_2 and NO_2 are located in Pensacola, Escambia County, approximately 161 km west of the Smith Unit 3 site. The nearest FDEP stations monitoring for CO and lead are situated in Jacksonville, Duval County, approximately 441 km east of the Smith Unit 3 site. The nearest FDEP station that monitors ozone is located in Tallahassee, Leon County, approximately 158 km northeast of the Smith Unit 3 site. A summary of 1997 and 1998 ambient air quality data for these FDEP monitoring stations is provided in Tables 8-1 and 8-2.

In addition to the FDEP ambient air monitoring stations, Gulf also conducts ambient air monitoring for TSP, SO_2 , and NO_2 . Gulf currently operates two SO_2 monitoring stations in Bay County (East and North Remote Lynn Haven Stations), and one NO_2 monitoring station in Bay County (North Remote Lynn Haven Station). A summary of 1993—1995 and 1996—1998 ambient air quality data for these Gulf monitoring stations is provided in Tables 8-3 and 8-4.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 4.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several pollutants will be emitted from Smith Unit 3 in excess of their respective significant emission rates, preconstruction monitoring is generally required. However, the FDEP Rule 62-212.400(2)(e), F.A.C. provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 4-1. To assess the

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

Table 8-1. Summary of 1997 FDEP Ambient Air Quality Data

Pollutant	Site Location		Site No.	Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m ³)				
	County	City						1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM ₁₀	Bay	Panama City	3480-004-F02	13 SE	24-Hr Annual	Jan-Dec	56	62	52	62	25	150 ¹ 50 ²
	Gulf	Port St. Joe	3740-003-F02	60 SE	24-Hr Annual	Jan-Dec	53	65	54	65	23	
SO ₂	Escambia	Pensacola	3540-004-F01	161 W	1-Hr	Jan-Dec	8,715	291	254		11	1,300 ³
					3-Hr			233	191			260 ³
					24-Hr Annual			98	76			60 ²
	Escambia	Pensacola	3540-022-F02	161 W	1-Hr	Jan-Dec	8,657	432	403		12	1,300 ³
					3-Hr			333	322			260 ³
					24-Hr Annual			114	86			60 ²
NO ₂	Escambia	Pensacola	3540-004-F01	161 W	1-Hr Annual	Jan-Sep	6,161	105	98		16	100 ²
CO	Duval	Jacksonville	1960-080-H01	441 E	1-Hr	Jan-Dec	8,519	3,420	3,420			40,000 ³
					8-Hr			2,280	2,280			10,000 ³
CO	Duval	Jacksonville	1960-083-H01	441 E	1-Hr	Jan-Dec	8,544	7,980	5,700			40,000 ³
					8-Hr			3,420	3,420			10,000 ³
CO	Duval	Jacksonville	1960-084-H01	441 E	1-Hr	Jan-Dec	8,576	6,840	6,840			40,000 ³
					8-Hr			4,560	3,420			10,000 ³
CO	Duval	Jacksonville	1960-095-H01	441 E	1-Hr	Jan-Dec	8,074	7,980	5,700			40,000 ³
					8-Hr			3,420	3,420			10,000 ³
Ozone	Leon	Tallahassee	2340-003-F01	158 NE	1-Hr	Mar-Mar	345	135	110			235 ⁴
Lead	Duval	Jacksonville	1960-032-H01	441 E	24-Hr	Jan-Mar	15				0.0	1.5 ²
						Apr-Jun	15				0.0	
						Jul-Sep	15				0.0	
						Oct-Dec	13				0.0	
Lead	Duval	Jacksonville	1960-084-H01	441 E	24-Hr	Jan-Mar	15				0.0	1.5 ²
						Apr-Jun	15				0.0	
						Jul-Sep	14				0.0	
						Oct-Dec	14				0.0	

¹ 99th percentile² Arithmetic mean³ 2nd high⁴ 4th highest day with hourly value exceeding standard over a 3-year periodSources: FDEP, 1998 and 1999.
ECT, 1999.

Table 8-2. Summary of 1998 FDBP Ambient Air Quality Data

Pollutant	Site Location		Site No.	Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m ³)				
	County	City						1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM ₁₀	Bay	Panama City	12-005-004	13 SE	24-Hr Annual	Jan-Dec	54	73	64	73	28	150 ¹ 50 ²
	Gulf	Port St. Joe	12-045-1003	60 SE	24-Hr Annual	Jan-Dec	61	73	65	73	26	
SO ₂	Escambia	Pensacola	12-033-0004	161 W	1-Hr	Jan-Dec	8,707	334	310			
					3-Hr			253	214			1,300 ³
					24-Hr			60	57			260 ³
					Annual						10	60 ⁴
	Escambia	Pensacola	12-033-0022	161 W	1-Hr	Jan-Dec	8,595	477	360			
					3-Hr			264	211			1,300 ³
					24-Hr			63	63			260 ³
					Annual						10	60 ²
NO ₂	Duval	Jacksonville	12-031-0032	441 E	1-Hr Annual	Jan-Dec	8,204	124	124		28	100 ²
CO	Duval	Jacksonville	12-031-0080	441 E	1-Hr	Jan-Dec	8,311	9,576	7,296			40,000 ³
					8-Hr			5,130	3,306			10,000 ³
CO	Duval	Jacksonville	12-031-0083	441 E	1-Hr	Jan-Dec	8,013	5,586	5,472			40,000 ³
					8-Hr			3,534	3,306			10,000 ³
CO	Duval	Jacksonville	12-031-0084	441 E	1-Hr	Jan-Dec	8,417	6,954	6,270			40,000 ³
					8-Hr			3,762	3,762			10,000 ³
CO	Duval	Jacksonville	12-031-0095	441 E	1-Hr	Jan-Dec	2,111	5,016	4,218			40,000 ³
					8-Hr			2,280	2166			10,000 ³
Ozone	Leon	Tallahassee	12-073-0012	158 NE	1-Hr	Jan-Dec	199	202	190			235 ⁴
Lead	Duval	Jacksonville	12-031-0032	441 E	24-Hr		50					
						Jan-Mar					0.01	1.5 ²
						Apr-Jun					0.02	
						Jul-Sep					0.01	
Lead	Duval	Jacksonville	12-031-0084	441 E	24-Hr		62					
						Oct-Dec					0.02	
						Jan-Mar					0.01	1.5 ²
						Apr-Jun					0.01	
						Jul-Sep					0.01	
						Oct-Dec					0.02	

¹ 99th percentile² Arithmetic mean³ 2nd high⁴ 4th highest day with hourly value exceeding standard over a 3-year period

Sources: FDEP, 1998 and 1999.

ECT, 1999.

Table 8-3. Summary of 1993 - 1995 Gulf Power Ambient Air Quality Data

Pollutant	Site Location		Year	Site No.	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m ³)							
	County	Name						1st High	2nd High	Arithmetic Mean	Standard				
TSP	Bay	Smith Plant	1993		Annual	Jan-Dec				22.26*	50 ¹				
			1994		Annual	Jan-Dec				22.23*	50 ¹				
			1995		Annual	Jan-Dec				22.53*	50 ¹				
SO ₂	Bay	North Remote Lynn Haven	1993	2420-004J02	1-Hr	Jul-Sep	1,722	296	212						
					3-Hr			138	138			1,300 ²			
					24-Hr			47	32			260 ²			
			1994		1-Hr	Jan-Dec	6,884	479	401						
					3-Hr			238	199			1,300 ²			
					24-Hr			44	44			260 ²			
			1995		1-Hr	Jan-Dec	7,060	956	736						
					3-Hr			700	465			1,300 ²			
					24-Hr			154	136			260 ²			
			1993		East Remote Lynn Haven	1993	2420-005J02	1-Hr	Jul-Sep	1,487	207	186			
								3-Hr			183	97			1,300 ²
								24-Hr			27	26			260 ²
						1994		1-Hr	Jan-Dec	7,672	789	574			
								3-Hr			597	407			1,300 ²
								24-Hr			166	102			260 ²
						1995		1-Hr	Jan-Dec	6,095	1,138	778			
								3-Hr			504	475			1,300 ²
								24-Hr			256	157			260 ²
NO ₂	Bay	North Remote Lynn Haven	1993	2420-004J02	Annual	Jan-Dec					5.13*	100 ¹			
			1994		Annual	Jan-Dec					4.59*	100 ¹			
			1995		Annual	Jan-Dec					5.02*	100 ¹			

¹ Arithmetic mean² 2nd high

*Average of four quarterly geometric means.

Sources: Gulf Power, 1999.
ECT, 1999.

Table 8-4. Summary of 1996 -1998 Gulf Power Ambient Air Quality Data

Pollutant	Site Location		Year	Site No.	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m ³)			
	County	Name						1st High	2nd High	Arithmetic Mean	Standard
TSP	Bay	Smith Plant	1996		Annual	Jan-Dec				19.24*	50 ¹
			1997		Annual	Jan-Dec				18.56*	50 ¹
			1998		Annual	Jan-Dec				25.0*	50 ¹
SO ₂	Bay	North Remote Lynn Haven	1996	2420-004J02	1-Hr	Jan-Dec	7,232	1,107	1,005		
					3-Hr			1,005	961		1,300 ²
					24-Hr			76	63		260 ²
			1997		1-Hr	Jan-Dec	5,252	948	741		
					3-Hr			529	527		1,300 ²
					24-Hr			152	149		260 ²
			1998		Annual		6,328			16.3	60 ¹
					1-Hr	Jan-Dec		697	697		
					3-Hr			584	545		1,300 ²
					24-Hr			199	105		260 ²
					Annual					6.3	60 ¹
	Bay	East Remote Lynn Haven	1996	2420-005J02	1-Hr	Jan-Dec	5,674	919	888		
					3-Hr			721	708		1,300 ²
					24-Hr			248	167		260 ²
			1997		1-Hr	Jan-Dec	6,495	582	537		
					3-Hr			490	461		1,300 ²
					24-Hr			178	157		260 ²
			1998		Annual		6,112			17.1	60 ¹
					1-Hr	Jan-Dec		1035	838		
					3-Hr			629	587		1,300 ²
NO ₂	Bay	North Remote Lynn Haven	1996	2420-004J02	Annual	Jan-Dec				6.11*	100 ¹
			1997		Annual	Jan-Dec				13.43*	100 ¹
			1998		Annual	Jan-Dec				3.49*	100 ¹

¹ Arithmetic mean² 2nd high

*Average of four quarterly geometric means.

Sources: Gulf Power, 1999,
ECT, 1999.

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appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from the proposed facility. The results of these analyses are presented in detail in Section 7.2. The following paragraphs summarize the analyses results as applied to the preconstruction ambient air quality monitoring exemptions.

8.2.1 PM₁₀

The maximum 24-hour PM₁₀ impact was predicted to be 13.4 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$). This concentration is above the 10 $\mu\text{g}/\text{m}^3$ *de minimis* level. In accordance with EPA guidance (EPA, 1992a), representative, current (1997 and 1998) quality-assured ambient PM₁₀ data collected at the FDEP's PM₁₀ monitoring site located in Panama City, Bay County was used to satisfy the PSD pre-construction ambient air monitoring requirements for PM₁₀. A summary of the FDEP monitored PM₁₀ ambient air quality data is provided on Tables 8-1 and 8-2.

8.2.2 CO

The maximum 8-hour CO impact was predicted to be 38.4 $\mu\text{g}/\text{m}^3$. This concentration is well below the 575 $\mu\text{g}/\text{m}^3$ *de minimis* ambient impact level for CO. Therefore, a preconstruction monitoring exemption is appropriate in accordance with the PSD regulations.

8.2.3 SO₂

The maximum 24-hour SO₂ impact was predicted to be 1.7 $\mu\text{g}/\text{m}^3$. This concentration is well below the 13 $\mu\text{g}/\text{m}^3$ *de minimis* ambient impact level for SO₂. Therefore, a preconstruction monitoring exemption is appropriate in accordance with the FDEP PSD regulations.

8.2.4 OZONE

Because the proposed Smith Unit 3 will not exceed the PSD monitoring significance level (i.e., potential VOC emissions are less than 100 tpy), preconstruction monitoring for ozone is not required in accordance with the FDEP PSD regulations.

9.0 ADDITIONAL IMPACT ANALYSES

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to: (a) associated growth, (b) soils, vegetation, and wildlife, and (c) visibility impairment. Each of these topics is discussed in the following sections.

9.1 GROWTH IMPACT ANALYSIS

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

Impacts associated with construction of the Smith Unit 3 Project and ancillary equipment will be minor. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The Smith Unit 3 Project is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of Smith Unit 3 are anticipated. When operational, Smith Unit 3 is projected to generate approximately 29 new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas fuel demand due to operation of Smith Unit 3 CT/HRSGs will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

9.2.1 IMPACTS ON SOILS

All the soil types present on the site and in the immediate vicinity are nearly level, poorly drained soils and are described as very strongly acid (see Section 2.3.1.3 of the SCA for soil descriptions). The components of emissions from the power plant of potential impact to soils are SO₂ (including acid rain) and NO_x. However, there will be a net decrease in

NO_x emissions from the Lansing Smith Plant following installation of Unit 3 due to the contemporaneous installation of low-NO_x burners and an improved burner management system for Lansing Smith Unit 1. The primary effect of SO₂ and NO_x deposition and adsorption by soils is the resultant lowering of soil pH. Low soil pH will have an influence on most chemical and biological reactions in the soil including the level and availability of most plant nutrients in the soil. Based on the extremely low maximum incremental and total SO₂ impacts predicted and the ambient acidic nature of the soils, no impacts to soils resources at the plant site or the vicinity are expected.

9.2.2 IMPACTS ON VEGETATION

As described in Section 2.3.5 of the SCA, the vegetation on the proposed power plant site consists of relatively natural and planted vegetation represented mostly by pine plantation and cypress titi-swamp, as well as ruderal or remnant upland and wetland vegetation in areas previously cleared for construction of the existing transmission line right-of-way. The land use and vegetative cover in the immediate area surrounding the project area is a combination of pine plantation/cypress titi-swamp and developed land. The developed land mostly consists of the existing Smith Generating Plant to the south of the site. The vegetated areas in the immediate vicinity of the project site consists of pine plantation planted with slash pine and forested wetlands represented by cypress titi-swamps and hydric slash pine plantation.

Potential impacts to vegetation from SO₂, acid rain, and CO have been evaluated with respect to dose response curves that have been developed for various plant species and their sensitivity to these pollutants. Vegetation damages are described as impacts which result in foliar damage. Less apparent vegetation injury is described as a reduction in growth and/or productivity without visible damage as well as changes in secondary metabolites such as tannin and phenolic compounds. Vegetation damage often results from acute exposure to pollution (i.e., relatively high doses over relatively short time periods). Injury is also associated with prolonged exposures of vegetation to relatively low doses of pollutants (chronic exposure). Acute damages are usually manifested by internal physical

damage to foliar tissues which have both functional and visible consequences. Chronic injuries are typically more associated with changes in physiological processes. The following discussion summarizes descriptions from the literature of the effects upon vegetation associated with the pollutants of concern with the proposed power plant project.

SO₂

Natural (ambient) background concentrations of SO₂ range between 0.28 and 2.8 µg/m³ of SO₂ on a mean annual basis (Prinz and Brandt, 1985). The most common source of atmospheric SO₂ is the combustion of fossil fuels (Mudd and Kozlowski, 1975). Gaseous SO₂ primarily affects vegetation by diffusion through the stomata (Varshney and Garg, 1979). Small amounts of SO₂ may also be absorbed through the protective cuticle. Adverse effects upon plants from SO₂ are primarily due to impacts to photosynthetic processes. SO₂ can react with chlorophyll by causing bleaching or by phaeophytinization. This latter process constitutes a photosynthetic deactivation of the chlorophyll molecule. Acute damage due to SO₂ appears as marginal or intercostal areas of dead tissue which at first cause leaves to appear water soaked (Barrett and Benedict, 1970). Chronic injuries are less apparent; the leaves remain turgid and continue to function at a reduced level. In more severe cases of chronic SO₂ exposure, there is some bleaching of the chlorophyll which appears as a mild chlorosis or yellowing of the leaf and/or a silvery or bronzing of the undersurface. Species which are categorized as sensitive to SO₂ emissions are those which show damage to at least 5 percent of the leaf area upon being exposed to 131 to 1,310 µg/m³ SO₂ for a period of 8 hours (Jones *et al.* 1974).

Researchers have conducted numerous studies to determine the effects of SO₂ exposure to a wide variety of selected plant species. A review of the literature demonstrates that the most sensitive vascular plants (e.g., white ash, sumacs, yellow poplar, goldenrods, legumes, blackberry, southern pine, red oak, black oak, ragweeds) exhibit visible injury to short-term (3 hours) exposure to SO₂ concentrations ranging from 790 to 1,570 µg/m³ (*ibid.*). Caribbean pine (*Pinus caribaea*) seedlings similar in ecology and appearance to slash pine (*Pinus elliotti*) exhibited up to 5 percent needle necrosis when exposed to

1,310 $\mu\text{g}/\text{m}^3$ SO_2 for 4 hours (Umbach and Davis, 1988). Native plant species common to the region are either tolerant (red maple, live oak, cypress, slash pine) or sensitive (bracken fern) to SO_2 exposures (Woltz and Howe, 1981; U.S. Department of Agriculture, 1972; EPA, 1976; Loomis and Padgett, 1973). Complicating generalizations regarding SO_2 injury is the observation that the genetic variability of native annual plants can result in the selection of SO_2 -resistant strains in as little as 25 years (Westman *et al.* 1985).

Because of relative low chlorophyll content and the absence of a protective covering of the cuticle common in the leaves of higher plants, nonvascular plants such as lichens and bryophytes are relatively more sensitive to SO_2 injury and have been documented on those primitive plants at levels as low as 88 $\mu\text{g}/\text{m}^3$ (U.S. Department of Health, Education, and Welfare, 1971). Hart *et al.* (1976) showed that *Ramalina* spp., a lichen genus, exhibited a reduction of carbon dioxide uptake and biomass gain at SO_2 exposures of 400 $\mu\text{g}/\text{m}^3$ for 6 weeks. Tolerant lichens can resist SO_2 concentrations in the range of 79 to 157 $\mu\text{g}/\text{m}^3$; higher concentrations are deleterious to most nonvascular flora (LeBlanc and Rao, 1975).

The maximum total 3-hour average SO_2 concentration for the Smith Unit 3 Project is projected to be 7.6 $\mu\text{g}/\text{m}^3$. The maximum total predicted 24-hour average SO_2 concentration is 1.7 $\mu\text{g}/\text{m}^3$. Annually, the concentration is predicted to be 0.1 $\mu\text{g}/\text{m}^3$. All of these estimates are lower than doses known to cause vegetative injury.

H_2SO_4 Mist

Acidic precipitation or acid rain is coupled to the emissions of the pollutant SO_2 mainly formed during the burning of fossil fuels. This compound is oxidized in the atmosphere and dissolves in rain forming H_2SO_4 mist which falls as acidic precipitation (Ravera, 1989). Concentration data are not available, but H_2SO_4 mist has yielded necrotic spotting on the upper surfaces of leaves (Middleton *et al.* 1950).

Since the concentration of H_2SO_4 mist from the proposed power generating facility is directly dependent upon the availability of SO_2 and SO_2 concentrations are predicted to be well below levels which have been documented as negatively affecting vegetation, no impacts from H_2SO_4 mist are expected. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentration of aluminum in the soil water (Goldstein *et al.* 1985). Although effects of acid rain in eastern North America have been well publicized (decline of conifer forests in the Appalachians), documented detrimental effects of acid rain on Florida vegetation is lacking (Gholz, 1985; Charles, 1991).

CO

CO is not considered harmful to plants and is not known to be effectively taken up by plants (Bennett and Hill, 1975). Microorganisms within the soil appear to be a major sink for CO. No impacts to vegetation from CO are expected.

9.2.3 IMPACTS ON WILDLIFE

Air pollution impacts to wildlife have been reported in the literature although many of the incidents involved acute exposures to pollutants usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutant levels.

Based on a review of the limited literature on air pollutant effects on wildlife, it is unlikely that the levels of pollutants produced by this Project will cause injury or death to wildlife. Concentrations of pollutants will be low, emissions will be dispersed over a

large area, and mobility of wildlife will minimize their exposure to any unusual concentrations caused by equipment malfunction or unique weather patterns.

The acid rain effects on wildlife in Florida are primarily those related to aquatic animals. Acidified water may prevent fish egg hatching, damage larvae, and lower immunity factors in adult fish (Barker, 1983). Acid rain can also result in release of metals (especially aluminum) from lake sediments; this can cause a biochemical deterioration of fish gills leading to death by suffocation. However, the sensitivity of Florida lakes to acid rain is in question (*ibid.*). Florida lakes have a wide natural range of pH (from 4 to 8.8 pH units). According to Barker (1983) and Charles (1991), no evidence is currently available to clearly show that degradation of aquatic systems have occurred as a direct result of acid precipitation in Florida. The projected air emissions from the Smith Unit 3 Project which contribute to formation of atmospheric acids are not predicted to significantly increase acid precipitation and are predicted to have no impact on wildlife.

In conclusion, it is unlikely that the projected air emission levels from the proposed power plant will have any measurable direct or indirect effects on wildlife using the site or vicinity.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for the Project. Opacity of the Project CTG/HRSG unit exhausts will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the Project CTG/HRSGs will be low due to the exclusive use of pipeline quality natural gas. The Smith Unit 3 Project will comply with all applicable FDEP requirements pertaining to visible emissions.

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ATTACHMENT A—

APPLICATION FOR AIR PERMIT – TITLE V SOURCE



Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: Gulf Power Company	
2. Site Name: Lansing Smith Electric Generating Plant – Smith Unit 3	
3. Facility Identification Number: 0050014 [] Unknown	
4. Facility Location: Street Address or Other Locator: 4300 Highway 2300 City: Southport County: Bay Zip Code: 32409	
5. Relocatable Facility? [] Yes [<input checked="" type="checkbox"/>] No	6. Existing Permitted Facility? [<input checked="" type="checkbox"/>] Yes [] No

Application Contact

1. Name and Title of Application Contact: G. Dwain Waters Air Quality Programs Coordinator	
2. Application Contact Mailing Address: Organization/Firm: Gulf Power Company Street Address: One Energy Place City: Pensacola State: FL Zip Code: 32520-0328	
3. Application Contact Telephone Numbers: Telephone: (850)444 – 6527 Fax: (850) 444-6217	

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

- ☐ Initial Title V air operation permit for an existing facility which is classified as a Title V source.
- ☐ Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: _____

- ☐ Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: _____

Operation permit number to be revised: _____

- ☐ Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: _____

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

Operation permit number to be revised: _____

Reason for revision: _____

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

- ☒ Air construction permit to construct or modify one or more emissions units.
- ☐ Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.
- ☐ Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

Name : Robert G. Moore
Title : V. P. Power Generation/Transmission

2. Owner or Authorized Representative or Responsible Official Mailing Address :


Organization/Firm : Gulf Power Company
Street Address : One Energy Place
City : Pensacola
State : FL Zip Code : 32520-0100

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

Telephone : (850)444-6383 Fax : (850)444-6744

4. Owner/Authorized Representative or Responsible Official Statement :

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions units.*


Signature

5/27/99
Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: Thomas W. Davis Registration Number: 36777
2. Professional Engineer Mailing Address: Organization/Firm: Environmental Consulting & Technology, Inc. Street Address: 3701 Northwest 98th Street City: Gainesville State: FL Zip Code: 32606
3. Professional Engineer Telephone Numbers: Telephone: (352) 332-0444 Fax: (352) 332-6722

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [☒], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [☒], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [☐], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.



6/5/99
Date

Attach any exception to certification statement.

Poor Original

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
006	Combined Cycle Combustion Turbine Generator Unit No. 1 (CC-1)	AC1A	N/A
007	Combined Cycle Combustion Turbine Generator Unit No. 2 (CC-2)	AC1A	N/A
008	Salt Water Cooling Tower	AC1A	N/A

Application Processing Fee

Check one: [☐] Attached - Amount: \$ _____ [☒] Not Applicable

Note: Application processing fee will be submitted pursuant to the FPPSA.

Construction/Modification Information

1. Description of Proposed Project or Alterations:

Project consists of the addition of two nominal 170-MW General Electric 7241 FA combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs) equipped with supplemental duct burners (DBs), one nominal 200-MW steam turbine generator (STG), and one, 10 cell, mechanical draft salt water cooling tower. At average annual site conditions with duct burner firing, Unit 3 will generate 566 MW. At summer peaking site conditions with duct burner firing and steam power augmentation, Unit 3 will generate 574 MW. The CTGs and DBs will be fired exclusively with pipeline quality natural gas. The CTGs will include provisions for the optional use of evaporative coolers and steam power augmentation. The new combined-cycle CTG/HRSGs will be capable of operating at base load for up to 8,760 hours per year. The CTGs will normally operate between 50- and 100-percent load, with commensurate STG load.

2. Projected or Actual Date of Commencement of Construction: **November 1, 2000**

3. Projected Date of Completion of Construction: **February 1, 2002**

Application Comment

A. GENERAL FACILITY INFORMATION

1. Facility UTM Coordinates:			
Zone: 16		East (km): 625.03	North (km): 3,349.08
2. Facility Latitude/Longitude:			
Latitude (DD/MM/SS):		Longitude (DD/MM/SS):	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters):			

1. Name and Title of Facility Contact:	Richard Kraynak, Group Leader Operations		
2. Facility Contact Mailing Address:	Organization/Firm: Gulf Power Company – Lansing Smith		
	Street Address: 4300 Highway 2300		
	City: Southport	State: FL	Zip Code: 32409
3. Facility Contact Telephone Numbers:	Telephone: (850) 265-2318		
	Fax: (850) 271-1697		

Facility Regulatory Classifications**Check all that apply:**

1. <input type="checkbox"/> Small Business Stationary Source?	<input type="checkbox"/> Unknown
2. <input checked="" type="checkbox"/> Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. <input type="checkbox"/> Synthetic Minor Source of Pollutants Other than HAPs?	
4. <input checked="" type="checkbox"/> Major Source of Hazardous Air Pollutants (HAPs)?	
5. <input type="checkbox"/> Synthetic Minor Source of HAPs?	
6. <input checked="" type="checkbox"/> One or More Emissions Units Subject to NSPS?	
7. <input type="checkbox"/> One or More Emission Units Subject to NESHAP?	
8. <input type="checkbox"/> Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

See Attachment A-1	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap		4. Basis for Emissions Cap	5. Pollutant Comment
		lb/hour	tons/year		
NOX	A	N/A	3,587	ESCPD	Cap for Unit 1 and Unit 3
SO2	A	N/A	N/A	N/A	
CO	A	N/A	N/A	N/A	
PM10	A	N/A	N/A	N/A	
PM	A	N/A	N/A	N/A	
SAM	A	N/A	N/A	N/A	
VOC	A	N/A	N/A	N/A	
HCL	A	N/A	N/A	N/A	
H107	A	N/A	N/A	N/A	
HAPs	A	N/A	N/A	N/A	

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [<input checked="" type="checkbox"/>] Attached, Document ID: Fig. 2-3 [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
2. Facility Plot Plan: [<input checked="" type="checkbox"/>] Attached, Document ID: Fig. 2-4 [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
3. Process Flow Diagram(s): [<input checked="" type="checkbox"/>] Attached, Document ID: Fig. 2-5 [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [<input checked="" type="checkbox"/>] Attached, Document ID: Att. A-2 [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
5. Fugitive Emissions Identification: [<input type="checkbox"/>] Attached, Document ID: _____ [<input checked="" type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
6. Supplemental Information for Construction Permit Application: [<input checked="" type="checkbox"/>] Attached, Document ID: PSD App. [<input type="checkbox"/>] Not Applicable
7. Supplemental Requirements Comment: Items 1, 2, 3, 4, and 6 above are specific for the Smith Unit 3 project. See previously submitted Smith Electric Generating Plant Title V permit application for existing facility information.

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [] Attached, Document ID: _____ [] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [] Attached, Document ID: _____ [] Equipment/Activities On site but Not Required to be Individually Listed [] Not Applicable
10. Alternative Methods of Operation: [] Attached, Document ID: _____ [] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [] Attached, Document ID: _____ [] Not Applicable
12. Identification of Additional Applicable Requirements: [] Attached, Document ID: _____ [] Not Applicable
13. Risk Management Plan Verification: [] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID: _____) or previously submitted to DEP (Date and DEP Office: _____) [] Plan to be submitted to CEPPO (Date required: _____) [] Not Applicable
14. Compliance Report and Plan: [] Attached, Document ID: _____ [] Not Applicable
15. Compliance Certification (Hard-copy Required): [] Attached, Document ID: _____ [] Not Applicable

Items 8. through 15. above previously submitted – see Smith Electric Generating Plant Title V permit application.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)			
[<input checked="" type="checkbox"/>] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).			
[] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.			
[] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Regulated or Unregulated Emissions Unit? (Check one)			
[<input checked="" type="checkbox"/>] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.			
[] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.			
3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Emission unit consists of one General Electric (GE) 7241 FA combustion turbine generator (CTG) having a nominal rating of 170 megawatts (MW) and one fired heat recovery steam generator (HRSG). The CTG/HRSG unit will be fired exclusively with pipeline quality natural gas.			
4. Emissions Unit Identification Number:		[] No ID	
ID: 006 (CC-1)		[] ID Unknown	
5. Emissions Unit Status Code: C	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? [<input checked="" type="checkbox"/>]
9. Emissions Unit Comment: (Limit to 500 Characters)			

Emissions Unit Information Section 1 of 3

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

NO_x Controls

Dry low-NO_x combustors

2. Control Device or Method Code(s): **25 (dry low-NO_x)**

Emissions Unit Details

1. Package Unit:	
Manufacturer: General Electric	Model Number: PG7241(FA)

2. Generator Nameplate Rating: 170 MW
--

3. Incinerator Information:	
Dwell Temperature:	°F
Dwell Time:	seconds
Incinerator Afterburner Temperature:	°F

**B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)**

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	1,751 (LHV) mmBtu/hr (CTG only)	
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Requested Maximum Operating Schedule:		
	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):	<p>CTG maximum heat input is lower heating value (LHV) at 100 percent load, 0°F operating conditions. Heat input will vary with load and ambient temperature.</p> <p>HRSG duct burner maximum heat input is a nominal 275 MMBtu/hr (LHV).</p> <p>At average annual site conditions with duct burner firing, Unit 3 will generate 566 MW. At summer peaking site conditions with duct burner firing and steam power augmentation, Unit 3 will generate 574 MW.</p>	

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? CC-1		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 121 feet	7. Exit Diameter: 16.8 feet	
8. Exit Temperature: 186 °F	9. Actual Volumetric Flow Rate: 981,334 acfm	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: East (km): North (km):			
14. Emission Point Comment (limit to 200 characters): Stack temperature and flow rate are at 100 percent load, 65°F, evaporative cooling, and duct burner firing operating conditions (Case 6). Stack temperature and flow rate will vary with load, ambient temperature, and use of optional evaporative cooling, duct burner firing, and steam power augmentation.			

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine generator fired with pipeline quality natural gas.		
2. Source Classification Code (SCC): 20100201		3. SCC Units: Million Cubic Feet Burned
4. Maximum Hourly Rate: 1.845	5. Maximum Annual Rate: 16,162.2	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 950
10. Segment Comment (limit to 200 characters): Fuel heat content (Field 9) represents lower heating value (LHV).		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): HRSG duct burner fired with pipeline quality natural gas.		
2. Source Classification Code (SCC): 10100601		3. SCC Units: Million Cubic Feet Burned
4. Maximum Hourly Rate: 0.290	5. Maximum Annual Rate: 2,540.4	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 950
10. Segment Comment (limit to 200 characters): Maximum hourly rate (Field 4) based on nominal heat input of 275 MMBtu/hr (LHV) Maximum Annual Rate (Field 5) based on 8,760 hours per year. Fuel heat content (Field 9) represents lower heating value (LHV).		

DEP Form No. 62-210.900(1) - Form
Effective: 2/11/99

Emissions Unit Information Section 1 of 3

Pollutant Detail Information Page 2 of 14

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 116.6 lb/hour 350.7 tons/year		4. Synthetically Limited? [<input checked="" type="checkbox"/>]	
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: 116.6 lb/hr Reference: GE data		7. Emissions Method Code: 5	
8. Calculation of Emissions (limit to 600 characters): <p>Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 75.4 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 116.6 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.</p>			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):			

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: Other		2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 13 ppmvd @ 15% O₂		4. Equivalent Allowable Emissions: 58.3 lb/hour N/A tons/year	
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10 (initial only)			
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): <p>FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable to CTG/HRSG operations without duct burner firing or steam power augmentation.</p>			

Emissions Unit Information Section 1 of 3**Pollutant Detail Information Page 4 of 14****Allowable Emissions** Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 23 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 116.6 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable to CTG/HRSG operations at 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11).	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 16 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 78.7 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable to CTG/HRSG operations with duct burner firing and without steam augmentation.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 21.5 lb/hour 91.8 tons/year	4. Synthetically Limited? [<input checked="" type="checkbox"/>]
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year	
6. Emission Factor: 21.5 lb/hr Reference: GE data	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): <p>Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 20.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 21.5 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.</p>	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10% opacity	4. Equivalent Allowable Emissions: 21.5 lb/hour 91.8 tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 9 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): <p>FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable for all CTG/HRSG operating modes.</p>	

Emissions Unit Information Section 1 of 3

Pollutant Detail Information Page 6 of 14

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.03 lb/MMBtu	4. Equivalent Allowable Emissions: 8.3 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Methods 5, 5B, or 17 (Initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 40 CFR Part 60, §60.42a(a)(1), Subpart Da (NSPS); applicable to DB only.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 21.5 lb/hour 91.8 tons/year	4. Synthetically Limited? [<input checked="" type="checkbox"/>]
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year	
6. Emission Factor: 21.5 lb/hr Reference: GE data	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): <p>Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 20.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 21.5 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.</p>	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10% opacity	4. Equivalent Allowable Emissions: 21.5 lb/hour 91.8 tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 9 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): <p>FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable for all CTG/HRSG operating modes.</p>	

Emissions Unit Information Section 1 of 3

Pollutant Detail Information Page 8 of 14

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 12.7 lb/hour 52.3 tons/year	4. Synthetically Limited? [<input checked="" type="checkbox"/>]	
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year		
6. Emission Factor: 12.7 lb/hr Reference: GE data		7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): $(2.0 \text{ gr S}/100 \text{ ft}^3 \text{ gas}) \times (2,223,100 \text{ ft}^3 \text{ gas/hr}) \times (1 \text{ lb S}/7,000 \text{ gr S}) \times (2 \text{ lb SO}_2/\text{lb S})$ = 12.7 lb/hr SO₂ Annual emissions based on 11.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 12.4 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.20 lb/MMBtu	4. Equivalent Allowable Emissions: 55.0 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to DB only per 40 CFR Part 60, §60.43a(b)(2), NSPS.	

Emissions Unit Information Section 1 of 3

Pollutant Detail Information Page 10 of 14

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.8 weight % S fuel	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to CTG only per 40 CFR Part 60, §60.333(b), NSPS.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SAM	2. Total Percent Efficiency of Control:
3. Potential Emissions: <div style="display: flex; justify-content: space-around;"> 1.46 lb/hour 6.0 tons/year </div>	4. Synthetically Limited? [<input checked="" type="checkbox"/>]
5. Range of Estimated Fugitive Emissions: <div style="display: flex; justify-content: space-between;"> [] 1 [] 2 [] 3 _____ to _____ tons/year </div>	
6. Emission Factor: 1.46 lb/hr Reference: GE data	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): <p align="center">$(12.7 \text{ lb/hr SO}_2) \times (7.5/100) \times (98 \text{ lb H}_2\text{SO}_4/64 \text{ lb SO}_2) = 1.46 \text{ lb/hr H}_2\text{SO}_4$</p> <p>Annual emissions based on 1.36 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 1.43 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.</p>	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: <div style="display: flex; justify-content: space-around;"> lb/hour tons/year </div>
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

Emissions Unit Information Section 1 of 3

Pollutant Detail Information Page 12 of 14

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 16.8 lb/hour 46.4 tons/year		4. Synthetically Limited? [<input checked="" type="checkbox"/>]	
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: 16.8 lb/hr Reference: GE data		7. Emissions Method Code: 5	
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 9.8 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 16.8 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):			

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: Other		2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 3 ppmvd @ 15% O₂		4. Equivalent Allowable Emissions: 6.6 lb/hour N/A tons/year	
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25 (initial only)			
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to CTG/HRSG operations without duct burner firing or steam power augmentation.			

Emissions Unit Information Section 1 of 3**Pollutant Detail Information Page 14 of 14****Allowable Emissions** Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 6 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 16.8 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to CTG/HRSG operations at 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11).	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 4 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 10.2 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to CTG/HRSG operations with duct burner firing and without steam augmentation.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: <input type="checkbox"/> Rule <input checked="" type="checkbox"/> Other
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment (limit to 200 characters): Rule 62-212.400(5)(c), F.A.C. (BACT)	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: <input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour	
4. Method of Compliance: EPA Reference Method 9 (every 5 years)	
5. Visible Emissions Comment (limit to 200 characters): Excess emissions resulting from startup, shutdown, or malfunction not-to-exceed 2 hours in any 24 hour period unless authorized by FDEP for a longer duration. Rule 62-210.700(1), F.A.C. Applicant has requested up to 4 hours for cold startups and all shutdowns.	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	[<input checked="" type="checkbox"/>] Rule [<input type="checkbox"/>] Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Subpart Da. Specific CEMS information will be provided to FDEP when available.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: O₂	2. Pollutant(s):
3. CMS Requirement:	[<input checked="" type="checkbox"/>] Rule [<input type="checkbox"/>] Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Subpart Da. Specific CEMS information will be provided to FDEP when available.	

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

Supplemental Requirements

1. Process Flow Diagram [<input checked="" type="checkbox"/>] Attached, Document ID: <u>Fig. 2-5</u> [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
2. Fuel Analysis or Specification [<input checked="" type="checkbox"/>] Attached, Document ID: <u>Att. A-3</u> [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
3. Detailed Description of Control Equipment [<input checked="" type="checkbox"/>] Attached, Document ID: <u>Sect. 5.0</u> [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
4. Description of Stack Sampling Facilities To be provided [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
5. Compliance Test Report [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Previously submitted, Date: _____ [<input type="checkbox"/>] Not Applicable
6. Procedures for Startup and Shutdown [<input type="checkbox"/>] Attached, Document ID: _____ [<input checked="" type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
7. Operation and Maintenance Plan [<input type="checkbox"/>] Attached, Document ID: _____ [<input checked="" type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
8. Supplemental Information for Construction Permit Application See PSD application [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable
9. Other Information Required by Rule or Statute [<input type="checkbox"/>] Attached, Document ID: _____ [<input checked="" type="checkbox"/>] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [<input checked="" type="checkbox"/>] Attached, Document ID: <u>Att. A-4</u> [<input type="checkbox"/>] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable
13. Identification of Additional Applicable Requirements [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable
14. Compliance Assurance Monitoring Plan [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [<input type="checkbox"/>] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: _____ [<input type="checkbox"/>] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: _____ [<input type="checkbox"/>] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: _____ [<input type="checkbox"/>] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: _____ [<input type="checkbox"/>] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID: _____ [<input type="checkbox"/>] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable

Above items previously submitted, see Smith Electric Generating Plant Title V permit application.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION (All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)			
<input checked="" type="checkbox"/> This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).			
<input type="checkbox"/> This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.			
<input type="checkbox"/> This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Regulated or Unregulated Emissions Unit? (Check one)			
<input checked="" type="checkbox"/> The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.			
<input type="checkbox"/> The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.			
4. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Emission unit consists of one General Electric (GE) 7241 FA combustion turbine generator (CTG) having a nominal rating of 170 megawatts (MW) and one fired heat recovery steam generator (HRSG). The CTG/HRSG unit will be fired exclusively with pipeline quality natural gas.			
4. Emissions Unit Identification Number:		<input type="checkbox"/> No ID <input type="checkbox"/> ID Unknown	
ID: 007 (CC-2)			
5. Emissions Unit Status Code: C	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? <input checked="" type="checkbox"/>
9. Emissions Unit Comment: (Limit to 500 Characters)			

Emissions Unit Control Equipment

6. Control Equipment/Method Description (Limit to 200 characters per device or method):

NO_x Controls

Dry low-NO_x combustors

2. Control Device or Method Code(s): **25 (dry low-NO_x)**

Emissions Unit Details

1. Package Unit:	
Manufacturer: General Electric	Model Number: PG7241(FA)
2. Generator Nameplate Rating: 170 MW	
3. Incinerator Information:	
Dwell Temperature:	°F
Dwell Time:	seconds
Incinerator Afterburner Temperature:	°F

**B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)**

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	1,751 (LHV) mmBtu/hr (CTG only)	
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Requested Maximum Operating Schedule:	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
7. Operating Capacity/Schedule Comment (limit to 200 characters):		
<p>CTG maximum heat input is lower heating value (LHV) at 100 percent load, 0°F operating conditions. Heat input will vary with load and ambient temperature.</p> <p>HRSG duct burner maximum heat input is a nominal 275 MMBtu/hr (LHV).</p> <p>At average annual site conditions with duct burner firing, Unit 3 will generate 566 MW. At summer peaking site conditions with duct burner firing and steam power augmentation, Unit 3 will generate 574 MW.</p>		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? CC-2		7. Emission Point Type Code: 1	
8. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): N/A			
9. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
10. Discharge Type Code: V	6. Stack Height: 121 feet	7. Exit Diameter: 16.8 feet	
8. Exit Temperature: 186 °F	9. Actual Volumetric Flow Rate: 981,334 acfm	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: East (km): North (km):			
14. Emission Point Comment (limit to 200 characters): Stack temperature and flow rate are at 100 percent load, 65°F, evaporative cooling, and duct burner firing operating conditions (Case 6). Stack temperature and flow rate will vary with load, ambient temperature, and use of optional evaporative cooling, duct burner firing, and steam power augmentation.			

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine generator fired with pipeline quality natural gas.		
3. Source Classification Code (SCC): 20100201		3. SCC Units: Million Cubic Feet Burned
6. Maximum Hourly Rate: 1.845	7. Maximum Annual Rate: 16,162.2	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	10. Million Btu per SCC Unit: 950
10. Segment Comment (limit to 200 characters): Fuel heat content (Field 9) represents lower heating value (LHV).		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): HRSG duct burner fired with pipeline quality natural gas.		
3. Source Classification Code (SCC): 10100601		3. SCC Units: Million Cubic Feet Burned
6. Maximum Hourly Rate: 0.290	7. Maximum Annual Rate: 2,540.4	6. Estimated Annual Activity Factor:
11. Maximum % Sulfur:	12. Maximum % Ash:	13. Million Btu per SCC Unit: 950
14. Segment Comment (limit to 200 characters): Maximum hourly rate (Field 4) based on nominal heat input of 275 MMBtu/hr (LHV) Maximum Annual Rate (Field 5) based on 8,760 hours per year. Fuel heat content (Field 9) represents lower heating value (LHV).		

F. EMISSIONS UNIT POLLUTANTS (All Emissions Units)

[illegible]

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: <div style="display: flex; justify-content: space-around;"> 113.3 lb/hour 378.5 tons/year </div>	4. Synthetically Limited? <input checked="" type="checkbox"/>
5. Range of Estimated Fugitive Emissions: <div style="display: flex; justify-content: space-between;"> [] 1 [] 2 [] 3 _____ to _____ tons/year </div>	
6. Emission Factor: 113.3 lb/hr Reference: GE data	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): <p>Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 82.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 113.3 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.</p>	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: <div style="display: flex; justify-content: space-around;"> lb/hour tons/year </div>
5. Method of Compliance (limit to 60 characters): NO_x CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): <p>An annual, multi-unit NO_x emissions cap of 3,587 tpy is requested for Smith Units 1 and 3.</p> <p>CTG is subject to NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). DB is subject to NO_x limits of 40 CFR Part 60, Subpart Da (NSPS).</p>	

Emissions Unit Information Section 2 of 3

Pollutant Detail Information Page 2 of 14

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 116.6 lb/hour 350.7 tons/year	4. Synthetically Limited? [<input checked="" type="checkbox"/>]
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year	
6. Emission Factor: 116.6 lb/hr Reference: GE data	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 75.4 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 116.6 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 13 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 58.3 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable to CTG/HRSG operations without duct burner firing or steam power augmentation.	

Emissions Unit Information Section 2 of 3**Pollutant Detail Information Page 4 of 14****Allowable Emissions** Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
5. Requested Allowable Emissions and Units: 23 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 116.6 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable to CTG/HRSG operations at 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11).	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
6. Requested Allowable Emissions and Units: 16 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 78.7 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable to CTG/HRSG operations with duct burner firing and without steam augmentation.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 21.5 lb/hour 91.8 tons/year	4. Synthetically Limited? <input checked="" type="checkbox"/>
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year	
6. Emission Factor: 21.5 lb/hr Reference: GE data	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 20.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 21.5 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 10% opacity	4. Equivalent Allowable Emissions: 21.5 lb/hour 91.8 tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 9 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable for all CTG/HRSG operating modes.	

Emissions Unit Information Section 2 of 3

Pollutant Detail Information Page 6 of 14

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 0.03 lb/MMBtu	4. Equivalent Allowable Emissions: 8.3 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Methods 5, 5B, or 17 (Initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 40 CFR Part 60, §60.42a(a)(1), Subpart Da (NSPS); applicable to DB only.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 21.5 lb/hour 91.8 tons/year	4. Synthetically Limited? <input checked="" type="checkbox"/>
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year	
6. Emission Factor: 21.5 lb/hr Reference: GE data	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 20.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 21.5 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 10% opacity	4. Equivalent Allowable Emissions: 21.5 lb/hour 91.8 tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 9 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable for all CTG/HRSG operating modes.	

Emissions Unit Information Section 2 of 3

Pollutant Detail Information Page 8 of 14

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: <div style="display: flex; justify-content: space-around;"> 12.7 lb/hour 52.3 tons/year </div>	4. Synthetically Limited? <input checked="" type="checkbox"/>
5. Range of Estimated Fugitive Emissions: <div style="display: flex; justify-content: space-around;"> [] 1 [] 2 [] 3 _____ to _____ tons/year </div>	
6. Emission Factor: 12.7 lb/hr Reference: GE data	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): (2.0 gr S/100 ft³ gas) x (2,223,100 ft³ gas/hr) x (1 lb S/7,000 gr S) x (2 lb SO₂/lb S) = 12.7 lb/hr SO₂ Annual emissions based on 11.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 12.4 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 0.20 lb/MMBtu	4. Equivalent Allowable Emissions: 55.0 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to DB only per 40 CFR Part 60, §60.43a(b)(2), NSPS.	

Emissions Unit Information Section 2 of 3

Pollutant Detail Information Page 10 of 14

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 0.8 weight % S fuel	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to CTG only per 40 CFR Part 60, §60.333(b), NSPS.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SAM	2. Total Percent Efficiency of Control:
3. Potential Emissions: <div style="display: flex; justify-content: space-around;"> 1.46 lb/hour 6.0 tons/year </div>	4. Synthetically Limited? [<input checked="" type="checkbox"/>]
5. Range of Estimated Fugitive Emissions: <div style="display: flex; justify-content: space-between;"> [] 1 [] 2 [] 3 _____ to _____ tons/year </div>	
6. Emission Factor: 1.46 lb/hr Reference: GE data	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): <p>(12.7 lb/hr SO₂) x (7.5/100) x (98 lb H₂SO₄/64 lb SO₂) = 1.46 lb/hr H₂SO₄</p> <p>Annual emissions based on 1.36 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 1.43 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.</p>	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: <div style="display: flex; justify-content: space-around;"> lb/hour tons/year </div>
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

Emissions Unit Information Section 2 of 3

Pollutant Detail Information Page 12 of 14

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: <div style="display: flex; justify-content: space-around;"> 16.8 lb/hour 46.4 tons/year </div>	4. Synthetically Limited? [<input checked="" type="checkbox"/>]
5. Range of Estimated Fugitive Emissions: <div style="display: flex; justify-content: space-between;"> [] 1 [] 2 [] 3 _____ to _____ tons/year </div>	
6. Emission Factor: 16.8 lb/hr Reference: GE data	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): <p>Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 9.8 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 16.8 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.</p>	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 3 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: <div style="display: flex; justify-content: space-around;"> 6.6 lb/hour N/A tons/year </div>
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): <p>Limit applicable to CTG/HRSG operations without duct burner firing or steam power augmentation.</p>	

Emissions Unit Information Section 2 of 3

Pollutant Detail Information Page 14 of 14

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
5. Requested Allowable Emissions and Units: 6 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 16.8 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to CTG/HRSG operations at 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11).	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: Other	2. Future Effective Date of Allowable Emissions:
6. Requested Allowable Emissions and Units: 4 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 10.2 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25 (initial only)	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit applicable to CTG/HRSG operations with duct burner firing and without steam augmentation.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

2. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: <input type="checkbox"/> Rule <input checked="" type="checkbox"/> Other
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
6. Method of Compliance: EPA Reference Method 9	
7. Visible Emissions Comment (limit to 200 characters): Rule 62-212.400(5)(c), F.A.C. (BACT)	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

2. Visible Emissions Subtype:	2. Basis for Allowable Opacity: <input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour	
6. Method of Compliance: EPA Reference Method 9 (every 5 years)	
7. Visible Emissions Comment (limit to 200 characters): Excess emissions resulting from startup, shutdown, or malfunction not-to-exceed 2 hours in any 24 hour period unless authorized by FDEP for a longer duration. Rule 62-210.700(1), F.A.C. Applicant has requested up to 4 hours for cold startups and all shutdowns.	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	<input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
8. Continuous Monitor Comment (limit to 200 characters): Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Subpart Da. Specific CEMS information will be provided to FDEP when available.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: O₂	2. Pollutant(s):
3. CMS Requirement:	<input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
8. Continuous Monitor Comment (limit to 200 characters): Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Subpart Da. Specific CEMS information will be provided to FDEP when available.	

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

Supplemental Requirements

1. Process Flow Diagram [<input checked="" type="checkbox"/>] Attached, Document ID: <u>Fig. 2-5</u> [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
2. Fuel Analysis or Specification [<input checked="" type="checkbox"/>] Attached, Document ID: <u>Att. A-3</u> [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
3. Detailed Description of Control Equipment [<input checked="" type="checkbox"/>] Attached, Document ID: <u>Sect. 5.0</u> [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
4. Description of Stack Sampling Facilities To be provided [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
5. Compliance Test Report [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Previously submitted, Date: _____ [<input type="checkbox"/>] Not Applicable
6. Procedures for Startup and Shutdown [<input type="checkbox"/>] Attached, Document ID: _____ [<input checked="" type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
7. Operation and Maintenance Plan [<input type="checkbox"/>] Attached, Document ID: _____ [<input checked="" type="checkbox"/>] Not Applicable [<input type="checkbox"/>] Waiver Requested
8. Supplemental Information for Construction Permit Application See PSD application [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable
9. Other Information Required by Rule or Statute [<input type="checkbox"/>] Attached, Document ID: _____ [<input checked="" type="checkbox"/>] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [<input checked="" type="checkbox"/>] Attached, Document ID: <u>Att. A-4</u> [<input type="checkbox"/>] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable
13. Identification of Additional Applicable Requirements [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable
14. Compliance Assurance Monitoring Plan [<input type="checkbox"/>] Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [<input type="checkbox"/>] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: _____ [<input type="checkbox"/>] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: _____ [<input type="checkbox"/>] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: _____ [<input type="checkbox"/>] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: _____ [<input type="checkbox"/>] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID: _____ [<input type="checkbox"/>] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID: _____ [<input type="checkbox"/>] Not Applicable

Above items previously submitted, see Smith Electric Generating Plant Title V permit application.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION (All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)			
<input checked="" type="checkbox"/> This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).			
<input type="checkbox"/> This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.			
<input type="checkbox"/> This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Regulated or Unregulated Emissions Unit? (Check one)			
<input type="checkbox"/> The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.			
<input checked="" type="checkbox"/> The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.			
3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Salt water cooling tower. Tower is equipped with drift eliminators for control of PM/PM ₁₀ emissions.			
4. Emissions Unit Identification Number:		<input type="checkbox"/> No ID <input type="checkbox"/> ID Unknown	
ID: 008 (Cooling Tower)			
5. Emissions Unit Status Code: C	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? <input type="checkbox"/>
9. Emissions Unit Comment: (Limit to 500 Characters)			

Emissions Unit Information Section 3 of 3

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

Drift eliminators

2. Control Device or Method Code(s): **15**

Emissions Unit Details

1. Package Unit:

Manufacturer:

Model Number:

2. Generator Nameplate Rating: MW

3. Incinerator Information:

Dwell Temperature:

°F

Dwell Time:

seconds

Incinerator Afterburner Temperature:

°F

**B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Heat Input Rate:	mmBtu/hr	
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate:	125,000 gal/min	
4. Maximum Production Rate:		
5. Requested Maximum Operating Schedule:		
	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):		
Maximum process rate (Field 3) is cooling tower water recirculation rate.		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? TC-1 thru TC-10		2. Emission Point Type Code: 3	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): Cooling tower consists of ten cells.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 57 feet	7. Exit Diameter: 33.0 feet	
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: East (km): North (km):			
14. Emission Point Comment (limit to 200 characters): Cooling tower consists of 10 cells with 10 individual exhaust fans. Stack height and diameter provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient temperature.			

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): <p align="center">Salt water cooling tower recirculation water flow rate.</p>		
2. Source Classification Code (SCC):		3. SCC Units: <p align="center">Thousand gallons transferred</p>
4. Maximum Hourly Rate: <p align="center">7,500.0</p>	5. Maximum Annual Rate: <p align="center">65,700,000</p>	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): 		

Segment Description and Rate: Segment of

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

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[illegible]

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: <div style="display: flex; justify-content: space-between;"> 18.2 lb/hour 79.5 tons/year </div>	4. Synthetically Limited? <input type="checkbox"/>
5. Range of Estimated Fugitive Emissions: <div style="display: flex; justify-content: space-between;"> [] 1 [] 2 [] 3 _____ to _____ tons/year </div>	
6. Emission Factor: 18.2 lb/hr Reference: AP-42, Section 13.4	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): <p>(125,000 gal/min) x (0.001 gal/100 gal) x (29,000 lb PM/10⁶ lb water) x (8.345 lb/gal water) x (60 min/hr) = 18.15 lb/hr PM</p> <p>(18.15 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 79.5 ton/yr PM</p>	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: <div style="display: flex; justify-content: space-between;"> lb/hour tons/year </div>
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

Emissions Unit Information Section 3 of 3

Pollutant Detail Information Page 2 of 4

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: <div style="display: flex; justify-content: space-around;"> 18.2 lb/hour 79.5 tons/year </div>	4. Synthetically Limited? []
5. Range of Estimated Fugitive Emissions: <div style="display: flex; justify-content: space-between;"> [] 1 [] 2 [] 3 _____ to _____ tons/year </div>	
6. Emission Factor: 18.2 lb/hr Reference: AP-42, Section 13.4	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): $(125,000 \text{ gal/min}) \times (0.001 \text{ gal/100 gal}) \times (29,000 \text{ lb PM}/10^6 \text{ lb water}) \times (8.345 \text{ lb/gal water}) \times (60 \text{ min/hr}) = 18.15 \text{ lb/hr PM}$ $(18.15 \text{ lb/hr}) \times (8,760 \text{ hr/yr}) \times (1 \text{ ton}/2,000 \text{ lb}) = 79.5 \text{ ton/yr PM}$	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: <div style="display: flex; justify-content: space-around;"> lb/hour tons/year </div>
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

Emissions Unit Information Section 3 of 3

Pollutant Detail Information Page 4 of 4

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

**I. CONTINUOUS MONITOR INFORMATION – Not Applicable
(Only Regulated Emissions Units Subject to Continuous Monitoring)**

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
6. Continuous Monitor Comment (limit to 200 characters):	

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

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

Supplemental Requirements

1. Process Flow Diagram <input checked="" type="checkbox"/> Attached, Document ID: <u>Fig. 2-5</u> <input type="checkbox"/> Not Applicable <input type="checkbox"/> Waiver Requested
2. Fuel Analysis or Specification <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable <input type="checkbox"/> Waiver Requested
3. Detailed Description of Control Equipment <input checked="" type="checkbox"/> Attached, Document ID: <u>Sect. 5.0</u> <input type="checkbox"/> Not Applicable <input type="checkbox"/> Waiver Requested
4. Description of Stack Sampling Facilities <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable <input type="checkbox"/> Waiver Requested
5. Compliance Test Report <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously submitted, Date: _____ <input checked="" type="checkbox"/> Not Applicable
6. Procedures for Startup and Shutdown <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable <input type="checkbox"/> Waiver Requested
7. Operation and Maintenance Plan <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable <input type="checkbox"/> Waiver Requested
8. Supplemental Information for Construction Permit Application See PSD application <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
9. Other Information Required by Rule or Statute <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [] Attached, Document ID: _____ [] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [] Attached, Document ID: _____ [] Not Applicable
13. Identification of Additional Applicable Requirements [] Attached, Document ID: _____ [] Not Applicable
14. Compliance Assurance Monitoring Plan [] Attached, Document ID: _____ [] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: _____ [] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: _____ [] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: _____ [] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: _____ [] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID: _____ [] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID: _____ [] Not Applicable

Above items previously submitted, see Smith Electric Generating Plant Title V permit application.

DISKETTE/ CD/ OR
SLIDES
WERE REMOVED
AND PLACED IN A
FILE WITHIN THE
RECORDS
CENTER.

ATTACHMENT A-1

REGULATORY APPLICABILITY ANALYSES

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 1 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources.				
<i>Subpart A - General Provisions</i>				
Notification and Recordkeeping	§60.7		CC-1, CC-2 Gas Turbines Duct Burners	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CC-1, CC-2 Gas Turbines Duct Burners	Conduct performance tests as required by EPA or FDEP.
Compliance with Standards	§60.11		CC-1, CC-2 Gas Turbines Duct Burners	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CC-1, CC-2 Gas Turbines Duct Burners	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13		CC-1, CC-2 Gas Turbines Duct Burners	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CC-1, CC-2 Gas Turbines Duct Burners	General procedures regarding reporting deadlines.
<i>Subpart Da - Standard of Performance for Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978</i>				
Standards for Particulate Matter	§60.42a(a) and (b)		CC-1, CC-2 Duct Burners	Establishes PM limit of 13 ng/J (0.03 lb/MMBtu). Opacity shall not be greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
<i>Subpart Da - Standard of Performance for Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978 (continued)</i>				
Standards for Sulfur Dioxide	§60.43a(b)(2)		CC-1, CC-2 Duct Burners	Establishes SO ₂ limit of 86 ng/J (0.20 lb/MMBtu), 30-day rolling average.
Standards for Nitrogen Oxides	§60.44a(d)(1)		CC-1, CC-2 Duct Burners	For sources which commence construction after July 9, 1997, establishes NO _x limit of 1.6 lb/MWh, 30-day rolling average.
Compliance Provisions	§60.46a, all except (d)		CC-1, CC-2 Duct Burners	Describes compliance provisions for PM, SO ₂ , and NO _x standards. Paragraph (d) applies to FGD systems.
Emission Monitoring	§60.47a, all except (a) and (b)		CC-1, CC-2 Duct Burners	Continuous emissions monitoring requirements. NO _x CEM required. Continuous emissions monitoring of opacity [Paragraph (a)] and SO ₂ [Paragraph (b)] is not required where gaseous fuel is the only fuel combusted.
Compliance Determination Procedures and Methods	§60.48a (a) and (f)		CC-1, CC-2 Duct Burners	Initial performance testing requirements for electric utility combined cycle gas turbines.
Reporting Requirements	§60.49a		CC-1, CC-2 Duct Burners	Periodic reporting requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
<i>Subpart GG - Standard of Performance for Stationary Gas Turbines</i>				
Standards for Nitrogen Oxides	§60.332(a)(1) and (3), (b), and (f)		CC-1, CC-2 Gas Turbines	Establishes NO _x limit of 75 ppmv at 15% (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Standards for Sulfur Dioxide	§60.333		CC-1, CC-2 Gas Turbines	Establishes exhaust gas SO ₂ limit of 0.015 percent by volume (at 15% O ₂ , dry) and maximum fuel sulfur content of 0.8 percent by weight.
Monitoring Requirements	§60.334(a)	X		Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to ±5.0 percent. Applicable only to CTGs using water injection for NO _x control.
Monitoring Requirements	§60.334(b)(2) and (c)		CC-1, CC-2 Gas Turbines	Requires daily monitoring of fuel sulfur and nitrogen content unless custom schedule requested and approved. Defines excess emissions
Test Methods and Procedures	§60.335		CC-1, CC-2 Gas Turbines	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Cb, Cc, Cd, Ce, D, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to Smith Unit 3.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, CC, DD, EE, GG, II, JJ, KK, LL, OO, PP, QQ, RR, VV, EEE, GGG, III, and JJJ		X		None of the listed NESHAPS' contain requirements which are applicable to the Smith Unit 3 CTGs.
40 CFR Part 72 - Acid Rain Program Permits				
<i>Subpart A - Acid Rain Program General Provisions</i>				
Standard Requirements	§72.9 excluding §72.9(c)(3)(i), (ii), and (iii), and §72.9(d)		CC-1, CC-2	General Acid Rain Program requirements.
<i>Subpart B - Designated Representative</i>				
Designated Representative	§72.20 - §72.24		CC-1, CC-2	General requirements pertaining to the Designated Representative.
<i>Subpart C - Acid Rain Application</i>				
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		CC-1, CC-2	<p>Requirement to submit a complete Phase II Acid Rain permit application to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation.</p> <p>Requirement to submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted. (future requirement).</p>

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Acid Rain permit information requirements	§72.31		CC-1, CC-2	Lists information required for Acid Rain permit applications.
Permit Application Shield	§72.32		CC-1, CC-2	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.
<i>Subpart D - Acid Rain Compliance Plan and Compliance Options</i>				
General	§72.40(a)(1)		CC-1, CC-2	General SO ₂ compliance plan requirements.
General	§72.40(a)(2)	X		General NO _x compliance plan requirements are not applicable to Smith Unit 3.
<i>Subpart E - Acid Rain Permit Contents</i>				
Permit Shield	§72.51		CC-1, CC-2	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
<i>Subpart H - Permit Revisions</i>				
General Permit Revision Procedures Including Fast-Track Modifications	§72.80, §72.81, §72.82(a) and (c), §72.83, and §72.84		CC-1, CC-2	Procedures for permit revisions including fast-track modifications to Acid Rain Permits. (potential future requirement)
<i>Subpart I - Compliance Certification</i>				
Annual Compliance Certification Report	§72.90		CC-1, CC-2	Requirement to submit an annual compliance report. (future requirement)
40 CFR Part 75 - Continuous Emission Monitoring				
<i>Subpart A - General</i>				
Prohibitions	§75.5		CC-1, CC-2	General monitoring prohibitions.
<i>Subpart B - Monitoring Provisions</i>				

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
General Operating Requirements	§75.10		CC-1, CC-2	General monitoring requirements.
Specific Provisions for Monitoring SO ₂ Emissions	§75.11(d)(2)		CC-1, CC-2	SO ₂ continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.
Specific Provisions for Monitoring NO _x Emissions	§75.12(a) and (b)		CC-1, CC-2	NO _x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units
Specific Provisions for Monitoring CO ₂ Emissions	§75.13(b)		CC-1, CC-2	CO ₂ continuous monitoring requirements. Appendix G election will be made.
<i>Subpart B - Monitoring Provisions</i>				
Specific Provisions for Monitoring Opacity	§75.14(c)		CC-1, CC-2	Opacity continuous monitoring exemption for gas-fired units.
<i>Subpart C - Operation and Maintenance Requirements</i>				
Certification and Recertification Procedures	§75.20(b)		CC-1, CC-2	Recertification procedures (potential future requirement)
Certification and Recertification Procedures	§75.20(c)		CC-1, CC-2	Recertification procedure requirements. (potential future requirement)
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CC-1, CC-2	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		CC-1, CC-2	Specifies required test methods to be used for recertification testing (potential future requirement).
Out-Of-Control Periods	§75.24 except §75.24(e)		CC-1, CC-2	Specifies out-of-control periods and re- quired actions to be taken when out-of- control periods occur (excluding opacity).
<i>Subpart D - Missing Data Substitution Procedures</i>				
General Provisions	§75.30(a)(3), (b), (c)		CC-1, CC-2	General missing data requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CC-1, CC-2	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CC-1, CC-2	Missing data substitution procedure requirements.
<i>Subpart F - Recordkeeping Requirements</i>				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CC-1, CC-2	General recordkeeping requirements for NO _x and Appendix G CO ₂ monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CC-1, CC-2	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CC-1, CC-2	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CC-1, CC-2	Specific recordkeeping requirements for Appendix D SO ₂ monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CC-1, CC-2	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		CC-1, CC-2	Requirements pertaining to general recordkeeping for Appendix D SO ₂ monitoring.
<i>Subpart G - Reporting Requirements</i>				
General Provisions	§75.60		CC-1, CC-2	General reporting requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CC-1, CC-2	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.
<i>Subpart G - Reporting Requirements</i>				
Monitoring Plan	§75.62		CC-1, CC-2	Requires submittal of a monitoring plan no later than 45 days prior to the first scheduled certification test.
Recertification Application	§75.63		CC-1, CC-2	Requires submittal of a recertification application within 30 days after completing the recertification test. (potential future requirement)
Quarterly Reports	§75.64(a)(1) - (5), (b), (c), and (d)		CC-1, CC-2	Quarterly data report requirements.
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO ₂ under Phase I or Phase II.
40 CFR Part 77 - Excess Emissions				

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		CC-1, CC-2	Requirement to submit offset plans for excess SO ₂ emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO ₂ emissions. Required contents of offset plans are specified (potential future requirement) .
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CC-1, CC-2	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan (potential future requirement) .
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		CC-1, CC-2	Requirement to pay a penalty if excess emissions of SO ₂ occur at any affected unit during any year (potential future requirement) .
40 CFR Part 78 - Appeals Procedures				
Appeals Procedures for Acid Rain Program	§78		CC-1, CC-2	General Acid Rain Program appeals procedures. (potential future requirement)
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		Smith Unit 3 will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Gulf personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		Gulf will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Smith Unit 3 will not produce any products containing ozone depleting substances.
<i>Subpart F - Recycling and Emissions Reduction</i>				
Prohibitions	§82.154	X		Gulf personnel will not maintain, service, repair, or dispose of any appliances. All such activities will be performed by independent parties in compliance with §82.154 prohibitions.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in com- pliance with §82.156 required practices.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
<i>Subpart F - Recycling and Emissions Reduction</i>				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for house- hold or com- mercial purpos- es, including any air condi- tioner, refriger- ator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		Gulf personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.
Certification By Owners of Recov- ery and Recycling Equipment	§82.162	X		Gulf personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.
Reporting and Recordkeeping Requirements	§82.166(k), (m), and (n)		Appliances as defined by §82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 12 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Compliance Assurance Monitoring		X		Program only applies to emission units which are equipped with control devices, excluding inherent process equipment.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 53, 54, 55, 56, 57, 58, 59, 66, 67, 68, 69, 71, 73, 76, 77, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 95, and 96		X		The listed regulations do not contain any requirements which are applicable to Smith Unit 3.

Source: ECT, 1999.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.	X			Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.	X			Contains no applicable requirements.
Transferability of Definitions	62-4.021, .021, F.A.C.	X			Contains no applicable requirements.
General Prohibition	62-4.030, F.A.C. ¹		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	62-4.040, F.A.C. ¹		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050, F.A.C. ¹		X		General permitting requirements.
Surveillance Fees	62-4.052, F.A.C.	X			Not applicable to air emission sources.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes standard procedures for FDEP. Requirement is not applicable to Smith Unit 3.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial construction permit. Modification of permit conditions is not being requested.
Renewals	62-4.090, F.A.C. ¹		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.-430(3), F.A.C. (future requirement)
Suspension and Revocation	62-4.100, F.A.C. ¹		X		Establishes permit suspension and revocation criteria.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 2 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Financial Responsibility	62-4.110, F.A.C.	X			Contains no applicable requirements.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not included in this application.
Plant Operation - Problems	62-4.130, F.A.C.¹		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. (potential future requirement)
Review	62-4.150, F.A.C.	X			Contains no applicable requirements.
Permit Conditions	62-4.160, F.A.C.	X			Contains no applicable requirements.
Scope of Part II	62-4.200, F.A.C.	X			Contains no applicable requirements.
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.	X			General requirements for initial new source operation permits. (future requirement)
Water Permit Provisions	62-4.240 - 250, F.A.C.	X			Contains no applicable requirements.
Chapter 62-17, F.A.C. - Electrical Power Plant Siting				Unit 3	Power Plant Siting Act provisions.
Chapter 62-102, F.A.C. - Rules of Administrative Procedure - Rule Making			X		General administrative procedures.
Chapter 62-103, F.A.C. - Rules of Administrative Procedure - Final Agency Action			X		General administrative procedures.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-204, F.A.C. - State Implementation Plan					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.		X		Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W.
State Implementation Plan	62-204.800(1) - (6), F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800(7)(a), (b)2. and 39., (c), (d), and (e), F.A.C. ¹			CC1, CC-2	NSPS Subpart Da and GG; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(8) - (13), (15), (17), (20), and (22) F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800 (14), (16), (18), (19), F.A.C.			CC1, CC-2	Acid Rain Program; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(21), F.A.C. ¹		X		Protection of Stratospheric Ozone; see Table A-1 for detailed federal regulatory citations.
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-210.200, F.A.C.	X			Contains no applicable requirements.
Small Business Assistance Program	62-210.220, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permits Required	62-210.300(1) and (3), F.A.C.		X		Air construction permit required. Exemptions from permitting specified for certain facilities and sources.
Permits Required	62-210.300(2), F.A.C.		X		Air operation permit required. (future requirement)
Air General Permits	62-210.300(4), F.A.C.	X			Not applicable to Smith Unit 3.
Notification of Startup	62-210.300(5), F.A.C.	X			Sources which have been shut down for more than one year shall notify the FDEP prior to startup.
Emission Unit Reclassification	62-210.300(6), F.A.C.		X		Emission unit reclassification (potential future requirement)
Public Notice and Comment					
Public Notice of Proposed Agency Action	62-210.350(1), F.A.C.		X		All permit applicants required to publish notice of proposed agency action.
Additional Notice Require- ments for Sources Subject to Prevention of Significant Deterioration or Nonattain- ment Area New Source Review	62-210.350(2), F.A.C.		X		Additional public notice requirements for PSD and nonattainment area NSR applications.
Additional Public Notice Re- quirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.A.C.		X		Notice requirements for Title V operating permit applicants (future requirement) .
Public Notice Requirements for FESOPS and 112(g) Emission Sources	62-210.350(4) and (5), F.A.C.	X			Not applicable to Smith Unit 3.
Administrative Permit Corrections	62-210.360, F.A.C.	X			An administrative permit correction is not requested in this application.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reports Notification of Intent to Relocate Air Pollutant Emit- ting Facility	62-210.370(1), F.A.C.	X			Project does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facil- ity	62-210.370(3), F.A.C.		X		Specifies annual reporting requirements. (future requirement).
Stack Height Policy	62-210.550, F.A.C.		X		Limits credit in air dispersion studies to good engineering practice (GEP) stack heights for stacks constructed or modified since 12/31/70.
Circumvention	62-210.650, F.A.C.			Units with control equipment	An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700(1), F.A.C.		X		Excess emissions due to startup, shut down, and malfunction are permitted for no more than two hours in any 24 hour period unless specifically authorized by the FDEP for a longer duration. Excess emissions for more than two hours in a 24 hour period are specifically requested for Smith Unit 3. See Section 2.2 of the PSD permit application for details.
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to Smith Unit 3.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Excess Emissions	62-210.700(4), F.A.C.		X		Excess emissions caused entirely or in part by poor maintenance, poor operations, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction are prohibited. (potential future requirement) .
Excess Emissions	62-210.700(5), F.A.C.	X			Contains no applicable requirements.
Excess Emissions	62-210.700(6), F.A.C.		X		Excess emissions resulting from malfunctions must be reported to the FDEP in accordance with 62-4.130, F.A.C. (potential future requirement) .
Forms and Instructions	62-210.900(5), F.A.C.		X		Contains AOR requirements.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.	X			Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.		X		General air construction permit requirements.
Prevention of Significant Deterioration	62-212.400, F.A.C.		X		PSD permit required prior to construction of Smith Unit 3.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Smith Unit 3 is not located in a nonattainment area or a nonattainment area of influence.
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to Smith Unit 3.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), and (4), F.A.C.		X		Annual emissions fee and documentation requirements. (future requirement)
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. (future requirement)
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met (potential future requirement) .
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implement- ed pending permit revision if specific criteria are met (potential future requirement) .
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CC1, CC-2	Optional provisions for Acid Rain permit revisions (potential future requirement) .
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. (future requirement)
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.	X			Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements (future requirement).
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements (potential future requirement).
EPA Recommended Actions	62-213.430(5), F.A.C.	X			Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.		X		Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and condi- tions. (future requirement)
Forms and Instructions	62-213.900(1), F.A.C.		X		Contains annual emissions fee form requirements.
Chapter 62-214—Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	§62-214.100, F.A.C.	X			Contains no applicable requirements.
Applicability	§62-214.300, F.A.C.		X		Smith Unit 3 includes Acid Rain affected units, therefore compliance with §62-213 and §62-214, F.A.C., is required.
Applications	§62-214.320, F.A.C.			CC1, CC-2	Acid Rain application requirements. Application for new units are due at least 24 months before the later of 1/1/2000 or the date on which the unit commences operation.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CC1, CC-2	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. (future requirement)
Exemptions	§62-214.340, F.A.C.		X		An application may be submitted for certain exemptions (potential future requirement) .
Certification	§62-214.350, F.A.C.			CC1, CC-2	The designated representative must certi- fy all Acid Rain submissions. (future requirement)
Department Action on Applications	§62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Cor- rections	§62-214.370, F.A.C.			CC1, CC-2	Defines revision procedures and auto- matic amendments (potential future requirement) ..
Acid Rain Part Content	§62-214.420, F.A.C.	X			Agency procedures, contains no applicable requirements.
Implementation and Termination of Compliance Options	§62-214.430, F.A.C.			CC1, CC-2	Defines permit activation and termina- tion procedures (potential future requirement) .
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	62-256.300, F.A.C. ¹		X		Prohibits open burning.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	62-256.500, F.A.C. ¹		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	62-256.600, F.A.C. ¹		X		Prohibits industrial open burning
Open Burning allowed	62-256.700, F.A.C. ¹		X		Specifies allowable open burning activities. (potential future requirement)
Effective Date	62-256.800, F.A.C. ¹	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Fee	62-257, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-296 - Stationary Source - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C. ¹		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	62-296.320(3), F.A.C. ¹		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			Smith Unit 3 does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.417, F.A.C.	X			None of the referenced standards are applicable to Smith Unit 3.
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO _x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Smith Unit 3 is not located in an ozone nonattainment area or an ozone air quality maintenance area.
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO _x -Emitting Facilities	62-296.570, F.A.C.	X			Smith Unit 3 is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (i.e., is not located in Broward, Dade or Palm Beach Counties)
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Smith Unit 3 is not located in a lead non-attainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	§62-296.700 through 62-296.712, F.A.C.	X			Smith Unit 3 is not located in a PM non-attainment area or a PM air quality maintenance area.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 12 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility- Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
General Compliance Test Requirements	62-297.310, F.A.C.			CC-1, CC-2	Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.	X			Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains no applicable requirements.
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to Smith Unit 3.
CEMS Performance Specifications	62-297.520, F.A.C.	X			Contains no applicable requirements.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

¹ - State requirement only; not federally enforceable.

Source: ECT, 1999.

ATTACHMENT A-2

**II.E.4—PRECAUTIONS TO PREVENT EMISSIONS
OF UNCONFINED PARTICULATE MATTER**

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from Smith Unit 3 operations include:

- Vehicular traffic on paved and unpaved roads.
- Wind-blown dust from yard areas.
- Periodic abrasive blasting.

The following techniques may be used to control unconfined particulate matter emissions on an as-needed basis:

- Chemical or water application to:
 - o Unpaved roads
 - o Unpaved yard areas
- Paving and maintenance of roads, parking areas, and yards.
- Landscaping or planting of vegetation.
- Confining abrasive blasting where possible.
- Other techniques, as necessary.

ATTACHMENT A-3

III.L.2—FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
<u>Gas Composition</u>	
Hexane+	0.061
Propane	0.890
I-butane	0.189
N-butane	0.168
I-pentane	0.038
N-pentane	0.026
Nitrogen	0.527
Methane	93.813
CO ₂	1.024
Ethane	3.2820
<u>Other Characteristics</u>	
Heat content (HHV)	1,050 Btu/ft ³ at 14.73 psia, dry
Real specific gravity	0.5999
Sulfur content (maximum)	2.0 gr/100 scf

Note: Btu/ft³ = British thermal units per cubic foot.
psia = pounds per square inch absolute.
gr/100 scf = grains per 100 standard cubic foot.

Source: Koch, 1999.
Gulf, 1999.

ATTACHMENT A-4

ALTERNATE METHODS OF OPERATION

Gulf Power – Smith Unit 3
Alternate Methods of Operation

Emission Source	Method No.	Evaporative Cooling	Duct Burner Firing	Steam Power Augmentation	Annual Operating Hours (Hrs/Yr)
CC/HRSG-1, 2	1				8,760
	2	X			8,760
	3		X		8,760
	4	X	X		8,760
	5	X	X	X	1,000

Source: Gulf, 1999.

ATTACHMENT B—
CTG VENDOR INFORMATION

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

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Southern Company

ESTIMATED PERFORMANCE PG741(TA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	0.	0.	0.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,869	20,869	20,869
Fuel Temperature	Deg F	80	80	80
Output	kW	189,300.	142,000.	94,700.
Heat Rate (LHV)	Btu/kWh	9,250.	9,920.	11,850.
Heat Cons. (LHV) X 10 ⁶	Btu/h	1,751.	1,408.6	1,122.2
Exhaust Flow X 10 ³	lb/h	3867.	3079.	2515.
Exhaust Temp.	Deg F.	1071.	1106.	1155.
Exhaust Heat (LHV) X 10 ⁶	Btu/h	1054.7	882.9	765.0

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	64.	51.	40.
CO	ppmvd	15.	15.	15.
CO	lb/h	53.	42.	34.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
Particulates	lb/h	9.	9.	9.

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.89	0.91
Nitrogen	75.09	75.09	75.19
Oxygen	12.58	12.58	12.87
Carbon Dioxide	3.88	3.89	3.75
Water	7.55	7.55	7.29

SITE CONDITIONS

Elevation	ft.	96.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.04
Exhaust Loss	in Water	16.5
Relative Humidity	%	60
Application	7PH2 Hydrogen-Cooled Generator	
Combustion System	9/42 DLN Combustor	

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Southern Company**ESTIMATED PERFORMANCE PG7241(FA)**

Load Condition		BASE	75%	50%
Inlet Loss	in. H ₂ O	4.	4.	4.
Exhaust Loss	in. H ₂ O	16.5	16.5	16.5
Ambient Temp.	Deg F.	65.	65.	65.
Evap. Cooler Status		On	Off	Off
Evap. Cooler Effectiveness	%	85		
Fuel Type		Cost Gas	Cost Gas	Cost Gas
Fuel LHV	Btu/lb	20,869	20,869	20,869
Fuel Temperature	Deg F	80	80	80
Output	kW	172,400.	129,300.	86,200.
Heat Rate (LHV)	Btu/kWh	9,320.	10,090.	12,130.
Heat Cons. (LHV) X 10 ⁶	Btu/h	1,606.8	1,304.6	1,045.6
Exhaust Flow X 10 ³	lb/h	3524.	2894.	2390.
Exhaust Temp.	Deg F.	1122.	1148.	1192.
Exhaust Heat (LHV) X 10 ⁶	Btu/h	972.2	825.1	719.6

EMISSIONS

NOx	ppmv @ 15% O ₂	9.	9.	9.
NOx AS NO ₂	lb/h	59.	47.	38.
CO	ppmv	15.	15.	15.
CO	lb/h	48.	39.	32.
UHC	ppmv	7.	7.	7.
UHC	lb/h	14.	11.	9.
Particulates	lb/h	9.	9.	9.

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.89	0.89
Nitrogen	74.03	74.26	74.37
Oxygen	12.29	12.50	12.81
Carbon Dioxide	3.89	3.81	3.67
Water	8.91	8.54	8.26

SITE CONDITIONS

Elevation	ft.	96.0
Site Pressure	psia	14.65
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O₂ without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

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GE EUROPE + BLDG 2/312

Southern Company

ESTIMATED PERFORMANCE PG72J1(EA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Evap. Cooler Status		On	Off	Off
Evap. Cooler Effectiveness	%	85		
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,869	20,869	20,869
Fuel Temperature	Deg F	80	80	80
Output	kW	159,000.	119,300.	79,500.
Heat Rate (LHV)	Btu/kWh	9,550.	10,400.	12,510.
Heat Cons. (LHV) X 10 ⁵	Btu/h	1,518.5	1,240.7	994.5
Exhaust Flow X 10 ³	lb/h	3353.	2787.	2326.
Exhaust Temp.	Deg F.	1140.	1169.	1200.
Exhaust Heat (LHV) X 10 ⁶	Btu/h	931.9	796.9	692.7

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	56.	45.	36.
CO	ppmvd	15.	15.	15.
CO	lb/h	45.	37.	31.
UHC	ppmvd	7.	7.	7.
UHC	lb/h	13.	11.	9.
Particulates	lb/h	9.	9.	9.

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.87	0.89
Nitrogen	72.91	73.37	73.50
Oxygen	12.08	12.39	12.77
Carbon Dioxide	3.84	3.75	3.57
Water	10.31	9.62	9.28

SITE CONDITIONS

Elevation	ft.	96.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.04
Exhaust Loss	in Water	16.5
Relative Humidity	%	45
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		942 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

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GE EUROPE - BLDG 2/312

Southern Company**ESTIMATED PERFORMANCE PG741(FA)***100% W/PA*

Load Condition		BASE
Inlet Loss	in. H ₂ O	4.
Exhaust Loss	in. H ₂ O	16.5
Ambient Temp.	Deg F.	95.
Evap. Cooler Status		On
Evap. Cooler Effectiveness %		85
Fuel Type		Case Gas
Fuel LHV	Btu/lb	20,869
Fuel Temperature	Deg F	80
Output	kW	175,300.
Heat Rate (LHV)	Btu/kWh	9,150.
Heat Cons. (LHV) X 10 ⁶	Btu/h	1,604.
Exhaust Flow X 10 ³	lb/h	3471.
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10 ⁶	Btu/h	975.7
Steam Flow	lb/h	113,450.

EMISSIONS

NOx	ppmvd @ 15% O ₂	12
NOx AS NO ₂	lb/h	79
CO	ppmvd	15.
CO	lb/h	45.
UHC	ppmvd	7.
UHC	lb/h	14.
Particulates	lb/h	9.

EXHAUST ANALYSIS % VOL.

Argon	0.82
Nitrogen	69.06
Oxygen	11.04
Carbon Dioxide	3.84
Water	15.24

SITE CONDITIONS

Elevation	ft.	96.0
Site Pressure	psia	14.65
Relative Humidity	%	45
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O₂ without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

**ATTACHMENT C—
EMISSION RATE CALCULATIONS**

**Table C-1. Plant Smith Unit 3
CTG Operating Scenarios**

Case	Ambient Temperature (°F)	Load (%)	CTG-1	CTG-2	Evaporative Cooling	Steam Power Augmentation	Duct Burner Firing
1	0	100	X	X			
2	0	100	X	X			X
3	0	75	X	X			
4	0	50	X	X			
5	65	100	X	X	X		
6	65	100	X	X	X		X
7	65	75	X	X			
8	65	50	X	X			
9	95	100	X	X	X		
10	95	100	X	X	X	X	
11	95	100	X	X	X	X	X
12	95	100	X	X	X		X
13	95	75	X	X			
14	95	50	X	X			

Sources: ECT, 1999.
Gulf Power, 1999.

Table C-2. Plant Smith Unit 3
CTG/HRSG Hourly Emission Rates (Per CTG/HRSG)
Criteria Air Pollutants and Sulfuric Acid Mist

Temp. (°F)	Case	Load (%)	PM ₁₀ ¹		SO ₂ ²		H ₂ SO ₄ ³		Lead ⁴	
			(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
0	1	100	19.8	2.495	11.6	1.461	1.33	0.168	0.00077	0.00010
	2	100	20.8	2.620	12.7	1.600	1.46	0.184	0.00084	0.00011
	3	75	19.8	2.495	9.3	1.175	1.07	0.135	0.00062	0.00008
	4	50	19.8	2.495	7.4	0.936	0.85	0.108	0.00049	0.00006
65	5	100	19.8	2.495	10.6	1.341	1.22	0.154	0.00070	0.00009
	6	100	20.9	2.633	11.9	1.495	1.36	0.172	0.00078	0.00010
	7	75	19.8	2.495	8.6	1.089	0.99	0.125	0.00057	0.00007
	8	50	19.8	2.495	6.8	0.873	0.80	0.100	0.00046	0.00006
95	9	100	19.8	2.495	10.1	1.267	1.15	0.146	0.00066	0.00008
	10	100	19.8	2.495	10.6	1.338	1.22	0.154	0.00070	0.00009
	11	100	21.5	2.703	12.4	1.566	1.43	0.180	0.00082	0.00010
	12	100	21.0	2.647	11.9	1.501	1.37	0.172	0.00079	0.00010
	13	75	19.8	2.495	8.2	1.035	0.94	0.119	0.00054	0.00007
	14	50	19.8	2.495	6.6	0.830	0.76	0.095	0.00043	0.00005
Maximums			21.5	2.703	12.7	1.600	1.46	0.184	0.00084	0.00011

Temp. (°F)	Case	Load (%)	NO _x			CO			VOC		
			(ppmv) ⁵	(lb/hr)	(g/sec)	(ppmv) ⁵	(lb/hr)	(g/sec)	(ppmv) ⁵	(lb/hr)	(g/sec)
0	1	100	9.0	70.4	8.870	12.1	58.3	7.346	2.50	6.6	0.832
	2	100	10.1	78.7	9.910	15.0	78.7	9.910	3.40	10.2	1.289
	3	75	9.0	56.1	7.069	12.1	46.2	5.821	2.50	5.2	0.660
	4	50	9.0	44.0	5.844	12.6	37.4	4.712	2.89	4.4	0.850
65	5	100	9.0	64.9	8.177	11.9	52.8	6.653	2.50	6.2	0.776
	6	100	10.4	82.9	10.480	15.5	75.4	9.494	3.50	9.8	1.234
	7	75	9.0	51.7	6.514	12.2	42.9	5.405	2.55	5.2	0.651
	8	50	9.0	41.8	5.267	12.8	35.2	4.435	2.65	4.4	0.549
95	9	100	9.0	61.6	7.762	11.9	49.5	6.237	2.40	5.7	0.721
	10	100	9.0	86.9	10.949	11.2	49.5	6.237	2.53	5.0	0.632
	11	100	13.6	113.3	14.276	22.9	116.6	14.692	5.80	16.8	2.121
	12	100	10.6	80.6	10.159	15.8	73.3	9.231	3.60	9.6	1.206
	13	75	9.0	49.5	6.237	12.3	40.7	5.128	2.60	4.2	0.529
	14	50	9.0	39.6	4.990	13.0	34.1	4.297	2.73	5.0	0.632
Maximums			13.6	113.3	14.276	22.9	116.6	14.692	5.80	16.8	2.121

¹ Excludes sulfuric acid mist.

² Based on natural gas sulfur content of 2.0 gr/100 ft³.

³ Based on 7.5% conversion of SO₂ to H₂SO₄.

⁴ Based on EPA Electric Utility HAP emission factor of 3.70 x 10⁻¹ lb/10¹² Btu and natural gas heat content of 1,020 Btu/ft³.

⁵ Corrected to 15% O₂.

Sources: ECT, 1999.

GE, 1999.

Gulf Power, 1999.

Table C-3. Plant Smith Unit 3
CTG/HRSG Annual Emission Rates
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO _x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1,2	6	2	7,760	165.9	643.6	150.70	584.7	19.6	76.0
CTG/HRSG1,2	11	2	1,000	226.6	113.3	233.2	116.6	33.7	16.8
			Totals	N/A	756.9	N/A	701.3	N/A	92.8

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM ₁₀		SO ₂		Lead		H ₂ SO ₄	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1,2	6	2	7,760	41.8	162.2	23.7	92.1	0.0016	0.00000	2.7	10.6
CTG/HRSG1,2	11	2	1,000	42.9	21.5	24.9	12.4	0.0016	0.00001	2.9	1.4
			Totals	N/A	183.6	N/A	104.5	N/A	0.00001	N/A	12.0

Sources: ECT, 1999.
 GE, 1999.
 Gulf Power, 1999.

Table C-4. Plant Smith Unit 3
CTG/HRSG Exhaust Flow Rates (Per CTG/HRSG)

A. Exhaust Molecular Weight (MW)

Component	MW (lb/mole) Case	Exhaust Gas Composition - Volume %													
		100 % Load								75 % Load			50 % Load		
		0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	59 °F	95 °F
		1	2	5	6	9	10	11	12	3	7	13	4	8	14
Ar	39.944	0.90	0.90	0.88	0.88	0.87	0.82	0.81	0.87	0.89	0.89	0.87	0.91	0.89	0.89
N ₂	28.013	75.09	74.82	74.03	73.70	72.91	69.06	68.61	72.54	75.09	74.26	73.37	75.19	74.37	73.50
O ₂	31.999	12.58	11.80	12.29	11.35	12.08	11.04	9.68	11.03	12.58	12.50	12.39	12.87	12.81	12.77
CO ₂	44.010	3.88	4.23	3.89	4.31	3.84	3.84	4.46	4.32	3.89	3.81	3.75	3.75	3.67	3.57
H ₂ O	18.015	7.55	8.25	8.91	9.75	10.31	15.24	16.43	11.25	7.55	8.54	9.62	7.29	8.26	9.28
Totals		100.00	100.00	100.00	100.00	100.01	100.00	100.00	100.00	100.00	100.00	100.00	100.01	100.00	100.01
Exhaust MW (lb/mole)		28.49	28.44	28.34	28.29	28.18	27.64	27.57	28.12	28.49	28.37	28.25	28.51	28.39	28.27
Exhaust Flow (lb/sec)		1,074.17	1,076.39	978.89	981.25	931.39	964.17	968.06	935.14	855.28	803.89	774.17	698.61	663.89	646.11
Exhaust Temp. (°F)		192	190	188	186	175	170	170	183	170	166	180	159	155	173
(K)		362	361	360	359	353	350	350	357	350	348	355	344	341	351
Ambient Temp. (°F)		0	0	65	65	95	95	95	95	0	65	95	0	65	95
(K)		255	255	291	291	308	308	308	308	255	291	308	255	291	308
Exhaust O ₂ (Vol %, Dry)		13.61	12.86	13.49	12.58	13.47	13.03	11.58	12.43	13.61	13.67	13.71	13.88	13.96	14.08

B. Exhaust Flow Rates

Case	100 % Load								75 % Load			50 % Load		
	0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	59 °F	95 °F
	1	2	5	6	9	10	11	12	3	7	13	4	8	14
ACFM	1,076,530	1,077,167	980,124	981,334	918,862	962,248	968,750	936,283	828,210	776,637	768,024	664,209	629,708	633,397
Velocity (fps)	81.4	81.5	74.1	74.2	69.5	72.8	73.3	70.8	62.6	58.7	58.1	50.2	47.6	47.9
Velocity (m/s)	24.8	24.8	22.6	22.6	21.2	22.2	22.3	21.6	19.1	17.9	17.7	15.3	14.5	14.6
SCFM, Dry ¹	805,875	802,674	727,378	723,767	685,187	683,482	678,430	682,268	641,648	599,054	572,603	525,212	495,928	479,253

¹ At 68 °F.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table C-4. Plant Smith Unit 3
CTG/HRSO Exhaust Data (Per CTG/HRSO)

C. Correction of VOC Concentrations to 15% O₂, dry

Case															
	100 % Load								75 % Load			50 % Load			
	0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	65 °F	95 °F	
	1	2	5	6	9	10	11	12	3	7	13	4	8	14	
VOC (ppmv _w)	2.86	4.25	2.86	4.46	2.71	2.86	7.65	4.59	2.86	2.86	2.86	2.86	2.86	2.86	
VOC (ppmv _d)	3.09	4.63	3.14	4.94	3.02	3.37	9.16	5.17	3.09	3.13	3.16	3.08	3.12	3.15	
VOC (15% O ₂)	2.50	3.40	2.50	3.50	2.40	2.53	5.80	3.60	2.50	2.55	2.60	2.59	2.65	2.73	

D. Correction of CO Concentrations to 15% O₂, dry

Case															
	100 % Load								75 % Load			50 % Load			
	0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	65 °F	95 °F	
	1	2	5	6	9	10	11	12	3	7	13	4	8	14	
CO (ppmv _d)	15.00	20.43	15.00	21.86	15.00	15.00	36.16	22.69	15.00	15.00	15.00	15.00	15.00	15.00	
CO (15% O ₂)	12.14	15.00	11.95	15.50	11.91	11.24	22.90	15.80	12.14	12.24	12.31	12.61	12.76	12.97	

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table C-5. Plant Smith Unit 3

Natural Gas Fuel Flow Rates; Per CTG/HRS Unit

Case	100 % Load								75 % Load			50 % Load		
	0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	65 °F	95 °F
	1	2	5	6	9	10	11	12	3	7	13	4	8	14
Heat Input - LHV (MMBtu/hr)	1,751.0	1,917.9	1,606.8	1,791.4	1,518.5	1,604.0	1,876.9	1,798.4	1,408.6	1,304.6	1,240.7	1,122.2	1,045.6	994.5
Fuel Rate ¹ (lb/hr)	83,904	91,902	76,995	85,841	72,763	76,860	89,935	86,176	67,497	62,514	59,452	53,774	50,103	47,654
Fuel Rate (lb/sec)	23.307	25.528	21.387	23.845	20.212	21.350	24.982	23.938	18.749	17.365	16.514	14.937	13.918	13.237
Fuel Rate ² (10 ⁶ ft ³ /hr)	1.845	2.021	1.693	1.887	1.600	1.690	1.977	1.895	1.484	1.375	1.307	1.182	1.102	1.048

¹ Based on natural gas heat content of 20,869 Btu/lb (LHV).

² Based on natural gas density of 0.04548 lb/ft³.

Sources: ECT, 1999.

GE, 1999.

Gulf Power, 1999.

**Table C-6. Plant Smith Unit 3
CTG NSPS Subpart GG Limit (Per CTG)**

Fuel	PG7241FA Gas Turbine ISO Heat Rate (LHV)		F	NO _x Std (ppmvd)
	(Btu/kw-hr)	(kj/w-hr)		
Gas	9,150	9.654	0.0	111.9

Sources: ECT, 1999.
GE, 1999.

COOLING TOWER EMISSION RATE ESTIMATES

Particulate matter (PM/PM₁₀) emissions from the induced draft mechanical cooling tower were estimated using procedures found in AP42, Section 13.4, Wet Cooling Towers.

A. Cooling Tower Data

Total Liquid Drift = 0.001% of recirculation water flow rate

Total Liquid Drift = 0.001 gal / 100 gal recirculation water flow rate

Recirculation Water Flow Rate = 125,000 gal/min

Recirculation Water Total Dissolved Solids (TDS) = 29,000 ppmw

B. PM/PM₁₀ Emission Rate Calculations

$$\text{PM/PM}_{10} = (125,000 \text{ gal/min}) \times (0.001 \text{ gal} / 100 \text{ gal}) \times (8.345 \text{ lb} / \text{gal water}) \\ \times (29,000 \text{ lb PM/PM}_{10} / 10^6 \text{ lb water}) \times (60 \text{ min/hr})$$

$$\text{PM/PM}_{10} = 18.15 \text{ lb/hr}$$

$$\text{PM/PM}_{10} = 79.5 \text{ ton/yr (8,760 hours/year operation)}$$

ATTACHMENT D—
NO_x NETTING ANALYSIS

**Gulf Power Plant Smith Unit 3
NO_x Netting Analysis**

A. Unit 1 Baseline NO_x Emissions

Year	Fuel Usage		Fuel Heat Content		Total Heat Input (10 ⁶ Btu/yr)	CEMS NO _x Emission Rate (lb/10 ⁶ Btu)	NO _x Emission Rate (ton/yr)
	Coal (ton/yr)	Oil (gal/yr)	Coal (Btu/lb)	Oil (Btu/gal)			
1996 ^a	520,766.0	65,900	11,775	138,500	12,273,166	0.614	3,767.9
1998	522,256.5	70,760	11,765	138,480	12,298,494	0.557	3,425.1
2-Yr Average	521,511.3	68,330	11,770	138,490	12,285,830	0.586	3,596.5

B. Unit 3 NO_x Emissions (Two CTG/HRSG Units)

Operating Case	NO _x Emissions (lb/hr)	Operations (hr/yr)	NO _x Emissions (ton/yr)
6 ^b	165.9	7,760	643.6
11 ^c	226.6	1,000	113.3
Totals	N/A	8,760	756.9

C. Net Change in NO_x Emissions

Emission Source	'96, '98 Baseline (ton/yr) [lb/10 ⁶ Btu]	Following Unit 3 Installation (ton/yr) [lb/10 ⁶ Btu] ^d	Emission Rate Change (ton/yr)
Unit 1	3,596.5 [0.586]	2,830.4 [0.461]	-766.1
Unit 3	0.0	756.9	756.9
		Net Change	-9.1
Annual Cap for Unit 1 and Unit 3^e		3,587.4	

Notes:

- a - 1997 not used for averaging purposes due to 37 day outage occurring during 1997 per agreement with Clair Fancy/AI Linero (FDEP Division of Air Resources Management) on 1/25/99.
- b - Base load, 65 °F, evaporative cooling, duct burner firing.
- c - Base load, 95 °F, evaporative cooling, duct burner firing, and steam power augmentation.
- d - Based on installation of low-NO_x burners and improved burner management system.
- e - A federally enforceable annual NO_x emissions cap of 3,587 tpy for Unit 1 and Unit 3 is requested.

Sources: Gulf, 1999.
ECT, 1999.

June 3, 1999



Estimates of Changes in CO, VOC, and Particulate Emissions From Low NOx Firing at Gulf Power's Lansing Smith Unit 1

A substantial amount of information has been published regarding possible changes in emissions from coal-fired utility boilers resulting from the installation of low NOx combustion modifications. Some of the best information available was developed at Gulf Power's Plant Smith Unit 2, during the U. S. DOE's Clean Coal Project (CCP). The information developed during that program, along with other relevant published information, is discussed in the following paragraphs.

Carbon Monoxide (CO) – Data taken at the Smith Unit 2 CCP demonstration indicated that the CO emissions, starting at 10 to 15 ppm for the original burners, were slightly decreased (10 ppm) with the NOx burner modifications that closely match those proposed for Smith Unit 1¹.

Volatile Organic Compounds (VOC) – VOC's, like CO, are the result of incomplete combustion of the coal. Because of this relationship, normally VOC and CO emissions will track, with CO rising to several hundred ppm before significant VOC's appear. A study of air toxics was performed as part of the Smith Unit 2 CCP². In this report, all but one of the 19 identified compounds in the volatile organic sampling train (VOST) were lower in the low NOx firing test than in the baseline testing, with 10 of the 19 compounds not detected in the low NOx testing. (Even though the authors speculate that the baseline test samples may have been contaminated, most of the compounds were not detected in the low NOx firing case.) As further evidence of minimal impact from these burner changes, EPRI's Emission Factor Handbook³ makes no distinction between uncontrolled and low NOx firing for coal-fired boilers when estimating organic emissions. In summary, no changes are expected in the already low emissions of VOC's as a result of installing low NOx burner tips at Smith Unit 1.

Particulate Emissions – After the numerous low NOx modifications made to coal-fired boilers in the Southern Company electric system, the only impact on particulate emissions that has been seen is due to increased unburned carbon in the fly ash. This added carbon load, because it is not collected as efficiently as fly ash, can lead to increased mass emissions if the existing ESP is marginal. However, after the utility industry discovered these initial problems with unburned carbon, it was recognized that pulverizer performance can control the top coal particle size, and therefore the unburned carbon, and these problems have been mostly resolved. Even though the study of Smith Unit 2 described previously² found a slight increase in ESP outlet mass emissions from the base case to the most extreme low NOx test case, it is expected that the new low NOx burner

modifications at Smith Unit 1 will not cause any measurable increase in particulate emissions. The reason for this assertion is that the low NOx retrofit proposed uses a more advanced burner tip, without resorting to the extreme air staging that seems to cause the increase in unburned carbon in fly ash.



Larry S. Monroe, Ph.D.
Principal Research Engineer
Research and Environmental Affairs
Southern Company Services, Inc.

References

¹R. R. Hardman, L. L. Smith, and S. Tavoulareas, "Results from the ICCT T-Fired Demonstration Project Including the Effect of Coal Fineness on NOx Emissions and Unburned Carbon Levels," presented at the EPRI/EPA 1993 Joint Symposium on Stationary Combustion NOx Control, Miami Beach, Florida, May 1993.

²E. B. Dismukes, Measurement of Chemical Emissions Under the Influence of Low NOx Combustion Modifications, Final Report to Southern Company Service, Inc., Contract C-91-000017, October 1993.

³Emissions Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Plant, EPRI, Palo Alto, CA, TR-105611, November 1995.

**APPENDIX E—
DISPERSION MODELING FILES**

(One set of diskettes provided to FDEP)

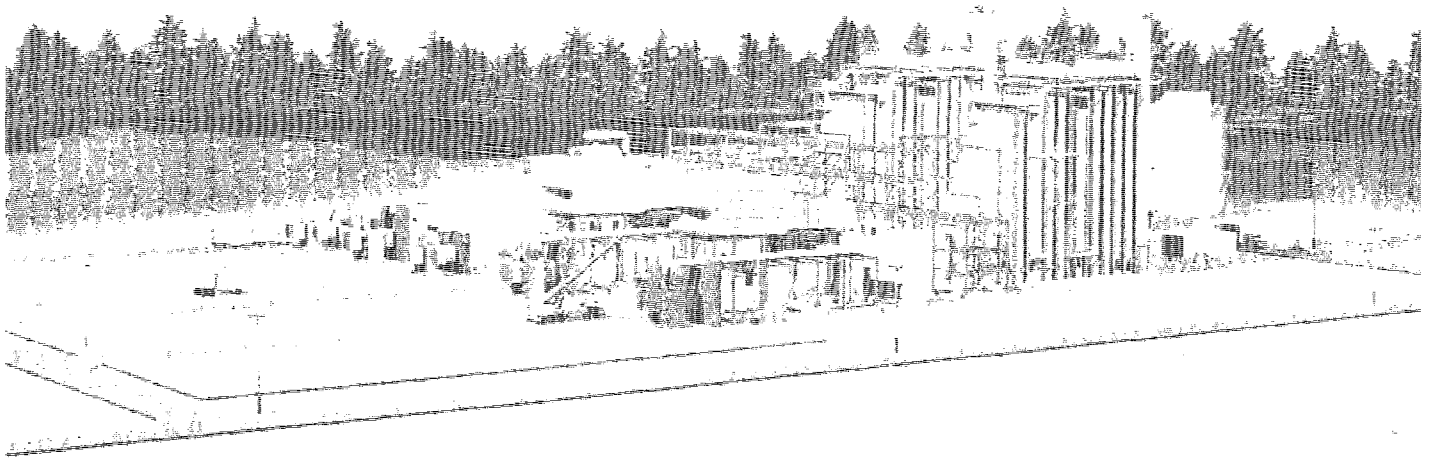
DISKETTE/ CD/ OR
SLIDES
WERE REMOVED
AND PLACED IN A
FILE WITHIN THE
RECORDS
CENTER.



APPENDIX 10.2.8
FEDERAL AVIATION
ADMINISTRATION APPLICATION

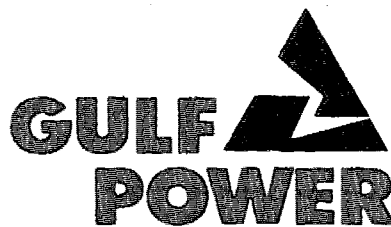
**FAA Stack Height Application
will be Submitted Later**

GULF POWER SMITH UNIT 3 Site Certification Application



Volume 5

June 1999



A SOUTHERN COMPANY

ECT

Environmental Consulting & Technology, Inc.

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS

APPENDIX 10.3
EXISTING ZONING/LAND USE
REGULATIONS

**Excerpts from 1990 Adopted Bay County Comprehensive
Plan (there are no separate zoning standards for
unincorporated areas of Bay County;
also see Appendix 10.2.1)**

include feedlots, or processing or distribution plants for agricultural products and supplies. Low-density residential use is allowed; refer to the table of residential densities.

K. Silvicultural

Silvicultural uses include forestry and buildings which are an accessory to this use.

Low-density residential use is allowed; refer to the table of residential densities.

L. Industrial

This type of use includes those wholesale and retail businesses for manufacturing, processing, storing, or distributing goods. Included in this category are uses which require primarily outdoor storage or the industrial activity itself is conducted outdoors. Such uses include, for example, LP gas storage and/or distribution, junkyards or salvage yards, waste-to-energy incinerators, recycling centers, Class I and Class II landfills, hazardous waste collection and handling centers.

M. Mining

The types of uses in this group include borrow pits, surface mining, rock quarries, strip mining, and any extraction activities. Buildings and businesses for the refinement, processing, packaging, and transportation of extracted materials are included in this group of uses.

2.02.03 Allowable Uses Within Each Land Use District

<i>LAND USE</i>	<i>LAND USE DISTRICT</i>										
	AG	SILV	R	NC	C	M/U	I	REC	CON	SPEC	P/S
Residential	A	A	A	A	A	A	P	P	P	A	P
Institutional	A	P	A	A	A	A	A	P	P	A	A
Outdoor Recreational	A	A	A	A	A	A	P	A	A	A	A
Professional Service and Office	P	P	A	A	A	A	P	P	P	A	A
Neighborhood Commercial	P	P	A	A	A	A	P	P	P	A	P
General Commercial	P	P	P	P	T/U	A	P	M	P	P	P
Public Service	A	A	P	P	P	P	A	P	P	P	A
Utilities	A	A	A	A	A	A	A	A	A	A	A
Low-Intensity Agricultural	A	A	RR	P	P	P	P	P	A	A	P
General Agricultural	A	P	P	P	P	P	P	P	P	A	P
Silvicultural	A	A	P	P	P	P	P	P	A	A	P
Industrial	P	P	P	P	P	P	A	P	P	P	A
Mining	A	A	P	P	P	P	A	P	P	P	A

NOTES:

A - ALLOWED USE, MUST MEET ALL APPLICABLE DEVELOPMENT STANDARDS IN THIS CODE.

P - PROHIBITED USE.

RR - ALLOWED IN RURAL RESIDENTIAL CHARACTER DISTRICT ONLY.

T/U - ALLOWED IN TRANSITIONAL AND URBAN CHARACTER DISTRICTS ONLY.

M - MARINAS ONLY.

UFLOOR - ALLOWED IN UPPER FLOOR(S) OF COMMERCIAL OR OFFICE USE ONLY.

INDUSTRIAL LANDS

POLICY 1.17.7: Industrial lands shall be classified as follows:

Industrial

Purpose: To provide areas for the location of industrial operations and to provide sufficient choice of suitable locations to encourage economic development of the county.

Land Uses: All industrial trade and service activities including industrial support services, such as administration, and public utilities

Location Criteria: Urban, transition and rural area

Intensity:	Floor Area Ratio	.30, Rural District
		.60, Transitional District
		1.0, Urban District
		.60, Coastal District
		.30, Deer Point Lake Watershed
	Impervious Surface Ratio	.45, Rural District
		.50, Transitional District
		.80, Urban District
		.65, Coastal District
		.45, Deer Point Lake Watershed

RECREATIONAL LANDS

POLICY 1.17.8: Recreational lands shall be classified as follows:

Recreation

Purpose: To provide for the location of public and private recreational land uses, including active and passive recreation areas.

Land Uses: Public recreation areas, private recreational facilities, including limited commercial uses, such as marinas, and public utilities

Location
Criteria: Rural, transition, and urban areas

Intensity: Floor Area Ratio .20, Rural District
.20, Transitional District
.20, Urban District
.20, Coastal District
.20, Deer Point Lake Watershed
.20, St. Andrews Impact Area District
Impervious Surface Ratio .10, Rural District
.10, Transitional District
.20, Urban District
.20, Coastal District
.10, Deer Point Lake Watershed
.20, St. Andrews Impact Area District

CONSERVATION LANDS

POLICY 1.17.9: Conservation lands shall be classified as follows:

Conservation

Purpose: To identify public and private lands held for conservation of natural features

Land Uses: Activities compatible with the purposes of conserving or protecting natural resources, including flood control, wildlife habitat protection, passive recreational uses, and silviculture applying the standards described under Future Land Use Objective 3.4, and public utilities

Location
Criteria: Areas held for conservation use

APPENDIX 10.4
EXISTING PERMITS RELATIVE
TO SMITH UNIT 3

ATTACHMENT 10.4-A
EXISTING INDUSTRIAL
WASTEWATER PERMIT

NOTICE OF PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

Gulf Power Company
One Energy Place
Pensacola, Florida 32520

Facility ID Number FL0002267


Attention: Jim Vick

Permit Number FL0002267 to Gulf Power Company, One Energy Place,
Pensacola, Florida 32520 for operation of Units 1 and 2 of the Lansing Smith Electric
Generation Plant, issued under Section 403.0885, Florida Statutes and DEP Rule 62-620,
Florida Administrative Code.

Any party to this permit has the right to seek judicial review of the permit under
section 120.68 of the Florida Statutes, by the filing of a Notice of Appeal under rule 9.110
of the Florida Rules of Appellate Procedure, with the Clerk of the Department of
Environmental Protection, Office of General Counsel, Mail Station 35, 3900
Commonwealth Boulevard, Tallahassee, Florida 32399-3000 and by filing a copy of the
notice of appeal accompanied by the applicable filing fees with the appropriate district
court of appeal. The notice of appeal must be filed within thirty days after this notice is
filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Adm. Sec. 
Mimi A. Drew
Division Director
Division of Water Facilities
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(904) 487-1855

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 04-16-98 to the listed persons.

[Clerk Stamp]

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

G. Shields 4-16-98
(Clerk) (Date)

Copies furnished to:

Danny Sparks - Chairman, Board of Bay County Commissioners
Jennifer Fitzwater - DEP Tallahassee
William Schaal - DEP Pensacola

**STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT**

PERMITTEE:

Gulf Power Company
One Energy Place
Pensacola, Florida 32520

PERMIT NUMBER: FL0002267
ISSUANCE DATE: April 17, 1998
EXPIRATION DATE: April 16, 2003
APPLICATION NO.: FL0002267-001-IW1S

FACILITY:-

Lansing Smith Electric Generation Plant
4300 County Road 2300
Bay County
Southport, Florida 32409

Latitude: 30° 16' 4.42" Longitude: 85° 42' 3.11"

This permit is issued under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. The above named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

TREATMENT FACILITIES:

Treated and untreated wastewater (except once-through cooling water and emergency overflow from the main sump) from the operation of Units 1 and 2 is discharged to the ash pond. Wastewater streams that discharge to the ash pond include boiler blowdown, water treatment filter backwash, air preheater wash, ash and pyrite sluice, coal pile runoff, yard runoff, treated metal cleaning waste, treated demineralizer regeneration waste, treated domestic wastewater, and other minor process and non-process waste streams.

Demineralizer regeneration waste is neutralized and allowed to settle in a retention pond prior to discharge to the ash pond. Metal cleaning waste is neutralized in pipe and is chemically precipitated and allowed to settle in a retention pond prior to discharge to the ash pond. Domestic wastewater receives secondary treatment in a extended aeration package treatment plant prior to discharge to the ash pond.

EFFLUENT DISPOSAL:

This permit authorizes discharges from Outfall D001 (once-through condenser cooling water and ash pond overflow, formerly Outfall 001), Outfall D015 (metal cleaning wastewater, formerly Outfall 002), Outfall D01C (ash pond overflow, formerly Outfall 003), Outfall D00D (main yard sump overflow, Outfall 004), and Outfall D01A (treated domestic wastewater, formerly Outfall 005). Outfall D001 discharges through a 10,200 foot discharge canal to Warren Bayou and hence to West Bay, both of which are Class II waters. Outfall D015 and Outfall A01A are internal outfalls that discharge to the ash pond. Outfall D01C is also an internal outfall that discharges to the discharge canal and combines with once-through cooling water. Outfall D00D discharges to Alligator Bayou (intake canal), a Class III marine water. This permit also authorizes the discharge of ash sluice waste and other low volume wastewaters to the ash pond and the recycling of ash pond water for ash sluice water.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in Part I 10 pages, Part II 1 page, Part III 3 pages, Part IV 1 page, Part V 1 page, Part VI 1 page, Part VII 6 pages, and Part VIII 5 pages of this permit.

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I. Effluent Limitations and Monitoring Requirements

A. Surface Water Discharges

1. During the period beginning on the issuance date of this permit and lasting through the expiration date, the permittee is authorized to discharge from **OUTFALL D001 - ONCE-THROUGH CONDENSER COOLING WATER (OTCW) AND ASH POND OVERFLOW** (formerly Outfall 001), during periods of normal plant operation through the discharge canal to Warren Bayou.

- a. Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS		
	Maximum	Maximum Monthly Average	Measurement Frequency	Sample Type	Sample Point
Flow, MGD	Report	Report	1/hour	Pump Logs	INT-2
Temperature Rise, °F ¹					
April - September	Report	18	4/day ¹	Calculated	INT-1
Winter	Report	20	4/day ¹	Calculated	EFF-1
pH Range, stand. units	6.5 (minimum) 8.5 (maximum)	NA	1/week	Grab	EFF-2
Total Residual Oxidants, mg/l	0.01	NA	1/week	Grab	EFF-2
Oil & Grease, mg/l	5.0	NA	1/month	Grab	EFF-2
Copper, ug/l	2.9 ²	NA	1/year	Composite ³	EFF-2
Lead, ug/l	5.6 ²	NA	1/year	Composite ³	EFF-2
Nickel, ug/l	8.3 ²	NA	1/year	Composite ³	EFF-2

- b. Total Residual Oxidant (TRO) means the value obtained using the amperometric titration method for total residual chlorine. Testing for TRO by titration shall be conducted according to the amperometric method, as specified in Section 4500-Cl D, Standard Methods for the Examination of Water and Wastewater, 19th Edition (or most current edition).
- c. Continuous chlorination of the cooling water intake is authorized by this permit.

¹ The cooling water intake and discharge at shall be monitored simultaneously four times per day spread out evenly over a 24-hour time period. The temperature rise shall be calculated for each temperature intake and discharge measurement and the daily temperature rise for any one day shall be average of all temperature rise values for that day.

² The actual limit shall be the water quality standard set forth in FAC 62-302.530 for Class II waters as specified here or the concentration of the intake cooling water, whichever is greater. If the Outfall 001 composite sample exceeds the intake concentration (and the intake concentration exceeds the water quality standard), the concentration of a minimum of five (5) additional subsamples shall be measured from the original intake and outfall composites and a "student's t-test" shall be run on these additional subsamples comparing discharge concentrations with the intake concentrations; unless the discharge concentration exceeds the intake concentration at the 95% confidence level, the facility shall be in compliance with the limitation.

³ Either 8-hour manual composite composed of 16 aliquots or 24-hour automatic composite.

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d. The location of sampling points as specified above are as follows:

INT-1 - OTCW condenser inlets.

EFF-1 - OTCW discharge structure.

INT-2 - OTCW circulator pump logs.

EFF-2 - Immediately downstream of the center of the second roadway embankment across the discharge canal downstream of the discharge structure.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

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2. During the period beginning on the issuance date of this permit and lasting through the expiration date, the permittee is authorized to discharge from internal **OUTFALL D015 - METAL CLEANING WASTEWATER** (formerly Outfall 002), to the ash pond.
- a. Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS		
	Maximum	Maximum Monthly Average	Measurement Frequency	Sample Type	Sample Point
Volume, gallons/batch ⁴	Report	Report	1/batch	Calculated	EFF-3
Total Copper, mg/l	1.0	1.0	1/batch	Composite ⁵	EFF-3
Total Iron, mg/l	1.0	1.0	1/batch	Composite ⁵	EFF-3

- b. Metal cleaning wastes shall mean any chemical cleaning compounds, rinse waters, or any other waterborn residues derived from chemical cleaning any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.
- c. The location of sampling points as specified above are as follows:

EFF-3 - Discharge from the metal cleaning waste treatment pond prior to discharge to the ash pond.

⁴ For one cleaning during a month, the same value for daily average and daily maximum shall be reported. For two or more cleanings during a month the average batch volume shall be reported as the monthly average and the maximum batch volume shall be reported as the maximum.

⁵ The composite shall consist of 8 aliquots collected at equal time intervals throughout the period of discharge.

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3. During the period beginning on the issuance date of this permit and lasting through the expiration date, the permittee is authorized to discharge from internal **OUTFALL D01C - ASH POND OVERFLOW** (formerly 003) to the discharge canal leading to Outfall D001. Wastewater streams that discharge to the ash pond include boiler blowdown, water treatment filter backwash, air preheater wash, ash and pyrite sluice, coal pile runoff, yard runoff, treated metal cleaning waste, reverse osmosis reject water, treated demineralizer regeneration waste, treated domestic wastewater, barge bilge water, and treated ground water from authorized remediation projects.
- a. Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS		
	Maximum	Maximum Monthly Average	Measurement Frequency	Sample Type	Sample Point
Flow, MGD	Report	Report	1/day	Flow meter	EFF-4
pH Range, stand. units	6.0(minimum) 9.0(maximum)	NA	1/week	Grab	EFF-4
Total Suspended Solids, mg/l	100.0	30.0	1/week	Grab	EFF-4
Oil & Grease, mg/l	20.0	15.0	1/2 weeks	Grab	EFF-4
Arsenic (total), ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Cadmium, ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Total Chromium, ug/l	Report ⁸	NA	2/year ⁶	Composite ⁷	EFF-4
Copper, ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Iron, ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Lead, ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Mercury, ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Nickel, ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Selenium, ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Zinc, ug/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4
Combined Radium 226 and 228, pCi/l	Report	NA	2/year ⁶	Composite ⁷	EFF-4

- b. The discharge from this outfall is intermittent; therefore, flow measurement or sampling is required only during periods of discharge.
- c. The location of sampling points as specified above are as follows:

EFF-4 - Discharge from the ash pond parshall flume.

⁶ Samples shall be taken during the first half and second half of the calendar year and shall be taken a minimum of 4 months apart when possible depending on the frequency of the ash pond overflow.

⁷ 24-hour composite sample.

⁸ If the total chromium level exceeds 50 ug/l, the permittee shall resample and Chromium VI analysis shall be performed and reported.

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4. During the period beginning on the issuance date of this permit and lasting through the expiration date, the permittee is authorized to discharge from **OUTFALL D00D - MAIN YARD SUMP OVERFLOW** (formerly Outfall 004) to the intake canal.

- a. Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS		
	Maximum	Maximum Monthly Average	Measurement Frequency	Sample Type	Sample Point
Flow, MGD	Report	NA	1/event	Calculation	EFF-5
Time of Discharge, minutes	Report	NA	1/event	Estimate	EFF-5
Oil & Grease, mg/l	5.0	NA	2/event	Grab ⁹	EFF-5
Total Suspended Solids, mg/l	100	30	2/event	Grab ⁹	EFF-5
pH	6.5 (minimum) 8.5 (maximum)	NA	2/event	Grab ⁹	EFF-5

- b. The discharge from this outfall is intermittent; therefore, flow measurement or sampling is required only during periods of discharge.
- c. All due diligence will be taken to not discharge air preheater and precipitator wash wastes during times of discharge from this outfall.
- d. The location of sampling points as specified above are as follows:

EFF-5 - The main yard sump at the nearest accessible point prior to discharge.

⁹ Samples shall be taken at the start and completion of discharge.

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5. During the period beginning on the issuance date of this permit and lasting through the expiration date, the permittee is authorized to discharge from internal **OUTFALL D01A - DOMESTIC WASTEWATER TREATMENT PLANT EFFLUENT** (formerly Outfall 005) to the ash pond.

- a. Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS		
	Maximum	Maximum Monthly Average	Measurement Frequency	Sample Type	Sample Point
Total Residual Chlorine, mg/l	0.5 (minimum)	NA	5/week	grab	EFF-6
Fecal Coliform, # per 100 ml	200	NA	1/month	grab	EFF-6

- b. The location of sampling points as specified above are as follows:

EFF-6 - Discharge from the chlorine contact chamber.

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B. Other Limitations and Monitoring and Reporting Requirements

1. The approved analytical methods and corresponding Department established MDL (method detection limit) and PQL (practical quantification limit) are listed for the following parameters:

Parameter	EPA Method	MDL (ug/l)	PQL (ug/l)
Arsenic	206.3/206.2/200.7	1.0/2.0/50.0	5.0/10.0/100.0
Cadmium	213.2/200.7/213.1	0.1/3.0/5.0	0.5/10.0/15.0
Chromium VI	7196	10.0	50.0
Copper	220.2	1.0	5.0
Iron	236.2/200.7/236.1	2.0/10.0/30.0	10.0/50.0/100.0
Lead	239.2	2.0	5.0
Mercury	245.1/245.2	0.2/0.2	0.5/0.5
Nickel	200.7	3.3	40.0
Selenium	270.2/270.3	2.0/2.0	5.0/5.0
Zinc	289.2/289.1/200.7	0.05/5.0/10.0	0.25/15.0/25.0
Total Residual Chlorine	330.1	30.0	30.0
Total Radium 226 and Radium 228	903.0	0.70 pCi/l	2.0 pCi/l
Oil & Grease	413.1	5000.0	5000.0

The MDLs and PQLs listed above shall constitute the minimum reporting levels for the life of the permit. The Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those listed above. Unless otherwise specified, sample results shall be reported as follows:

- results greater than or equal to the PQL shall be reported as the measured quantity.
- results less than the PQL and greater than or equal to the MDL shall be reported as the PQL value followed by the lab code "m" and the value of the MDL in parentheses, and shall be deemed equal to the MDL when necessary to calculate an average for that parameter and when determining compliance with permit limits. Any measurement greater than the permit limit but less than the PQL shall not be considered a permit violation if the permit limit is less than the PQL but greater than or equal to the MDL..
- results less than the MDL shall be reported as the MDL followed by the lab code "u". A value of one half the MDL or half the effluent limit, whichever is lower, shall be used for that sample when necessary to calculate an average for that parameter. Values less than the MDL are considered to demonstrate compliance with an effluent limit or monitoring requirement. [62-4.246, 6-13-96]

2. Monitoring requirements specified in Section I.A of this permit shall begin on May 1, 1998.

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3. Monitoring results obtained for each calendar month shall be summarized for that month and reported on a Discharge Monitoring Report (DMR), Form 62-620.910(10), postmarked no later than the 28th day of the month following the completed calendar month. For example, data for January shall be submitted by February 28. Signed copies of the DMR shall be submitted to the address specified below:

Florida Department of Environmental Protection
Wastewater Facilities Regulation Section, Mail Station 3551
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

If no discharge occurs during the reporting period, sampling requirements of this permit do not apply. The statement "No discharge" shall be written on the DMR form. If, during the term period of this permit, the facility ceases to discharge, the Department shall be notified immediately upon cessation of discharge. Such notification shall be in writing.

4. Unless specified otherwise in this permit, all other reports and notifications required by this permit, including twenty-four hour notifications, shall be submitted to or reported to, as appropriate, the Department's Northwest District Office at the address specified below:

Florida Department of Environmental Protection
Northwest Florida District
160 Government Center
Pensacola, Florida 32501-5794
Phone Number (850) 595-8300

5. In order to determine compliance with the discharge limitations specified in Section I.A of this permit sampling results shall be calculated and reported as follows:

Daily Average Value - the average of all sampling results for a parameter over a single day.

Monthly Average Value - the average of all sample results for a parameter over a monthly period.

Maximum - the maximum limitation for a single sampling result or, for report only, the maximum value of all sampling results during the reporting period.

6. After two years of data collection the permittee may request by permit revision a reduction in parameter monitoring frequencies in accordance with EPA Document 833-R-96-001 entitled Interim Guidance for Performance Based Reduction of NPDES permit Monitoring Frequencies (April 19, 1996).
7. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.
8. Discharge of uncontaminated storm water, intake screen backwash water, turbine oil cooler water, and hydrogen generator cooler water is permitted without limitations or monitoring requirements, except that there shall be no discharge of floating oil.
9. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of a visible oil sheen at any time. Any such discharges shall be reported to the Department when submitting DMR's.

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10. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit.

A permit revision from the Department shall be required prior to the use of any biocide or chemical additive used in the cooling system (except chlorine as authorized elsewhere in this permit) or any other portion of the treatment system which may be toxic to aquatic life. The permit revision request shall include:

- a. Name and general composition of biocide or chemical
- b. Frequencies of use
- c. Quantities to be used
- d. Proposed effluent concentrations
- e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)
- f. Product data sheet
- g. Product label

The Department shall review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without a permit revision by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

11. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately discharges to waters of the State is prohibited, unless specifically authorized elsewhere in this permit. The discharge of plant ash transport water, resulting from the combustion of on-specification used oil as authorized under the Resource Conservation and Recovery Act and 40 CFR Part 266, via the ash pond shall be an authorized discharge of this permit.
12. The permittee shall periodically survey all ash pond dikes and toe areas for structural integrity. Not later than December 31, 1998, and annually thereafter, the permittee shall certify that no breaches or structural defects resulting in the discharges to surface waters of the State were observed during the previous calendar year. In the event that such defect(s) exists and results in potential discharge to surface waters of the State, the permittee shall notify the Department within fifteen (15) days of becoming aware of the situation and provide a proposed course of corrective action and implementation schedule.
13. The permittee shall not store coal, soil, or other similar erodible materials in a manner in which runoff is uncontrolled, or conduct construction activities in a manner which produces uncontrolled runoff.
14. Not later than December 31, 1998, the permittee shall certify that the ash pond provides the necessary minimum wet weather detention volume to contain the combined volume for all direct rainfall and all rainfall runoff to the pond resulting from the 10-year, 24-hour rainfall event and maximum dry weather plant waste flows which could occur during a 24-hour period. This volume shall be calculated between the top of the sediment level and the minimum overflow discharge elevation (stop logs, weirs, etc.) on the ash pond effluent structure to the return channel. [Note: A valved discharge pipe below the elevation of the top-most stop log may be provided to allow the minimum necessary flow of ash sluice recycle to the return channel during periods of the low ash pond water level.] If the permittee can demonstrate that the recycle canal provides acceptable treatment volume, this additional detention volume can be included. All data necessary to support this certification shall be submitted with the certification to the Department.

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Not later than December 31, 2000, the permittee shall again certify that the ash pond provides the minimum wet weather volume as specified above based on a physical survey of the pond and shall provide a summary of the calculations to support the certification.

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II. Combustion By-Products Management Requirements

- A. Combustion by-products produced by the operation of Plant Lansing Smith: ash, non-hazardous metal cleaning wastewater sludge, and other solid waste approved by the Department shall be disposed of in the on-site 72 acre solid waste management facility permitted through this permit or to another appropriate solid waste management facility permitted by the Department.
- B. The disposal of combustion by-products in the on-site solid waste management facility permitted by the this permit shall be in accordance with the construction application, submitted September 19, 1985, Drawing D-31114 revised September 17, 1985. FDEP letter June 19, 1996 and the requirements of Chapter 62-701, F.A.C., except as modified by Evaluation of Solid Waste Management Practices and Requirements for the Florida Electric Utility Industry.
- C. A copy of the engineering drawings, plans, reports, construction permit, and supporting information shall be kept at this landfill at all times for reference and inspections.
- D. Small amounts of accumulated debris that has been removed from the plant's cooling water intake screens, consisting mainly of vegetation, may be placed in a central location near the ash landfill.
- E. In no event shall any solid waste other than combustion by-products or other materials approved by the Department be disposed of on the plant site other than in areas specifically designated in the application.
- F. The solid waste management facility was constructed in phases. The liner beneath the ground level cells consists of either of the following two construction materials:
- Minimum 1 foot clay liner with maximum permeability of 1×10^{-7} cm/sec compacted to 90% of Proctor, or
 - 60 mil HPDE liner and geosynthetic clay liner
- G. The final cover system, including the drainage soil, top soil and seeding, shall be completed within 180 days after the final waste deposit date.
- H. Final closure of the facility shall comply with the provisions of Rules 62-701.600 through 62-701.620, FAC, except as modified by Evaluation of Solid Waste Management Practices and Requirements for the Florida Electric Utility Industry and any additional requirements in effect at the time wastes cease to be accepted by the facility.
- I. Surface water runoff shall be controlled during operation under this permit and shall comply with FAC Chapter 62-302 at the site boundary.

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III. Groundwater Monitoring Requirements

- A. During the period of operation authorized by this permit, the permittee shall sample ground water in accordance with this permit and the approved ground water monitoring plan prepared under Rule 62-522.600, F.A.C.
- B. All new ground water monitoring wells identified by the approved plan shall be installed within 180 days of issuance of the approval. Within 60 days of installation of a new monitoring well, the permittee shall submit detailed information on the well's location and construction on DEP Form 62-522.900(3). [62-522.600, 12/9/96]
- C. The following monitoring wells are included in the ground water monitoring plan.

Well Name	WAFR Site #	DEP Test Site ID	Depth (Feet-BLS)	Aquifer Monitored	Well Type	Well Location	New or Existing
LB-1	29224	NA	TBD	Surficial class G-II	Background	TBD, northwest of landfill	New
9-3A	137	1003A11485	14.9	Surficial class G-II	Intermediate	500 ft S of SW corner of Ash Pond	Existing
9-9	136	1003A11486	17.6	Surficial class G-II	Intermediate	400 ft S of SE corner of Ash Pond	Existing
9-7	135	1003A11487	26.7	Surficial class G-II	Intermediate	200 ft S of Ash Pond	Existing
9-12A	134	1003A11488	15.5	Surficial class G-II	Intermediate	500 ft S of SW corner of Ash Landfill	Existing
M-5	138	1003A11484	20.0	Surficial class G-II	Compliance	900 ft S of NE property corner	Existing
LC-1	29233	NA	TBD	Surficial class G-II	Compliance	TBD, southeast of Ash Landfill	New

- D. A zone of discharge previously established for the Plant Lansing Smith facility operation is continued, more specifically described as follows:
- The zone of discharge extends horizontally to the former property lines and along the discharge canal right of way or mean high water line as depicted on the attached map and vertically from the land surface to the top of the Intracoastal Formation. [62-520.200(23), and 62-522.410]
- E. Analyses shall be conducted on un-filtered samples, unless the approval steps outlined in the FDEP document entitled Determining Representative Ground Water Samples, Filtered or Unfiltered (January 1994) have been met and approved by the Department.
- F. If a monitoring well becomes damaged or cannot be sampled for some reason, the permittee shall notify the Department with a written report within thirty days detailing the circumstances and remedial measures taken or proposed. Replacement of monitoring wells shall be approved in advance by the Department.
- G. Ground water monitoring test results shall be submitted on form Groundwater Monitoring Report Part D and shall be submitted in conjunction with the DMR in accordance with condition I.B.2.

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- H. The wells included in the ground water monitoring plan shall be sampled for the parameters and at the frequencies listed below:

Parameters (units)	Ground Water Standards	Monitoring Requirements	
		Frequency	Sample Type
Water level (MSL)	Class G-II NA	Annual	in-situ (see condition I. below)
pH (SU)	NA, exempt by rule (6.5-8.5 SU) SDWS	Annual	grab
specific conductance (μ mhos/cm)	NA	Annual	grab
Aluminum (μ g/l)	NA, exempt by rule (0.200 mg/l) SDWS	Annual	grab
Arsenic (μ g /l)	0.050 mg/l PDWS	Annual	grab
Cadmium (μ g /l)	0.005 mg/l PDWS	Annual	grab
Chloride (mg/l)	NA, exempt by rule (250.0 mg/l) SDWS	Annual	grab
Chromium (μ g /l)	0.100 mg/l PDWS	Annual	grab
Copper (μ g /l)	NA, exempt by rule (1.000 mg/l) SDWS	Annual	grab
Iron (mg/l)	NA, exempt by rule (0.300 mg/l) SDWS	Annual	grab
Lead (μ g /l)	0.015 mg/l PDWS	Annual	grab
Manganese (μ g /l)	NA, exempt by rule (0.050 mg/l) SDWS	Annual	grab
Mercury (μ g /l)	0.002 mg/l PDWS	Annual	grab
Nickel (μ g /l)	0.100 mg/l PDWS	Annual	grab
Selenium (μ g /l)	0.050 mg/l PDWS	Annual	grab
Sodium (mg/l)	160.0 mg/l PDWS	Annual	grab
Sulfate (mg/l as SO ₄)	NA, exempt by rule (250 mg/l) SDWS	Annual	grab
Total Dissolved Solids (TDS) mg/l	NA, exempt by rule (500 mg/l) SDWS	Annual	grab
Total Suspended Solids (TSS) mg/l	NA	Annual	grab
Turbidity (NTU)	NA	Annual	grab (field analysis)
Zinc (μ g /l)	NA, exempt by rule (5.0 mg/l) SDWS	Annual	grab

- I. All monitoring well water levels shall be measured on the same day and recorded prior to evacuating the wells for sample collection. Measurements, referenced to mean sea level, shall include the top of the well casing, depth to ground water, and the calculated ground water elevation at a precision of plus or minus 0.01 feet.
- J. Ground water monitoring wells shall be evacuated or purged prior to sampling to obtain a representative sample. All sampling procedures shall be in accordance with the approved ground water monitoring plan.

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- K. Any new wells shall be of an appropriate screen length and diameter so as to provide reliable and representative water quality results. Sieve analyses shall be submitted and shall be used for proper well design. Required well construction permits shall be obtained from the Northwest Florida Water Management District. Upon installation and after settling, new wells shall be properly developed. Upon completion of construction of new wells, the lithologic logs, "as-installed" diagrams and descriptions of well development shall be submitted to the Department.
- L. All wells shall be located by a registered Florida land surveyor and the coordinates shall be reported in accordance with Rule 62-701.510(3)(d)1., FAC. Existing wells not used in the approved monitoring network for collection of samples or water elevation data shall be properly maintained or shall be properly abandoned in accordance with Rule 62-532.500(4), FAC. Appropriate well abandonment permits shall be obtained from the Northwest Florida Water Management District.
- M. Rainfall at the site shall be measured on a daily basis and the results submitted with the annual monitoring reports.
- N. A complete sampling record shall be provided for each monitor well. This record shall include water level; total depth of the well; volume of water in the well; volume of water removed; stabilization documentation including pH, conductivity, and temperature; time interval of purging; time sample is taken; and device(s) used for purging (including discharge rate) and sampling.
- O. In the event that water quality monitoring shows a violation of the applicable water quality standards, the permittee shall arrange for a confirmation resampling within 15 days after the permittee's receipt of laboratory results. In the event that the permittee chooses not to conduct the reconfirmation sampling, the Department shall consider the initial analysis to be representative of the current water quality conditions at this facility. If the initial results demonstrates or the resampling confirms groundwater contamination, the permittee shall notify the Department in writing within 14 days of this finding. Upon notification by the Department, permittee shall initiate assessment monitoring and corrective actions in accordance with Rule 62-701.510(7), F.A.C.
- P. With permit renewal, a written technical report shall be prepared and submitted to the Department which summarizes and interprets the water quality data and water levels from permit issuance to present. The report shall be submitted by a qualified professional and shall contain the following items at a minimum:
1. Tables and graphs of water quality data, including hydrographs, for all monitoring wells. Rainfall data should be included with the hydrographs.
 2. A comparison of water quality results between background well, downgradient wells.
 3. A summary of all violations of applicable water standards.
 4. Ground water contour maps for each sampling event.
 5. A discussion of any data that is thought to be inconsistent or suspect.
 6. A summary of the physical condition of the monitoring system. This should be based on visual observation and sampling records.

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IV. Other Land Application Requirements: NA

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V. Operation and Maintenance Requirements

A. Operation of Treatment and Disposal Facilities

1. The permittee shall ensure that the operation of this facility is as described in the application and supporting documents.
2. The operation of the pollution control facilities described in this permit shall be under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control appropriate for those facilities.

B. Record keeping Requirements:

1. The permittee shall maintain the following records on the site of the permitted facility and make them available for inspection:
 - a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;
 - b. Reports, other than those required in items a. and b. of this section, required by the permit for at least three years from the date the report was prepared, unless otherwise specified by Department rule;
 - c. Records of all data, including reports and documents used to complete the application for the permit for at least three years from the date the application was filed, unless otherwise specified by Department rule;
 - d. A copy of the current permit;
 - e. A copy of any required record drawings;
 - f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule

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VI. Compliance Schedules and Self-imposed Improvement Schedules

A. Schedule of Compliance

1. The permittee shall achieve compliance with the effluent limitations specified for discharges in accordance with the following schedule:

a. Operational level attained.....Issuance Date (ID) of permit

b. Best Management Practices Pollution Prevention(BMP3) Plan (See Part VII, Subpart C)

(1) Develop plan..... ID of permit plus 6 months

(2) Implement plan..... ID of permit plus 12 months

2. No later than 14 calendar days following a date identified in the above schedule of compliance, the permittee shall submit either a report of progress or, in the case of specific actions being required by an identified date, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

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VII. Other Specific Conditions

A. Specific Conditions Applicable to all permits

1. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file with the Department, are made a part hereof.
2. If significant historical or archaeological artifacts are discovered at any time within the project site, the permittee shall immediately notify the District Office and the Bureau of Historic Preservation, Division of Archives, History and Records Management, R.A. Gray Building, Tallahassee, Florida 32301.
3. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under this permit, shall be signed and sealed by the professional(s) who prepared them.
4. This permit satisfies industrial wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Duty to Reapply

1. The permittee shall submit an application to renew this permit at least 180 days before the expiration date of this permit.
2. The permittee shall apply on the appropriate form listed in Rule 62-620.910, F.A.C., and in the manner established in Rules 62-620.400 through 62-620.460, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.
3. An application filed in accordance with subsections 1. and 2. of this part shall be considered timely and sufficient. When an application for renewal of a permit is timely and sufficient, the existing permit shall not expire until the Department has taken final action on the application for renewal or until the last day for seeking judicial review of the agency order or a later date fixed by order of the reviewing court.
4. The late submittal of a renewal application shall be considered timely and sufficient for the purpose of extending the effectiveness of the expiring permit only if it is submitted and made complete before the expiration date.

C. Specific Conditions Related to Best Management Practices Condition

1. Best Management Practices Plan :

In accordance with Rule 62-620.620(1)(n), the permittee shall develop and implement a Best Management Practices incorporating pollution prevention measures. References which may be used in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act", found at 40 CFR Section 122.44(k), the Storm Water Management Industrial Activities Guidance Manual, EPA/833-R92-002 and other EPA documents relating to Best Management Practice guidance.

2. Definitions:

- a. The term "pollutants" refers to conventional, non-conventional and toxic pollutants, as appropriate for the NPDES storm water program and toxic pollutants.
- b. Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.

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- c. Non-conventional pollutants are those which are not defined as conventional or toxic, such as phosphorus, nitrogen or ammonia. (Ref: 40 CFR Part 122, Appendix D, Table IV)
- d. For purposes of this part, Toxic pollutants include, but are not limited to: a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, and b) any substance (that is not also a conventional or non-conventional pollutant) for which EPA has published an acute or chronic toxicity criterion, or that is a pesticide regulated by the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA).
- e. "Pollution prevention" refers to the first category of EPA's preferred hazardous waste management strategy - source reduction.
- f. "Significant Materials" is defined as raw materials; fuels; materials such as solvents and detergents; hazardous substances designated under Section 101(14) of CERCLA; and any chemical the facility is required to report pursuant to EPCRA, Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge.
- g. "Source reduction" means any practice which: i) reduces the amount of any pollutant entering a waste stream prior to recycling, treatment or disposal; and ii) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.
- h. "BMP3" means a Best Management Pollution Prevention Plan incorporating the requirements of 40 CFR § 125, Subpart K, plus pollution prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.
- i. "Reportable Quantity (RQ) Discharge" A RQ release occurs when a quantity of a hazardous substance or oil is spilled or released within a 24-hour period of time and exceeds the RQ level assigned to that substance under CERCLA or the Clean Water Act. These levels or quantities are defined in terms of gallons or pounds. Regulations listing these quantities are contained at 40 CFR 302.4, 40 CFR 117.21 and 40 CFR 110.
- j. The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

3. Best Management Practices/Pollution Prevention Plan:

The permittee shall develop and implement a BMP3 plan for the facility which is the source of wastewater and storm water discharges. The plan shall be directed toward reducing those pollutants of concern which discharge, or could discharge, to surface waters to and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants and significant materials, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including storm water, water and waste treatment, and plant ancillary activities.

4. Signatory Authority & Management Responsibilities:

A copy of the BMP3 plan shall be retained at the facility and shall be made available to the permit issuing authority upon request.

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The BMP3 plan shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP3 program. The BMP3 plan shall be signed and reviewed by the plant management.

5. BMP3 Plan Requirements:

The following requirements may be incorporated by reference from existing facility procedures:

- a. Name and description of facility
- b. A site map - At a minimum the site map must include information of the following: discharge points ("outfalls"); drainage patterns; identification of the types of pollutants likely to be discharged from each drainage area; direction of flow; surface water bodies, including any proximate stream, river, lake, or other waterbody receiving storm water discharge from the site; structural control measures (physically constructed features used to control storm water flows); locations of "significant materials" exposed to storm water; locations of industrial activities (such as fueling stations, loading and unloading areas, vehicle or equipment maintenance areas, waste disposal areas, storage areas).
- c. A materials inventory including the types of materials that are handled, stored, or processed onsite, particularly significant materials. To complete the materials inventory, the permittee must list materials that have been exposed to storm water in the past 3 years (focus on areas where materials are stored, processed, transported, or transferred and provide a narrative description of methods and location of storage and disposal areas, materials management practices, treatment practices, and any structural/nonstructural control measures.
- d. A list of significant spills and leaks of toxic or hazardous materials that have occurred in the past 3 years. "Significant spills" includes releases in excess of reportable quantities.
- e. A summary of any existing storm water sampling data and a description of the sample collection procedures used.
- f. A site evaluation summary - The Site Evaluation Summary should provide a narrative description of activities with a high potential to contaminate storm water at the site, including those associated with materials loading and unloading, outdoor storage, outdoor manufacturing or processing, onsite disposal, and significant dust or particulate generating activities. The summary should also include a description of any pollutants of concern that may be associated with such activities.
- g. A narrative description of the following BMP's:
 - (i) - Good Housekeeping Practices
 - (ii) - Preventive Maintenance The permittee must develop a preventive maintenance program that involves inspections and maintenance of storm water management devices and routine inspections of facility operations to detect faulty equipment. Equipment (such as tanks, containers, and drums) should be checked regularly for signs of deterioration.
 - (iii) - Visual Inspections Regular inspections shall be performed by qualified, trained plant personnel. Reports shall note when inspections were done, the name of the person who conducted the inspection, which areas were inspected, what problems were found, and what steps were taken to correct any problems.

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- (iv) - Spill Prevention and Responses Areas where spills are likely to occur and their drainage points must be clearly identified in the BMP3 plan. Employees shall be made aware of response procedures, including material handling and storage requirements, and should have access to appropriate cleanup equipment.
- (v) - Sediment and Erosion Control The BMP3 must identify activities that present a potential for significant soil erosion and measures taken to control such erosion.
- (vi) - Management of Runoff The permittee must describe existing storm water controls found at the facility and any additional measures that can be implemented to improve the prevention and control of polluted storm water. Examples include: vegetative swales, reuse of collected storm water, infiltration trenches, and detention ponds.

6. Best Management Practices & Pollution Prevention Committee:

A Best Management Practices Committee (Committee) should be established to direct or assist in the implementation of the BMP3 plan. The Committee should be comprised of individuals within the plant organization who are responsible for developing, implementing, monitoring of success, and revision of the BMP3 plan. The activities and responsibilities of the Committee should address all aspects of the facility's BMP3 plan. The scope of responsibilities of the Committee should be described in the plan.

7. Employee Training:

Employee training programs shall inform appropriate personnel of the components & goals of the BMP3 plan and shall describe employee responsibilities for implementing the plan. Training shall address topics such as good housekeeping, materials management, recordkeeping and reporting, spill prevention & response, as well as specific waste reduction practices to be employed. The plan shall identify periodic dates for such training.

8. Plan Review & Modification:

If following review by the Permit Issuing Authority, or authorized representative, the BMP3 plan is determined insufficient, he/she may notify the permittee that the BMP3 plan does not meet one or more of the minimum requirements of this Part. Upon such notification from the Permit Issuing Authority, or authorized representative, the permittee shall amend the plan and shall submit to the Permit Issuing Authority a written certification that the requested changes have been made. The permittee shall have 30 days after such notification to make the necessary changes. A longer period of time may be granted by the Permit Issuing Authority if warranted due to the complexity of the change.

The permittee shall modify the BMP3 plan whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to surface waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by Permit Issuing Authority in the same manner as described above.

9. Annual Site Compliance Evaluation:

Qualified personnel must conduct site compliance evaluations at appropriate intervals, but at least once a year. Compliance evaluations shall include:

- inspection of storm water drainage areas for evidence of pollutants entering the drainage system;
- evaluation of the effectiveness of BMP's;

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- observations of structural measures, sediment controls, and other storm water BMP's to ensure proper operation;

- revision of the plan as needed within 2 weeks of the inspection, and implementation of any necessary changes within 12 weeks of the inspection; and

- preparation of a report summarizing inspection results and follow-up actions, identifying the date of inspection and personnel who conducted the inspection.

The inspection report shall be signed by the plant environmental engineering staff and plant management and kept with the BMP3 plan.

10. Recordkeeping and Internal Reporting:

For at least one year after the expiration of this permit, the permittee shall record and maintain records of spills, leaks, inspections, and maintenance activities. For spills and leaks, records should include information such as the date and time of the incident, weather conditions, cause, and resulting environmental problems.

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D. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:
[62-620.624(1)]
 - (a) That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
 - (1) One hundred micrograms per liter,
 - (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter for antimony, or
 - (3) Five times the maximum concentration value reported for that pollutant in the permit application.
 - (b) That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
 - (1) Five hundred micrograms per liter,
 - (2) One milligram per liter for antimony, or
 - (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

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VIII. General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. [62-620.610(1), 11-29-94]
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. [62-620.610(2), 11-29-94]
3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. [62-620.610(3), 11-29-94]
4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. [62-620.610(4), 11-29-94]
5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. [62-620.610(5), 11-29-94]
6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. [62-620.610(6), 11-29-94]
7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. [62-620.610(7), 11-29-94]
8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. [62-620.610(8), 11-29-94]
9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon

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presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to

- a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;
 - b. Have access to and copy any records that shall be kept under the conditions of this permit;
 - c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and
 - d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules. [62-620.610(9), 11-29-94]
10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, Florida Statutes, or Rule 62-620.302, Florida Administrative Code. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. [62-620.610(10), 11-29-94]
11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. [62-620.610(11), 11-29-94]
12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. [62-620.610(12), 11-29-94]
13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. [62-620.610(13), 11-29-94]
14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. [62-620.610(14), 11-29-94]
15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. [62-620.610(15), 11-29-94]
16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300, 62.420 or 62.620.450, F.A.C., as applicable, at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.300 for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. [62-620.610(16), 11-29-94]
17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for

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any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

- a. A description of the anticipated noncompliance;
 - b. The period of the anticipated noncompliance, including dates and times; and
 - c. Steps being taken to prevent future occurrence of the noncompliance.
[62-620.610(17), 11-29-94]
18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapter 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate.
- a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10).
 - b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.
 - c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.
 - d. Any laboratory test required by this permit for domestic wastewater facilities shall be performed by a laboratory that has been certified by the Department of Health and Rehabilitative Services (DHRS) under Chapter 10D41, F.A.C., to perform the test. In domestic wastewater facilities, on-site tests for dissolved oxygen, pH, and total chlorine residual shall be performed by a laboratory certified to test for those parameters or under the direction of an operator certified under Chapter 61E12-41, F.A.C.
 - e. Under Chapter 62-160, F.A.C., sample collection shall be performed by following the protocols outlined in "DEP Standard Operating Procedures for Laboratory Operations and Sample Collection Activities" (DEP-QA-001/92). Alternatively, sample collection may be performed by an organization who has an approved Comprehensive Quality Assurance Plan (CompQAP) on file with the Department. The CompQAP shall be approved for collection of samples from the required matrices and for the required tests.
[62-620.610(18), 11-29-94]
19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. [62-620.610(19), 11-29-94]
20. The permittee shall report to the Department any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.
- a. The following shall be included as information which must be reported within 24 hours under this condition:
 - (1). Any unanticipated bypass which causes any reclaimed water or the effluent to exceed any permit limitation or results in an unpermitted discharge,
 - (2). Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
 - (3). Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
 - (4). Any unauthorized discharge to surface or ground waters.

PERMITTEE:

Gulf Power Company
One Energy Place
Pensacola, Florida 32520

PERMIT NUMBER:

FL0002267

ISSUANCE DATE:

April 17, 1998

DATE:

April 16, 2003

APPLICATION NO.:

FL0002267-001-IW1S

- b. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department shall waive the written report.
[62-620.610(20), 11-29-94]
21. The permittee shall report all instances of noncompliance not reported under Conditions VIII.17 and .19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Condition VIII.20 of this permit. [62-620.610(21), 11-29-94]
22. Bypass Provisions.
 - a. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
 - (1). Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
 - (2). There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
 - (3). The permittee submitted notices as required under Condition VIII.22.b. of this permit.
 - b. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Condition VIII. 20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.
 - c. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Condition VIII.22. a. of this permit.
 - d. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Condition VIII.22. a. through c. of this permit.
[62-620.610(22), 11-29-94]
23. Upset Provisions
 - a. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
 - (1). An upset occurred and that the permittee can identify the cause(s) of the upset;
 - (2). The permitted facility was at the time being properly operated;
 - (3). The permittee submitted notice of the upset as required in Condition VIII. 20. of this permit; and
 - (4). The permittee complied with any remedial measures required under Condition VIII.5. of this permit.
 - b. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.
 - c. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.
[62-620.610(23), 11-29-94]

PERMITTEE:

Gulf Power Company
One Energy Place
Pensacola, Florida 32520

Executed in Tallahassee, Florida.

PERMIT NUMBER:

FL0002267

ISSUANCE DATE:

April 17, 1998

DATE:

April 16, 2003

APPLICATION NO.:

FL0002267-001-IW1S

STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL PROTECTION



Division Director

Mimi A. Drew

Division of Water Facilities

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(904) 487-1855

ATTACHMENT 10.4-B
EXISTING WATER USE PERMIT



J. William McCartney
Executive Director

Northwest Florida Water Management District

Route 1, Box 3100, Havana, Florida 32333

December 7, 1984



(904) 487-1770

Dear Applicant:

Consumptive Use Permit Application No. SO 3012
Consumptive Use Permit No. S 850072

Your Consumptive Use Permit was approved by the Governing Board of the Northwest Florida Water Management District at the Public Hearing on November 30, 1984, subject to the terms and conditions set forth in the enclosed permit document.

Thank you for your full cooperation in assisting the District to fulfill the requirements of Chapter 373 of the Florida Statutes and Chapter 40A-2 of the Florida Administrative Code. Please let us know if we could be of any future assistance to you.

Sincerely,

F.E. Recio, Director
Regulatory Division

FER/as

Enclosure

DAVAGE RUNNELS
Chairman - Destin

WILLIAM C. SMITH
Vice Chairman - Tallahassee

MARION TIDWELL

Sec./Treas. - Chumuckla

TOM S. COLDEWEY
Port St. Joe

W. FRED BOND
Pensacola

CANDIS M. HARBISON
Panama City

R. L. PRICE, JR.
Graceville

DR. LOUIS J. ATKINS
Blountstown

BLUCHER B. LINES
Quincy

NORTHWEST FLORIDA WATER MANAGEMENT DISTRICT
(NFWMD)

STANDARD WATER USE PERMIT

Permit Granted to:
Gulf Power Company - Lansing
Smith Electric Generating Plant

P. O. Box 1151

Pensacola, Florida 32520
(Legal Name and Address)

County Bay Area B

Application No.: S03013

Permit No.: S850073 - System

Date Permit Granted: November 30, 1984

Permit Expires on: December 1, 1999

Source Classification: Floridan Aquifer

Use Classification: Power Generation

Location: Section 1 1/4 Section

Township 3 South Range 15 West

Terms and standard conditions of this Permit are as follows:

1. That all statements in the application and in supporting data are true and accurate and based upon the best information available, and that all conditions set forth herein will be complied with. If any of the statements in the application and in the supporting data are found to be untrue and inaccurate, or if Permittee fails to comply with all of the conditions set forth herein, then this Permit shall be revoked as provided by Chapter 373.243, Florida Statutes.
2. This Permit is predicated upon the assertion by Permittee that the use of water applied for and granted is and continues to be a reasonable and beneficial use as defined in Section 373.019(4), Florida Statutes.
3. This Permit is conditioned on the Permittee having obtained or obtaining all other necessary permit(s) to construct, operate and certify withdrawal facilities and the operation of water system.
4. This Permit is issued to the Permittee contingent upon continued ownership, lease or other present control of property rights in underlying, overlying, or adjacent lands. This permit may be assigned to a subsequent owner as provided by Chapter 40A-2.351, F.A.C. and the acceptance by the assignee of all terms and conditions of the Permit.

5. This Permit authorizes the Permittee to make a combined average annual withdrawal of 265,300,000* gallons of water per day with a maximum total combined withdrawal rate not to exceed 276,880,000** gallons during a single day. Withdrawals are authorized as shown in the table below:

6. WITHDRAWAL POINT I.D. NUMBER & LOCATION	GALLONS PER DAY AVERAGE	GALLONS PER DAY MAXIMUM	MANAGEMENT LEVEL
Ground Water:			
L.S.G.P. No. 1, Sec. 1, T3S, R15W		720,000	
L.S.G.P. No. 2, Sec. 1, T3S, R15W		720,000	
L.S.G.P. No. 3, Sec. 1, T3S, R15W		720,000	
L.S.G.P. No. 4, Sec. 1, T3S, R15W		720,000	
Surface Water:			
L.S.G.P. No. 1A North Bay		68,500,000	
L.S.G.P. No. 1B North Bay		68,500,000	
L.S.G.P. No. 2A North Bay		68,500,000	
L.S.G.P. No. 2B North Bay		68,500,000	

7. The use of the permitted water withdrawal is restricted to the use classification set forth by the Permit. Any change in the use of said water shall require a modification of this Permit.
8. The District's staff, upon proper identification, will have permission to enter, inspect and observe permitted and related facilities in order to determine compliance with the approved plans, specifications and conditions of this Permit.
9. The District's staff, from time to time upon providing prior notice and proper identification, may request permission to collect water samples for analysis, measure static and/or pumping water levels and collect any other information deemed necessary to protect the water resources of the area.
10. The District reserves the right, at a future date, to require the Permittee to submit monthly or quarterly pumpage records for any or all withdrawal point(s) covered by this Permit.
11. Permittee shall mitigate any adverse impact caused by withdrawals permitted herein on legal water withdrawals and uses, and on adjacent land use, which existed at the time of permit application. The District reserves the right to curtail permitted withdrawal rates if the withdrawal causes an adverse impact on legal uses of water, or adjacent land use, which existed at the time of permit application.

*Averages: 700,000 GPD Ground Water
264,600,000 GPD Surface Water
265,300,000 GPD Combined Total

**Maximum:
2,880,000 GPD Ground Water
274,000,000 GPD Surface Water
276,880,000 GPD Combined Total

12. Permittee shall not cause significant saline water intrusion or increased chloride levels. The District reserves the right to curtail permitted withdrawal rates if withdrawals cause significant saline water intrusion or increased chloride levels.
13. The District, pursuant to Section 373.042, Florida Statutes, at a future date may establish minimum and/or management water levels in the aquifer, aquifers, or surface waters hydrologically associated with the permitted withdrawals; these water levels may require the Permittee to limit withdrawal from these water sources at times when water levels decline below established levels.
14. Nothing in this Permit should be construed to limit the authority of the Northwest Florida Water Management District to declare water shortages and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate and implement a plan during periods of water shortage pursuant to Section 373.246, Florida Statutes.
 - (a) In the event of a declared water shortage, water withdrawal reductions shall be made as ordered by the District.
 - (b) In the event of a declared water shortage, the District may alter, modify or inactivate all or parts of this Permit.
15. Any Special Permit Conditions enumerated in Attachment A and/or any other conditions enumerated in Attachment B are herein made a part of this permit.


Authorized Signature, NFWMD

ATTACHMENT 10.4-C
NO_x COMPLIANCE PLAN

One Energy Place
Pensacola, Florida 32520

850.444.6111



July 27, 1998

Mr. Scott M. Sheplak, P.E.
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Dear Mr. Sheplak:

RE: Plant Lansing Smith Title IV Phase II NOx Compliance Plan
ORIS Code: 643
FDEP Draft Permit No: 005014-001-AV

Attached, please find Gulf Power's revised Phase II NOx Compliance Plan and associated NOx Averaging Plan for the Lansing Smith Electric Generating Plant (ORIS Code 643). Please note that the new original signed copy of the averaging plan is attached to Gulf Power's Crist Title IV NOx Compliance Plan submission dated July 27, 1998. *This revised submission changes the System NOx Averaging Plan to two decimal points instead of four as originally submitted on December 18, 1997.*

The NOx compliance plan for this unit utilizes a NOx averaging plan that includes other affected units in the Southern Company. Title V permitting authorities with jurisdiction over the units in the plan include the States of Alabama, Georgia and Mississippi, as well as the Jefferson County Department of Health in Alabama. Our sister operating companies within the Southern Company are providing their respective state environmental regulatory agencies a copy of this NOx averaging plan with their Phase II NOx permit compliance plans, thereby fulfilling the requirement of the General Instructions (Item 4a) to provide a copy of the plan to other Title V permitting authorities with jurisdiction over any units in the plan.

If you have any questions or need further information regarding the Lansing Smith Title IV Phase II Compliance and Averaging Plan, please call me at (850) 444.6527.

Sincerely,

G. Dwain Waters, Q.E.P.
Air Quality Programs Coordinator

Page 2

Mr. Scott Sheplack

July 27, 1998

cc: Robert G. Moore, Gulf Power Company
James O Vick, Gulf Power Company
L. A. Jeffers, Gulf Power Company
Stan H. Houston, Gulf Power Company
Danny Herrin, Southern Company Services
Brian L. Beals EPA Region IV

Florida Department of Environmental Protection

Phase II NO_x Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is:



New



Revised

Page ☐ of ☐

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	Lansing Smith Electric Generating Plant Plant Name	FL State	643 ORIS Code
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.		

Poor Original

ID#	ID#	ID#	ID#	ID#	ID#
1	2				
Type	Type	Type	Type	Type	Type
T	T				

(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)☐☐☐☐☐☐(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)☐☐☐☐☐☐

(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)

☐☐☐☐☐☐(d) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase II dry bottom wall-fired boilers)☐☐☐☐☐☐(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)☐☐☐☐☐☐

(f) Standard annual average emission limitation of 0.65 lb/mmBtu (for cell burner boilers)

☐☐☐☐☐☐

(g) Standard annual average emission limitation of 0.85 lb/mmBtu (for cyclone boilers)

☐☐☐☐☐☐

(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)

☐☐☐☐☐☐

(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)

☐☐☐☐☐☐(j) NO_x Averaging Plan (include NO_x Averaging form)☒☒☐☐☐☐

(k) Common stack pursuant to 40 CFR 75.17(a)(2)(IIA) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)

☐☐☐☐☐☐

Poor Original**LANSING SMITH ELECTRIC GENERATING PLANT**

Plant Name (from Step 1)

Page ☐ of ☐**STEP 2, cont'd.**

ID#	ID#	ID#	ID#	ID#	ID#
Type	Type	Type	Type	Type	Type

(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)

☐ ☐ ☐ ☐ ☐ ☐

(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)

☐ ☐ ☐ ☐ ☐ ☐

(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)

☐ ☐ ☐ ☐ ☐ ☐

(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing

☐ ☐ ☐ ☐ ☐ ☐

(p) Repowering extension plan approved or under review

☐ ☐ ☐ ☐ ☐ ☐

STEP 3

Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

Poor Original

STEP 3, cont'd.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name James O. Vick	
Signature <i>James O. Vick</i>	Date 7/27/98



Phase II NO_x Averaging Plan

For more information, see instructions and refer to 40 CFR 76.11

This submission is: ☐ New ☒ Revised

Page 1

Page ☐ of ☐

STEP 1

Identify the units participating in this averaging plan by plant name, State, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
See Page 3					

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate
averaged over the units if they are
operated in accordance with the
proposed averaging plan

0.46

Btu-weighted annual average
emission rate for same units
operated in compliance with
40 CFR 76.5, 76.6 or 76.7

0.46

$$\frac{\sum_{i=1}^n (R_{Li} \times HI_i)}{\sum_{i=1}^n HI_i}$$

$$\frac{\sum_{i=1}^n [R_{1i} \times HI_i]}{\sum_{i=1}^n HI_i}$$

Where,

- R_{Li} = Alternative contemporaneous annual emission limitation for unit i, in lb/mmBtu, as specified in column (b) of Step 1;
 R_{1i} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;
 HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;
 n = Number of units in the averaging plan

Plant Name (from Step 1)

NO_x Averaging - Page 2

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year _____ through calendar year _____ unless notification to terminate the plan is given.

☒ Treat this plan as ☒ identical plans, each effective for one calendar year for the following calendar years: 2000, 2001, 2002, 2003 and 2004 unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

- (i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
 - (a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan.
 - (b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
 - (B) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(i)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
 - (iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(i)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Charles D. McCrary

Signature

Charles D. McCrary

Date

7/20/98

Southern Company Averaging Plan Participating Plants

Plant Name (from Step 1)

as Listed in Step 1.

NO_x Averaging - Page 3

STEP 1
Continue the
identification of
units from Step 1,
page 1, here.

Plant Name	State	ID #	(a)	(b)	(c)
			Emission Limitation	Alt. Contemp. Emission Limitation	Annual Heat Input Limit
Barry	AL	1	0.40	0.49	10,805,761
Barry	AL	2	0.40	0.49	10,643,159
Barry	AL	3	0.40	0.49	17,148,763
Barry	AL	4	0.40	0.37	25,471,720
Barry	AL	5	0.40	0.45	50,897,853
Bowen	GA	1	0.45	0.42	45,395,755
Bowen	GA	2	0.45	0.43	46,911,826
Bowen	GA	3	0.45	0.43	59,796,338
Bowen	GA	4	0.45	0.43	62,106,898
Branch	GA	1	0.68	0.99	14,906,580
Branch	GA	2	0.50	0.72	16,571,123
Branch	GA	3	0.68	0.84	27,015,768
Branch	GA	4	0.68	0.84	28,967,878
Crist	FL	4	0.45	0.52	3,062,929
Crist	FL	5	0.45	0.60	4,850,348
Crist	FL	6	0.50	0.45	17,603,755
Crist	FL	7	0.50	0.45	32,267,381
Daniel	MS	1	0.45	0.28	28,010,957
Daniel	MS	2	0.45	0.26	29,025,313
Gadsden	AL	1	0.45	0.65	2,473,380
Gadsden	AL	2	0.45	0.68	2,333,659
Gaston	AL	1	0.50	0.43	15,666,430
Gaston	AL	2	0.50	0.43	15,642,121
Gaston	AL	3	0.50	0.43	16,016,613
Gaston	AL	4	0.50	0.43	15,780,983
Gaston	AL	5	0.45	0.42	43,137,116
Gorgas	AL	6	0.46	0.86	5,058,595
Gorgas	AL	7	0.46	0.86	5,052,447
Gorgas	AL	8	0.40	0.49	11,173,785
Gorgas	AL	9	0.40	0.30	10,939,664
Gorgas	AL	10	0.40	0.76	46,251,622
Greene Co	AL	1	0.68	0.98	19,524,675
Greene Co	AL	2	0.46	0.43	18,839,670

Southern Company Averaging Plan Participating Plants
 as Listed in Step 1.

NO_x Averaging - Page 4

STEP 1
 Continue the
 identification of
 units from Step 1,
 page 1, here.

Plant Name	State	ID #	(a)	(b)	(c)
			Emission Limitation	Alt. Contemp. Emission Limitation	Annual Heat Input Limit
Hammond	GA	1	0.50	0.83	4,539,663
Hammond	GA	2	0.50	0.83	6,333,156
Hammond	GA	3	0.50	0.83	6,439,818
Hammond	GA	4	0.50	0.45	26,126,591
Kraft	GA	1	0.45	0.58	2,974,849
Kraft	GA	2	0.45	0.58	2,238,703
Kraft	GA	3	0.45	0.58	3,971,009
L. Smith	FL	1	0.40	0.62	9,199,644
L. Smith	FL	2	0.40	0.44	10,154,723
McDonough	GA	1	0.45	0.42	18,934,013
McDonough	GA	2	0.45	0.42	17,338,565
McIntosh	GA	1	0.50	0.86	8,568,975
Miller	AL	1	0.46	0.29	53,814,591
Miller	AL	2	0.46	0.29	52,772,559
Miller	AL	3	0.46	0.29	49,093,163
Miller	AL	4	0.46	0.29	55,722,252
Mitchell	GA	3	0.45	0.62	5,322,072
Scherer	GA	1	0.40	0.50	52,573,864
Scherer	GA	2	0.40	0.50	55,563,600
Scherer	GA	3	0.45	0.29	37,912,770
Scherer	GA	4	0.40	0.30	70,093,731
Scholz	FL	1	0.50	0.68	1,855,434
Scholz	FL	2	0.50	0.77	1,864,795
Wansley	GA	1	0.45	0.41	53,141,279
Wansley	GA	2	0.45	0.42	49,741,786
Watson	MS	4	0.50	0.50	17,100,575
Watson	MS	5	0.50	0.65	33,455,317
Yates	GA	1	0.45	0.48	3,853,527
Yates	GA	2	0.45	0.48	4,687,321
Yates	GA	3	0.45	0.48	3,981,916
Yates	GA	4	0.45	0.40	7,087,706
Yates	GA	5	0.45	0.40	5,186,897
Yates	GA	6	0.45	0.33	13,373,298
Yates	GA	7	0.45	0.30	14,601,869

APPENDIX 10.5
MONITORING PROGRAMS

ATTACHMENT 10.5-A
FDHR LETTER

DIVISIONS OF FLORIDA DEPARTMENT OF STATE

Office of the Secretary
Office of International Relations
Division of Elections
Division of Corporations
Division of Cultural Affairs
Division of Historical Resources
Division of Library and Information Services
Division of Licensing
Division of Administrative Services



MEMBER OF THE FLORIDA CABINET

State Board of Education
Trustees of the Internal Improvement Trust Fund
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Florida Land and Water Adjudicatory Commission
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Division of Bond Finance
Department of Revenue
Department of Law Enforcement
Department of Highway Safety and Motor Vehicles
Department of Veterans' Affairs

FLORIDA DEPARTMENT OF STATE

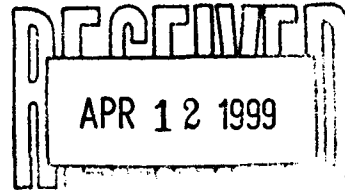
Katherine Harris

Secretary of State

DIVISION OF HISTORICAL RESOURCES

April 7, 1999

Mr. Darren L. Stowe
Environmental Consulting & Technologies, Inc.
5405 Cypress Center Drive, Suite 200
Tampa, Florida 33609



RE: DHR Project File No. 991458
Cultural Resource Assessment Request
L. Smith Plant Unit 3
Bay County, Florida

Dear Mr. Stowe:

In accordance with the procedures contained in Chapter 403, Florida Statutes, we have reviewed the above referenced project for possible impact to archaeological and historical sites or properties listed, or eligible for listing, in the National Register of Historic Places, or otherwise of archaeological, historical or architectural value.

A review of the Florida Master Site File indicates that no significant archaeological or historical sites are recorded for or likely to be present within the project area. Furthermore, because of the project location and/or nature it is unlikely that any such sites will be affected. Therefore, it is the opinion of this office that the proposed project will have no effect on historic properties listed, or eligible for listing, in the *National Register of Historic Places*.

If you have any questions concerning our comments, please contact Scott Edwards, Historic Preservation Planner, at 850-487-2333 or 800-847-7278. Your interest in protecting Florida's historic properties is appreciated.

Sincerely,

Laura A. Kammerer

for

George W. Percy, Director
Division of Historical Resources
and
State Historic Preservation Officer

GWP/Ese

R.A. Gray Building • 500 South Bronough Street • Tallahassee, Florida 32399-0250 • <http://www.flheritage.com>

<input type="checkbox"/> Director's Office (850) 488-1480 • FAX: 488-3355	<input type="checkbox"/> Archaeological Research (850) 487-2299 • FAX: 414-2207	<input checked="" type="checkbox"/> Historic Preservation (850) 487-2333 • FAX: 922-0496	<input type="checkbox"/> Historical Museums (850) 488-1484 • FAX: 921-2503
<input type="checkbox"/> Historic Pensacola Preservation Board (850) 595-5985 • FAX: 595-5989	<input type="checkbox"/> Palm Beach Regional Office (561) 279-1475 • FAX: 279-1476	<input type="checkbox"/> St. Augustine Regional Office (904) 825-5045 • FAX: 825-5044	<input type="checkbox"/> Tampa Regional Office (813) 272-3843 • FAX: 272-2340

ATTACHMENT 10.5-B
SURFACE WATER QUALITY ANALYSIS

LOG NO: T9-31171
Received: 22 APR 99
Reported: 29 APR 99

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0328

Project: Creek
Sampled By: Savannah Laboratories
Code: 140290429
Page 1

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED	
31171-1	Ditch	04-22-99/1630	
31171-2	Equipment Blank	04-22-99/1558	
PARAMETER		31171-1	31171-2
Residual Chlorine (Measured in Field) (SM 4500 Cl G), mg/l		<0.05	---
Specific Conductance (Field), umhos/cm		85.85	---
pH (Measured in Field), units		3.97	---
Temperature at Sampling Time, Degrees C		28.2	---
Purgeables (624)			
Benzene, ug/l		<1.0	<1.0
Bromodichloromethane, ug/l		<1.0	<1.0
Bromoform, ug/l		<1.0	<1.0
Carbon tetrachloride, ug/l		<1.0	<1.0
Chloroform, ug/l		<1.0	<1.0
Chloromethane, ug/l		<1.0	<1.0
Dibromochloromethane, ug/l		<1.0	<1.0
1,1-Dichloroethene, ug/l		<1.0	<1.0
Methylene chloride (Dichloromethane), ug/l		<5.0	<5.0
1,1,2,2-Tetrachloroethane, ug/l		<1.0	<1.0
Tetrachloroethene, ug/l		<1.0	<1.0
Trichloroethylene, ug/l		<1.0	<1.0
Analysis Date		04.28.99	04.28.99

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www.savlabs.com

LOG NO: T9-31171
Received: 22 APR 99
Reported: 29 APR 99

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Project: Creek
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED	
31171-1	Ditch	04-22-99/1630	
31171-2	Equipment Blank	04-22-99/1558	
PARAMETER		31171-1	31171-2
PP-Base Neutral Compounds (625)			
Acenaphthene, ug/l		<10	<10
Acenaphthylene, ug/l		<10	<10
Anthracene, ug/l		<10	<10
Benzo(a)anthracene, ug/l		<10	<10
Benzo(a)pyrene, ug/l		<10	<10
3,4-Benzofluoranthene (Benzo(b)fluoranthene), ug/l		<10	<10
Benzo(g,h,i)perylene, ug/l		<10	<10
Benzo(k)fluoranthene, ug/l		<10	<10
bis(2-Ethylhexyl) phthalate, ug/l		<10	<10
Butyl benzyl phthalate, ug/l		<10	<10
Chrysene, ug/l		<10	<10
Dibenzo(a,h)anthracene, ug/l		<10	<10
Diethyl phthalate, ug/l		<10	<10
Dimethyl phthalate, ug/l		<10	<10
Di-n-Butyl phthalate, ug/l		<10	<10
2,4-Dinitrotoluene, ug/l		<10	<10
Di-n-Octyl phthalate, ug/l		<10	<10
Fluoranthene, ug/l		<10	<10
Fluorene, ug/l		<10	<10
Hexachlorobutadiene, ug/l		<10	<10
Indeno(1,2,3-cd)pyrene, ug/l		<10	<10
Naphthalene, ug/l		<10	<10
Phenanthrene, ug/l		<10	<10
Pyrene, ug/l		<10	<10
1-Methylnaphthalene, ug/l		<10	<10
2-Methylnaphthalene, ug/l		<10	<10
Analyst		JS	JS
Analysis Date		04.28.99	04.28.99

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Project: Creek
Sampled By: Savannah Laboratories
Code: 140290429
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED
31171-1	Ditch	04-22-99/1630
31171-2	Equipment Blank	04-22-99/1558
PARAMETER	31171-1	31171-2
Phosphorus Pesticides (614)		
Azinphos methyl, ug/l	<1.0	<1.0
Demeton-O, ug/l	<2.5	<2.5
Demeton-S, ug/l	<2.5	<2.5
Diazinon, ug/l	<1.0	<1.0
Disulfoton, ug/l	<2.0	<2.0
Malathion, ug/l	<1.0	<1.0
Parathion Ethyl, ug/l	<1.0	<1.0
Parathion Methyl, ug/l	<0.50	<0.50
Analyst	MT	MT
Analysis Date	04.27.99	04.27.99

LOG NO: T9-31171
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One Energy Place
Pensacola, FL 32520-0328Project: Creek
Sampled By: Savannah Laboratories
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED	
31171-1	Ditch	04-22-99/1630	
31171-2	Equipment Blank	04-22-99/1558	
PARAMETER		31171-1	31171-2
Chlorinated Pesticides (608)			
Aldrin, ug/l		<0.050	<0.050
alpha-BHC, ug/l		<0.050	<0.050
beta-BHC, ug/l		<0.050	<0.050
delta-BHC, ug/l		<0.050	<0.050
gamma-BHC, ug/l		<0.050	<0.050
Chlordane, ug/l		<0.50	<0.50
4,4'-DDD, ug/l		<0.10	<0.10
4,4'-DDE, ug/l		<0.10	<0.10
4,4'-DDT, ug/l		<0.10	<0.10
Dieldrin, ug/l		<0.10	<0.10
Endosulfan I, ug/l		<0.050	<0.050
Endosulfan II, ug/l		<0.10	<0.10
Endosulfan Sulfate, ug/l		<0.10	<0.10
Endrin, ug/l		<0.10	<0.10
Endrin Aldehyde, ug/l		<0.10	<0.10
Heptachlor, ug/l		<0.050	<0.050
Heptachlor Epoxide, ug/l		<0.050	<0.050
Toxaphene, ug/l		<3.0	<3.0
PCB-1016, ug/l		<0.50	<0.50
PCB-1221, ug/l		<0.50	<0.50
PCB-1232, ug/l		<0.50	<0.50
PCB-1242, ug/l		<0.50	<0.50
PCB-1248, ug/l		<0.50	<0.50
PCB-1254, ug/l		<0.50	<0.50
PCB-1260, ug/l		<0.50	<0.50
Analyst		CWA	CWA
Analysis Date		04.27.99	04.27.99

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Mr. Mike Markey
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Project: Creek
Sampled By: Savannah Laboratories
Code: 140290429
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED	
31171-1	Ditch	04-22-99/1630	
31171-2	Equipment Blank	04-22-99/1558	
PARAMETER		31171-1	31171-2
Methoxychlor (8081), ug/l		<0.50	<0.50
Analyst		CWA	CWA
Analysis Date		04.27.99	04.27.99
Mirex (608), ug/l		<0.50	<0.50
Analyst		DM	DM
Analysis Date		04.27.99	04.27.99
N-Hexane Extractable Material (1664)			
Oil & Grease , mg/l		<5.0	<5.0
Analyst		MF	MF
Analysis Date		04.26.99	04.26.99
Analysis Time		1400	1400
Surfactants (MBAS) (425.1)			
Surfactants, mg/l		190	<0.10
Analyst		MF	MF
Analysis Date		04.23.99	04.23.99
Analysis Time		1700	1700

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Project: Creek
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED
31171-1	Ditch	04-22-99/1630
31171-2	Equipment Blank	04-22-99/1558
PARAMETER	31171-1	31171-2
Metals by ICP (200.7)		
Cadmium, ug/l	<5.0	<5.0
Chromium, ug/l	<10	<10
Copper, ug/l	<25	<25
Iron, ug/l	40000	<50
Lead, ug/l	6.2	<5.0
Nickel, ug/l	<40	<40
Selenium, ug/l	<10	<10
Zinc, ug/l	51	<20
Beryllium, ug/l	<4.0	<4.0
Thallium, ug/l	<10	<10
Analyst	CLD	CLD
Analysis Date	04.26.99	04.26.99
Mercury (245.1)		
Mercury, ug/l	<0.20	<0.20
Analyst	KW	KW
Analysis Date	04.26.99	04.26.99
Silver (272.2-MIBK)		
Silver, ug/l	<0.050	<0.050
Analyst	BP	BP
Analysis Date	04.26.99	04.26.99
Total Recoverable Phenolics (EPA 420.1)		
Phenolics, Total Recoverable, mg/l	0.035	<0.010
Analyst	DP	DP
Analysis Date	04.26.99	04.26.99

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Project: Creek
Sampled By: Savannah Laboratories
Code: 140290429
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED	
31171-1	Ditch	04-22-99/1630	
31171-2	Equipment Blank	04-22-99/1558	
PARAMETER		31171-1	31171-2
Total Cyanide (EPA 335.2)			
Cyanide, mg/l		<0.010	<0.010
Analyst		SK	SK
Analysis Date		04.27.99	04.27.99
Fluoride (340.2)			
Fluoride, mg/l		<0.20	<0.20
Analyst		LFT	LFT
Analysis Date		04.26.99	04.26.99
Nitrate + Nitrite-N (353.2)			
Nitrate + Nitrite-N, mg/l		<0.050	<0.050
Analyst		NR	NR
Analysis Date		04.23.99	04.23.99
Phosphorus, Total (365.4)			
Total Phosphorus, mg/l		0.17	<0.10
Analyst		NR	NR
Analysis Date		04.27.99	04.27.99
Orthophosphate-P (365.2)			
Ortho Phosphate-P, mg/l		<0.050	<0.050
Analyst		LFT	LFT
Analysis Date		04.23.99	04.23.99
Analysis Time		1110	1110
Turbidity (180.1)			
Turbidity, NTU		46	<0.10
Analyst		EDB	EDB
Analysis Date		04.23.99	04.23.99
Analysis Time		1620	1620

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Project: Creek
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED
31171-1	Ditch	04-22-99/1630
31171-2	Equipment Blank	04-22-99/1558
PARAMETER	31171-1	31171-2
Dissolved Oxygen		
Dissolved Oxygen, mg/l	9.0	---
Analyst	JM	---
Analysis Date	04.22.99	---
Analysis Time	2059	---

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Project: Creek
Sampled By: Savannah Laboratories
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED
31171-3	Trip Blank #1	04-22-99/1204
PARAMETER	31171-3	
Purgeables (624)		
Benzene, ug/l		<1.0
Bromodichloromethane, ug/l		<1.0
Bromoform, ug/l		<1.0
Bromomethane, ug/l		<1.0
Carbon tetrachloride, ug/l		<1.0
Chlorobenzene, ug/l		<1.0
Chloroethane, ug/l		<1.0
2-Chloroethylvinyl ether, ug/l		<1.0
Chloroform, ug/l		<1.0
Chloromethane, ug/l		<1.0
Dibromochloromethane, ug/l		<1.0
1,2-Dichlorobenzene, ug/l		<1.0
1,3-Dichlorobenzene, ug/l		<1.0
1,4-Dichlorobenzene, ug/l		<1.0
1,1-Dichloroethane, ug/l		<1.0
1,2-Dichloroethane, ug/l		<1.0
1,1-Dichloroethene, ug/l		<1.0
cis-1,2-Dichloroethylene, ug/l		<1.0
trans-1,2-Dichloroethylene, ug/l		<1.0
1,2-Dichloropropane, ug/l		<1.0
cis-1,3-Dichloropropene, ug/l		<1.0
trans-1,3-Dichloropropene, ug/l		<1.0
Ethylbenzene, ug/l		<1.0
Methylene chloride (Dichloromethane), ug/l		<5.0
1,1,2,2-Tetrachloroethane, ug/l		<1.0

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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED
31171-3	Trip Blank #1	04-22-99/1204
PARAMETER	31171-3	
Tetrachloroethene, ug/l	<1.0	
Toluene, ug/l	<1.0	
1,1,1-Trichloroethane, ug/l	<1.0	
1,1,2-Trichloroethane, ug/l	<1.0	
Trichloroethylene, ug/l	<1.0	
Trichlorofluoromethane, ug/l	<1.0	
Vinyl chloride, ug/l	<1.0	
Analysis Date	04.28.99	

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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED		
31171-4	Method Blank			
31171-5	Accuracy (%Rec)			
31171-6	Precision (%RPD)			
PARAMETER		31171-4	31171-5	31171-6
Purgeables (624)				
Benzene, ug/l		<1.0	104 %	13 %
Bromodichloromethane, ug/l		<1.0	---	---
Bromoform, ug/l		<1.0	---	---
Carbon tetrachloride, ug/l		<1.0	---	---
Chloroform, ug/l		<1.0	---	---
Chloromethane, ug/l		<1.0	---	---
Dibromochloromethane, ug/l		<1.0	---	---
1,1-Dichloroethene, ug/l		<1.0	68 %	10 %
Methylene chloride (Dichloromethane), ug/l		<5.0	---	---
1,1,2,2-Tetrachloroethane, ug/l		<1.0	---	---
Tetrachloroethene, ug/l		<1.0	---	---
Trichloroethylene, ug/l		<1.0	104 %	16 %
Chlorobenzene, %		---	106 %	17 %
Toluene, %		---	100 %	14 %
Analysis Date		04.27.99	04.27.99	---

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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED		
31171-4	Method Blank			
31171-5	Accuracy (%Rec)			
31171-6	Precision (%RPD)			
PARAMETER		31171-4	31171-5	31171-6
PP-Base Neutral Compounds (625)				
Acenaphthene, ug/l		<10	82 %	0.6 %
Acenaphthylene, ug/l		<10	---	---
Anthracene, ug/l		<10	---	---
Benzo(a)anthracene, ug/l		<10	---	---
Benzo(a)pyrene, ug/l		<10	---	---
3,4-Benzofluoranthene (Benzo(b)fluoranthene), ug/l		<10	---	---
Benzo(g,h,i)perylene, ug/l		<10	---	---
Benzo(k)fluoranthene, ug/l		<10	---	---
bis(2-Ethylhexyl) phthalate, ug/l		<10	---	---
Butyl benzyl phthalate, ug/l		<10	---	---
Chrysene, ug/l		<10	---	---
Dibenzo(a,h)anthracene, ug/l		<10	---	---
Diethyl phthalate, ug/l		<10	---	---
Dimethyl phthalate, ug/l		<10	---	---
Di-n-Butyl phthalate, ug/l		<10	---	---
2,4-Dinitrotoluene, ug/l		<10	84 %	1.0 %
Di-n-Octyl phthalate, ug/l		<10	---	---
Fluoranthene, ug/l		<10	---	---
Fluorene, ug/l		<10	---	---
Hexachlorobutadiene, ug/l		<10	---	---
Indeno(1,2,3-cd)pyrene, ug/l		<10	---	---
Naphthalene, ug/l		<10	---	---
Phenanthrene, ug/l		<10	---	---
Pyrene, ug/l		<10	92 %	5.8 %
1-Methylnaphthalene, ug/l		<10	---	---
2-Methylnaphthalene, ug/l		<10	---	---
Analyst		JS	JS	---
Analysis Date		04.28.99	04.29.99	---

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LOG NO: T9-31171
Received: 22 APR 99
Reported: 29 APR 99

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0328

Project: Creek
Sampled By: Savannah Laboratories
Code: 140290429
Page 13

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED		
31171-4	Method Blank			
31171-5	Accuracy (%Rec)			
31171-6	Precision (%RPD)			
PARAMETER		31171-4	31171-5	31171-6
Phosphorus Pesticides (614)				
Azinphos methyl, ug/l		<1.0	---	---
Demeton-O, ug/l		<2.5	---	---
Demeton-S, ug/l		<2.5	---	---
Diazinon, ug/l		<1.0	82 %	6.1 %
Disulfoton, ug/l		<2.0	---	---
Malathion, ug/l		<1.0	---	---
Parathion Ethyl, ug/l		<1.0	92 %	5.4 %
Parathion Methyl, ug/l		<0.50	84 %	3.6 %
Analyst		MT	MT	---
Analysis Date		04.27.99	04.27.99	---

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Project: Creek
Sampled By: Savannah Laboratories
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Page 14

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED		
31171-4	Method Blank			
31171-5	Accuracy (%Rec)			
31171-6	Precision (%RPD)			
PARAMETER		31171-4	31171-5	31171-6
Chlorinated Pesticides (608)				
Aldrin, ug/l		<0.050	68 %	1.4 %
alpha-BHC, ug/l		<0.050	75 %	2.7 %
beta-BHC, ug/l		<0.050	122 %	4.1 %
delta-BHC, ug/l		<0.050	66 %	1.5 %
gamma-BHC, ug/l		<0.050	79 %	.0 %
Chlordane, ug/l		<0.50	---	---
4,4'-DDD, ug/l		<0.10	82 %	3.7 %
4,4'-DDE, ug/l		<0.10	84 %	0 %
4,4'-DDT, ug/l		<0.10	83 %	2.4 %
Dieldrin, ug/l		<0.10	78 %	0 %
Endosulfan I, ug/l		<0.050	86 %	0 %
Endosulfan II, ug/l		<0.10	94 %	0 %
Endosulfan Sulfate, ug/l		<0.10	91 %	2.2 %
Endrin, ug/l		<0.10	88 %	1.1 %
Endrin Aldehyde, ug/l		<0.10	98 %	4.1 %
Heptachlor, ug/l		<0.050	72 %	0 %
Heptachlor Epoxide, ug/l		<0.050	82 %	1.2 %
Toxaphene, ug/l		<3.0	---	---
PCB-1016, ug/l		<0.50	---	---
PCB-1221, ug/l		<0.50	---	---
PCB-1232, ug/l		<0.50	---	---
PCB-1242, ug/l		<0.50	---	---
PCB-1248, ug/l		<0.50	---	---
PCB-1254, ug/l		<0.50	---	---
PCB-1260, ug/l		<0.50	---	---
Analyst		CWA	CWA	---
Analysis Date		04.27.99	04.27.99	---

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Received: 22 APR 99
Reported: 29 APR 99

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0328

Project: Creek
Sampled By: Savannah Laboratories
Code: 140290429
Page 15

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED		
31171-4	Method Blank			
31171-5	Accuracy (%Rec)			
31171-6	Precision (%RPD)			
PARAMETER		31171-4	31171-5	31171-6
Methoxychlor (8081), ug/l		<0.50	97 %	2.1 %
Analyst		CWA	CWA	---
Analysis Date		04.27.99	04.27.99	---
Mirex (608), ug/l		<0.50	---	---
Analyst		DM	---	---
Analysis Date		04.27.99	---	---
N-Hexane Extractable Material (1664)				
Oil & Grease , mg/l		<5.0	84	1.2 %
Analyst		MF	MF	---
Analysis Date		04.26.99	04.26.99	---
Analysis Time		1400	1400	---
Surfactants (MBAS) (425.1)				
Surfactants, mg/l		<0.10	88 %	13.6 %
Analyst		MF	MF	---
Analysis Date		04.23.99	04.23.99	---
Analysis Time		1700	1700	---

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Pensacola, FL 32520-0328

Project: Creek
Sampled By: Savannah Laboratories
Code: 140290429
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REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED		
31171-4	Method Blank			
31171-5	Accuracy (%Rec)			
31171-6	Precision (%RPD)			
PARAMETER	31171-4	31171-5	31171-6	
Metals by ICP (200.7)				
Cadmium, ug/l	<5.0	100 %	1.0 %	
Chromium, ug/l	<10	100 %	0 %	
Copper, ug/l	<25	104 %	0 %	
Iron, ug/l	<50	103 %	0 %	
Lead, ug/l	<5.0	102 %	0.98 %	
Nickel, ug/l	<40	101 %	0 %	
Selenium, ug/l	<10	100 %	1.0 %	
Zinc, ug/l	<20	100 %	0 %	
Beryllium, ug/l	<4.0	100 %	0 %	
Thallium, ug/l	<10	102 %	0 %	
Analyst	CLD	CLD	---	
Analysis Date	04.26.99	04.26.99	---	
Mercury (245.1)				
Mercury, ug/l	<0.20	94 %	11 %	
Analyst	KW	KW	---	
Analysis Date	04.26.99	04.26.99	---	
Silver (272.2-MIBK)				
Silver, ug/l	<0.050	101 %	2.0 %	
Analyst	BP	KW	---	
Analysis Date	04.26.99	04.26.99	---	
Total Recoverable Phenolics (EPA 420.1)				
Phenolics, Total Recoverable, mg/l	<0.010	118 %	4.2 %	
Analyst	DP	DP	---	
Analysis Date	04.26.99	04.26.99	---	

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One Energy Place
Pensacola, FL 32520-0328

Project: Creek
Sampled By: Savannah Laboratories
Code: 140290429
Page 17

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED		
31171-4	Method Blank			
31171-5	Accuracy (%Rec)			
31171-6	Precision (%RPD)			
PARAMETER		31171-4	31171-5	31171-6
Total Cyanide (EPA 335.2)				
Cyanide, mg/l		<0.010	99 %	0 %
Analyst		SK	SK	---
Analysis Date		04.27.99	04.27.99	---
Fluoride (340.2)				
Fluoride, mg/l		<0.20	114 %	0 %
Analyst		LFT	LFT	---
Analysis Date		04.26.99	04.26.99	---
Nitrate + Nitrite-N (353.2)				
Nitrate + Nitrite-N, mg/l		<0.050	92 %	1.1 %
Analyst		NR	NR	---
Analysis Date		04.23.99	04.23.99	---
Phosphorus, Total (365.4)				
Total Phosphorus, mg/l		<0.10	85 %	2.3 %
Analyst		NR	NR	---
Analysis Date		04.27.99	04.27.99	---
Orthophosphate-P (365.2)				
Ortho Phosphate-P, mg/l		<0.050	92 %	4.3 %
Analyst		LFT	LFT	---
Analysis Date		04.23.99	04.23.99	---
Analysis Time		1110	1110	---
Turbidity (180.1)				
Turbidity, NTU		<0.10	93 %	0 %
Analyst		EDB	EDB	---
Analysis Date		04.23.99	04.23.99	---
Analysis Time		1620	1620	---

GRAB AND COMPOSITE FIELD SAMPLING LOG

From Permit:	Sample Type:
Client Name: <u>Gulf Power</u>	<input checked="" type="checkbox"/> Water <input type="checkbox"/> Soil <input type="checkbox"/> Sediment <input type="checkbox"/> Sludge
Site Name: <u>Ditch (CREEK)</u>	<input checked="" type="checkbox"/> Surface <input type="checkbox"/> Surface <input type="checkbox"/> Boring <input type="checkbox"/> Other: _____
Site GMS #: _____	<input type="checkbox"/> Wastewater <input type="checkbox"/> Pile
Site Testsite #: _____	

Weather Conditions: ☐ Other: Temp mid 80's Very Windy 10+ Knots Dusty conditions
☒ Sunny ☐ Partly Cloudy ☐ Cloudy ☐ Foggy ☐ Light Rain ☐ Heavy Rain ☒ Dry Ground ☐ Wet Ground

Sampling Equipment: Water / Sludge

☐ 1. Beaker ☐ 2. Bottle ☐ 3. Bailer ☐ 4. DO Dunker ☐ 5. Peristaltic Pump
 Material: ☐ Glass ☐ Teflon ☐ Poly ☐ SS Tubing Material: ☐ Teflon ☐ Silicone ☐ Poly
☐ 6. Autosampler Refrigeration: ☐ Yes ☐ No
 Collection Vessel Material: ☐ Glass ☐ Teflon ☐ Poly Tubing Material: ☐ Teflon ☐ Silicone

Sampling Equipment: Soil / Sediment / Sludge

☐ 7. Trowel ☐ 8. Spoon ☐ 9. Shovel ☐ 10. Corer ☐ 11. Auger ☐ 12. Ponar Dredge ☒ 13. Other
 Material: ☐ SS ☐ Aluminum Material: ☐ SS Material: ☐ SS Material: Dipper
☐ Teflon-coated SS ☐ PVC ☐ Galvanized Steel Material: Poly

Sample Collection:

☒ A. Grab Sampling Device: 13 Time Started: _____
 Time Collected: 4:30 pm Date Collected: 4/22 Time Completed: _____
☐ B. Other Aliquot Composite: _____ portions of _____ ml _____ g each collected from
 Date Collected: _____ locations indicated on the site map.
☐ C. Composite Time Composite: _____ portions of _____ ml each collected at intervals of
 Sampling Device: _____ min. _____ hr. from the site indicated on the site map. ☐ Manual ☐ Automatic
 Time Collected: _____ Depth Composite: _____ portions of _____ ml _____ g collected at depth intervals
 Date Collected: _____ of _____ ft. Depths collected: _____

Order Of Parameters Collected (number 1-6):

- | | |
|---|--------------------|
| 1 | - Volatiles |
| 2 | - Extr. Organics |
| 3 | - Total Metals |
| 4 | - Dissolved Metals |
| 5 | - Microbiological |
| 6 | - Inorg./Rads |

Comments: SLP 97.2 ALL TIMES ARE E.S.T.
Took Eg. Sample @ 3:58 pm
RCl2 0.00 Took Reading AT 17.00

Sample Appearance:

Water: ☐ Clear ☒ Turbid ☐ Sheen ☒ Color: COTEE/BROWN
 Soil: ☐ Clay ☐ Sand ☐ Loam ☐ Color: _____

Field Measurements:

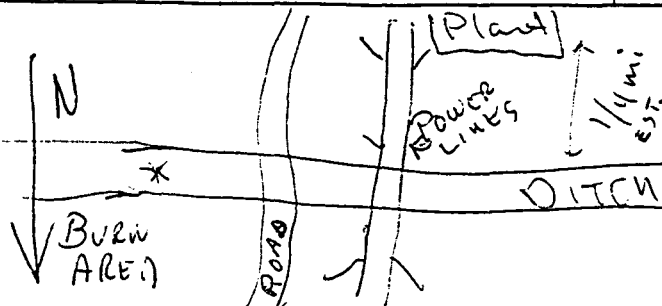
Time: 4:50 pm Calibration: 4.02 (units @ pH 4)
 pH: 3.97 6.98 (units @ pH 7)
 D.O.: 9.67 (units @ pH 10)
 Spec. Cond.: 85.85 (mg/l)
 Temp: 28.2° 100.4 (accuracy)

Date	Time
4/22	3:40 pm

Checklist:

- ☒ Bottles Labelled
☒ Well Locked
☒ Samples Iced
☒ Custody Form Completed

Site Map:



* Sample Point 20yds From
 DIRT ROAD
 NOTE: AREA NORTH OF
 DITCH HAD BEEN BURNED
 WITHIN PAST 2 1/2-3 wks
 DIRT
 BACK OF BURNED WOOD
 STILL Present.

Date / Time Sampling Completed:

4/22/99 17:15

Signature of Sampler:

LOG NO: T9-31171
Received: 22 APR 99
Reported: 29 APR 99

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0328

Project: Creek
Sampled By: Savannah Laboratories
Code: 161590429
Page 18

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES	DATE/ TIME SAMPLED
31171-4	Method Blank	
31171-5	Accuracy (%Rec)	
31171-6	Precision (%RPD)	

PARAMETER	31171-4	31171-5	31171-6
-----------	---------	---------	---------

Method: EPA 40 CFR Part 136
Florida Dept. of Health Certification No.: E81005, E87089
FDEP CompQAP No.: 890142G

Note: Guthion is reported as Azinphos methyl.


Laura B. Snead, Project Manager

SL SAVANNAH LABORATORIES & ENVIRONMENTAL SERVICES, INC.

ANALYSIS REQUEST AND CHAIN OF CUSTODY RECORD

- ☐ 5102 LaRoche Avenue, Savannah, GA 31404
☒ 2846 Industrial Plaza Drive, Tallahassee, FL 32301
☐ 414 SW 12th Avenue, Deerfield Beach, FL 33442
☐ 900 Lakeside Drive, Mobile, AL 36693
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 Phone: (334) 666-6633
 Phone: (813) 885-7427
 Phone: (504) 764-1100

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 Fax: (954) 421-2584
 Fax: (334) 666-6696
 Fax: (813) 885-7049
 Fax: (504) 725-1163

PROJECT REFERENCE CREEK		PROJECT NO.		P.O. NUMBER		MATRIX TYPE		REQUIRED ANALYSES										PAGE 1 OF 2			
PROJECT LOC. (State) FL		SAMPLER(S) NAME John Lipply		PHONE		FAX		AQUEOUS (WATER) SOLID OR SEMISOLID AIR NONAQUEOUS LIQUID (oil, solvent, etc.) CN LITE PLMS TURBIDITY/TSS LITE PLMS BOD/COD/5-DAY PCBs LITE ANALYSIS O&G 1000 W/M METAL 500 W/M PLMS MBAS 500 W/M PLMS Hg 250 W/M PLMS NO3+NO2/TP 250 W/M PLMS OPD4 (PP) 100 W/M PLMS VOC's 40 W/M Vials												STANDARD REPORT DELIVERY <input type="checkbox"/>	
CLIENT NAME Gulf Power		CLIENT PROJECT MANAGER Mike Markey																		EXPEDITED REPORT DELIVERY (surcharge) <input type="checkbox"/>	
CLIENT ADDRESS (CITY, STATE, ZIP) South Port FL																				Date Due:	
SAMPLE		SL NO.		SAMPLE IDENTIFICATION						NUMBER OF CONTAINERS SUBMITTED										REMARKS	
DATE	TIME																				
4/22/99	1558			Eg Blank		✓		1	1	6	1	1	1	1	1	1	3				
4/22/99	16:30			Ditch		✓		1	1	6	1	1	1	1	1	1	3				
4/22/99	1204			TRIP Blank 1		✓											3				
RELINQUISHED BY: (SIGNATURE)		DATE		TIME		RELINQUISHED BY: (SIGNATURE)		DATE		TIME		RELINQUISHED BY: (SIGNATURE)		DATE		TIME					
<i>John Lipply</i>		4/22/99		1230		<i>John Lipply</i>		4/22/99		1920											
RECEIVED BY: (SIGNATURE)		DATE		TIME		RECEIVED BY: (SIGNATURE)		DATE		TIME		RECEIVED BY: (SIGNATURE)		DATE		TIME					
<i>John Lipply</i>		4/22/99		1230		<i>John Lipply</i>		4/22/99		1230											
LABORATORY USE ONLY																					
RECEIVED FOR LABORATORY BY: (SIGNATURE)		DATE		TIME		CUSTODY INTACT		CUSTODY SEAL NO.		SL LOG NO.		LABORATORY REMARKS:									
<i>Ben Hm</i>		4/22/99		1940		<input checked="" type="checkbox"/> YES <input type="checkbox"/> NO				T931171											

ORIGINAL



**SAVANNAH LABORATORIES
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ANALYSIS REQUEST AND CHAIN OF CUSTODY RECORD

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[illegible]

ORIGINAL

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LOG NO: T9-31463
Received: 18 MAY 99
Reported: 21 MAY 99

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0328

Project: Creek
Sampled By: Savannah Laboratories
Code: 104090521
Page 1

REPORT OF RESULTS

LOG NO	SAMPLE DESCRIPTION , LIQUID SAMPLES	DATE/ TIME SAMPLED
31463-1	Ditch	05-18-99/1150
PARAMETER	31463-1	
Surfactants (MBAS) (425.1)		
Surfactants, mg/l	0.80	
Analyst	MF	
Analysis Date	05.18.99	
Analysis Time	1230	

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Project: Creek
Sampled By: Savannah Laboratories
Code: 104090521
Page 2

REPORT OF RESULTS

DATE/
TIME SAMPLED

LOG NO	SAMPLE DESCRIPTION , QC REPORT FOR LIQUID SAMPLES			
31463-2	Method Blank			
31463-3	Accuracy (%Rec)			
31463-4	Precision (%RPD)			
PARAMETER		31463-2	31463-3	31463-4
Surfactants (MBAS) (425.1)				
Surfactants, mg/l		<0.10	93 %	6.4 %
Analyst		MF	MF	---
Analysis Date		05.18.99	05.18.99	---
Analysis Time		1230	1230	---

Method: EPA 40 CFR Part 136
Florida Dept. of Health Certification No.: E81005
FDEP CompQAP No.: 890142G


Laura B. Snead, Project Manager



ANALYSIS REQUEST AND CHAIN OF CUSTODY RECORD

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[illegible]

TOTAL P.02

ATTACHMENT 10.5-C
SOIL BORING LOGS

Southern Company Services, Inc.
Soil Boring Log











Borehole No.:
CT-1


Project: SMITH COMBINED CYCLE
Location: NORTH OF PLANT (SITE CERTIFICATION)
Elevation: N. 465070.57 E. 1589603.64 CT1D
Logger: R. TINSLEY
Dates drilled: 9/9/99
Hole closure: BACKFILL AND CAVE

Drilling Co.: SCS ATLANTA
Driller: DON IVEY
Rig type: TRACK CME-850
Drilling method: MUD ROTARY
No. SPT: 19 **No. UD:** 0 **Total depth:** 96'
Sampling method: SPLIT SPOON

Page 1 of 3

Water level	Elev. (ft.)	Depth (ft)	Soil type	Description	Sample No.	Interval	Blows/6" (N)	Recovery (%)	Comments	Well Log	Monitoring Well
		0		Black, organic MUCK							
		5		Light tan, fine-coarse grained SAND, clean	SS-1		5-10-11 (21)	50	Black flecks slightly wet		
		10		Black, silty, fine-coarse grained SAND, loose	SS-2		4-4-3 (7)	75	Wet		
		15		Gray, slightly silty fine- very coarse grained SAND, loose	SS-3		3-4-4 (8)	75	Some angulate Qtz up to 1/4" also w/rounded to 1/16" & micas		
		20		Dark, bluish-green clayey fine-medium SAND w/shell fragments and whole shells (shell hash)	SS-4		1-2-2 (4)	100	Black flecks, abundant (Jackson's Bluff?) Calcareous		
		25		Fine- grained SAND, SAA; but silty, loose	SS-5		4-6-5 (11)	100	Bryozoans		
		30		Greenish gray w/large shell fragments and some small pods of loosely cemented material, loose	SS-6		6-5-6 (11)	100	Sample shell, abundant black minerals		
		35		SAA; w. no shells, loose, occasional loosely cemented nodules	SS-7		4-3-4 (7)	100			
		40		SAA, loose	SS-8		3-3-4 (7)	80			

		Grayish green fine- grained SAND, loose	SS-9		3-3-4 (7)	100	Calcareous, but no large shells	
45								
		SAA; loose	SS-10		3-3-3 (6)	80	Black mineral specks, very few broken shells	
50								
		SAA; loose	SS-11		3-3-4 (7)	80	Calcareous, SAA	
55								
		Greenish gray, silty clayey fine- grained SAND, loose	SS-12		1-2-2 (4)	80	SAA;	
60								
		SAA; very loose	SS-13		1-2-2 (4)	80	SAA:	
65								
		SAA; loose	SS-14		2-3-3 (6)	80	Calcareous, black mineral specks	
70								
		SAA; very loose	SS-15		1-2-2 (4)	80	Calcareous	
75								
		Green, fine- grained silty very firm, almost dry SAND, some brown mottling	SS-16		5-12-16 (28)	80		
80							Hit hard @-82' for ~6"	
		Green, fine- grained, silty loose, SAND, wet again	SS-17		4-3-4 (7)	80		
85								
		Green, calcareous, fine- grained sandy clay	SS-18		4-4-4 (8)	80		
90								

	<div data-bbox="245 172 315 566"> <div>90</div> <div>95</div> <div>100</div> </div>	<div data-bbox="363 317 617 344">Green, very stiff clay, almost dry</div> <div data-bbox="363 366 464 408">Hard Lenses Top of Rock</div> <div data-bbox="363 427 660 453">Boring Terminated @96' Loss of water</div>	SS-19	<div data-bbox="919 306 959 387">  </div>	3-11-7 (18)	80	<div data-bbox="1104 366 1300 391">Lost water had to pull out</div> <div data-bbox="1104 444 1300 506">Hole caved as Rods were pulled 9/10/99 Hole full of water</div>	
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Southern Company Services, Inc.
Soil Boring Log











Borehole No.:
CT-2

Project: SMITH COMBINED CYCLE
Location: NORTH OF PLANT (GEOTECHNICAL INVESTIGATION)
Elevation: N. 465301.47 E. 1589804.56 CT2S
Logger: R. TINSLEY
Dates drilled: 9/10/99
Hole closure: BACKFILL AND CAVE

Drilling Co.: SCS ATLANTA
Driller: DAVID IVEY
Rig type: TRACK CME-850
Drilling method: MUD ROTARY
No. SPT: 19 **No. UD:** 0 **Total depth:** 96'
Sampling method: SPLIT SPOON

Page 1 of 3

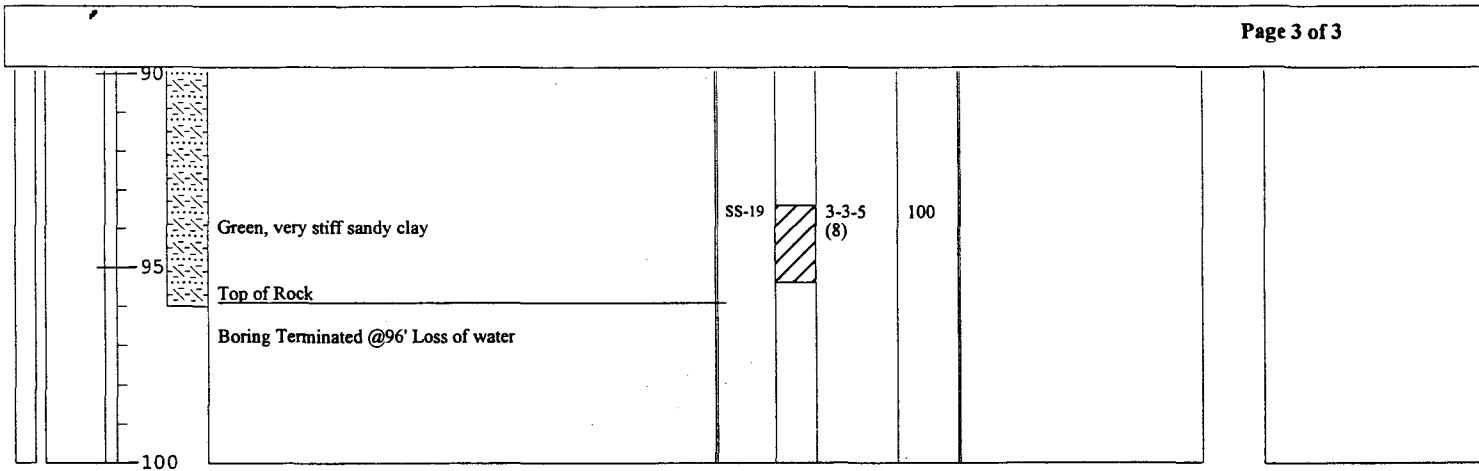
Water level	Elev. (ft.)	Depth (ft)	Soil type	Description	Sample No.	Interval	Blows/6" (N)	Recovery (%)	Comments	Well Log	Monitoring Well
		0		Black, organic MUCK							
		5		Tan, firm, fine-medium grained SAND, saturated	SS-1		6-13-14 (27)	25			
		10		Brown, fine-coarse grained SAND, silty and loose	SS-2		4-4-3 (7)	20			
		15	SAA		SS-3		3-2-1 (3)	20			
		20		Grayish green, very loose, clayey silty fine-medium grained SAND	SS-4		WOH	90	Not Calcareous (Jackson's Bluff?)		
		25		Grayish green clacareous SAND, silty, fine-grained	SS-5		5-7-8 (15)	80	Black minerals in shell hash		
		30	SAA		SS-6		6-5-8 (13)	50	Abundant black minerals, w/larger shell fragments		
		35		SAA; some loosely cemented nodules	SS-7		4-5-5 (10)	80			
		40		SAA; w/o nodule's	SS-8		2-3-4 (7)	100			

Depth (ft)	Soil Description	Sample ID	Soil Profile	Penetration (blows/ft)	Unit Weight (pcf)	Remarks
45	SAA; Grayish green, calcareous, fine- grained silty SAND	SS-9		3-3-4 (7)	80	Abundant black minerals, finely crushed shells
50	SAA; loose	SS-10		3-3-3 (6)	80	
55	SAA; loose	SS-11		4-3-4 (7)	80	Black minerals, less abundant
60	SAA; loose, very silty w/ some clay	SS-12		1-2-1 (3)	80	Black minerals, reduced to minute specks
65	SAA; loose, very silty, very fine- to fine-grained SAND, some clay	SS-13		1-2-3 (5)	100	SAA; some large shell fragments
70	SAA; very silty, some clay, loose	SS-14		2-2-3 (5)	100	
75	SAA; w/increase in fines	SS-15		1-2-2 (4)	80	
80	Green, silty clayey, almost dry, fine grained SAND w/brown mottling	SS-16		5-6-9 (15)	100	Same color change as seen in CT1
						Hit hard @-82' for ~6"
85	SAA; w/some black mottling, wet	SS-17		2-3-3 (6)	100	
90	Grayish Green, sandy CLAY, calcareous, stiff, wet but not saturated	SS-18		3-4-3 (7)	100	

Southern Company Services, Inc.
Soil Boring Log

Borehole No.:
CT-2

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Southern Company Services, Inc.
Soil Boring Log

Borehole No.:
CT-5

Project:	SMITH COMBINED CYCLE	Drilling Co.:	SCS ATLANTA	Page 1 of 3
Location:	SLASH PINE FOREST - 600' EAST OF TRANSMISSION ROW	Driller:	DAVID IVEY	
Elevation:	N. 465301.47 E. 1589804.56 CT2S	Rig type:	TRACK CME-850	
Logger:	R. TINSLEY	Drilling method:	MUD ROTARY	
Dates drilled:	9/16/99	No. SPT:	19	No. UD: 0 Total depth: 98'
Hole closure:	BACKFILL AND CAVE	Sampling method:	SPLIT SPOON	

Water level	Elev. (ft.)	Depth (ft)	Soil type	Description	Sample No.	Interval	Blows/6" (N)	Recovery (%)	Comments	Well Log	Monitoring Well
		0									
		5		Grayish brown silty Qtz SAND, fine-medium grained, poorly sorted, well drained	SS-1	4-8-12 (20)	50				
		10		Dk. Brown, organic, silty Qtz SAND, fine- coarse grained, poorly sorted, well graded	SS-2	5-4-4 (8)	100				
		15		Grayish brown silty Qtz SAND	SS-3	2-1-1 (2)	50				
		20		Olive Gray, clayey sandy silt, organic MUCK, slightly gravelly sand present	SS-4	WOH	50				
		25		Greenish gray sandy Silt	SS-5	2-3-4 (7)	90				
		30		SAA; Greenish gray silty fine sand	SS-6	4-6-6 (12)	100				
		35		SAA	SS-7	4-5-5 (10)	100				
		40		SAA	SS-8	2-3-3 (6)	100				

45 SAA; Subtle increase in silica

50 SAA

55 SAA

60 SAA

65 SAA

70 SAA

75 SAA

80 SAA

85 SAA

90 SAA; w/clay (trace amounts)

SS-9

3-3-3
(6)

90

SS-10

3-4-3
(7)

80

SS-11

3-3-3
(6)

80

SS-12

2-2-1
(3)

80

SS-13

1-1-1
(2)

100

SS-14

3-3-2
(5)

90

SS-15

1-2-2
(4)

100

SS-16

5-8-9
(17)

100

SS-17

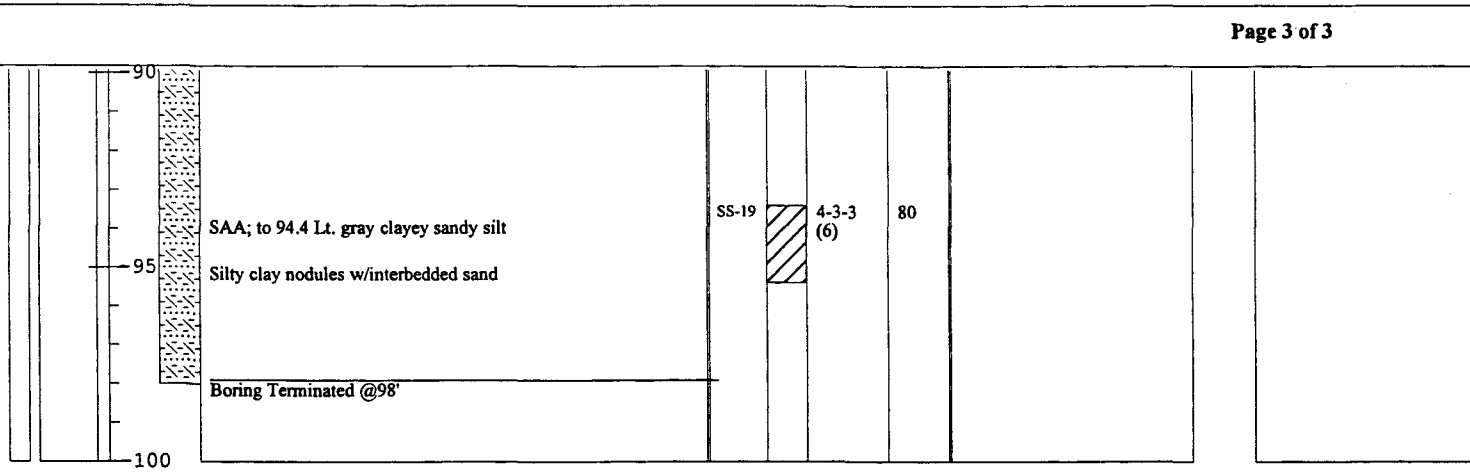
3-3-3
(6)

100

SS-18

3-3-4
(7)

100



Southern Company Services, Inc.
Soil Boring Log

Project:	Smith CT Placements	HOLE No. CT-7S&D
Location:	N. of plant in pine plantation	
Purpose:	Geotechnical Investigation	SHEET 1 OF 1
Position	Surface Elevation:	
Rig Type: CME 850	Contractor: SCS	Driller: David Ivey
Drilling Method: HSA	Boring Depth: 28' bls.	No. SPT: 4
Date Started: 2/5/99	Date Completed: 2/5/99	No. UD Samples: 1
Hole Closure:		Date Logged: 2/5/99

Depth (ft.)	Soil Description	SAMPLE				Comments
		No.	%	Rec.	SPT Values Blows/6"	
0						
5	Saturation. Grayish Brn. organic quartz SND., s/silt, med-coarse grained, loose SAA.		ss	100	3-7-10	apparent water-table.
10	SAA.		ss	50	8-8-3	embedded wood frags.
15	Gravelly SAND w/clayey silt Brn., mottled, clayey silty sand. Green-grey, fossiliferous marl. ubiquitous crystals of pyrolusite - manganese dioxide		ss	<10	0-0-1	grain size analysis. very loose and saturated.
20			ST		N/A	Advanced ST to 15' bls.
25	SAA.		CEC			Jackson Bluff sediments - ~1.5' in thickness.
30	SAA.		ss	100	2-4-6	Intercoastal sediments- marl weathered to silt/sand particles.
35						
40						
45						
50						Terminated boring. grain size analysis.

SS = Split Spoon; ST = Shelby Tube;

CEC = Cation Exchange Capacity

Southern Company Services, Inc.
Soil Boring Log

Project:	Smith CT Placements	HOLE No. CT-8D
Location:	N. of plant	
Purpose:	Geotechnical Investigation	SHEET 1 OF 2
Position	Surface Elevation:	
Rig Type: CME 850	Contractor: SCS	Driller: Don Geldbaugh
Drilling Method: HSA	Boring Depth: 96.6' bts.	No. SPT: 9
Date Started: 2/17/99	Date Completed: 2/18/99	No. UD Samples: 2
Hole Closure:		Date Logged: 2/17&18/99

Depth (ft.)	Soil Description	SAMPLE				Comments
		No.	SPT Values Blows/6"	%Rec.	SPT Values Blows/6"	
0	Bm to olive-gray to tan, mottled silty quartz SND., fn-med.-grained. Black to gray-white silty quartz SND. Saturation. SAA.					woody detritus. apparent water-table.
5						
10	Bm.-olive-gray silty quartz SND.			ST	0	
15	SAA; w/woody detritus nodules, trace amts of clay, organic muck. Greenish-grey, fossiliferous marl, w/blackish pyrolusite crystals.			ST CEC		Jackson Bluff sediments - ~1' in thickness. Intercoastal sediments - marl weathered to silt and sand.
20	SAA.			ss	100	9-8-11 Spooned from 18.8 to 20.3
25						
30	SAA; fossil content less; s/quartz sand.			ss	90	5-7-9 Spooned from 28.8 to 30.3
35						
40	Greenish-gray marl w/ quartz SND., trace of clay.			ss	90	Spooned from 38.8 to 40.3
45						
50	SAA.			ss	90	4-4-7 Spooned from 48.8 to 50.3

SS = Split Spoon; ST = Shelby Tube;
D= Dennison; P=Pitcher; O=Other

CEC = Cation Exchange Capacity

Southern Company Services, Inc.
Soil Boring Log

Project: Smith CT Placements		HOLE No. CT-8D	
Location: N. of plant			
Purpose: Geotechnical Investigation		SHEET 2 OF 2	
Position		Surface Elevation:	
Rig Type: CME 850		Contractor: SCS	Driller: Don Geldbaugh
Drilling Method: HSA		Boring Depth: 96.6' bls.	No. SPT: 4
Date Started: 2/17/99		Date Completed: 2/18/99	No. UD Samples: 2
Hole Closure:		Date Logged: 2/17&18/99	

Depth (ft.)	Soil Description	SAMPLE			Comments
		No.	%Rec.	SPT Values Blows/6"	
50					
55					
60	Greenish-gray marl w/ fine-grained quartz sand, trace amts of olive-gray clay.		ss 100	2-2-6	Spooned from 58.8 to 60.3
65					
70	Olive-gray marl w/ trace of clay.		ss 100	1-2-3	Spooned from 68.8 to 70.3
75					
80	Olive-gray marl, silty, trace of clay. Nodule of indurated fossiliferous marl.		ss 100	1-2-4	Spooned from 78.8 to 80.3 increase in torque pressure.
85	Olive-gray marl, clayey silt, s/quartz sand, fossiliferous and pyrolusite.		ss 100	1-1-2	Spooned from 83.8 to 85.3 Augured to 93.8' w/o sampling.
90	Olive-gray silty CLAY, stiff, mal- leable.				
95	SAA.		ss 100	1-4-8	Spooned from 93.8 to 95.3
100	Contact of Floridian Limestone -96.8'		CEC		Augur refusal -boring term.

SS = Split Spoon; ST = Shelby Tube;	CEC = Cation Exchange Capacity
D= Dennison; P=Pitcher; O=Other	

Southern Company Services, Inc.
Soil Boring Log

Project: Smith CT Placements		HOLE No. CT-11	
Location: Area of proposed Cooling Towers			
Purpose: Geotechnical Investigation		SHEET 1 OF 2	
Position		Surface Elevation:	
Rig Type: D-45		Contractor: SCS	
Drilling Method: Mud Rotary - 95.5'; Rock Coring - 106'		Driller: Don Geldbaugh	
Date Started: 3/30/99		No. SPT: 9	
Date Completed: 4/1/99		No. UD Samples: 0	
Hole Closure:		Date Logged: 3/30 through 4/1	

Depth (ft.)	Soil Description	SAMPLE			Comments
		No.	%Rec.	SPT Values Blows/5"	
0	0-8" black organic/humic loamy SND.				
5	Brown to Grey, mottled, quartz SND, medium density, fine-grained, well sorted, poorly graded, saturated.	ss	100	20-16-14	Zone of Saturation ~1' bls. Split-barrel sample at 3.5 to 5'
10	Bm/gray/black silty quartz SND., poorly sorted, well graded, loose and wet.	ss	100	3-3-4	Split-barrel sample at 8.5 to 10'
15	Bm-Gray quartz SND, coarse-grained, subrounded, loose; woody detritus	ss	100	3-3-3	Gray-tan silty quartz SND seam Split-barrel sample at 13.5 to 15'
20	Olive-gray to brn. clayey silty quartz SND, fine-grained, friable.		N/A	N/A	~contact of Jackson Bluff.
25	Dk. Gray quartz SND, coarse-grained. Greenish-Gray Marl, silty w/ fn. quartz sand, sequence loose and friable.	ss	100	2-6-6	~terminus of Jackson Bluff - 24'. pyrolusite and/or hematite-ubiquitous; contact of Intercoastal at 24'
35	SAA.	ss	90	4-6-6	
45	SAA.	ss	100	3-5-7	
50					

SS = Split Spoon; ST = Shelby Tube; D= Dennison; P=Pitcher; O=Other	CEC = Cation Exchange Capacity
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Southern Company Services, Inc.
Soil Boring Log

Project: Smith CT Placements		HOLE No. CT-11	
Location: Area of proposed Cooling Towers			
Purpose: Geotechnical Investigation		SHEET 2 OF 2	
Position		Surface Elevation:	
Rig Type: D-45		Contractor: SCS	
Drilling Method: Mud Rotary to 95.5'; Rock Coring to 106'		Driller: Don Geldbaugh	No. UD Samples: 0
Date Started: 3/30/99	Date Completed: 4/1/99	No. SPT: 9	
Hole Closure:		Date Logged: 3/30 through 4/1	

Depth (ft.)	Soil Description	SAMPLE			Comments
		No.	%Rec.	SPT Values Blows/6"	
50					
55	Greenish-gray Marl, silty w/ fn. quartz sand; sequence friable.	ss	100	4-5-6	Split-barrel sample 53.5'-55'
65	SAA w/fossiliferous nodules.	ss	100	1-2-4	Split-barrel sample 63.5'-65'
75	SAA.	ss	100	3-7-8	Split-barrel sample 73.5'-75'
80	Fossiliferous Limestone nodule 79.8-81.8.				Increase in downward torque.
85	Greenish-gray Marl, fossiliferous.	n/a	0	2-3-5	Split barrel sample 83.5-85' drilled to limestone w/o sampling
95	Olive-gray silty CLAY lens, stiff, malleable.				-2' in thickness - Inferred from cuttings
100	Limestone, consolidated, massive from 95.5 to 96.5'; grades into fractured, weathered, granular limestone, fossiliferous, greenish-gray coloration.				Augur refusal. initiated rock coring at 95.5' molds and casts of pelyceps. SAA to 106' - terminus of boring.

SS = Split Spoon; ST = Shelby Tube; D= Demmison, P=Pitcher, O=Other	CEC = Cation Exchange Capacity
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Southern Company Services, Inc.
Soil Boring Log

Borehole No.:
CT-12

Page 1 of 3

Project: SMITH COMBINED CYCLE
Location: NORTH OF PLANT (SITE CERTIFICATION)
Elevation: E. W.
Logger: R. TINSLEY
Dates drilled: 4/6/99
Hole closure: GROUT

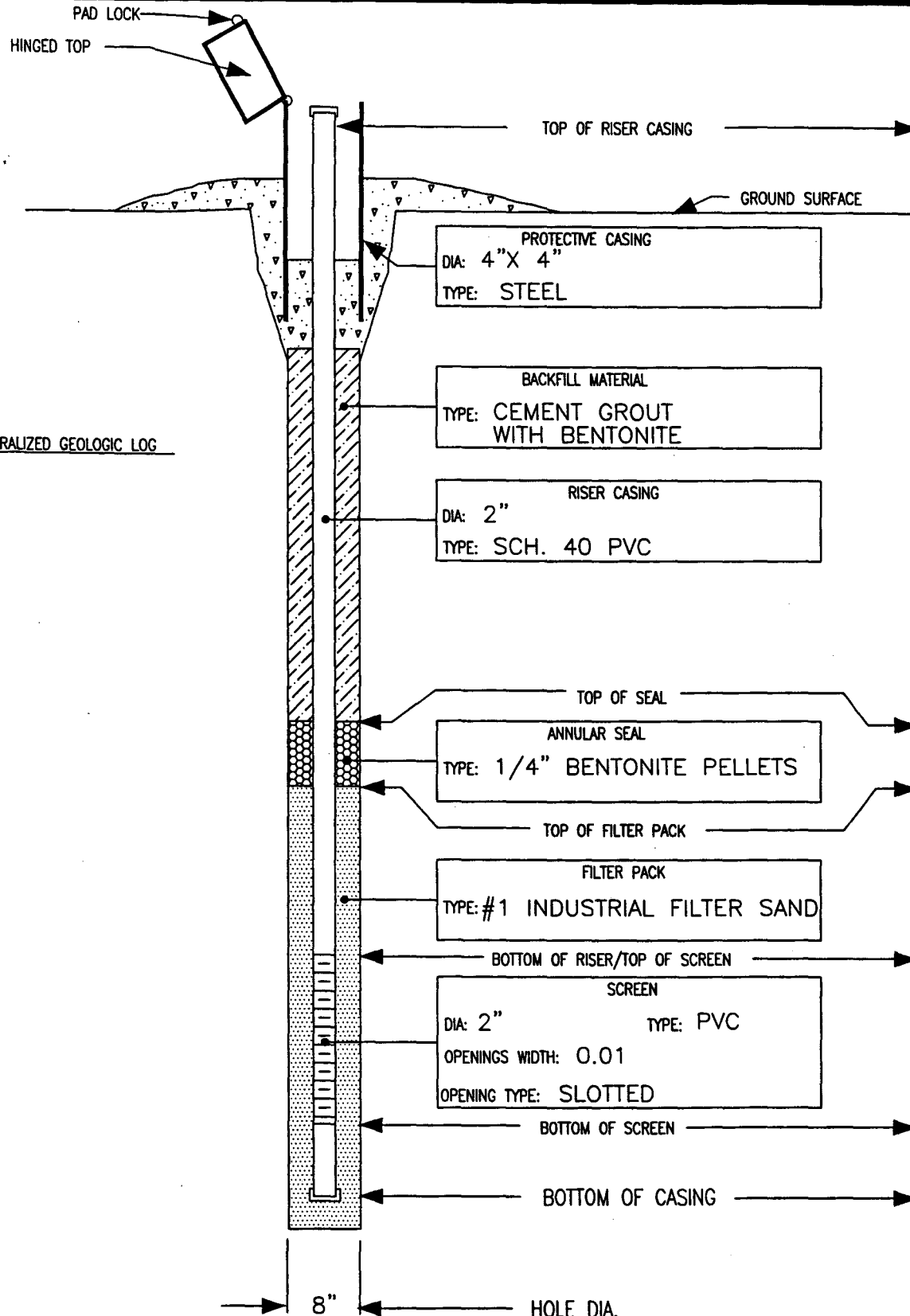
Drilling Co.: SCS ATLANTA
Driller: DON GELDBAUGH
Rig type: CME-850
Drilling method: MUD ROTARY
No. SPT: 18 **No. UD:** 0 **Total depth:** 106'
Sampling method: SPLIT SPOON

Water level	Elev. (ft.)	Depth (ft)	Soil type	Description	Sample No.	Interval	Blows/6" (N)	Recovery (%)	Comments	Well Log	Monitoring Well
		0		Black, organic muck							
		5		Light brown to dark brown, silty fine- to medium-grained Qtz SAND, wet	SS-1	6-9-12	(21)	25			
		10		Dark brown fine- to medium grained Qtz SAND silty, wet	SS-2	5-6-6	(12)	75			
		15		Organics (roots) greenish, very slightly (fine) sandy, Jackson Bluff @ 14.5', CLAY, stiff, wet	SS-3	1-2- WOH	(2)	100	J.B. at 14.5'		
		20		Greenish gray; calcareous fine- grained sand w/shell fragments & whole shells; loose to slightly stiff, wet	SS-4	3-6-11	(17)	100	attempted UD @ 14'-16' @CT12D, no recovery		
		25		SAA; w/slightly clayey (~3") @~24.5' w/loosely cemented material	SS-5	4-4-8	(12)	100	Black minerals, abundant (rounded grains)		
		30	SAA		SS-6	7-7-8	(15)	—			
		35	SAA		SS-7	4-5-6	(11)	80			
		40	SAA		SS-8	4-5-7	(12)	80			
									Rounded grains, tiny black grains		

				grains			
45	SAA	SS-9	3-5-6 (11)	50			
50	SAA	SS-10	4-5-7 (12)	75			
55	SAA; No large shells	SS-11	3-4-4 (8)	100			
60	SAA; loose	SS-12	2-2-4 (6)	100			
65	SAA; loose w/some larger shell fragments	SS-13	2-3-3 (6)	100			
70	SAA	SS-14	2-4-4 (8)	90			
75	SAA Becoming clayey, very fine- grained	SS-15	2-3-5 (8)	90			
80	~79' hit hard layer of cemented limestone SAA; Silty clayey SAND w/some brown mottling	SS-16	2-5-26 (31)	100	3' of hard drilling		
85		SS-17	3-2-6 (8)	100			
90	SAA; Clayey Sand	SS-18	3-2-6 (8)	100	(collected fir testing)		

(8)							
90	Very stiff, green clay w/shell fragments, porous						
95	TOP OF ROCK 96; -96.5' very fossiliferous, very porous, mottled	—1—			(collected)		
					Total water loss @ TOR		
100	1st run 96' -101'						
				3 1/5'	Weathered, large fossils, black specks as above		
	Gray green to black, consolidated limestone (upper 6")			60%			
105	Some fines may have washed out						
	Gray green fossiliferous, porous			5 1/5'	Pelecypods, Bryzoans		
	Boring Terminated @106' Complete loss of water				water loss		
110							

ATTACHMENT 10.5-D
WELL CONSTRUCTION LOGS

WELL CONSTRUCTION LOG			PROJECT SMITH COMBINED CYCLE	WELL NO. CT-1S
SITE NORTH OF PLANT (SITE CERTIFICATION)			LOCATION N.465068.38 E.1589602.80	
BEGUN 2/2/99	COMPLETED 2/2/99	PREPARED BY R. TINSLEY	CONTRACTOR SCS	
 <p style="position: absolute; top: 160px; left: 140px;">PAD LOCK</p> <p style="position: absolute; top: 180px; left: 140px;">HINGED TOP</p> <p style="position: absolute; top: 230px; left: 550px;">TOP OF RISER CASING</p> <p style="position: absolute; top: 270px; left: 700px;">GROUND SURFACE</p> <p style="position: absolute; top: 290px; left: 530px;">PROTECTIVE CASING DIA: 4"X 4" TYPE: STEEL</p> <p style="position: absolute; top: 370px; left: 530px;">BACKFILL MATERIAL TYPE: CEMENT GROUT WITH BENTONITE</p> <p style="position: absolute; top: 440px; left: 570px;">RISER CASING DIA: 2" TYPE: SCH. 40 PVC</p> <p style="position: absolute; top: 560px; left: 570px;">TOP OF SEAL</p> <p style="position: absolute; top: 580px; left: 550px;">ANNULAR SEAL TYPE: 1/4" BENTONITE PELLETS</p> <p style="position: absolute; top: 640px; left: 550px;">TOP OF FILTER PACK</p> <p style="position: absolute; top: 660px; left: 580px;">FILTER PACK TYPE: #1 INDUSTRIAL FILTER SAND</p> <p style="position: absolute; top: 710px; left: 510px;">BOTTOM OF RISER/TOP OF SCREEN</p> <p style="position: absolute; top: 730px; left: 600px;">SCREEN DIA: 2" TYPE: PVC OPENINGS WIDTH: 0.01 OPENING TYPE: SLOTTED</p> <p style="position: absolute; top: 810px; left: 550px;">BOTTOM OF SCREEN</p> <p style="position: absolute; top: 850px; left: 550px;">BOTTOM OF CASING</p> <p style="position: absolute; top: 920px; left: 370px;">8"</p> <p style="position: absolute; top: 920px; left: 540px;">HOLE DIA.</p>			DEPTH	ELEV.
			2.97	9.77
			0.00	6.80
			0.50	6.30
			2.00	4.80
			6.00	0.80
			16.00	-9.20
			16.35	-9.55

GENERALIZED GEOLOGIC LOG



WELL CONSTRUCTION LOG			PROJECT SMITH COMBINED CYCLE	WELL NO. CT-1D
SITE NORTH OF PLANT (SITE CERTIFICATION)		LOCATION N.465070.57 E.1589603.64		
BEGUN 2/2/99	COMPLETED 2/2/99	PREPARED BY R. TINSLEY	CONTRACTOR SCS	
<p>HINGED TOP</p> <p>TOP OF RISER CASING</p> <p>GROUND SURFACE</p> <p>PROTECTIVE CASING DIA: 4" TYPE: STEEL WITH LOCKING CAP</p> <p>BACKFILL MATERIAL TYPE: CEMENT GROUT WITH BENTONITE</p> <p>RISER CASING DIA: 2" TYPE: SCH. 40 PVC</p> <p>TOP OF SEAL</p> <p>ANNULAR SEAL TYPE: 1/4" BENTONITE PELLETS</p> <p>TOP OF FILTER PACK</p> <p>FILTER PACK TYPE: #1 INDUSTRIAL FILTER SAND</p> <p>BOTTOM OF RISER/TOP OF SCREEN</p> <p>SCREEN DIA: 2" TYPE: PVC OPENINGS WIDTH: 0.01 OPENING TYPE: SLOTTED</p> <p>BOTTOM OF SCREEN</p> <p>BOTTOM OF CASING & HOLE</p> <p>8" HOLE DIA.</p>			DEPTH 2.02 0.00 15.00 26.00 28.00 38.00 38.50	ELEV. 8.82 6.80 -8.20 -19.20 -21.20 -31.20 -31.70

GENERALIZED GEOLOGIC LOG

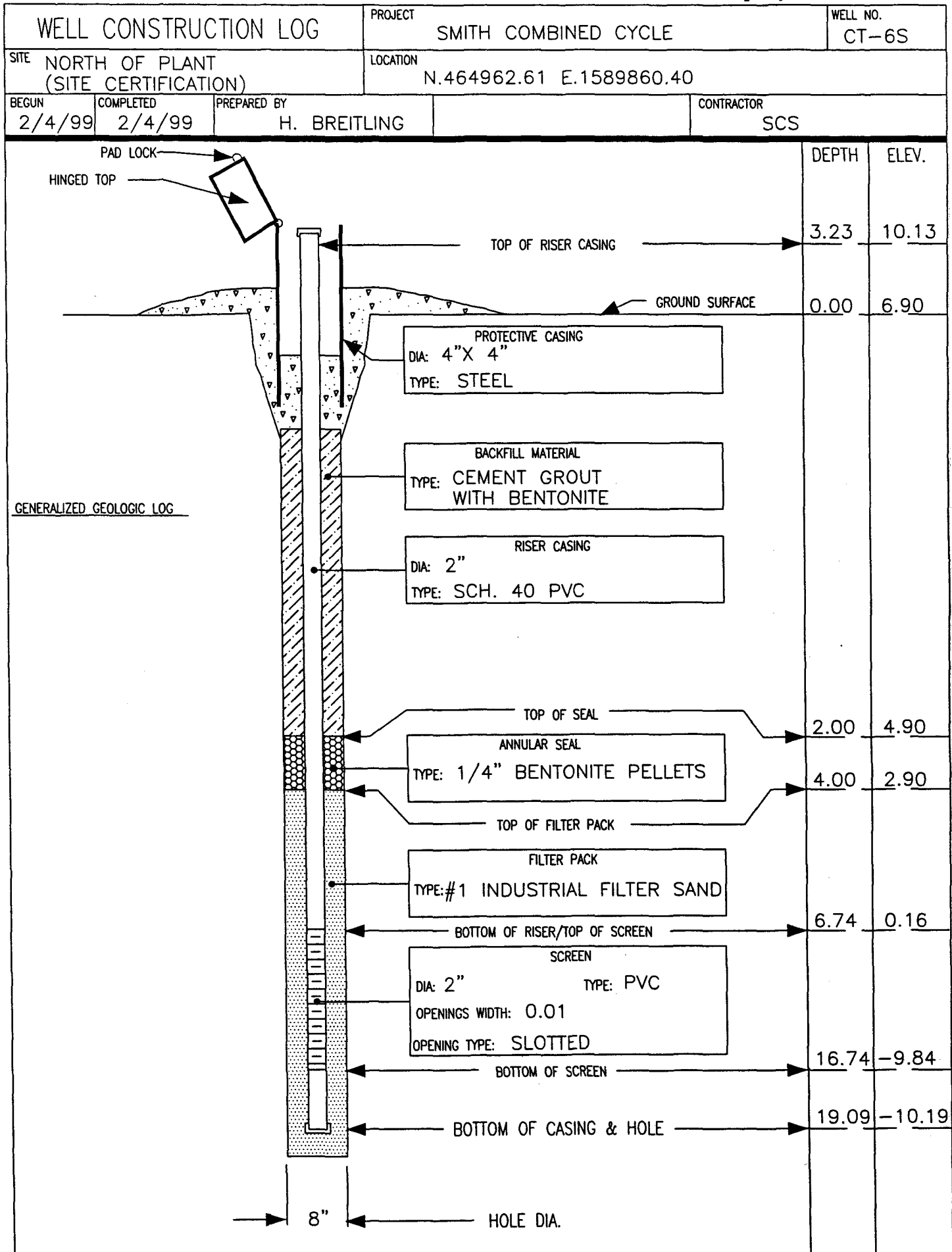


WELL CONSTRUCTION LOG		PROJECT		WELL NO.	
SMITH COMBINED CYCLE		CT-2S			
SITE		LOCATION			
NORTH OF PLANT (SITE CERTIFICATION)		N.465301.47 E.1589804.56			
BEGUN	COMPLETED	PREPARED BY			CONTRACTOR
2/3/99	2/3/99	H. BREITLING			SCS
<p>Diagram labels: PAD LOCK, HINGED TOP, TOP OF RISER CASING, GROUND SURFACE, PROTECTIVE CASING (DIA: 4"X 4", TYPE: STEEL), BACKFILL MATERIAL (TYPE: CEMENT GROUT WITH BENTONITE), RISER CASING (DIA: 2", TYPE: SCH. 40 PVC), TOP OF SEAL, ANNULAR SEAL (TYPE: 1/4" BENTONITE PELLETS), TOP OF FILTER PACK, FILTER PACK (TYPE: #1 INDUSTRIAL FILTER SAND), BOTTOM OF RISER/TOP OF SCREEN, SCREEN (DIA: 2", TYPE: PVC, OPENINGS WIDTH: 0.01, OPENING TYPE: SLOTTED), BOTTOM OF SCREEN, BOTTOM OF CASING & HOLE, 8" HOLE DIA.</p>				DEPTH	ELEV.
				3.49	10.09
				0.00	6.60
				2.00	4.60
				4.00	2.60
				6.27	0.33
				16.27	-9.67
				16.62	-10.02

GENERALIZED GEOLOGIC LOG



WELL CONSTRUCTION LOG		PROJECT SMITH COMBINED CYCLE		WELL NO. CT-5D	
SITE NORTH OF PLANT (SITE CERTIFICATION)		LOCATION N.464952.55 E.1590127.72			
BEGUN 2/4/99	COMPLETED 2/4/99	PREPARED BY H. BREITLING	CONTRACTOR SCS		
			DEPTH	ELEV.	
			1.72	8.62	
			0.00	6.90	
GENERALIZED GEOLOGIC LOG					
			23.00	-16.10	
			25.00	-18.10	
			28.34	-21.44	
			38.34	-31.44	
			38.69	-31.79	





WELL CONSTRUCTION LOG			PROJECT SMITH COMBINED CYCLE		WELL NO. CT-7S
SITE NORTH OF PLANT (SITE CERTIFICATION)			LOCATION N.464774.73 E.1589750.80		
BEGUN 2/5/99	COMPLETED 2/5/99	PREPARED BY H. BREITLING	CONTRACTOR SCS		
<p style="position: absolute; top: 160px; left: 140px;">PAD LOCK HINGED TOP</p> <p style="position: absolute; top: 225px; left: 550px;">TOP OF RISER CASING</p> <p style="position: absolute; top: 265px; left: 700px;">GROUND SURFACE</p> <p style="position: absolute; top: 290px; left: 530px;">PROTECTIVE CASING DIA: 4"X 4" TYPE: STEEL</p> <p style="position: absolute; top: 375px; left: 530px;">BACKFILL MATERIAL TYPE: CEMENT GROUT WITH BENTONITE</p> <p style="position: absolute; top: 440px; left: 570px;">RISER CASING DIA: 2" TYPE: SCH. 40 PVC</p> <p style="position: absolute; top: 560px; left: 580px;">TOP OF SEAL</p> <p style="position: absolute; top: 585px; left: 550px;">ANNULAR SEAL TYPE: 1/4" BENTONITE PELLETS</p> <p style="position: absolute; top: 640px; left: 550px;">TOP OF FILTER PACK</p> <p style="position: absolute; top: 665px; left: 580px;">FILTER PACK TYPE: #1 INDUSTRIAL FILTER SAND</p> <p style="position: absolute; top: 715px; left: 510px;">BOTTOM OF RISER/TOP OF SCREEN</p> <p style="position: absolute; top: 735px; left: 600px;">SCREEN DIA: 2" TYPE: PVC OPENINGS WIDTH: 0.01 OPENING TYPE: SLOTTED</p> <p style="position: absolute; top: 815px; left: 550px;">BOTTOM OF SCREEN</p> <p style="position: absolute; top: 855px; left: 550px;">BOTTOM OF CASING</p> <p style="position: absolute; top: 920px; left: 380px;">8" HOLE DIA.</p>				DEPTH	ELEV.
				3.85	10.75
				0.00	6.90
				1.00	5.90
				2.00	3.90
				4.12	2.78
				14.12	-7.22
				14.47	-7.57

GENERALIZED GEOLOGIC LOG



WELL CONSTRUCTION LOG		PROJECT SMITH COMBINED CYCLE		WELL NO. CT-7D
SITE NORTH OF PLANT (SITE CERTIFICATION)		LOCATION N.464774.28 E.1589746.49		
BEGUN 2/5/99	COMPLETED 2/5/99	PREPARED BY H. BREITLING	CONTRACTOR SCS	
<div style="display: flex; align-items: center;"> <div style="flex: 1;"> <p style="position: absolute; top: 180px; left: 140px;">HINGED TOP</p> <p style="position: absolute; top: 225px; left: 550px;">TOP OF RISER CASING</p> <p style="position: absolute; top: 265px; left: 700px;">GROUND SURFACE</p> <p style="position: absolute; top: 290px; left: 530px;">PROTECTIVE CASING DIA: 4" TYPE: STEEL WITH LOCKING CAP</p> <p style="position: absolute; top: 375px; left: 530px;">BACKFILL MATERIAL TYPE: CEMENT GROUT WITH BENTONITE</p> <p style="position: absolute; top: 440px; left: 570px;">RISER CASING DIA: 2" TYPE: SCH. 40 PVC</p> <p style="position: absolute; top: 560px; left: 580px;">TOP OF SEAL</p> <p style="position: absolute; top: 585px; left: 550px;">ANNULAR SEAL TYPE: 1/4" BENTONITE PELLETS</p> <p style="position: absolute; top: 640px; left: 550px;">TOP OF FILTER PACK</p> <p style="position: absolute; top: 665px; left: 580px;">FILTER PACK TYPE: #1 INDUSTRIAL FILTER SAND</p> <p style="position: absolute; top: 715px; left: 510px;">BOTTOM OF RISER/TOP OF SCREEN</p> <p style="position: absolute; top: 735px; left: 600px;">SCREEN DIA: 2" TYPE: PVC OPENINGS WIDTH: 0.01 OPENING TYPE: SLOTTED</p> <p style="position: absolute; top: 815px; left: 550px;">BOTTOM OF SCREEN</p> <p style="position: absolute; top: 855px; left: 510px;">BOTTOM OF CASING & HOLE</p> <p style="position: absolute; top: 920px; left: 380px;">8"</p> <p style="position: absolute; top: 920px; left: 540px;">HOLE DIA.</p> </div> <div style="flex: 0.5; text-align: center;"> <p>DEPTH</p> <p>ELEV.</p> </div> </div>			2.44	9.34
			0.00	6.90
			13.00	-6.10
			15.00	-8.10
			17.69	-10.79
			27.69	-20.79
			28.04	-21.14

GENERALIZED GEOLOGIC LOG



WELL CONSTRUCTION LOG		PROJECT	WELL NO.
NORTH OF PLANT (SITE CERTIFICATION)		SMITH COMBINED CYCLE	CT-11S
BEGUN	COMPLETED	PREPARED BY	CONTRACTOR
4/6/99	4/6/99	H. BREITLING	SCS

DEPTH	ELEV.
3.83	12.43
0.00	8.6
2.0	6.60
4.0	4.60
6.0	2.60
16.0	-7.40
16.35	-7.75

DESCRIPTION	DEPTH	ELEV.
TOP OF RISER CASING	3.83	12.43
GROUND SURFACE	0.00	8.6
PROTECTIVE CASING DIA: 4" X 4" TYPE: STEEL		
BACKFILL MATERIAL TYPE: CEMENT GROUT WITH BENTONITE		
RISER CASING DIA: 2" TYPE: SCH. 40 PVC		
TOP OF SEAL	2.0	6.60
ANNULAR SEAL TYPE: 1/4" BENTONITE PELLETS	4.0	4.60
TOP OF FILTER PACK		
FILTER PACK TYPE: #1 INDUSTRIAL FILTER SAND		
BOTTOM OF RISER/TOP OF SCREEN	6.0	2.60
SCREEN DIA: 2" TYPE: PVC OPENINGS WIDTH: 0.01 OPENING TYPE: SLOTTED		
BOTTOM OF SCREEN	16.0	-7.40
BOTTOM OF CASING	16.35	-7.75
HOLE DIA.	8"	

GENERALIZED GEOLOGIC LOG

PAD LOCK

HINGED TOP

TOP OF RISER CASING

GROUND SURFACE

PROTECTIVE CASING
DIA: 4" X 4"
TYPE: STEEL

BACKFILL MATERIAL
TYPE: CEMENT GROUT WITH BENTONITE

RISER CASING
DIA: 2"
TYPE: SCH. 40 PVC

TOP OF SEAL

ANNULAR SEAL
TYPE: 1/4" BENTONITE PELLETS

TOP OF FILTER PACK

FILTER PACK
TYPE: #1 INDUSTRIAL FILTER SAND

BOTTOM OF RISER/TOP OF SCREEN

SCREEN
DIA: 2"
TYPE: PVC
OPENINGS WIDTH: 0.01
OPENING TYPE: SLOTTED

BOTTOM OF SCREEN

BOTTOM OF CASING

HOLE DIA.



WELL CONSTRUCTION LOG			PROJECT SMITH COMBINED CYCLE		WELL NO. CT-12S	
SITE NORTH OF PLANT (SITE CERTIFICATION)			LOCATION N.464539.38 E.1590289.93			
BEGUN	COMPLETED	PREPARED BY			CONTRACTOR	
4/6/99		DON GELDBAUGH			SCS	
<p style="text-align: center;">8" HOLE DIA.</p>			DEPTH	ELEV.		
			4.05	11.35		
			0.00	7.3		
			PROTECTIVE CASING			
			DIA: 4"X 4"			
			TYPE: STEEL			
			BACKFILL MATERIAL			
			TYPE: CEMENT GROUT WITH BENTONITE			
			RISER CASING			
DIA: 2"						
TYPE: SCH. 40 PVC						
TOP OF SEAL		1.00	6.3			
ANNULAR SEAL						
TYPE: 1/4" BENTONITE PELLETS		3.00	4.3			
TOP OF FILTER PACK						
FILTER PACK						
TYPE: #1 INDUSTRIAL FILTER SAND						
BOTTOM OF RISER/TOP OF SCREEN		4.0	3.3			
SCREEN						
DIA: 2" TYPE: PVC						
OPENINGS WIDTH: 0.01						
OPENING TYPE: SLOTTED						
BOTTOM OF SCREEN		14.0	-6.7			
BOTTOM OF CASING		14.0	-6.7			

GENERALIZED GEOLOGIC LOG



WELL CONSTRUCTION LOG		PROJECT SMITH COMBINED CYCLE		WELL NO. CT-12D
SITE NORTH OF PLANT (SITE CERTIFICATION)		LOCATION N.464536.22 E.1590295.49		
BEGUN 4/6/99	COMPLETED	PREPARED BY DON GELDBAUGH	CONTRACTOR SCS	
<p style="margin-top: 20px;">GENERALIZED GEOLOGIC LOG</p>		DEPTH	ELEV.	
		3.66	11.36	
		0.00	7.7	
		PROTECTIVE CASING DIA: 4" X 4" TYPE: STEEL		
		BACKFILL MATERIAL TYPE: CEMENT GROUT WITH BENTONITE		
		RISER CASING DIA: 2" TYPE: SCH. 40 PVC		
		19.0	-11.3	
		21.0	-13.3	
		FILTER PACK TYPE: #1 INDUSTRIAL FILTER SAND		
		23.0	-15.3	
SCREEN DIA: 2" TYPE: PVC OPENINGS WIDTH: 0.01 OPENING TYPE: SLOTTED				
33.0	-25.3			
BOTTOM OF CASING			33.0	-25.3
8"		HOLE DIA.		

ATTACHMENT 10.5-E

SLUG TESTS

Plant Smith
SLUG TEST ANALYSIS SUMMARY

Piezometer	Test	Hydraulic Conductivity (ft/day)	Hydraulic Conductivity (cm/sec)
Shallow Piezometers			
CT1S	CT1SIN	0.32	1.1E-04
CT1S	CT1SOUT	0.19	6.7E-05
	Average	0.26	9.0E-05
CT2S	CT2SIN2	0.40	1.4E-04
CT2S	CT2SOUT2	0.38	1.3E-04
	Average	0.39	1.4E-04
CT5S	CT5SIN1	1.6	5.6E-04
CT5S	CT5SOUT1	2.2	7.8E-04
	Average	1.9	6.7E-04
CT6S	CT6SIN1	0.64	2.3E-04
CT6S	CT6SOUT1	0.22	7.8E-05
	Average	0.43	1.5E-04
CT7S	CT7SIN1	1.1	3.9E-04
CT7S	CT7SOUT2	1.2	4.2E-04
	Average	1.2	4.1E-04
Shallow Piezometer Overall Average		0.83	2.9E-04
Deep Piezometers			
CT1D	CT1DIN1	6.2	2.2E-03
CT1D	CT1DOUT1	5.1	1.8E-03
	Average	5.7	2.0E-03
CT5D	CT5DIN1	6.0	2.1E-03
CT5D	CT5DOUT1	4.9	1.7E-03
	Average	5.5	1.9E-03
CT7D	CT7DIN1	7.0	2.5E-03
CT7D	CT7DOUT1	6.4	2.3E-03
	Average	6.7	2.4E-03
Deep Piezometer Overall Average		5.9	2.1E-03

Note: Values based upon typical piezometer conditions.

Gulf Power Company
Plant Smith

Results Compiled by Southern Company Services

	Test Type	Initial Displacement	Casing Radius	Borehole Radius	Screen Length	Aquifer Thickness	Y Intercept	A Unitless	B Unitless	C Unitless
Shallow Piezometers										
CT1S	In	1.96	0.08	0.33	10	14	1.96	4.833	0.08227	4.8179
	Out	1.57	0.08	0.33	10	14	1.57	4.833	0.08227	4.8179
CT2S	In	1.69	0.08	0.33	10	14	1.69	4.833	0.08227	4.8179
	Out	1.48	0.08	0.33	10	14	1.48	4.833	0.08227	4.8179
CT5S	In	1.56	0.08	0.33	10	14	1.56	4.833	0.08227	4.8179
	Out	1.70	0.08	0.33	10	14	1.70	4.833	0.08227	4.8179
CT6S	In	1.78	0.08	0.33	10	14	1.78	4.833	0.08227	4.8179
	Out	1.02	0.08	0.33	10	14	1.02	4.833	0.08227	4.8179
CT7S	In	1.60	0.08	0.33	10	14	1.60	4.833	0.08227	4.8179
	Out	1.72	0.08	0.33	10	14	1.72	4.833	0.08227	4.8179
Deep Piezometers										
CT1D	In	2.19	0.08	0.33	10	77	1.82	4.833	0.08227	4.8179
	Out	1.03	0.08	0.33	10	77	1.03	4.833	0.08227	4.8179
CT5D	In	2.19	0.08	0.33	10	77	2.19	4.833	0.08227	4.8179
	Out	1.41	0.08	0.33	10	77	1.41	4.833	0.08227	4.8179
CT7D	In	2.35	0.08	0.33	10	77	1.82	4.833	0.08227	4.8179
	Out	1.74	0.08	0.33	10	77	1.74	4.833	0.08227	4.8179

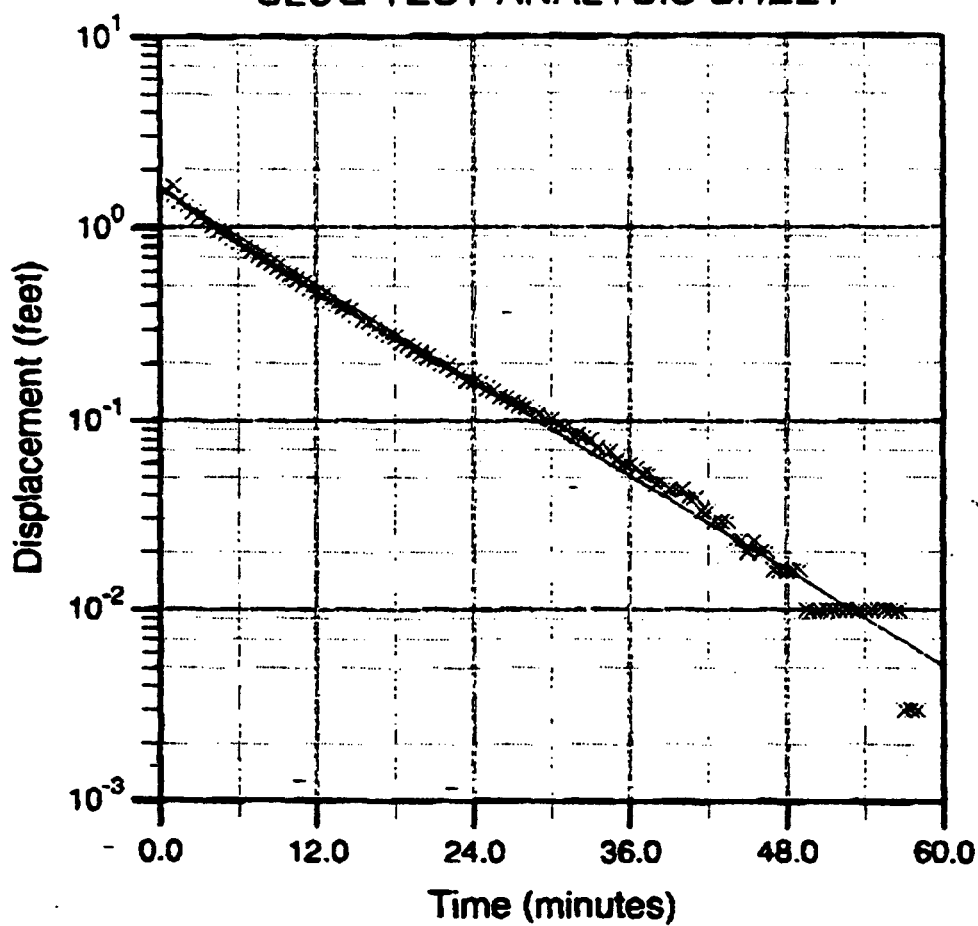
Displacement, Radii, Length, and Thickness are in feet.

A, B, & C are variables used in the Bouwer and Rice method and are calculated by Aquifer Win32.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

SLUG TEST ANALYSIS SHEET



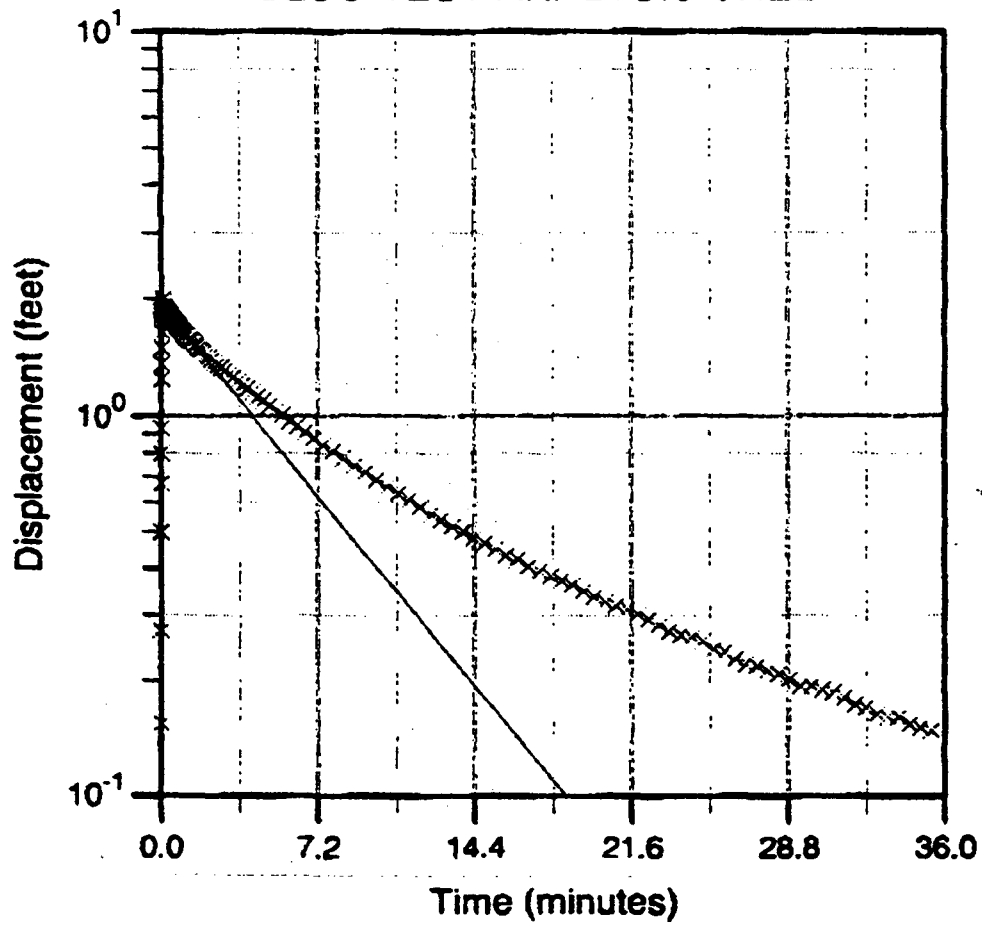
Hydraulic Conductivity 0.187029 ft/d

Site Name Plant Smith

Area Name CT 1S

Test Designator CT1SOUT

SLUG TEST ANALYSIS SHEET



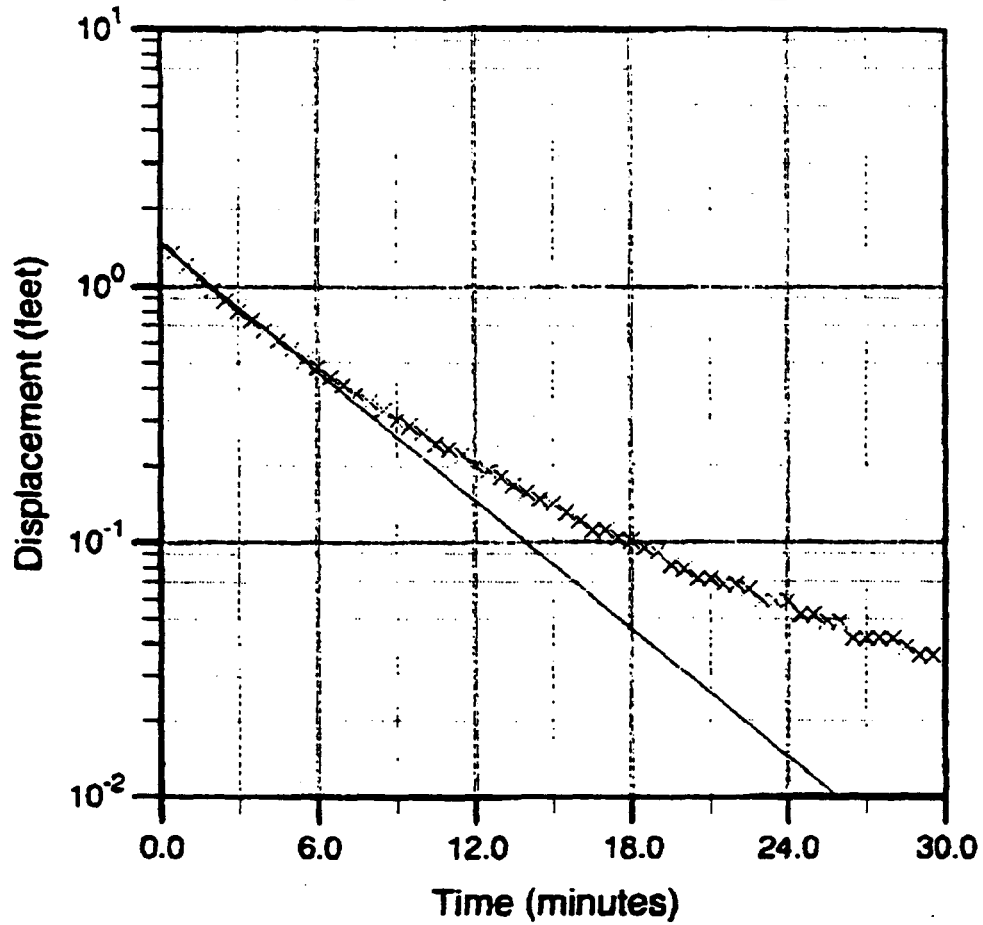
Hydraulic Conductivity 0.314953 ft/d

Site Name Plant Smith

Area Name CT 1S

Test Designator CT1SIN

SLUG TEST ANALYSIS SHEET



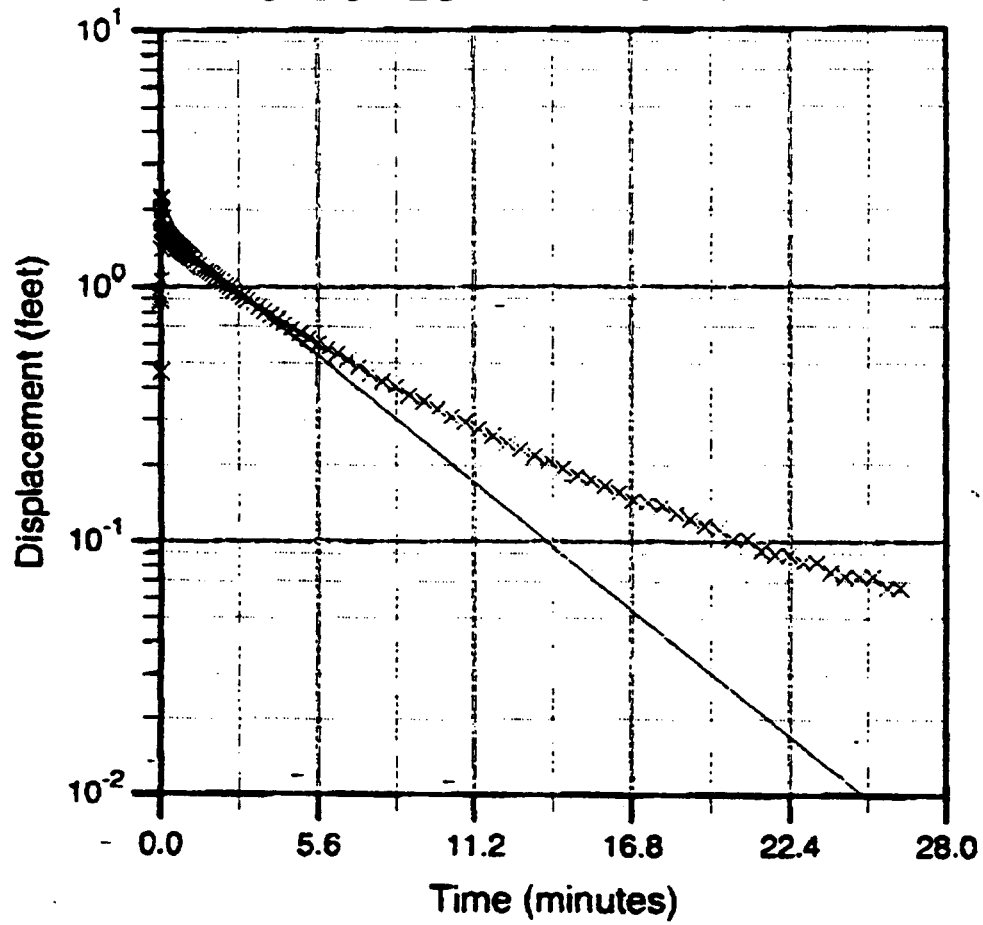
Hydraulic Conductivity 0.379337 ft/d

Site Name Plant Smith

Area Name CT 2S

Test Designator CT2SOUT2

SLUG TEST ANALYSIS SHEET



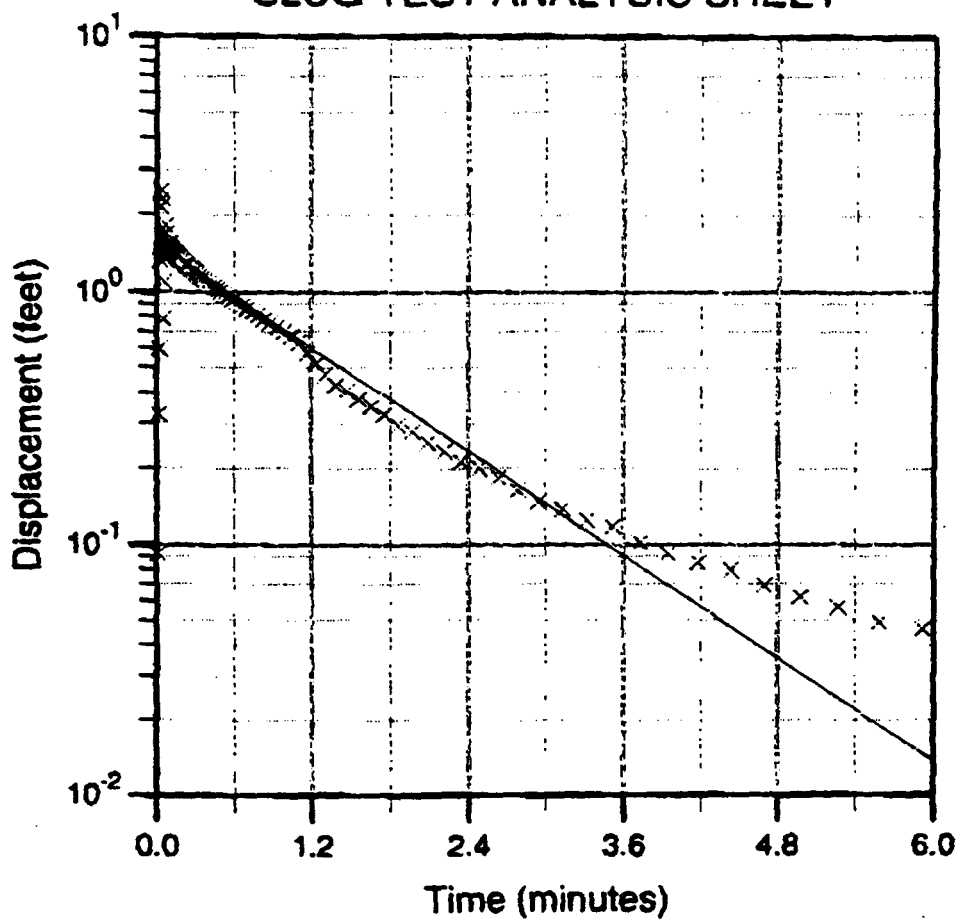
Hydraulic Conductivity 0.402896 ft/d

Site Name Plant Smith

Area Name CT 2S

Test Designator CT2SIN2

SLUG TEST ANALYSIS SHEET



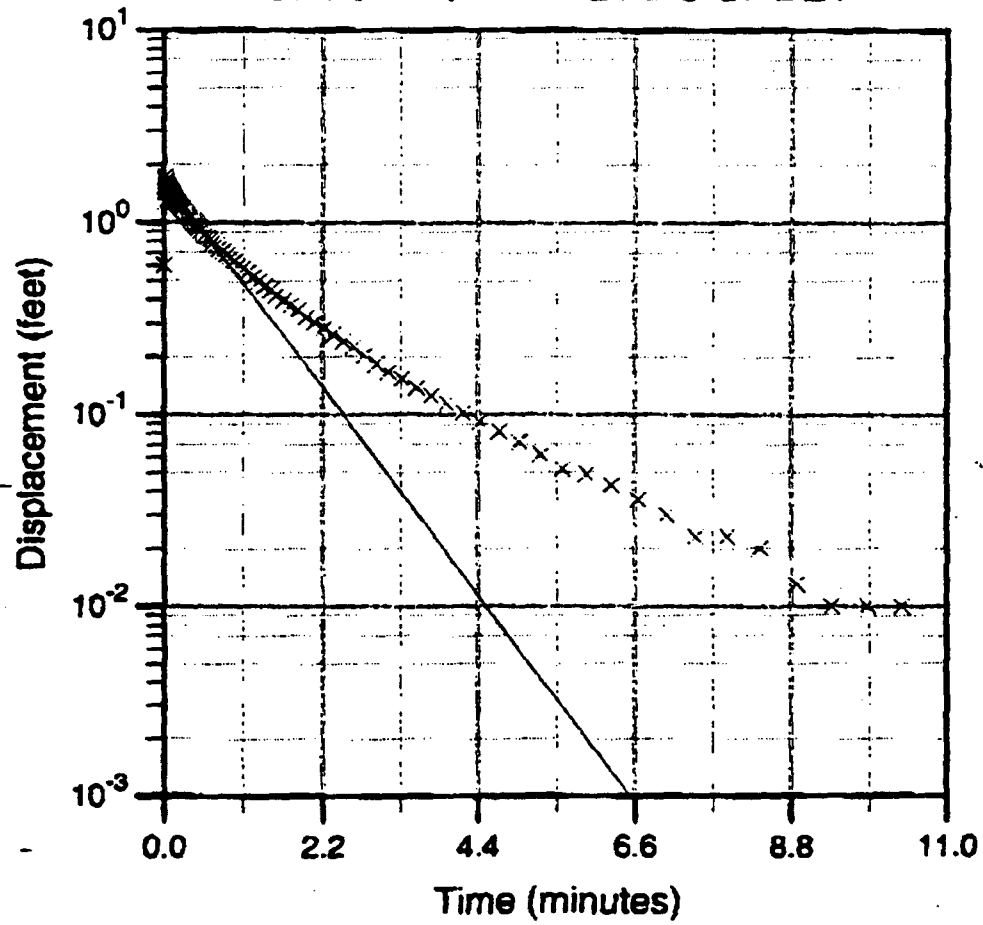
Hydraulic Conductivity 1.5474 ft/d

Site Name Plant Smith

Area Name CT 5S

Test Designator CT5SIN1

SLUG TEST ANALYSIS SHEET



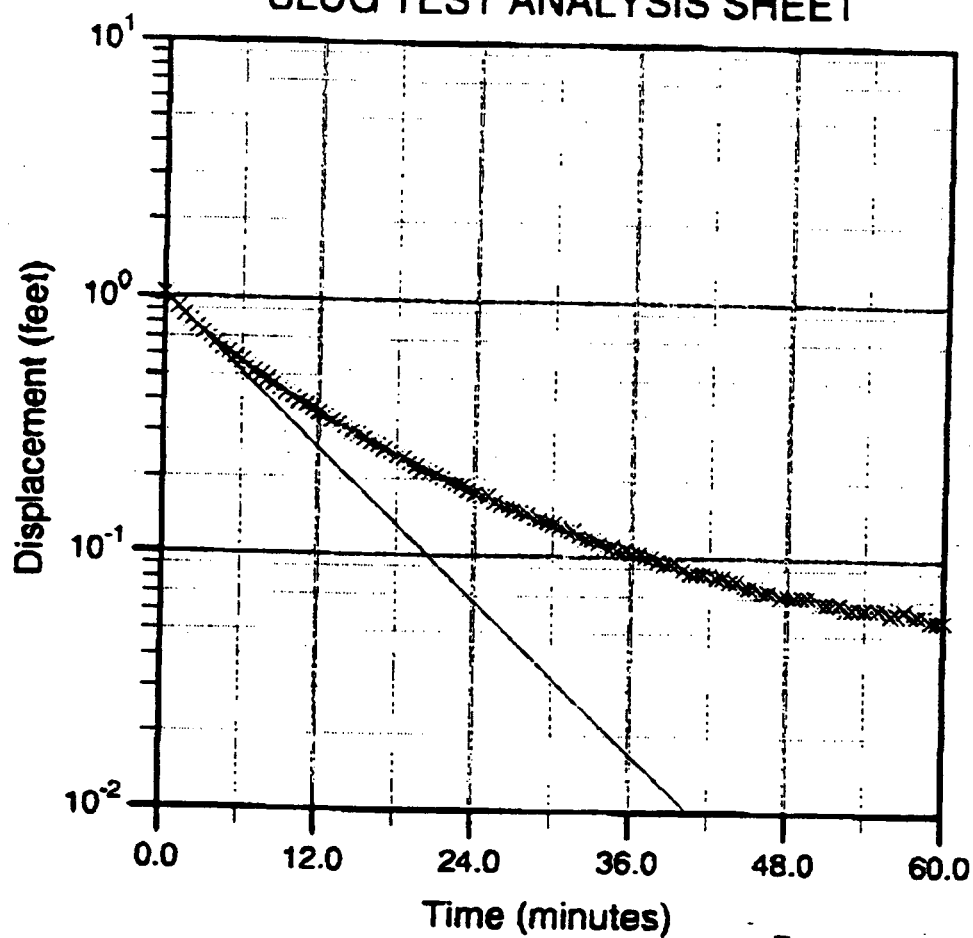
Hydraulic Conductivity 2.23844 ft/d

Site Name Plant Smith

Area Name CT 5S

Test Designator CT5SOUT1

SLUG TEST ANALYSIS SHEET



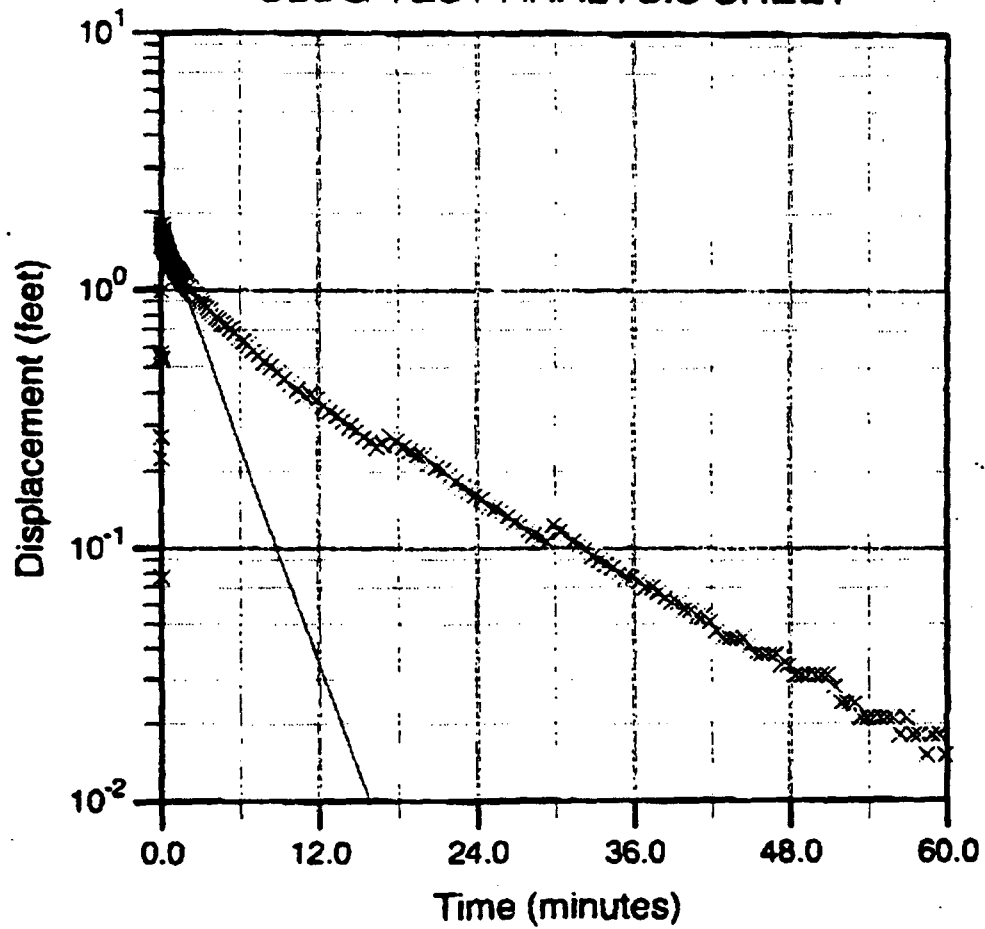
Hydraulic Conductivity 0.224284 ft/d

Site Name Plant Smith

Area Name CT 6S

Test Designator CT6SOUT1

SLUG TEST ANALYSIS SHEET



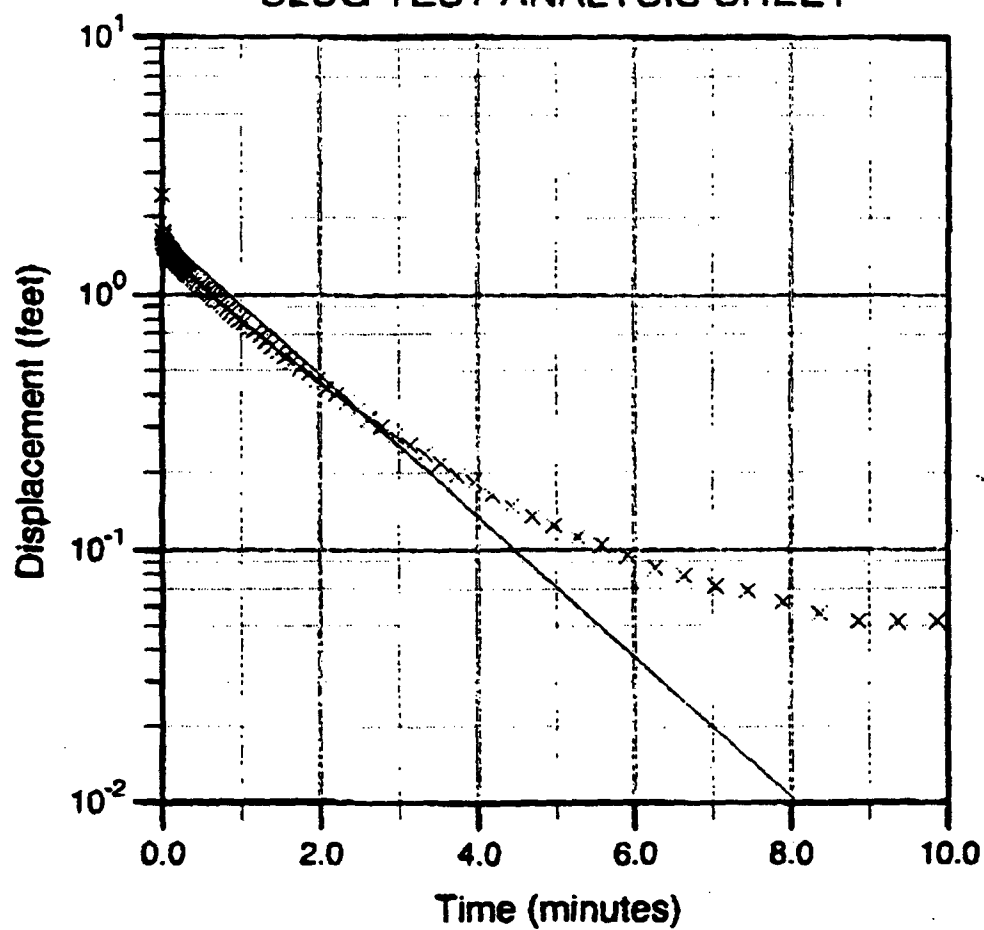
Hydraulic Conductivity 0.646379 ft/d

Site Name Plant Smith

Area Name CT 6S

Test Designator CT6SIN1

SLUG TEST ANALYSIS SHEET



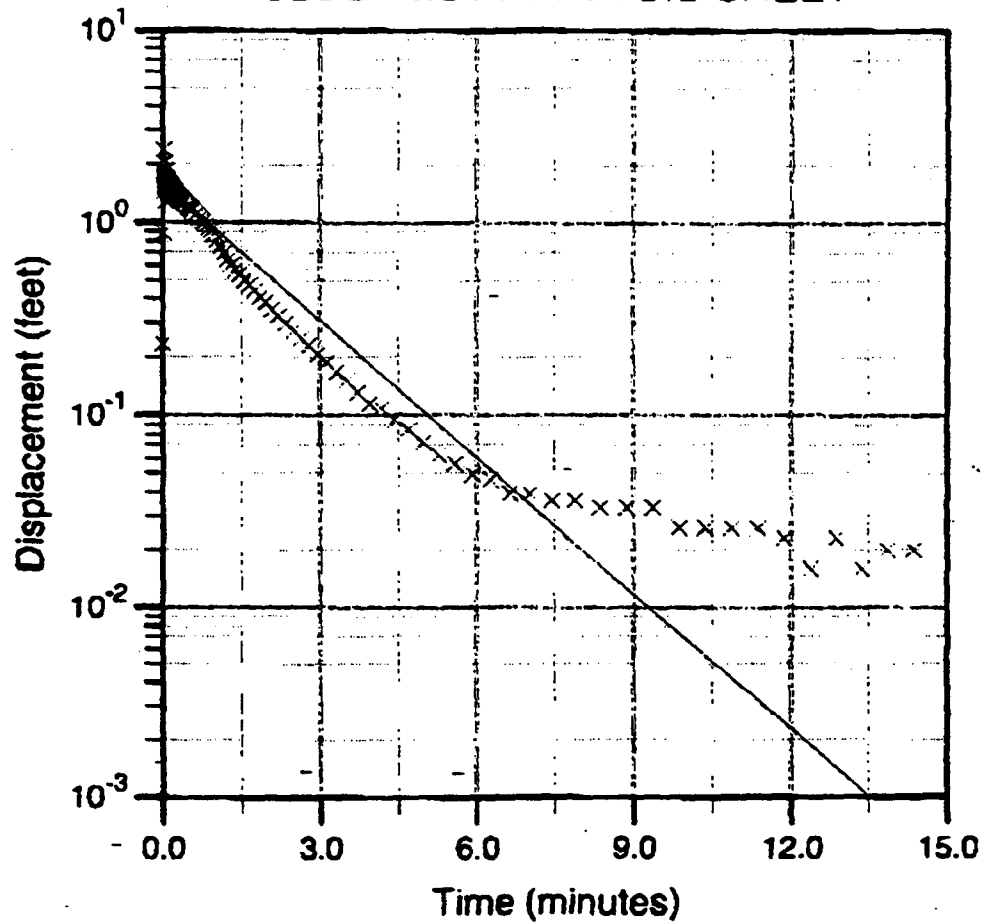
Hydraulic Conductivity 1.25048 ft/d

Site Name Plant Smith

Area Name CT 7S

Test Designator CT7SOUT2

SLUG TEST ANALYSIS SHEET



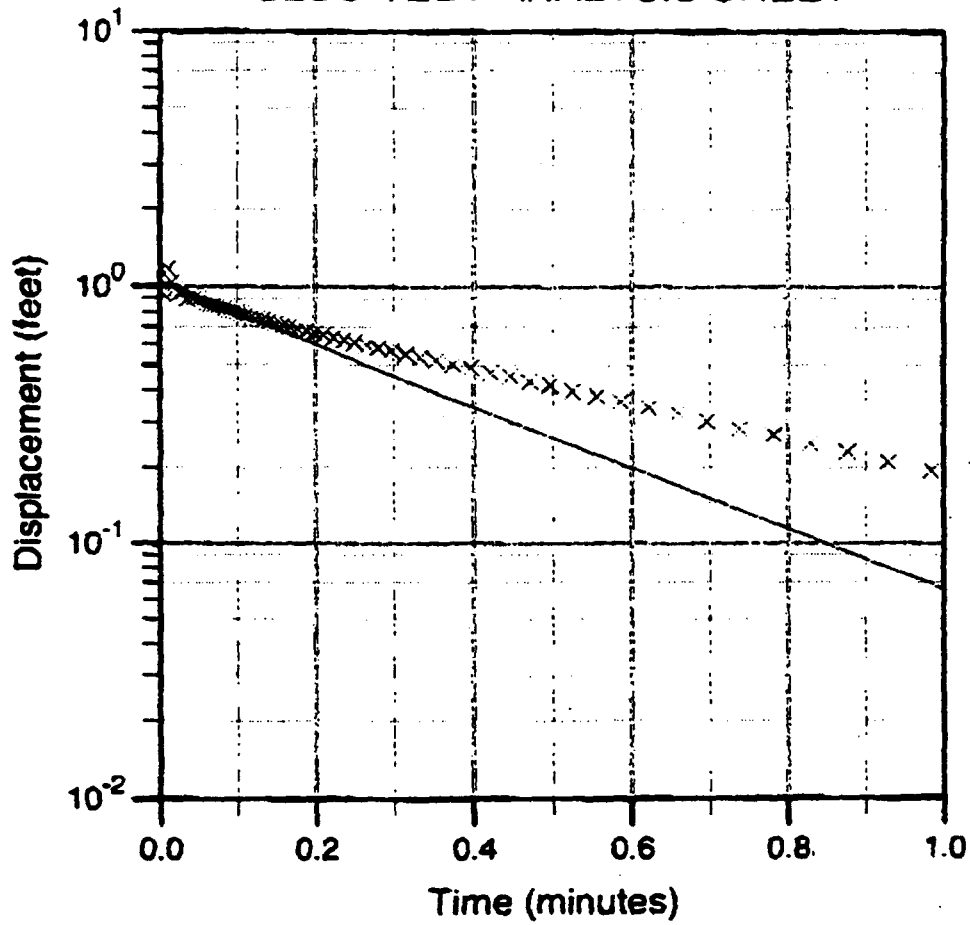
Hydraulic Conductivity 1.07239 ft/d

Site Name Plant Smith

Area Name CT 7S

Test Designator CT7SIN1

SLUG TEST ANALYSIS SHEET



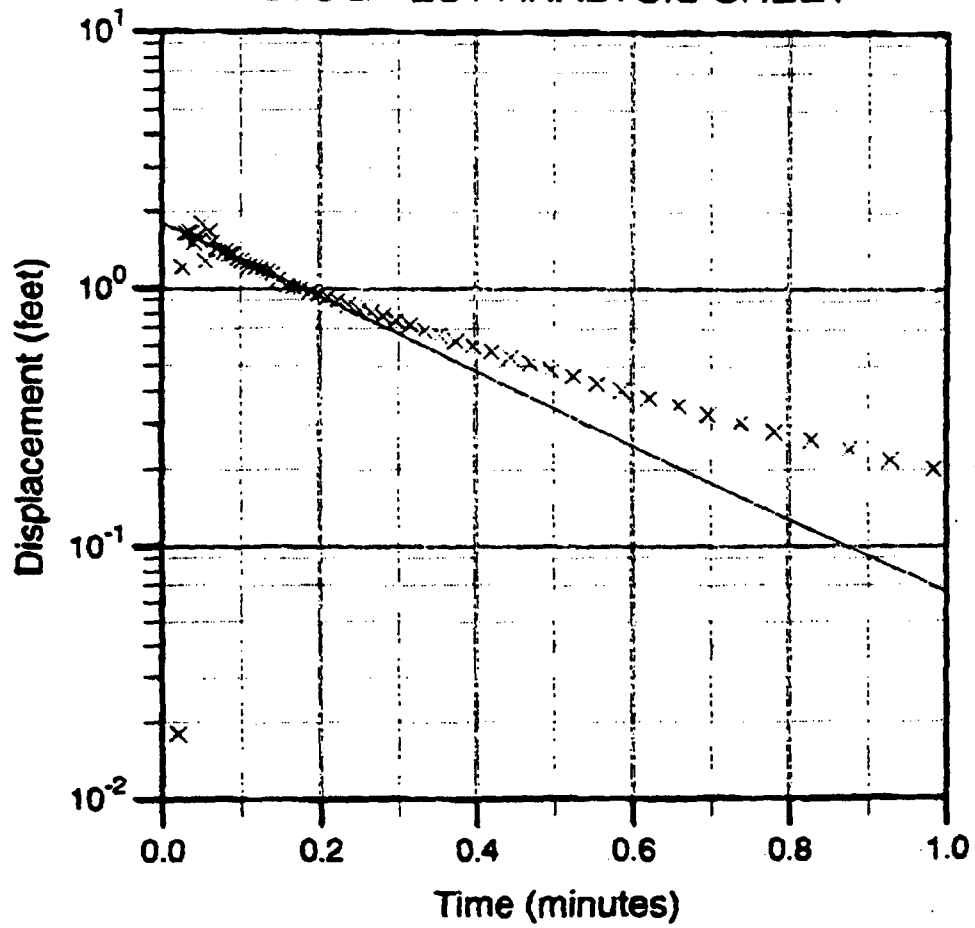
Hydraulic Conductivity 5.13661 ft/d

Site Name Plant Smith

Area Name CT 1D

Test Designator CT1DOUT1

SLUG TEST ANALYSIS SHEET



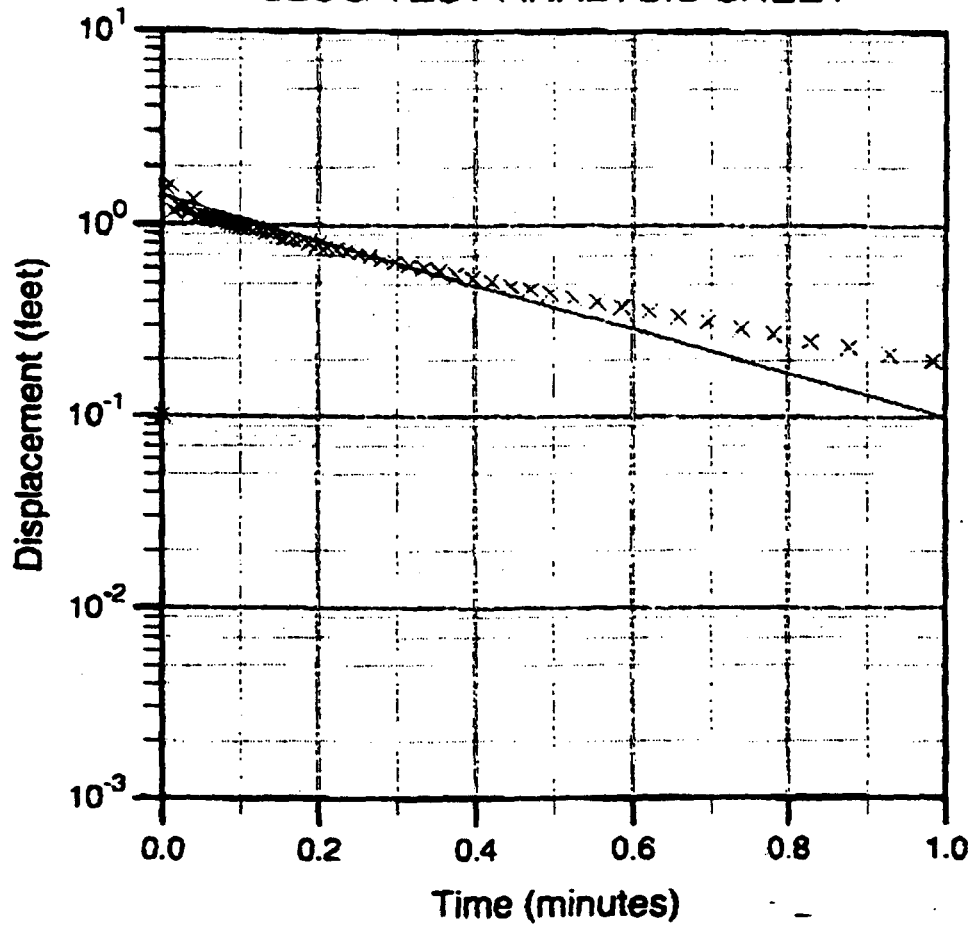
Hydraulic Conductivity 6.17934 ft/d

Site Name Plant Smith

Area Name CT 1D

Test Designator CT1DIN1

SLUG TEST ANALYSIS SHEET



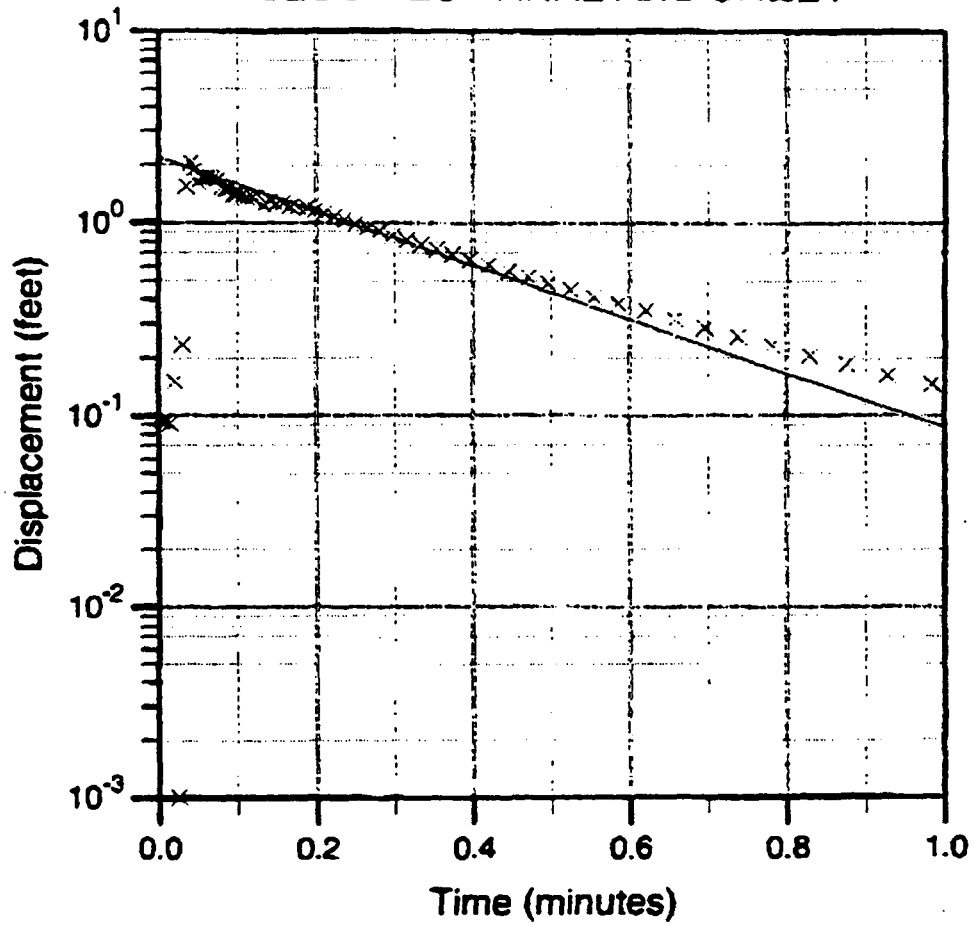
Hydraulic Conductivity 4.93489 ft/d

Site Name Plant Smith

Area Name CT 5D

Test Designator CT5DOUT1

SLUG TEST ANALYSIS SHEET



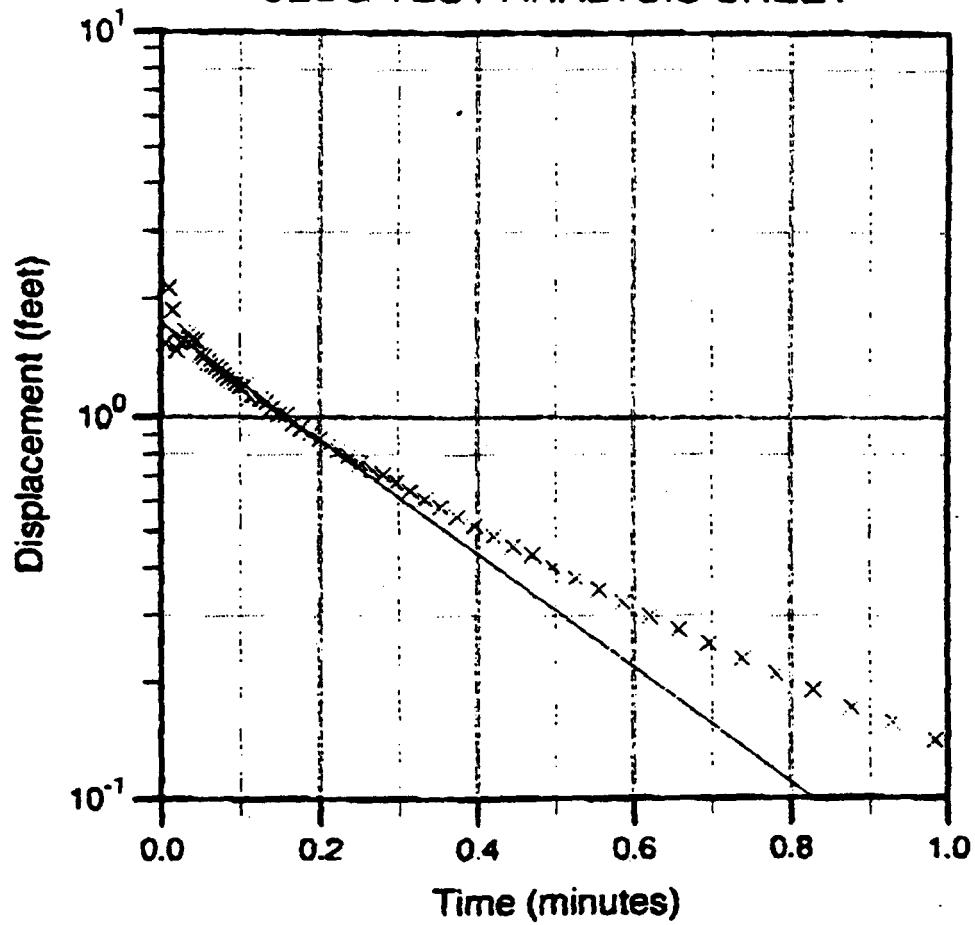
Hydraulic Conductivity 6.0077 ft/d

Site Name Plant Smith

Area Name CT 5D

Test Designator CT5DIN1

SLUG TEST ANALYSIS SHEET



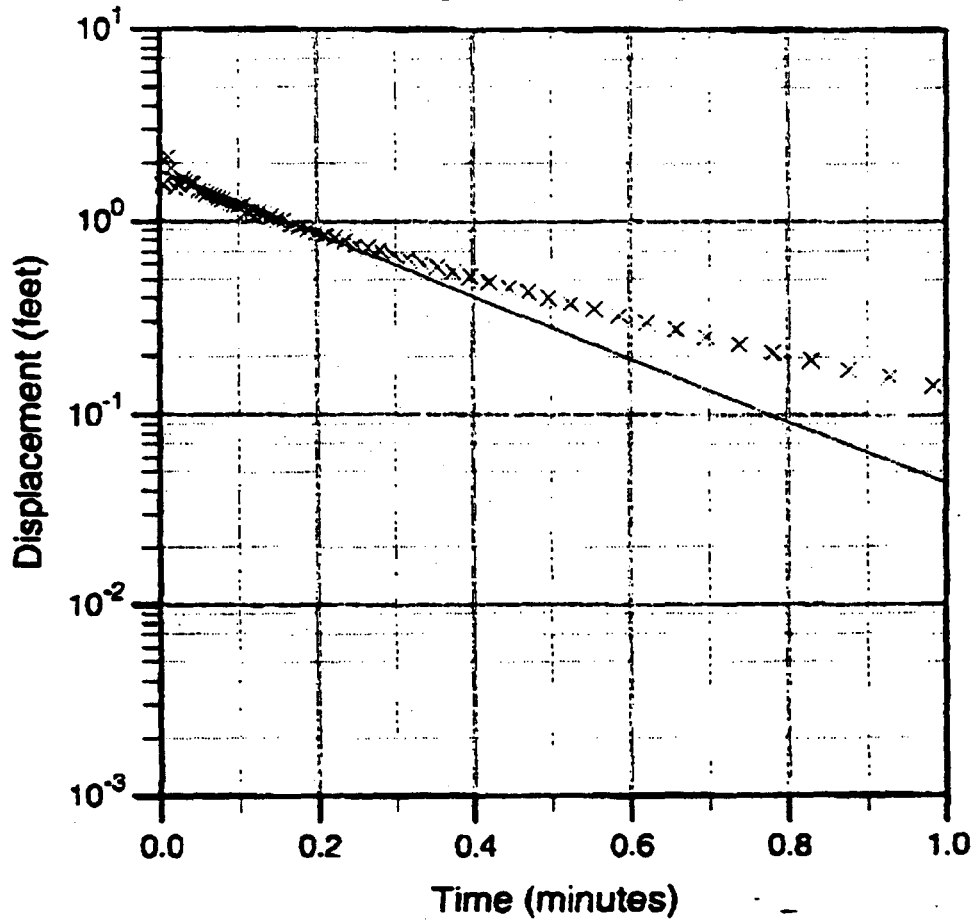
Hydraulic Conductivity 6.43127 ft/d

Site Name Plant Smith

Area Name CT 7D

Test Designator CT7DOUT1

SLUG TEST ANALYSIS SHEET



Hydraulic Conductivity 6.95176 ft/d

Site Name Plant Smith

Area Name CT 7D

Test Designator CT7DIN1

ATTACHMENT 10.5-F
SOILS ANALYSIS

**SOUTHERN COMPANY
CENTRAL LABORATORY**



Southern Company Services
Gulf Power Company
Plant Smith CT Site Investigation

May 5, 1999

Ms. Rhonda Tinsley

Mr. Ray Halbert
Southern Company

Enclosed are the test results for the soil samples delivered to the Southern Company, Central Laboratory on April 9, 1999. Performed test included Gradation (ASTM D-422), Wash #200 (ASTM D-1140), and Falling-Head Permeability (EM-LST, Appendix VII).

Laboratory soil sample #1, represents a UD sample material from Plant Smith, from a depth of 13.0' to 15.0'. This sample was classified as probable gray silty sand material or a SM by the Unified Soil Classification System or an A-4 (0.0) by the AASHTO System. The average Coefficient of Permeability using the Falling-Head Permeability Method was 1.3×10^{-6} cm. per sec. Gradation was as follows:

Sieve Analysis

<u>Sieve Size:</u>	<u>% Passing:</u>
#4	100.0
#8	99.8
#10	99.3
#16	97.6
#30	88.2
#40	77.3
#50	69.7
#100	55.3
#200	40.7

Laboratory soil sample #2, represents a Split-Spoon sample material from Plant Smith, from a depth of 95.0' to 97.0'. This sample was classified as probable gray silt material or an ML by the Unified Soil Classification System or an A-4 (0.0) by the AASHTO System. The dry density was 85.6 pcf, wet density was 118.5 pcf, % moisture was 38.5%. The average Coefficient of Permeability using the Falling-Head Permeability Method was 5.8×10^{-7} cm. per sec. This sample was remolded at 97% of in-situ dry density at 38.5% moisture. Gradation was as follows:

Sieve Analysis

<u>Sieve Size:</u>	<u>% Passing:</u>
#4	100.0
#8	99.8
#10	99.8
#16	99.6
#30	99.4
#40	99.2
#50	99.0
#100	98.6
#200	97.1

We appreciate the opportunity to assist you on this project. If there are any questions or if we can be of any further assistance, please call at extension (205/664-6266) or 8-255-6266.

Sincerely,

Ray Halbert
Southern Company

2711 West 15th Street
Panama City, FL 32401



Tel: (850) 769-4773
Fax: (850) 872-9967
E-Mail: SES1@Beaches.net

Geotechnical &
Environmental
Consultants

Southern Company
P.O. Box 2625
Birmingham, AL 35202

September 21, 1998
File No: F-98-565

ATTENTION: Mr. Joel Miller

SUBJECT: Lab Testings for Samples from Lansing Smith Plant in Bay County, Florida.

Dear Mr. Miller:

Southern Earth Sciences, Inc., has partially completed the laboratory testing on samples brought to our lab by Mr. Hal Brightling. Attached you will find the results of our grain sizes and -200 sieve analyses. The three (3) hydrometer tests requested have not been completed at this time.

We appreciate the opportunity to be of service to you on this project. Should additional information be required, please advise.

Yours Very Truly,

SOUTHERN EARTH SCIENCES, INC.

A handwritten signature in black ink, appearing to read "James T. Vickers".

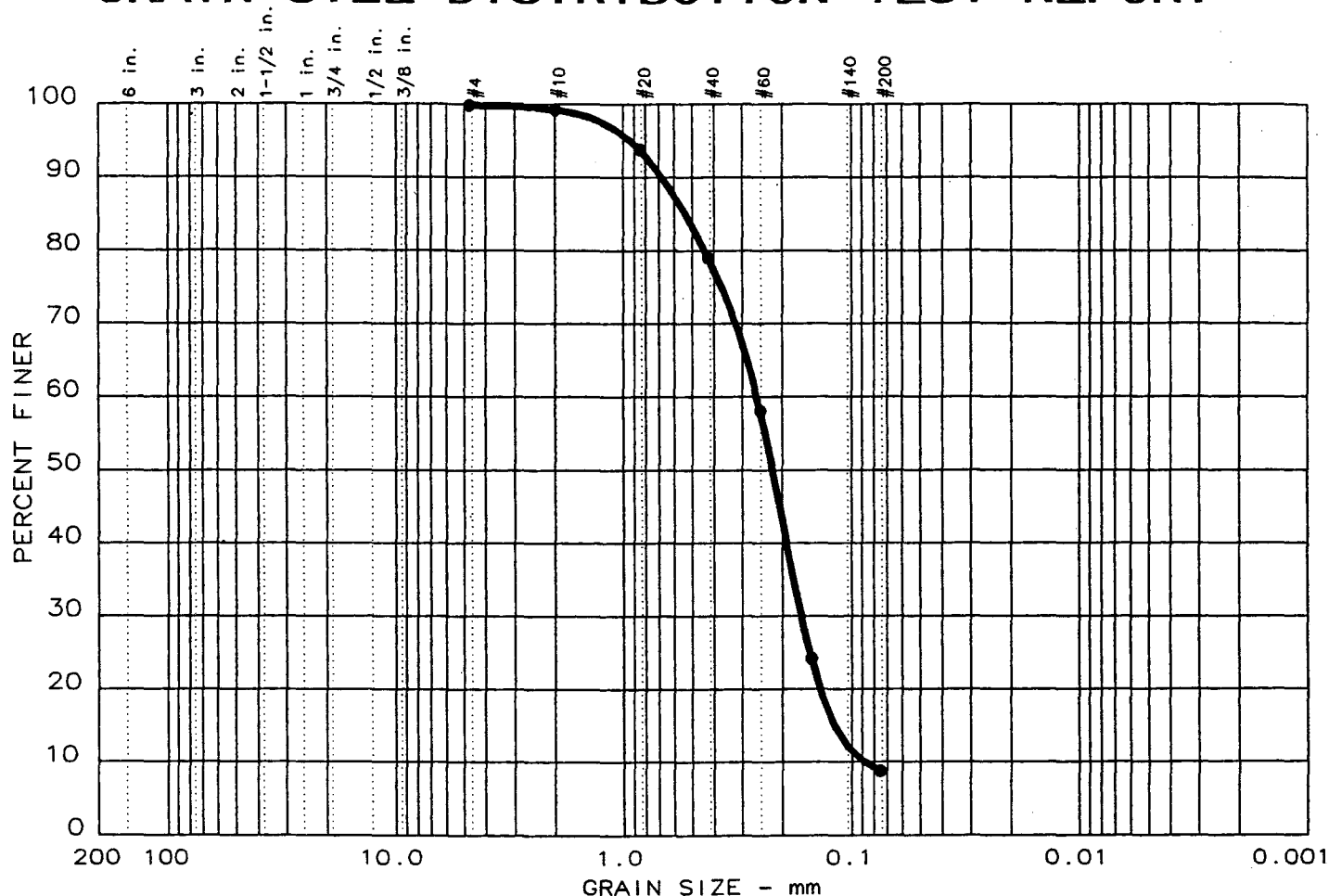
James T. Vickers, E.I.
Staff Engineer

A handwritten signature in black ink, appearing to read "Michael K. Varner".

Michael K. Varner, P.E.
Eng. Reg. No. 15037
State of Florida

9/21/98

GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
6	0.0	0.2	91.1	8.7	

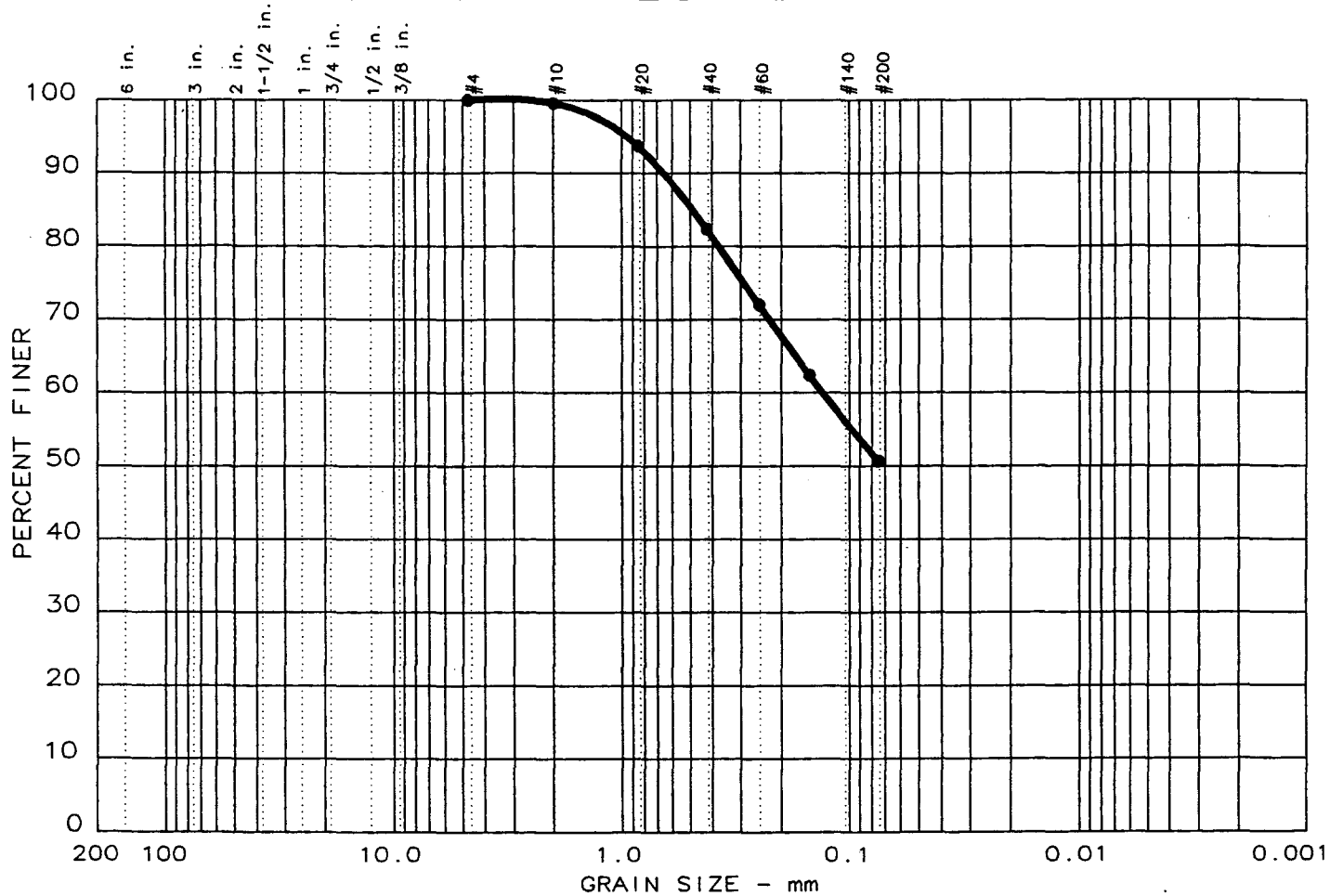
LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
		0.54	0.26	0.22	0.165	0.1184	0.0878	1.21	2.9

MATERIAL DESCRIPTION	USCS	AASHTO
Gray Slightly Silty Fine SAND	SP-SM	A-3

Project No.: F-98-565 Project: Lansing Smith Plant Lab Testing Location: CT-4 8.8 - 10.3 Date: 9/21/98	Remarks:
GRAIN SIZE DISTRIBUTION TEST REPORT SOUTHERN EARTH SCIENCES, INC.	

Figure No. _____

GRAIN SIZE DISTRIBUTION TEST REPORT



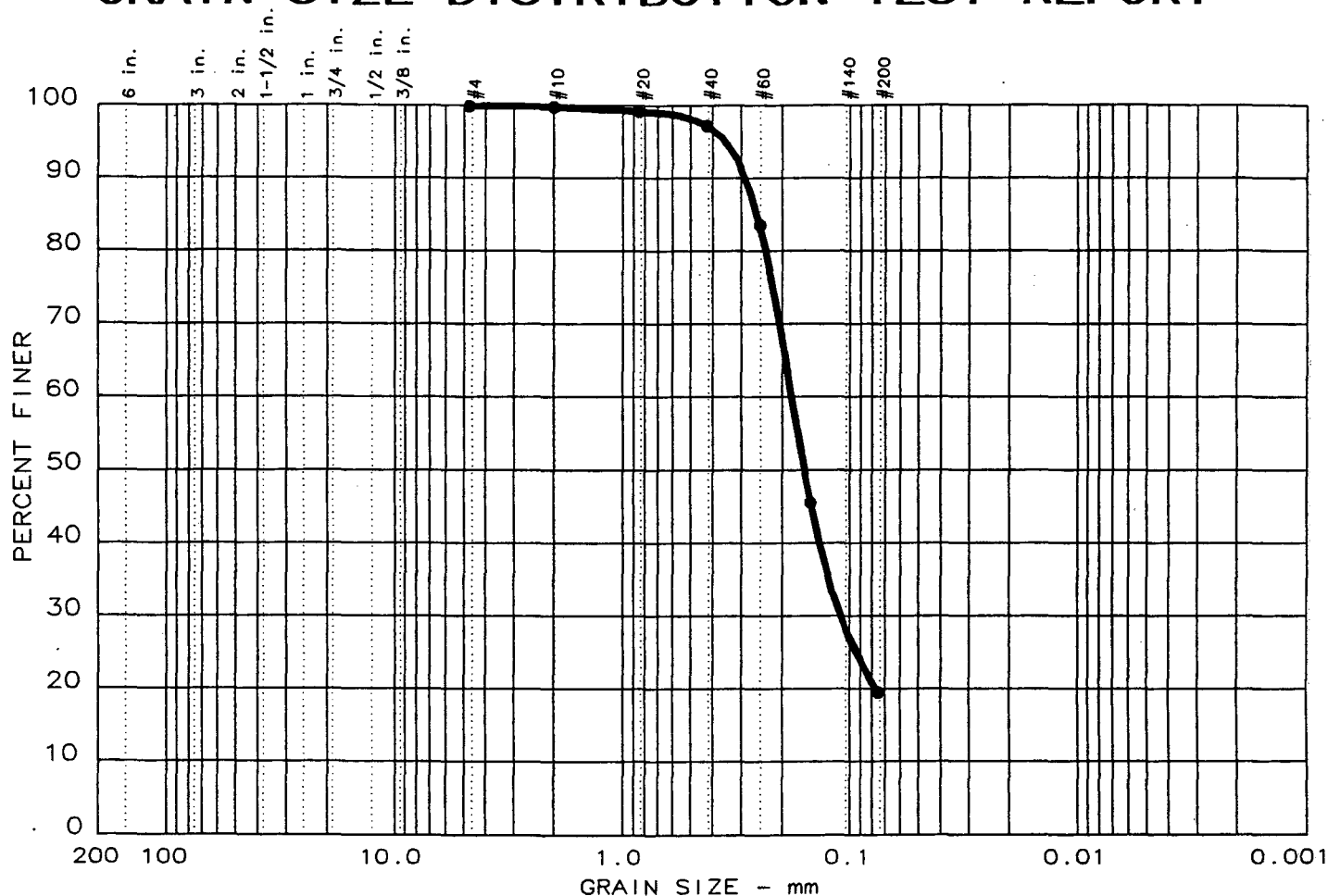
Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
5	0.0	0.0	49.3	50.7	

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
		0.48	0.13						

MATERIAL DESCRIPTION	USCS	AASHTO
Gray Silty Sandy CLAY	ML	A-4

Project No.: F-98-565 Project: Lansing Smith Plant Lab Testing Location: CT-4 18.8 - 20.3 Date: 9/21/98	Remarks: Figure No. _____
GRAIN SIZE DISTRIBUTION TEST REPORT SOUTHERN EARTH SCIENCES, INC.	

GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
• 4	0.0	0.1	80.4	19.5	

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
•		0.26	0.18	0.16	0.110				

MATERIAL DESCRIPTION	USCS	AASHTO
• Gray Silty Fine SAND	SM	A-2-4

Project No.: F-98-565
 Project: Lansing Smith Plant Lab Testing
 • Location: CT-4 33.8 - 35.3

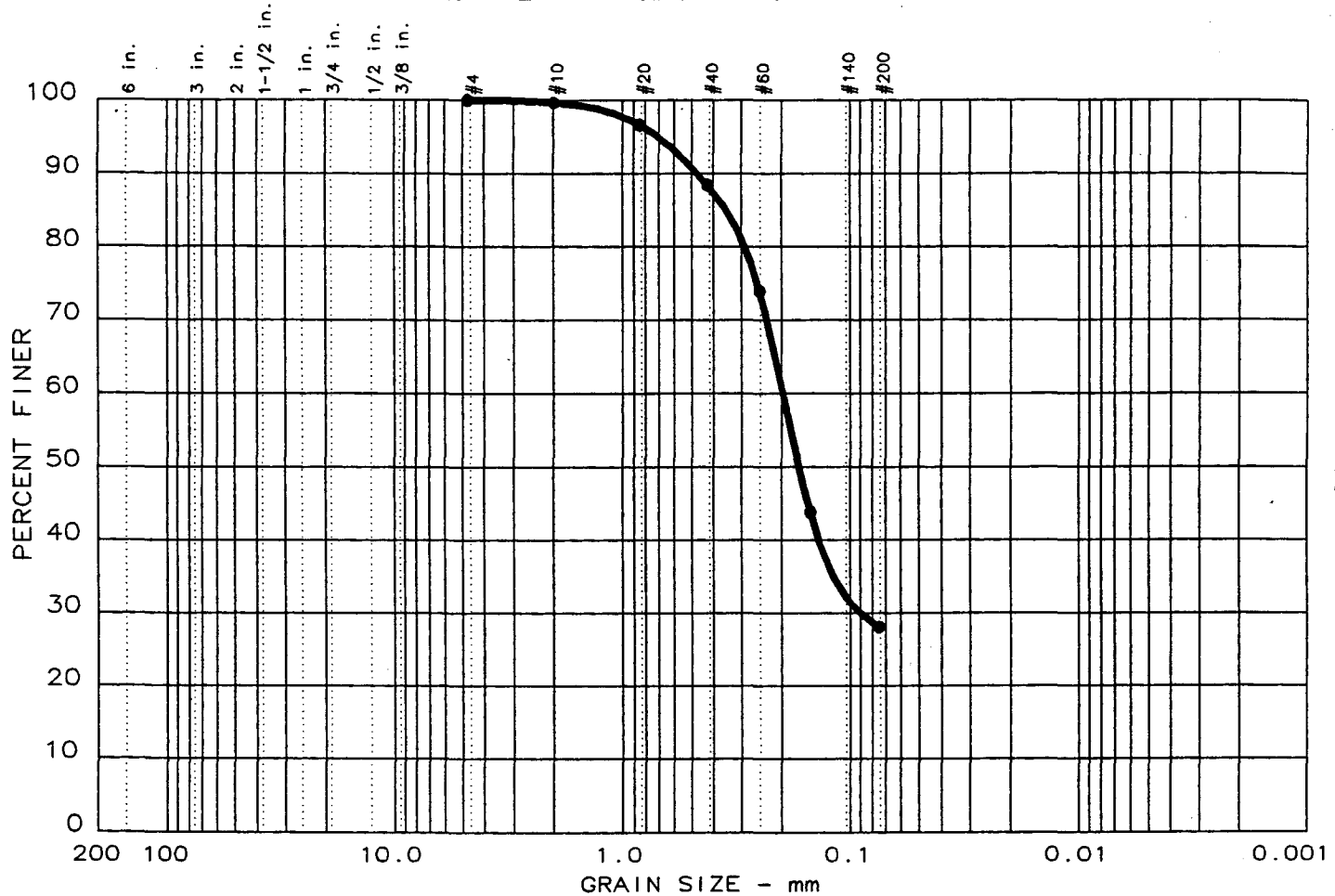
Date: CT-4

Remarks:

GRAIN SIZE DISTRIBUTION TEST REPORT
SOUTHERN EARTH SCIENCES, INC.

Figure No. _____

GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
● 2	0.0	0.0	71.9	28.1	

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
●		0.35	0.20	0.17	0.090				

MATERIAL DESCRIPTION	USCS	AASHTO
● Gray Silty Fine SAND	SM	A-2-4

Project No.: F-98-565
 Project: Lansing Smith Plant Lab Testing
 ● Location: CT-4 53.8 - 55.3

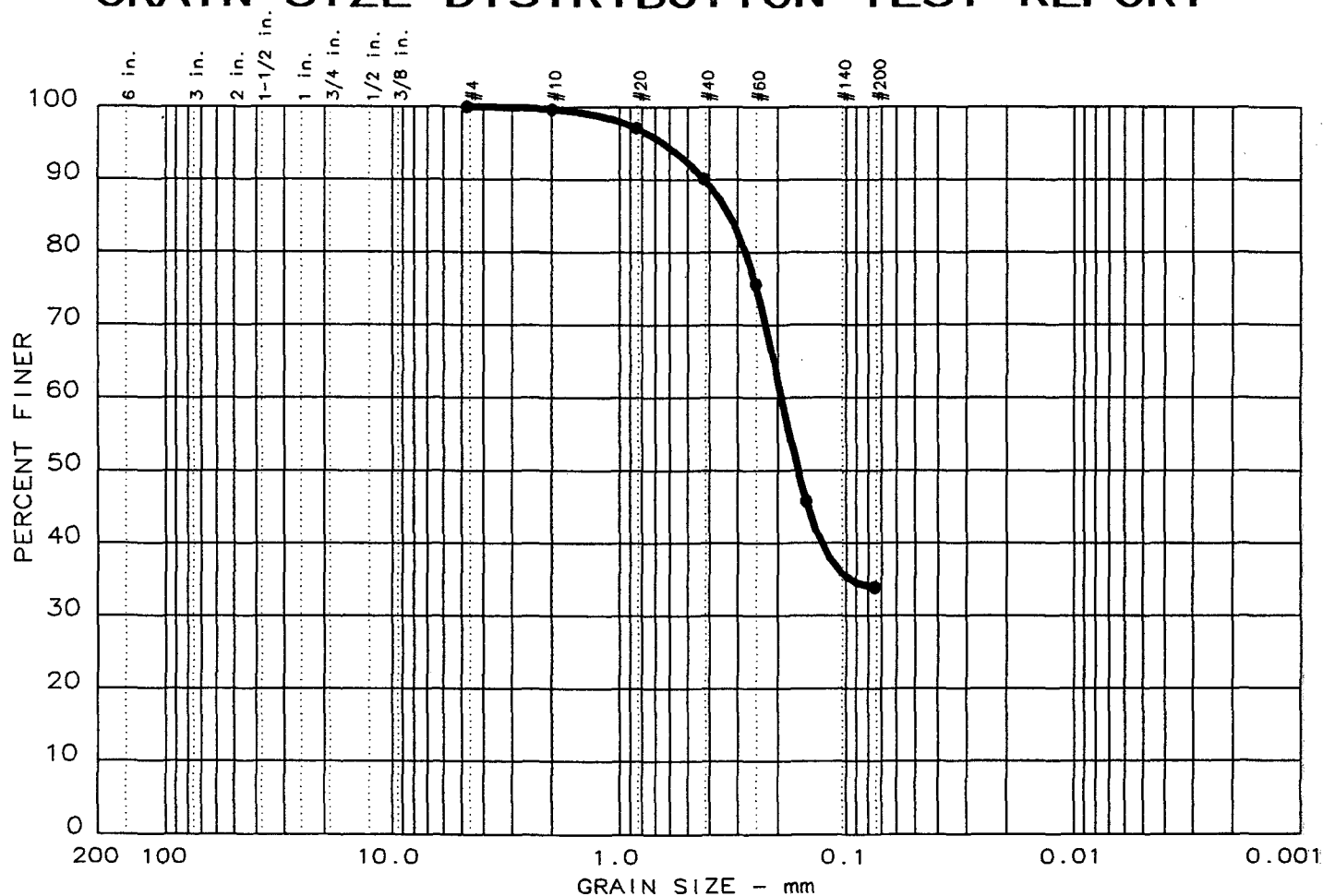
Date: 9/21/98

GRAIN SIZE DISTRIBUTION TEST REPORT
SOUTHERN EARTH SCIENCES, INC.

Remarks:

Figure No. _____

GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
1	0.0	0.0	66.1	33.9	

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
		0.32	0.19	0.16					

MATERIAL DESCRIPTION	USCS	AASHTO
Gray Silty Fine SAND	SM	A-2-4

Project No.: F-98-565
 Project: Lansing Smith Plant Lab Testing
 Location: CT-4 78.8 - 80.3

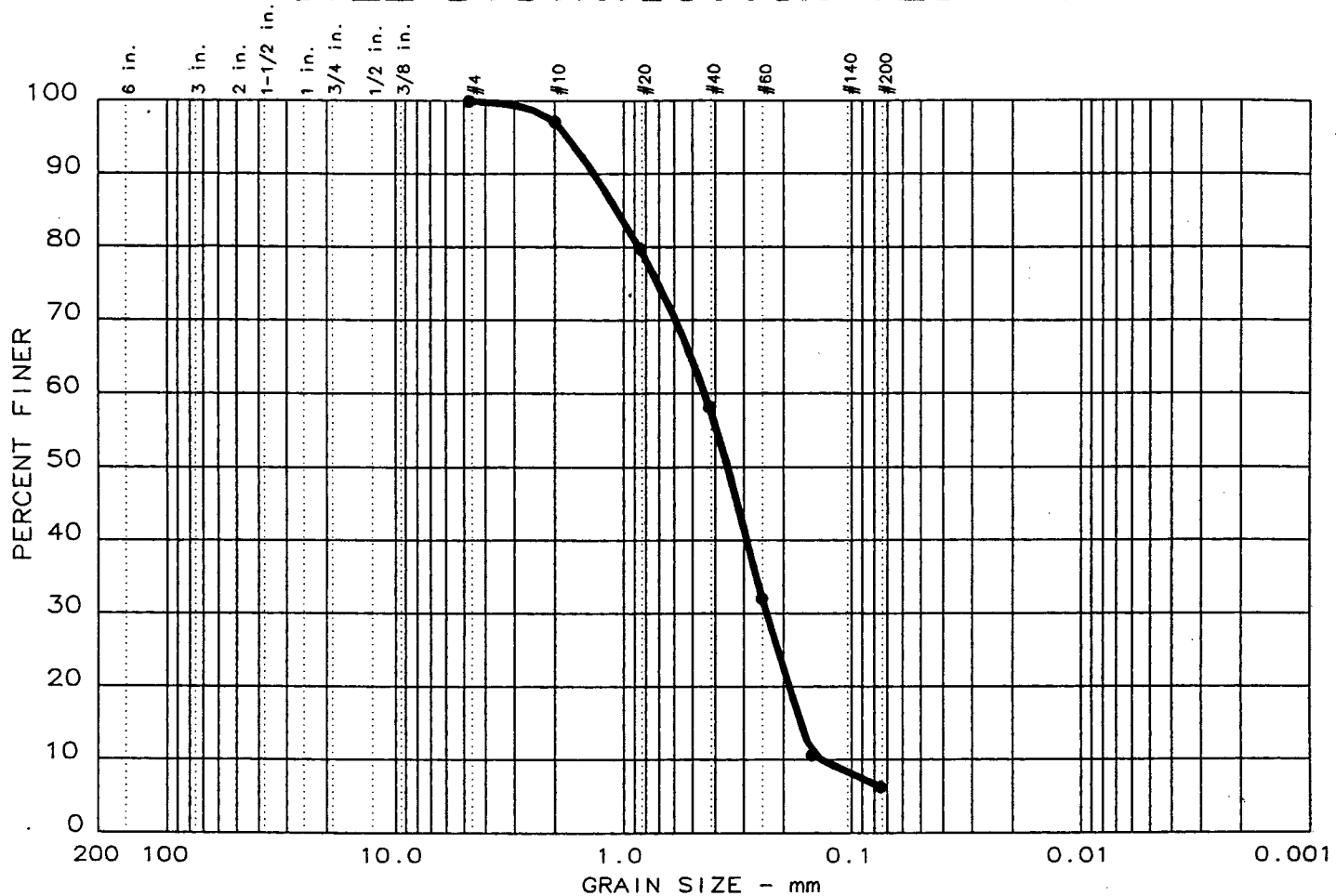
Date: 9/21/98

GRAIN SIZE DISTRIBUTION TEST REPORT
SOUTHERN EARTH SCIENCES, INC.

Remarks:

Figure No. _____

GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
• 11	0.0	0.1	93.7	6.2	

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
•		1.07	0.44	0.35	0.238	0.1663	0.1337	0.95	3.3

MATERIAL DESCRIPTION	USCS	AASHTO
• Gray Slightly Silty Fine SAND	SP-SM	A-3

Project No.: F-98-565
 Project: Lansing Smith Plant Lab Testing
 • Location: CT-5 8-8 - 10.4

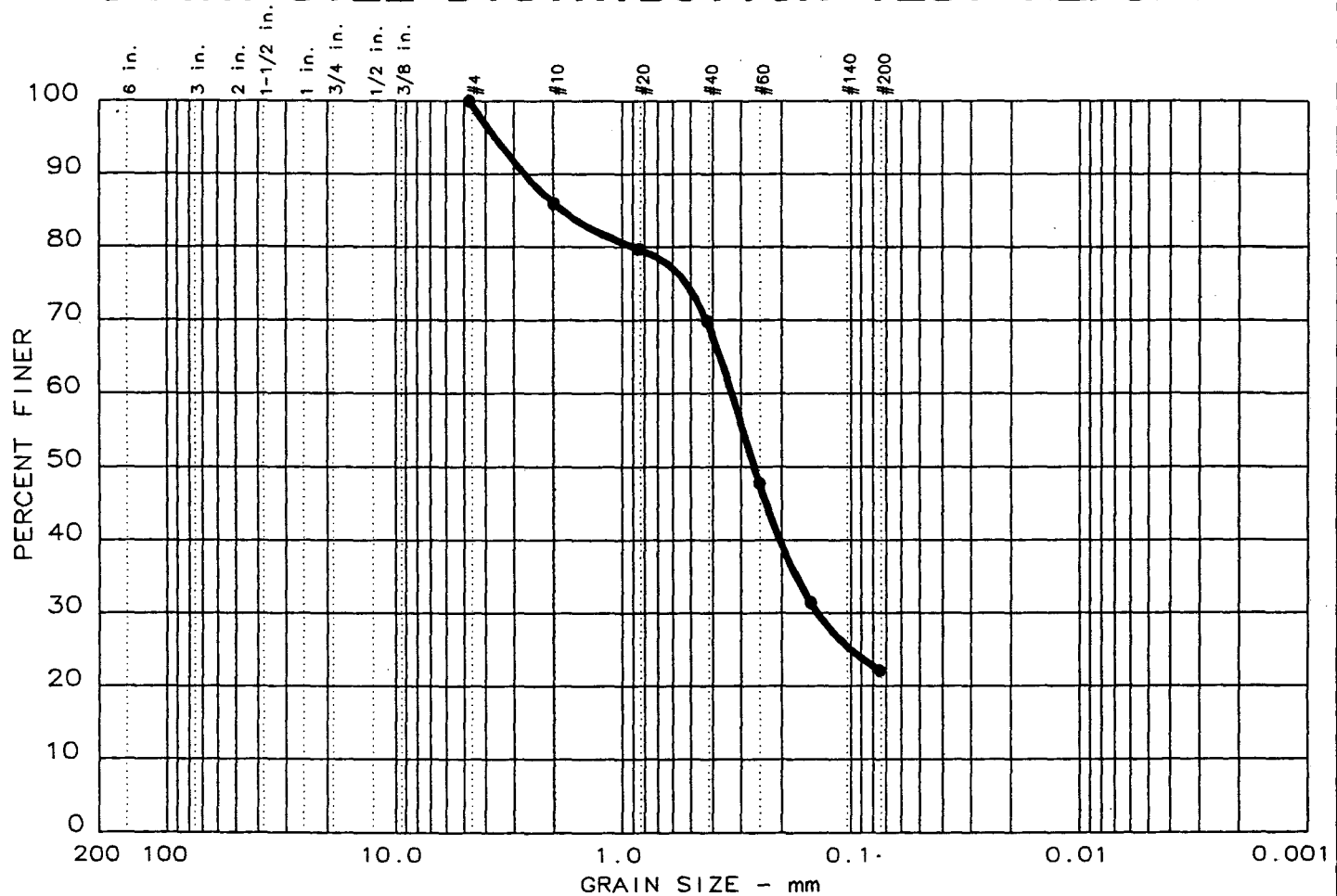
Date: 9/21/98

GRAIN SIZE DISTRIBUTION TEST REPORT
SOUTHERN EARTH SCIENCES, INC.

Remarks:

Figure No. _____

GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
9	0.0	0.0	77.8	22.2	

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
		1.82	0.33	0.26	0.140				

MATERIAL DESCRIPTION	USCS	AASHTO
Gray Silty Fine SAND	SM	A-2-4

Project No.: F-98-565
 Project: Lansing Smith Plant Lab Testing
 Location: CT-5 28.8 - 30.3

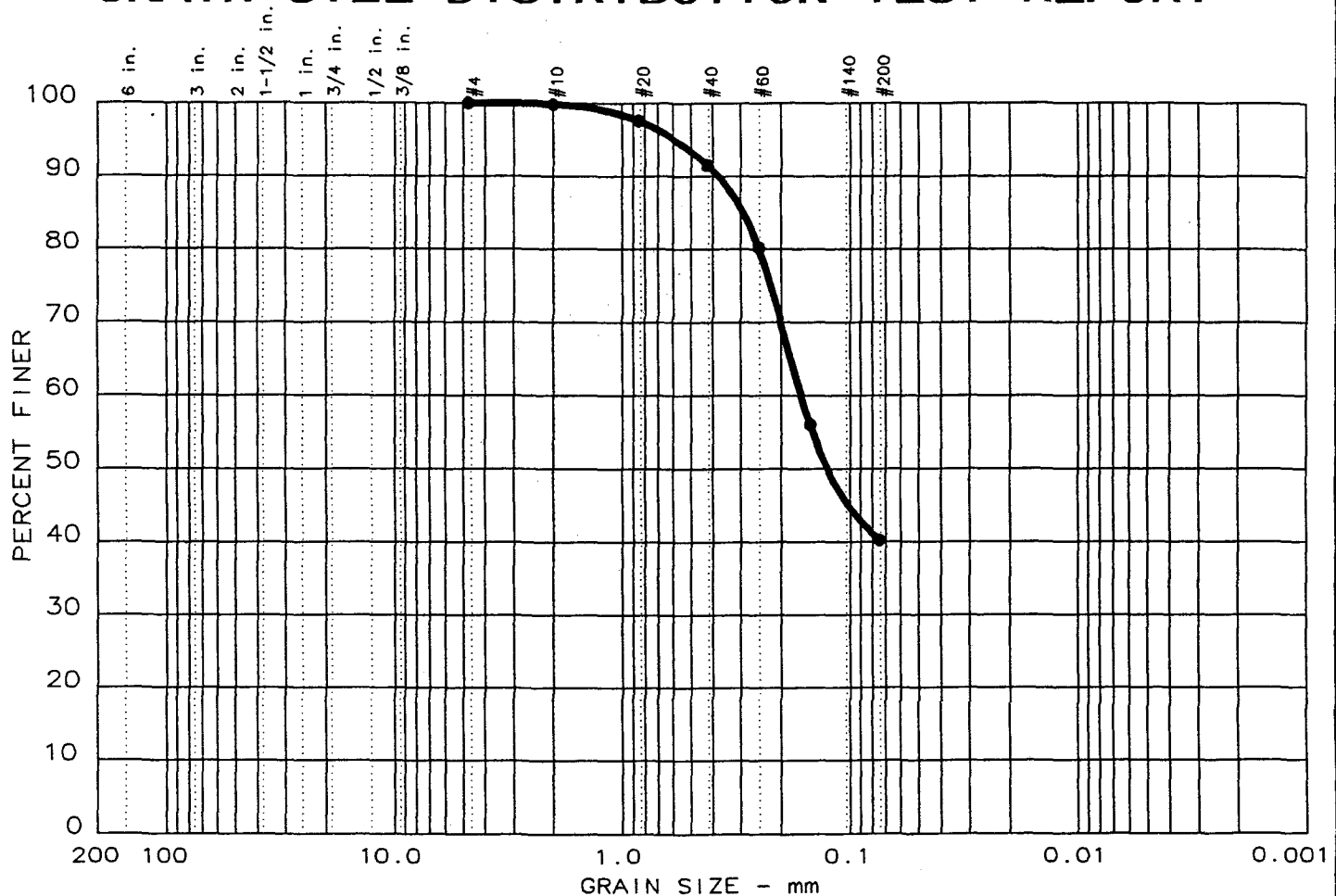
Date: 9/21/98

GRAIN SIZE DISTRIBUTION TEST REPORT
SOUTHERN EARTH SCIENCES, INC.

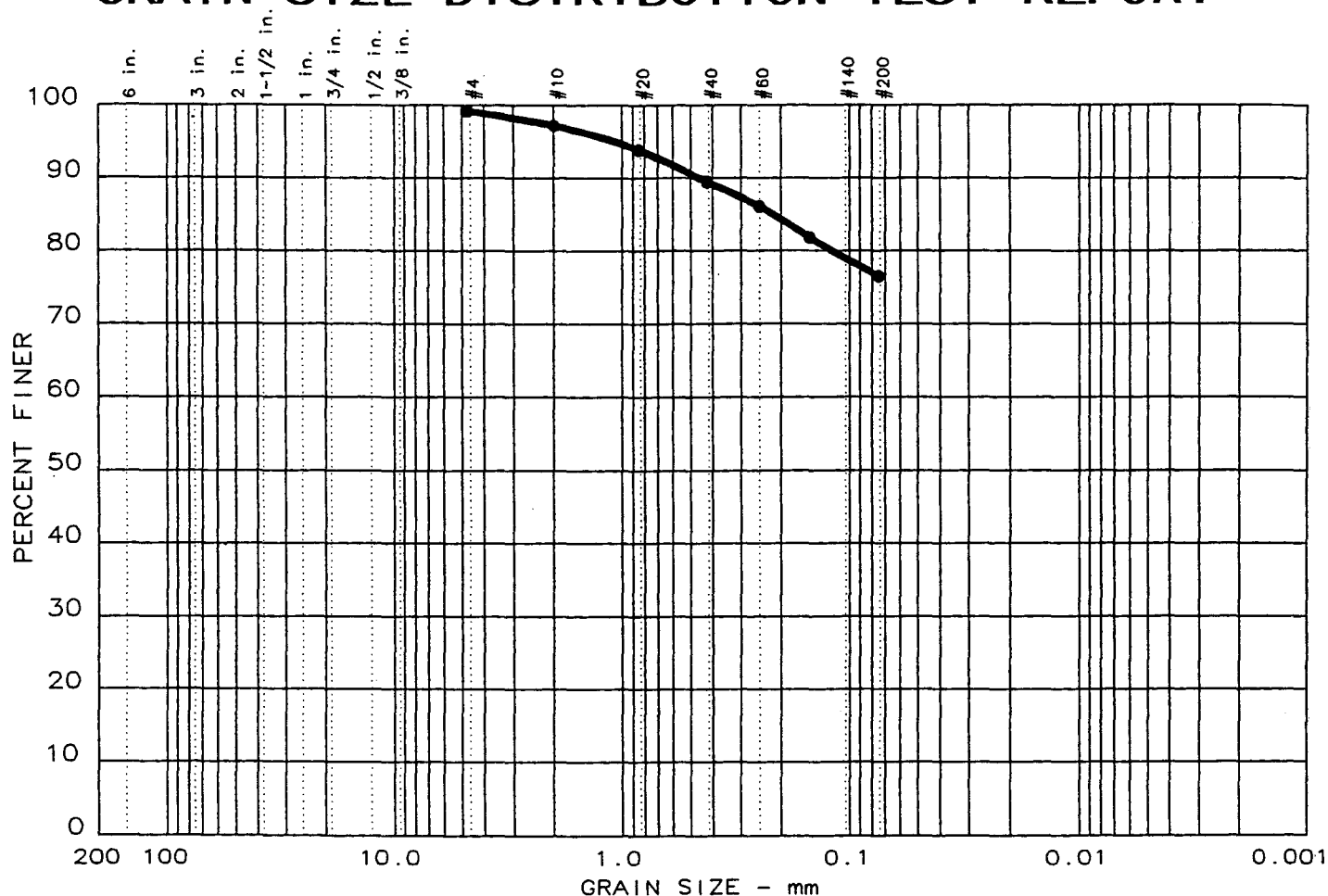
Remarks:

Figure No. _____

GRAIN SIZE DISTRIBUTION TEST REPORT



GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
7	0.0	0.8	22.7	76.5	

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
		0.22							

MATERIAL DESCRIPTION	USCS	AASHTO
Gray Silty Sandy CLAY	ML	A-4

Project No.: F-98-565
 Project: Lansing Smith Plant Lab Testing
 • Location: CT-5 93.8 - 95.3

Date: 9/21/98

Remarks:

GRAIN SIZE DISTRIBUTION TEST REPORT
SOUTHERN EARTH SCIENCES, INC.

Figure No. _____

Panama City, FL

2711 West 15th Street
Panama City, FL 32401

SOUTHERN EARTH SCIENCES, inc.



Tel: (850) 769-4773
Fax: (850) 872-9967
E-Mail: SES1@Beaches.net

Geotechnical &
Environmental
Consultants

Southern Company
P.O. Box 2625
Birmingham, AL 35202

September 25, 1998
File No: F-98-565

ATTENTION: Mr. Joel Miller

SUBJECT: Lab Testings for Samples from Lansing Smith Plant in Bay County, Florida.

Dear Mr. Miller:

Southern Earth Sciences, Inc., has completed the laboratory testing on samples brought to our lab by Mr. Hal Breightling. Attached is a copy of the results from the three (3) hydrometer tests.

We appreciate the opportunity to be of service to you on this project. Should additional information be required, please advise.

Yours Very Truly,

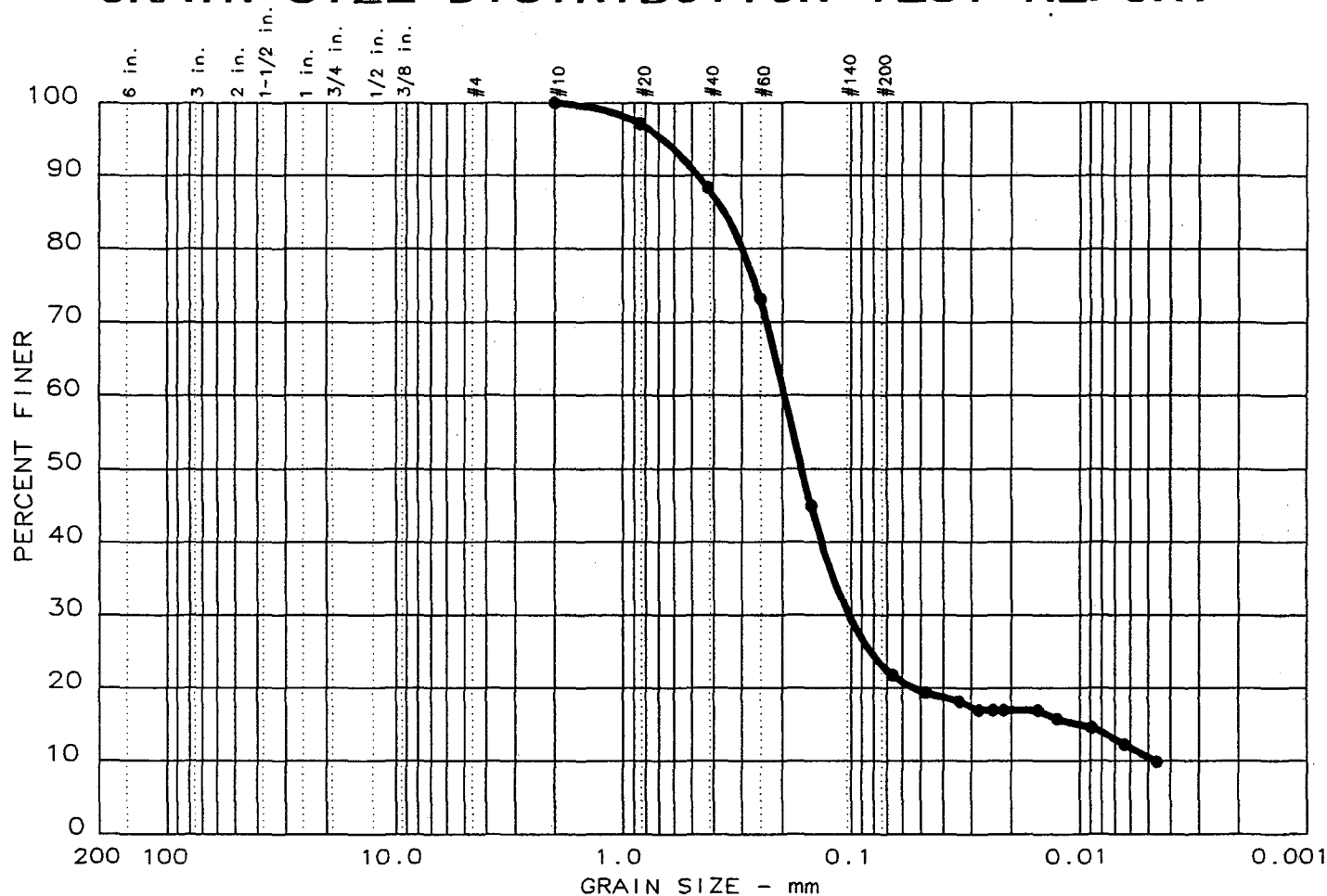
SOUTHERN EARTH SCIENCES, INC.

James T. Vickers, E.I.
Staff Engineer

Michael K. Varner, P.E.
Eng. Reg. No. 15037
State of Florida

9/25/98

GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
• 14	0.0	0.0	76.6	12.9	10.5

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
•		0.36	0.19	0.16	0.102	0.0100	0.0046	11.60	42.2

MATERIAL DESCRIPTION	USCS	AASHTO
• Gray Silty Fine Sand	SM	A-2-4

Project No.: F-98-565
 Project: Lansing Smith Plant Lab Testing
 • Location: CT-5 48.8 - 50.3

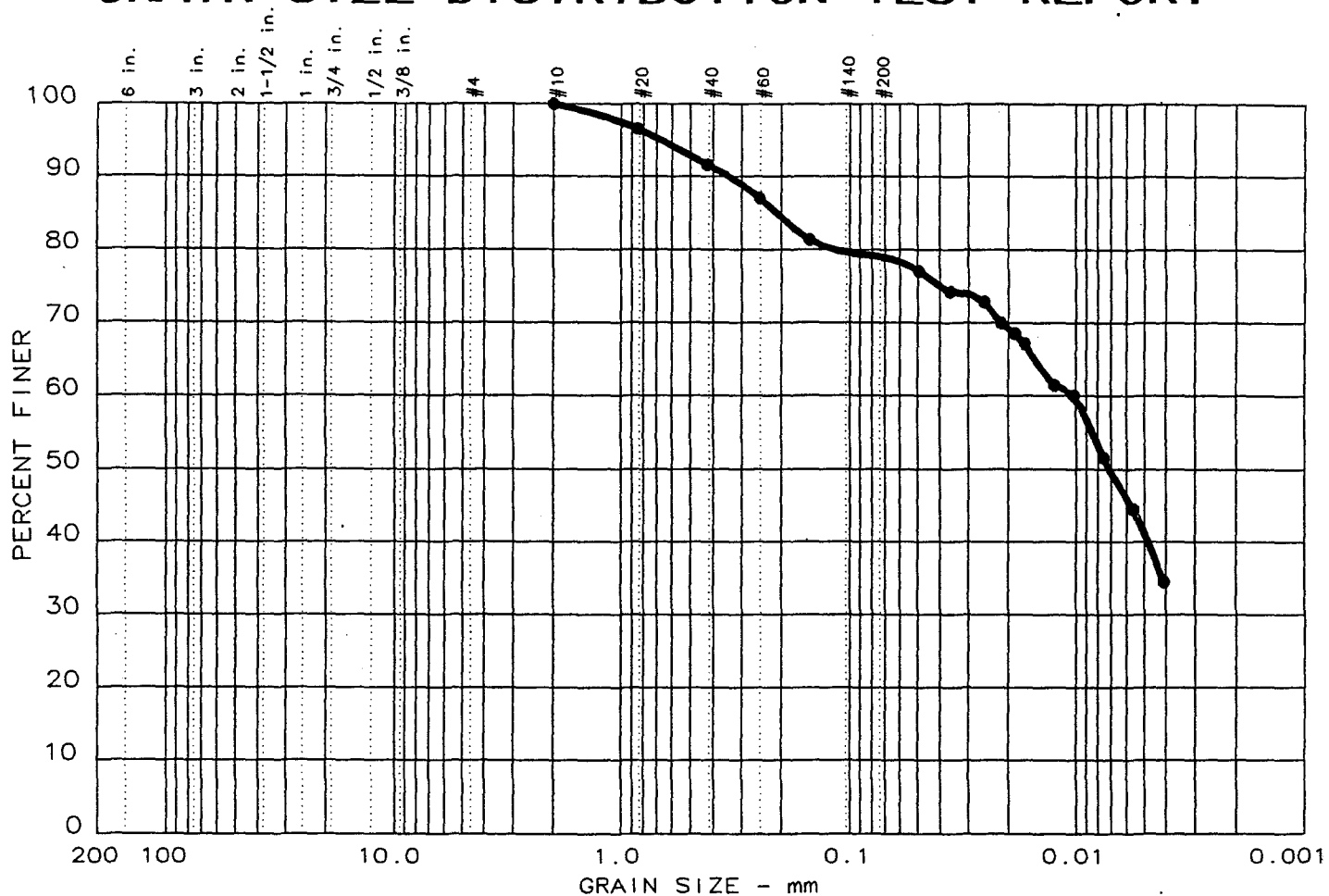
Date: 9/24/98

GRAIN SIZE DISTRIBUTION TEST REPORT
SOUTHERN EARTH SCIENCES, INC.

Remarks:

Figure No. _____

GRAIN SIZE DISTRIBUTION TEST REPORT





LAW

ENGINEERING AND ENVIRONMENTAL SERVICES

March 15, 1999

Ms. Rhonda Tinsley
Southern Co. Services, Inc.
42 Inverness Center Parkway
Birmingham, AL 35242

Chemical Analysis of Samples Received on 03/02/99
Project No. 2059927935

Dear Ms. Tinsley:

Law Engineering and Environmental Services, Inc., National Laboratories has completed its analysis of your samples and reports the results on the following pages. These results relate only to the contents of the samples as submitted.

If further assistance is needed, please feel free to contact me at (850) 857-0606 ext.155.

Sincerely,

LAW ENGINEERING AND ENVIRONMENTAL SERVICES, INC.
NATIONAL LABORATORIES

Bill Rubert
Project Manager

Enclosures: Data Report
 Invoice

3355 McLemore Drive
Pensacola, Florida 32514
(850) 857-0606

LAW ENVIRONMENTAL NATIONAL LABORATORIES

TEST DATA REPORT

03/15/99

--- Project Information ---

Ms. Rhonda Tinsley

Page 1

Southern Co. Services, Inc.

Project Name: GULFPOWR

42 Inverness Center Parkway

Project No. 2059927935

Birmingham, AL 35242

--- Sample Information ---

Station ID: CT-7 15'-15.5'

Date Sampled: 02/05/99

Lab ID: AB66435

Time Sampled: 14:00

Collector: H. BREITLING

Log In Date: 03/02/99

Log In Time: 16:14

--- Test Information ---

Analysis

Parameter	Units	Method	Rpt Lim	Result	Date	Tech
10610-9081-CAL Cation Exchange C	meq/100g	SW9081	0.0500	4.37	03/05/99	NK

Remarks:

Signed: CB Causey

Carl B. Causey

Technical Services Director

LAW ENVIRONMENTAL NATIONAL LABORATORIES

TEST DATA REPORT

03/15/99

--- Project Information ---

Ms. Rhonda Tinsley

Page 1

Southern Co. Services, Inc.

Project Name: GULFPOWR

42 Inverness Center Parkway

Project No. 2059927935

Birmingham, AL 35242

--- Sample Information ---

Station ID: CT-8 13'-15'

Date Sampled: 02/17/99

Lab ID: AB66436

Time Sampled: 13:00

Collector: H. BREITLING

Log In Date: 03/02/99

Log In Time: 16:14

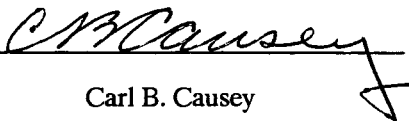
--- Test Information ---

Analysis

Parameter	Units	Method	Rpt Lim	Result	Date	Tech
10610-9081-CAL Cation Exchange C	meq/100g	SW9081	0.0500	11.4	03/05/99	NK

Remarks:

Signed:



Carl B. Causey

Technical Services Director

LAW ENVIRONMENTAL NATIONAL LABORATORIES

TEST DATA REPORT

03/15/99

--- Project Information ---

Ms. Rhonda Tinsley

Southern Co. Services, Inc.

42 Inverness Center Parkway

Birmingham, AL 35242

Page 1

Project Name: GULFPOWR

Project No. 2059927935

--- Sample Information ---

Station ID: CT-8 78.8' - 80.3'

Lab ID: AB66437

Collector: H. BREITLING

Date Sampled: 02/17/99

Time Sampled: 15:50

Log In Date: 03/02/99

Log In Time: 16:14

--- Test Information ---

Analysis

Parameter	Units	Method	Rpt Lim	Result	Date	Tech
10610-9081-CAL Cation Exchange C	meq/100g	SW9081	0.0500	3.66	03/05/99	NK

Remarks:

Signed: 

Carl B. Causey

Technical Services Director

LAW ENVIRONMENTAL NATIONAL LABORATORIES

TEST DATA REPORT

03/15/99

--- Project Information ---

Ms. Rhonda Tinsley

Southern Co. Services, Inc.

42 Inverness Center Parkway

Birmingham, AL 35242

Page 1

Project Name: GULFPOWR

Project No. 2059927935

--- Sample Information ---

Station ID: CT-8 83.8' - 85.3'

Lab ID: AB66438

Collector: H. BREITLING

Date Sampled: 02/17/99

Time Sampled: 16:55

Log In Date: 03/02/99

Log In Time: 16:14

--- Test Information ---

Analysis

Parameter	Units	Method	Rpt Lim	Result	Date	Tech
10610-9081-CAL Cation Exchange C	meq/100g	SW9081	0.0500	5.76	03/05/99	NK

Remarks:

Signed: CB Causey

Carl B. Causey

Technical Services Director

LAW ENVIRONMENTAL NATIONAL LABORATORIES

TEST DATA REPORT

03/15/99

--- Project Information ---

Ms. Rhonda Tinsley

Southern Co. Services, Inc.

42 Inverness Center Parkway

Birmingham, AL 35242

Page 1

Project Name: GULFPOWR

Project No. 2059927935

--- Sample Information ---

Station ID: CT-8 93.8' - 95.3'

Lab ID: AB66439

Collector: H. BREITLING

Date Sampled: 02/17/99

Time Sampled: 17:15

Log In Date: 03/02/99

Log In Time: 16:14

--- Test Information ---

Analysis

Parameter	Units	Method	Rpt Lim	Result	Date	Tech
10610-9081-CAL Cation Exchange C	meq/100g	SW9081	0.0500	16.8	03/05/99	NK

Remarks:

Signed: CB Causey

Carl B. Causey

Technical Services Director

05778



Tel. (850) 857-0606
Fax (850) 969-6169

SAMPLED BY Harold E. Breithing

PARAMETERS REQUESTED

HW - Haz. Waste

12:20

INVOICE

From: Law Eng. & Env. Svcs., Inc.
Pensacola Branch
3355 McLemore Drive
Pensacola, Florida 32514

Invoice Number: 1060009900 Date: March 15, 1999

To: Ms. Rhonda Tinsley
Southern Co. Services, Inc.
42 Inverness Center Parkway
Birmingham, AL 35242
Project No. 2059927935

The following charges are due for the indicated samples which were
submitted to this laboratory on 03/02/99:

Lab Sample I.D.: AB66436 AB66435 AB66437 AB66438 AB66439

Purchase order number: 20599279

Parameter Analyzed	Quantity	Unit Price	Total Price
10610-9081-CAL Cation Exchange C	5	\$85.00	\$425.00
Analysis charges subtotal for this invoice:			\$425.00
Total amount due on this invoice:			\$425.00

Remit payment to: LAW ENG. & ENV. SVCS., INC.
7477 COLLECTION CENTER DR.
CHICAGO, IL 60693-0076

**SOUTHERN COMPANY
CENTRAL LABORATORY**



Southern Company Services
Gulf Power Company
Plant Smith CT Site Investigation

April 14, 1999

Ms. Rhonda Tinsley

Mr. Ray Halbert
Southern Company

Enclosed are the test results for the soil samples delivered to the Southern Company, Central Laboratory on April 9, 1999. Performed test included Gradation (ASTM D-422), Wash #200 (ASTM D-1140), and Falling-Head Permeability (EM-LST, Appendix VII).

Laboratory soil sample #1, represents a UD sample material from Plant Smith, from a depth of 13.0' to 15.0'. This sample was classified as probable gray silty sand material or a SM by the Unified Soil Classification System or an A-4 (0.0) by the AASHTO System. The average Coefficient of Permeability using the Falling-Head Permeability Method was 1.3×10^{-6} cm. per sec. Gradation was as follows:

Sieve Analysis

<u>Sieve Size:</u>	<u>% Passing:</u>
#4	100.0
#8	99.8
#10	99.3
#16	97.6
#30	88.2
#40	77.3
#50	69.7
#100	55.3
#200	40.7

Laboratory soil sample #2, represents a Split-Spoon sample material from Plant Smith, from a depth of 95.0' to 97.0'. This sample was classified as probable gray silt material or an ML by the Unified Soil Classification System or an A-4 (0.0) by the AASHTO System. The average Coefficient of Permeability using the Falling-Head Permeability Method was (in progress) cm. per sec. Gradation was as follows:

Sieve Analysis

<u>Sieve Size:</u>	<u>% Passing:</u>
#4	100.0
#8	99.8
#10	99.8
#16	99.6
#30	99.4
#40	99.2
#50	99.0
#100	98.6
#200	97.1

We appreciate the opportunity to assist you on this project. If there are any questions or if we can be of any further assistance, please call at extension (205/664-6266) or 8-255-6266.

Sincerely,

Ray Halbert

Southern Company

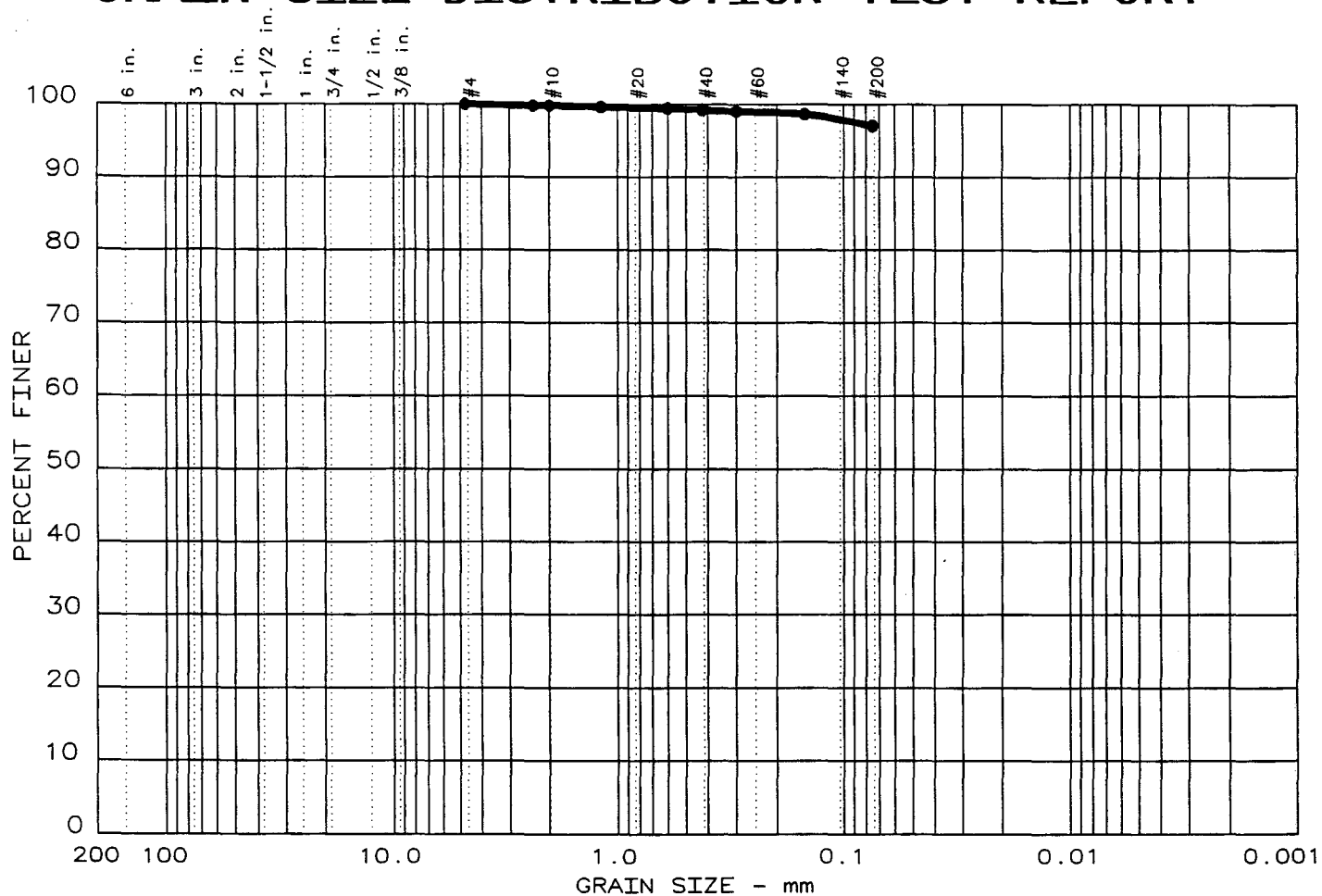
Sieve Size	Approx. Grain Size (mm)
6 in.	152.4
3 in.	76.2
2 in.	50.8
1-1/2 in.	38.1
1 in.	25.4
3/4 in.	19.0
1/2 in.	12.5
3/8 in.	9.5
#4	4.75
#10	2.0
#20	0.85
#40	0.425
#60	0.25
#140	0.106
#200	0.075

PERCENT FINER

GRAIN SIZE - mm

Project No.: 9022 Project: Gulf - Plant Smith CT Site Investigation ● Location: Gulf - Plant Smith, Boring CT-7	Remarks: UD Depth 13.0' to 15.0'
Date: 04/14/99	
GRAIN SIZE DISTRIBUTION TEST REPORT SOUTHERN COMPANY SERVICES	Lab No.: 1

GRAIN SIZE DISTRIBUTION TEST REPORT



Test	% +3"	% GRAVEL	% SAND	% SILT	% CLAY
● 13	0.0	0.0	2.9	97.1	

LL	PI	D ₈₅	D ₆₀	D ₅₀	D ₃₀	D ₁₅	D ₁₀	C _c	C _u
● N.A.	N.A.								

MATERIAL DESCRIPTION	USCS	AASHTO
● Probable Gray Silt	ML	A-4(0.0)

Project No.: 9022
 Project: Gulf - Plant Smith CT Site Investigation
 ● Location: Gulf - Plant Smith, Boring CT-12

Date: 04/14/99

GRAIN SIZE DISTRIBUTION TEST REPORT
SOUTHERN COMPANY SERVICES

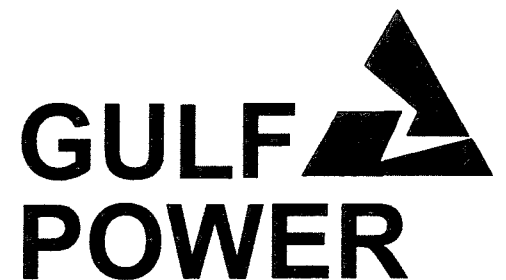
Remarks:
 Split-Spoon
 Depth 95.0' to 97.0'

Lab No.: 2

ATTACHMENT 10.5-G
GROUND WATER MODELING REPORT

PLANT LANSING SMITH MODFLOW AND SHARP MODELING REPORT

MAY 1999



A SOUTHERN COMPANY

PLANT LANSING SMITH
MODFLOW AND SHARP MODELING REPORT

Prepared by


Earth Science and Environmental Engineering
Southern Company Services

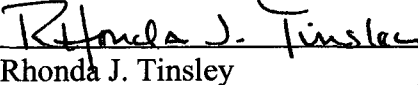
For

Gulf Power Company

May 1999

Poor Original


Steven C. Bearce
Originator
Florida P.E. No. 191


Rhonda J. Tinsley
Originator
Engineering Geologist

EXECUTIVE SUMMARY

Gulf Power Company is upgrading its water supply wells at its Lansing Smith Electric Generating Plant, in Southport, Bay County, Florida, by operating a previously permitted new well and redistributing flows among the three existing wells. Groundwater flow and density-driven flow models were used to evaluate local and regional effects of the upgrade. A groundwater flow model, called MODFLOW, was used to evaluate groundwater-flow effects within Bay County, Florida. A density-driven groundwater flow model, called SHARP, was used to study local freshwater and saltwater interface relations in a smaller area around the power plant.

Results of this study show that:

- Adding the fourth well will not adversely affect the Floridan Aquifer System or the nearest major user.
- Regional head declines are only attributable to county-wide water production increases over time.
- Operating the four permitted wells will not effect the Surficial Aquifer System or its related wetlands.
- Some minor upconing of chloride bearing water will occur but will not significantly affect the Floridan Aquifer System or the nearest major user, the City of Lynn Haven.
- The upconing is local in nature and will not degrade the Floridan Aquifer System and is expected to dissipate rapidly.
- Operating the new well will allow the existing plant wells to operate at a lower rate, which will allow their chloride levels to decrease.

Based on the results of this study, Gulf Power Company recommends:

- Operating a fourth well at the plant.
- Reducing daily flow from the existing plant wells to 480,000 gallons per day.
- Pumping the fourth well at a rate up to 720,000 gallons per day to compensate for the reduced flow from the existing wells.
- Automate pumping schedules in the existing wells to ensure daily rotation.
- Conduct quarterly chlorides monitoring in all plant water-supply wells.

PLANT LANSING SMITH
GROUNDWATER MODELING REPORT

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1.0 INTRODUCTION AND OBJECTIVES

Gulf Power Company (Gulf) is renewing their Consumptive Use Permit (CUP) and requesting a modification to the current permit limitations at Lansing Smith Electric Generating Plant (Plant Smith). Gulf is presenting this request and accompanying report on a subregional groundwater flow model and site scale groundwater-density flow model in support of the permit. This site is located in the central portion of Bay County in Sections 25 and 36, Township 2 South, Range 15 West (Figure 1). This report addresses the elements requested by the Northwest Florida Water Management District (NFWMD) for the permit renewal. Gulf is requesting authorization to increase groundwater withdrawals from 720,000 gallons per day to a proposed rate of 1,200,000 gallons per day at the end of the permit period. This will be accomplished by installing the previously permitted well 4 at Plant Smith. The location of the new well number 4 is shown on Figure 1.

The objective of this study is to assess potential effects from the requested groundwater withdrawals at the request of the NFWMD. The specific goal for the modeling is to evaluate whether the annual average daily withdrawal from the wells will:

- Create significant hydrogeologic effects on the host aquifer, including excessive drawdown and saltwater intrusion.
- Create significant hydrogeologic effects on the adjacent aquifers.
- Create significant hydrogeologic effects on local wetlands.
- Create significant hydrogeologic effects on existing legal users of water.

MODFLOW (McDonald, 1988) was used to evaluate regional flow to the plant's wells and effects on the closest major user of the same water source, the City of Lynn Haven, Florida. Another model, called SHARP (Essaid, 1990), was used to evaluate the site specific saltwater-freshwater interface.

2.0 GEOLOGY

This section describes the general and site specific geology of Bay County and Plant Smith, respectively. The stratigraphy, lithology, structure, and physiography are presented. Several publications, including *Geology of Bay County* (Schmidt and Clark, 1980) and *Florida's Ground Water Quality Monitoring Program Background Hydrogeochemistry*, (Maddox and others, 1992) characterize the area in detail and provide much of the information for this section.

2.1 General Geology

Unconsolidated sediments and rock ranging in age from late Pre-Cambrian to Recent underlie Bay County. Table 1 presents the stratigraphic nomenclature for the geology of Bay County (Schmidt and Clark, 1980). Figure 2 shows a generalized geologic section of the region. Descriptions of the geologic units are outlined below.

2.2 Regional Stratigraphy

Very few deep wells have been drilled in Bay County. Granite of possible late Pre-Cambrian has been encountered in the deepest wells. Paleozoic sediments range from Early Ordovician to Early Devonian (Schmidt and Clark, 1980).

Overlying the Paleozoic rocks, the Triassic Eagle Mills Formation is present in most of Bay County, thinning toward the east. Upper Jurassic formations include the Norphlet, Smackover, Haynesville, and the Cotton Valley Group. Undifferentiated Lower Cretaceous sands and shales overlie the Cotton Valley Group. These sands are overlain by the Upper Cretaceous Tuscaloosa Group. The Eutaw Formation, a calcareous fine sandstone to a sandy chalk with limestone, overlies the Tuscaloosa. The remaining Upper Cretaceous sediments are, in ascending order, the Austin Age, Taylor Age and Navarro Age (Schmidt and Clark, 1980).

Cenozoic sediments lie unconformably over the upper Cretaceous sediments. The undifferentiated sandy clay and soft limestone of the Midway Stage is overlain by Undifferentiated Wilcox, which includes glauconitic shale. Overlying the Wilcox, in ascending order are the Tallahatta and Lisbon Formations, Ocala, Marianna and Suwanee Limestones (Schmidt and Clark, 1980).

The Tampa Stage Limestone, which overlies the Suwanee, may grade into the overlying Chipola and Bruce Creek Limestones. The Bruce Creek is overlain by the Intracoastal Formation or the Jackson Bluff Formation. The Bruce Creek is more indurated than the Intracoastal Formation which can also be distinguished from the Bruce Creek by the olive-green color and abundant microfossils in the Intracoastal (Schmidt and Clark, 1980).

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

ERA	PERIOD	EPOCH	ROCK UNITS OR FORMATIONS, AND DESCRIPTIONS		APPROXIMATE DEPTH IN FEET BELOW SURFACE (NOT TO SCALE)
CENOZOIC	QUATERNARY	RECENT	UNDIFFERENTIATED QUARTZ SANDS		100
		PLEISTOCENE	UNDIFFERENTIATED CLAYEY SANDS AND GRAVELS		
	NEOGENE	PLIOCENE	JACKSON BLUFF FORMATION	GRAY-OLIVE GREEN, CLAYEY, SANDY, SHELL MARL.	300
			INTRACOASTAL FORMATION	GRAY-OLIVE GREEN, SANDY, ARGILLACIOUS, POORLY CONSOLIDATED VERY MICROFOSSILIFEROUS CALCARENITE.	
		MIDDLE MIOCENE	BRUCE CREEK LIMESTONE	WHITE TO LIGHT YELLOW, MODERATELY INDURATED, GRANULAR LIMESTONE.	400
			CHIPOLA FORMATION	SANDY, VERY LIGHT-ORANGE, FOSSILIFEROUS LIMESTONE.	
		LOWER	TAMPA STAGE LIMESTONES	SANDY, MICRITIC, WHITE TO LIGHT GRAY LIMESTONES.	500
		PALEOGENE	OLIGOCENE	SUWANNEE LIMESTONE	LIGHT GRAY TO YELLOW GRAY, DOLOMITIC LIMESTONE, OFTEN HIGHLY ALTERED, SUCROSIC, ALTERED FOSSIL TYPES, LIGHT GRAY, MASSIVE, CHALKY, GLAUCONITIC, SLIGHTLY SANDY LIMESTONE, ABUNDANT LARGE FORAMINIFERA.
	MARIANNA LIMESTONE				
	EOCENE		OCALA LIMESTONES	LIGHT ORANGE TO WHITE, HIGH POROSITY LIMESTONES; SMALL AMOUNTS OF SAND AND CHERT; GLAUCONITE IN LOWER FACIES ABUNDANT MICRO-FOSSILS.	1,000
			LISBON	CREAM-COLORED, GLAUCONITIC, SANDY LIMESTONE; LIGHT GRAY CLAY; SOFT PYRITIC LIMESTONE; GRAY, CALCAREOUS, GLAUCONITIC SAND.	
			TALLAHATTA	CREAM-COLORED, GLAUCONITIC, SANDY, CLAYEY LIMESTONE, AND GRAY, SANDY, CALCAREOUS CLAY.	
			UNDIFFERENTIATED WILCOX	SANDY, CREAM-COLORED, GLAUCONITIC LIMESTONE; CALCAREOUS SAND; GRAY, PASTY LIMESTONE; MICACEOUS CLAY.	
	PALEOCENE	UNDIFFERENTIATED MIDWAY	GRAY, MICACEOUS, SANDY CLAY; WITH SEAMS OF SANDY, SOFT LIMESTONE.	3,000	
MESOZOIC	CRETACEOUS	UPPER	SELMA GROUP	MARLS, CALCAREOUS CLAYS, AND LIMESTONE; INTERBEDDED SANDS, GLAUCONITIC, MICACEOUS.	7,000
			EUTAW FORMATION TUSCALOOSA FORMATION	CALCAREOUS SANDSTONE, SANDY CHALK. MARINE AND NON-MARINE SANDS AND SHALES.	
		LOWER	UNDIFFERENTIATED	REDDISH-BROWN SHALES AND SANDSTONES.	
	JURASSIC	COTTON VALLEY GROUP HAYNESVILLE FORMATION SMACKOVER FORMATION NORPHLET FORMATION	VARICOLORED MUDSTONE AND SANDSTONE. RED-GRAY, CALCAREOUS SHALES, SANDSTONES, MICRITE. LIMESTONE, DOLOMITIC LIMESTONES. RED SANDSTONES, SILTSTONES AND SHALES.	10,000	
		TRIASSIC	EAGLE MILLS FORMATION		MICACEOUS SANDSTONES; ARGILLACEOUS SILTSTONES; WELL INDURATED SHALES; OFTEN CONTAINS SILLS AND DIKES OF IGNEOUS ROCKS.
	PALEOZOIC	CAMBRIAN	QUARTZITE/META-ARKOSE	11,000	
PRE-CAMBRIAN			GRANITE	"BASEMENT"?	13,000

Table 1
Geology of Bay County

The Intracoastal is overlain by the Jackson Bluff Formation. In Bay County, the Jackson Bluff Formation occurs as a thin blanket-like deposit and consists of calcareous sandy clay to clayey sand with macrofossils. Sand covers the Jackson Bluff. The surficial unit consists of clayey and silty sand and gravel (probably Citronelle), reworked clayey sands (Pliocene), terrace sands (Pleistocene) and Recent coastal sands. The Pliocene and Pleistocene sands are related to fluctuating sea levels during glacial and interglacial periods. The Recent sands are the result of longshore marine forces (Schmidt and Clark, 1980).

2.3 Hydrogeology

Generalized descriptions of the hydrogeologic units in the vicinity of Plant Smith are presented in Table 2. The units are summarized below:

- *Surficial Aquifer System* consists of undifferentiated terrace marine and fluvial deposits, the Citronelle and underlying undifferentiated Pliocene deposits.
- *Intermediate System* consists of the coarse clastics of the Jackson Bluff Formation and the Intracoastal Formation.
- *Floridan Aquifer System* in this area includes the Bruce Creek Limestone and the Suwanee Limestone.
- *The Sub-Floridan Confining Unit* is overlain by a vast thickness of sediment, which limits the importance of the unit in this area.

2.4 Plant Smith Area Stratigraphy

Plant Smith is located on the Pamlico Terrace in an area of low relief between elevation zero and ten feet mean sea level (MSL). The site is underlain by a thick sequence of Tertiary-age sediments that generally dip to the southwest. Sediments in the area are primarily marine and estuarine and represent ancient coastal environments or marine terraces. After the marine terraces were deposited, they were mixed with underlying sediments during a marine transgression occurring in the Pleistocene Epoch. They consist of a sand, clay, silt and shell mixtures. Formations identified include:

- Recent sediments consisting of loose, relatively permeable silts and sands and extend to approximately 20 feet below the surface.
- Jackson Bluff Formation, a Pliocene-aged sandy clay to clayey sand unit found sporadically throughout Bay County. In the Plant Smith area, the unit is encountered at approximately 20 feet below the surface with variable thickness ranging from 1 to 7 feet.
- Intracoastal Formation, a wedge shaped deposit of calcareous silts and sands with varying amounts of clay. This unit occurs below the Jackson Bluff to approximately 100 feet below the ground surface in the vicinity of Plant Smith.
- Bruce Creek Limestone, a white to light yellow-gray, moderately indurated limestone dominated by macrofossils. The unit has a maximum thickness along the coast of about 300 feet.

PANHANDLE FLORIDA			
SYSTEM	SERIES	FORMATION	HYDROSTRATIGRAPHIC UNIT
QUATERNARY	HOLOCENE	UNDIFFERENTIATED TERRACE MARINE AND FLUVIAL DEPOSITS	SURFICIAL AQUIFER SYSTEM
	PLEISTOCENE		
TERTIARY	PLIOCENE	CITRONELLE FORMATION UNDIFFERENTIATED	INTERMEDIATE AQUIFER SYSTEM OR INTERMEDIATE CONFINING UNIT
	MIOCENE	COARSE CLASTICS/JACKSON BLUFF FORMATION ALUM BLUFF GROUP PENSACOLA CLAY INTERCOASTAL FORMATION HAWTHORN FORMATION CHIPOLA FORMATION BRUCE CREEK LIMESTONE ST. MARKS FORMATION CHATTAHOOCHEE FORMATION	
		CHICKASAWHAY LIMESTONE SUWANNEE LIMESTONE MARIANNA LIMESTONE BUCATUNNA CLAY	FLORIDAN AQUIFER SYSTEM
		OCALA GROUP LISBON FORMATION TALLAHATTA FORMATION OLDER ROCKS UNDIFFERENTIATED	
		UNDIFFERENTIATED	SUB-FLORIDAN CONFINING UNIT
	PALEOCENE	UNDIFFERENTIATED	
CRETACEOUS AND OLDER		UNDIFFERENTIATED	

* Terminology follows usage of Florida Bureau of Geology.

Table 2
Relationship Between Regional Hydrogeologic Units And
Major Stratigraphic Units In The Florida Panhandle
(After Southeastern Geological Society Ad Hoc Committee, 1986)

2.5 Plant Smith Area Structure

The thick sequence of marine sediments underlying Bay County is controlled in part by the Appalachicola Embayment, which is the dominant geologic structure in the Central Florida Panhandle. The Apalachicola Embayment is a southwesterly plunging basin characterized by increased sedimentation toward the coast, where total thickness can reach up to 15,000 feet (Schmidt and Clark, 1980). Additional regional structures that affect the geology of Bay County include the Chattahoochee Anticline. Figure 3 presents the principal geologic structures in northwest Florida.

2.6 Plant Smith Area Physiography

Bay County is located within the Coastal Plain physiographic province, East Gulf Coastal Plain section. Bay County lies within four physiographic subdivisions: Sand Hills, Sinks and Lakes, Flat-Woods Forest, and Beach Dunes and Wave Cut Bluffs. The largest portion of the county, including the Plant Smith area, lies within the Flat-Woods Forest. This division is characterized by slightly rolling to flat terrace land at elevations below 70 feet MSL. The Flat-Woods Forest is generally well-drained except for low-lying areas surrounding the bays. This includes the 0 to 10-foot terraces in the Plant Smith area. These low-lying areas may be inundated during extended rains.

The geomorphology of Northwest Florida is the result of the interaction of depositional and erosional events associated with sea level fluctuations. Bay County is located within the northern or proximal geomorphic division (White, 1970). Within this division, Bay County is predominantly located within the Gulf Coastal Lowlands, often characterized by poorly drained, swampy areas (Scott and others, 1991).

2.7 Plant Smith Lithologic Description

Figures 4 presents a cross-section based on the site investigation results. Three hydrogeologic units were identified:

- the Surficial Aquifer System
- the Intermediate System
- the Floridan Aquifer System

2.7.1 Surficial Aquifer System

Plant Smith is underlain by approximately 15 to 20 feet of surficial sediments of black organic topsoil and tan to brown, slightly silty fine- to medium-grained sands and medium- to coarse-grained sands. Laboratory grain-size classification identifies the surficial soils as SP to SM, poorly graded sands and silty sands.

The average hydraulic conductivity of the surficial unit is 2.9×10^{-4} centimeters per second (cm/sec). The average results of slug tests performed in the surficial aquifer are presented below.

Table 3 - Hydraulic Conductivity of the Surficial Aquifer

Surficial Piezometer	Hydraulic Conductivity (ft/day)	Hydraulic Conductivity (cm/sec)
CT1S	0.25	8.85×10^{-5}
CT2S	0.39	1.38×10^{-4}
CT5S	1.89	6.68×10^{-4}
CT6S	0.44	1.54×10^{-4}
CT7S	1.16	4.10×10^{-4}
Average	0.83	2.9×10^{-4}

2.7.2 Intermediate System

The Intermediate System, below the surficial sands, consists of the Jackson Bluff Formation and the Intracoastal Formation. At about 20 feet below ground surface, the sediments become dark bluish-green to olive-gray, clayey, fine- to medium-grained calcareous sands with shell fragments and abundant phosphorite. This is identified as the Jackson Bluff Formation. The Jackson Bluff is consistent across the area and has been identified in other investigations at Plant Lansing Smith. The unit is recognized by the distinct color and composition change from the overlying quartz sands. An undisturbed Shelby tube sample of the clayey material was collected from one boring and subjected to a falling head permeability test in the laboratory with a result of 1.3×10^{-6} cm/sec, indicating a silt or silty sand. Grain-size analysis of the sandy portion of the sample indicates a Unified Soil Classification of SM, a silty sand.

Below the Jackson Bluff Formation, the sediments are described as grayish green, silty, fine-grained calcareous sand with whole shells, shell fragments, loosely cemented nodules and abundant phosphorite. This unit, identified as the Intracoastal Formation, is approximately 75 feet thick in the Plant Smith area. Some thin layers of clay are present. Grain-size analyses of samples collected from the Intracoastal identify the sediments as SM, silty sands with up to 40 percent fines. Above the contact with the underlying rock, approximately ten feet of stiff, green clay was encountered. Grain-size analysis of the clay yields a Soil Classification of ML, a clayey silt with 76.5 percent fines and a permeability of 5.8×10^{-7} cm/sec.

Slug testing of three piezometers in the Intracoastal Formation indicate the average hydraulic conductivity of 2.09×10^{-3} cm/sec. The results of the slug testing are presented in the table below.

Table 4 - Hydraulic Conductivity of the Intracoastal Formation

Intermediate Piezometer	Hydraulic Conductivity (ft/day)	Hydraulic Conductivity (cm/sec)
CT1D	5.66	2.00×10^{-3}
CT5D	5.47	1.93×10^{-3}
CT7D	6.69	2.36×10^{-3}
Average	5.94	2.09×10^{-3}

2.7.3 Floridan Aquifer System

Six borings were taken to auger refusal. The consolidated limestone was encountered between 95.50 feet and 98.3 feet below the ground surface at each boring, indicating that the top of the rock is very consistent across the site. Ten feet of rock was cored in two locations. Recovery in five-foot runs ranged from 60 to 100 percent with some loss due to washout of fines. The upper foot is very hard and consolidated and darker in color. The underlying grayish green rock is softer, highly fossiliferous, porous, and shows some evidence of water movement along fractures. Complete loss of water occurred at the top of rock due to high porosity. The thickness of this unit was not determined in the drilling program but the Floridan is estimated at over 700 feet in Bay County. A pumping test in the plant water supply wells shows the transmissivity to be 4000 ft²/day and the storage coefficient to be 0.0003.

2.8 Water Quality

The report entitled *Florida's Ground Water Quality Monitoring Program Background Hydrogeochemistry* (Maddox and others, 1992) is a compilation of the initial quantification of background groundwater quality in each of the major aquifer systems. The report provides details of the temperature, pH, total dissolved solids, specific conductance, cations, anions, trace metals and organics identified through analyses of thousands of wells throughout the state.

2.8.1 Surficial Aquifer System

The Surficial Aquifer System is not a major source of water in the NFWFMD but is mainly used for irrigation and to maintain surface-water features. Water in the Surficial Aquifer System is soft and generally unmineralized. The sand-rich aquifer has the ability to sorb metals and anions in moderate amounts. Based on the report, the total dissolved solids in the Surficial Aquifer System are low with concentrations ranging from 15 to 1000 milligrams per liter (mg/l). The median concentration is 74 mg/l, with concentration increasing toward the coast.

The chloride distribution in the Surficial Aquifer in the NFWFMD are low due to the continental influences on precipitation. Concentrations ranges from 1.8 to a maximum of 410 mg/l, with a median of 7 mg/l (Maddox and others, 1992). Figures 5 and 6 show the distribution of the total dissolved solids and chloride in the Surficial Aquifer System.

2.8.2 Intermediate System

The Intermediate System is generally not an important water-bearing unit in the northwest Florida. Locally, the unit provides limited amounts of water for small, domestic wells. The total dissolved solids in the Intermediate System range from 36 to 390 mg/l, with a median value of 165 mg/l (Maddox and others, 1992). Distribution of chlorides in the aquifer show considerable variability. Chloride concentrations are low in the northern part of the district where the rainfall is dominated by continental influence. Concentrations increase toward the coast. Based on the data from the Ground Water Quality Program, the minimum concentration within northwest Florida is 1.7 mg/l and the maximum is 58.0 mg/l, with a median of 5.3 mg/l. Figures 7 and 8 show the distribution of the total dissolved solids and chloride in the Intermediate System aquifer.

2.8.3 Floridan Aquifer System Properties and Water Quality

The Floridan Aquifer System is the most prolific aquifer system in the southeastern United States and underlies all of Florida. The system provides more than 90 per cent of the water supplies in northwest Florida except in part of Santa Rosa County and Escambia County (Maddox and others, 1992). The Floridan dips to the south and ranges from over 100 feet above sea level in the northern part of the Panhandle to more than 300 feet below sea level in Bay County. The elevation of the top of the Floridan ranges from about 50 feet above sea level to 50 feet below sea level throughout most of the Econfina Creek Basin where the aquifer is approximately 500 to 600 feet thick (Richards, 1997).

Ground water availability in the Floridan is a function of permeability, thickness, proximity to unsuitable water and recharge rates. Where the Intermediate System is thin and permeable, higher recharge rates occur and secondary porosity is enhanced, increasing aquifer permeability (Richards, 1997). In the coastal portion of Bay County, in the Plant Smith area, the Floridan is thick but low recharge rates, low permeability, and proximity of salt water within and above the Floridan may result in low to moderate ground water availability.

Figures 9 and 10 represent the elevation of the top and bottom of the Floridan Aquifer System in the Econfina Creek Basin and surrounding area. The potentiometric surface varies widely throughout the state and may be affected by extensive pumping of groundwater. Figure 11 shows the potentiometric surface of the Floridan in Bay and surrounding counties.

The quality of the Floridan unit has been extensively studied since the aquifer is the most important source of potable water to the State. Compared to the Surficial and Intermediate sands and clays, the mineral assemblage in the Floridan is less complex, consisting mostly of calcite and dolomite and as a result, the unit contains a high calcium content compared to the overlying units. In Bay County, total dissolved solids in the Floridan are related to the salt-water zone and flow systems. High concentrations are often the result of contact with soluble carbonates and mixing with saline water at the bottom of the aquifer and at the coast. Concentrations are lowest in the interior areas where the aquifer is recharged by rainfall and the residence time is shorter. Within northwest Florida, the total dissolved solids concentration of the Floridan ranges from 42 to 810 mg/l, with a median of 200 mg/l (Maddox and others, 1992). Figure 12 shows the distribution of total dissolved solids in the Floridan Aquifer.

The chloride distribution in the Floridan in the Plant Smith area is similar to the other aquifer systems in the state. Concentrations are generally low inland, in recharge areas and shallow wells. Concentrations are highest in deeper wells near the coast and in areas of salt water intrusion caused by pumping. Within northwest Florida, the chloride distribution ranges from 1.7 to 300 mg/l, with a median of 6.3 mg/l. Figure 13 shows the distribution of chloride concentration in the Floridan Aquifer (Maddox and others, 1992).

The average concentration of chlorides in seawater is around 19,000 mg/kg. This chloride concentration is quite large in comparison to the average chloride concentration found in other waters. The chloride concentration in rivers and other surface waters and precipitation is generally less than 10 mg/L. The Florida Department of Environmental Protection and the United States Environmental Protection Agency have established a secondary standard for the concentration of chlorides in drinking water as 250 mg/L. At a concentration of 250 mg/L or greater, water will taste salty. Any chloride concentration in excess of 100 mg/L is considered to have been effected by salt water. The USGS classifies any salinity greater than 30 parts per thousand as being saline, any salinity greater than 0.5 parts per thousand but less than 30 parts per thousand as being brackish, and any salinity less than 0.5 parts per thousand as fresh water (Maddox and others, 1992).

Existing wells at the Lansing Smith Electric Generating Plant are tested for chlorides as part of the boiler-water chemistry testing program. Results for these wells are listed in Table 5. These results show some brief excursions above the secondary standard; however, resampling shows quick recovery to acceptable levels. This is most likely due to local upconing of the transition zone between freshwater and salt water which occurs in the Floridan Aquifer System along the coastal areas.

Table 5 - Measured Chloride Concentrations from the Plant Smith Wells

Year /Well	1965	1966	1970	1972	1978	1979	1980	1981	1982	1983	1984	1985	1993	1994	1995	1996	1997	1998	1999
Well #1	8	8	6	6	9	12	10	12	14	16	12	31	136*	68*	130*	174*	260*	290	43.5
Well #2	8	8	7	5	12	25	26	30	30	24	13	34				114			175
Well #3						10	10	10	9	48	12	23				122			144

Chloride measurements from boiler-water quality monitoring testing program.

Results listed in mg/l.

* Average of several samples.

2.9 Karst Hydrogeology

Florida is underlain by carbonate units subject to dissolution by slightly acidic recharge from rainfall. Karst topography is the irregular surface that results from the solution cavities. Sinkholes are one of the most notable features of karst topography and are usually recognizable on topographic maps as circular features, often filled with water.

In the northern portion of Bay County within the Sand Hill Lakes area, karst topography is recognized by the lack of perennial or intermittent streams, and the presence of closed surface water drainage basins. The groundwater within the Surficial Aquifer percolates through the Intermediate System and recharges the Floridan Aquifer. In the southern portion of the county, near the Plant Smith, the limestone is deeply buried and sinkhole activity is extremely rare. Since sinkholes and collapse features are responses to water moving down into the limestone, they generally form in areas where the limestone aquifer is being recharged. The area around Plant Smith is identified as an area of generally no recharge to the Floridan Aquifer (Stewart, 1980). The probability of karst development is very low and unlikely to occur in the Plant Smith area.

3.0 MODELED HYDROGEOLOGIC SETTING

A variety of hydrogeologic studies providing information for the Plant Smith area are available in the literature. Many of these studies have included modeling efforts completed and published by NFWFMD and/or the U.S. Geological Survey (USGS). A related groundwater flow model was developed by Richards (1997). Climatic and hydrogeologic data including rainfall, evapotranspiration, hydraulic conductivity, transmissivity, storage coefficient, leakance, and recharge, are addressed in Barr and Wagner (1981) and Scott and others (1991).

The site-specific hydrogeologic conditions were evaluated through onsite geologic and water level data and review of reports prepared for Gulf. These reports included pertinent data for the vicinity of the Plant Smith and also include other nearby locations and public-domain data.

4.0 BAY COUNTY GROUNDWATER FLOW MODEL

4.1 MODFLOW Groundwater Model

MODFLOW was used to create the groundwater-flow model for the Plant Smith simulations. A disk copy of input files for MODFLOW is provided as Attachment A.

4.1.1 Conceptual Model

Based on the hydrogeological data reviewed, a conceptual hydrogeologic framework was prepared. Figure 14 illustrates the area studied by Gulf. This modeling effort was not intended to duplicate the large scale regionally calibrated Econfinia Creek Drainage Basin model developed by NFWFMD staff. Rather, the approach taken for this application was to develop a relatively simple, yet realistic, ground water flow model to simulate conditions representative of Plant Smith and its proposed groundwater use.

4.1.2 Numerical Model and General Assumptions

The MODFLOW model was selected based on its applicability to the aquifer framework (three-dimensional character) and its wide acceptance among groundwater professionals.

MODFLOW is perhaps the most well known and most widely applied ground water model in hydrogeologic studies. Inputs to the model include spatial information, aquifer properties, and events. MODFLOW solves the following partial differential equation:

$$\frac{\partial}{\partial x} K_x \left(\frac{\partial h}{\partial x} \right) + \frac{\partial}{\partial y} K_y \left(\frac{\partial h}{\partial y} \right) + \frac{\partial}{\partial z} K_z \left(\frac{\partial h}{\partial z} \right) = S \frac{\partial h}{\partial t} - \omega$$

where: x, y, z = Cartesian coordinates (with the z -axis aligned vertically)

K_x, K_y, K_z = x, y, z - components of hydraulic conductivity

h = potentiometric head for Surficial Aquifer System, aquifer thickness substituted in for Floridan Aquifer System

S = specific storage

t = time

ω = volumetric source or sink, representing a source or sink of water such as recharge, pumpage, leakage, etc.

The primary assumptions for this modeling application are:

- Groundwater acts as an incompressible fluid.
- Flow in all hydrogeologic units is Darcian.
- The Surficial Aquifer System is homogeneous and isotropic.
- The Surficial Aquifer System is completely unconfined.
- The Floridan Aquifer System is heterogeneous and isotropic.

- The Floridan Aquifer System is bound on the top by a leaky aquitard called the Intermediate System.
- The Floridan Aquifer System's bottom is completely confined by the Sub-Floridan Confining Unit.
- The simulated area is isothermal.
- All MODFLOW simulated water is fresh.
- The Intermediate System is heterogeneous and isotropic.
- Flow through the Intermediate System is strictly vertical.

4.1.3 Finite-Difference Grid and Data Requirements

The Lansing Smith model area is divided into cells to make a finite-difference grid for the ground water flow model (Figures 14 and 15). The constantly-spaced grid covers an area of approximately 1400 square miles. The grid consists of 123 columns and 87 rows to provide a model grid of 10,781 cells per layer. Cell spacing is constant at 2,159 feet. The three principal hydrogeologic units are represented in the model with two explicit layers and one implicit layer. Following is a summary of each layer:

- Layer 1 is used to actively simulate the hydrostatic pressures in the Surficial Aquifer System such that flows between the aquifers are included in the impacts evaluation. Head predictions were compared to the Econfina Drainage Basin to visually check similarity.
- The Intermediate System is implicitly modeled as a leakance term (vertical conductance variable in MODFLOW). However, heads are not actively calculated for this system.
- Layer 2 is used to actively simulate the Floridan Aquifer System and the effects the proposed well will have on surrounding users and the existing hydrogeology.

Table 6 cross-references model input requirements, data ranges, and data sources.

Table 6 Summary of MODFLOW model inputs.

Parameter	Range	Source	Figure Number	Calculation
Hydraulic Conductivity Surficial Aquifer	23 feet per day	Gulf Power, 1993a, 1993b, and 1996	None	Approximate average of 3 Surficial System Sites
Surficial Aquifer Top	0 to 140 feet MSL	Richards 1997 and Gulf Power, 1993a, 1993b, and 1996	16	None
Surficial Aquifer Bottom	-50 to 20 feet MSL	Richards 1997 and Gulf Power, 1993a, 1993b, and 1996	17	None
Surficial Aquifer Specific Yield/Effective Porosity	0.1	Gulf Power, 1993a, 1993b, and 1996	None	Approximate average of 3 Surficial System Sites
Recharge	40 inches/year		None	None
Evapotranspiration	50.37 inches/year Extinction Depth of 10 feet	Calibration variable	None	None
Intermediate System Leakage	0.00002/day to 0.00122 /day	Richards 1997 and Gulf Power, 1993a	18	Kv/b
Intermediate System Effective Porosity (for MODPATH)	0.001	Estimated typical value for clayey material.	None	None
Hydraulic Conductivity of Floridan System	1 ft/day to 3,289 ft/day	Richards 1997, Scott, 1991, and Barr, 1981	None	T/b
Top Elevations of Floridan Aquifer System	-450 to 50 ft MSL	Scott, 1991	9	None
Bottom Elevations of Floridan Aquifer System	-1700 to -535 ft MSL	Scott, 1991	10	None
Storage Coefficient of Floridan Aquifer System	0.0004	Barr, 1981	None	None
Porosity (for MODPATH)	0.1	Estimated effective porosity	None	
Critical Time Step	0.087 day	Anderson, 1992	--	=S(cell area)/4T
Space and Time Units	Feet and days	--	--	--

Kv = Vertical hydraulic conductivity

B = System thickness

T = Transmissivity

S = Storage coefficient

4.2 Boundary Conditions

MODFLOW assumes that the outer edge of the model grid are no-flow boundaries. All water moving through the modeled flow system is balanced through boundary conditions within the grid. The types of boundary conditions used in this model include:

- Constant-head boundary.
- Specified-flow boundary.
- Head-dependent flow boundary.

Figures 14 and 15 show the placement and type of boundary conditions used in the model. For the surficial aquifer system, constant head conditions are used in the Gulf of Mexico to define the southern-most edge of the model. Inactive cells are used south of the Gulf of Mexico constant head boundaries and in other smaller areas which are excluded from the model. Head-dependent flow boundaries regulate the direction groundwater will move with respect to another head, typically a surface water body. MODFLOW uses a program module call the River Package to represent head-dependent flow boundaries. Figure 14 shows the use of this boundary condition and the surface-water bodies represented in the model, including:

- Portions of the Gulf of Mexico.
- The inland bays.
- Econfinia Creek.
- Chipola Creek.

Data used for the River Package includes:

- Bathymetry – Estimated from USGS Topographic maps.
- Surface area within a cell – the Gulf of Mexico and the bays are the same as the cell area; however, rivers and creeks are estimated to be 50 feet wide and one cell length long.
- Sediment thickness – estimated to be 1-foot thick for simplifying conductance calculation.
- Vertical hydraulic conductivity of sediment – estimated to be 10 feet per day.
- Surface water head – The Gulf of Mexico and the bays are assigned 0 feet MSL. River and creek heads are estimated from inflection points on the USGS 1:250,000 scale topographic map of the Florida Panhandle.

Another MODFLOW module called the General Head Boundary package was used to define the northern boundary of the model and portions of the western boundary. This is another head-dependent flow boundary condition which is suited for simulating groundwater underflow into, or out of, the model. Data requirements include:

- A groundwater head (estimated from Richards, 1997).
- A calculated conductance value which assumes a hydraulic conductivity equal to the aquifer's, a flow distance from the head to the interior of the cell equal to the cell's length (2159 feet), the boundary width is the same as the cell width, and the saturated thickness is estimated between the assigned head and an assumed bottom elevation of 20 feet MSL.

Boundary conditions used for simulating the Floridan Aquifer System include constant head conditions and specified flow conditions. Constant-head conditions are shown on Figure 15. These represent the area where:

- The aquifer's head is equal to the Gulf of Mexico's head (0 feet MSL) on the southern boundary.
- The head of the Floridan Aquifer System occurring in areas upgradient of the model.

The specified-flow boundary conditions shown on Figure 15 are all permitted wells in Bay County which have flows greater than 75,000 gallons per day. Lower capacity wells were not included, but could represent a major combined withdrawal from the Floridan Aquifer System.

4.3 MODFLOW Execution and Calibration

The model was executed or run for three scenarios:

- Steady-state flow with no pumping wells. This is considered a predevelopment simulation for comparing before and after conditions at Plant Smith. Predicted heads were also used to initialize the SHARP simulation.
- Steady-state flow with pumping wells, except the proposed well number 4 at Plant Smith. This simulation was used for model calibration and provided heads for initializing the transient simulation and comparing steady state drawdowns with the City of Lynn Haven.
- Transient-flow with pumping wells, addition of proposed well number 4, and four percent production increase per year for all wells over the five year permit period.

Model execution consisted of running the steady state simulations and adjusting the input to better relate to known groundwater conditions in a process called calibration. After calibration, the transient simulation was run for a period of five years, which was further broken down to reflect a NFWFMD estimate of area production increases. Table 7 lists the time periods used and expected water needs at Plant Smith.

Table 7 – Summary of Transient Simulation Events.

Permit Year	2000	2001	2002	2003	2004
Area Wells	All wells at permitted level	All area wells increased by 4%	All area wells increased by 4%	All area wells increased by 4%	All area wells increased by 4%
Plant Wells	Wells 1, 2, and 3 at permitted levels of 0.72 MGD	Wells 1, 2, and 3 decreased to combined total 0.48 MGD	Wells 1, 2, and 3 remain at combined total 0.48 MGD	Wells 1, 2, and 3 remain at combined total 0.48 MGD	Wells 1, 2, and 3 remain at combined total 0.48 MGD
Proposed Plant Well Number 4	Not Simulated	Well 4 added at 0.52 MGD	Well 4 remains at 0.52 MGD	Well 4 increased to 0.72 MGD	Well 4 remains at 0.72 MGD

MGD = Million gallons per day.

Model calibration is the process of reasonably adjusting model parameters or boundary conditions such that simulated results approach known (measured) values of aquifer head. This was done by subtracting predicted heads from points of known head for a specific point in time. This calculation produces a number called a residual. The residual is used to measure accuracy of predictions across the study area. A statistic called the absolute residual mean was calculated as a measure of the model's ability to predict heads within a certain tolerance. Although exact calibration is achievable, an absolute residual mean of approximately 5 feet was used for acceptance, given that closer matches occurred near the Plant Smith Location in the model. Calibration points are shown for the Floridan Aquifer System on Figure 15.

4.4 MODFLOW Simulation Results

Table 8 lists the calibration statistics for the steady state simulation with all current pumping wells permitted for 75,000 gallons per day. The predicted heads for the Floridan Aquifer System Simulation have a calculated absolute residual mean of 5.3. This is mainly due to discrepancies in the western area of the model (Steelfield LF well and J.H. Rawls well). Visual comparison of the Floridan Aquifer System results to those of Richards (1997) in the vicinity of the site and areas north of Panama City are in close agreement. The predicted heads in the Panama City Beach area are higher than shown in Richards' model. This is attributed to a difference in the number of wells used in this model and Richards' model, which used all permitted wells with flows equal to and greater than 55,000 gallons per day. This difference was not included in the Plant Smith model because the proposed site is too far away to affect the plant predictions. Comparing Figures 21 and 22 show the effects of using well 4 at Plant Smith.

Figures 19 and 20 show the predicted heads of the predevelopment steady state model. The Surficial Aquifer System predicted heads are similar to the head dependent conditions in the Econfina Creek drainage basin model. The Floridan Aquifer System results are similar to the predevelopment heads that Richards' model predicted.

The steady state heads with all wells currently permitted to pump 75,000 gallons per day are shown in Figures 21, 22 and 23 (showing proposed Plant Smith well 4). Comparing Figures 19 and 21 shows that current pumping in the Floridan Aquifer System has virtually no effect on the Surficial Aquifer System. Average drawn-down heads are listed in Table 8 for Plant Smith and the City of Lynn Haven wells. These drawn-down heads represent an average head for the model cells containing wells at Plant Smith and Lynn Haven. Table 8 shows that adding the fourth well and adjusting existing well-flows downward at Plant Smith will not cause heads in the City of Lynn Haven wells to experience more than 0.75 foot of draw-down under steady state conditions.

Figure 24 shows the predicted heads at the end of the five year permit period (2004). The assumed 4 percent per year production increase in surrounding wells caused heads to drop on a regional scale approximately 1 to 2 feet as compared to the steady state simulation (Figures 22 and 23). However, these continuing declines are not attributable to the Plant Smith wells but to the regional increase in water usage.

Table 8 Summary of Model Calibration Points and Statistics

Name	Model X	Model Y	Model Layer	Observed Head	Computed Head	Residual
Steelfield LF	21463.40	155210.86	2	42.85	31.609242	11.240758
J.H. Rawls	39634.50	147081.68	2	44.97	31.458809	13.511191
USGS Lake Five-O	99656.53	173023.32	2	40.63	40.461322	0.168678
Georges 40 FLD	115630.00	177696.00	2	38.74	36.873530	1.866470
Camp Herbert Watts	135630.00	170696.00	2	34.65	33.960302	0.689698
McCall Sod Farm	110634.00	141196.00	2	30.20	25.858956	4.341044
Absolute Residual Mean	5.30					
Residual Standard Deviation	5.21					
Sum of Squares	5.30					
Min. Residual	0.17					
Max. Residual	13.51					
Head Range	14.77					
Head Range/Std	0.35					

Table 9 Summary of Drawn-Down Heads at Plant Smith and Lynn Haven

Period	Smith (WSW3)	Lynn Haven
Before Well 4	2.86	-4.25
After Well 4	4.83	-5

Heads listed in ft-MSL.

5.0 SALTWATER INTERFACE STRESS MODEL

In coastal areas, saltwater intrusion is a natural phenomena. Water supply wells which are placed into aquifers in coastal areas may increase the areal extent of saltwater intrusion or cause local upconing of saltwater. The occurrence of saltwater intrusion in coastal areas is due to density-driven flow of saltwater. This flow generally equilibrates such that the freshwater “floats” above intruded saltwater. The contact between the freshwater and the saltwater is called the freshwater/saltwater interface. A transition zone containing brackish water occurs at this interface due to the mixing of the freshwater and saltwater. The geometry of the transition zone may be hard to quantify because of data representation problems. One way to handle this problem is to treat the transition zone as the part of the salt water domain and define one interface with no mixing. This is called the sharp interface approach. The mathematical expression known as the Ghyben-Herzberg relation states that in coastal areas, the depth to the saltwater interface is 40 times the aquifer’s freshwater head below a common datum, usually taken to be mean sea level. The USGS SHARP computer program for modeling the freshwater and saltwater relation at the plant site was used to evaluate potential stress on the interface from pumping in the nearest wells (Plant Smith wells 1, 2 and 3) and new well 4.

5.1 Conceptual SHARP Model

The area modeled with SHARP , is derived from a subarea of the MODFLOW model (Figure 14). Based on the hydrogeological data reviewed, a conceptual hydrogeologic framework was prepared. Figure 25 is a diagram illustrating the conceptualization of the site hydrogeologic conditions.

5.2 Numerical Model and General Assumptions

The SHARP model was selected based on its applicability to the aquifer framework (three-dimensional character) and the “worst-case nature” of its results (all water below interface considered saltwater even though it may be brackish). Inputs to the model include spatial information, aquifer properties, and events. SHARP simultaneously solves the same equation as MODFLOW for both freshwater and salt-water areas. The SHARP interface (a worst case Ghyben-Herzberg interface) is predicted based on the predicted freshwater and saltwater head relationships.

The primary assumptions for this model are:

- Groundwater acts as an incompressible fluid.
- Flow in all hydrogeologic units is Darcian.
- The Surficial Aquifer System is homogeneous and isotropic.
- The Surficial Aquifer System is unconfined except in the case where saltwater bodies overly the aquifer.

- The Floridan Aquifer System is heterogeneous and isotropic.
- The Floridan Aquifer System is bound on the top by a leaky aquitard called the Intermediate System.
- The Floridan Aquifer System's bottom is completely confined by the Sub-Floridan Confining Unit.
- The simulated domain is isothermal.
- The Intermediate System is heterogeneous and isotropic.
- Flow through the Intermediate System is strictly vertical.
- Shoreline mixing is assumed to be insignificant for the purposes of this study.

5.3 SHARP Finite-Difference Grid and Data Requirements

The Plant Smith model area is divided into cells to make a finite- difference grid for the dual density SHARP model (Figures 26 and 27). The grid consists of 40 columns and 40 rows to provide a model grid of 1600 cells per layer. Cell spacing is constant in the x and y directions, but slightly different. The three principal hydrogeologic units are represented in the model with two explicit layers and one implicit layer. Following is a summary of each layer:

- Layer 1 is used to actively simulated the Floridan Aquifer System and the effects the proposed well will have on surrounding users and the existing hydrogeology.
- The Intermediate System is implicitly modeled as a leakance term. However, heads are not actively calculated for this system.
- Layer 2 is used to actively simulate the hydrostatic pressures in the Surficial Aquifer system such that flows between the aquifers are included in the evaluation.

Table 10 lists the SHARP input requirements and the source of the data used in the model. The original computer input file is included in the computer-disk holder page.

5.4 Boundary Conditions

SHARP allows two boundary conditions to be used in model, these are:

- Freshwater and saltwater constant-head boundary.
- Specified-flow boundary.

Figures 26 and 27 show the placement and type of boundary conditions used in the model. The Floridan Aquifer System layer (Figure 26) uses:

- No-flow cells in the same manner as the Surficial Aquifer System layer.
- Freshwater constant-head conditions are used inside the border of no-flow cells to define the edges of the freshwater aquifer.
- Saltwater constant-head cells most likely are beyond the southern boundary of this model. For this reason they are not included.
- Specified-flow conditions are used to simulate flow from water wells.

Table 10 - Summary of SHARP Model Inputs.

Parameter	Range	Source	Calculation
Hydraulic Conductivity Surficial Aquifer	0.000266 feet per second	Gulf Power, 1993a, 1993b, and 1996	Approximate average of 3 Surficial System Sites
Surficial Aquifer Thickness	50 feet	Required input.	Simplified term because lack of evapotranspiration causes program to write warning about head and exceeding land surface
Surficial Aquifer Bottom	-50 to -25 feet MSL	Richards 1997 and Gulf Power, 1993a, 1993b, and 1996	None
Surficial Aquifer Specific Yield/Effective Porosity	0.1	Gulf Power, 1993a, 1993b, and 1996	Approximate average of 3 Surficial Aquifer System Sites
Intermediate System Leakance	5.5×10^{-10} per second	Simplified from values in this area of the MODFLOW model	--
Hydraulic Conductivity of Floridan System	0.0000347 to 0.000127 ft/sec	Richards, 1997, Scott, 1991, and Barr, 1981	T/b
Thickness of Floridan Aquifer System	720 to 736 feet	Scott, 1991	None
Floridan Aquifer System Bottom	-965 to -830 ft MSL	Scott, 1991	None
Storage Coefficient of Floridan Aquifer System	0.0004	Barr, 1981	None
Porosity	0.1	Estimated effective porosity	
Space and Time Units	Feet and seconds	--	--
Critical time step	1000 seconds	Anderson, 1992	$=S(\text{cell area})/4T$
Initial Heads for Surficial and Floridan aquifer systems	--	MODFLOW results	--

K_v = Vertical hydraulic conductivity

B = System thickness

T = Transmissivity (site value from Barr, 1981)

S = Storage coefficient

Data for defining these conditions were derived from the MODFLOW results presented earlier.

The Surficial Aquifer System layer (Figure 27) uses:

- No-flow cells (a special condition of specified flow boundary) around the edges to prevent water budget problems in the model
- Freshwater constant-head conditions are used inside the border (except the southern border) of no-flow cells to define the edges of the freshwater aquifer.
- Saltwater constant-head cells are used inside the southern row of no-flow cells to initialize the saltwater portion of the aquifer. The inland bays were also represented as saltwater constant-head boundaries.

Data for defining these conditions were derived from the MODFLOW results presented earlier. For simplicity in the representing the bays, freshwater MODFLOW head results were used without converting to equivalent saltwater heads.

The specified-flow boundary conditions shown on Figure 27 are all Plant Smith's permitted wells. Table 11 lists the wells and how they were utilized in the simulation.

Table 11 – Summary of Simulated Pumping.

Permit Year	1965 through 2000	2001	2002	2003	2004
Existing Plant Permitted Wells	Wells 1, 2, and 3 at permitted levels of 0.72 MGD	Wells 1, 2, and 3 decreased to combined total 0.48 MGD	Wells 1, 2, and 3 remain at combined total 0.48 MGD	Wells 1, 2, and 3 remain at combined total 0.48 MGD	Wells 1, 2, and 3 remain at combined total 0.48 MGD
Proposed Plant Permitted Well Number 4	Not Simulated	Well 4 added at 0.52 MGD	Well 4 remains at 0.52 MGD	Well 4 increased to 0.72 MGD	Well 4 remains at 0.72 MGD

MGD = million gallons per day

5.5 SHARP Model Execution and Calibration

The model was executed for two types of situations:

- Steady-state flow with no pumping wells. This is considered a predevelopment simulation for initializing the Ghyben-Herzberg interface in the Floridan Aquifer System.
- Transient flow with pumping wells, addition of proposed well number 4, and increased pumping from well number 4.

Model execution consisted of running the steady state simulation to predict the SHARP interface within the Floridan Aquifer System. Because the constant head conditions were taken from a calibrated model, head calibration was not performed. However, the predicted Ghyben-Herzberg interface elevations were checked for reasonableness by

spot-checking predictions against the mathematical relation discussed earlier. The transient events used in the model are also defined in Table 7.

5.6 SHARP Simulation Results

The predicted steady-state heads and Ghyben-Herzberg (SHARP) interface are shown along model column 18 in Figure 28. Features worth noting are:

- The Surficial Aquifer System is shown to be too shallow to be impacted by saltwater intrusion (this ignores the small zone of mixing near the shoreline).
- The SHARP interface within the Floridan Aquifer System slopes to the north and bulges upward under the Bay areas.
- The division of the upper and lower portions of the Floridan by the predicted SHARP interface is consistent with earlier studies by Barr (1981) and Wagner (1980).
- SHARP results do not include specific chloride concentration predictions.

The transient results at the end of the present permit period are shown in Figure 29. Significant features indicated by SHARP are:

- Some upconing of interface to the existing permitted wells.
- The consistency of the original interface within about 3,000 feet of the pumping center on both the north and south sides (this is also true for the eastern extent and the western extents, even though they are not shown).

The transient results for the end of the next five-year long permit period are shown in Figure 30. Significant features predicted by SHARP are:

- The upconing of interface to the existing permitted wells is still present but reduced in elevation.
- Some upconing of the interface to the proposed new well location.
- The consistency of the original interface within about 3,000 feet of the pumping center on both the north and south sides (this is also true for the eastern extent and the western extents, even though they are not shown).
- The predicted interface at the proposed location of permitted well number 4 occurred within the permit period.
- Pumping of well 4 allows reduction in upconing under the existing wells due to their reduced pumping rate that allows the freshwater head to increase.

6.0 CONCLUSIONS

The results of the flow and density-driven flow models indicate that:

- Adding another well and increasing Plant Smith's permitted flow will not adversely affect the Floridan Aquifer System or other users of this resource.
- Regional head declines are attributable to the 4 percent per year increases by all major users of the Floridan Aquifer System in Bay County.
- Addition of the fourth permitted well will not adversely affect the Surficial Aquifer System or its associated wetlands at Plant Smith.
- SHARP model results indicate that minor local upconing of chloride bearing water will occur but will not significantly impact the Floridan Aquifer System or the nearest major user, the City of Lynn Haven.
- SHARP results also indicate that the fourth well will not cause degradation of the Floridan Aquifer System.
- Addition of well 4 will decrease saltwater encroachment in wells 1 through 3 without adversely affecting other wells in the region.

Comparing the drawn-down heads for Plant Smith and the City of Lynn Haven, Florida, (the nearest major user) show that the new well not adversely affect other users. The results shown in Figure 22 when compared against the predicted results with well 4. (Figure 23) show a small enlargement of the drawdown cone at Plant Smith, but drawdowns around the City of Lynn Haven's wells are virtually unchanged from Figure 22 to 23. The transient results shown in Figure 24 show a slightly increasing regional decline in head. However, the relationship shown in Figures 22 and 23 and Table 8 indicate regional head declines are attributable to the 4 percent per year increases (NFWMD production projection) by all major users of the Floridan Aquifer System in Bay County.

The MODFLOW results also clearly demonstrate that addition of the fourth permitted well will not adversely affect the Surficial Aquifer System or its associated wetlands at the Plant Smith location. This is seen by comparing the predicted predevelopment Surficial Aquifer System heads in Figure 19 against Figure 21. In the figures, the predicted Surficial Aquifer System heads remain the same for the cases of no wells and all wells pumping in the Floridan Aquifer System.

The SHARP model results indicate that minor local upconing of chloride bearing water will occur but will not significantly affect the Floridan Aquifer System or the nearest major user, the City of Lynn Haven. A SHARP interface occurs between the elevations of -700 and -250 feet MSL. in the subsurface under the Plant Smith and nearby surroundings. The SHARP results show the existing three wells cause some local upconing of the SHARP interface between the years 1965 through 1999 (Figure 29). The chloride levels measured by Gulf (Table 5) shed light on what the SHARP interface represents, that the chlorides are present and may increase and dissipate rapidly over time. The SHARP model indicates a similar pattern for the Plant Smith wells by predicting an increase in interface elevation over time. However, in the surrounding area,

chloride levels are not predicted to be affected by pumping in the Plant Smith wells (Figures 29 and 30). Plant Smith chloride results also indicate that periods of increased chlorides dissipate rapidly. This is supported by the SHARP simulation results, shown in Figure 30, which shows that a local cone developed under the fourth well rather rapidly (less than four years) and the pre-existing upconing at the existing wells rapidly dissipate (less than four years) to a lower level (again, in less than four years). Since the upconing process is reversible, it stands to reason that the dissipation of the cone would occur in approximately the same time frame as it formed (in less than four years). The SHARP results also indicate that the fourth well will not cause degradation of the Floridan Aquifer System on a regional scale by comparing the predevelopment interface (Figure 28) to the unperturbed portions of the interface in Figures 29 and 30.

7.0 RECOMMENDATIONS

This study has shown that no adverse or irreversible impacts will occur to the Floridan Aquifer System due to the operation of the already permitted but not installed fourth well at Plant Smith in Southport, Bay County, Florida. Gulf recognizes the importance of the Floridan Aquifer System to the successful operation of the plant and to the community. Gulf believes this study warrants recommending:

- Future use of the fourth well at the proposed location.
- Reducing daily flow from the existing wells 1, 2, and 3 to allow chloride levels to remain lower to the south after well number 4 comes on line.
- Pumping the fourth well at its permitted rate to compensate for the reduced rate in the existing wells.
- After bringing well 4 on line, install an automated system to rotate pumping schedules on a daily basis among wells 1, 2, and 3. This recommendation is important in order to ensure proper daily rotation.
- Conduct quarterly chlorides monitoring in all Plant Smith water supply wells to ensure water quality remains high for both the Floridan Aquifer System and the plant.

8.0 REFERENCES

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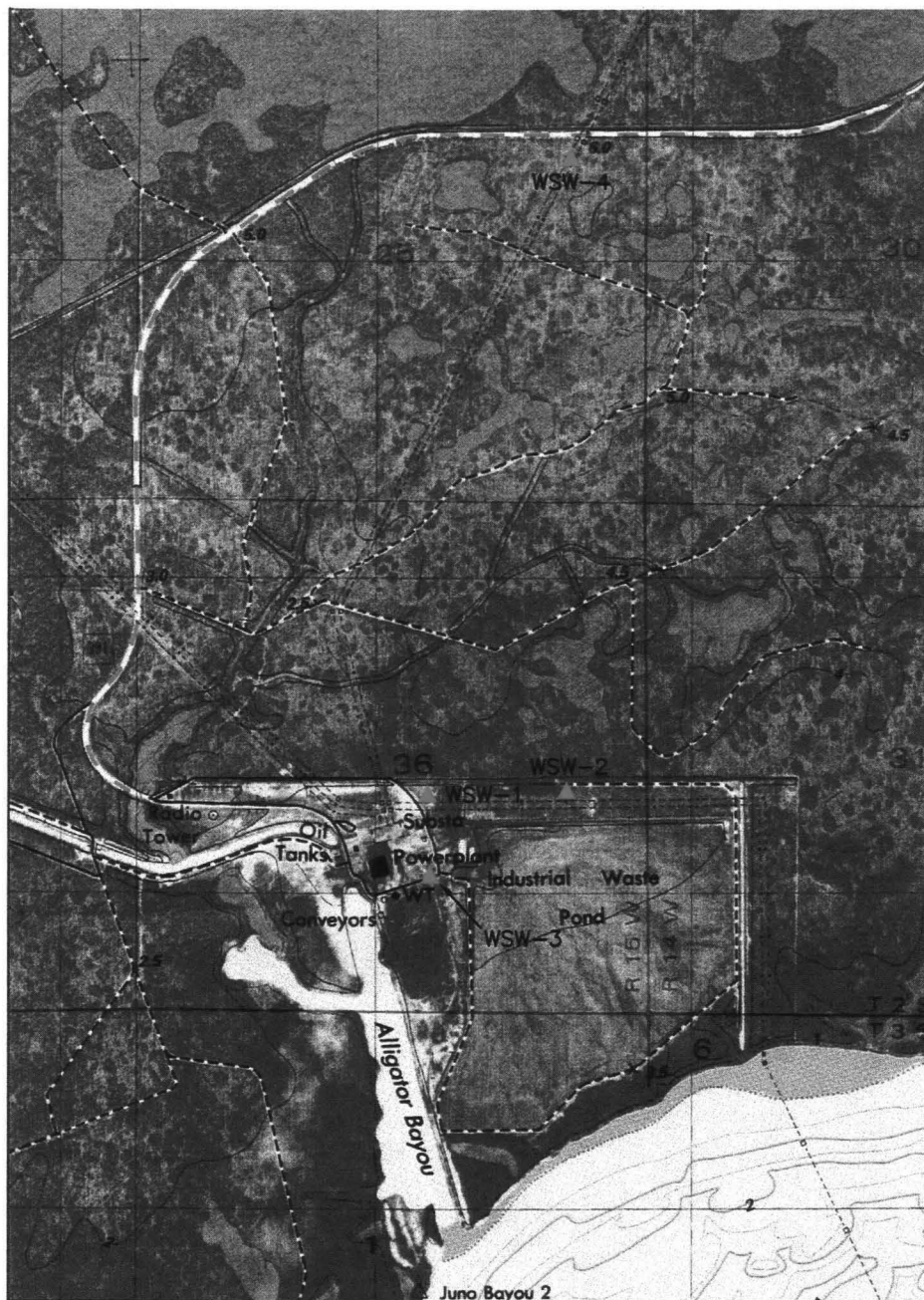
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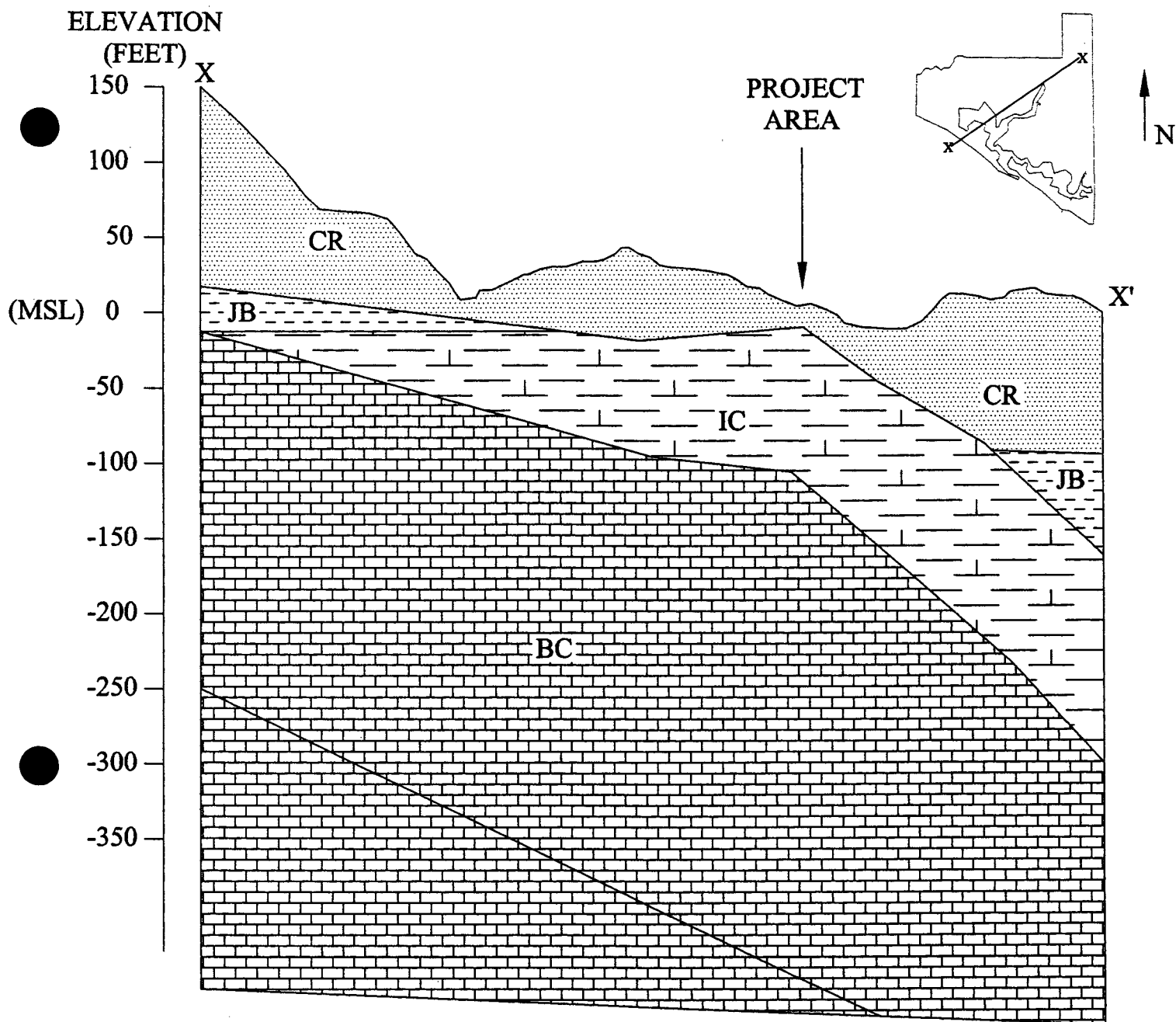
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▲ APPROX. WATER SUPPLY WELL LOCATION

1000 0 1000 2000 3000 4000 5000 FEET

SCALE 1:24000

Figure 1
Plant Smith Location Map
and Water Well Supply



LEGEND:

CR = CITRONELLE FORMATION AND RECENT SANDS
 JB = JACKSON BLUFF FORMATION
 IC = INTRACOASTAL FORMATION
 BC = BRUCE CREEK LIMESTONE

Figure 2
 Geologic Cross Section
 of Bay County Florida
 (After Schmidt and Clark, 1980)

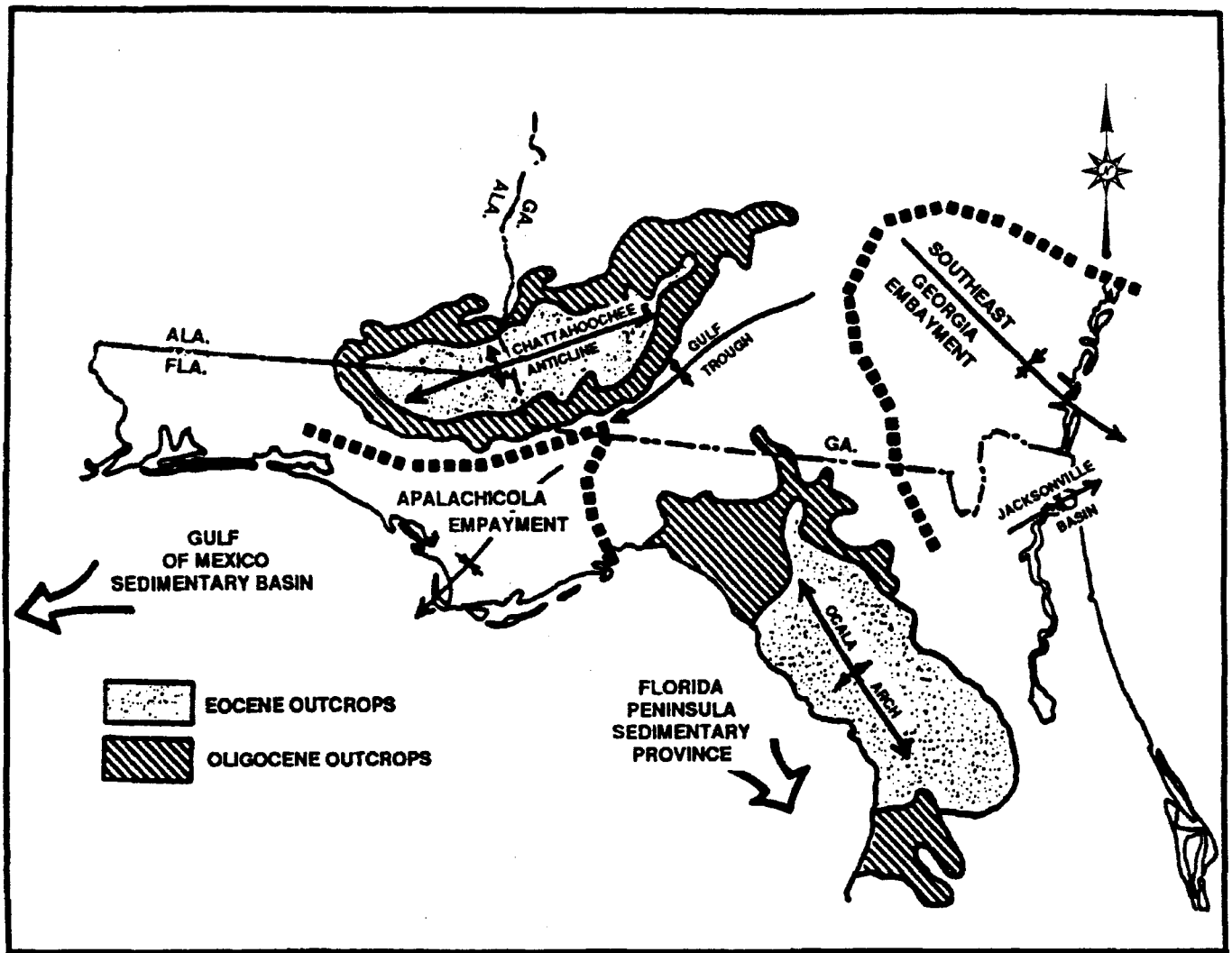
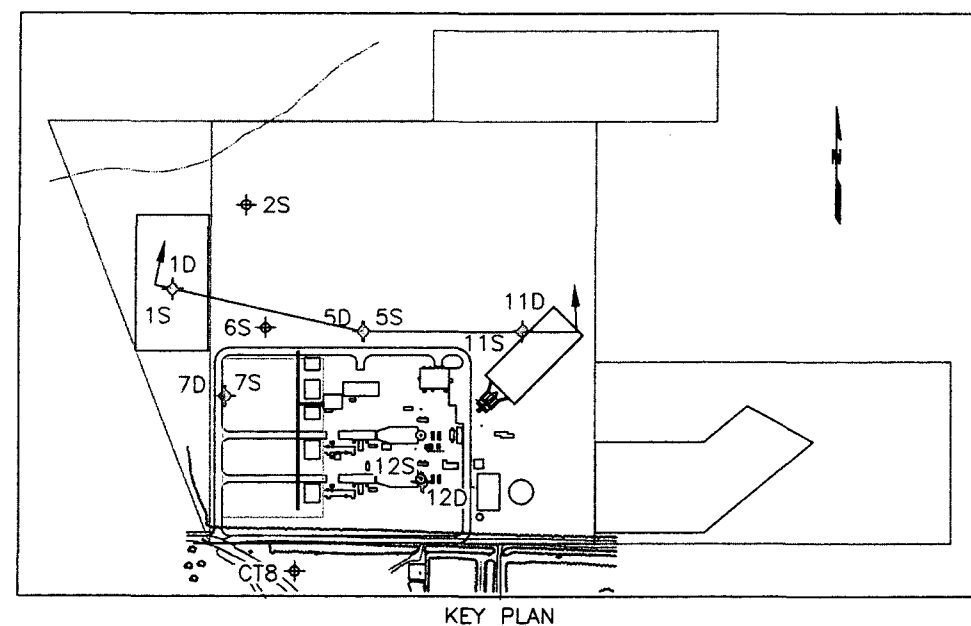
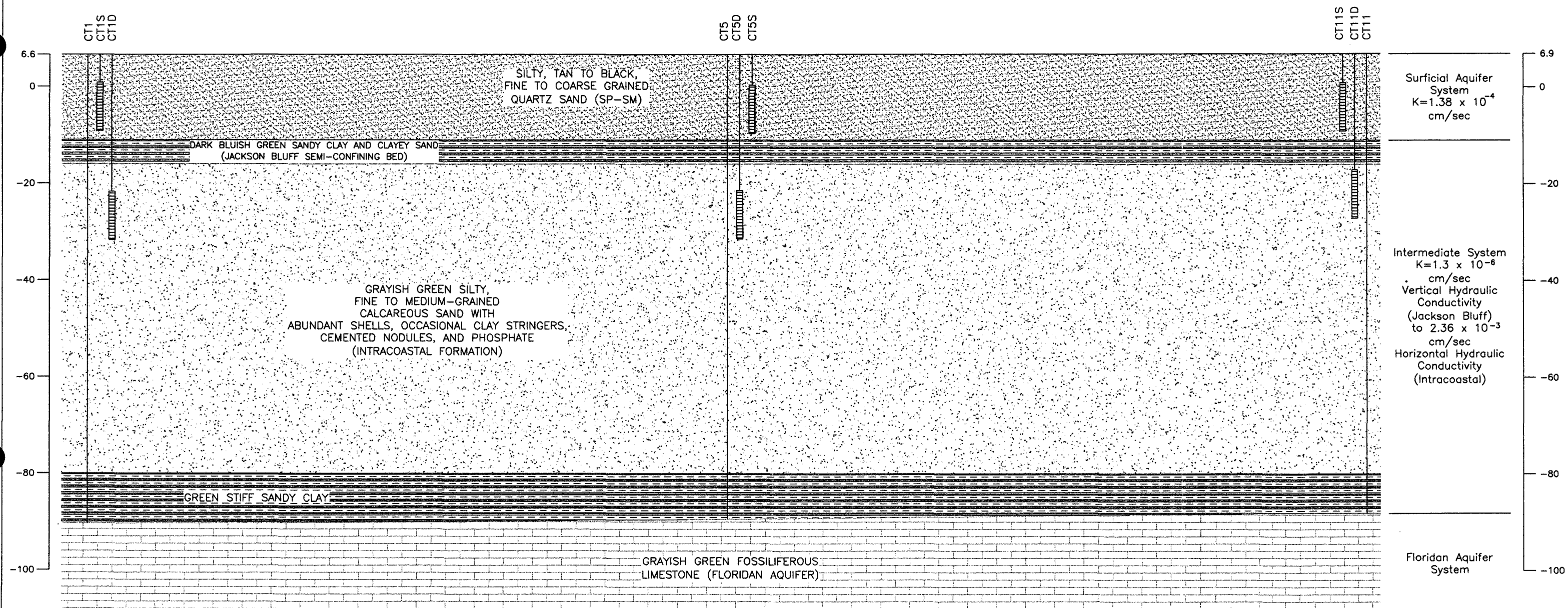


Figure 3
Regional Geologic Structures
of the Florida Panhandle
(After Schmidt, 1984)



HORIZONTAL SCALE: 1" = 80'
 VERTICAL SCALE: 1" = 20'

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Figure 4
Plant Smith
Typical Geological
Section

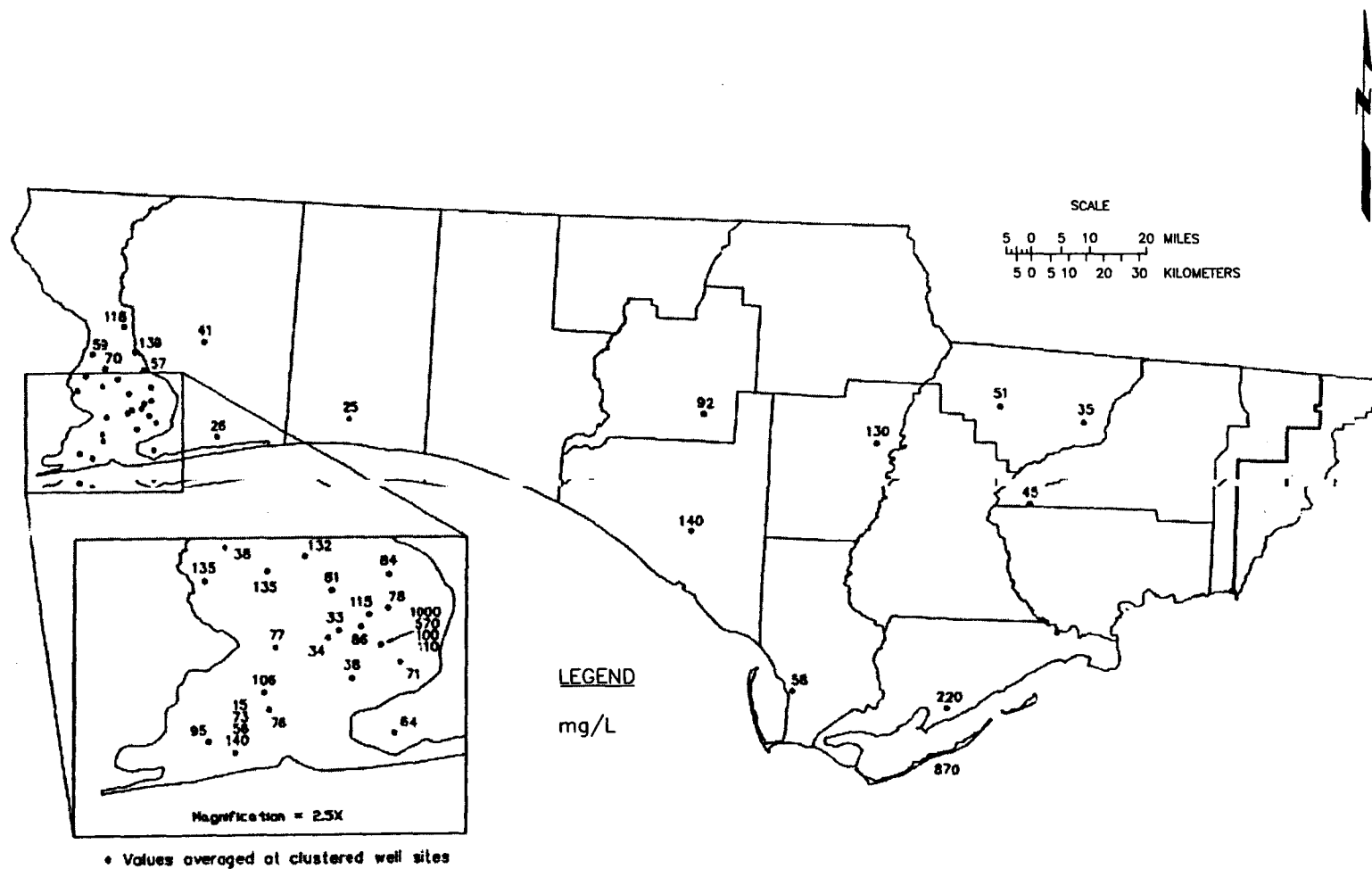


Figure 5
 Distribution of Total Dissolved Solids (TDS; mg/L)
 in the Surficial Aquifer System
 (Maddox and others, 1992)

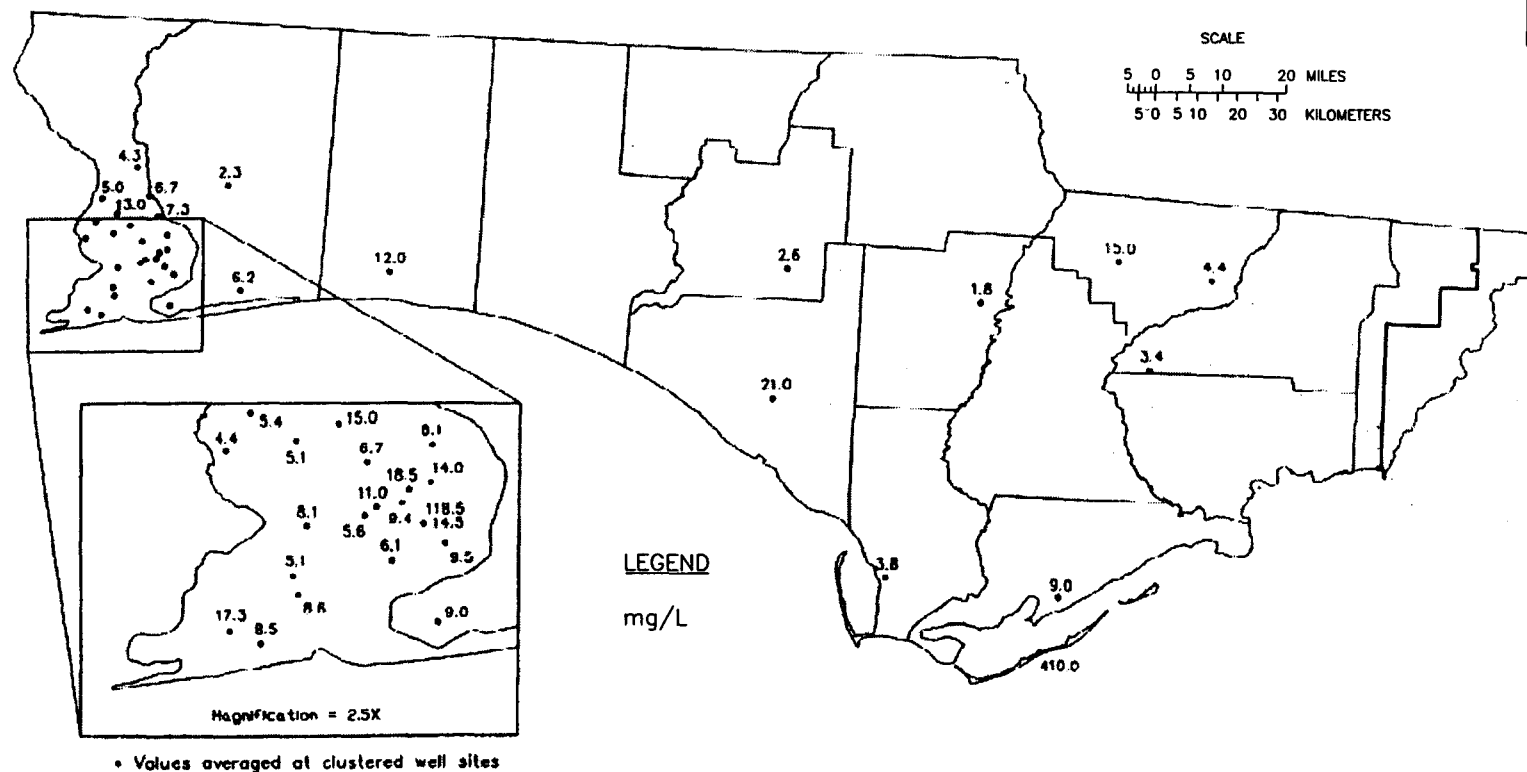


Figure 6
 Distribution of Total Chloride (Cl; mg/L)
 in the Surficial Aquifer System
 (Maddox and others, 1992)

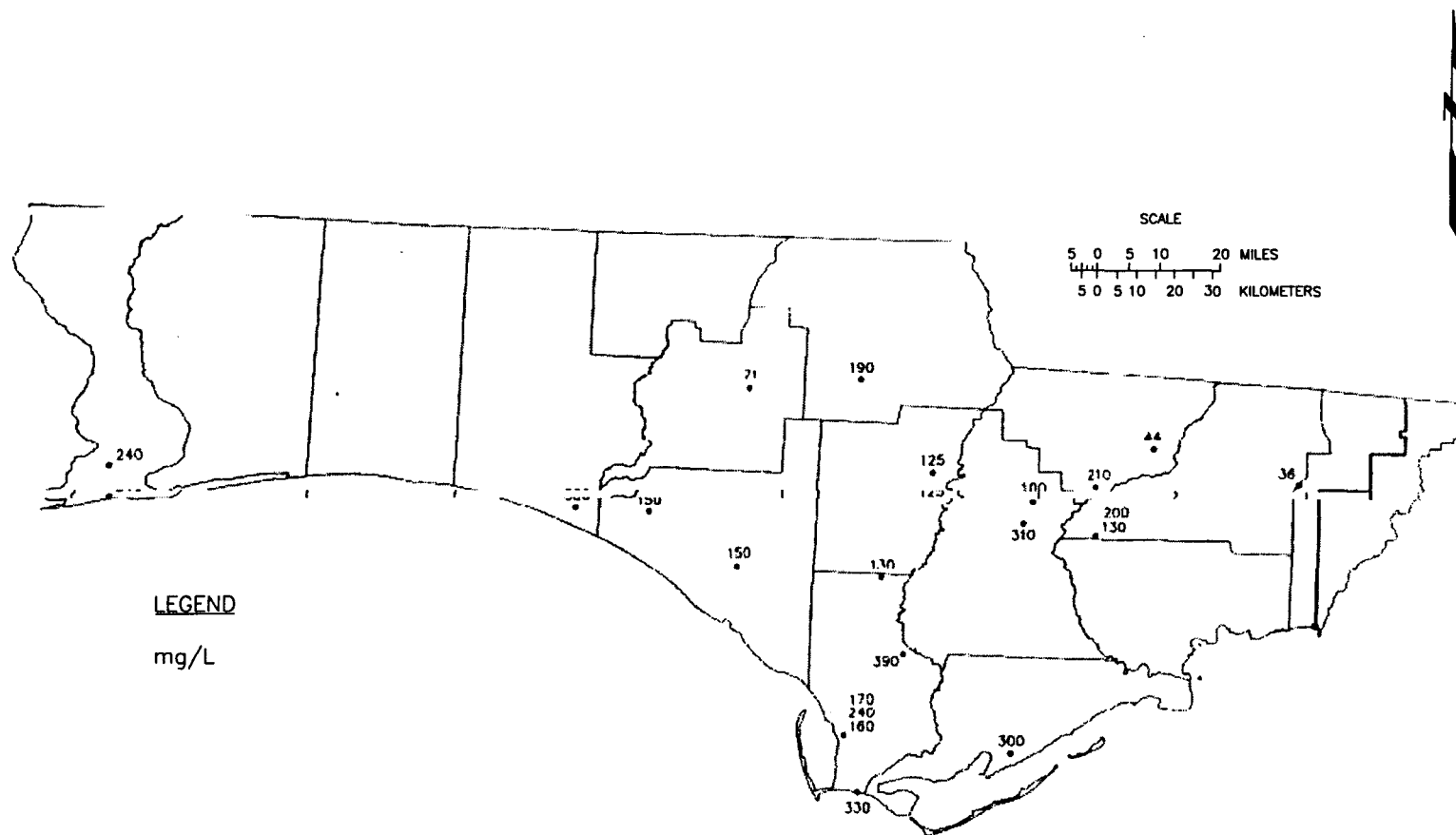


Figure 7
Distribution of Total Dissolved Solids (TDS; mg/L)
in the Intermediate Aquifer System
(Maddox and others, 1992)

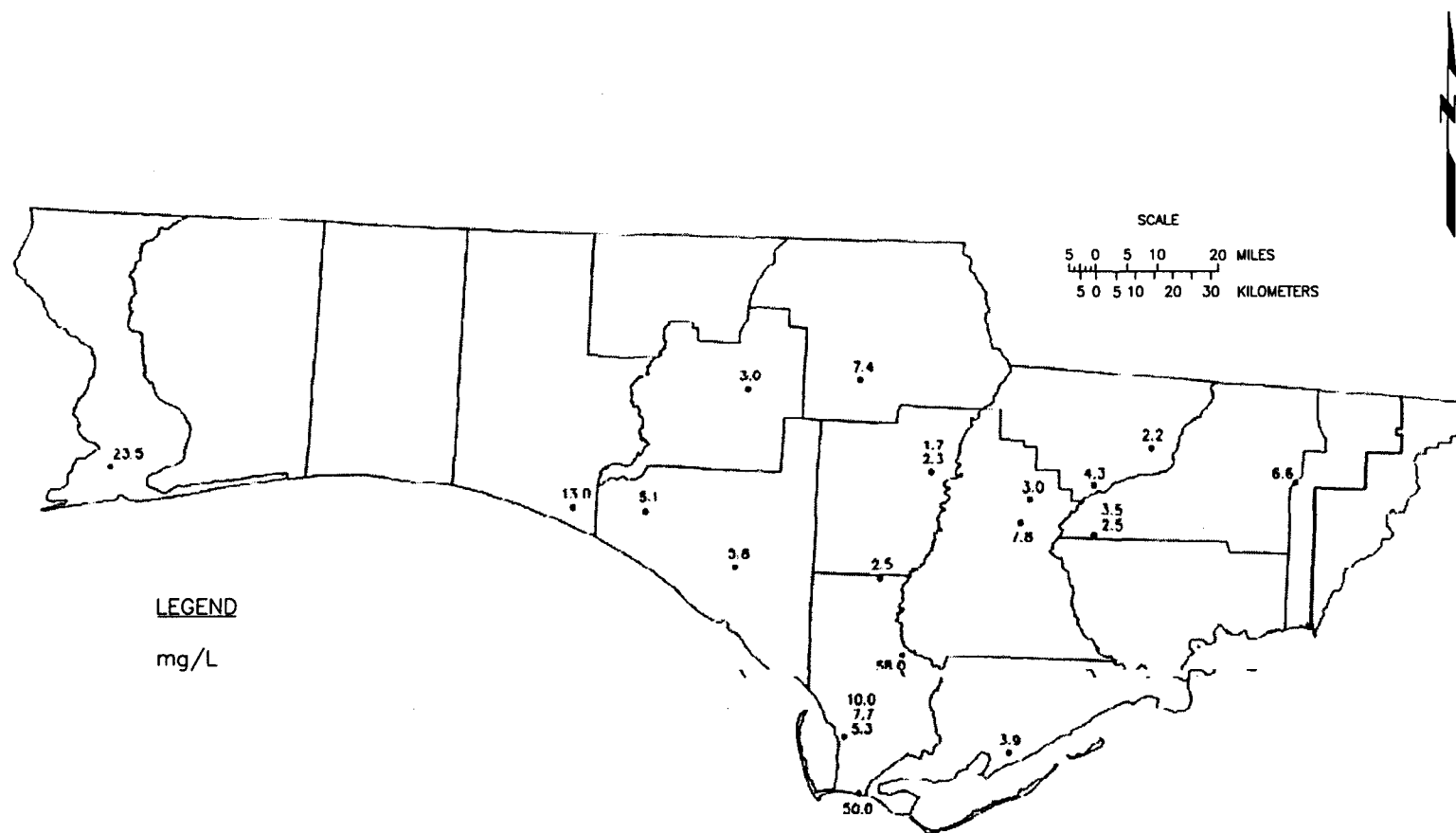


Figure 8
Distribution of Total Chloride (Cl; mg/L)
in the Intermediate Aquifer System
(Maddox and others, 1992)

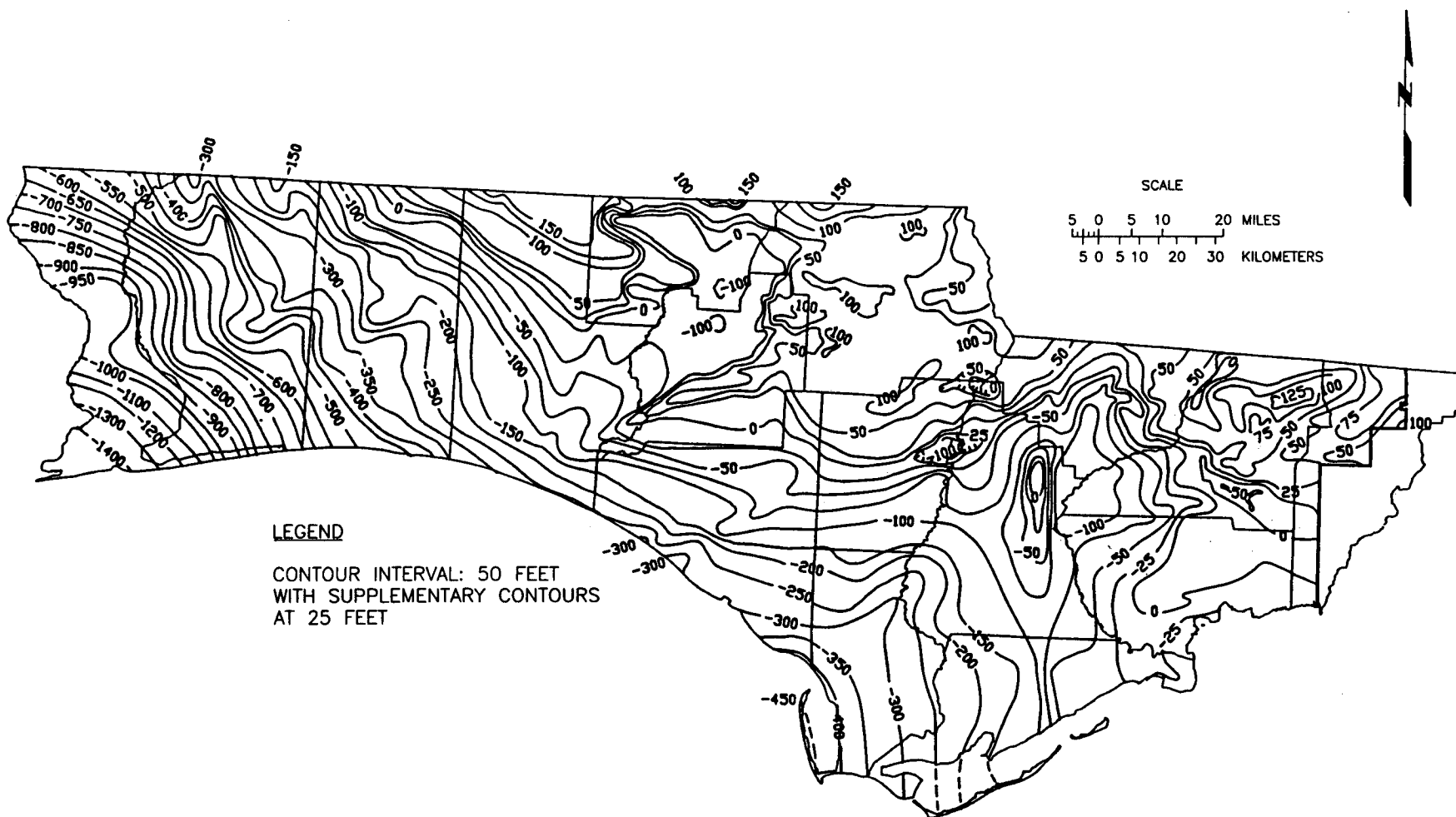


Figure 9
Top of the Floridan Aquifer System
(Scott and others, 1991)

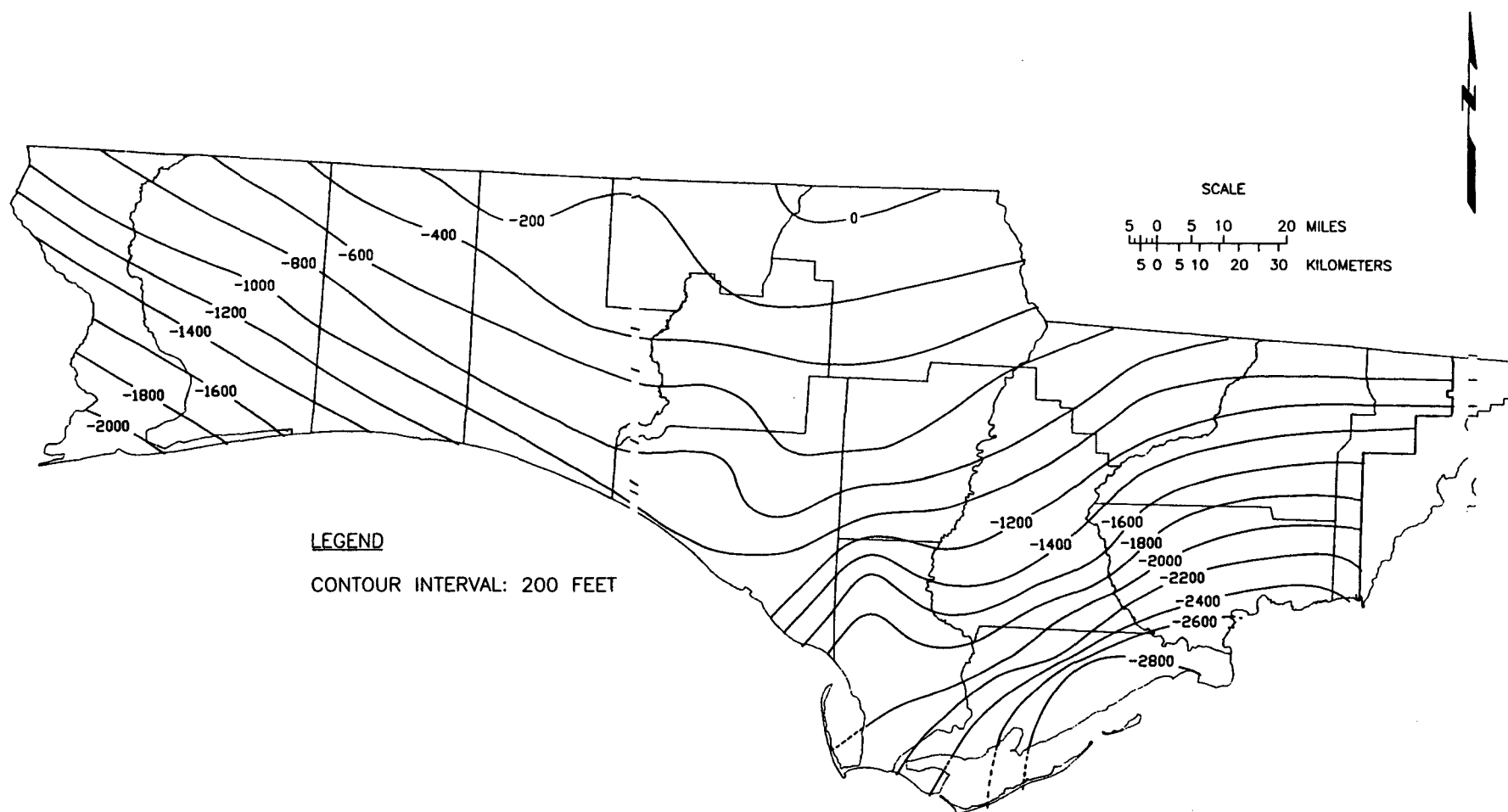


Figure 10
Base of the Floridan Aquifer System
(Scott and others, 1991)

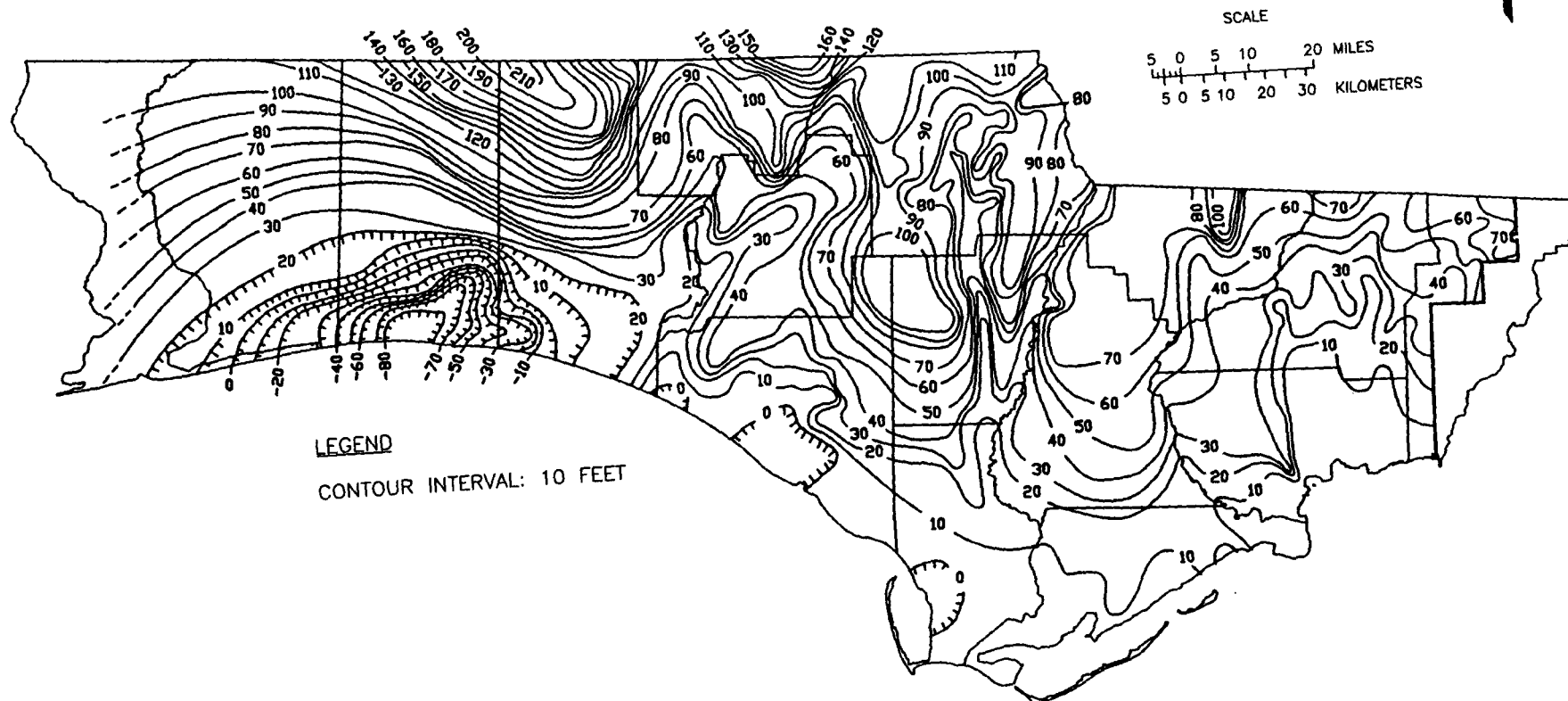


Figure 11
Floridan Aquifer System
Potentiometric Surface
(Scott and others, 1992)

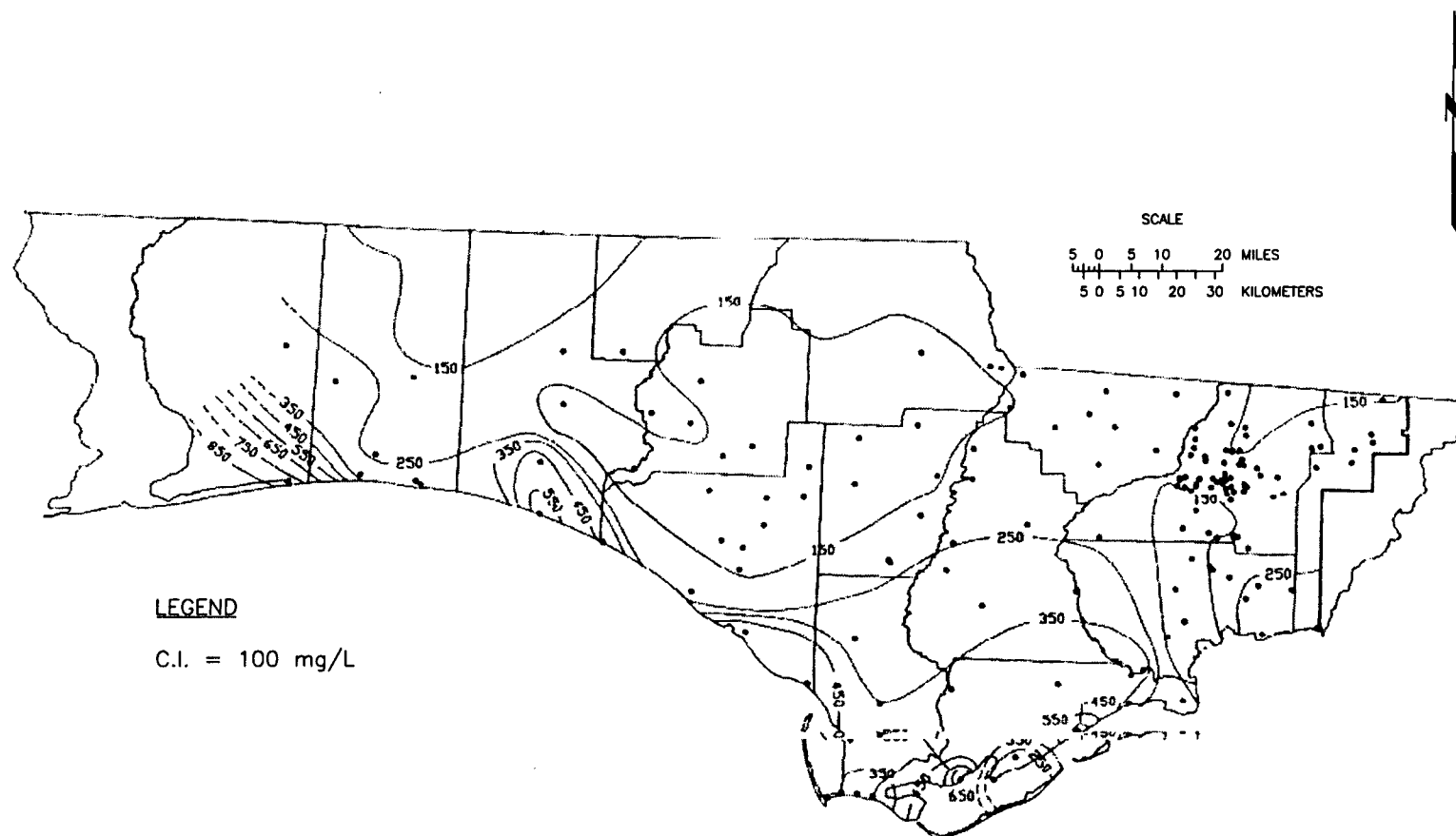


Figure 12
Distribution of Total Dissolved Solids (TDS; mg/L)
in the Floridan Aquifer System
(Maddox and others, 1992)

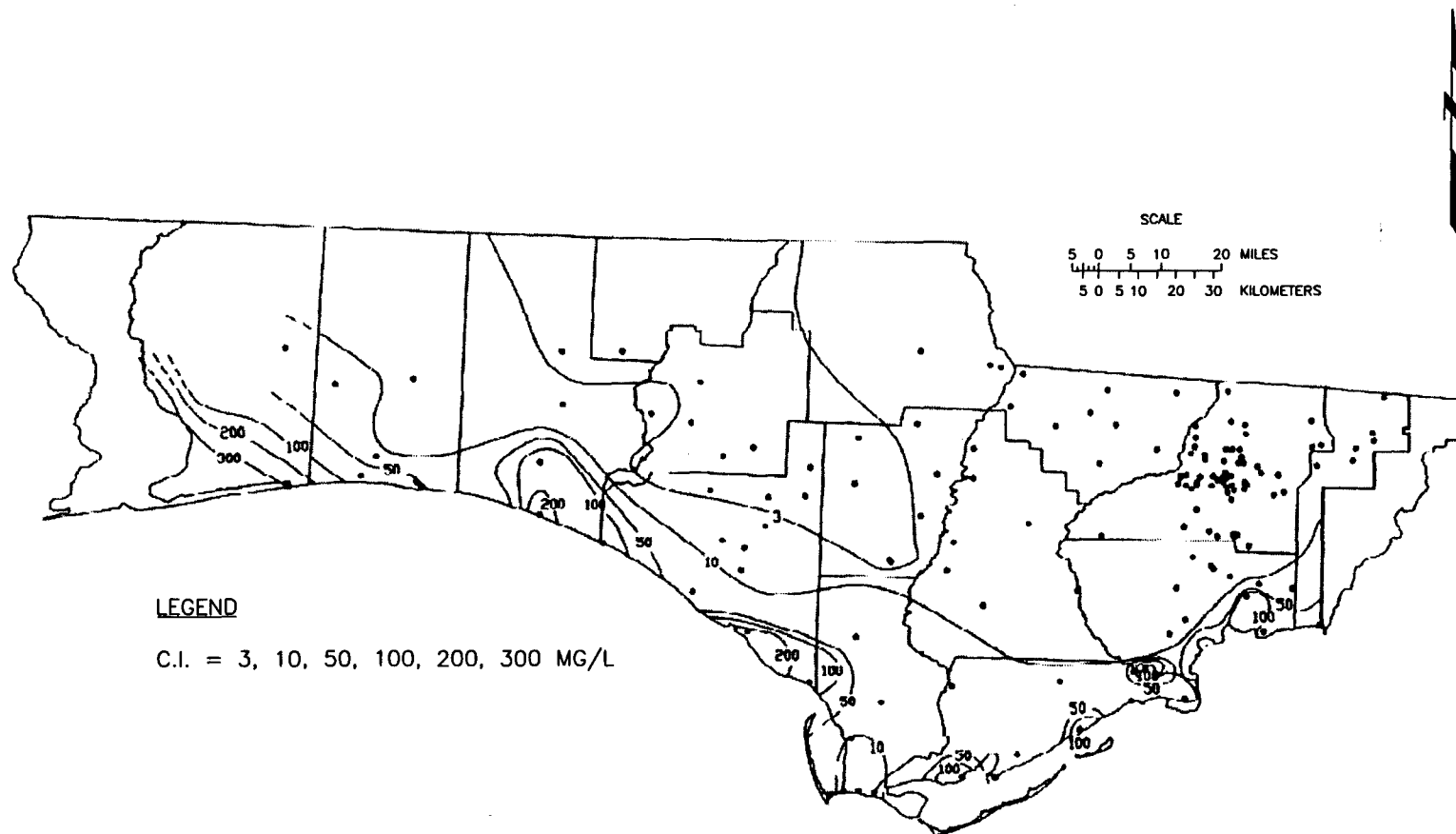


Figure 13
Distribution of Total Chloride (Cl; mg/L)
in the Floridan Aquifer System
(Maddox and others, 1992)

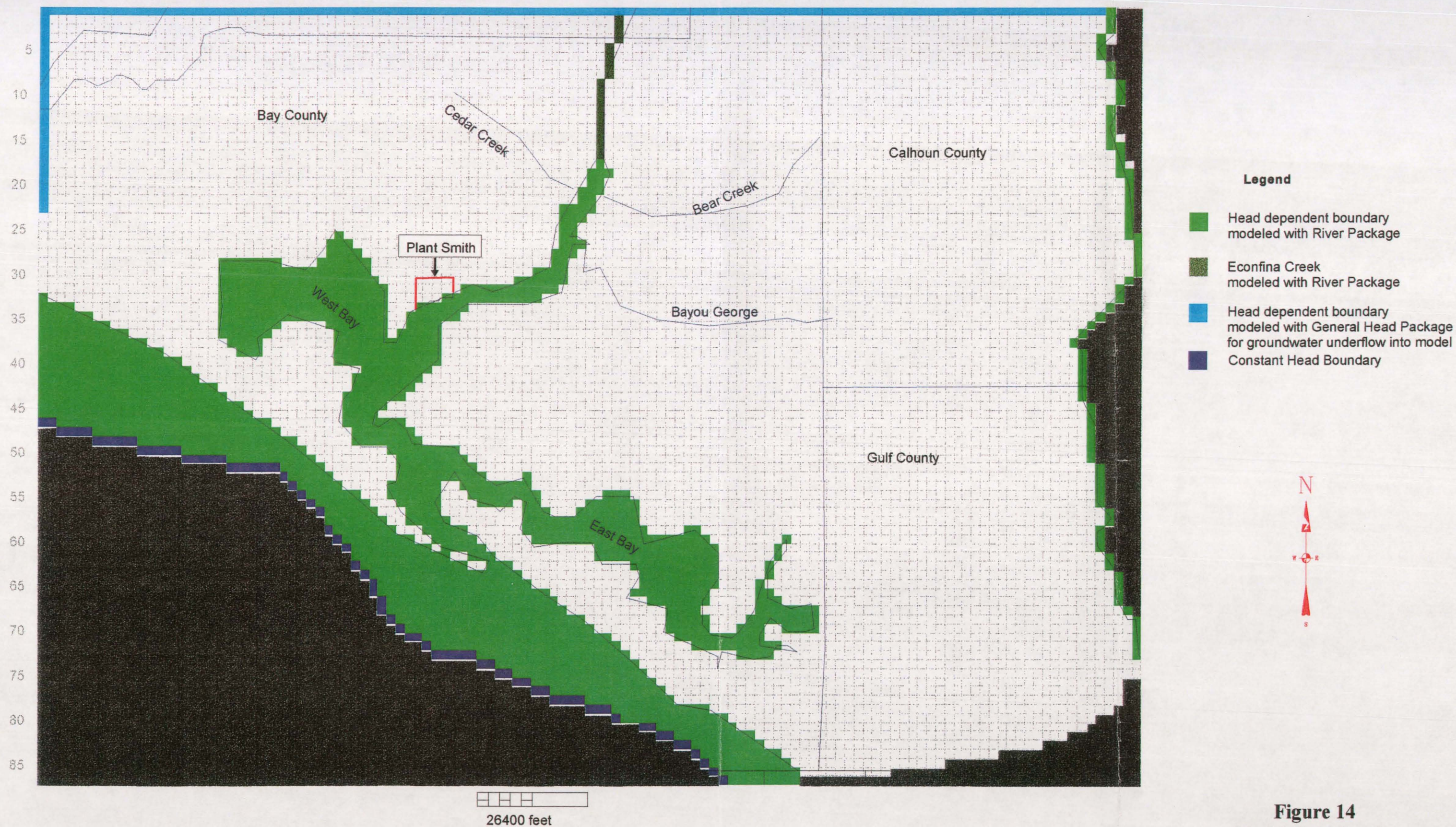


Figure 14
Model Grid for the
Surficial Aquifer System

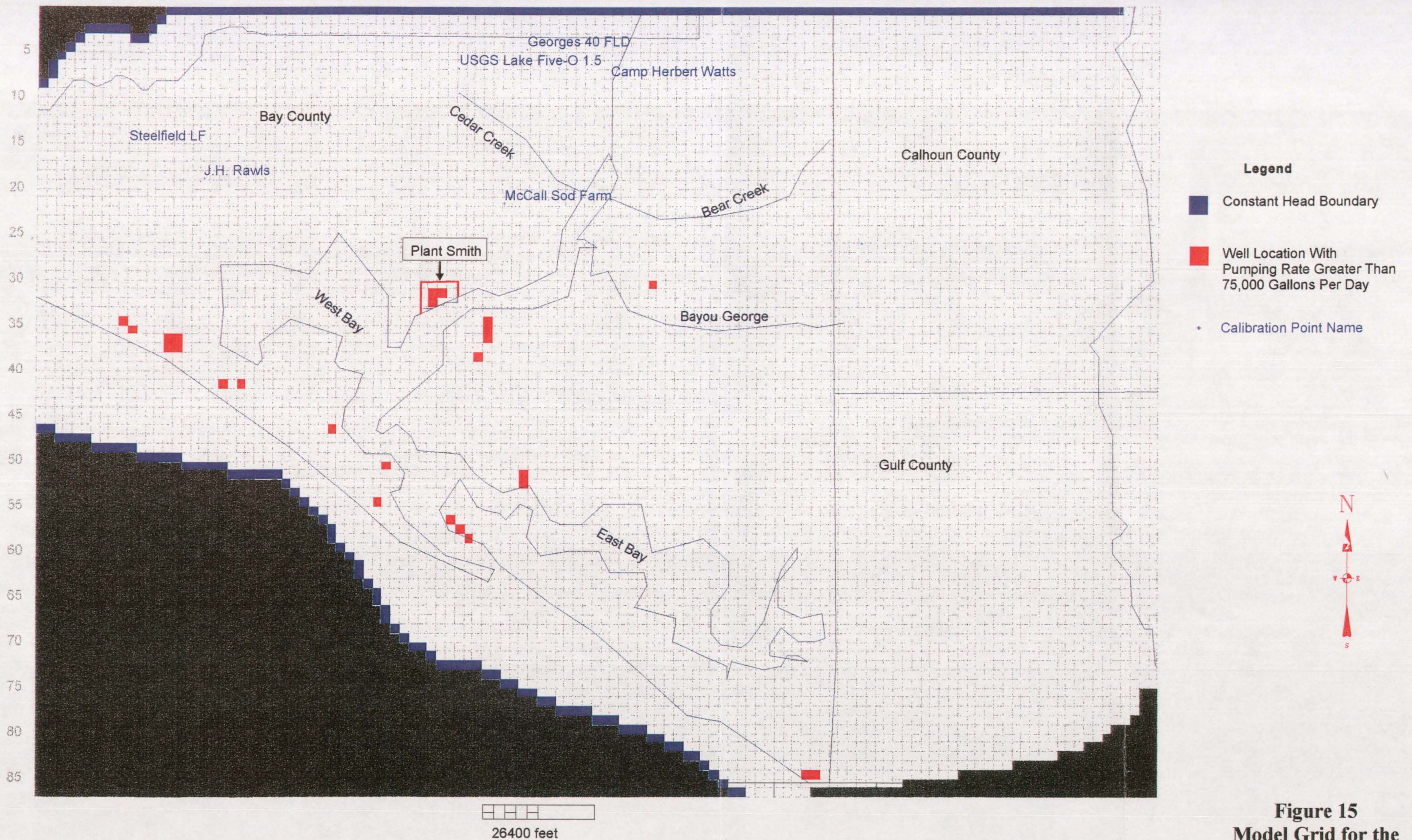
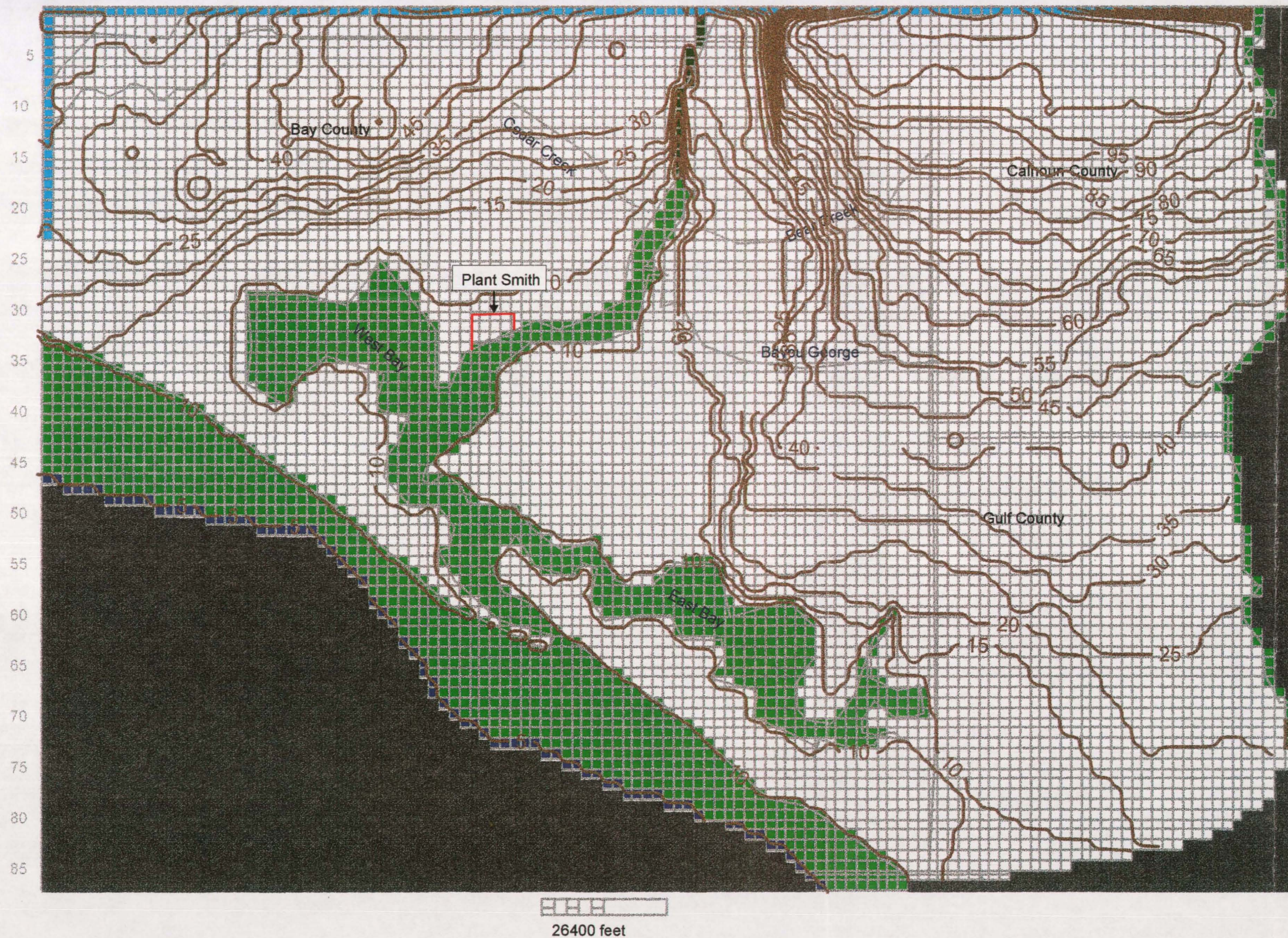


Figure 15
Model Grid for the
Floridan Aquifer System



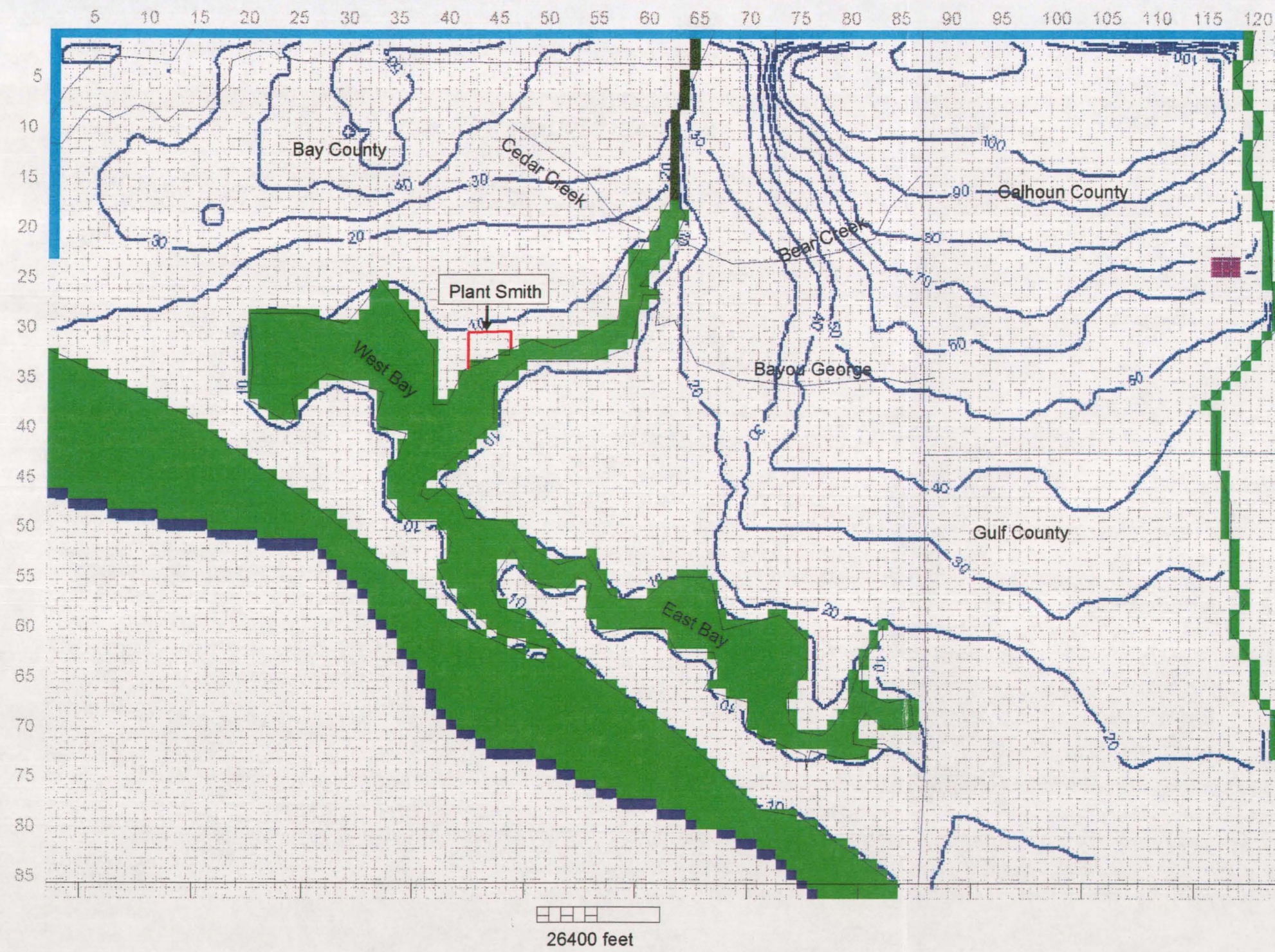
- Legend**
- Layer Top Elevation Contour with contour interval of 5 feet
 - Head dependent boundary modeled with River Package
 - Econfinia Creek modeled with River Package
 - Head dependent boundary modeled with General Head Package for groundwater underflow into model
 - Constant Head Boundary
 - Inactive Cells



Figure 16
Surficial Aquifer System
Top Elevation Contours
(ft MSL)



Figure 18
Intermediate System Leakance Values Used
in Layer 1 Vertical Conductance Array



- Legend**
- Head dependent boundary modeled with River Package
 - Econfinia Creek modeled with River Package
 - Head dependent boundary modeled with General Head Package for groundwater underflow into model
 - Constant Head Boundary

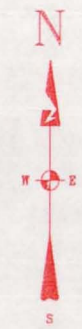


Figure 19
Predicted Predevelopment
Surficial Aquifer System Heads

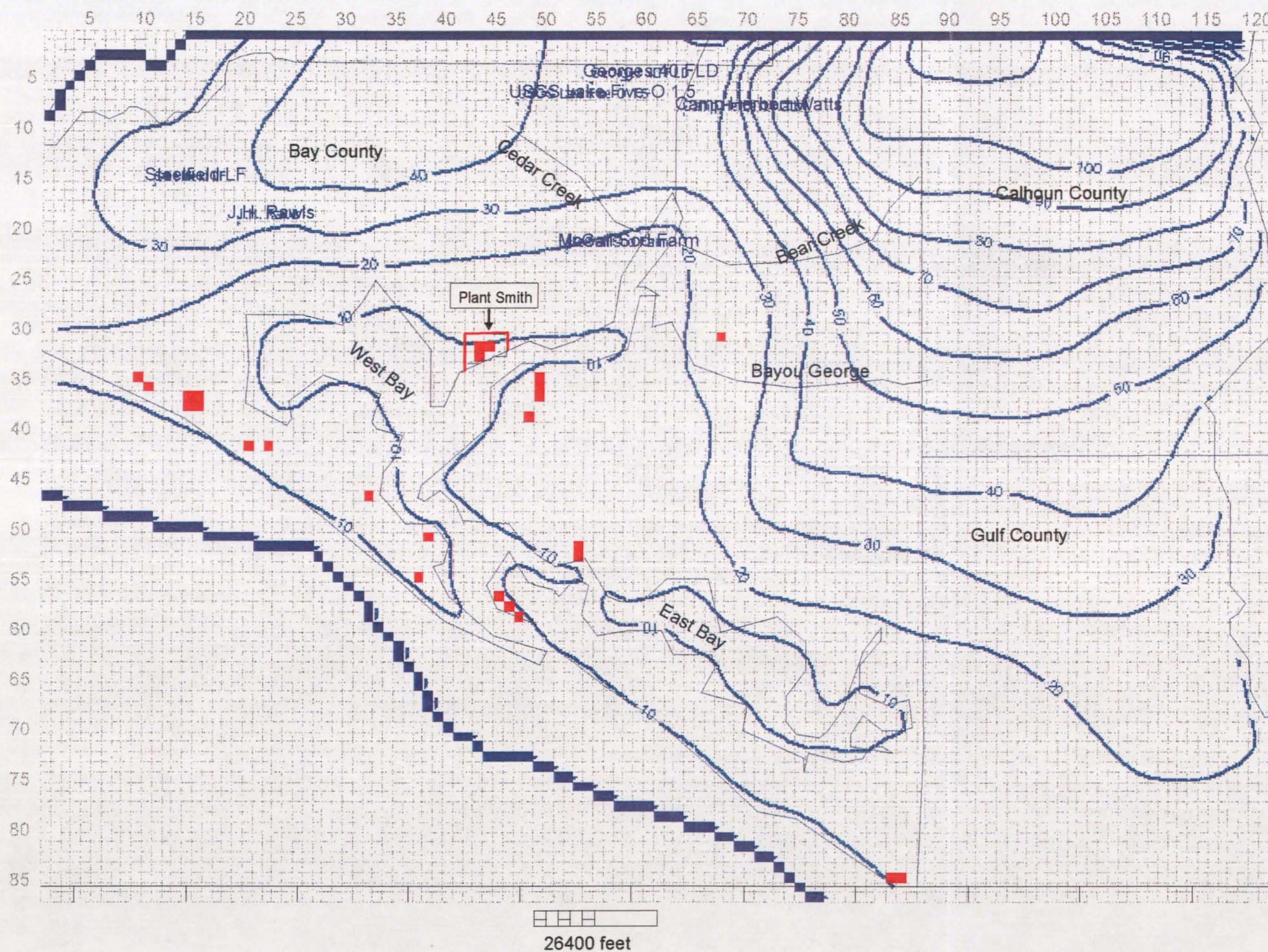


Figure 20
Predicted Predevelopment
Floridan Aquifer System Heads
No Wells Pumped in this Simulation

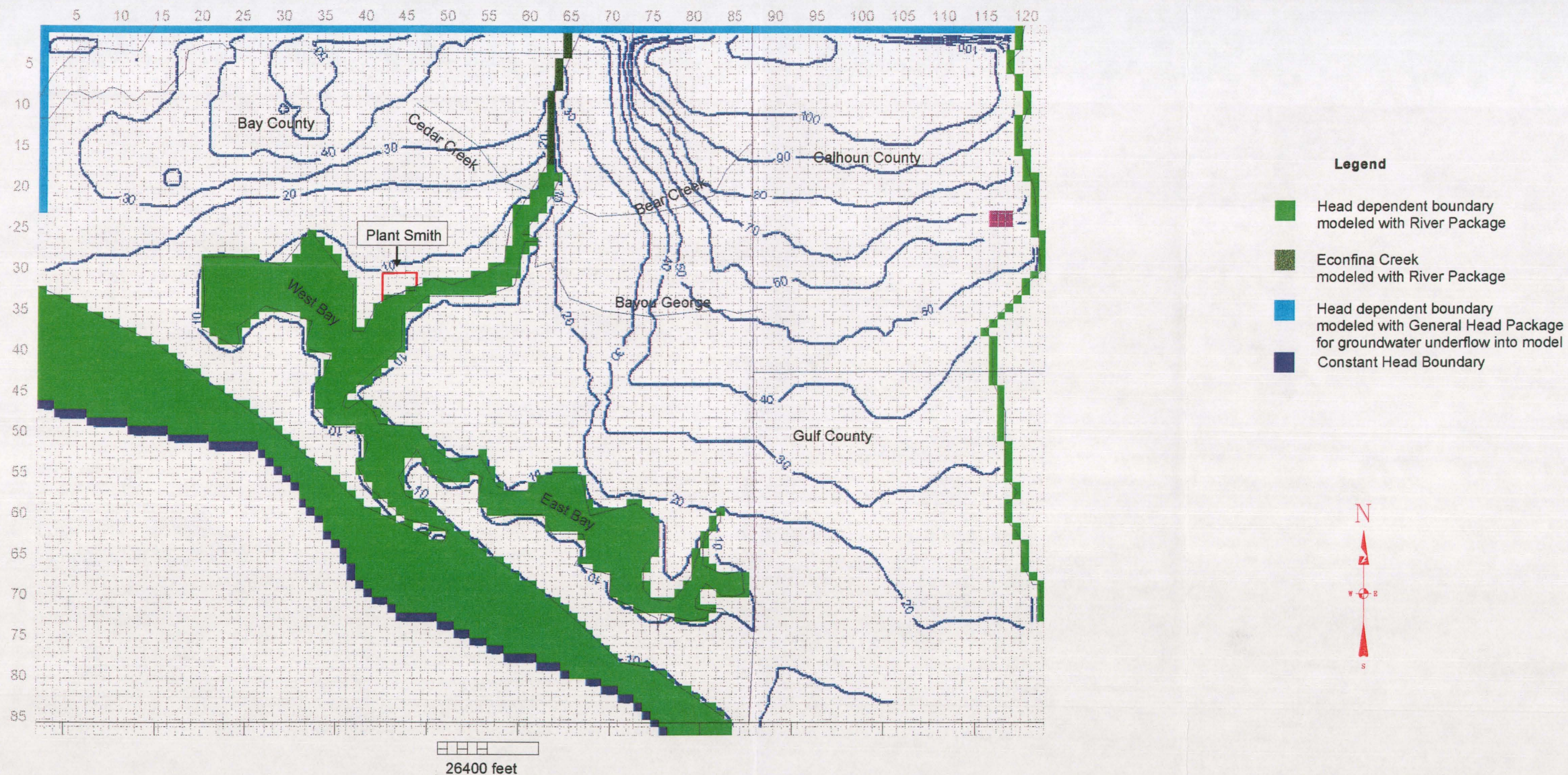


Figure 21
Predicted Surficial Aquifer System Heads
With Wells Pumping In the Floridan Aquifer System

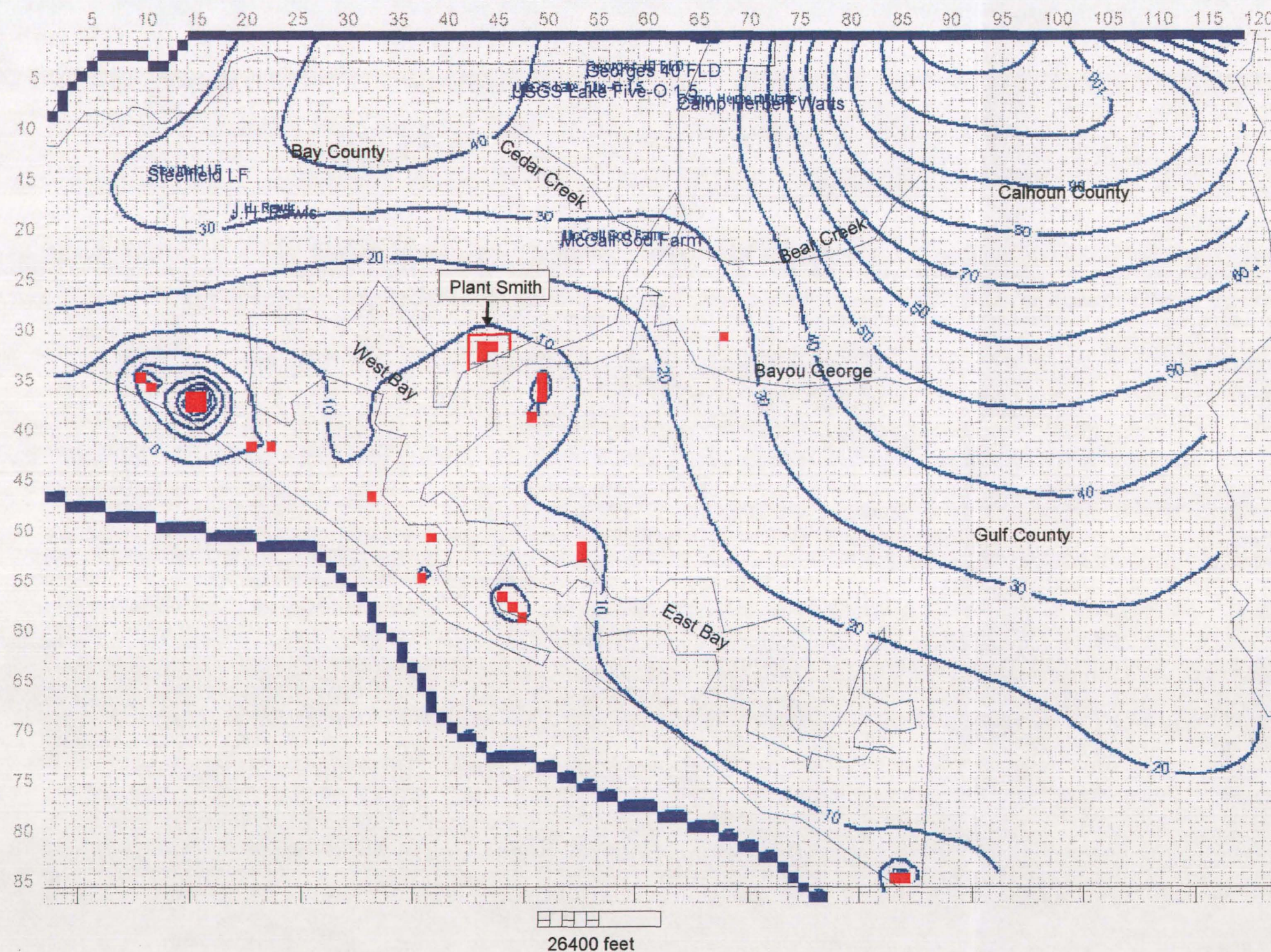
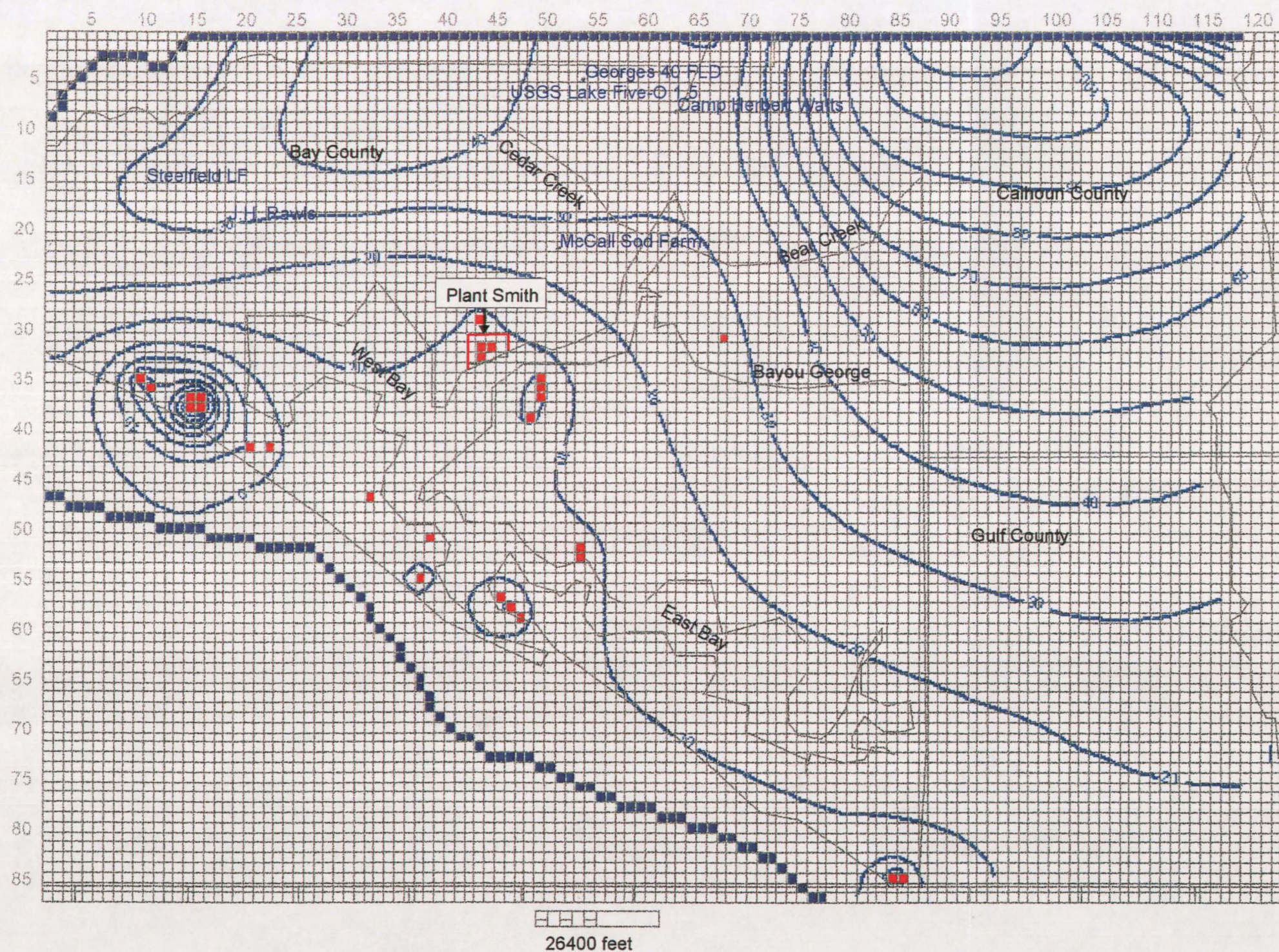


Figure 22
Predicted Floridan System Heads
With Existing Wells Pumping



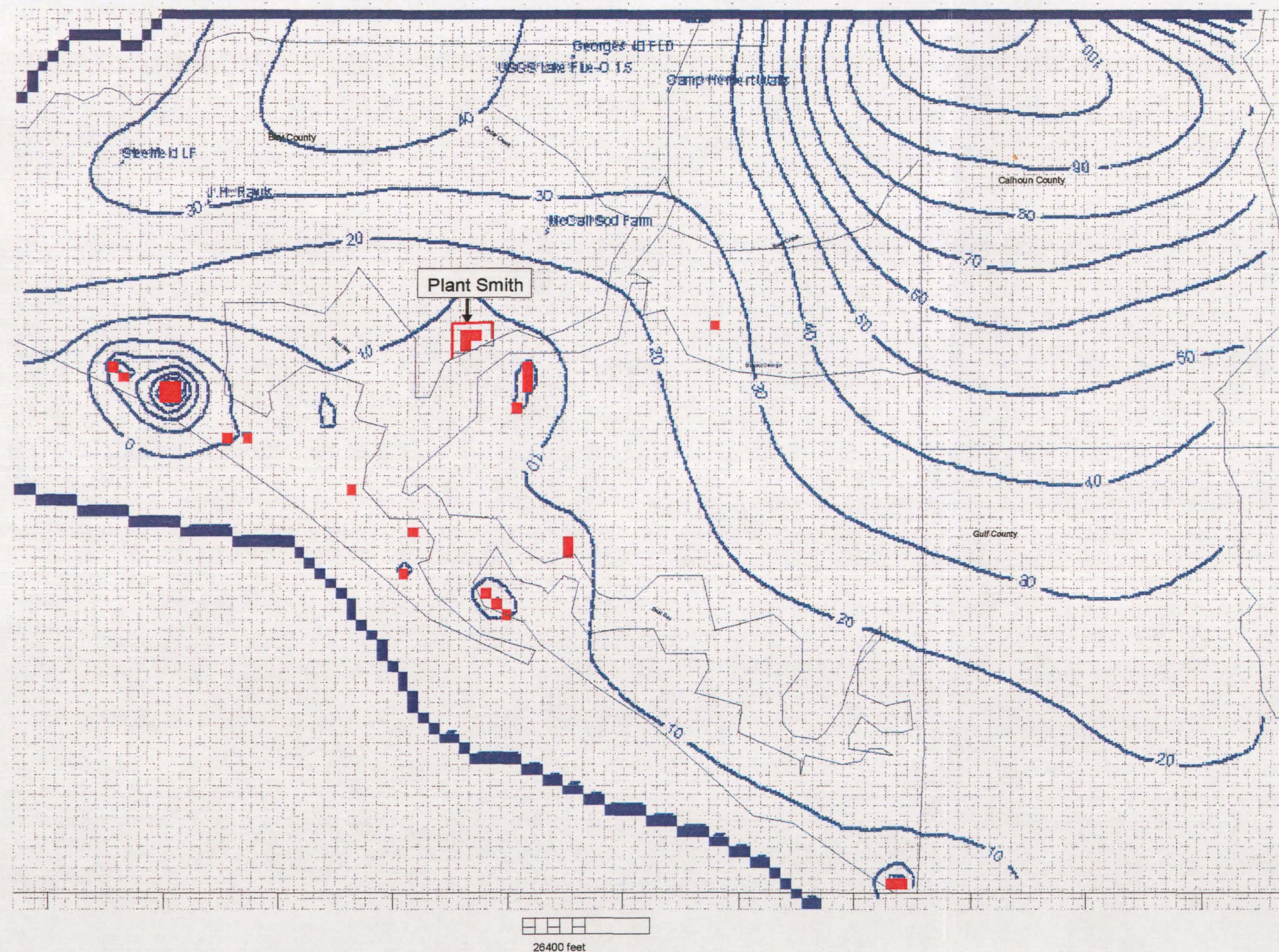
Legend

Constant Head Boundary

Well Location With
Pumping Rate Greater Than
75,000 Gallons Per Day



Figure 23
Predicted Floridan System Heads
With Existing Wells Pumping and
New Lansing Smith Well 4



- Legend**
- Constant Head Boundary
 - Well Location With Pumping Rate Greater Than 75,000 Gallons Per Day



Figure 24
Predicted Transient Heads in the
Floridan Aquifer System at the
End of the Next Permit Period

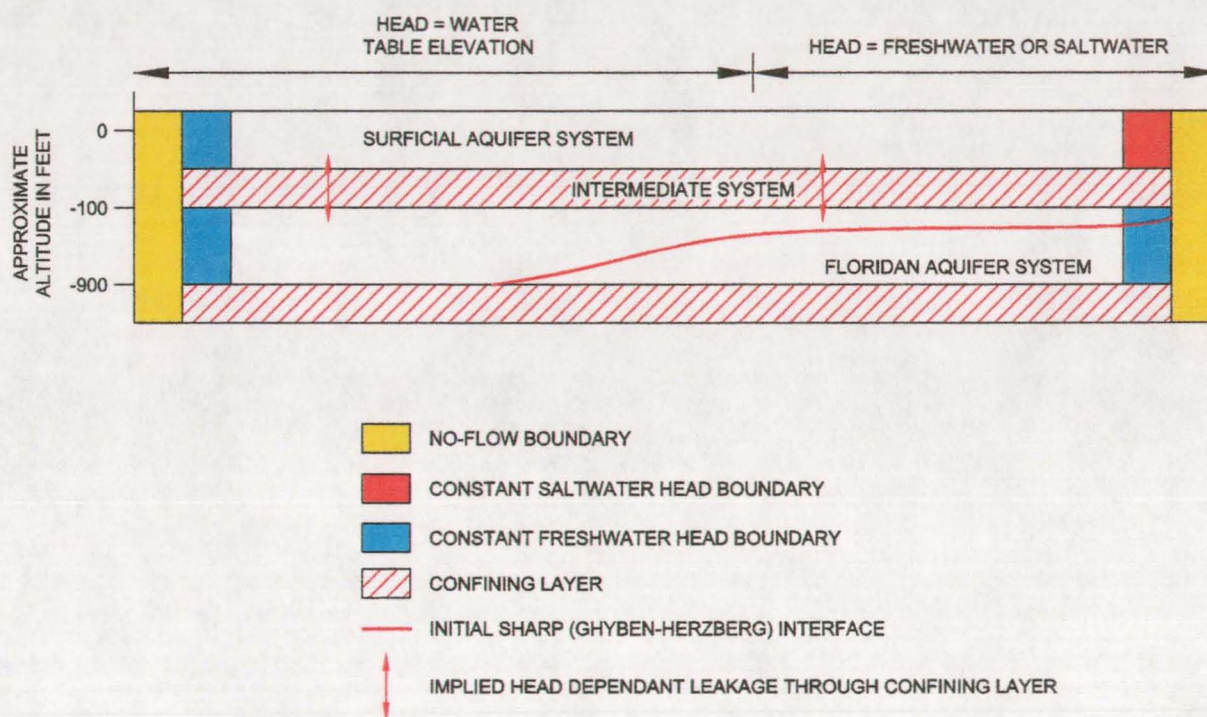
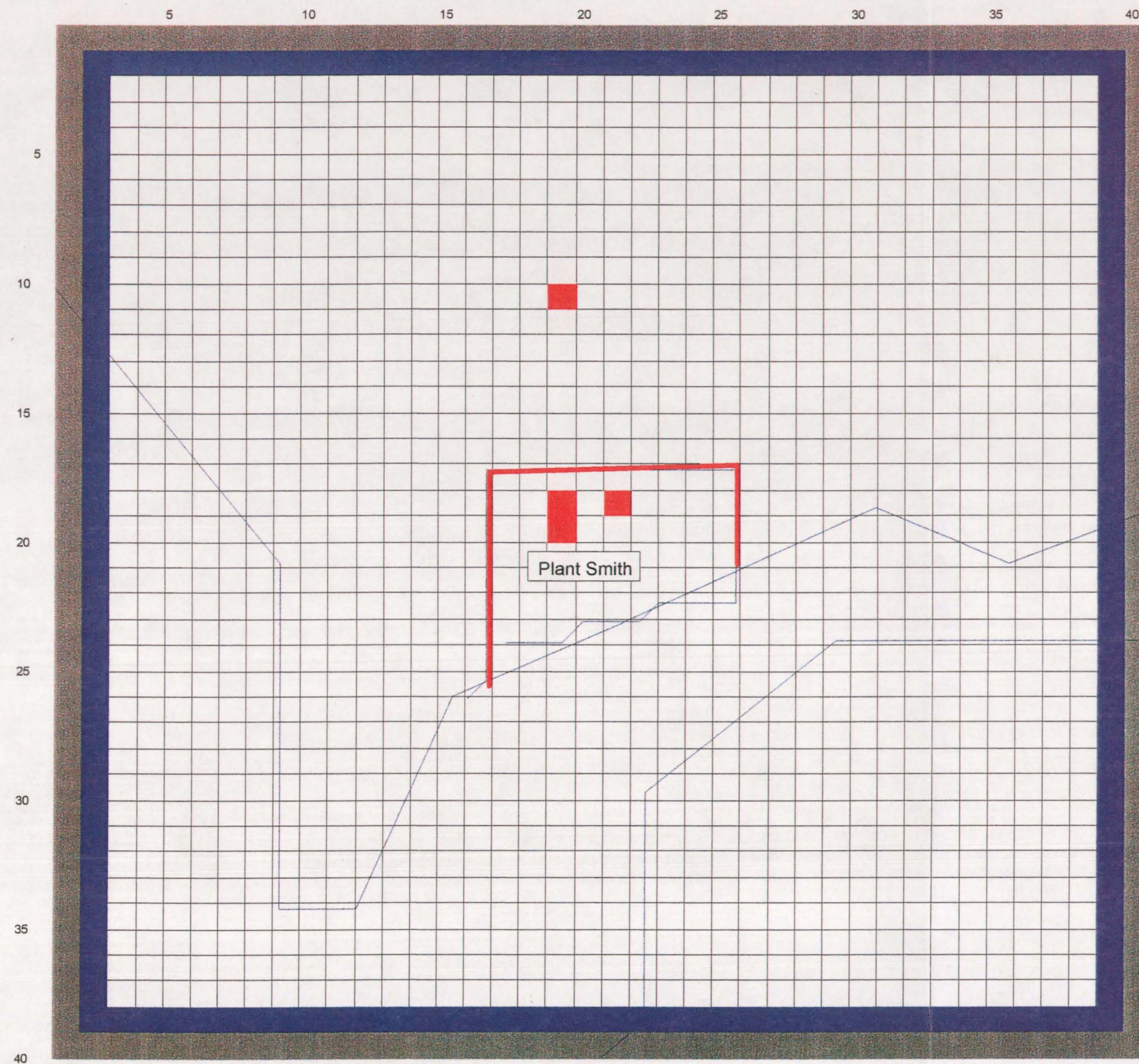


Figure 25
SHARP Conceptual
Model Section



Legend

- Plant Wells Modeled as Specified Flow Boundaries
- Freshwater Constant-Head Boundary
- No Flow Boundary Condition

Scale

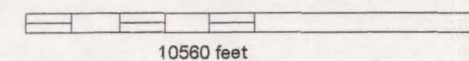
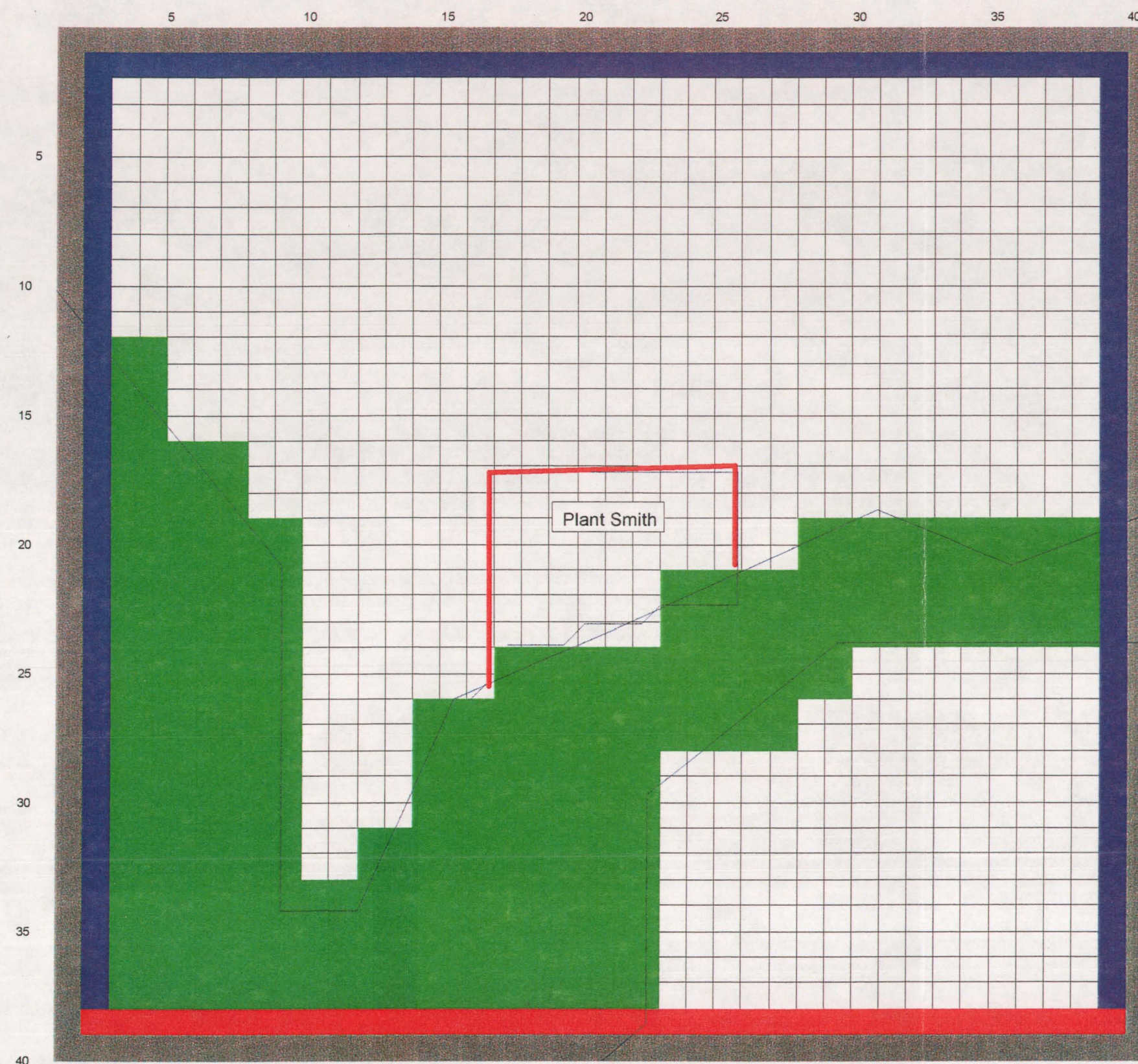


Figure 26
Plant Smith SHARP Grid
for Layer 1 (Floridan
Aquifer System)



Legend

- Bay Area Saltwater Constant Head Boundary
- Saltwater Constant-Head Used to Initialize SHARP Interface
- Freshwater Constant-Head Boundary
- No Flow Boundary Condition

Scale

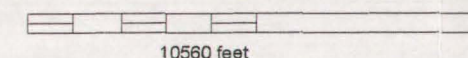


Figure 27
Plant Smith SHARP Grid
for Layer 2 (Surficial
Aquifer System)

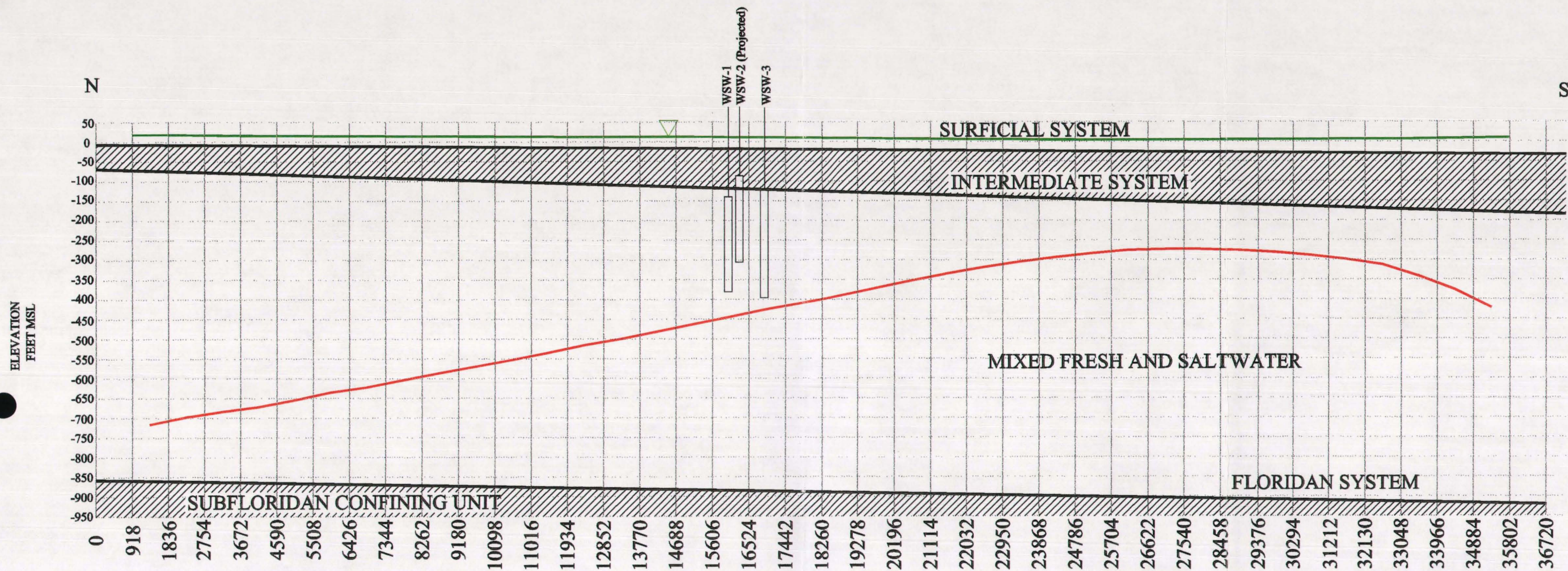
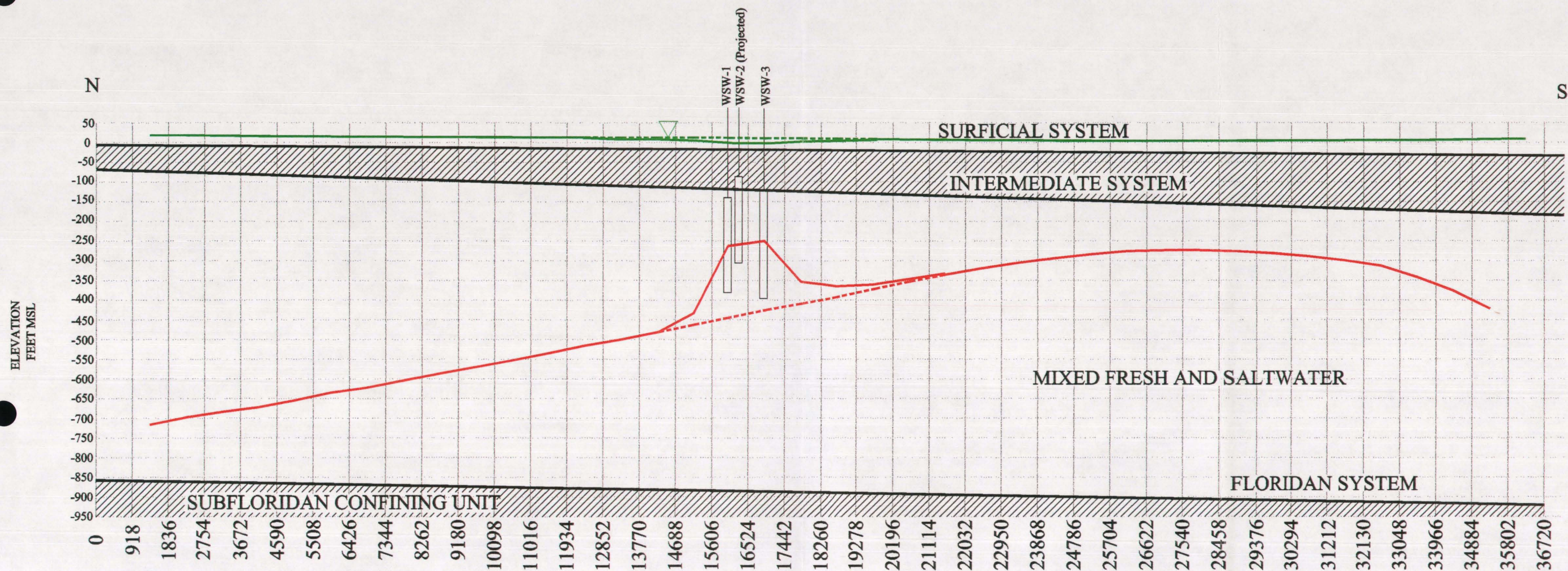





FIGURE 28

PREDICTED PREDEVELOPMENT SHARP INTERFACE



Horizontal Scale = 1:2500

Vertical Scale = 1:250

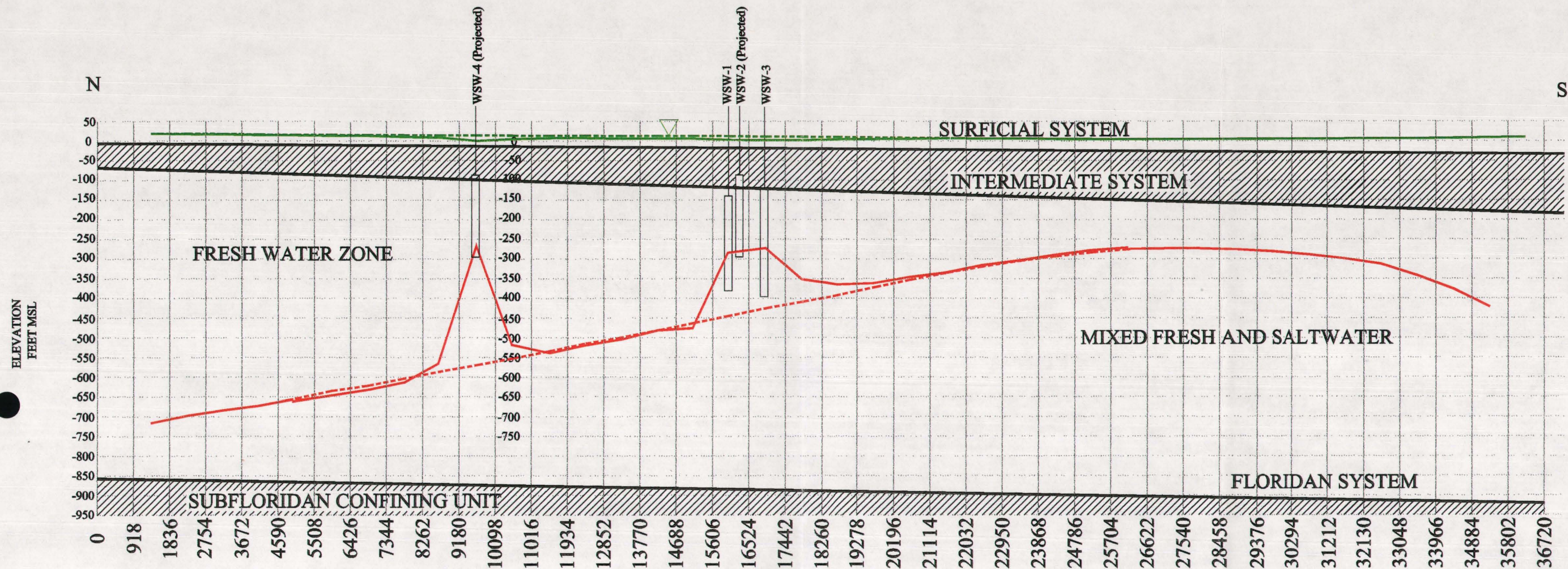
-  FLORIDAN AQUIFER SYSTEM HEAD (LAYER 1)
-  SURFICIAL AQUIFER SYSTEM (LAYER 2)
-  SHARP STEADY STATE INTERFACE (PREDEVELOPMENT-DASHED)

WSW

WATER SUPPLY WELL - OPEN AREAS REPRESENT INTAKE INTERVAL

FIGURE 29

PREDICTED EXISTING 1999
SHARP INTERFACE



Horizontal Scale = 1:2500

Vertical Scale = 1:250

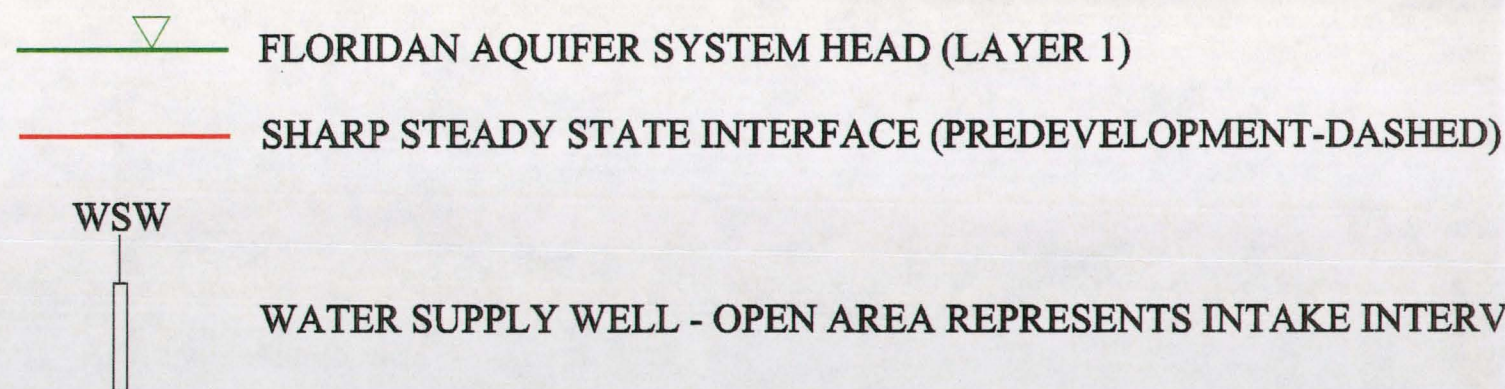


FIGURE 30

PREDICTED SHARP INTERFACE
AT END OF NEXT PERMIT PERIOD
(2004)

ATTACHMENT 10.5-H
FLY ASH TEST RESULTS

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

CERTIFICATE OF ANALYSIS

TO: Mr. Lamar Larrimore

Address: SCS
14N-8195

Description: Plant Smith / DA - Composite

Customer Account: SHWSCS

Sample Date: 15-Oct-98

Customer ID:

Received Date: 12-May-99

Laboratory ID Number: AD15356

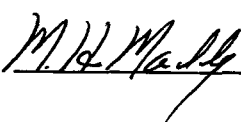
Test Name	Reference	VSpec	MDL	Result	Units
Arsenic, Total	EPA 3051	1.	41		mg/kg
Barium, Total	EPA 3051	1.	239		mg/kg
Cadmium, Total	EPA 3051	1.	10		mg/kg
Chromium, Total	EPA 3051	1.	102		mg/kg
Lead, Total	EPA 3051	1.	35		mg/kg
Mercury, Total	EPA 3051	0.05	< 0.01		mg/kg
Selenium, Total	EPA 3051	2.	Not Detected		mg/kg
Silver, Total	EPA 3051	1.	Not Detected		mg/kg
Solids Content of Sample	EPA 1311	0.1	100.		per cent
pH of TCLP Extract	EPA 1311	0.	5.54		
Extraction Fluid #	EPA 1311	0.	1.		
Mercury, TCLP Extractable	EPA1311/7470	0.0002	Not Detected		mg/l
Arsenic, TCLP Extractable	EPA1311/6010	0.009	0.025		mg/l
Lead, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Chromium, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Cadmium, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Arsenic, SPLP Extractable	EPA1312	0.006	0.016		mg/l
Silver, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Barium, SPLP Extractable	EPA1312	0.006	0.033		mg/l
Lead, TCLP Extractable	EPA1311/6010	0.007	Not Detected		mg/l
Selenium, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Selenium, TCLP Extractable	EPA1311/6010	0.02	Not Detected		mg/l
Chromium, TCLP Extractable	EPA1311/6010	0.002	0.024		mg/l
Barium, TCLP Extractable	EPA1311/6010	0.003	0.712		mg/l

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments **Note: This sample was originally submitted Oct 21, 1998 and analyzed as Laboratory Sample # AC28853.**

CC:

Quality Control



Supervision



Date: 6/2/99

GENERAL TEST LABORATORY
P.O. Box 2641
BIRMINGHAM, ALABAMA
35291 (205) 664 - 6081



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Customer ID:

Received Date: 12-May-99

Laboratory ID Number: AD15356

Test Name	Reference	VSpec	MDL	Result	Units
Mercury, SPLP Extractable	EPA1312		0.006	Not Detected	mg/l
Cadmium, TCLP Extractable	EPA1311/6010		0.001	0.032	mg/l
Silver, TCLP Extractable	EPA1311/6010		0.006	Not Detected	mg/l

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Sample Date : 15-Oct-98

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Received Date : 12-May-99

Laboratory ID Number : AD15357

Test Name	Reference	VSpec	MDL	Result	Units
Arsenic, Total	EPA 3051	1.	46		mg/kg
Barium, Total	EPA 3051	1.	164		mg/kg
Cadmium, Total	EPA 3051	1.	13		mg/kg
Chromium, Total	EPA 3051	1.	123		mg/kg
Lead, Total	EPA 3051	1.	230		mg/kg
Mercury, Total	EPA 3051	0.05	< 0.01		mg/kg
Selenium, Total	EPA 3051	2.	Not Detected		mg/kg
Silver, Total	EPA 3051	1.	Not Detected		mg/kg
Solids Content of Sample	EPA 1311	0.1	100.		per cent
pH of TCLP Extract	EPA 1311	0.	5.67		
Extraction Fluid #	EPA 1311	0.	1.		
Mercury, TCLP Extractable	EPA1311/7470	0.0002	Not Detected		mg/l
Selenium, SPLP Extractable	EPA1312	0.006	0.004		mg/l
Lead, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Chromium, SPLP Extractable	EPA1312	0.006	0.090		mg/l
Cadmium, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Arsenic, SPLP Extractable	EPA1312	0.006	0.015		mg/l
Silver, SPLP Extractable	EPA1312	0.006	Not Detected ⁴		mg/l
Barium, SPLP Extractable	EPA1312	0.006	0.29		mg/l
Lead, TCLP Extractable	EPA1311/6010	0.007	0.061		mg/l
Arsenic, TCLP Extractable	EPA1311/6010	0.009	0.009		mg/l
Selenium, TCLP Extractable	EPA1311/6010	0.02	Not Detected		mg/l
Chromium, TCLP Extractable	EPA1311/6010	0.002	0.014		mg/l
Barium, TCLP Extractable	EPA1311/6010	0.003	0.228		mg/l

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments **Note: This sample was originally submitted Oct 21, 1998 and analyzed as Laboratory Sample # AC28854.**

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Customer ID :

Received Date : 12-May-99

Laboratory ID Number : AD15357

Test Name	Reference	VSpec	MDL	Result	Units
Mercury, SPLP Extractable	EPA1312		0.006	Not Detected	mg/l
Cadmium, TCLP Extractable	EPA1311/6010		0.001	0.173	mg/l
Silver, TCLP Extractable	EPA1311/6010		0.006	Not Detected	mg/l

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Arsenic, Total	EPA 3051	1.	41		mg/kg
Barium, Total	EPA 3051	1.	239		mg/kg
Cadmium, Total	EPA 3051	1.	10		mg/kg
Chromium, Total	EPA 3051	1.	102		mg/kg
Lead, Total	EPA 3051	1.	35		mg/kg
Mercury, Total	EPA 3051	0.05	< 0.01		mg/kg
Selenium, Total	EPA 3051	2.	Not Detected		mg/kg
Silver, Total	EPA 3051	1.	Not Detected		mg/kg
Solids Content of Sample	EPA 1311	0.1	100.		per cent
pH of TCLP Extract	EPA 1311	0.	5.54		
Extraction Fluid #	EPA 1311	0.	1.		
Mercury, TCLP Extractable	EPA1311/7470	0.0002	Not Detected		mg/l
Arsenic, TCLP Extractable	EPA1311/6010	0.009	0.025		mg/l
Lead, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Chromium, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Cadmium, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Arsenic, SPLP Extractable	EPA1312	0.006	0.016		mg/l
Silver, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Barium, SPLP Extractable	EPA1312	0.006	0.033		mg/l
Lead, TCLP Extractable	EPA1311/6010	0.007	Not Detected		mg/l
Selenium, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Selenium, TCLP Extractable	EPA1311/6010	0.02	Not Detected		mg/l
Chromium, TCLP Extractable	EPA1311/6010	0.002	0.024		mg/l
Barium, TCLP Extractable	EPA1311/6010	0.003	0.712		mg/l

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Customer ID :

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Test Name	Reference	VSpec	MDL	Result	Units
Mercury, SPLP Extractable	EPA1312		0.006	Not Detected	mg/l
Cadmium, TCLP Extractable	EPA1311/6010		0.001	0.032	mg/l
Silver, TCLP Extractable	EPA1311/6010		0.006	Not Detected	mg/l

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Chromium, Total	EPA 3051	1.	123		mg/kg
Lead, Total	EPA 3051	1.	230		mg/kg
Mercury, Total	EPA 3051	0.05	< 0.01		mg/kg
Selenium, Total	EPA 3051	2.	Not Detected		mg/kg
Silver, Total	EPA 3051	1.	Not Detected		mg/kg
Solids Content of Sample	EPA 1311	0.1	100.		per cent
pH of TCLP Extract	EPA 1311	0.	5.67		
Extraction Fluid #	EPA 1311	0.	1.		
Mercury, TCLP Extractable	EPA1311/7470	0.0002	Not Detected		mg/l
Selenium, SPLP Extractable	EPA1312	0.006	0.004		mg/l
Lead, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Chromium, SPLP Extractable	EPA1312	0.006	0.090		mg/l
Cadmium, SPLP Extractable	EPA1312	0.006	Not Detected		mg/l
Arsenic, SPLP Extractable	EPA1312	0.006	0.015		mg/l
Silver, SPLP Extractable	EPA1312	0.006	Not Detected ⁴		mg/l
Barium, SPLP Extractable	EPA1312	0.006	0.29		mg/l
Lead, TCLP Extractable	EPA1311/6010	0.007	0.061		mg/l
Arsenic, TCLP Extractable	EPA1311/6010	0.009	0.009		mg/l
Selenium, TCLP Extractable	EPA1311/6010	0.02	Not Detected		mg/l
Chromium, TCLP Extractable	EPA1311/6010	0.002	0.014		mg/l
Barium, TCLP Extractable	EPA1311/6010	0.003	0.228		mg/l

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Test Name	Reference	VSpec	MDL	Result	Units
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Cadmium, TCLP Extractable	EPA1311/6010		0.001	0.173	mg/l
Silver, TCLP Extractable	EPA1311/6010		0.006	Not Detected	mg/l

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