Florida Electrical Power Plant Siting Act
Site Certification Application

Volume 1 of 3

Cane Island Power Park – Unit 4

Submitted by:

Florida Municipal Power Agency
Kissimmee Utility Authority

April 2008

FMPA
Florida Municipal Power Agency
Community Power. Statewide Strength.

KUA
KISSIMMEE UTILITY AUTHORITY

Site Certification Application

Engineering Certification Statement

Cane Island Power Park - Unit 4

I, the undersigned, hereby certify that:

The engineering features of Cane Island Power Park – Unit 4 as described in this Site Certification Application, have been prepared, designed, or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles; and,

To the best of my knowledge, this information submitted in support of this application is true, accurate, and complete based on reasonable techniques, estimates, materials, and information gathered and evaluated by qualified personnel; and,

To the best of my knowledge, there is reasonable assurance that the Unit 4 project described in this application, when properly operated and maintained, will comply with all applicable rules of the Department of Environmental Protection and South Florida Water Management District.

Stanley A. Armbruster April 1, 2008
Florida License No. 30562
Black & Veatch
11401 Lamar
Overland Park, Kansas

STANLEY A. ARMBRUSTER
LICENSE
30562
STATE OF FLORIDA
PROFESSIONAL ENGINEER

Applicant Information

Applicants' Official Name

Florida Municipal Power Agency (FMPA)
Kissimmee Utility Authority (KUA)

Address

FMPA	KUA
8553 Commodity Circle	1701 West Carroll Street
Orlando, FL 32819-9002	Kissimmee, FL 34741

Address of Official Headquarters

FMPA	KUA
8553 Commodity Circle	1701 West Carroll Street
Orlando, FL 32819-9002	Kissimmee, FL 34741

Business Entity

FMPA: Joint Action Agency
KUA: Municipality

Names, Owners, etc.

Not applicable

Name and Title of Chief Executive Officers

FMPA: Mr. Roger A. Fontes, General Manager and CEO
KUA: Mr. James C. Welsh, President and General Manager

Name, Address, and Telephone Number of Official Representative Responsible for Obtaining Certification

Ms. Susan Schumann, Cane Island Power Park - Unit 4 Licensing and Permitting Manager
8553 Commodity Circle
Orlando, FL 32819-9002
407-355-7767

Site Location

Cane Island Power Park
6075 Old Tampa Highway
Intercession City, Florida
Osceola County

Nearest Incorporated City

Kissimmee

Latitude and Longitude (center of site)

Lat: 28^0, 16 min, 50 sec N Long: 81^0, 32 min, 00 sec W

UTM 27 Coordinates (center of site; km)

North: 3128000 East: 447500

Section, Township, and Range

Sections 29 and 32, Township 25 South, Range 28 East

Location of Any Directly Associated Transmission Facilities

Not applicable

Nameplate Generating Capacity (Existing units)

Unit 1: Nominal 40 MW Simple Cycle Combustion Turbine Unit
Unit 2: Nominal 120 MW Combined Cycle Combustion Turbine Unit
Unit 3: Nominal 250 MW Combined Cycle Combustion Turbine Unit

Capacity of Proposed Additions

Unit 4: Nominal 300 MW Combined Cycle Combustion Turbine Unit (150 MW Combustion Turbine Generator and 150 MW Steam Turbine Generator)

Remarks:

FMPA is a nonprofit, joint action agency formed by 30 municipal electric utilities serving approximately 2 million Floridians. FMPA's primary purpose is to develop competitive power supply and related services for its members.

KUA is a body politic organized and existing under the laws of the State of Florida. By City Ordinance, the City of Kissimmee, Florida, established the KUA as part of the government of the City of Kissimmee. KUA owns, operates, and manages the municipal electric system established by the City of Kissimmee. KUA serves approximately 58,000 customers in Kissimmee and surrounding areas.

The Cane Island Power Park is a certified site under the Florida Electrical Power Plant Siting Act, Site Certification PA 98-38.

Table of Contents
Volume 1

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Volume 3

PSD Air Permit Application

Tables

Table of Contents (Continued)

Tables (Continued)

Table of Contents (Continued)

Tables (Continued)

Table of Contents (Continued)

Tables (Continued)

Figures

Table of Contents (Continued)

Figures (Continued)

Table of Contents (Continued)

Figures (Continued)

Table of Contents (Continued)

Figures (Continued)

Preface

This Site Certification Application (SCA) is submitted by the Florida Municipal Power Agency (FMPA) and the Kissimmee Utility Authority (KUA) for certification of Unit 4 at the Cane Island Power Park (CIPP) site. This application addresses all state, regional, and local permitting requirements under review of the Florida Electrical Power Plant Siting Act (Act), Sections 403.501 – 403.518, Florida Statutes, as amended. The application includes the following major section headings:

- 1.0, Background Information.
- 2.0, Site and Vicinity Characterization.
- 3.0, The Plant and Directly Associated Facilities.
- 4.0, Effects of Site Preparation, and Plant and Associated Facility Construction.
- 5.0, Effects of Plant Operation.
- 6.0, Transmission Lines and Other Linear Facilities.
- 7.0, Economic and Social Effects of Plant Construction and Operation.
- 8.0, Site and Plant Design Alternatives.
- 9.0, Coordination.
- 10.0, Permit Applications.
- Appendices.

Project Information

The CIPP site is an existing power plant site located at 6075 Old Tampa Highway near Intercession City, Osceola County, Florida. The three existing units (Units 1, 2, and 3) at the site were certified under the Act in 1999. Unit 4 is proposed as a nominal 300 megawatt (MW) one-on-one combined cycle generating unit consisting of an F-class combustion turbine generator (CTG), a heat recovery steam generator (HRSG), a condensing steam turbine generator (STG), and a mechanical draft cooling tower. Duct burners will be installed in the HRSG inlet to provide increased steam turbine generator output for peaking capacity. Unit 4 will have the capability to operate in steam bypass mode. Natural gas will be the only fuel for the combustion turbine and the HRSG duct burners. Unit 4 will be installed with modern pollution control devices and will use reuse water for cooling. Unit 4 will be added to the existing certified CIPP site.

Unit 4 is scheduled for commercial operation in May 2011. Unit 4 will be interconnected to Progress Energy's transmission system for transmission access by FMPA's members. FMPA is the owner and project manager for Unit 4 permitting, certification, and construction. KUA will operate the unit on behalf of FMPA.

Project Impacts

Air

Unit 4, as proposed, qualifies as a major source under the Prevention of Significant Deterioration (PSD) program, because it will emit more than 100 tons per year (tpy) of at least one regulated pollutant. The CIPP is located in an attainment area for all criteria pollutants, except PM_{10} and lead, which are unclassifiable.

Unit 4 has the potential to emit nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), sulfuric acid mist (H_2SO_4 [SAM]), and particulate matter (PM/PM_{10}) above PSD significance thresholds. Accordingly, a full PSD analysis was performed for those pollutants emitted above the PSD thresholds, including the following:

- Best Available Control Technology (BACT) Analysis.
- Ambient Air Quality Impact Analysis.
- Additional Impact Analysis.

The technology proposed to control emissions from Unit 4 includes dry low-NO_x burners and selective catalytic reduction (SCR) for the control of NO_x, the use of natural gas, and good combustion controls to reduce CO, PM/PM_{10}, SO_2, and SAM emissions.

An air dispersion modeling analysis was performed to determine the Unit 4 maximum SO_x, NO_x, CO, and PM/PM_{10} air quality impacts. The maximum air quality impacts at all modeled receptors were less than the applicable PSD significant impact levels, and consequently below the less stringent de minimis ambient background monitoring levels. As such, multi-source modeling of nearby existing sources for PSD increment consumption and ambient air quality standards (AAQS) comparison was not required.

The Unit 4 predicted pollutant impact concentrations are well below the threshold levels above which the air quality may be significantly affected. Moreover, an additional impact assessment determined that the Unit 4 visual impacts, PSD Class I regional haze impacts, air quality impacts on vegetation and soils, and air quality impacts due to growth, are inconsequential as the predicted levels are well below threshold levels.

Water Use

The Unit 4 cooling tower will use approximately 2.8 million gallons of treated sewage effluent (or reuse water) per day when firing natural gas at full load and average ambient conditions. This effluent will be supplied from the Toho Water Authority (Toho) reuse water pipeline adjacent to the southern boundary of the CIPP site. At full load operation, approximately 865,000 gallons per day (gpd) of process wastewaters will be returned to the Toho pipeline for reuse downstream or disposal.

Service, potable, and fire water will be supplied by onsite groundwater wells. Under full load operation, Unit 4 will require 134,000 gallons of service water per day in addition to the currently authorized amount. The majority of this amount is required for power cycle demineralized makeup water supply and evaporative cooler makeup supply. The Upper Floridan Aquifer is the water source.

In addition to the normal service water demand, KUA/FMPA also requests the use of 2.8 million gpd of groundwater for short-term/emergency supply (30 days/year) to the cooling tower, if needed, in the event reuse water is unavailable.

Land

The 1,027 acre CIPP site was issued Conditional Use Permit (CU/SDP 92-86) for electrical power plant use of the site by the Osceola County Board of Commissioners in 1993, and certified under the Florida Electrical Power Plant Siting Act in 1999. Unit 4 will be located within the previously certified CIPP site. In 1998, the Siting Board determined the CIPP site to be in compliance with the then-existing land use plans and zoning ordinances of Osceola County, Florida. See Section 403.508, F.S. In all respects, the proposed electrical power plant remains consistent and in compliance with those local land use plans and zoning ordinances.

A complete biophysical assessment of the property during Units 1 and 2 permitting, and subsequent monitoring, concluded that the property is not inhabited by any federal- or state-listed threatened or endangered species, with the exception of the recently listed gopher tortoise (state threatened). The majority of the site (860 acres) was placed in conservation easements granted to the South Florida Water Management District (SFWMD) and the Florida Fish and Wildlife Conservation Commission (FFWCC).

The Department of Historical Resources had cleared the site for development during Units 1 and 2 permitting, stating that there are no archaeological, historic, or cultural sites present on the property or in the immediate vicinity that are considered eligible for listing on the *National Register of Historic Places*.

Wastewater and Solid Waste

Unit 4 process wastewaters will be collected, treated, and discharged at two locations onsite. Potentially oil-contaminated wastewaters are routed to an oil/water separator for treatment prior to groundwater discharge through a new percolation pond. Cooling tower and evaporative cooler blowdown, neutralization basin effluent, and boiler blowdown are collected and returned to the Toho reuse pipeline after pH adjustment. All wastewaters returned to the Toho pipeline are treated to meet applicable Toho agreement limits prior to discharge. Licensed contractors remove boiler and combustion turbine cleaning wastewaters, and spent SCR modules.

Sanitary wastewaters will be discharged to an existing, onsite septic tank/tile field system. Uncontaminated stormwaters will be directed to an onsite storm water detention basin.

Office trash and other low-volume solid wastes will be collected and managed onsite for disposal at an approved facility by a licensed contractor.

Socioeconomics

Operation of Unit 4 should have positive incremental socioeconomic impacts in Osceola County through employment and associated tax revenues. During the peak period of Unit 4 construction, approximately 313 jobs will be created by the construction project. The net direct employment effect from Unit 4 will be the creation of approximately two additional full-time operations positions. Unit 4 is not anticipated to adversely impact the local or regional services or infrastructure.

Need for Power

FMPA will file a separate Need for Power petition and application with the PSC for Cane Island Unit 4 in accordance with the Act, Section 403.519, Florida Statutes.

Schedule

The anticipated Unit 4 site certification major milestone schedule is as follows:

- SCA filed April 1, 2008.
- Need for Power Petition filed May 1, 2008.
- Florida Department of Environmental Protection (FDEP) Issues Completeness Statement in May 2008.
- Land Use Hearing in July 2008.
- Need for Power Order Issued by PSC in September 2008.
- Land Use Order Issued in October 2008.
- FDEP Issues Project Analysis in December 2008.

- Certification Hearing in January 2009.
- Siting Board Hearing in April 2009.
- Site Certification Order and PSD Permit Issued in April 2009.
- Start of Construction in July 2009.
- Unit 4 Commercial Operation in May 2011.

Acronyms and Abbreviations

AADT	Average Annual Daily Traffic
AAQIA	Ambient Air Quality Impact Analysis
AAQS	Ambient Air Quality Standards
Act	Florida Electrical Power Plant Siting Act
amsl	Above mean sea level
ANL	Argonne National Laboratory
ANSI	American National Standard Institute
AQCS	Air Quality Control System
ARP	All-Requirements Project
BACT	Best Available Control Technology
bcf	Billion cubic feet
BEA	Bureau of Economic Analysis
bgs	Below ground surface
bls	Below land surface
BOD	Biochemical oxygen demand
BOR	Basis of Review
Btu	British thermal unit
Btu/h	British thermal units per hour
cfs	Cubic feet per second
$CaCO_3$	Calcium carbonate
CIPP	Cane Island Power Park
CN	Curve Number
CO	Carbon monoxide
COD	Chemical oxygen demand
COE	US Army Corps of Engineers
CTG	Combustion turbine generator
CU/SDP	Conditional Use/Site Development Plan
dBA	Decibels (A-weighted)
dBC	Decibels (C-weighted)
DCIS	Distributed Control and Information System
DHR	Division of Historical Resources, Florida Department of State
ECF	East Central Florida
EIS	Environmental Impact Statement
EPA	US Environmental Protection Agency
ERP	Environmental Resource Permit

EPRI	Electric Power Research Institute
F	Degrees Fahrenheit
FAA	Federal Aviation Administration
FAS	Floridan Aquifer System
FAAQS	Florida Ambient Air Quality Standards
FAC	Florida Administrative Code
FCREPA	Florida Committee on Rare and Endangered Plants and Animals
FDA	Florida Department of Agriculture
FDEP	Florida Department of Environmental Protection
FDHR	Florida Division of Historical Resources
FDOT	Florida Department of Transportation
FFWCC	Florida Fish and Wildlife Conservation Commission
FGFWFC	Florida Game and Fresh Water Fish Commission
FGT	Florida Gas Transportation Company
FMPA	Florida Municipal Power Agency
FNAI	Florida Natural Areas Inventory
FS	Florida Statutes
GEP	Good Engineering Practice
gpd	Gallons per day
gpm	Gallons per minute
GPR	Ground Penetrating Radar
gr/dscf	Grains per dry standard cubic foot
H_2SO_4	Sulfuric acid mist (SAM)
HAP	Hazardous Air Pollutant
HgA	Mercury, absolute
HRSG	Heat recovery steam generator
HHV	Higher Heating Value
IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISCST	Industrial Source Complex Short-Term
ISM	Kissimmee (Municipal) Gateway Airport
ISO	International Organization for Standardization
JCAHO	Joint Commission on the Accreditation of Healthcare Organizations
kg	Kilogram(s)
kg/s	Kilograms per second
km	Kilometer(s)

KUA	Kissimmee Utility Authority
kWh	kilowatt-hour
LAER	Lowest achievable emission rate
lb/h	Pounds per hour
lb/MBtu	Pounds per million British thermal units
LFA	Lower Floridan Aquifer
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
m	Meters
MBtu	Million British thermal units
MCO	Orlando International Airport
mgd	Million gallons per day
mg/L	Milligrams per liter
mg/m^3	Milligrams per cubic meter
mm	Millimeters
MSA	Metropolitan Statistical Area
MSDS	Material Safety Data Sheet
msl	Mean sea level
MW	Megawatt(s)
MWh	Megawatt-hour
NEMA	National Electrical Manufacturers Association
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NGVD	National Geodetic Vertical Datum
NML	Noise monitoring location
NOAA	National Oceanic and Atmospheric Administration
NOI	Notice of Intent
NO_x	Nitrogen oxides
NP	Natural Electrical Potential
NPDES	National Pollutant Discharge Elimination System
NRCS	Natural Resources Conservation Service
NSPS	New Source Performance Standards
NSR	New Source Review
NWS	National Weather Service
O&M	Operations and Maintenance
ORL	Orlando Executive Airport
OSHA	Occupational Safety and Health Administration

OUC	Orlando Utilities Commission
PE	Progress Energy
PM/PM_{10}	Particulate matter/particulate matter less than 10 microns
ppm	Parts per million
ppmvd	Parts per million by volume dry
PSC	Florida Public Service Commission
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch, gauge
PTE	Potential to Emit
PTPLU-2	Screening level point source dispersion model
RIMS II	Regional Input-Output Modeling System
RO	Reverse osmosis
SACTI	Seasonal/annual cooling tower impact
SAM	Sulfuric acid mist (H_2SO_4)
SAS	Surficial aquifer system
SCA	Site Certification Application
scfm	Standard cubic feet per minute
SCR	Selective catalytic reduction
SFWMD	South Florida Water Management District
SIP	State Implementation Plan
SJRWMD	St. Johns River Water Management District
SOCDS	State of the Cities Data Systems
SO_2	Sulfur dioxide
SOR	Save Our Rivers
SPT	Standard Penetration Test
SQG	Small Quantity Generator
STG	Steam turbine generator
TCLP	Toxicity Characteristic Leaching Procedure
TDS	Total dissolved solids
TOC	Total organic carbon
Toho	Toho Water Authority (formerly City of Kissimmee Water and Sewer Department
tpy	Tons per year
TRPH	Total Residual Petroleum Hydrocarbons
TRS	Total reduced sulfur
TSP	Total suspended particulate
TSS	Total suspended solids

UFA	Upper Floridan Aquifer
$\mu g/m^3$	Micrograms per cubic meter
ULSD	Ultra-low sulfur diesel
ULSFO	Ultra-low sulfur fuel oil
UNAMAP	User's Network for the Applied Modeling of Air Pollution
USFWS	US Fish and Wildlife Service
USGS	US Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile organic compound
WWTP	Wastewater treatment plant

1.0 Background Information

The Cane Island Power Park (CIPP) currently includes three existing units and associated support facilities, certified under the Act in 1999. Unit 1 is a nominal 40 MW simple cycle combustion turbine unit; Unit 2 is a nominal 120 MW combined cycle combustion turbine unit; Unit 3 is a nominal 250 MW combined cycle combustion turbine unit. Units 1 and 2 began commercial operation in 1995; and Unit 3 began commercial operation in 2001. Units 1, 2, and 3 fire natural gas as the primary fuel; No. 2 fuel oil is stored onsite as backup fuel. The electricity generated is stepped up in voltage for distribution to the power grid.

Unit 4 is proposed as a nominal 300 MW one-on-one combined cycle combustion turbine unit that will fire natural gas and liquid natural gas (LNG) as the only fuels. FMPA and KUA also request that LNG be one of the certified fuels for Units 1-3 and future units at the CIPP. The electricity generated by Unit 4 will be stepped up in voltage for distribution to the power grid and FMPA members. Unit 4 is scheduled for commercial operation in May 2011.

1.1 Need for Power Application

FMPA and KUA will submit a Petition to Determine Need for Electrical Power Plant and accompanying Need for Power Application to the Florida Public Service Commission (PSC) for the CIPP Unit 4 Project on May 1, 2008.

1.2 FMPA, the All Requirements Project, and KUA

FMPA is a nonprofit, public, joint action agency consisting of a group of 30 municipal electric utilities with the primary purpose of developing competitive power supply and related services.

FMPA's mission is to develop economical and competitive power supply projects, to be proactive in providing member services, and to promote the image of public power, enabling its member utilities to succeed in a rapidly changing environment. Each member appoints one representative to FMPA's Board of Directors, which governs the Agency's activities.

Each member utility is locally owned and operated; however, municipal utilities share common concerns that can best be solved by working together. This helps reduce the cost of power, as municipal utilities can obtain power from several power plants rather than depending on a few. Through FMPA, municipals have been successful in reducing power costs, diversifying power supply resources, and providing a measure of competition in the wholesale market.

FMPA is specifically authorized under the Joint Power Act to undertake joint projects for its members and to issue tax-exempt bonds and other obligations to finance the costs of such projects. Pursuant to that authority, FMPA developed the All Requirements Project (ARP) to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the needs of the ARP members who include 15 municipal utilities serving approximately 180,000 customers throughout Florida. ARP members purchase all their capacity and energy from the ARP. FMPA meets the ARP's needs through electricity generated by FMPA owned or co-owned facilities, as well as power purchases from generating ARP members (i.e., members with their own generating capacity and purchases) and other, non-ARP member utilities.

KUA is a member of FMPA and the ARP. KUA owns, operates, and manages the municipal electric system established by the City of Kissimmee, and is the sixth largest municipal utility in Florida. KUA serves approximately 58,000 customers in Kissimmee and surrounding areas.

2.0 Site and Vicinity Characterization

To assess the potential impacts a project may have on the social and biological environment, it is necessary to establish a set of baseline or existing conditions for the project area. This section provides that characterization for the CIPP. This section describes the CIPP and Osceola County sociopolitical and biophysical environment.

2.1 Site and Associated Facilities Delineation

This section provides information concerning the physical, biological, and sociological characteristics of the existing site and project area that might be affected by the construction and operation of CIPP Unit 4 (Unit 4).

2.1.1 Site Location

The CIPP is located within rural northwest Osceola County, Florida. Figure 2.1-1 shows the general location of the CIPP, which is 20 miles southwest of Orlando, 5 miles west of Kissimmee, and 1 mile northwest of Intercession City. The CIPP address is 6075 Old Tampa Highway, Intercession City.

The CIPP occupies 1,027 acres in Section 29 and a portion of Section 32, Township 25 South, Range 28 East, in Osceola County. Figure 2.1-2 shows the CIPP boundaries and identifies adjacent properties. Table 2.1-1 provides the names and addresses of the adjacent property owners. Unit 4 will be a new unit located north of Unit 3 as shown on Figure 2.1-3. Approximately 167 acres have been permitted for power development and support facilities at the CIPP.

2.1.2 Site Modification

Proposed site modifications will consist of construction and operation of Unit 4, a 300 MW (nominal) combined cycle combustion turbine generating unit. The development of the Unit 4 power block area will occupy approximately 9 acres north of the existing Units 1, 2, and 3.

New major equipment associated with Unit 4 will include a CTG, HRSG, steam generator, and cooling tower. Unit 4 will be interconnected to the existing CIPP substation, approximately 500 feet from the new unit. As explained in Section 6.0, a few of the existing transmission poles in the power block area will be relocated to accommodate Unit 4. There will also be wastewater treatment facilities, water storage tanks, and a storm water detention area for Units 3 and 4. Similar facilities associated with the operation of Units 1, 2, and 3 exist onsite.

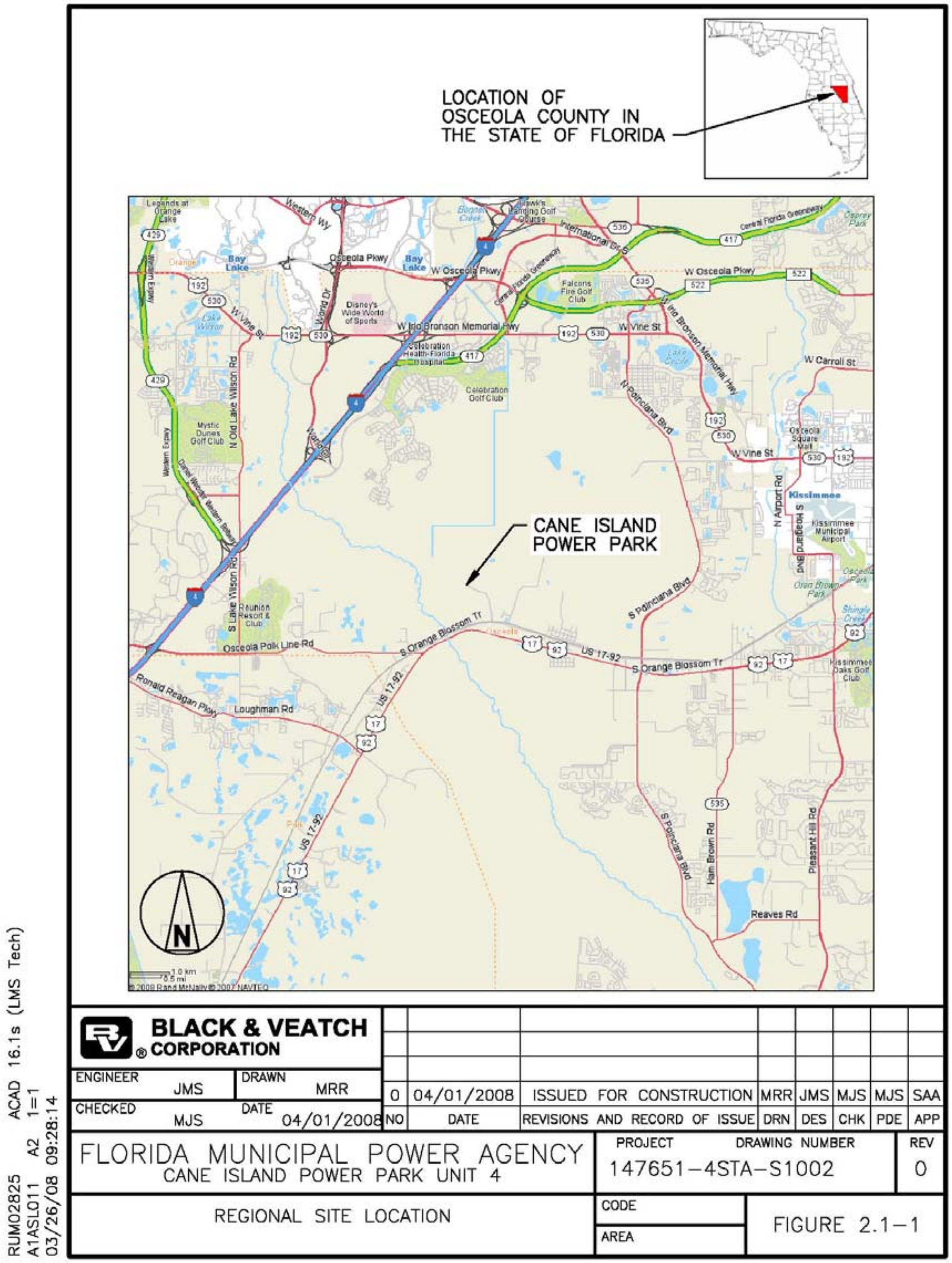


Figure 2.1-1
Regional Site Location

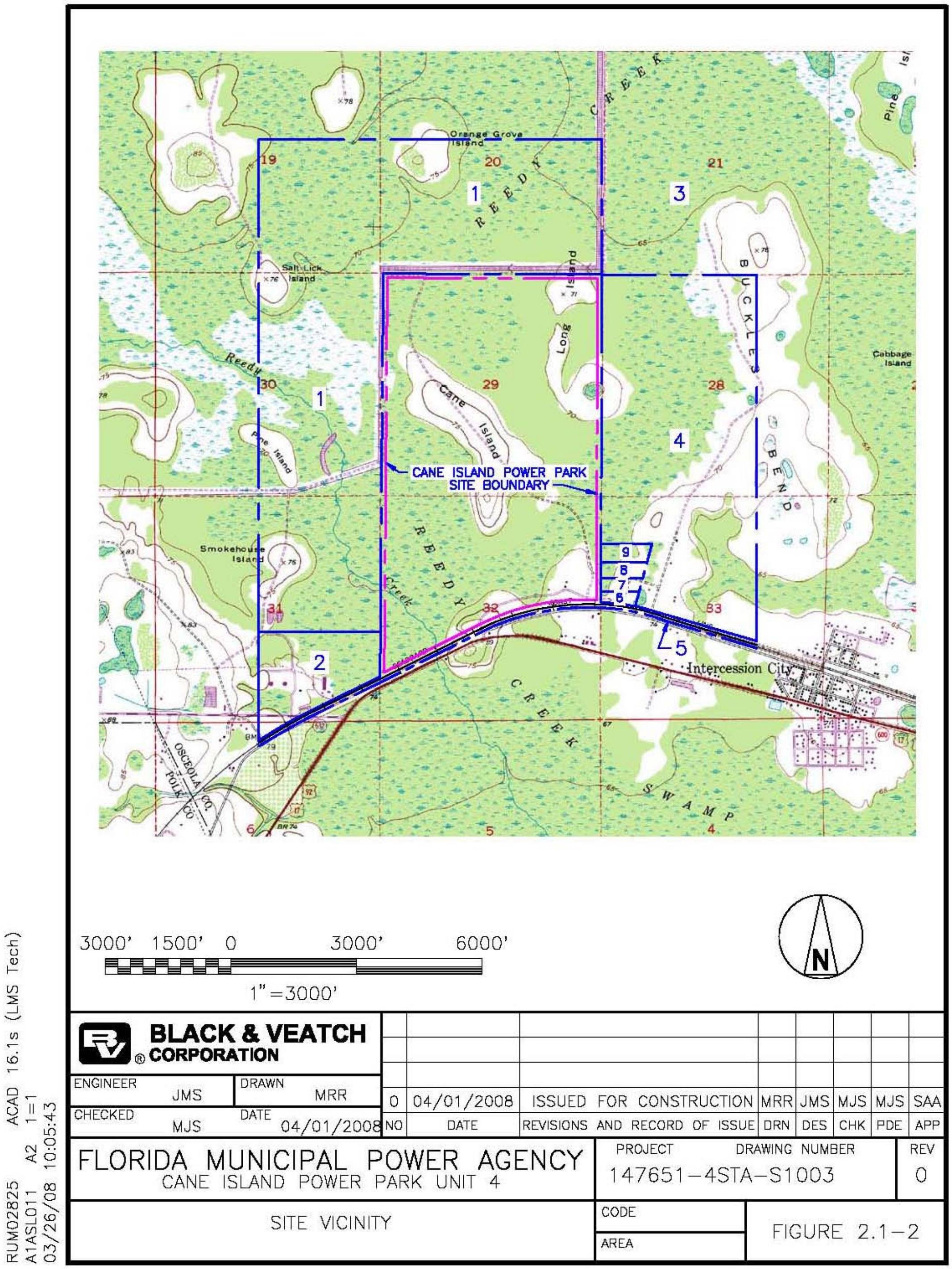
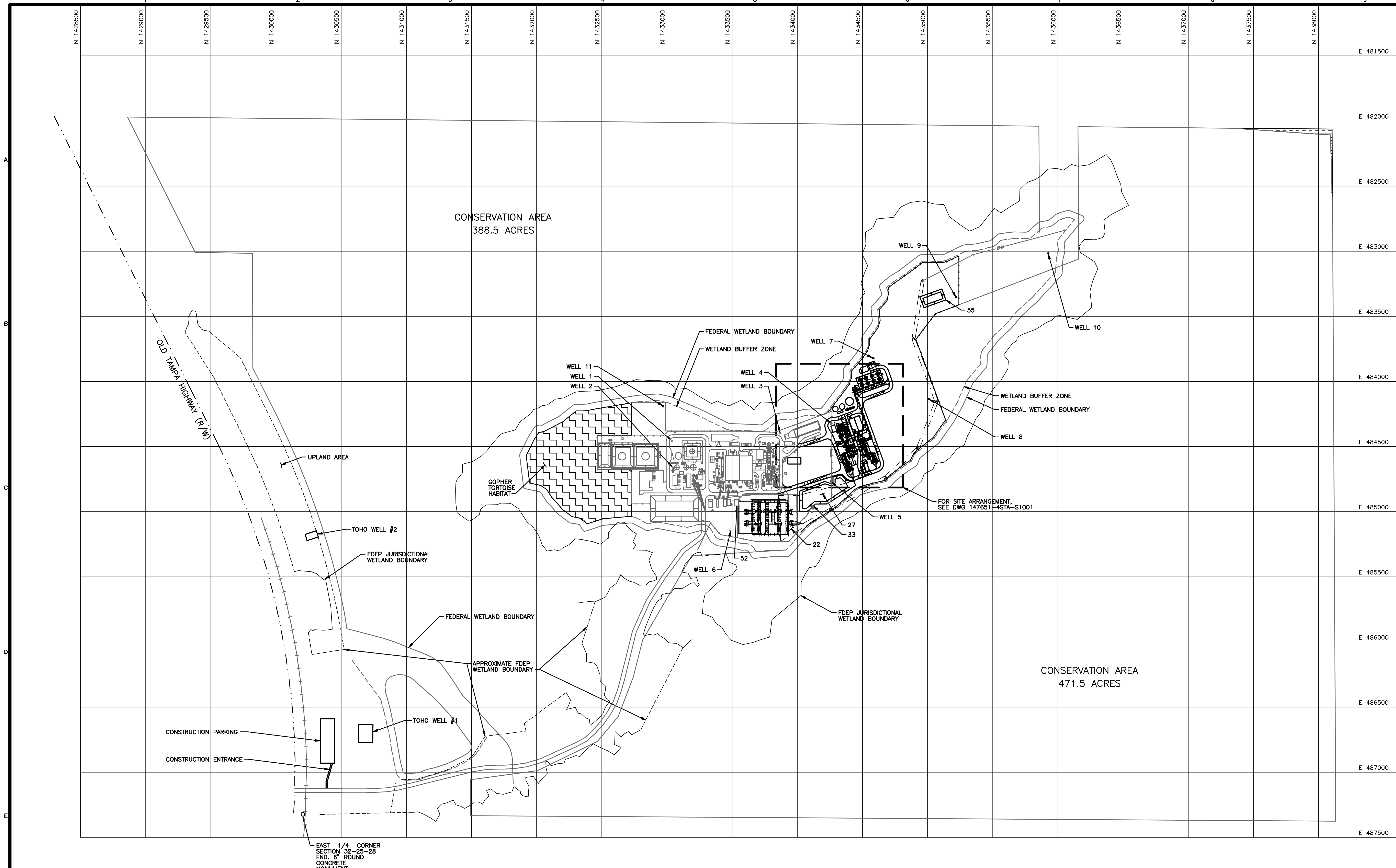


Figure 2.1-2
Site Vicinity

Table 2.1-1
Adjacent Property Owners
Cane Island Power Park

Parcel Number	Map ID	Property Owner
21-25-28-0000-0010-0000	3	Ecosystems Mitigation Bank P. O. Box 540285 Orlando, FL 32854
28-25-28-0000-0010-0000 33-25-28-0000-0010-0000	4	BK Ranch LC (1200 Wooten Rd./1301 Wooten Rd.) 2003 Via Tuscany Winter Park, FL 32789
33-25-28-0000-0047-0000	9	Matt L. Joiner 1356 Montzen Rd. Davenport, FL 33837
33-25-28-0000-0040-0000	8	William Dampier (1364 Montzen Rd.) P. O. Box 336 Intercession City, FL 33848
33-25-28-0000-0050-0000	7	David Haley 1386 Montzen Rd. Davenport, FL 33837
33-25-28-0000-0060-0000	6	Freda Poppleton (1398 Montzen Rd.) 3300 S. Indiana Ave. Saint Cloud, FL 34769
N/A	5	CSX Transportation 3701 Causeway Blvd. Tampa, FL 33619
31-25-28-0000-0040-0000	2	Florida Power Corp. (6525 Osceola Polk Line Rd.) P. O. Box 14042 St. Petersburg, FL 33733
19-25-28-0000-0010-0000 20-25-28-0000-0010-0000 20-25-28-0000-0020-0000 30-25-28-0000-0010-0000 30-25-28-0000-0020-0000 31-25-28-0000-0010-0000	1	Reedy Creek Improvement District 1900 Hotel Plaza Blvd. P. O. Box 10170 Lake Buena Vista, FL 32830



FACILITIES LEGEND

ID	FACILITY
22	SUBSTATION
27	DETENTION POND
33	DETENTION POND DISCHARGE
52	SWITCHYARD CONTROL BUILDING (EXISTING)
55	PERC POND

LEGEND

WETLAND BUFFER ZONE
OVERHEAD TRANSMISSION LINE
FDEP JURISDICTIONAL WETLAND BOUNDARY
FENCE LINE
GOPHER TORTOISE HABITAT

NOTES

FOR PERMITTING PURPOSE ONLY
APPROVED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0	04/01/2008	ISSUED FOR CONSTRUCTION	MRR	JMS	MJS	MJS	SAA

300' 150' 0 300' 600'
SCALE: 1"=300'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE REG NO.

BLACK & VEATCH CORPORATION
ENGINEER JMS DRAWN MRR
CHECKED MJS DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4
SITE PLAN

PROJECT DRAWING NUMBER 147651-4STA-S1000 REV 0
CODE
AREA
FIG 2.1-3

RUN02825 E1 ACAD 16.1s (LMS Tech)
A1ASL017 1=1
02/20/08 08:26:28

2.1.3 Existing and Proposed Uses

Through negotiations with the SFWMD and the Florida Game and Fresh Water Fish Commission (FGFWFC), which is now called the Florida Fish and Wildlife Conservation Commission (FFWCC), 860 acres of CIPP uplands and wetlands were dedicated as a conservation area during the permitting of Units 1 and 2. Copies of these easement agreements are provided in Subsection 10.5.1, Appendix F. The remaining 167 acres are designated for power generation and support uses. Approximately 47 of these 167 acres are on the central portion of the geographic feature known as Cane Island where Units 1, 2, and 3 are located and where Unit 4 will be located. Unit 4 will occupy approximately 9 acres, while construction of the project will require impacts to approximately 24.2 acres. Utility corridors comprise the remaining development acreage. No new offsite transmission facilities will be required for Unit 4. Further details are found in Section 4.1.

2.1.4 Flood Zones

The SFWMD required during the permitting of Units 1 and 2 that the site access road be located 2 feet above the 10 year, 24 hour storm elevation, which is 69 feet National Geodetic Vertical Datum (NGVD). The access road center line is at 71 feet NGVD. Roads in the power block area were required to be located 4.5 feet above the 10 year, 24 hour storm elevation, which is 76.25 feet NGVD. Road crown elevations are and will continue to be at or above 80.75 feet NGVD.

The SFWMD also requires that the finished floor elevations in the power block area be located at or above the 100 year, 72 hour storm elevation. The 100 year, 72 hour storm elevation is 79.97 feet NGVD. The finished floor elevations for Unit 4 will be at 82.00 feet NGVD.

2.2 Sociopolitical Environment

2.2.1 Governmental Jurisdictions

CIPP is located within an unincorporated area of Osceola County. The southern boundary of Orange County is 4.5 miles north of the power block (site). The northeast boundary of Polk County is 2 miles southwest of the site. The western city limit of Kissimmee is 5 miles east of the site. The incorporated town of Campbell is 4.5 miles southeast of the site. The unincorporated town of Intercession City is 1 mile southeast of the site. The unincorporated town of Loughman is 3.5 miles southwest of the site.

2.2.2 Demography and Ongoing Land Use

2.2.2.1 Land Use. Osceola County is a 1,506 square mile area that serves as the south/central boundary of the Central Florida Region and the Greater Metropolitan Area.

It constitutes 2.8 percent of the state land area of 53,927 square miles. The CIPP is located in rural northwest Osceola County.

Located at the headwaters of the Lake Okeechobee/Florida Everglades ecosystem, Osceola County is bounded by the Kissimmee River and is home to the Kissimmee Chain of Lakes, which includes some of Florida's finest fishing and recreational attractions. The county is also home to three federal wildlife management preserves at Bull Creek, Prairie Lakes, and Three Lakes. Osceola County's economic base is dominated by tourism, because it is a gateway to Walt Disney World and other Central Florida attractions. The area's historical investments in ranching and citrus are still very strong, while light industry and service enterprises are growing.

The two major cities in Osceola County are Kissimmee and St. Cloud. The City of Kissimmee, the county seat, is 18 miles due south of Orlando. Well known for its year-round desirable climate and abundant recreational opportunities, Kissimmee covers roughly 17 square miles. Its current population of 59,364 makes it the largest city in Osceola County although it is relatively small when compared to Florida's largest municipalities.

Osceola County's only other incorporated city, St. Cloud, is 9 miles east of Kissimmee, and approximately 45 miles west of the City of Melbourne on the Atlantic Coast. St. Cloud has 2.5 miles of lakefront and an extensive park program. St. Cloud is adjacent to the Florida Turnpike, making travel to Orlando and the International Airport only a 25 minute drive away.

The topography of the CIPP is unpronounced and considered relatively flat. It consists primarily of grassland with a few scattered trees and is situated on a slightly elevated ridge of dry sand (the geographic feature known as Cane Island) surrounded by the wetlands of Reedy Creek Swamp. The nearest Federal PSD Class I Area is the Chassahowitzka National Wildlife Refuge located 85 miles to the northwest.

The site is located 1 mile northwest of Intercession City, north of Old Tampa Highway. The southern border is determined by a CSX Transportation railroad line that parallels Osceola Polk Line Road. The site is surrounded on all sides by a significant buffer of trees (Reedy Creek Swamp), with the western boundary border also bordering Davenport Creek Swamp.

Interstate 4 is anticipated to be the predominant route that temporary construction workers from outside Osceola County will use to commute to the site. To get to the site from Interstate 4, workers will exit the interstate onto Osceola Polk Line Road and travel onto South Orange Blossom Trail/US Highway 17-92 and will then turn north onto Old Tampa Highway, where the site access road, Bobroff Blvd, is reached.

2.2.2.2 Land Use Plans and Zoning. The CIPP site is designated as Rural/Agriculture under the existing future land use map of the Osceola County Comprehensive Plan's future land use element. Electric utility facilities are permitted uses as an Institutional use in that future land use designation. The CIPP site is zoned as Agriculture/Conservation under the existing Osceola County zoning ordinances. Electrical power plants are a conditional use in this zoning district. The property was approved for use as an electrical power plant in 1993 by the Osceola Board of Commissioners and KUA was issued a Conditional Use Permit (CU/SDP 92-86) authorizing power plant construction and operation on the property. The Conditional Use permit recognized the site could support up to 1,000 MW of generating capacity, comprised of multiple electrical generating units on the portion of the site to be occupied by Unit 4 Refer to Sections 10.3 and 10.4 related to existing zoning and land use plans.

In 1999, the Siting Board determined that the Power Park site was consistent with the existing land use plans and zoning ordinances of Osceola County. The Siting Board found that the use of the 1,027 acre CIPP site for electrical generating facilities was consistent with the County's zoning for the CIPP site and with the Conditional Use permit issued by the County for the CIPP site. In all respects, the proposed Unit 4 electrical power plant is consistent and in compliance with local land use plans and zoning ordinances.

Osceola County future land use maps indicate no change in the anticipated land use pattern for the CIPP site or the adjacent land area in the future, confirming that the CIPP site will continue to be compatible with the predominant land use in the immediate project vicinity. As the land surrounding the site is not developed, the construction of Unit 4 will not create any negative visual impacts or disturb any residential areas.

2.2.2.3 Population Statistics. The population of Osceola County was estimated to be 235,153 in 2005 by the University of Florida's Florida Housing Data Clearinghouse. Osceola County's population constituted roughly 1.3 percent of the estimated 2005 state population of 17,918,453. The Osceola County population increased by 36.3 percent between 2000 and 2005, compared to a 12.1 percent growth for Florida. The respective 1990 to 2000 growth rate was 60.1 percent for Osceola County compared to 23.5 percent at the state level.

Table 2.2-1 lists the projected population levels for Florida and the counties surrounding the CIPP. The Osceola County population is expected to increase to 346,699 in 2015, a growth of 47 percent over 2005 estimates. This is above the 21.5 percent overall growth projected for the state.

Table 2.2-2 indicates that the age distribution of the Osceola County population is comparable to that of the state, with the largest difference occurring in the 65 years old and over category, where only 11.3 percent of the Osceola County population was classified in 2005 versus 16.8 percent at the state level.

Table 2.2-1
State of Florida, Osceola County and Surrounding Counties
Population Projections 2005 -2020
(in thousands)

Location	2005	2010	2015	2020	Annual Average Growth Rate, 2005-2020
Brevard County	532.0	583.8	632.1	677.2	1.6%
Highlands County	93.5	101.4	108.8	115.8	1.4%
Indian River County	130.0	147.0	162.5	177.0	2.1%
Lake County	263.0	313.2	359.9	403.8	2.9%
Okeechobee County	37.8	39.5	41.2	42.8	0.8%
Orange County	1,043.4	1,197.7	1,340.6	1,473.6	2.3%
Osceola County	235.1	292.7	346.7	397.7	3.6%
Polk County	541.8	599.0	651.2	699.0	1.7%
Seminole County	411.7	460.0	504.1	544.7	1.9%
Florida Population	17,918.5	19,920.2	21,767.0	23,475.4	1.8%

Source: Florida Housing Data Clearinghouse, University of Florida
http://flhousingdata.shimberg.ufl.edu/a/profiles?action=results&nid=3400

Table 2.2-2
Age Distribution in State of Florida, Osceola County,
and Surrounding Counties in 2005

Location	Population under 5 Years Old	Population under 18 Years Old	Population 65 Years or Older
Brevard County	5.1%	20.9%	20.1%
Highlands County	5.0%	19.2%	31.0%
Indian River County	4.9%	18.9%	27.0%
Lake County	5.4%	19.9%	26.7%
Okeechobee County	7.3%	24.9%	16.1%
Orange County	7.7%	26.0%	9.5%
Osceola County	7.3%	26.2%	11.3%
Polk County	6.9%	24.5%	17.6%
Seminole County	6.0%	24.2%	10.8%
Florida Population	6.3%	22.9%	16.8%

Source: US Government Federal Statistics,
http://www.fedstats.gov/qf/states/12000.html

Table 2.2-3 presents population information for Kissimmee and Orlando for selected years. Kissimmee had an estimated 2000 population of 47,814, and the median age for the city's population was 30.6. The 2000 population of Orlando was 185,951 with a median age of 35.4, which was still below the Florida average of 38.7

Table 2.2-3
Population Statistics for Kissimmee and Orlando,
1990 and 2000

Year	Kissimmee	Orlando
1990	30,050	164,693
2000	47,814	185,951

Source: US Census Bureau, http://factfinder.census.gov/servlet/SAFFPopulation?_event=Search&geo_id=01000US&_geoContext=&_street=&_county=kissimmee&_cityTown=kissimmee&_state=04000US12&_zip=&_lang=en&_sse=on&ActiveGeoDiv=geoSelect&_useEV=&pctxt=fph&pgsl=010&_submenuId=population_0&ds_name=null&_ci_nbr=null&qr_name=null&reg=null%3Anull&_keyword=&_industry=

2.2.3 Easements, Title, Agency Works

There are no easements or titles to be obtained for the CIPP or Unit 4. The entire site is owned by KUA and FMPA. There are no new offsite linear facilities proposed for this project.

2.2.4 Regional Scenic, Cultural, and Natural Landmarks

There are more than 30 recorded scenic, cultural, or natural landmarks within 5 miles of the CIPP. The National Registry of Natural Landmarks does not list any sites for Osceola County.

The cultural resources within 5 miles of the CIPP include the FDEP/Disney Conservation Easement north and west of the site, and the playground/park in Intercession City. Another cultural resource is the Fletcher Park Monument on the US 17/92 bridge over Reedy Creek. Two historical bridges, the South Orange Blossom Trail Bridge and the Disney 5000 13 Bridge, are located in the Intercession City area.

Homely Cow Dip, an historical structure, is located near the junction of US Highways 192 and I 4. Other historic structures that occur within the 5 mile radius include the following: (1) Lake Wilson Boy Scout Camp, Oak Island Road, Kissimmee; (2) Homestead Cemetery, Kinney Harmon Road, Davenport; and (3) Rodgers House, Old Wilson Lake, Loughman.

Two historic residences are in Campbell, and 20 historic structures (mainly residences) are present near Intercession City. These structures are as follows:

- 4480 Old Tampa Highway, Campbell.
- 4489 Old Tampa Highway, Campbell.
- 5552 Old Tampa Highway, Intercession City.
- 5618 Old Tampa Highway, Intercession City.
- 531 Tallahassee Blvd, Intercession City.
- 5958 Tomoka Road, Intercession City.
- 4936 South Orange Blossom Trail, Intercession City.
- 4955 South Orange Blossom Trail, Intercession City.
- 5508 South Orange Blossom Trail, Intercession City.
- 5505 South Orange Blossom Trail, Intercession City.
- 5510 South Orange Blossom Trail, Intercession City.
- 4955 South Orange Blossom Trail, Intercession City.
- 5515 South Orange Blossom Trail (Rainbow Trailer Park Office), Intercession City.
- 5540 South Orange Blossom Trail, Intercession City.
- 5544 South Orange Blossom Trail, Intercession City.
- 5548 South Orange Blossom Trail, Intercession City.
- 5535 South Orange Blossom Trail, Intercession City.
- 5551 South Orange Blossom Trail, Intercession City.
- 5581 South Orange Blossom Trail, Intercession City.
- 5599 South Orange Blossom Trail, Intercession City.
- 5605 South Orange Blossom Trail, Intercession City.
- 5637 South Orange Blossom Trail, Intercession City.

The CIPP conservation easement is not a Save Our Rivers (SOR) property. However, approximately 500 to 600 acres south of Highway 92 and approximately 1,000 acres north of the CIPP are SOR properties.

2.2.5 Archaeological and Historic Sites

The *National Register of Historic Places* lists seven sites in Osceola County. These sites include the Colonial Estate, First United Methodist Church, the Kissimmee Historic District, the Old Holy Redeemer Catholic Church, and the Osceola County Courthouse, all located in Kissimmee. The remaining two sites include the Desert Inn in Yeehaw Junction and the Grand Army of the Republic Memorial Hall in St. Cloud.

In January 1992, in association with construction and operation of Units 1 and 2, the Florida Division of Historical Resources (FDHR) was requested to conduct an assessment of known or potential cultural resources onsite and in the project area. The FDHR indicated in February 1992 that there were no known archeological or historical resources onsite or within the project area listed on the *National Register of Historic Places*, but recommended that a systematic survey of the site and project area be conducted prior to any project land disturbing activities.

A Phase I cultural resources investigation of the CIPP and associated corridors was conducted by Janus Research/Piper Archaeology of St. Petersburg, Florida, in May 1992. The investigation discovered 13 previously unrecorded sites, seven prehistoric and six historic. It was the consultant's opinion that none of the sites were eligible for listing on the *National Register of Historic Places*. All of the historic sites were outside of direct impact areas. The Phase I report was submitted to the FDHR for review in June 1992. On July 23, 1992, the FDHR issued a clearance letter concurring with the consultant's opinion and approving the project for construction.

Correspondence to the FDHR in March 2008 provides a description of the project and requests up-to-date information about archaeological and cultural resources. A copy of the project review letter to FDHR is included in Subsection 10.5.4.

2.2.6 Socioeconomics and Public Services

2.2.6.1 Labor Force. Labor force statistics for Florida, Osceola County, and the surrounding counties are shown in Table 2.2-4. According to the Florida Research and Economic Database, Osceola County had a September 2007 total civilian labor force of 126,946, of which 4.5 percent were unemployed. Osceola County's unemployment rate was in line with those of surrounding counties, which ranged from 3.7 to 7.0 percent. Osceola County's unemployment rate was only slightly higher than the overall state unemployment rate of 4.3 percent for September 2007 and matched the national unemployment rate of 4.5 percent. Annual figures for 2006 show a similar pattern, with the Osceola County unemployment rate at 3.4 percent, a 3.3 percent rate for Florida, and a 4.6 percent rate nationally.

2.2.6.2 Employment by Occupation. Employment figures by occupation for the Orlando-Kissimmee Metropolitan Statistical Area (MSA) for May 2006 are shown in Table 2.2-5. This MSA includes not only Orlando and Kissimmee, but also towns from Osceola, Orange, Seminole, and Lake counties. There were 1,019,280 people employed among all occupations within this MSA; the largest occupation category was in the office and administrative support occupation (191,350 or 18.8 percent). This category was followed by sales and related occupation (132,160 or 13.0 percent), and the food preparation and serving occupation (110,350 or 10.8 percent).

Table 2.2-4
Labor Force Statistics for Osceola County, Area Counties Surrounding the Cane Island, Florida, and the US

Area	Civilian Labor Force	Employment	Unemployment	Unemployment Rate
September 2007 Labor Force Statistics				
Brevard County	266,773	254,833	11,940	4.5%
Highlands County	43,133	40,883	2,250	5.2%
Lake County	61,597	57,292	4,305	7.0%
Indian River County	128,959	123,235	5,724	4.4%
Okeechobee County	18,439	17,287	1,152	6.2%
Orange County	601,260	578,008	23,252	3.9%
Osceola County	126,946	121,236	5,710	4.5%
Polk County	278,180	264,756	13,424	4.8%
Seminole County	246,515	237,487	9,028	3.7%
Florida	9,297,000	8,901,000	396,000	4.3%
US	153,400,000	146,448,000	6,952,000	4.5%
Annual 2006 Labor Force Statistics				
Brevard County	261,417	252,864	8,553	3.3%
Highlands County	41,684	40,194	1,490	3.6%
Lake County	59,596	57,102	2,494	4.2%
Indian River County	123,126	119,036	4,090	3.3%
Okeechobee County	17,497	16,786	711	4.1%
Orange County	575,990	558,312	17,678	3.1%
Osceola County	121,189	117,105	4,084	3.4%
Polk County	269,119	259,755	9,364	3.5%
Seminole County	236,170	229,395	6,775	2.9%
Florida	8,989,000	8,693,000	296,000	3.3%
US	151,428,000	144,427,000	7,001,000	4.6%

Source: Florida Research and Economic Database, http://fred.labormarketinfo.com/analyzer/seltime.asp?cat=LAB&session=LABFORCE&subsession=99&tableused=LABFORCE&rollgeo=04&defaultcode=&time=&currsubsessavail=&siclevel=3&naicslvl=6&incsource=&sgltime=0&AreaAbr=cnty&blnFirstGeog=True&geo=1204000097&areaname=Osceola%20County

Table 2.2-5
Employment by Occupation for Orlando-Kissimmee MSA and Florida, May 2006

Occupation	Orlando-Kissimmee MSA		Florida	
	Employment Level	Percent of Total	Employment Level	Percent of Total
All Occupations	1,019,280	100	7,869,210	100
Management	29,750	2.9	231,960	3.0
Business and Financial Operations	47,300	4.6	360,270	4.6
Computer and Mathematical Science	22510	2.2	149,660	1.9
Architecture and Engineering Occupations	19040	1.9	127,420	1.6
Life, Physical, and Social Science	6,710	0.7	50,050	0.6
Community and Social Services	7,110	0.7	80,800	1.0
Legal	7,070	0.7	69,320	0.9
Education, Training, and Library	52,160	5.1	390,160	5.0
Arts, Design, Entertainment, Sport, and Media	14,480	1.4	94,400	1.2
Healthcare Practitioner and Technical Occupations	42,520	4.2	413,180	5.3
Healthcare Support Operations	20,280	2.0	200,440	2.6
Protective Service	22,270	2.2	208,240	2.7
Food Preparation and Serving	110,350	10.8	739,750	9.4
Building and Grounds Cleaning and Maintenance	46,510	4.6	311,490	4.0
Personal Care and Service	36,590	3.6	205,230	2.6
Sales and Related	132,160	13.0	984,230	12.5
Office and Administrative Support	191,350	18.8	1,508,910	19.2
Farming, Fishing, and Forestry	2,930	0.3	38,740	0.5
Construction and Extraction	64,580	6.3	513,750	6.5
Installation, Maintenance, and Repair	41,170	4.0	322,170	4.1
Production Occupations	37,010	3.6	353,550	4.5
Transportation and Material Moving	65,420	6.4	515,490	6.6

Source: Bureau of Labor Statistics, http://stats.bls.gov/oes/current/oes_36740.htm

In the Orlando-Kissimmee MSA, the largest employer, by far, is the Walt Disney World Company with 56,800 employees. Orange County Public Schools employs the next largest number of employees, with 24,063, followed by Florida Hospital (19,220) and Universal Orlando (12,500). Other major employers in the area include Orlando Regional Healthcare (11,093), the University of Central Florida (8,946), Central Florida Investments (8,300), and Orange County Government (7,426).

2.2.6.3 Employment by Industrial Sector. Table 2.2-6 lists the employment by industrial sector for the Orlando-Kissimmee MSA, Osceola County, and Florida in 2006. Major employment sectors in the county included the leisure and hospitality sector (21.6 percent) as well as the trade, transportation, and utilities sector (21.4 percent). Education and health services (11.1 percent) and professional and business services (8.9 percent) also made up a significant portion of the Osceola County employment by industry in 2006.

Compared to the state, Osceola County had a relatively higher concentration of employment in the leisure and hospitality sector (21.6 percent versus 11.5 percent). The county was well below the state percentage in the professional and business services sector (8.9 percent versus the state's 17.1 percent), and education and health services (11.1 percent for the county versus 18.4 percent in the state).

2.2.6.4 Baseline Employment Projections. Employment projections are available by sector for the Orlando-Kissimmee MSA employment region and for the state through the Florida Research and Economic Database. Projections covering 2007 and 2015 are shown in Table 2.2-7. For this period, the community and social services sector in the Orlando-Kissimmee region is expected to experience the largest annual average growth rate (5.0 percent per year). The life, physical, and social science sector (4.1 percent), healthcare support sector (3.5), and the healthcare practitioners and technical sector (3.4 percent) also are expected to increase at an annual average rate of more than 3.3 percent.

Compared to the state of Florida in general, the Orlando-Kissimmee MSA is expected to realize higher growth rates in most sectors. These include the community and social services sector (5.0 percent versus 2.2 percent) and the life, physical, and social sciences sector (4.1 percent versus 2.1 percent). The following sectors also have 0.7 percent more growth each, in the MSA versus the state of Florida: education, training and library; building and grounds cleaning and maintenance; healthcare practitioners, and technical.

Table 2.2-6
Employment by Industry in Osceola County and Florida, 2006

Industry	Orlando-Kissimmee MSA		Osceola County		Florida	
	Percent	Number	Percent	Number	Percent	Number
Education and Health Services	10.5	110,474	11.1	13,452	18.4	1,425,582
Information	2.6	27,097	0.8	969.512	2.2	170,450
Trade, Transportation, and Utilities	20	211,408	21.4	25,934	20.8	1,611,528
Manufacturing	4.3	45,085	2.4	2,909	5.2	402,882
Natural Resources and Mining	0.7	7,130	N/D	N/D	1.3	100,720
Other Services	2.8	29,674	2.3	2,787	3.1	240,180
Leisure and Hospitality	17.5	184,734	21.6	26,177	11.5	890,989
Construction	8.9	94,490	9	10,907	7.6	588,827
Financial Activities	6.4	67,388	5.4	6,544	6.8	526,846
Professional and Business Services	15.6	165,258	8.9	10,786	17.1	1,324,862
Public Administration	4.4	46,695	6.4	7,756	5.8	449,368
Unclassified	5.5	58,079	0.1	121.189	0.1	7,748

Source: Enterprise Florida,
http://www.eflorida.com/profiles/CountyReport.asp?CountyID=30&Display=all

Table 2.2-7
Baseline Employment Projections, 2007-2015

Industry	Orlando-Kissimmee MSA Employment Region 2007 Estimate	Orlando-Kissimmee MSA Employment Region 2015 Projected	Orlando-Kissimmee MSA Employment Region Annual Average Growth Rate	Florida 2007 Estimate	Florida 2015 Projected	Florida Annual Average Growth Rate
Office and Administrative Support	188,261	214,319	1.6	1,573,303	1,727,537	1.2
Sales and Related	133,261	156,936	2.1	1,150,570	1,308,450	1.6
Food Preparation and Serving Related	97,954	119,956	2.6	764,151	907,275	2.2
Construction and Extraction	63,735	70,031	1.2	621,154	680,431	1.1
Transportation and Material Moving	63,026	71,851	1.7	547,915	619,819	1.6
Education, Training, and Library	53,888	68,909	3.1	440,598	531,404	2.4
Building and Grounds Cleaning and Maintenance	49,019	60,006	2.6	381,876	459,634	2.3
Business and Financial Operations	48,840	60,450	2.7	419,642	498,847	2.2
Personal Care and Service	44,076	54,146	2.6	288,952	341,312	2.1
Installation, Maintenance, and Repair Occupations	43,808	51,715	2.1	364,679	417,534	1.7
Management Occupations	39,323	46,259	2.1	365,363	415,208	1.6
Healthcare Practitioners and Technical	38,494	50,258	3.4	452,600	560,170	2.7
Production	34,921	38,558	1.2	369,718	392,120	0.7
Computer and Mathematical	27,700	35,950	3.3	170,453	218,588	3.2
Arts, Design, Entertainment, Sports, and Media	23,524	27,595	2.0	149,436	170,877	1.7
Healthcare Support	18,375	24,180	3.5	222,697	282,378	3.0
Protective Support	16,674	19,025	1.7	219,695	248,090	1.5
Architecture and Engineering	11,618	13,374	1.8	137,294	160,722	2.0
Legal	11,485	14,627	3.1	92,018	115,668	2.9
Community and Social Services	9,903	12,234	5.0	111,221	132,498	2.2
Life, Physical, and Social Science	6,380	8,804	4.1	59,014	69,864	2.1
Farming, Fishing, and Forestry	4,865	4,951	0.2	85,092	86,682	0.2
Total	1,029, 098	1,223,414	2.2	8,987,444	10,345,108	1.8

Source: Florida Research and Economic Database, http://fred.labormarketinfo.com/lmi/area/area_occupations.asp?session=areadeatail&geo=1201000000

2.2.6.5 General Income Characteristics. Total and per capita income information for Osceola County and for Florida are listed in Table 2.2-8. According to the US Bureau of Economic Affairs, Osceola County, the total personal income in 2005 was $5.10 billion and the state total was $616.77 billion; these figures constituted increases of 10.7 percent and 9.1 percent, respectively, from 2004. The per capita income level for the county was $22,008 per person in 2005, and compared to a per capita income of $20,901 the previous year, and $20,260 in 2003. The 2005 per capita income in the county was significantly below that at the state level, which was $34,712. According to the 2004 US Census, 12.2 percent of the population in Osceola County lived in poverty. The corresponding figure for the state was 11.9 percent.

Table 2.2-8
Total and Per Capita Personal Income ($000s), 2003-2005

	Orlando-Kissimmee		Osceola County		Florida	
Year	Per Capita Income	Total Personal Income	Per Capita Income	Total Personal Income ($000s)	Per Capita Income	Total Personal Income ($000s)
2003	$28,387	$51,110,355	$20,260	$4,175,478	$30,290	$514,377,645
2004	$30,068	$55,966,086	$20,901	$4,602,693	$32,546	$565,211,107
2005	$31,557	$60,951,385	$22,008	$5,094,559	$34,712	$616,766,729

Source: US Bureau of Economic Affairs,
http://www.bea.gov/regional/REMDmap/REMDMap.aspx

2.2.6.6 Source of Income. Information on sources of income for the area surrounding the CIPP is listed in Table 2.2-9 for 2004 and 2005. According to the US Bureau of Economic Analysis, personal income was the largest source of county income in both years: personal current transfer receipts; retirement benefits; and dividends, interest, and rent also each generated more than 1 billion dollars in income.

2.2.6.7 Average Wage and Salary Income, by Sector. Table 2.2-10 lists the average annual wage by industry in Osceola County in 2006. The manufacturing industry had the highest average annual wage at $45,055. The next highest paid sectors were information at $43,408 and public administration at $40,383. The leisure and hospitality sector ($19,754) and other services ($23,853) had the lowest recorded average annual wages for 2006.

Table 2.2-9
Source of Income for 2004 and 2005[1]
(in thousands of dollars)

	Orlando – Kissimmee MSA		Osceola County, Florida		Florida	
Category	2004	2005	2004	2005	2004	2005
Personal Income[2]	$55,966,086	$60,951,385	$4,602,693	$5,094,559	$564,997,468	$604,131,000
Net Earnings	$39,311,164	$43,476,708	$3,152,845	$3,530,529	$333,089,178	$362,586,955
Personal Current Transfer Receipts	$8,587,307	$8,724,433	$1,026,401	$1,003,628	$94,828,431	$98,667,268
Income Maintenance[3]	$852,670	$869,699	$71,786	$82,079	$8,385,252	$8,956,379
Unemployment Insurance Benefit Payments	$113,494	$88,492	$19,427	$27,412	$1,176,540	$918,857
Retirement and Other	$7,621,143	$7,766,242	$1,009,461	$1,095,584	$85,266,639	$88,792,032
Dividends, Interest, and Rent	$8,067,615	$8,750,244	$423,447	$560,401	$137,079,859	$142,876,777

[1]Source: US Bureau of Economic Affairs, http://www.bea.gov/regional/index.htm
[2]Net earning by place of residence is earnings by place of work less contributions for government social insurance, plus an adjustment to convert earnings by place of work to a place of residence basis. Earnings by place of work is the sum of wage and salary disbursements, supplements to wages and salaries, and proprietors' income.
[3]Income Maintenance payments consist largely of supplemental security income payments, family assistance, food stamp payments, and other assistance payments, including general assistance.

Table 2.2-10
Average Annual Wage by Industry, 2006 ($)

Industry	Osceola County
Construction	$34,975
Education and Health Services	$38,894
Financial Activities	$37,405
Information	$43,408
Leisure and Hospitality	$19,754
Manufacturing	$45,055
Natural Resources and Mining	N/D
Other Services	$23,853
Professional and Business Services	$27,958
Public Administration	$40,383
Trade, Transportation, and Utilities	$26,201
Unclassified	$28,191

Source: Enterprise Florida,
http://www.eflorida.com/floridasregionsSubpage.aspx?id=284

Table 2.2-11 lists the income by occupation for the Orlando-Kissimmee MSA in May 2006. For all occupations, the average income was $34,930 in the MSA, though there was significant variation among individual occupations. The highest income category was in the management occupation ($93,420), followed by the legal occupation ($88,370), and the computer and mathematical science occupation ($61,650).

2.2.6.8 Baseline Income Projections. Table 2.2-12 contains baseline income projections through 2011 for Osceola County and Florida. The projected categories include per capita income and total personal income, and the projections assume that the 2002 through 2005 average annual growth rate for these categories continues to apply through 2011 at the county and state level. Projections indicate that under the assumptions made, the per capita income in Osceola County would increase to $22,008 in 2005 and to $33,028 in 2011. This compares to respective figures of $34,001 and $40,599 for Florida. The total personal income in Osceola County increases to $5.09 billion in 2005 and to $10.06 billion in 2011 under the forecast, while the state income would increase from $604.13 billion in 2005 to $809.59 billion in 2011.

2.2.6.9 Housing. According to the US Census Bureau, there were 89,902 occupied housing units in Osceola County in 2006; this was approximately 1.0 percent of the 8,533,419 units in the state. Osceola County’s total number of housing units in 2006 grew by 52 percent in the 6 years between the 2000 census, when 72,293 units were reported. Over 62 percent of the county housing unit stock consisted of single units, while multi-units and mobile homes were approximately 25 percent and 12 percent of the total units, respectively. Approximately 82 percent of the 2006 housing units were built in 1980 or later, with 5.5 percent built before 1960. Approximately 69 percent of residents moved into units after 2000; nearly 91 percent have moved to their residence in 1990 or later.

The Orlando-Kissimmee MSA had a total of 749,928 housing units in 2006, and this constituted 8.8 percent of the total state’s overall units. Additional statistics shown in Table 2.2-13 indicate that single units made up two-thirds of the MSA housing stock in 2006, with 7.8 percent classified as mobile homes and 25.5 percent as multi-units. The housing unit stock around Orlando and Kissimmee is relatively young, reflecting the recent population growth. Approximately 68 percent of the housing stock in 2006 was built in 1980 or later, and only 10 percent of the housing units were built before 1960. Approximately 64 percent of the 2006 population moved into their housing unit in 2000 or later, and approximately 86 percent moved into the unit in 1990 or later.

Table 2.2-11
Mean Annual Average Wages
Income by Occupation for Orlando-Kissimmee MSA and Florida
May 2006 (in Dollars)

Occupation	Orlando-Kissimmee	Florida
All Occupations	34,930	35,820
Management	93,420	94,650
Business and Financial Operations	55,380	55,550
Computer and Mathematical Science	61,650	60,310
Architecture and Engineering Occupations	59,220	58,980
Life, Physical, and Social Science	51,370	52,630
Community and Social Services	36,950	37,060
Legal	88,370	78,830
Education, Training, and Library	40,230	43,940
Arts, Design, Entertainment, Sport, and Media	42,800	42,430
Healthcare Practitioner and Technical Occupations	57,930	59,780
Healthcare Support Occupations	24,120	23,940
Protective Service	32,450	34,730
Food Preparation and Serving	19,300	19,010
Building and Grounds Cleaning and Maintenance	20,670	20,780
Personal Care and Service	21,000	22,740
Sales and Related	33,660	34,710
Office and Administrative Support	27,940	28,050
Farming, Fishing, and Forestry	21,370	19,740
Construction and Extraction	32,860	32,680
Installation, Maintenance, and Repair	35,510	35,360
Production Occupations	27,300	27,700
Transportation and Material Moving	26,920	27,220

Source: US Department of Labor, Bureau of Labor Statistics, May 2006 Metropolitan Area Occupational Employment and Wage Estimates, http://stats.bls.gov/cew/home.htm

Table 2.2-12
Projection of Baseline Income Figures for Osceola County and Florida

Year	Osceola County		Florida	
	Per Capita Income	Total Personal Income ($1,000s)	Per Capita Income	Total Personal Income ($1,000s)
2003	$20,260	$4,175,478	$30,290	$514,377,645
2004	$20,901	$4,602,693	$32,534	$564,997,468
2005	$22,008	$5,094,559	$34,001	$604,131,000
2006	$23,549	$5,705,906	$35,021	$634,337,550
2007	$25,197	$6,390,615	$36,072	$666,054,428
2008	$26,961	$7,157,489	$37,154	$699,357,149
2009	$28,848	$8,016,387	$38,268	$734,325,006
2010	$30,867	$8,978,354	$39,416	$771,041,257
2011	$33,028	$10,055,756	$40,599	$809,593,319

Sources: Projections made by Black & Veatch.
Enterprise Florida,
http://www.eflorida.com/profiles/CountyReport.asp?CountyID=30&Display=all

Table 2.2-13
Profile of Selected Housing Characteristics in 2006

Category	Orlando-Kissimmee MSA Number (out of 749,928 occupied housing units)	Orlando-Kissimmee MSA Percent	Osceola County Number (out of 89,902 occupied housing units)	Osceola County Percent
Units in Structure				
Single-Unit, Detached	467,205	62.3	56,369	62.7
Single-unit, Attached	32,997	4.4	2,517	2.8
Two Apartments	13,499	1.8	1,708	1.9
Three or Four Apartments	27,747	3.7	3,506	3.9
Five to Nine Apartments	47,995	6.4	7,282	8.1
Ten or More Apartments	101,240	13.5	7,462	8.3
Mobile Home or other Type of Housing	58,494	7.8	11,058	12.3
Year Structure Built				
2000 or Later	153,735	20.5	25,982	28.9
1990-1999	169,484	22.6	26,611	29.6
1980-1989	182,982	24.4	21,217	23.6
1960-1979	167,984	22.4	11,148	12.4
1940-1959	60,744	8.1	3,147	3.5
1939 or Earlier	14,249	1.9	1,708	1.9
Rooms				
One Room	2,250	0.3	90	0.1
Two or Three Rooms	81,742	10.9	7,282	8.1
Four or Five Rooms	293,222	39.1	36,680	40.8
Six or Seven Rooms	255,725	34.1	32,634	36.3
Eight or More Rooms	116,239	15.5	13,216	14.7
Year Householder Moved into Unit				
2005+	206,355	27.5	25,622	28.5
2000 - 2004	276,981	36.9	36,244	40.3
1990 to 1999	163,052	21.7	19,579	21.8
1980-1989	63,014	8.4	6,137	6.8
1970 to 1979	24,595	3.3	1,890	2.1
1969 or Earlier	15,931	2.1	430	0.5

Source: US Census Bureau, 2000 and 2006 Census data, S2504 Physical Housing Characteristics for Occupied Housing Units,
http://factfinder.census.gov

2.2.6.10 Existing Housing Stock. Table 2.2-14 lists additional Census Bureau data about the Orlando-Kissimmee MSA and Osceola County housing units. Of the total 749,928 housing units in the MSA, 0.4 percent of the housing units were classified as lacking complete plumbing facilities, and 0.7 percent were lacking complete kitchen facilities. Approximately 9 percent had no telephone service.

The vast majority of homes (91.6 percent) in the Orlando-Kissimmee MSA were heated by electricity in 2006, while only 5.9 percent were heated by utility gas. Use of other fuel sources was marginal.

Osceola County's housing characteristics looked similar to those in the MSA. Of the MSA housing units, approximately 8.0 percent had no telephone, 0.6 percent lacked plumbing, and 0.4 percent did not have complete kitchen facilities.

The number of persons per household was essentially the same at the MSA and state levels according to US Census data. Of the occupied housing units in the Orlando-Kissimmee area, 97.5 percent contained 1.00 or fewer occupants per room. For Osceola County, 97.9 percent had 1.00 or fewer occupants to each room.

Of the total number of houses in the Orlando-Kissimmee MSA, 84.3 percent were occupied and 15.7 percent were vacant, with 9.9 percent of vacant houses designated for seasonal, recreational, or occasional use. In Osceola County, 91.5 percent of houses were occupied, leaving 8.5 percent vacant. A smaller percentage (3.2 percent) was for seasonal or recreational use.

2.2.6.11 Building Activity. Table 2.2-15 indicates that the building activity for Osceola County has continued at a rapid pace during the recent past, as reflected in the number of housing unit building permits issued. According to the US Department of Housing and Urban Development, in 2006, a total of 8,006 permits were issued for the county, and this was equal to approximately 2.6 percent of the 2002 existing housing stock. From 2002 through 2006, the type of housing unit for which a building permit was issued was primarily for single family structures, although five+ unit multi-family structures also comprised a significant percentage in 2002 (32 percent) and in other years.

2.2.6.12 Housing Costs. Osceola County features a diversity of residential areas and a wide range of housing prices. The average home prices for Osceola County in 2005 are shown in Table 2.2-16, based on information from the Florida Housing Data Clearing-house of the University of Florida. The cost of housing was relatively affordable in 2005. A single family home averaged $144,976, and mobile homes cost an average of $73,475. Condominiums, on the other hand, were considerably more expensive averaging over $400,000.

Table 2.2-14
Selected Housing Characteristics for the Orlando-Kissimmee MSA
and Osceola County from the 2006 Census

Category	Orlando- Kissimmee MSA		Osceola County	
	Number	Percent	Number	Percent
Lacking Complete Plumbing Facilities	3,013	0.40	575	0.64
Lacking Complete Kitchen Facilities	5,123	0.68	375	0.42
No Telephone Service	66,260	8.84	7,253	8.07
Occupants Per Room				
1.00 or less	731,379	97.53	87,980	97.86
1.01 to 1.50	15,329	2.04	1,799	2.00
1.51 or More	3,220	0.43	123	0.14
House Heating Fuel				
Utility Gas	39,205	5.9	N/A	N/A
Bottled, Tank, or Liquified Petroleum Gas (LPG)	7,444	1.1	N/A	N/A
Electricity	604,718	91.6	N/A	N/A
Fuel Oil, Kerosene, etc.	3,898	0.6	N/A	N/A
Coal or Coke	0	0.0	N/A	N/A
All Other Fuels	1,649	0.3	N/A	N/A
No Fuel Used	3,112	0.5	N/A	N/A
Types of Houses Orlando-Kissimmee MSA and Osceola County from the 2000 Census				
Total Number of Houses	683,551	100.0	72,293	100.0
Total Number of Vacant Houses	58,303	8.5	11,316	15.7
Total Number of Seasonal/ Recreational Houses	21,534	3.2	6,599	9.1

Source: US Census Bureau, 2006 Census data, S2504 Physical Housing Characteristics for Occupied Housing Units,
http://factfinder.census.gov

Table 2.2-15
Housing Unit Building Permits
2002-2006

Units	2002	2003	2004	2005	2006
Osceola County, FL					
Single-Family Structures	3,541	4,692	6,316	5,841	5,772
Multi-Family Structures	1,772	823	2,754	2,155	2,234
Two-Unit Multi-Family Structures	36	8	26	8	4
Three- and Four-Unit Multi-Family Structures	58	19	37	40	154
Five+ Unit Multi-Family Structures	1,678	796	2,691	2,107	2,076
Total	5,313	5,515	9,070	7,996	8,006
Orlando-Kissimmee MSA, FL					
Single-Family Structures	15,914	20,751	25,049	24,802	23,646
Multi-Family Structures	8,068	5,602	6,047	9,231	7,338
Two-Unit Multi-Family Structures	148	152	148	32	96
Three- and Four-Unit Multi-Family Structures	122	88	183	322	421
Five+ Unit Multi-Family Structures	7,798	5,362	5,716	8,877	6,821
Total	23,982	26,353	31,096	34,033	30,984

Source: US Dept. of Housing and Urban Development, State of the Cities Data Systems (SOCDS), http://socds.huduser.org/permits/index.html

Table 2.2-16
Average Home and Rental Prices in Osceola County

Average Home Prices, 2005	
Description	
Single Family Home	$144,976
Mobile Home	$73,475
Condominium	$421,269
Average Price of Rentals, 2000	
Studio One Bedroom Apartment	$655
Two Bedroom Apartment	$814
Three Bedroom	$1,019

Source: Florida Housing Data Clearinghouse, http://flhousingdata.shimberg.ufl.edu/a/profiles?action=results&nid=4900

Additional housing cost information is available from the 2000 US Census. Table 2.2-17 shows that in 2000, 47.7 percent of the housing in Osceola County had a value of between $50,000 and $99,999. The second highest percentage of owner-occupied housing units was in the $100,000 to $149,000 range (32.2 percent of the units). The 2000 US Census also reported that 18.7 percent of the housing units were not mortgaged and, of those units mortgaged, 31.9 percent had monthly owner costs between $700 and $999 per month; 26.5 percent had a monthly mortgage between $1,000 and $1,499 per month; and 10.4 percent had a monthly mortgage between $500 and $699 per month. According to US Census data, 43.1 percent of the county population spent less than 20 percent of household income on monthly owner costs.

For rental units, the 2000 US Census reported that 43.2 percent of the renter-occupied units in Osceola County had a gross rent between $500 and $749 per month, 32.1 percent were between $750 and $999 per month, and 10.3 percent were between $300 and $499 per month. According to the 2000 Census, 24.0 percent of renters spent less than 20 percent of their income on rent and 38.4 percent of renters spent 35 percent or more on rent.

In addition to the housing and rental stock, Orlando and Kissimmee offer a wide variety of temporary lodging, reflecting the area's status as a destination for recreational seekers. The Kissimmee Convention and Visitors' Bureau Web site lists 144 motels, inns, hotels, RV parks, and short-term apartments in the area.

2.2.6.13 Education. According to the School District of Osceola County Web site, the county has a total of 42 public schools. Of these, 26 are elementary schools, 10 are middle schools, and the remaining 17 are high schools. The public schools serve over 51,000 students. Parents have the option of choosing their child's school in accordance with certain rules and limits.

There are several options for higher education in the county. There are three community colleges: Valencia (53,800 students), Seminole (29,500 students), and Lake-Sumter (4,650 students). In addition, there are five vocational/technical schools and several alternative school options.

A wide variety of colleges and universities also help to meet the region's educational needs. With an enrollment of nearly 47,000 students, the University of Central Florida (UCF) ranks as the seventh largest university in the nation. Its research facilities have been fundamental in supporting the region's growing technology clusters. The adjacent Central Florida Research Park is known as one of the top research parks for industry/university research collaboration and technology commercialization.

Table 2.2-17
Selected Housing Cost Characteristics for Osceola County, 2000

Category	Number (out of 72,293)	Percent
Value of Specified Owner-Occupied Units		
Less than $50,000	1,043	3.3
$50,000 to $99,999	15,275	47.7
$100,000 to $149,999	10,311	32.2
$150,000 to $199,000	2,874	9.0
$200,000 to $299,999	1,691	5.3
$300,000 to $499,000	584	1.8
$500,000 to $999,999	196	0.6
$1,000,000 plus	48	0.1
Median	$99,300	N/A
Selected Monthly Owner Costs as a Percent of Household Income		
Less than 15 percent	8,254	25.8
15 to 19 percent	5,551	17.3
20 to 24 percent	5,361	16.7
25 to 29 percent	3,450	10.8
30 to 34 percent	2,590	8.1
35 percent or more	6,573	20.5
Not computed	243	0.8
Gross Rent of Specified Renter-Occupied Units		
Less than $200	260	1.3
$200 to $299	276	1.4
$300 to $499	2,016	10.3
$500 to $749	8,478	43.2
$750 to $999	6,297	32.1
$1,000 to $1,499	1,436	7.3
$1,500 or more	155	0.8
No cash rent	725	3.7
Median	714	N/A
Gross Rent as a Percent of Household Income		
Less than 15 percent	1,859	9.5
15 to 19 percent	2,852	14.5
20 to 24 percent	2,806	14.3
25 to 29 percent	2,334	11.9
30 to 34 percent	1,844	9.4
35 percent or more	6,904	35.1
Not computed	1,044	5.3

Source: US Census Bureau, 2000 Census, DP-4 Profile of Selected Housing Characteristics: 2000 (SF 3), Osceola County, Florida, http://www.census.gov

Several other top-rated colleges and technical schools provide a constant supply of talented graduates to local employers. Full Sail Real World Education is a 4 year private school that enrolls 4,500 students annually. Rollins, a private liberal arts college, enrolls 3,475 students per year. The Florida Hospital College, which is both private and independent, has the next highest enrollment of 1,000 students annually.

According to the Florida Legislature's Office of Economic and Demographic Research, 15.7 percent of Osceola County's population had a bachelor's degree or higher in 2006, to the state percentage 22.3.

2.2.6.14 Transportation. The project area's transportation system is highly developed because of the region's popularity as a tourist destination.

Airports. The three airports that serve the area are Kissimmee Municipal, Orlando International, and the Orlando Executive. The Kissimmee (Municipal) Gateway Airport (ISM) accommodates general aviation air service 24 hours a day with two paved airport runways of 5,000 and 6,000 feet. A number of flight training schools, hangars, and a variety of recreational activities are located on the airport property. The Gateway Airport is owned and operated by the City of Kissimmee, and its air traffic control tower operates from 7:00 a.m. to 10:00 p.m. daily.

According to its Web site, the Orlando International Airport (MCO), located 12 miles from Orlando, is one of the 30 busiest airports in the world. It is the third largest airport in the United States and covers 23 square miles. MCO has four parallel runways, two of which are 12,000 feet in length, one of which is 10,000 feet, and the last is 9,000 feet. It has an airfield capacity of 140 operations per hour through its one landside terminal and four airside terminals. The airport serves 74 domestic and 16 international airlines. These airlines utilize MCO to fly in and out of over 80 US and numerous international destinations. The airport accommodates 35 million passengers annually.

The Orlando Executive Airport (ORL) is located near downtown Orlando, but is a general aviation airport and is not served by commercial airlines. It has a Federal Aviation Administration (FAA) Staffed Control Tower and two paved runways, which are 6,003 feet and 4,638 feet. The ORL offers many services to the community - including law enforcement, air ambulance, and search/rescue capabilities. Its central location, quality approaches, and the ability to handle quick take-off demands make ORL ideally suited for these operations.

Port Canaveral. Port Canaveral is major deepwater port of entry in the state of Florida, located 50 miles east of Orlando. With depths of 39 to 41 feet, it is the world's first quadramodal foreign trade zone, interchanging freight among land, air, water, and space. The port encompasses 4,160 acres, making it one of the largest general purpose foreign trades zones in the country. Port Canaveral provides uncongested highway access in all directions to all markets. More than 4.5 million short tons of cargo passed through the port in 2006, and over 4.5 million cruise passengers passed through its six terminals in 2006, making it the second biggest cruise port in the world.

Highway Transportation. Because the impact area is a major business and tourist hub, the area transportation network includes several high capacity volume highways. Among the busiest of these are Interstate 4 and the Florida Turnpike. Other important highways include State Road 417 (GreeneWay State Road 408 /East-West Expressway) and State Road 528 (Beachline Expressway). US 17/92, 27, and 441 are also major routes in the area.

2.2.6.15 Medical Facilities. Orlando and Kissimmee benefit from a number of modern health care facilities offering a wide diversity of care as outlined in the Kissimmee/Osceola County Chamber of Commerce Relocation Guide.

The Osceola Regional Medical Center is a 235 bed hospital located in Osceola County, Florida, and 7.4 miles east of the power plant site. Completed in April 1997, and with a recent $55 million expansion, the hospital is designed to be patient friendly and blends state-of-the-art technology with comfort and convenience for patients and visitors. The hospital features all private rooms, Level 2 neonatal care, and an open heart program. It also offers a wide variety of health care programs and specialties, wound care center, community education programs, and a mammography center. The hospital is Joint Commission on the Accreditation of Healthcare Organizations (JCAHO) accredited.

Florida Health Kissimmee, part of the Florida Hospital System and located near the plant, has recently updated its surgical and ICU departments. Plans are for the facility to double the size of its emergency department and build a new 50 bed patient tower, as well as a new multi-specialty physician office. The facility is located approximately 12 miles northeast of the Cane Island site.

The Lakeland Regional Medical Center, the Lake Wales Medical Centers, and Winter Haven Hospital are farther to the west and south of the CIPP. Lakeland Regional Medical Center has the second busiest emergency room in the state. As Polk County’s only state-designated Level 2 trauma center, it is equipped with state-of-the-art, life saving equipment; a dedicated chest pain management staff to expedite cardiac cases; and a 10 bed pediatric emergency center with tools specific to a child’s needs. It is 32.5 miles southwest of the Cane Island site.

The Lake Wales Medical Center is 26 miles almost directly south of the Cane Island site and consists of a 154 bed acute care hospital committed to delivering essential medical care to residents living in the Greater Lake Wales area. With over 50 active physicians, it provides a comprehensive range of inpatient and outpatient services.

Winter Haven Hospital was established in 1926 and serves as the major medical center for east Polk County. The hospital is a division of Mid-Florida Medical Services, a locally owned and operated 501(C)(3) not-for-profit organization that is governed by an independent Board of Trustees made up of local business and civic leaders who serve without pay. The hospital has 527 licensed hospital beds and is almost 24 miles southwest of the CIPP.

In addition to the above full-service hospitals, there are several “walk-in” facilities available to serve the impact area, and there are various entities that provide paramedic/ambulance services. For example, each of the fire stations within the City of Kissimmee has an ambulance. All city firefighters are also trained as Emergency Medical Technicians (EMTs) or paramedics.

2.2.6.16 Firefighting Facilities. The Osceola County Department of Public Safety provides fire protection for the CIPP, as well as all unincorporated areas within Osceola County. Many other political jurisdictions also employ professional and volunteer firefighting personnel. The Intercession City volunteer fire station is closest in proximity to the CIPP and is roughly 1-1/2 miles from the site. The County also has stations in several nearby locations, and the City of Kissimmee has staff firefighters on call at all times. The City of Orlando also has officers and firefighters in its many stations.

2.2.6.17 Police Protection. The CIPP is unincorporated and, therefore, receives its police protection from the Osceola County Sheriff’s Department. The Sheriff’s Department headquarters is located between Kissimmee and St. Cloud. It has a professional staff of more than 500 men and women who deliver a range of community-based law enforcement and crime prevention programs to local citizens. Other parts of the impact area divide police protection responsibilities amongst local municipal police forces, the Florida Highway Patrol, and other county sheriff’s departments.

The Orlando Police Department has over 1,000 employees to serve residents through crime prevention, criminal investigations and apprehension, neighborhood policing, and involvement through the schools.

The Kissimmee Police Department’s Patrol Division is comprised of eight patrol squads that are responsible for providing police services to six patrol beats, 7 days a week, 24 hours a day. The Patrol Division, the largest division within the Agency, has an authorized strength of 55 police officers, eight civilian community service officers, and nine sergeants, four lieutenants also called Watch Commanders, one Captain, and one Deputy Chief. Three of the officers are assigned to K-9 and two to full-time DUI enforcement. Patrol officers are State of Florida certified and are prepared to deal with medical emergencies, to arrest criminal offenders, and to provide assistance to those in need.

The Florida Highway Patrol also has jurisdiction within the area. One troop of officers handles the Florida Turnpike operations, and the district troops are responsible for 30 other subdivided areas of the state. In total, the state has 2,360 patrol officers of which 1,813 are sworn and 547 are non-sworn.

2.2.6.18 Recreation Facilities. The Orlando-Kissimmee area offers numerous recreational activities and attractions; many are related to nature and the outdoors. Some of the main recreational activities include golf, fishing and hunting, parks and hiking trails, and nature tours.

Given the region's relatively temperate climate, many people take advantage of the 130 golf courses surrounding Orlando. The more than 800 indoor and outdoor tennis courts in the area also provide easy access to recreational opportunities.

Hiking is also a popular activity within Osceola County. There are over 25 parks, preserves, and hiking trails just around Kissimmee. These allow for all-day hikes complete with woods, water, and wildlife or simply a relaxing stroll along the lakefront. Roughly 20 area nature tour businesses are available to assist with planning more structured activities. These can include: photographing native Florida wildlife from an airboat, horseback riding on trails along a cattle ranch, having photographs taken with alligators, or picking oranges in local citrus groves. Osceola County has a very active parks division that supports activities as diverse as frogging in Upper Reedy Creek to wildflower viewing along Lake Russell. Local public parks also offer over 3,000 acres of campground.

Kissimmee offers some of the best freshwater fishing in the world. The Kissimmee Chain-of-Lakes is recognized worldwide for its trophy largemouth bass, and it holds several bass tournament world records. Fishing and hunting guides are available year-round to accommodate individual and group excursions. The Orlando-Kissimmee region has almost 20 fishing charters and guide services. The more than 2,000 area freshwater lakes also offer ample opportunity for boating and sailing.

The area is also famous for its theme and water parks; it is home to the Walt Disney World® Resort, SeaWorld® Orlando, and Universal Orlando® Resort. The Walt Disney World Resort includes Animal Kingdom, Downtown Disney, Disney's Hollywood Studios, Magic Kingdom Park, and the Epcot Center. SeaWorld Orlando features Orca whale, sea lion, and dolphin shows, zoological displays featuring various other marine animals, and a variety of thrill rides. Universal Orlando Resort is the number one movie and TV-based theme park in the world and offers a variety of family friendly rides, dining, and shopping.

The region hosts several cultural events and festivals. These include the EPCOT International Flower and Garden Festival, Jazzfest Kissimmee, the Kissimmee Bluegrass Festival, and the Osceola Art Festival.

There are also a variety of museums in the area, which include: G.A.R. Museum (St. Cloud), Kissimmee Air Museum, Orange County Regional History Center (Orlando), Orlando Fire Museum, Orlando Museum of Art, Orlando Science Center, Osceola County Historical Society and Pioneer Museum (Kissimmee), St. Cloud Heritage Museum, St. Cloud Historical Museum, USSSA Sports Museum and Hall of Fame (Kissimmee), Veterans Tribute Museum (Kissimmee), White 1 Foundation Focke Wulf 190 Project and Museum (Kissimmee).

The Orlando-Kissimmee MSA offers several opportunities to watch sports. The Arena Football League (AFL) Orlando Predators and the Orlando Magic basketball team are both based in the area. The Atlanta Braves and Houston Astros baseball teams conduct spring training in the vicinity. The University of Central Florida hosts Division 1 football in the area, and Kissimmee hosts the Silver Spurs Rodeo twice a year.

Other recreational and cultural activities include events with the Central Florida Zoo, Orlando Opera Company, Jai-Alai, and the Southern Ballet Company. The Osceola County Historical Society features an 1898 house, a 1900 general store, a pole-barn, blacksmith shop, and sugar cane mill. The Museum of Pioneer Artifacts portrays the history of Osceola County of Florida. The authentic Medieval Life Village is the only permanent medieval village existing in the United States. The Grand Ceremonial Arena seats 1,100 guests and offers performances each evening plus matinee shows during certain times of the year.

2.2.6.19 Electricity and Gas. Electric service in Osceola County is provided by the Florida Power Corporation, KUA, and the City of St. Cloud. Natural gas service is provided by TECO Energy, an S&P 500 energy company headquartered in Tampa, Florida.

Because the Cane Island project is near Intercession City and will help meet the power requirements of the FMPA, the focus of this section will be on FMPA. The FMPA is a nonprofit, joint action agency formed by 30 municipal electric utilities. It is a public agency, whose primary purpose is to develop competitive power supply and related services.

FMPA currently has five power supply projects. The All-Requirements project is the largest of these, supplying more than 1,500 MW of wholesale power during peak demand to 15 cities. The other four projects consist of both nuclear and coal fired plants.

CIPP currently receives fuel from Florida Gas Transmission (FGT) and Gulfstream pipelines in the area. FGT is an approximately 5,000 mile pipeline extending from south Texas to south Florida with a mainline capacity of 2.3 billion cubic feet (bcf)/day. FGT provides natural gas transportation services to customers in peninsular Florida.

Existing lines to the site are adequate for Unit 4, and no new lines are required. The line into the site is 20 inches in diameter. The unit will run on only natural gas, and there will be no backup fuel.

KUA partners with the City of Kissimmee, Sanitation Division, and Toho to do its billing. The partnership provides benefit to customers who receive electric service by receiving a single bill for electric, water, refuse, and wastewater services. Average service fees for the Orlando Metro area is provided in Table 2.2-18.

Table 2.2-18
Average Residential Monthly Charges in Metro Orlando by System, Fiscal Year 2007

System	2006
Electric	$52.33
Water	$26.54
Wastewater	NA
Gas	$88.03

Source: The Metro Orlando Economic Development Commission, http://www.orlandoedc.com/Data%20Center/Utilities

Table 2.2-19 lists the FMPA Statement of Revenues, Expenses, and Changes in Net Assets for fiscal years 2006 and 2007. The utility realized $704.7 million in operating revenues, compared to operating expenses of nearly $651.4 million for 2006. This resulted in non-operating loss before capital contributions and extraordinary items of $19.9 million. The largest operating expense category was fuel expense ($291.3 million) followed by purchased power expenses ($238.7 million). As a public entity, FMPA is not subject to property or sales tax.

KUA is the FMPA member that serves much of the area surrounding the CIPP. KUA is the sixth largest utility in Florida, and its system extends over 85 square miles. Its services include electricity, wastewater, water, internet access, Web hosting and design, telephone, and security. In 2006, KUA supplied approximately 58,000 electric customers with 305 MW of power.

Table 2.2-19
FMPA Statement of Revenues, Expenses, and Changes in
Net Assets for Fiscal Years 2007 and 2006 ($000s)

FMPA Activity	Fiscal Year 2007	Fiscal Year 2006
Operating Revenues:		
Billings to Participants	$671,885	$646,014
Amounts to be Recovered		
(Refunded to) Participants	(18,950)	(33,438)
Sales to Others	51,811	19,869
Interest Income		17,986
Total Operating Revenues	**$704,746**	**$651,371**
Operating Expenses		
Operation and Maintenance (O&M)	69,277	58,989
Fuel Expense	291,271	247,332
Nuclear Fuel Amortization	2,375	2,208
Spent Fuel Fees	359	432
Purchased Power	238,690	231,792
Transmission Services	22,003	23,174
General and Administrative	26,411	24,431
Interest Expense	3,919	3,476
Depreciation	26,439	24,676
Decommissioning	2,526	2,660
Capitalized Development Projects and Allocated Costs	(8,975)	(8,477)
Total Operating Expense	**$674,295**	**$610,693**
Total Operating Income (Loss)	30,451	$21,752
Non-Operating Income (Expense)		
Interest Expense	(40,315)	(35,903)
Amortization of Debt-Related Costs	(6,422)	(6,479)
Investment Income	31,745	17,986
Development Fund Fees	930	940
Write Off of Coal Project	(5,880)	
Total Non-Operating Income (Expense)	**(19,942)**	**(23,456)**
Change in Net Assets Before Regulatory Asset Adjustment	10,509	(1,704)
Regulatory Asset Adjustment	(9,298)	2,922
Change in Net Assets After Regulatory Adjustments	1,211	1,218
Net Assets at Beginning of Year	11,129	9,911
Net Assets at End of Year	12,430	11,129

Source: “Florida Municipal Power Annual Report Year Ended September 30,,2007,”

2.2.6.20 Water Supply. Many small-scale independent water treatment systems serve a small network of customers within the impact area. If a customer does not have access to a small water treatment network, potable water service is typically provided by either a local municipality (e.g., Kissimmee, Orlando, St. Cloud) or Florida Water Services, Inc.

Toho is the local water provider serving the corporate limits of Kissimmee as well as parts of central and northwest Osceola County. Toho produces, treats, and distributes approximately 22.5 million gallons per day (mgd) of potable water and treats approximately 12 mgd of wastewater for its customers. It currently serves 45,000 water, 40,000 wastewater, and 7,000 reuse water customers. Toho maintains 500 miles of water mains, 466 miles of sewer mains, as well as 84 miles of reuse water mains, and has a staff of 135 employees.

Toho owns and operates 11 water and 6 wastewater plants. It has distributed public access reuse water since 1992 to selected parts of the service area.

2.2.6.21 Wastewater Treatment Facilities. There will be five major sources of wastewater: sanitary waste, oil/water separator effluent, cooling tower blowdown, treated chemical wastewaters, and evaporative cooler blowdown. Sanitary wastes will be routed to the existing site septic system. Oil/water separator effluent will be directed to a new onsite percolation pond. Other wastewaters, consisting primarily of cooling tower blowdown, will be returned to the Toho pipeline for additional reuse or disposal.

2.2.6.22 Solid Waste Disposal. Solid waste collection and disposal is often handled by local governments within the project impact area. In the past, these services have been provided to CIPP not through a municipality, but by a licensed contractor. The current contractor for the CIPP may or may not be the service provider by the time Unit 4 is fully operational.

2.3 Biophysical Environment

2.3.1 Geohydrology

Several types of geologic data were used to identify the subsurface conditions at the CIPP:

(1) Published literature providing regional geologic information for Florida's Osceola County geologic setting performed by and for the US Geological Survey, the Florida Geologic Survey, the SJRWMD, and the SFWMD.

(2) Onsite subsurface investigations performed under the supervision of Black & Veatch.

(3) Installation of two production wells to the deep Floridan Aquifer. These data sources provide information on the CIPP stratigraphy, aquifers, geomorphology and soil engineering properties.

(4) Pump tests at four deep wells located within the site performed under supervision of Black & Veatch.

(5) A Floridan Aquifer System (FAS) test site near Intercession City, east of the CIPP.

Information from these sources was used to evaluate regional geologic features affecting development at the CIPP and to determine the site-specific geology.

2.3.1.1 Geologic Description of the CIPP Area. The following discussion of regional geology has been condensed from the references cited in this report, but principally from Shaw and Trost (1984), Miller (1986), Tibbals (1990), and McGurk and Presley (2001).

The CIPP lies within the transitional physiographic boundary between the Lake Wales Ridge and the Osceola Plain. Regional geology for this area consists of Pleistocene Age undifferentiated surficial deposits underlain by the Miocene Age Hawthorne Formation underlain by Eocene Age limestone deposits.

In 2001 to 2003, under the direction of the SFWMD, three wells were drilled and completed within the deep FAS at a test site located near Intercession City in northwest Osceola County (Bennett and Rectenwald, 2003). These wells are located approximately 4 miles southeast of the CIPP.

Geologic information obtained from the test wells indicates that two major aquifer systems underlie the region, the surficial aquifer system (SAS), and the FAS. These aquifer systems are composed of multiple, discrete aquifers separated by low permeability “confining” units that occur throughout this Tertiary/Quaternary-aged sequence. A stratigraphic section based on these test wells is presented on Figure 2.3-1.

The FAS consists of a series Tertiary Age limestone and dolostone units. The system includes permeable sediments of the Ocala Limestone, Avon Park Formation, and the Oldsmar Formation. The Paleocene Age Cedar Keys Formation with evaporitic gypsum and anhydrite forms the lower boundary of the FAS (Miller, 1986), which was not penetrated at the test site.

The uppermost hydrogeologic unit is the SAS, which consists of Pliocene to Holocene Age sediments as described by Tibbals (1990). The lithology of the SAS deposits consist of sand, clay, and shell. The upper horizon is composed of fine- to medium-grained quartz sand with organic material and iron staining. Below this horizon are shell beds intermixed with clay layers. The thickness of the SAS ranges from less than 20 feet in places where pre-Pleistocene sediments lie near the surface to as much as 100 feet where sands have filled sinkhole depressions in karstic areas.

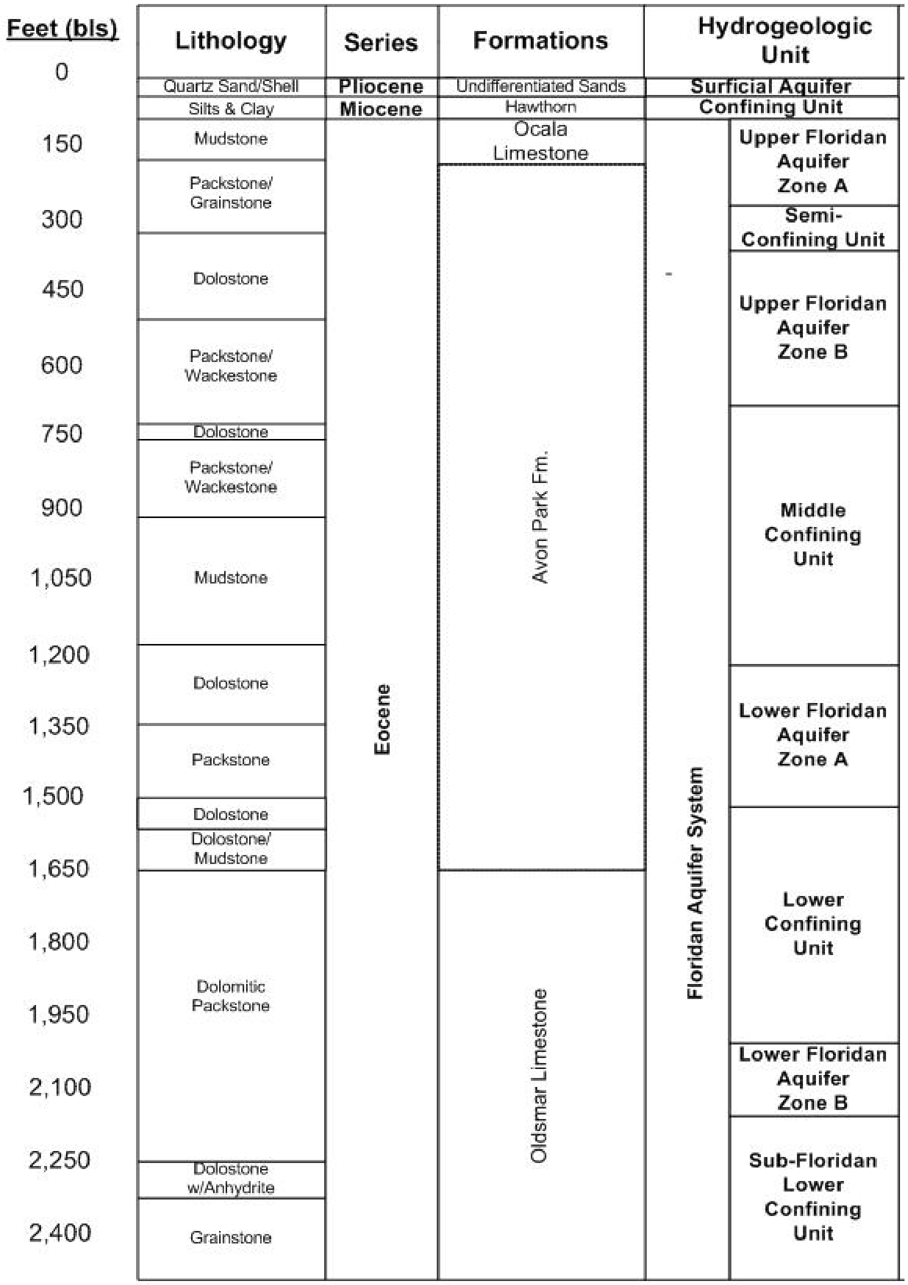


Figure 2.3-1
Geologic, Lithologic, and Hydrogeologic Section based on a Test Well near Intercession City (Modified from Bennett and Rectenwald, 2003)

The Hawthorne Formation includes sandy phosphatic limestones and sandy calcareous clays. The calcareous clays are light greenish-gray to dark green with black to brown phosphoritic sand. The limestone is white to yellow and becomes harder and more phosphatic towards the base. The top of the Hawthorne Formation in the region is generally about elevation 50 feet NGVD, approximately 30 feet below ground surface (bgs). Thickness varies considerably, but is approximately 50 feet in the northwest corner of the county.

Limestone found below the Hawthorne Formation consists of the Ocalla Group and Avon Park Limestone. The Ocalla Group is composed of a white to cream, chalky, soft coquina of foraminifera. The top of the Ocalla Group is an eroded surface that underlies the Hawthorne Formation. The deposition of the Ocalla Group is believed to have occurred in an open, shallow, marine environment. The Ocalla Group is easily recognizable by the abundance of flat and saddle shaped foraminifera.

Underlying the Ocalla Group is the Avon Park Limestone. The limestone is dark brown to cream, very hard to soft, finely crystalline to chalky, fossiliferous dolomite and limestone. It is believed that the Avon Park Limestone was a shallow marine deposit that received little clastic material. The formation is distinguished from overlying formations by the abundance of sand-sized, cone-shaped forams.

The CIPP is located in Seismic Risk Zone 0, one of the most seismically stable areas of the United States. The potential for damage from a seismic event is minimal. All of the earthquakes that have occurred in Florida have had a Modified Mercalli Intensity of VI or less, and have caused very minor damage.

2.3.1.2 Detailed Lithologic Description.

Summary of Field Investigations. A subsurface investigation was performed for Cane Island Units 1 and 2 from July 1992 to September 1992. The Subsurface Investigation Data Report for Units 1 and 2 was completed in November 1992 and revised in March 1993 (Black & Veatch, 1992).

The 1992 subsurface investigation included 11 soil borings with depths ranging from 50 feet to 122 feet bgs. Rock coring was performed in three of the 11 borings. A total of five test pits were excavated by a backhoe at the site. Two test pits were excavated on the Cane Island site, two pits were excavated adjacent to the plant access road, and one pit was excavated in the proposed borrow area. The test pits ranged in depth from approximately 5 feet to 8 feet bgs. Four piezometers were installed onsite to an approximate depth of 25 feet. Slug tests were performed in two piezometers to determine the horizontal coefficient of permeability. Cone penetrometer soundings were performed at 12 locations with a truck-mounted electric cone penetrometer rig. Total depths ranged from 60 feet to 114 feet. A total of three infiltrometer tests were completed using a double-ring infiltrometer. One test was performed onsite at the proposed location of the surface water detention pond and two were performed along the plant access road. Soil resistivity tests were completed at 10 locations using the Wenner Four-Pin method. A series of laboratory tests were performed on samples obtained during the 1992 subsurface investigation. The tests included natural moisture content, density, Atterberg limits, organic content, specific gravity, sieve and hydrometer analysis, triaxial and unconfined compression strength, consolidation, California Bearing Ratio, and modified proctor compaction. The 1992 subsurface investigation revealed subsurface anomalies at the northern end on Units 1 and 2.

In 1993, P.E. Lamoreaux (PELA) performed an assessment of sinkhole development at the power block area under the direction of Black & Veatch. The study consisted of a review of background literature, an evaluation of the 1992 Standard Penetration Test (SPT) borings and cone penetrometer soundings, a review of aerial photography of the site, a site reconnaissance, a detailed geophysical study of the site, and a report of the investigation (PELA, 1993). PELA utilized ground penetrating radar (GPR) to determine the extent of the buried sinkholes and generated a large scaled map delineating areas where raveling zones were most likely present. PELA indicated the buried areas of karstic erosion shown on the map were significant long-term foundation dangers for heavy structures, and design modifications were necessary to correct the problem.

In August 1999, a subsurface investigation program was performed to determine the site stratigraphy and pertinent geotechnical engineering properties of the soil, which underlie the proposed Unit 3 plant facilities (Black & Veatch, 1999b). This subsurface investigation consisted of the following activities:

- Eight rotary wash boreholes.
- One hollow stem auger borehole.
- Fifteen static cone penetrometer tests.
- Three soil resistivity tests.
- Laboratory tests on selected samples.

Depths for the borings ranged from 47.0 feet to 76.0 feet bgs. SPT samples were collected during drilling. Groundwater levels were recorded in all eight rotary wash borings at the completion of the drilling activities and/or after 24 hours had past since the completion of the boring.

Fifteen static cone penetrometers were performed using 5,000 kg capacity hydraulic penetrometer equipment. Depths for the cone penetrometers ranged from 78 feet to 109 feet bgs. Several of the cone penetrometer soundings encountered the top of the limestone deeper than the typical elevation of +10 feet msl and very loose to loose material above the limestone.

Three soil resistivity tests (R-1, R-2, and R-3) were performed at three specific locations (Boring BV-1, Cone C-5, and Cone C-12), respectively. Resistances were measured using a Werner Configuration of four electrodes in accordance with ASTM G57.

A laboratory testing program was performed in order to classify the soil layers and to estimate engineering properties. The tests included natural moisture content, grain size analysis, and Atterberg limits.

For the construction of additional power plant facilities (Unit 4) to the north of Units 1, 2, and 3, PELA was engaged in 2007 to conduct a karst hazard investigation of the site expansion (PELA, 2007). The core of the investigation was to be an extension of the earlier 1993 GPR grid of the site, but the new phase also included natural electrical potential (NP) measurements over possible areas of subsidence indicated on the radar graphs. NP responds to the downward leakage of water and is used to indicate recharge areas that are most at risk for future collapse or subsidence. SPT borings were also made in the larger areas of potential subsidence and in nearby, undisturbed locations.

Three wells were constructed near Intercession City to facilitate aquifer testing and long-term monitoring of the FAS (Bennett and Rectenwald, 2003). The first well, a telescoping style, multi-zone monitor well (referred to as OSF-97, 98, 99), was drilled to a total depth of 2,480 feet below land surface (bls) and completed in three distinct hydrogeologic units. The second well is a 4 inch diameter single zone monitor well (referred to as OSF-100) completed between 110 and 260 feet bls, which monitors the uppermost production unit (Zone A) of the Upper Floridan Aquifer (UFA). The third well, a telescoping style tri-zone, test-production well (referred to as IC_PW), was completed to 1,500 feet, with a final 8 inch diameter casing set at 1,210 feet in depth. In addition, two shallow monitor wells (2 inch diameter - PVC) were completed in the surficial aquifer (referred to as IC_SAS) and the Hawthorn Confining Unit (referred to as IC_HCU).

Results of the Investigations. Several of the cone penetrometer soundings encountered the top of limestone deeper than the typical elevation of +10 feet msl and very loose to loose material above the limestone. This very loose soil is similar to soil found in previous investigations, which indicates the presence of paleokarst sinkholes within the construction area of Unit 3. Sinkholes are characteristic of a karst terrain, most frequently found in limestone. Downward internal drainage causes dissolved channels in the limestone. Sediments overlaying the limestone may be eroded downward through the channels. The subsurface zone, which is undermined by the karstic erosion, is called a “raveling” zone. It is characterized by very low bearing strength sediments, as indicated by 0 to 1 or 2 blowcounts in the SPT test. The depth to limestone is greater in the raveling zones because the material is located over channels where the limestone has been intensely dissolved.

The 1999 subsurface investigation encountered a larger raveling zone than detected in the ground penetrating radar study performed in 1993. The larger area suggests the 1993 radar study was not able to detect the complete limits of the raveling zones. The existing topography for Cane Island Unit 3 varies from approximately Elevation +87 feet to +76 feet msl. The highest elevation is located along the elevated berms of the existing containment areas on the southern end of the site. The lowest elevation is located in northwest comer of the Unit 3 construction area. A general description of the site-specific geology is described below, followed by a detailed description of the soil profile generated for the main power block.

The surface stratum consists of a topsoil layer generally less than 1 foot thick consisting of grassy sand with some roots. Underlying the topsoil is 25 feet to 50 feet of loose to medium dense sand. Color varied from orangish tan to whitish light gray. Ground water was recorded at the completion of the borehole and/or 24 hours after the completion of the borehole. The static water level at the time of the investigation was estimated at Elevation +71 feet msl.

Borings BV-1, BV-2, and BV-3 encountered a “hardpan” layer at approximately Elevation +65 feet msl. This layer is approximately 5 feet thick and was most evident at the northwest corner of the site (Boring BV-2) and became less evident heading southeast (Boring BV-3). This layer consisted of dark brown, dense sand with a strong sulfur odor. This layer may perch water during periods of heavy rainfall.

Underlying the surficial deposits is a loose to very loose zone. The zone consists of sands intermixed with clayey sands and was identified by its white to light gray color and low blowcounts. The sands are very loose, fine in grain size, and poorly graded. The fines are a silty clay with low plasticity. This layer varies from 15 feet to 50 feet thick.

The white to light gray clayey sand is underlain by the Hawthorne Formation that consists of dark olive green clayey sand with some clay and silt. The formation is identified by its color and presence of shell fragments. This material varies from soft to stiff and from low to medium plasticity. The thickness of this layer varies from 5 to 15 feet and is considered part of the loose zone within the main power block. A light gray to brown sand was encountered below the Hawthorne Formation in Borings BV-1 and BV-2. This material is loose to very loose and is approximately 5 feet thick. The presence of this layer between the Hawthorne Formation and bedrock indicates the presence of karstic erosion in the northwest comer of Unit 3. This is also evident in static cone penetrometer soundings C-2.

A dense to very dense layer of highly weathered limestone, logged as calcareous sand, was encountered from 63 to 108 feet bgs. This layer was encountered immediately below the Hawthorne Formation in Borings BV-3, BV-4, BV-5, BV-7, and BV-9.

Predominant soil layers within the main power block profile are, in descending order from the surface, as follows:

(1) Loose Sand from 12 to 17 feet thick. Color is predominately orangish tan with some iron oxide staining. Black sand (topsoil), less than 1 foot thick, noted in Borings BV-5 and BV-6. The sand is considered loose, fine in grain size, and poorly graded. The ground water table was encountered approximately 7 feet bgs or Elevation +71 feet msl. The average standard penetration blowcount is 7.

(2) Medium Dense Sand to Clayey Sand lies below Layer 1 and is approximately 20 feet thick. This layer is predominantly fine in grain size and poorly graded. Color varies from brown to gray to whitish light gray. The average standard penetration blowcount is 12.

(3) Very Loose Clayey Sand lies below Layer 2 and ranges in thickness from 25 feet to 60 feet. The static cone penetrometer soundings encountered the maximum thickness of this layer. This layer is intermixed with thin layers of silt and clay. The sand is very loose and fine in grain size. The average standard penetration blowcount is 4.

(4) Very Dense Limestone lies below Layer 3 and is considered a highly weathered limestone. This layer was logged as a calcareous sand. The average standard penetration blowcount exceeds 50.

The 2007 karst hazard investigation identified five significant areas, and numerous smaller or less definite areas of karstic undermining were detected by GPR. The NP data indicated several areas where downward leakage was probable and several areas where such leakage was possible, but less definite. The 1993 PELA report did not include NP measurements or analysis of water levels. Therefore, it is unknown whether similar areas of leakage existed on the Units 1 and 2 site.

Geologic information obtained from the three wells installed near Intercession City identified two discrete zones in the UFA, separated by a semi-confining unit (Bennett and Rectenwald, 2003). These two productive horizons are designated as "Zone A and Zone B." Zone A corresponds to the upper one-third of the aquifer and coincides with the Ocala Limestone and upper part of the Avon Park Formation. The top of this interval is marked by a lost circulation horizon (permeable zone) at 110 feet bls near the contact between the Hawthorn Group and Ocala Limestone. Low permeable mudstones and inter-bedded bluish-gray clays define the lower limits of Zone A at 260 feet bls.

Low permeable mudstone units inter-bedded with poorly indurated bluish-gray clays and dense, microcrystalline dolostone units from 260 to 360 feet bls act as an intervening, semi-confining unit separating Zone A from Zone B in the UFA. Zone B corresponds to the lower two-thirds of the UFA. This zone corresponds to fractured and cavernous dolostone units in the upper portion of the Avon Park Formation.

2.3.1.3 Bearing Strength. The subsurface investigation programs performed by Black & Veatch in 1993 and 1999 determined the power block area stratigraphy and material properties. The subsurface soils were sampled by split barrel tests recording standard penetration blowcounts. In addition to the soil classification tests, consolidation and triaxial strength tests were performed on selected samples to determine the engineering properties of the clayey materials.

The performance of the foundation systems for the project must have an acceptable factor of safety against failure of the foundation element or bearing soils, and limit total and differential settlements to an acceptable level that will not result in damage to, or loss of service of, the supported facility.

The results of the subsurface investigations indicated that several foundation types would need to be used to support different portions of the project. The main criterion was the settlement limitations that bearing capacity will not support. This is based on the thickness of the upper sands. For heavily loaded, settlement sensitive structures (such as the main power block structures) deep foundations consisting of friction piling or thick mat foundations supported onsite soils densified by ground modification techniques such as vibro replacement or compaction grouting were to be used to meet design constraints. Shallow mat or individual spread footings were to be used for lightly loaded facilities.

The existing units were constructed using shallow foundations consisting of mats and spread and strip footings. However, ground improvement methods consisting of stone columns, deep dynamic compaction, and compaction grouting were utilized to prepare the subsurface materials for the constructed facilities. Facilities constructed in areas outside of the mapped buried karstic features employed the use of stone columns and deep dynamic compaction. Facilities constructed within areas of the mapped buried karstic features employed the use of compaction grouting and deep dynamic compaction. The compaction grouting was successful in mitigating the karstic hazards at the site. The Units 1 and 2 foundations have been performing very satisfactorily since installation in 1994, and the Unit 3 foundations have been performing very satisfactorily since 2000; it is anticipated that similar construction methods will be used for Unit 4.

2.3.2 Subsurface Hydrology

The regional hydrogeologic system beneath the CIPP consists of a surficial aquifer and the FAS. The surficial aquifer is separated from the Floridan Aquifer by the relatively low permeable deposits of the Hawthorn Formation.

2.3.2.1 Subsurface Investigation Program. The subsurface hydrology of the power block area was determined by a review of existing reference documents, installation of shallow piezometers, ground water levels collected in 2007 to 2008 from eight borings, and two surface ponds installed in the vicinity of Unit 4. Surface water infiltration was determined using double ring infiltrometer tests. Infiltrometer Test I-1 was performed in 1993 at the location of the Units 1 and 2 surface water detention pond; Tests I-2 and I-3 were performed along the entrance corridor.

In addition to the temporary piezometers installed during the investigation, three monitoring wells were installed for the purpose of long-term monitoring of the surficial aquifer. Four production water wells were installed into the Floridan Aquifer for use in Unit 3 (in addition to the two deep wells installed to support Unit 1 and 2 operations). The wells were cased to a depth of 150 feet bgs. All six wells are completed; total well depths ranged from 300 to 360 feet bgs.

The Surficial Aquifer. The surficial aquifer at the CIPP consists of the upper unconfined sands of the Pleistocene and Recent age. The fine grained sand layer extends to approximately 35 feet bgs. Underlying the sand layer is the Hawthorne Formation, a silty clay/clayey sand layer that acts as a separation or confining unit for the Floridan Aquifer.

The surficial aquifer is recharged by precipitation and discharges into lakes, streams, and occasionally to the Floridan Aquifer by downward percolation. The surficial aquifer will have a tendency to mirror ground surface elevation. This is readily seen at the CIPP because the installed piezometers indicate a higher water table at the raised elevation of Cane Island compared to the surrounding wetlands. The surrounding wetlands are very flat. Overall local gradient would seem to be slightly influenced by the Bonnet Creek Canal located to the north and northwest of Cane Island, causing a very slight gradient to the north. Localized surficial aquifer gradient below Cane Island consists of radial outward flow caused by recharge during precipitation events.

Ground water levels measured from piezometers installed in the proposed Unit 4 area of the CIPP are given in Table 2.3-1.

Table 2.3-1
Water Level Data Collected at Unit 4

Monitoring Well and Infiltration Pond Number	Ground Elevation	Water Level Elevation 11/2/07	Water Level Elevation 11/7/07	Water Level Elevation 11/9/07	Water Level Elevation 11/16/07	Water Level Elevation 11/29/07	Water Level Elevation 12/21/07	Water Level Elevation 1/9/08	Water Level Elevation 1/24/08
B4-1a	78.82	71.6	73.12	73.4	73.3	72.62	72.23	71.80	71.70
B4-4a	79.20	73	[1]NA	73.7	73.6	73.17	73.16	73.00	73.00
B4-5	77.41	71.9	72.51	72.T	72.3	71.83	71.54	71.17	71.41
B4-6	77.43	NA	NA	72.3	72.4	71.91	71.43	71.03	71.66
B4-7S	77.54	NA	NA	NA	NA	NA	NA	71.20	72.05
B4-8	77.76	71.7	NA	72.9	72.6	71.99	71.70	71.29	71.66
B4-9	78.06	NA	73.81	73.8	73.4	72.81	72.41	71.99	72.73
I-1 (Unit 4 pond)	77.85	NA	NA	NA	NA	NA	NA	NA	73.12
I-2 (Unit 5 pond)	79.70	NA	NA	NA	NA	NA	NA	NA	72.51

(1)NA - Not available.

The highest ground water table encountered during the 2007 to 2008 investigation was in Boring B4-1a at Elevation +73.4 feet msl. The lowest ground water table was encountered in Borings B4-5 and B4-7 at Elevation +71 feet msl. The average ground water level was estimated as Elevation +72 feet msl. The elevation of the ground water table will fluctuate because of local seasonal conditions. The rainy season in Central Florida is normally between June and September. It is anticipated that ground water levels will vary between 2 to 3 feet, with the seasonal high occurring near the time of the current subsurface investigation. The ground water is not anticipated to be brackish.

In 1993, surface water infiltration was determined using double ring infiltrometer tests. Infiltrometer Test I-1 was performed on Cane Island at the location of the Units 1 and 2 surface water detention pond. Tests I-2 and I-3 were performed along the entrance corridor. Test results are as follows:

Test No.	Steady-State Infiltration Rate (in/h)
I-1	21.5
I-2	10.2
I-3	7.3

As part of the Unit 4 subsurface investigation, Ardaman and Associates performed three additional double ring infiltrometer tests (Ardaman and Associates, 2007). Test results are as follows:

Test No.	Steady-State Infiltration Rate (in/h)
I-1	6.5
I-2	10.0
I-3	8.5

Results of the infiltrometer tests confirm the very high permeability of the surficial sands encountered on Cane Island. Permeabilities conducted at locations along the entrance corridor were much lower in the silty materials associated with the near surface soils of the wetlands.

As a result of these investigations, the following characteristics were established for the surficial aquifer in the immediate power block vicinity. Maximum high ground water was estimated to be at approximately Elevation 74 feet. Low ground water elevation was estimated to be Elevation 69.5 feet. It could be expected during the course of seasons for the surficial aquifer water levels to vary by 3 to 4 feet. Vertical permeability of the surficial sands is estimated to be 30 feet/day.

The Floridan Aquifer. The Floridan Aquifer is the principal aquifer of the Florida Peninsula. The aquifer is typically confined by the Hawthorne Formation with variable potentiometric head across the state. Within the Orange and Osceola county areas, the potentiometric surface of the aquifer ranges from Elevation 70 to 80 feet msl, which correlates closely with measured data within the installed wells. This very productive aquifer can have yields from the upper zone as high as 4,000 gpm. Yields vary with location.

Well development data from the installation and testing of the four wells installed into the Floridan Aquifer is presented in Table 2.3-2. Based upon the pumping rates and drawdowns, the transmissivity is relatively high in two of the wells (Wells 3 and 5) and moderately high in Wells 4 and 6.

Table 2.3-2
Units 3 and 4 Production Well Information

Well ID	Total Depth (feet)	Pumping Rate (gpm)	Length of Test (hours)	Final Drawdown	Well Diameter (inches)
Cane Island Well 3	360	450-460	24 hrs	10 ft. 10 in.	10
Cane Island Well 4	360	450	24 hrs	57 ft. 1 in	10
Cane Island Well 5	360	460	24 hrs	3 ft 2 in	10
Cane Island Well 6	360	470	24 hrs	31 ft 1 in	10

Several aquifer tests were conducted at the three wells installed near Intercession City (Bennett and Rectenwald, 2003). The first aquifer performance test was conducted on the interval between 110 and 260 feet bls (Zone A). Analysis of data yielded a transmissivity value of 115,000 gallons per day per foot (gpd/ft) of aquifer and a storage coefficient of 2.2×10^{-5}.

Water levels in the overlying confining unit and Zone B of the UFA declined during the drawdown phase of the aquifer performance test, indicating semi-confined conditions. Zone B corresponds to the lower two-thirds of the UFA with the majority of water production from 360 to 425 feet bls. This zone corresponds to fractured and cavernous dolostone units in the upper portion of the Avon Park Formation. Smaller, less productive intervals continue from 425 to 680 feet bls. A second aquifer performance test was conducted on the interval between 360 and 680 feet bls. Analysis of test data yielded a transmissivity of 510,000 gpd/ft and a storage coefficient of 6.1×10^{-5}.

From a regional consideration, surficial deposits for the area consist of unconsolidated clastic deposits to a depth of approximately 150 feet. These undifferentiated deposits consist of sands, clays, clayey sands, and sandy phosphatic clays. The age of these materials ranges from middle Miocene to Recent. Some small irrigation and domestic water supplies are obtained from this zone. Underlying the clastic deposits is the Inglis Formation, from the Ocalla Group. This is the uppermost limestone member of the Floridan Aquifer, all other members having been eroded in this area. This formation consists of partially to highly dolomitized, highly fossiliferous limestone with some local soft chalky zones. Thickness of the Inglis Formation in this area is approximately 75 feet.

The principal water bearing unit for the Floridan Aquifer in this region is the Avon Park Limestone. The Avon Park stratum is described as dark brown to cream, very hard to soft, granular to chalky to finely crystalline, highly fossiliferous limestone. This aquifer is the source of all major public, industrial, and irrigation water supplies for this region. The CIPP is located on the northernmost fringe of flowing artesian conditions for the Floridan Aquifer. This study assumed that the aquifer was confined by the clay present in the clastic deposits above the Inglis Formation.

On Cane Island, the Hawthorne Formation thickness varies, but is approximately 35 feet. The Floridan Aquifer was encountered below the Hawthorne Formation at approximately 70 feet bgs. Piezometric head for the Floridan Aquifer is approximately 14 feet bgs, but is confined by the Hawthorne Formation. Measured piezometric head within the surficial aquifer was approximately 10 feet bgs.

Water required for Units 1 and 2 operations is obtained from the Floridan Aquifer by two wells constructed into the aquifer. Water is pumped from one well, with the second well acting as a backup well. The ground water wells were designed to each pump 200 gpm. The wells consist of 8 inch diameter black steel casing grouted to 150 feet bgs, with a 6 inch diameter open hole to 300 feet in PW-1 and 360 feet in PW-2. The wells were permitted and constructed to standards as specified by the SFWMD. Well and aquifer characteristics determined from pump tests conducted on the wells at the time of installation resulted in a predicted yield of 90 gpm per foot of drawdown, with a maximum recommended pumping rate of 450 gpm per well. Additional aquifer characteristics determined for wellfield studies indicate a confined aquifer with a transmissivity of 26,740 ft^3/day/ft.

2.3.2.2 Karst Hydrology. A description of the karst conditions encountered at the site is presented in Subsection 2.3.1.

2.3.3 Site Water Budget and Area Users

A summary of the requested information is included in this subsection.

2.3.3.1 Orlando Climatological Conditions. The following meteorological information was collected from the Orlando International Airport. This is the closest National Weather Service (NWS) office to the CIPP, approximately 20 miles northeast of the CIPP, at Elevation 96 feet msl. The Orlando airport data are considered to be representative of long-term, CIPP conditions due to the proximity to the CIPP.

2.3.3.2 Temperature and Precipitation. Normal monthly and annual temperatures are presented in Table 2.3-3. The annual average temperature for the period of record is 72.8° F. The warmest month is typically August; the coldest month is typically January.

Table 2.3-3
Monthly and Annual Temperatures and Rainfall

Monthly Mean:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Max Temp (F)	71.8	73.9	78.8	83	88.2	91	92.2	92	90.3	85	78.9	73.3
Min Temp (F)	49.9	51.3	55.9	59.9	65.9	71.3	72.6	73	71.9	65.5	58.7	52.6
Mean Temp (F)	60.9	62.6	67.4	71.5	77.1	81.2	82.4	82.5	81.1	75.3	68.8	63
Rainfall (inches)	2.43	2.35	3.54	2.42	3.74	7.35	7.15	6.25	5.76	2.73	2.32	2.31

Source: http://www.srh.noaa.gov/mlb/normals.html.

Normal monthly and annual rainfall totals are presented in Table 2.3-2. The annual average for the period of record is approximately 48 inches. Rainfall is greatest in the summer months, May through September. April has the lowest average rainfall.

2.3.3.3 Evapotranspiration and Runoff. Rainfall averages about 48 inches per year in the Orlando area. A portion of this rainfall is intercepted by vegetation or stored in small depressions on the surface, a portion infiltrates into the soil, and the remainder directly runs off during storm events. Base flow in streams is sustained by ground water inflow from the shallow aquifer system, which is recharged from storm water infiltration. The Natural Resource Conservation Service (NRCS) estimates evaporation of 50 inches per year in this area from shallow lakes and reservoirs. Evaporation also occurs to a lesser degree from soil surfaces and as transpiration from vegetation. The total evaporation and transpiration is known as evapotranspiration, which varies with surface conditions.

2.3.3.4 Water Use. There are five major well users located approximately 4 miles from the CIPP. These users are Polk and Orange County utilities, City of St. Cloud, Reedy Creek Improvement District, and the City of Kissimmee (SWWMD, 2006). A summary of their past and projected water use is provided in Table 2.3-4.

Table 2.3-4
Water Use at Potable Water Treatment Facilities
(within a 4 mile radius)

Facility	2000 Average Daily Flow (mgd)	Projected 2010 Average Daily Flow (mgd)	Raw Water Sources
Polk County Utilities	2.19	4.03	FAS[1]
Orange County Utilities	15.12	30.13	FAS
City of St. Cloud	3.28	8.17	FAS
Reedy Creek Improvement District	19.54	21.18	FAS
City of Kissimmee	21.87	44.65	FAS

[1]Florida Aquifer System

2.3.4 Surficial Hydrology

The geographic feature Cane Island is crowned in the central portion and drains to the east or to the west into Reedy Creek Swamp. The elevation at the site is 5 to 15 feet higher than that of the surrounding swamp.

Reedy Creek Swamp has very little gradient. The eastern portion of the swamp is drained by Shingle Creek, which discharges into Lake Tohopekaliga. The western portion of the swamp, which includes the plant site, drains to Reedy Creek.

Reedy Creek flows from northwest to southeast. It is located approximately 3,000 feet southwest of the power block. The gradient of Reedy Creek in the vicinity of the plant site is approximately 0.023 percent. Reedy Creek discharges into Lake Russell, approximately 13 miles downstream from the CIPP.

The native soil in the power bock area is predominantly classified as Candler sand by the NRCS. This material is excessively drained, with very rapid permeability. The water table in this soil is typically in excess of 72 inches.

The native soil in the swamp surrounding the site is predominately classified as Pompano fine sand by the NRCS. This material is nearly level and typically covered with standing water. Permeability of this soil is very rapid.

The water surface elevation in Reedy Creek Swamp is subject to seasonal variation, with rising water during the summer rainy season. The swamp is considered a Class III body of water, as defined in Florida Administrative Code (FAC) 62-302.400.

Since May 1970, the flow in Reedy Creek has been regulated by Reedy Creek Improvement District Structure 40 (S-40), which is located 3,500 feet west of the power block. The peak flow rate in Reedy Creek at the US Geological Survey (USGS) gauging station 1.0 mile downstream from S-40 is 790 cfs. The minimum flow rate at this gauging station is 0.0 cfs. The highest annual mean and lowest annual mean flows at this station are 182 cfs and 15.2 cfs, respectively.

Limited water quality data are available at S-40 for portions of the period from January 1985 to 1992. For this period of record, the maximum daily mean specific conductance was 308 microsiemens. The minimum daily mean specific conductance was 93 microsiemens/cm. The maximum daily mean dissolved oxygen content was 9.1 milligrams per liter (mg/L). The minimum daily mean dissolved oxygen content was 0.0 mg/L. The maximum and minimum daily mean water temperatures were 28.9 and 6.8 degrees Celsius, respectively.

Additional water quality data are presented in the Water Resources Atlas of Florida for Lake Tohopekaliga, which is approximately 7.5 miles east of the CIPP. The mean pH of the water is 8. The mean conductivity is 300 micromhhos. The mean color is 80 PTC (Psuedo True Color). Mean turbidity is 7.5 NTU (Nephlometric Turbidity Unit). The mean total phosphorus is 0.3 mg/L, and the mean total nitrogen is 2.0 mg/L. These values are typical for surface waters in central Florida.

The CIPP is not required to monitor any surface waters in the project area.

2.3.5 Vegetation/Land Use

Cane Island lies within the Osceola Plain physiographic section of central Florida. The local relief of the area ranges from 65 to 75 feet NGVD. The Bonnet Creek Canal borders the Cane Island site on the north and west boundaries, Reedy Creek crosses the southwest corner of the property, SR-17/92 and the CSX railroad border the Cane Island site on the south, and undeveloped land borders the site on the east. The geographic feature of Cane Island is essentially surrounded by Reedy Creek mixed hardwood swamp.

A botanical survey was conducted on CIPP property in January 1991, prior to site development. Plants identified during the 1991 survey and subsequent surveys are listed in Appendix C1 of Subsection 10.5.1. Figure 2.3-2 shows vegetation and land use of the CIPP .

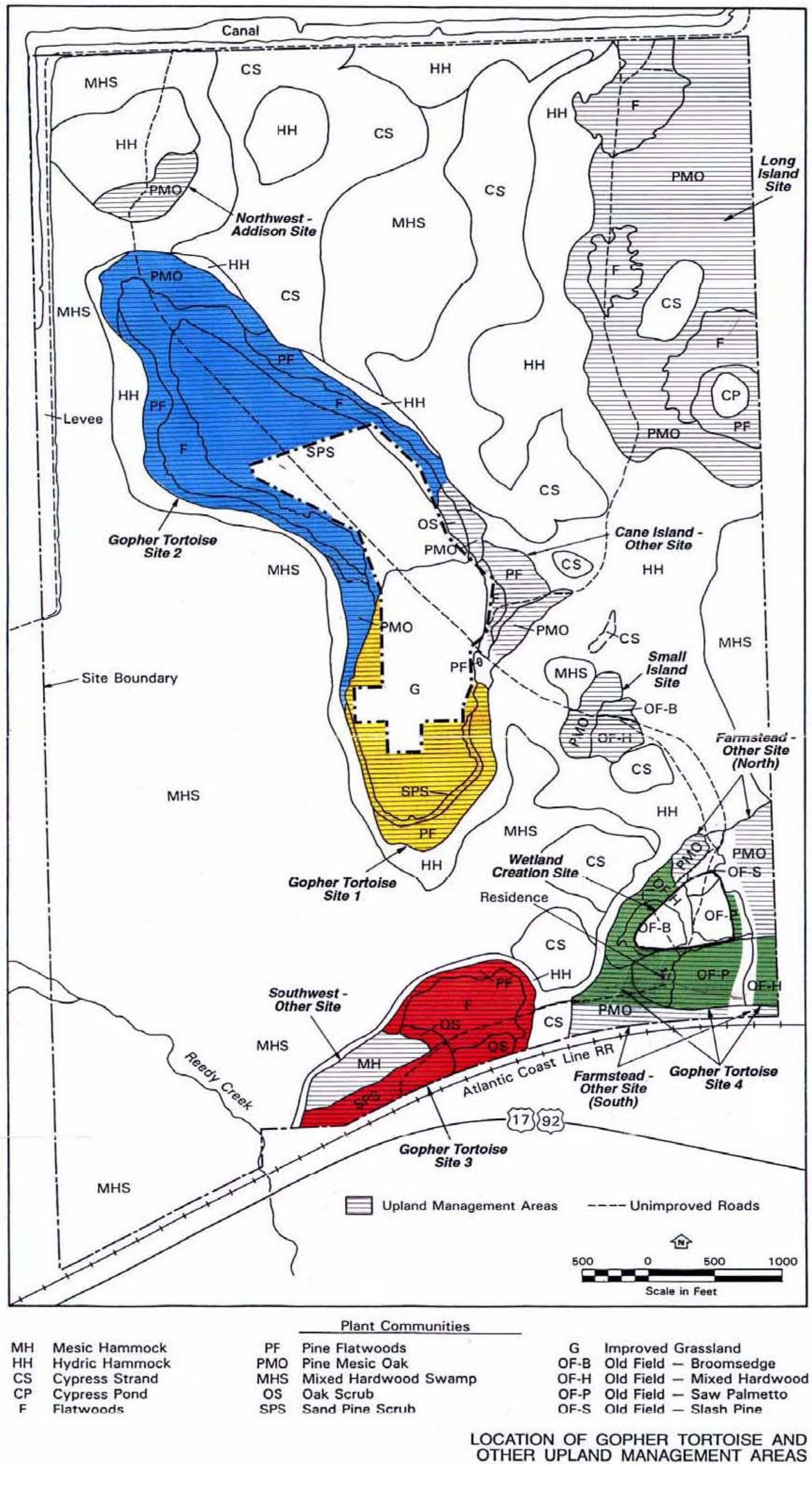


Figure 2.3-2
Plant Communities and Gopher Tortoise Management Areas

Units 1 and 2 were constructed primarily in the improved grassland plant community; Unit 3 in the improved grassland and sand pine scrub. The plant communities adjacent to the improved grassland and the sand pine scrub include flatwoods, pine flatwoods, pine mesic oak, and hydric hammock.

Improved grassland is an artificial plant community that occurs on the southern half of Cane Island. The original vegetation, sand pine scrub, was removed and exotic grasses were planted by the previous owner. The soils are well-drained and the topography is flat. The vegetation consists of sparse overstory and understory with dense ground cover. The overstory and understory species include sand live oak (*Quercus geminata*), Florida hickory (*Carya floridana*), cabbage palm (*Sabal palmetto*), beauty bush (*Callicarpa americana*), and coralbeans (*Erythrina herbacea*). The ground cover is dominated by grasses: *Eustachys glauca* (no common name), bahiagrass (*Paspalum notatum*), thin paspalum (*Paspalum setaceum*), natal grass (*Rhynchyletrum repens*), and broomsedge (*Andropogon virginicus*). Other species observed in the ground cover are prickly-pear cactus (*Opuntia humifusa*), sedge (*Cyperus retrorsus*), hairy indigo (*Indigoifera hirsuta*) and cottonweed (*Froelichia floridana*).

Sand pine scrub is a natural upland community that occurs on the northern half of Cane Island on flat terrain with well-drained soils. The overstory is dominated by sand pine *(Pinus clausa)*, sand live oak *(Quercus geminata)*, Chapman's oak *(Quercus chapmanii)*, and scrub oak *(Quercus inopina)*. The shrubby understory includes rusty lyonia *(Lyonia ferruginea)*, fetterbush *(Lyonia lucida)*, *palmetto (Serenoa repens)*, and *rosemary (Ceratiola ericoides)*. Ground cover is typically sparse with few species, including: wire-grass *(Aristida stricta)*, golden aster *(Heterotheca graminifolia)*, yellow buttons *(Balduina angustifolia)*, several *Cladonia* spp., beak rush *(Rhynchospora megalocarpa)*, white-head bogbuttons *(Lachnocaulon anceps)*, yellow-eyed grass *(Xyris brevifolia)*, and broomsedge.

Pine-mesic oak is an upland community on flat to sloping terrain with well-drained soils. It is associated with most of the plant communities at the study area. This community is dominated by slash pine (*Pinus elliottii)*, laurel oak (*Quercus laurifolia*), and Virginia live oak (*Quercus virginiana*), which form a dense canopy often reaching 60 to 80 feet in height. The midstory is usually open, but may approach closure. It includes cabbage palm, loblolly bay (*Gordonia lasianthus*), wax myrtle (*Myrica cerifera*), dahoon holly (*Ilex cassine*), sweet gum (*Liquidambar styraciflua*), and swamp honeysuckle (*Rhododendron viscosum*). The understory and ground cover tend to be sparse, but may be somewhat thick in transitional zones with other communities.

Hydric hammock is a wetland community with a flat to slightly sloping topography, which may be inundated for up to 6 months per year. It is often situated between xeric upland communities and wetlands that are flooded for longer periods. The vegetation is characterized by a canopy of cabbage palm, Virginia live oak, laurel oak, slash pine, water oak, red maple. The sparse understory and ground cover include wax myrtle, loblolly bay, greenbrier (*Smilax bona-nox*), grapevines (*Vitis* sp.), golden polypodium (*Poypodium aureum*), marsh fern (*Thelypteris palustris*), cinnamon fern (*Osmunda cinnamonca*), Florida shield fern (*Dryopteris indoviciana*), longleaf chasmanthium (*Chasmanthium sessilfolium*), and cypress witchgrass (*Dicantheleum dichotomum*).

Flatwoods is a natural upland community found on flat topography and well-drained soils. Under the right conditions, this community should mature into pine flatwoods. Characteristically, it is associated with sand pine scrub, sandhills (not at the project site), oak scrub, pine flatwoods, and hydric hammock. Onsite, flatwoods are found on Long Island and to the south near the site entrance. This community encircles the northern half of Cane Island. At Cane Island, flatwoods canopy cover is sparse to nonexistent with an occasional slash pine encroaching from the pine flatwoods. The understory is dense and includes inkberry (*Ilex glabra*), fetterbush, rusty lyonia, sand live oak, and palmetto. Ground cover ranges from sparse to somewhat dense and includes seedlings of the understory, as well as wire-grass, prickly-pear cactus, white-head bogbuttons, British soldier moss (*Cladonia leporina*), shiny blueberry (*Vaccinium myrsinites*), needle-leaf witchgrass (*Dichanthelium aciculare*), and Atlantic St. John’s wort (*Hypericum reductum*).

Pine flatwoods is an upland community with flat to slightly sloping topography and well to moderately drained soils. Canopy cover consists of primarily slash pine and may be dense or open. Mid-canopy, which often approaches closure includes loblolly bay, wax myrtle, water oak, and cabbage palm. Typical understory species include inkberry, palmetto, fetterbush, and dahoon holly. Ground cover is sparser than the understory and includes shiny blueberry, cinnamon fern, grapevines (*Vitis* sp.), and greenbrier.

2.3.6 Ecology

This section identifies endangered, threatened, and other sensitive species that have the potential to occur in the project area which might reasonably be expected to be affected by the construction and operation of Unit 4. Sensitive species include plants and animals listed as endangered or threatened by the USFWS; species listed by the FFWCCC as endangered, threatened, or of special concern; species listed as game, fur-bearers, or freshwater game fish,; and, species which are indicators of, endemic to, or are unique to specific plant communities and habitat types.

The USFWS and FFWCCC were consulted during the permitting efforts for Units 1 through 3. The USFWS was contacted in March 2008 to advise them of the proposed Unit 4. A copy of this letter is included in Subsection 10.2.4. The FFWCC is a statutory party to the certification process.

Field surveys for endangered, threatened, and other sensitive species were conducted in 1991 and 1992 prior to site development. Additionally, qualitative vegetation and wildlife surveys are performed once every 5 years (beginning in 2005), as monitoring efforts required by the FFWCC and SFWMD for construction of the CIPP.

No federally listed plant or animal species have been recorded onsite, none have been observed during surveys, and no critical habitat for federally listed species occurs within the CIPP boundaries (refer to Figure 2.3-3 for the USFWS letter dated July 20, 1998). Marginal habitat for the Florida scrub jay (federally threatened) was discovered on the northern half of Cane Island, but no scrub jays have been observed during surveys.

Table 2.3-5 lists federally-protected plant species that are known to occur in Osceola County. However, these species are not known to occur on CIPP property. Additionally, there is state and federally-listed species that occur either on the CIPP property or in adjacent habitats (Table 2.3-5). These particular species include birds, amphibians, reptiles, and mammals. However, only two state listed animals have been found onsite. The gopher tortoise (*Gopherus polyphemus*), a state threatened species and the Florida mouse (*Podomys floridanus*), a state species of special concern.

The gopher tortoise occurs in high concentrations in the improved grassland on the southern end of Cane Island. It is also found in the sand pine scrub community on the northern half of Cane Island, but in much lower concentrations (Black & Veatch, 1998), and in other upland areas of the property designated as management areas as shown on Figure 2.3-2. The diet of the gopher tortoise typically consists of broad-leaved grasses, wiregrass and legumes but may include other plant materials, animals, and organic matter (Cox et. al., 1987). The improved grassland provides an abundant supply of grasses, including wiregrass and the open canopy of the improved grassland provides sunlight necessary for proper egg incubation.

The Florida mouse is commonly associated with the gopher tortoise. It often excavates its den along the burrow shaft and will center much of its foraging activities around the burrow of the gopher tortoise. Food of the Florida mouse consists principally of seeds, but includes leaves and an occasional insect.

United States Department of the Interior

FISH AND WILDLIFE SERVICE
South Florida Ecosystem Office
P.O. Box 2676
Vero Beach, Florida 32961-2676

July 20, 1998

RECEIVED
JUL 2? 1998
EAS

J. Michael Soltys, Licensing Manager
Black and Veatch
P.O. Box 8405
Kansas City, Missouri 64114

Dear Mr. Soltys:

Thank you for your letter to the U.S. Fish and Wildlife Service (FWS) requesting information on the presence of federally listed species in the vicinity of the site described in your letter. The project site is located in Intercession City, Osceola County, Florida.

The FWS has reviewed the information in your letter as well as information available to us on the presence of threatened or endangered species in the vicinity of the project site. From this review, we find no evidence of federally listed species on the project site. Additionally, Wesley Shockley (FWS biologist) conducted a preliminary site inspection on July 10, 1998. No threatened or endangered species were observed during that visit, though inclement weather reduced the probability of encountering wildlife during the inspection. Therefore, we would appreciate the opportunity to revisit the site by attending the upcoming interagency site inspection. No critical habitat has been designated on the project site.

We have provided for your consideration a list of species that are protected as either threatened or endangered under the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*), as well as candidates for listing which may be present in Osceola County. Since this list does not include State-listed species, the Florida Game and Fresh Water Fish Commission should be contacted to identify those species potentially present in the vicinity.

In addition, we are providing you with a list of species that we would consider during our review of any proposal associated with this project. This list represents species that the FWS is required to protect and conserve under other authorities, such as the Fish and Wildlife Coordination Act (16 U.S.C. 661 *et seq.*) and the Migratory Bird Treaty Act (16 U.S.C. 701 *et seq.*). We are providing this list as technical assistance only. If you would like to discuss means and methods to conserve these species, please contact this office.

Figure 2.3-3 (Page 1 of 2)
Copy of USFWS Letter dated July 20, 1998

Thank you for the opportunity to provide this information. If you have any questions, please contact Mr. Shockley at (561) 562-3909.

Sincerely,

James J. Slack
Project Leader
South Florida Field Office

Enclosures

cc: COE, Tampa, FL (w/o enclosures)
GFC, Punta Gorda, FL (w/o enclosures)

Figure 2.3-3 (Page 2 of 2)
Copy of USFWS Letter dated July 20, 1998

Table 2.3-5
State and Federally-Listed Species in Osceola County

Federally-Protected Plants

Nolina brittoniana (Britton's beargrass, Federal Endangered)

Polygala lewtonii (Lewton's polygala, Federal Endangered)

Paronychia chartacea (Papery whitlow-wort, Federal Threatened)

Encyclia tampensis (butterfly orchid, Commercially Exploited)

Clitoria fragrans (Pigeon wings, Federal Threatened)

Chionanthus pygmaeus (Pygmy fringe-tree, Federal Endangered)

Polygonella myriophylla (Sandlace, Federal Endangered)

Eriogonum longifolium var. gnaphalifolium (Scrub buckwheat, Federal Threatened)

Lupinus aridorum (Scrub lupine, Federal Endangered)

Warea amplexifolia (Wide-leaf warea, Federal Endangered)

Federal and State-Protected Animals

Florida scrub jay (*Aphelocoma coerulescens*, State Threatened, Federally Threatened)

Gopher frog (*Rana capito*, State Species of Special Concern)

American alligator (*Alligator mississippiensis*, State Species of Special Concern, Federally Threatened)

Eastern Indigo snake (*Drymarchon corais couperi*, State Threatened, Federally Threatened)

Gopher Tortoise (*Gopherus polyphemus*, State Threatened)

Bald eagle (*Haliaeetus leucocephalus*, State Threatened)

Red-cockaded woodpecker (*Picoides borealis*, State Species of Special Concern, Federally Endangered)

Florida panther (*Felis concolor coryi*, State Endangered, Federally Endangered)

Florida mouse (*Podomys floridanus*, State Species of Special Concern)

Florida black bear (*Ursus americanus floridanus*, State Threatened)

2.3.6.1 Species-Environmental Relationships. It is possible that all of the animals mentioned above use CIPP as habitat for feeding. This habitat is likely used by eastern cottontails, squirrels, and gopher tortoises as habitat for breeding. Eastern cottontails and squirrels usually occur in forested areas and are known to nest very close to human activity. Gopher tortoises occur in areas that have well-drained, sandy soils, which allow easy burrowing, support an abundance of herbaceous ground cover, and generally have an open canopy with sparse shrub cover (Cox et. al., 1987).

Several common animals classified as fur bearers and game animals occur or could potentially occur in the CIPP area. However, the potential for the game and furbearer species to occur in the power block area is low because of the disturbances and human presence during operation and maintenance of the facilities. Prior to any construction at theCIPP, and on a regular basis since operation, wildlife monitoring efforts have recorded over 100 species. A list of the animal species observed at the CIPP is included in Appendix C2 of Subsection 10.5.1.

2.3.6.2 Pre-Existing Stresses. Prior to KUA acquiring the property and prior to construction of any power generation facilities on Cane Island, pre-existing stresses were caused by the alteration and removal of habitat on the southern end of Cane Island. The alteration and removal of habitat was done in an attempt to attract game animals for hunters.

Environmental stresses existing prior to construction of Unit 4 include removal of habitat for project construction, noise from operation, and activity of pedestrian and vehicular traffic for maintenance of Units 1-3 facilities. The remaining vegetation on the southern end of Cane Island has been granted to the SFWMD in a conservation easement. This area is monitored and managed according to the *Cane Island Project Mitigation Plan*. The remaining vegetation on the north end of Cane Island is also in conservation easement and is monitored and managed. The conservation and exclusion areas are shown on Figure 2.1-3.

2.3.6.3 Measurement Programs. Initial vegetation and wildlife investigations of the CIPP site began in 1991 as part of an Environmental Assessment for the proposed simple cycle combustion turbine facility (Unit 1). Environmental studies were conducted by Black & Veatch and its consultant, Alvarez, Lehman & Associates, Inc. (Gainesville, Florida). Studies consisted of protected species surveys, general wildlife surveys, plant species identification, plant community assessments, and wetland delineations.

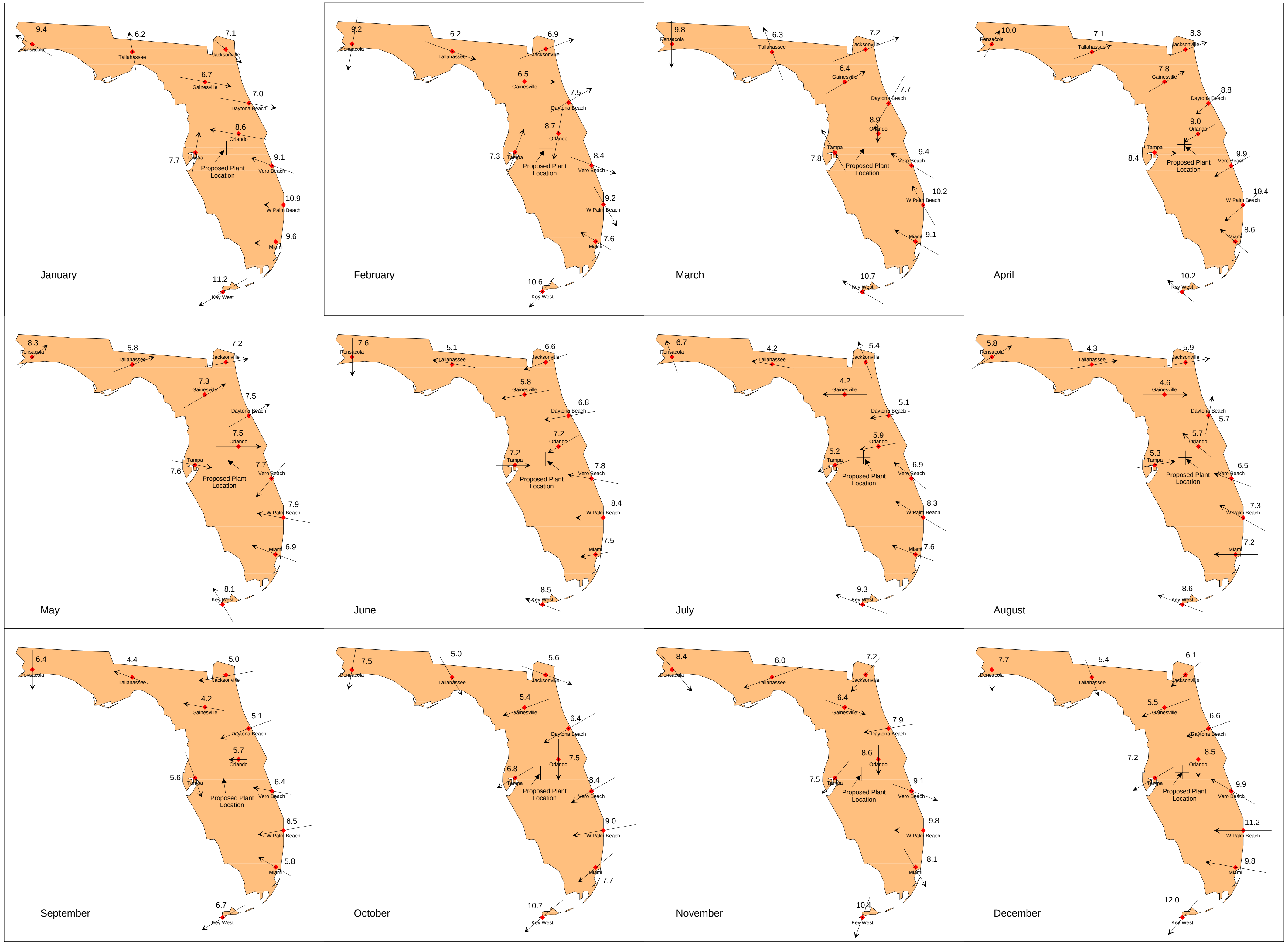
Measurement programs were established to assess floral and faunal characteristics resulting from development of the power generation facilities. The *Cane Island Project Mitigation Plan* describes the original measurement and monitoring programs in detail. Line transects, nested quadrats, and meter square quadrats were originally used to assess the composition of the upland and wetland vegetation. Quantitative vegetation and wildlife monitoring was conducted as required until 2005. In 2004, KUA requested and was granted release from the quantitative (direct) monitoring requirements in effect over the upland and wetland management areas and created wetland, which had been in effect since 1993. In exchange for that release, KUA committed to conducting appropriate annual habitat management and maintenance activities, and qualitative habitat assessments once every 5 years beginning in September 2005. The results of the 2005 assessment indicated that the habitats were in good condition, and the 2006-2007 field observations support this conclusion. Growth and abundance of the trees originally planted in the created wetland as mitigation were quantitatively assessed from 1993-1996. The created wetland was declared successful in 1997 by the Corps of Engineers and subsequently incorporated into the SFWMD conservation easement. Since 1998, this wetland has been monitored and managed annually for exotics.

Wildlife is recorded by opportunistic observations. Quantitative wildlife monitoring efforts were conducted in 1993 and 1997. Monitoring efforts are now in accordance with the 2004 modification of the CIPP Mitigation Plan. Annual habitat monitoring reports are submitted to the SFWMD and FFWCC.

2.3.7 Meteorology and Ambient Air Quality

2.3.7.1 Regional Climatology/Meteorology. The prevailing subtropical marine climate of the central Florida region results from the influence of the warm waters of the Atlantic Ocean and the Bermuda high-pressure system. Long, warm, humid summers and short, mild winters prevail. Because of the southerly location and marine influences, this area has a climate characterized by small annual and diurnal temperature variations. Rainfall is moderate to heavy during the summer (rainy season) and light during the winter (dry season). Well developed extratropical migratory high- and low-pressure centers usually travel north of the region.

Winds are of moderate speed and blow predominantly from the south to southeast during the spring and summer (March through August). During the fall and winter months (September through February), the predominant direction is from the north. Monthly and annual wind speed and prevailing direction for selected Florida locations are given on Figures 2.3-4 and 2.3-5, respectively. According to the NOAA Coastal Services Center, there is a 26 percent chance per year (or about one in 4 years) that a hurricane will track within 50 nautical miles of CIPP. Of the hurricanes that pass the CIPP area, the origin of the hurricane is mainly from the southeast or southwest.



NOTE: Numbers Given are Scalar Average Wind Speed in Miles per Hour.
Arrows Fly with Wind.

SOURCE: Local Climatological Data – Annual Summary with Comparative Data.
National Climatic Center; Asheville, North Carolina. 2006.

Figure 2.3-4
Monthly Average Wind Speed and Prevailing Direction for Selected Florida Cities

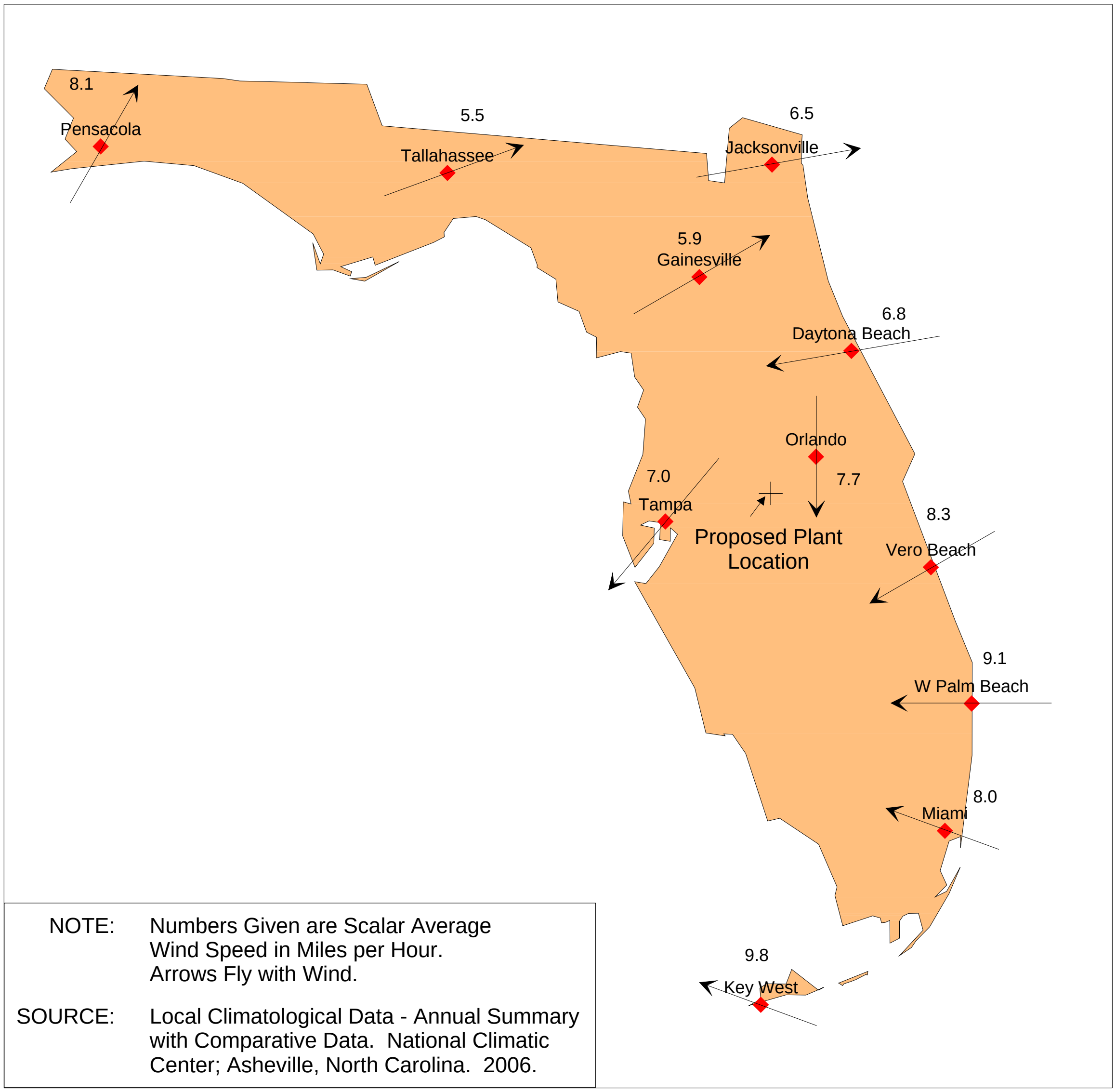


Figure 2.3-5
Annual Average Wind Speed and Prevailing
Direction for Selected Florida Cities

The average annual rainfall in this region is approximately 50 inches. Summer precipitation due to frequent afternoon thundershowers exceeds winter precipitation due to frontal systems, pre-frontal squall lines, and wave disturbances along fronts stalled over the Florida peninsula. Summer precipitation is mostly of the convective type, resulting in frequent summertime afternoon thundershowers in this region. Thunderstorms are present approximately 80 days a year. Tropical disturbances periodically cause significant precipitation during the summer and fall seasons.

Extremely hot weather is rare because of the ocean influence; maximum temperatures over a summer average near 90° F in the CIPP region. Winter temperatures are mild, slightly above 60° F, interrupted only a few times each season by the northerly or northwesterly advection of polar air. The record lows for the region are near 20° F. Only rarely do temperatures fall below freezing. Inland locations generally display a greater range of temperatures because of the rapid heating and cooling of ground surfaces as compared with water bodies. With the abundance of lakes in this region, average annual humidities are high, ranging in percent from the mid-50s during the afternoon to the upper-80s at night.

The dispersion characteristics of the region are generally good because of land-sea and lake breeze circulations, good ventilation, mixing due to convective instability, and flat terrain.

2.3.7.2 Site Climatology. The CIPP is located in central Florida approximately 45 miles inland from the Atlantic Ocean. This region of the United States is subject to a subtropical climate that is partly influenced by the Atlantic Ocean. This results in small to moderate variations in temperature and relative humidity throughout the year. Monthly precipitation is fairly consistent, with a peak in the summer months. The summers are long and rather warm, with periods of hot and humid weather. The winters are mild with occasional cool mornings due to invasion of cool northern air.

There are no existing local meteorological data with long periods of record for the CIPP. However, there is a location with meteorological data covering long periods of record that are considered representative of the CIPP. This location is the NWS office in Orlando, Florida. The NWS office is approximately 20 miles northwest of the CIPP at an elevation of 95 feet above msl. A detailed discussion of the site climatology follows.

Temperatures and Humidity. The temperature variation from season to season is slight, with warm, humid summers and mild winters. Table 2.3-6 presents a summary of the means and extremes of monthly and daily dry-bulb temperatures. Temperatures around 80° F occur during the summer months. The hottest months are July and August, with a mean monthly temperature of 82.4° F. The daily minimum and maximum

Table 2.3-6
Dry-Bulb Temperature Data

Month	Normal Temperature Monthly[a] (°F)	Normal Temperature Daily Minimum[b] (°F)	Normal Temperature Daily Maximum[b] (°F)	Extreme Temperature Lowest[c] (°F)	Extreme Temperature Highest[c] (°F)
January	60.2	48.9	70.4	19	87
February	62.2	51.4	72.9	26	90
March	66.8	55.8	77.4	25	92
April	71.6	60.4	82.5	38	96
May	77.2	66.4	87.5	48	102
June	81.0	71.5	89.9	53	100
July	82.4	73.3	91.1	64	101
August	82.4	73.7	90.9	64	100
September	80.9	72.5	88.9	56	98
October	74.9	65.9	83.6	43	95
November	68.0	57.9	77.7	29	89
December	62.2	51.6	72.1	20	90
Annual	72.5	62.4	82.1	19	102
Season					
Summer	81.9	72.8	90.6	53	101
Fall	74.6	65.4	83.4	29	98
Winter	61.5	50.6	71.8	19	90
Spring	71.9	60.9	82.5	25	102

Notes:
Source: United States Department of Commerce. Local Climatological Data – Annual Summary with Comparative Data – Orlando, Florida (KMCO, WBAN: 12815). National Climatic Center; Asheville, North Carolina. 2006.
[a]Period of record: 1953 – 2006.
[b]Period of record: 1957 – 2006.
[c]Period of record: 1943 – 2006.

temperature averages are 73.3° F and 91.1° F, respectively, for July and 73.7° F and 90.9° F, respectively, for August. Subfreezing temperatures rarely occur (i.e., approximately 3 days per year), and subzero temperatures have never been recorded. In some years, no freezing temperatures occur.

January is the coldest month, with a mean monthly temperature of 60.2° F. Average January daily minimum and maximum temperatures are 48.9° F and 70.4° F, respectively. The absolute temperature range is from 102° F (May) to 19° F (January).

Table 2.3-7 presents a summary of the wet-bulb and dry-bulb design temperatures. The 1 and 2 percent wet-bulb temperatures for June through September are 79° F and 78° F, respectively. The 1 and 2 percent dry-bulb temperatures, based on historical data from June through September, are 92° F and 91° F, respectively. The 1 percent temperatures are exceeded only 1 percent of the time, and the 2 percent temperatures are exceeded 2 percent of the time. Table 2.3-7 also includes other design temperatures for percentages of 0.4, 97.5, 99.0, and 99.6.

Table 2.3-7
Wet-Bulb and Dry-Bulb Design Temperatures
for Orlando, Florida

Percent of Time	Temperatures (°F)	
	Wet-Bulb	Dry-Bulb
0.4	80	93
1.0	79	92
2.0	78	91
97.5	--	45
99.0	--	40
99.6	--	36

Notes:
Source: "Engineering Weather Data." AFCCC/DOC1. Published by NCDC. Version 1.0. December 23, 1999. Orlando, FL. WMO No. 722050. (Period of record: 1967 – 1996).

Average relative humidities are presented in Table 2.3-8. The table shows that the average annual relative humidity is approximately 76 percent. Hourly average minimum and maximum values are 48 percent and 93 percent and occur at 1300 in April and 0700 in August and September, respectively. The relative humidity does not vary significantly from season to season, with spring days being slightly drier. Heavy fog visibility (1/4 mile or less) averages only 18 days per year at Orlando.

Table 2.3-8
Normal Relative Humidity Data

Month	Hour (Local Standard Time)				
	0100 (percent)	0700 (percent)	1300 (percent)	1900 (percent)	Normal (percent)
January	86	89	57	70	75
February	85	89	53	64	72
March	85	90	51	62	71
April	85	88	48	60	69
May	87	89	50	64	72
June	90	91	58	73	77
July	91	92	59	76	79
August	92	93	60	78	80
September	92	93	61	79	80
October	89	91	57	76	77
November	89	91	57	75	77
December	88	90	59	74	77
Annual	88	91	56	71	76
Season					
Summer	91	92	59	76	79
Fall	90	92	58	77	78
Winter	86	89	56	69	75
Spring	86	89	50	62	71

Notes:
Source: United States Department of Commerce. Local Climatological Data – Annual Summary with Comparative Data – Orlando, Florida (KMCO, WBAN: 12815). National Climatic Center; Asheville, North Carolina. 2006. (Period of record: 1977 – 2006).

Heating and Cooling Degree-Days. Units of degree-days can be used as an indicator of heating or cooling requirements. One heating degree-day is accumulated for each degree that the daily mean temperature drops below the base temperature of 65° F. Cooling degree-days are accumulated when the daily mean temperature is above 65° F. Table 2.3-9 gives mean monthly and annual degree-day totals considered representative of the Project area.

Precipitation. Normal monthly and annual precipitation (rain) totals are shown in Table 2.3-10. As shown in the table, precipitation is highest during the summer and into the fall months. During the period 1977 to 2006, the annual precipitation ranged from 30.38 inches to 67.85 inches. Only a trace of snowfall was recorded during the same period. Extreme monthly precipitation totals are listed in Table 2.3-11. The highest recorded 24 hour rainfall total in Orlando was 9.67 inches (September 1945). Maximum recorded rainfall totals for various time periods are presented in Table 2.3-12. Precipitation maximums and intensities for various return periods and durations are shown in Table 2.3-13.

Wind Characteristics. Five years of wind data (1999 to 2003) were used to generate the monthly, annual, and seasonal wind roses from Orlando, Florida, as shown on Figures 2.3-6 through 2.3-22. These wind roses are considered appropriate in describing the general wind flow at the Project. Table 2.3-14 includes the annual percent frequency of occurrence of the wind speed categories for each of the 16 wind directions. The annual wind rose shows a predominance of a northerly wind. The fall and winter months show a predominance of winds from the north at a maximum speed of 11 to 17 knots. The spring months show an abundance of easterly winds. Summer months show a predominance of winds from the south and east.

The Orlando fastest observed 2 minute and 5 second wind speeds on record are 79 and 105 miles per hour, respectively. The periods of record for the fastest 2 minute and 5 second wind speeds are both 10 years.

2.3.7.3 Atmospheric Dispersion. Atmospheric dispersion depends primarily on four meteorological parameters:

- Height of the mixing layer (mixing height).
- Wind speed within the mixing layer.
- Frequency of low level temperature inversions.
- Atmospheric stability.

Table 2.3-9
Heating and Cooling Degree-Day Data

Month	Normal Degree-Day	
	Heating	Cooling
January	204	44
February	124	59
March	58	128
April	11	202
May	0	378
June	0	486
July	0	545
August	0	547
September	0	484
October	4	318
November	42	150
December	149	64
Annual	593	3,405

Notes:
Source: Southeast Regional Climate Center. Historical Climate Summaries – General Climate Summary Tables. Orlando, Florida (86628). Base 65° F. http://www.sercc.com/climateinfo/historical/historical.html (Period of record: 1974 – 2006).

Table 2.3-10
Total Precipitation Data

Month	Normal Precipitation (inches)
January	2.43
February	2.35
March	3.54
April	2.42
May	3.74
June	7.35
July	7.15
August	6.25
September	5.76
October	2.73
November	2.32
December	2.31
Annual	48.35

Notes:
Source: United States Department of Commerce. Local Climatological Data – Annual Summary with Comparative Data – Orlando, Florida (KMCO, WBAN: 12815). National Climatic Center; Asheville, North Carolina. 2006. (Period of record: 1977 – 2006).

Table 2.3-11
Extreme Precipitation Data

Month	Extreme Precipitation[a]			Extreme Snowfall[b]	
	Maximum 24 Hour (inches)	Maximum Monthly (inches)	Minimum Monthly (inches)	Maximum 24 Hour (inches)	Maximum Monthly (inches)
January	4.19	7.23	0.15	Trace	Trace
February	4.38	8.74	0.10	0	0
March	5.03	11.38	0.02	Trace	Trace
April	5.65	9.10	0.14	Trace	Trace
May	3.18	10.36	0.43	Trace	Trace
June	8.40	18.28	1.58	0	0
July	8.19	19.57	2.60	Trace	Trace
August	5.29	16.11	2.83	Trace	Trace
September	9.67	15.87	0.43	0	0
October	7.74	14.51	0.35	0	0
November	5.87	10.29	0.03	0	0
December	3.61	12.63	Trace	0	0
Annual	9.67	19.57	Trace	Trace	Trace

Notes:
Source: United States Department of Commerce. Local Climatological Data – Annual Summary with Comparative Data – Orlando, Florida (KMCO, WBAN: 12815). National Climatic Center; Asheville, North Carolina. 2006.
[a] Period of record: 1943 – 2006.
[b] Period of record: 1973 – 2006.

Table 2.3-12
Maximum Recorded Rainfall Data for Orlando, Florida

Duration	Rainfall (inches)	Date
5 minutes[a]	0.82	April 13, 1952
10 minutes[a]	1.25	July 25, 1960
15 minutes[a]	1.80	July 23, 1958
30 minutes[a]	3.42	July 25, 1960
60 minutes[b]	5.75	July 25, 1960
2 hours[b]	7.95	July 25, 1960
3 hours[b]	8.16	July 25, 1960
6 hours[b]	8.19	July 25, 1960
12 hours[b]	8.19	July 25, 1960
24 hours[b]	9.67	September 15, 1943

Notes:
Source: United States Weather Bureau, Maximum Recorded United States Point Rainfall for 5 Minutes to 24 Hours at 296 First-Order Stations, Technical Paper No. 2, Washington, D.C., 1963.

[a]Period of record: 1952-1961.
[b]Period of record: 1941-1961.

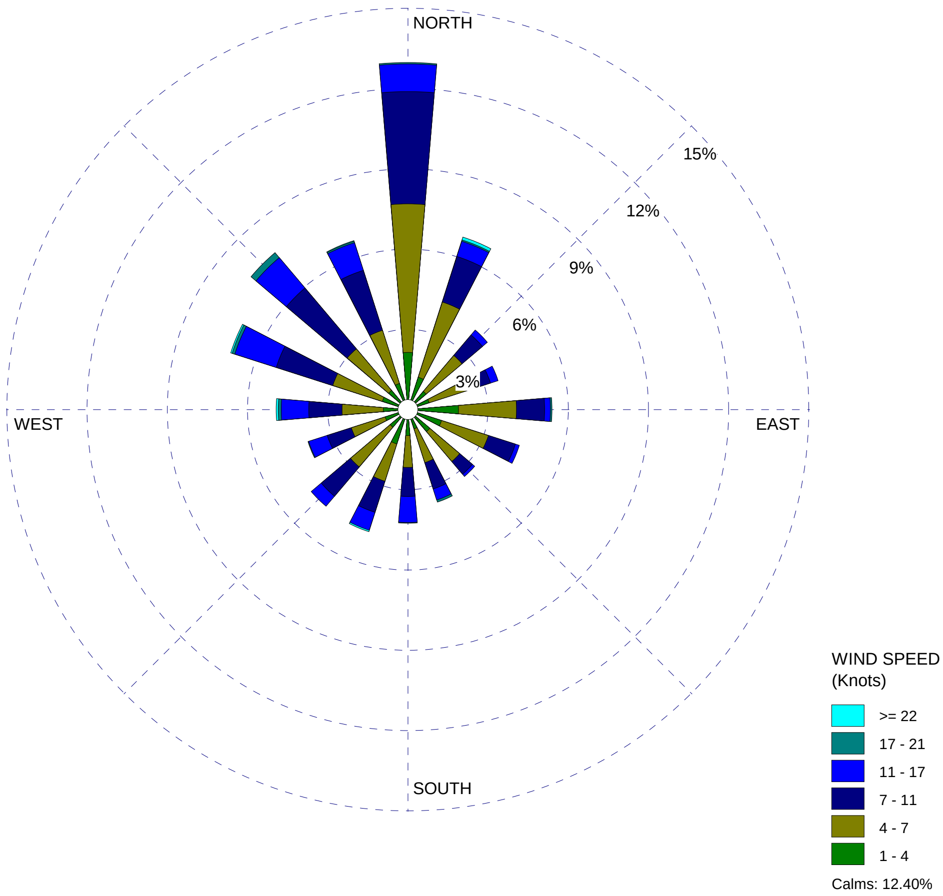
Table 2.3-13
Precipitation Amounts and Intensities for
Selected Durations and Return Periods
Expected in the CIPP Area

Precipitation Amounts							
	Return Period						
Duration (hours)	1 Year (inches)	2 Year (inches)	5 Year (inches)	10 Year (inches)	25 Year (inches)	50 Year (inches)	100 Year (inches)
1/2	1.55	1.80	2.15	2.40	2.81	3.01	3.25
1	2.00	2.22	2.78	3.08	3.40	3.80	4.10
2	2.31	2.72	3.30	3.70	4.30	4.80	5.35
3	2.53	2.80	3.65	4.25	4.80	5.40	5.95
6	2.90	3.45	4.45	5.25	5.90	6.30	7.50
12	3.25	4.25	5.25	6.25	7.50	8.30	8.90
24	3.70	4.70	6.20	7.50	8.50	9.50	10.50
Precipitation Intensities							
	Return Period						
Duration (hours)	1 Year (inches)	2 Year (inches)	5 Year (inches)	10 Year (inches)	25 Year (inches)	50 Year (inches)	100 Year (inches)
1/2	3.10	3.60	4.30	4.80	5.62	6.02	6.50
1	2.00	2.22	2.78	3.08	3.40	3.80	4.10
2	1.16	1.36	1.65	1.85	2.15	2.40	2.68
3	0.84	0.93	1.22	1.42	1.60	1.80	1.98
6	0.48	0.58	0.74	0.88	0.98	1.05	1.25
12	0.27	0.35	0.44	0.52	0.63	0.69	0.74
24	0.15	0.20	0.26	0.31	0.35	0.40	0.44

Notes:
Source: United States Weather Bureau, Rainfall Frequency Atlas of the United States for Durations from 30 Minutes to 24 Hours and Return Periods from 1 to 100 Years, Technical Paper No. 40, Washington, DC, May 1961.

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **1999-2003 Jan 1 - Jan 31 00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **12.40%**	TOTAL COUNT: **3701 hrs.**	
	AVG. WIND SPEED: **6.62 Knots**	DATE: **2/13/2008**	PROJECT NO.:

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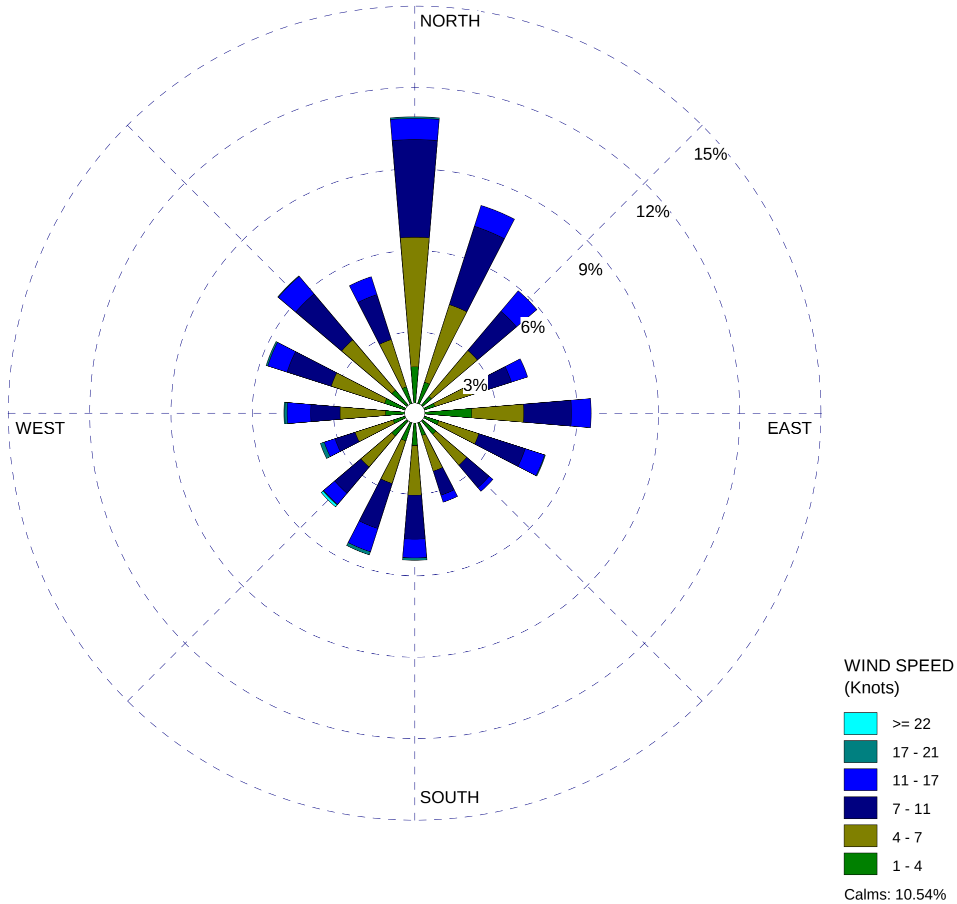
Figure 2.3-6
January Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **1999-2003** **Feb 1 - Feb 28** **00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **10.54%**	TOTAL COUNT: **3341 hrs.**	
	AVG. WIND SPEED: **6.71 Knots**	DATE: **2/13/2008**	PROJECT NO.:

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Figure 2.3-7
February Wind Rose for Orlando, Florida
Period: 1999-2003

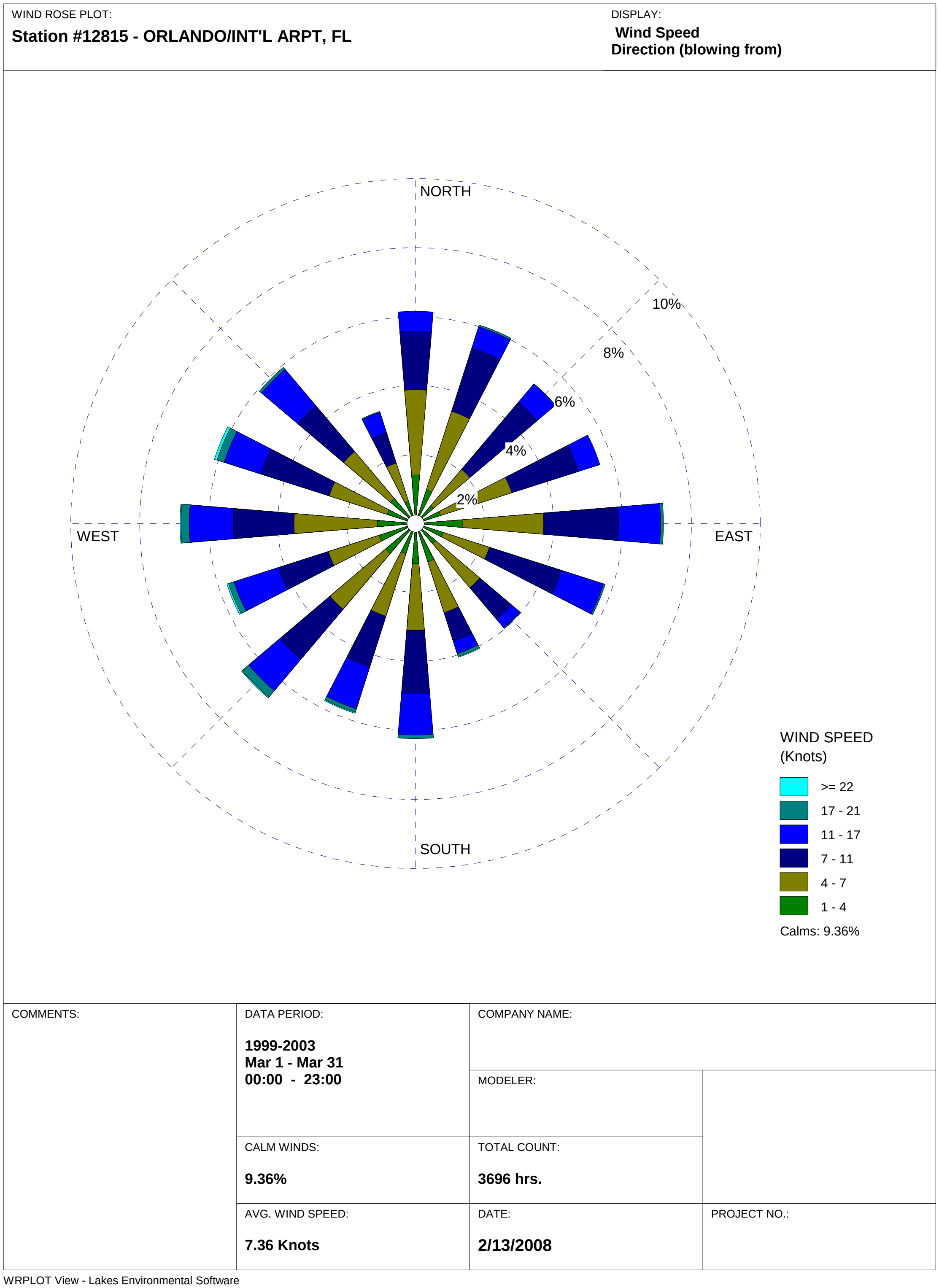
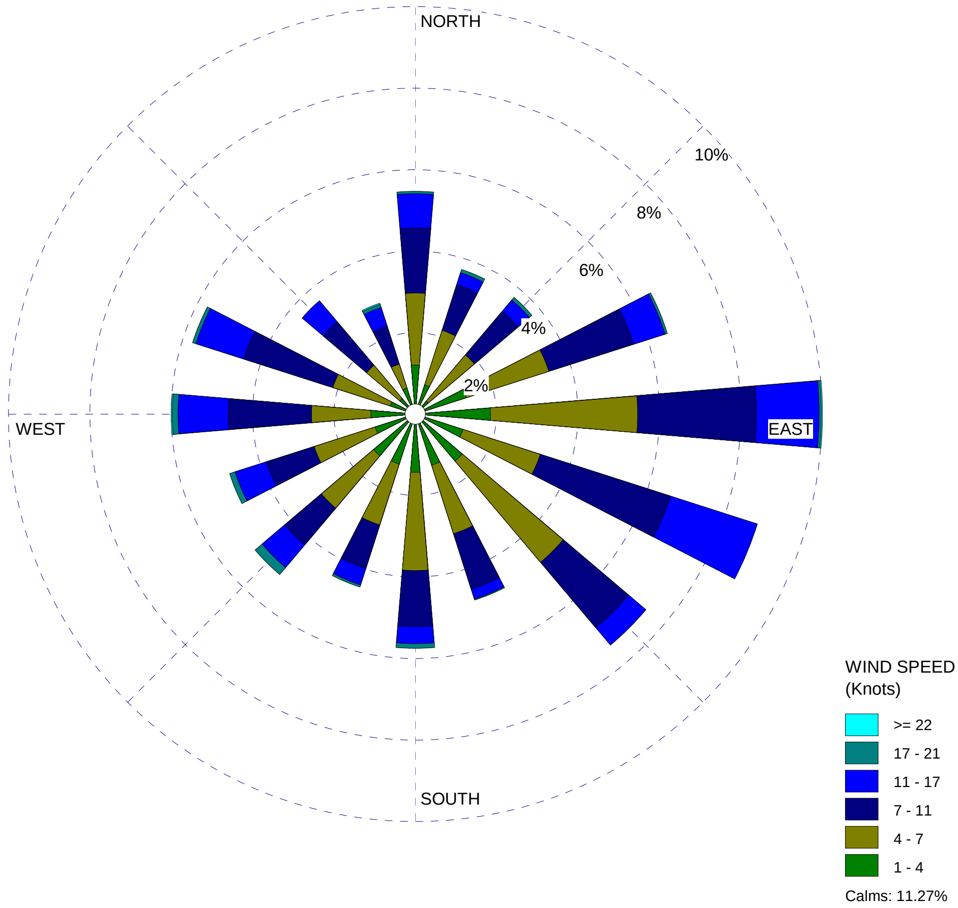


Figure 2.3-8
March Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **1999-2003** **Apr 1 - Apr 30** **00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **11.27%**	TOTAL COUNT: **3575 hrs.**	
	AVG. WIND SPEED: **6.94 Knots**	DATE: **2/13/2008**	PROJECT NO.:

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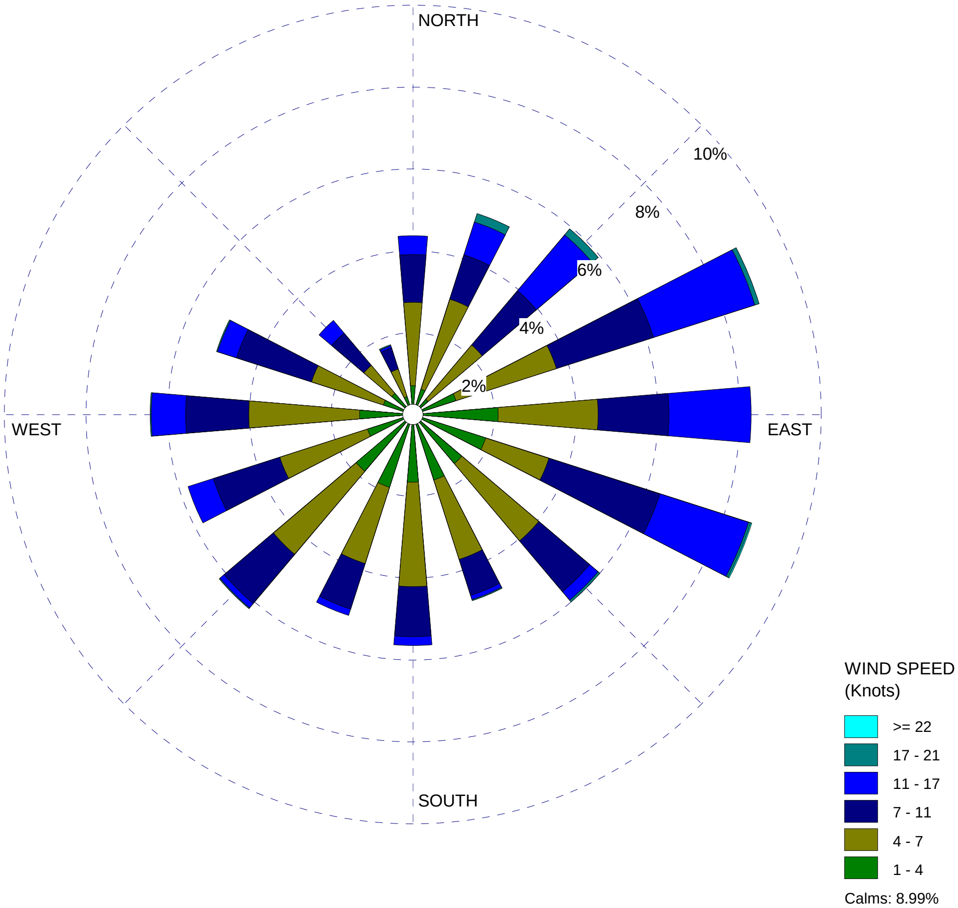
Figure 2.3-9
April Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



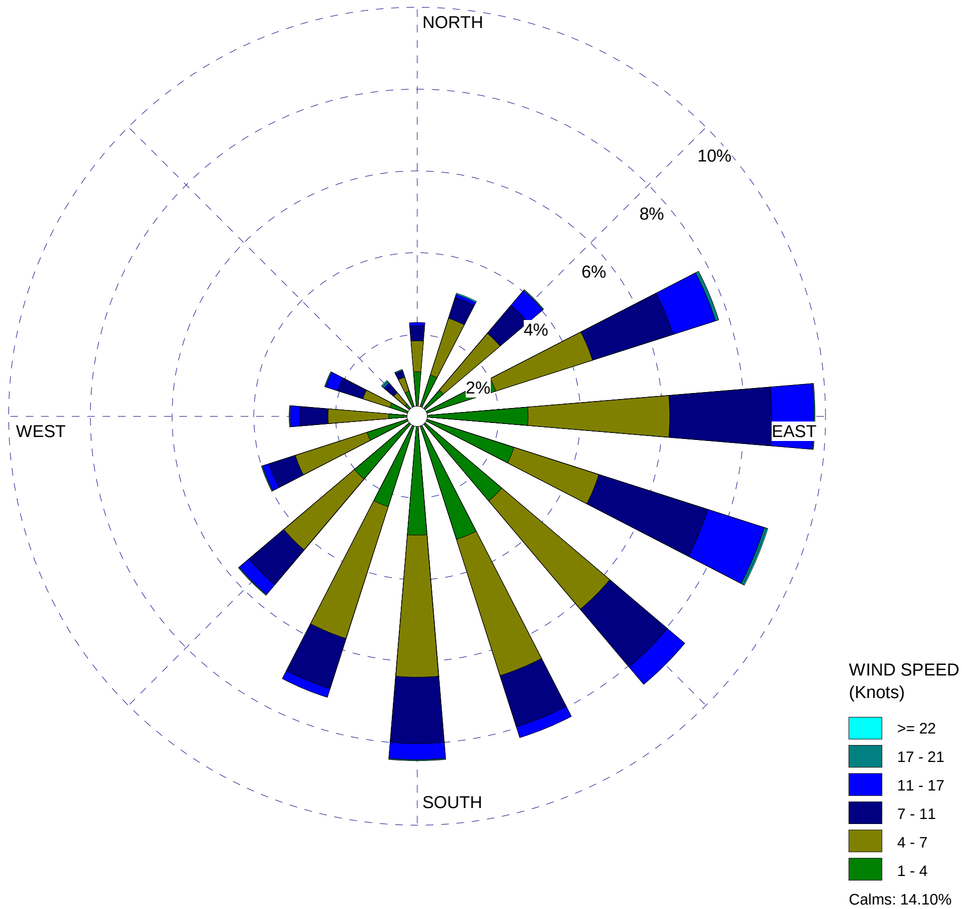
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	1999-2003 **May 1 - May 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **8.99%**	TOTAL COUNT: **3693 hrs.**	
	AVG. WIND SPEED: **6.85 Knots**	DATE: **2/13/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-10
May Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
1999-2003
Jun 1 - Jun 30
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
14.10%

TOTAL COUNT:
3582 hrs.

AVG. WIND SPEED:
5.62 Knots

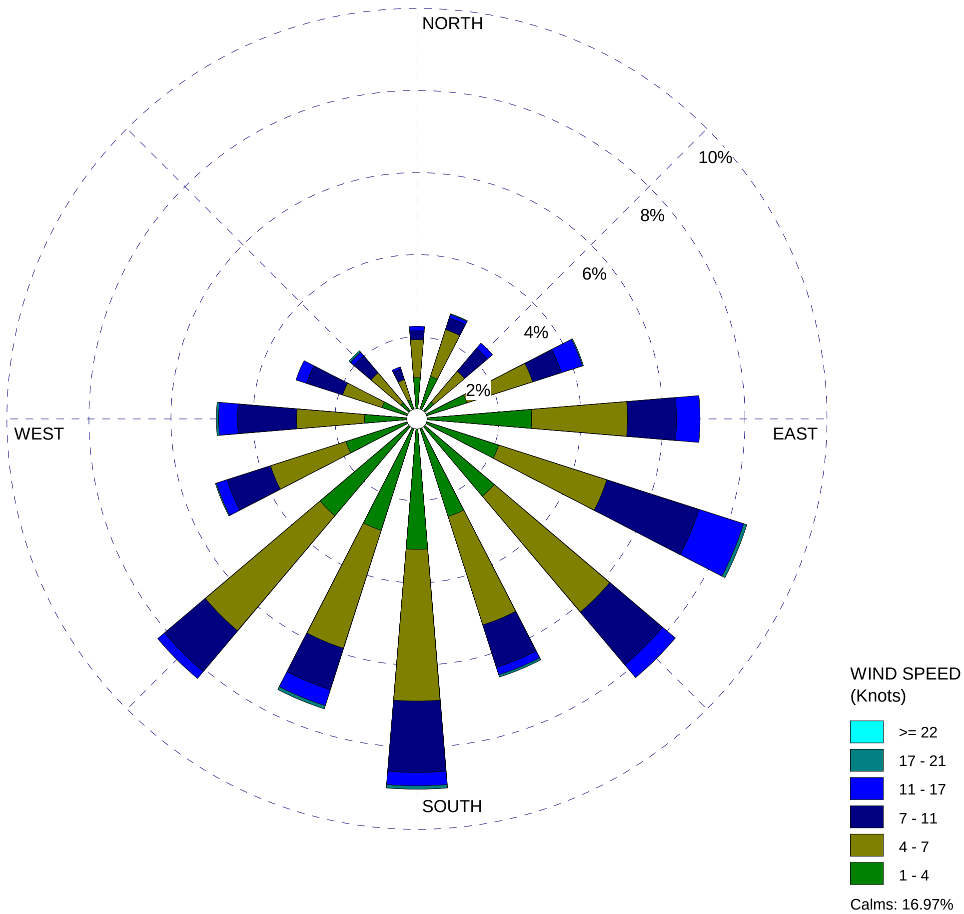
DATE:
2/13/2008

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-11
June Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:	DISPLAY:
Station #12815 - ORLANDO/INT'L ARPT, FL	**Wind Speed** **Direction (blowing from)**



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	1999-2003 **Jul 1 - Jul 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **16.97%**	TOTAL COUNT: **3689 hrs.**	
	AVG. WIND SPEED: **5.25 Knots**	DATE: **2/13/2008**	PROJECT NO.:

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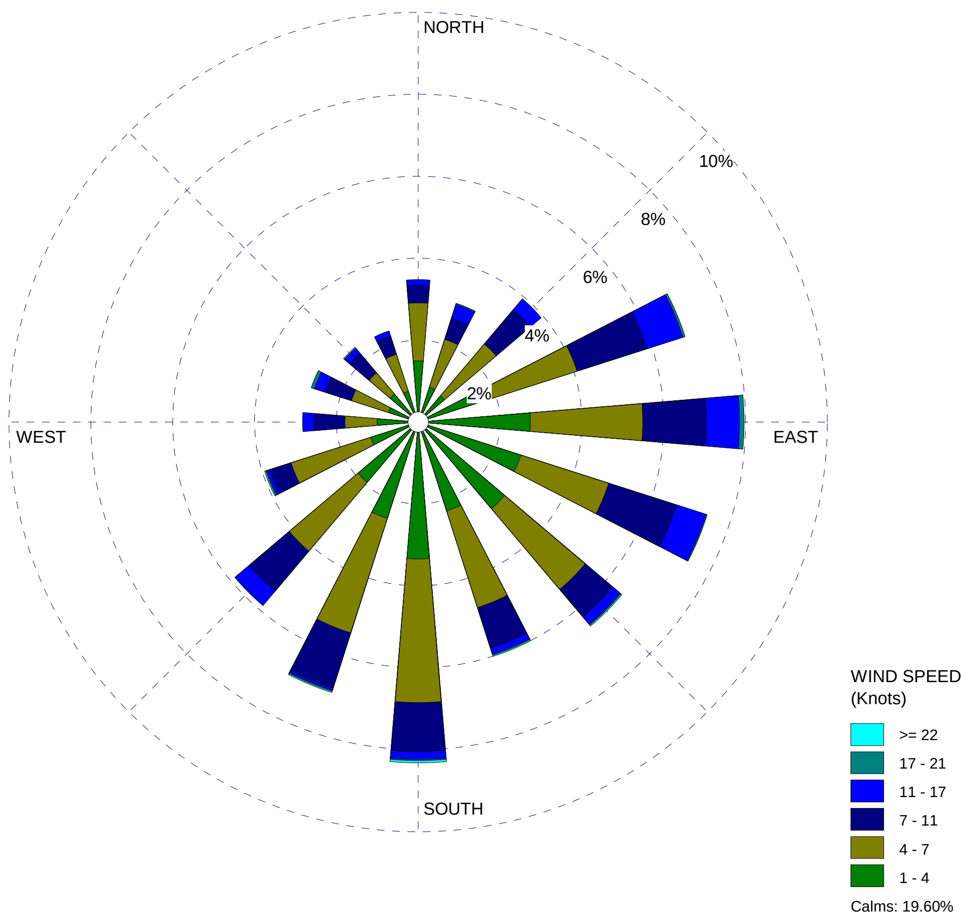
Figure 2.3-12
July Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
1999-2003
Aug 1 - Aug 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
19.60%

TOTAL COUNT:
3688 hrs.

AVG. WIND SPEED:
5.10 Knots

DATE:
2/13/2008

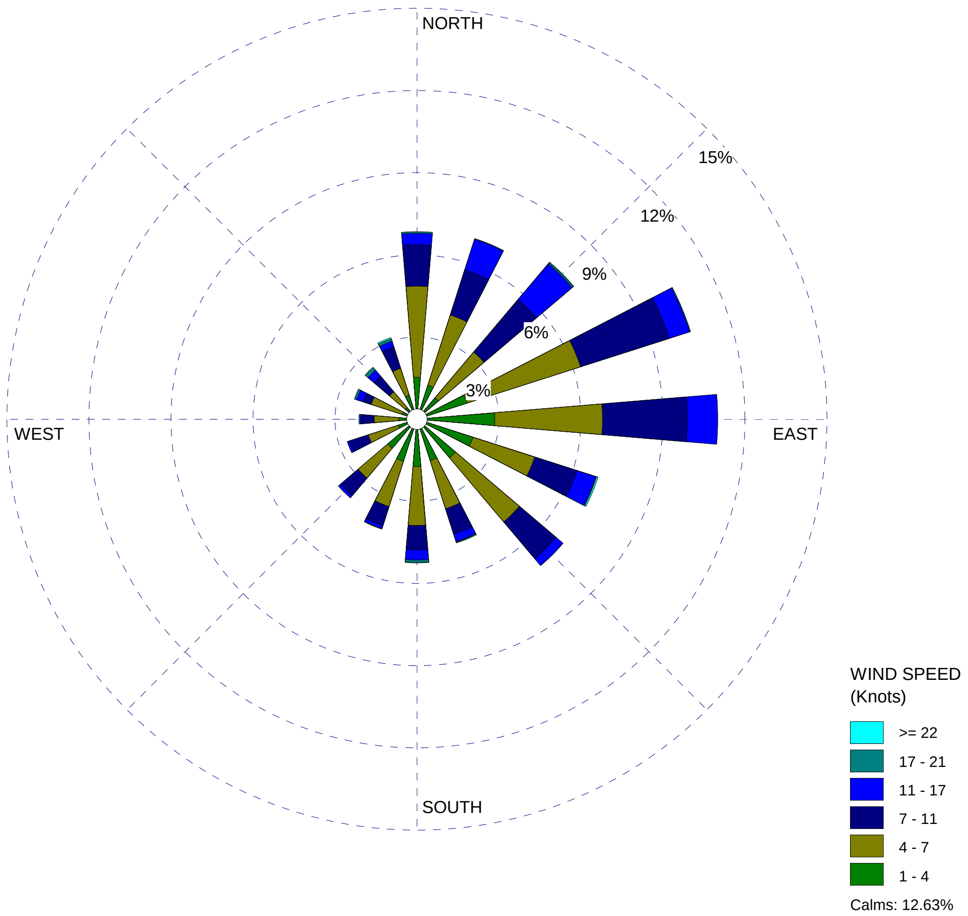
PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-13
August Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	1999-2003 **Sep 1 - Sep 30** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **12.63%**	TOTAL COUNT: **3588 hrs.**	
	AVG. WIND SPEED: **6.11 Knots**	DATE: **2/13/2008**	PROJECT NO.:

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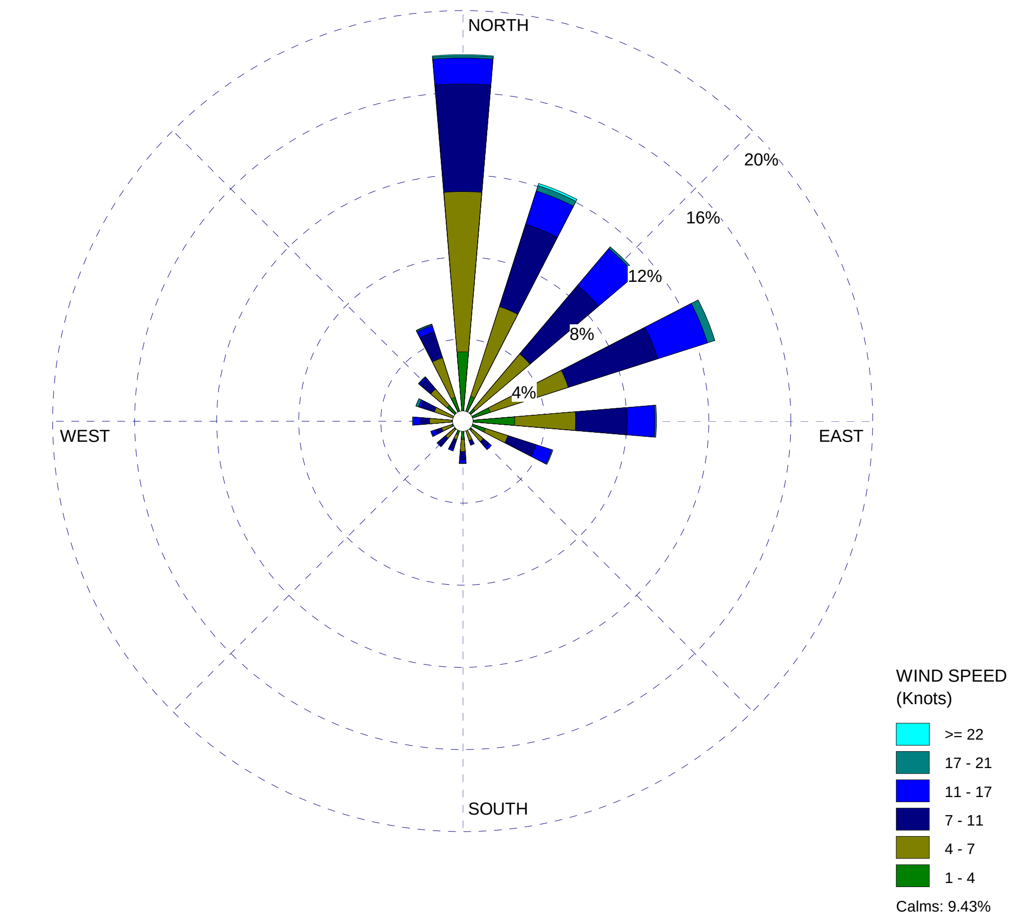
Figure 2.3-14
September Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
1999-2003
Oct 1 - Oct 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
9.43%

TOTAL COUNT:
3711 hrs.

AVG. WIND SPEED:
7.01 Knots

DATE:
2/13/2008

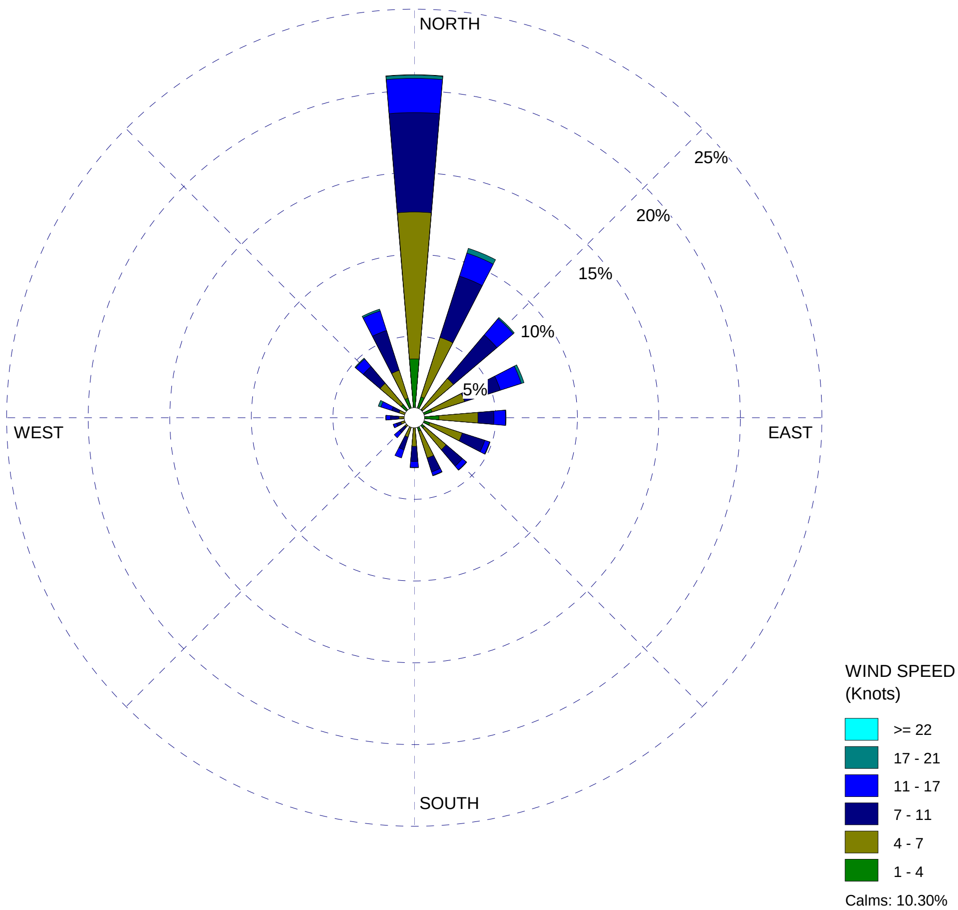
PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-15
October Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
1999-2003
Nov 1 - Nov 30
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
10.30%

TOTAL COUNT:
3592 hrs.

AVG. WIND SPEED:
6.97 Knots

DATE:
2/13/2008

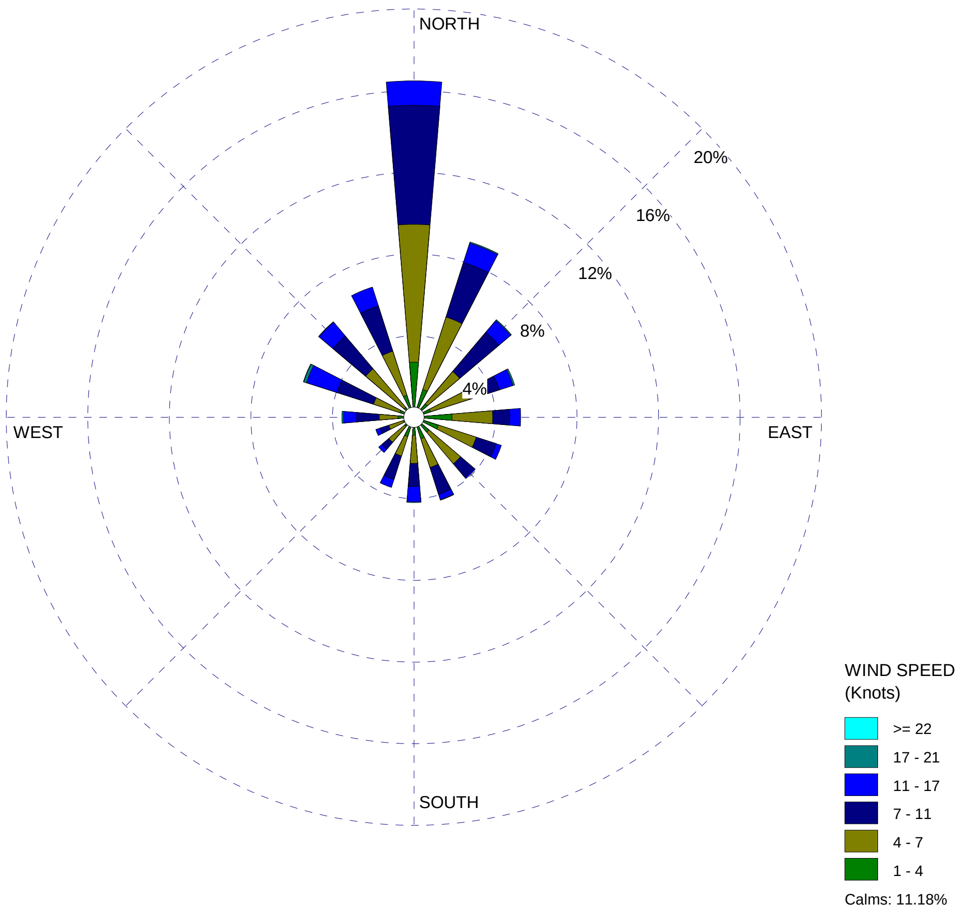
PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-16
November Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



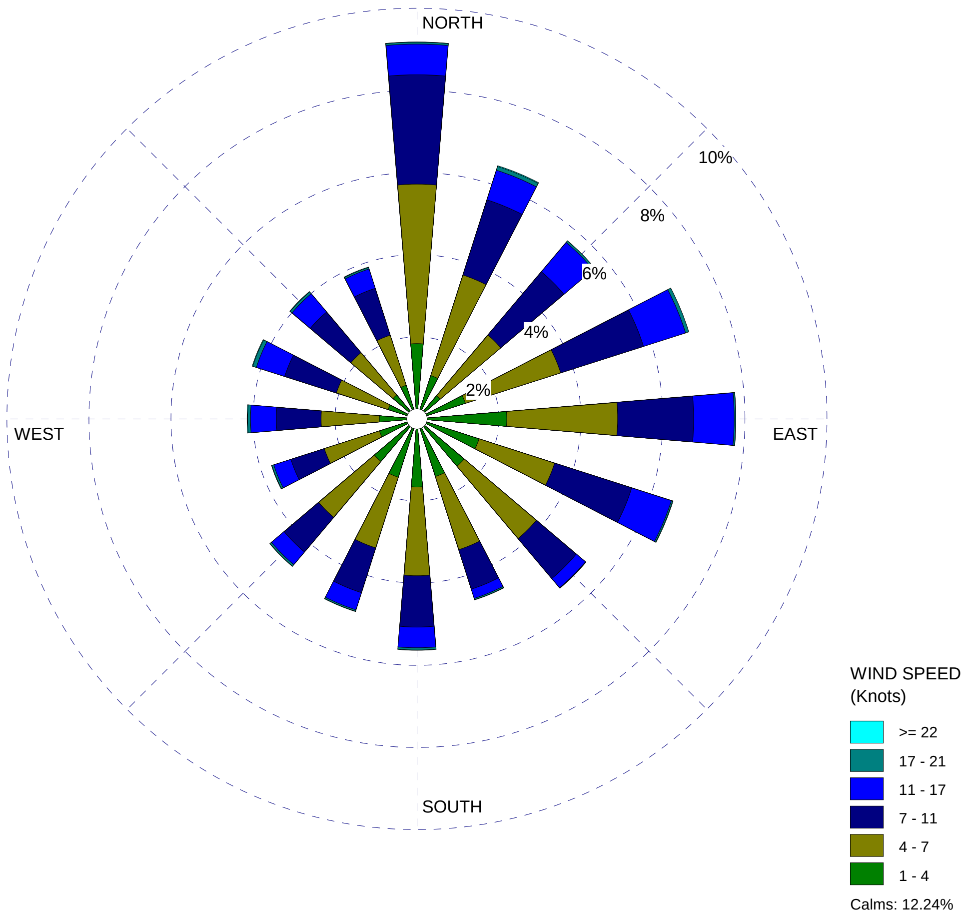
COMMENTS:	DATA PERIOD: **1999-2003** **Dec 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME:
		MODELER:
	CALM WINDS: **11.18%**	TOTAL COUNT: **3711 hrs.**
	AVG. WIND SPEED: **6.64 Knots**	DATE: **2/13/2008**
		PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-17
December Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



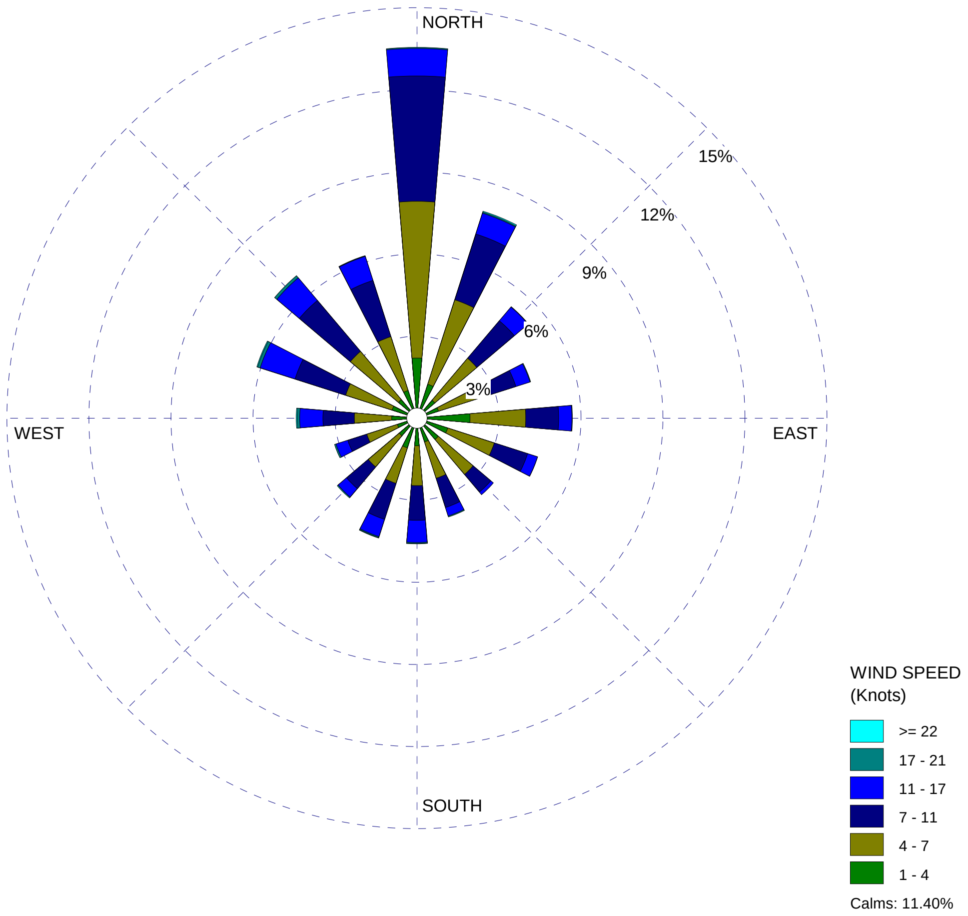
COMMENTS:	DATA PERIOD: **1999-2003** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **12.24%**	TOTAL COUNT: **43591 hrs.**	
	AVG. WIND SPEED: **6.43 Knots**	DATE: **2/13/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-18
Annual Wind Rose for Orlando, Florida
Period: 1999-2003

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



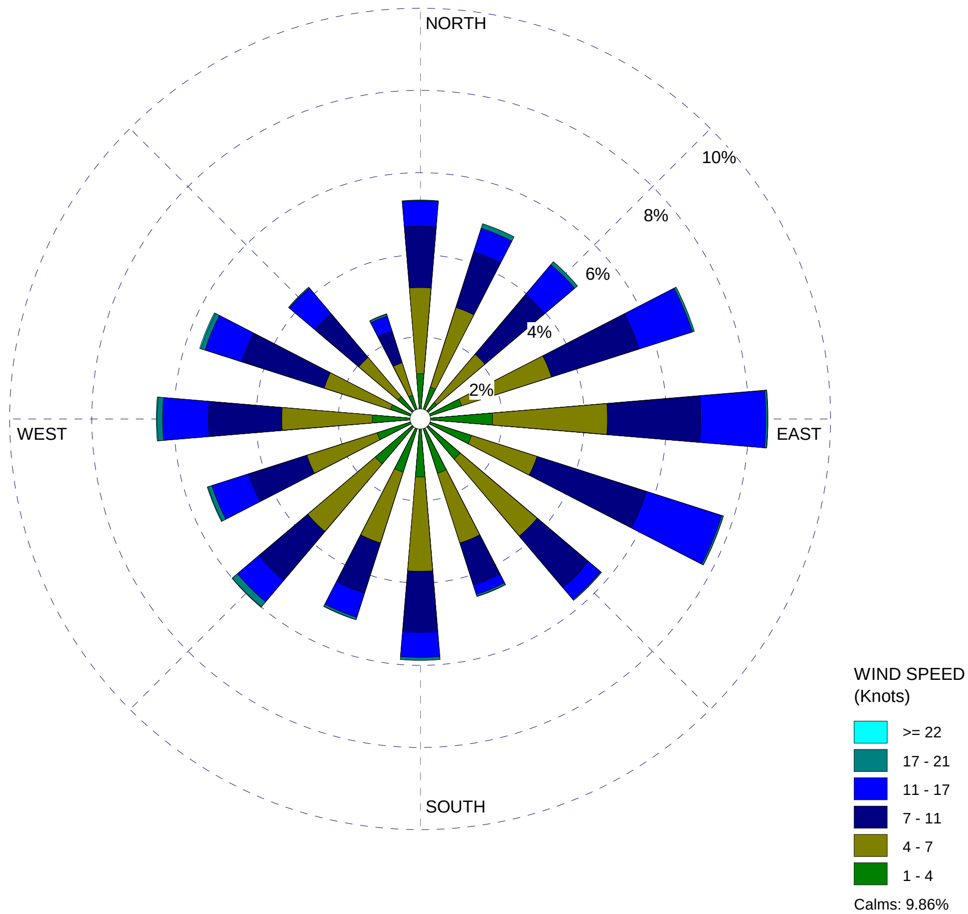
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	1999-2003 **Check Date Range Report** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **11.40%**	TOTAL COUNT: **10753 hrs.**	
	AVG. WIND SPEED: **6.66 Knots**	DATE: **2/13/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-19
Winter Wind Rose for Orlando, Florida
Period: 1999-2003 (December, January, February)

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



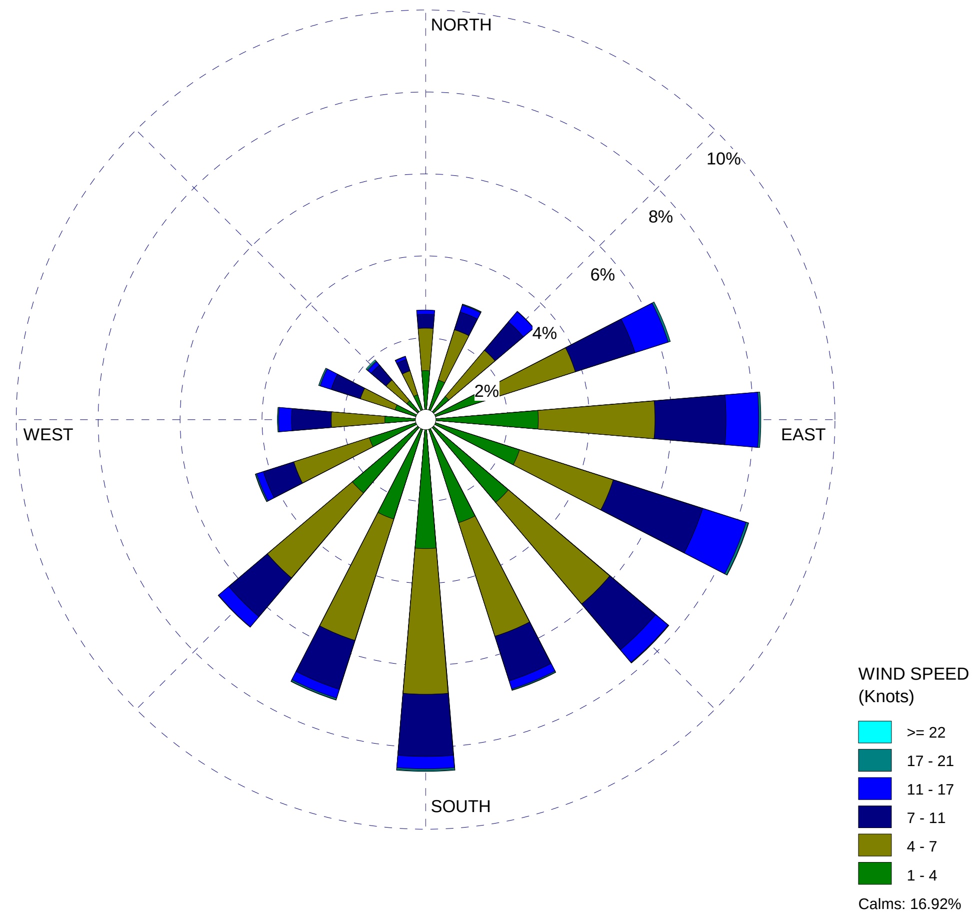
COMMENTS:	DATA PERIOD: **1999-2003 Mar 1 - May 31 00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **9.86%**	TOTAL COUNT: **10964 hrs.**	
	AVG. WIND SPEED: **7.05 Knots**	DATE: **2/13/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-20
Spring Wind Rose for Orlando, Florida
Period: 1999-2003 (March, April, May)

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



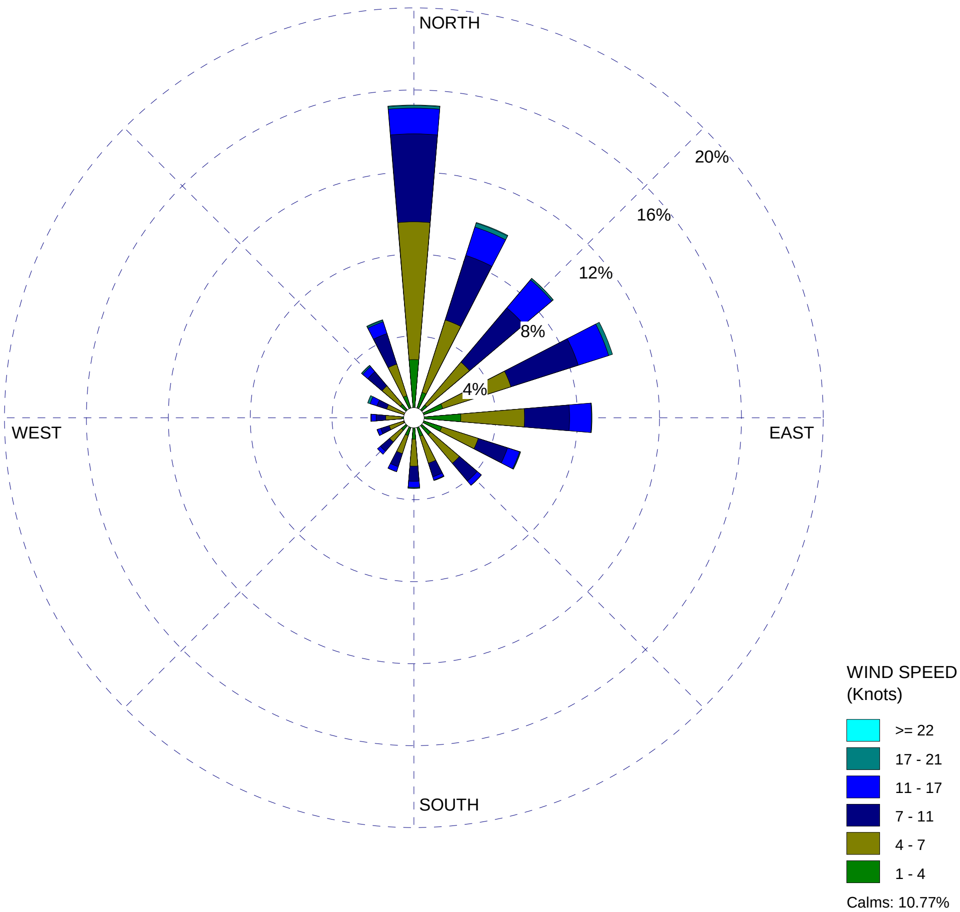
COMMENTS:	DATA PERIOD: **1999-2003** **Jun 1 - Aug 31** **00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **16.92%**	TOTAL COUNT: **10959 hrs.**	
	AVG. WIND SPEED: **5.32 Knots**	DATE: **2/13/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-21
Summer Wind Rose for Orlando, Florida
Period: 1999-2003 (June, July, August)

WIND ROSE PLOT:
Station #12815 - ORLANDO/INT'L ARPT, FL

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **1999-2003** **Sep 1 - Nov 30** **00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **10.77%**	TOTAL COUNT: **10891 hrs.**	
	AVG. WIND SPEED: **6.70 Knots**	DATE: **2/13/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 2.3-22
Fall Wind Rose for Orlando, Florida
Period: 1999-2003 (September, October, November)

Table 2.3-14
Annual Wind Rose
Percent Frequency Distribution

Direction Sector	Wind Speed Categories[a] (knots)							Total (percent)
	Calms	0-3	3-7	7-12	12-18	18-24	>24	
E	0.080	0.064	1.093	5.426	3.941	0.436	0.014	11.053
ENE	0.041	0.052	0.812	3.884	2.978	0.392	0.016	8.176
ESE	0.121	0.084	1.634	5.586	3.927	0.276	0.007	11.635
N	0.112	0.228	1.342	1.326	0.671	0.046	0.000	3.724
NE	0.030	0.084	0.771	2.373	1.803	0.199	0.000	5.260
NNE	0.027	0.123	0.621	1.079	0.737	0.039	0.002	2.629
NNW	0.335	0.429	2.928	2.588	0.931	0.059	0.002	7.272
NW	0.303	0.500	2.971	2.729	1.070	0.075	0.000	7.649
S	0.192	0.258	2.038	1.584	0.671	0.073	0.009	4.824
SE	0.210	0.180	2.229	5.084	4.144	0.301	0.018	12.167
SSE	0.178	0.201	1.618	2.029	1.686	0.251	0.002	5.965
SSW	0.162	0.210	1.673	1.015	0.402	0.082	0.011	3.555
SW	0.219	0.315	1.899	1.141	0.438	0.087	0.021	4.119
W	0.201	0.340	1.609	1.031	0.413	0.052	0.009	3.656
WNW	0.178	0.402	1.748	1.239	0.447	0.034	0.011	4.059
WSW	0.299	0.347	1.951	1.223	0.383	0.048	0.007	4.258
Total	2.688	3.818	26.935	39.337	24.642	2.451	0.130	100.000

Notes:
Source: Derived from hourly Orlando, Florida (Station No. 12815). Period: 1999-2003.

[a]Calms = 0 knots
Categories are grouped by the following scheme: 0 - 3 means greater than 0 knots and less than or equal to 3 knots, 3 - 7 means greater than 3 knots and less than or equal to 7 knots, etc.

Holzworth has estimated mean mixing depths and average wind speed within the mixing layer for 62 NWS radiosonde stations within the 48 contiguous states. The morning and afternoon mixing depths are calculated from the twice daily vertical temperature profiles and the morning and afternoon surface temperatures. Within the mixing depth, relatively vigorous mixing occurs. Diffusion within layers above this height is inhibited because of thermal buoyancy considerations (i.e., neutral or slightly stable conditions). The worst dispersion conditions occur when both the mixing depth and wind speed are low. In general, Holzworth's data show that Florida has the best combinations of greater mixing depths and higher wind speeds than other areas. Table 2.3-15 presents values of seasonal and annual morning and afternoon mixing depths and wind speed representative of the Project area.

Table 2.3-15
Estimated Average Mixing Heights and Average Wind Speeds
Through the Mixed Layer Representative
of the CIPP Area

	Morning		Afternoon	
Season	Mixing Height (m)	Wind Speed (m/s)	Mixing Height (m)	Wind Speed (m/s)
Winter	436	6.1	1,079	6.6
Spring	526	5.8	1,544	6.8
Summer	674	4.3	1,526	5.3
Fall	439	5.6	1,429	6.8
Annual	519	5.4	1,394	6.4

Notes:
Source: Holzworth, G.C. "Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States." Washington DC, USEPA. January 1972. Table B-1; Tampa, Florida.

Atmospheric stability, in conjunction with general wind patterns, indicates the potential of the atmosphere to disperse airborne pollutants. Atmospheric conditions are typically categorized as unstable, neutral, or stable. An unstable atmosphere is one in which relatively rapid dispersion takes place in both the horizontal and vertical direction. Viewed in terms of changes in temperature with height, an unstable atmosphere is characterized by a sharp decrease in temperature with height. Neutral conditions are common in the atmosphere and are associated with moderate diffusion rates. Temperatures also decrease with height in a neutral atmosphere, but not as rapidly as under unstable conditions (neutral conditions are associated with the adiabatic lapse rate).

A stable atmosphere is characterized by slight decreases, or even increases of temperature with height, and greatly reduced dispersion rates in comparison with unstable or neutral atmospheres.

The stability classifications presented in this subsection are based on the well known Pasquill, Gifford, Turner method, which assigns a stability on the basis of surface wind speed, cloud cover, and solar altitude (Turner). Stability classes range from Class A (most unstable) to Class G (most stable). Class D represents a neutral stability condition. The joint frequency distribution of wind speed, wind direction, and stability at Orlando, Florida, is summarized in Tables 2.3-16 through 2.3-22.

2.3.7.4 Ambient Air Quality. One requirement in obtaining site certification and applicable air quality permits is to demonstrate that the operation of the proposed facility will not cause or contribute to a violation of any federal or state AAQS or allowable air quality increment. This demonstration is included in Section 5.6 of Volume 1 and in Volume 3 (PSD Application), which also addresses many of the requirements of the PSD permit application. One necessary part of the application is to establish representative values for background air quality for applicable pollutants. The existing air quality in the vicinity of the Project is described in this subsection, including applicable standards and allowable incremental effects. The impact predictions resulting from the consideration of the proposed source emissions are also described in Volume 3 of this SCA.

Air Quality Standards. AAQS have been set to protect public health (primary standards) and public welfare (secondary standards). In addition, the state of Florida has adopted AAQS. The federal and state AAQS are given in Table 2.3-23.

In addition to ambient standards, the operation of the unit must not cause air quality incremental impacts beyond those specified by PSD criteria. The CIPP area is classified as PSD Class II. Class II PSD increments will be applicable for this analysis in all areas surrounding the CIPP.

Existing Air Quality. The state of Florida has been conducting air quality monitoring for criteria pollutants at locations throughout the state for many years. The USEPA AIRS Data, accessed on the Internet, provides the most recent monitoring data for use in establishing background concentrations for applicable criteria pollutants. FDEP and EPA guidance would generally require the use of the highest or second highest monitored concentrations to establish conservative background concentrations for the Project area. The most recent data (2007 data), along with the maximum recorded value during the period of record available (1997-2007) from the nearest monitoring location, are presented in Table 2.3-24. The 2007 data represents the background air quality levels at the CIPP site, while the maximum recorded values are presented for a historical perspective. Pursuant to a pre-application meeting with FDEP-BAR, site-specific ambient air monitoring and data collection were not required.

Table 2.3-16
Distribution of Hours of Occurrence of Wind Speed
and Wind Direction for Stability Class A

Direction Sector	Wind Speed Categories[a] (knots)							Total Hours
	Calms	0-3	3-7	7-12	12-18	18-24	>24	
E	0	0	5	0	0	0	0	5
ENE	0	0	3	0	0	0	0	3
ESE	0	0	1	0	0	0	0	1
N	0	1	1	0	0	0	0	2
NE	0	1	3	0	0	0	0	4
NNE	2	0	4	0	0	0	0	6
NNW	1	0	1	0	0	0	0	2
NW	1	0	2	0	0	0	0	3
S	1	1	5	0	0	0	0	7
SE	0	1	5	0	0	0	0	6
SSE	1	1	1	0	0	0	0	3
SSW	1	1	5	0	0	0	0	7
SW	0	1	3	0	0	0	0	4
W	0	0	4	0	0	0	0	4
WNW	2	0	1	0	0	0	0	3
WSW	0	1	8	0	0	0	0	9
Total	9	8	52	0	0	0	0	69

Notes:
Source: Derived from hourly Orlando, Florida (Station No. 12815). Period: 1999-2003.

[a]Calms = 0 knots
Categories are grouped by the following scheme: 0 - 3 means greater than 0 knots and less than or equal to 3 knots, 3 - 7 means greater than 3 knots and less than or equal to 7 knots, etc.

Table 2.3-17
Distribution of Hours of Occurrence of Wind Speed and Wind Direction for Stability Class B

Direction Sector	Wind Speed Categories[a] (knots)							Total Hours
	Calms	0-3	3-7	7-12	12-18	18-24	>24	
E	1	2	56	77	0	0	0	136
ENE	0	1	47	36	0	0	0	84
ESE	0	0	56	88	2	0	0	146
N	0	5	44	6	0	0	0	55
NE	0	6	55	28	0	0	0	89
NNE	0	6	39	16	0	0	0	61
NNW	2	4	54	5	0	0	0	65
NW	5	5	57	8	0	0	0	75
S	1	4	36	14	0	0	0	55
SE	0	2	62	42	1	0	0	107
SSE	1	4	41	19	0	0	0	65
SSW	0	3	44	8	0	0	0	55
SW	0	5	65	9	1	0	0	80
W	2	3	54	9	0	0	0	68
WNW	2	7	54	10	0	0	0	73
WSW	2	2	38	15	0	0	0	57
Total	16	59	802	390	4	0	0	1,271

Notes:
Source: Derived from hourly Orlando, Florida (Station No. 12815). Period: 1999-2003.

[a]Calms = 0 knots
Categories are grouped by the following scheme: 0 - 3 means greater than 0 knots and less than or equal to 3 knots, 3 - 7 means greater than 3 knots and less than or equal to 7 knots, etc.

Table 2.3-18
Distribution of Hours of Occurrence of Wind Speed
and Wind Direction for Stability Class C

Direction Sector	Wind Speed Categories[a] (knots)							Total Hours
	Calms	0-3	3-7	7-12	12-18	18-24	>24	
E	2	5	45	489	165	5	0	711
ENE	2	2	43	329	86	1	0	463
ESE	3	5	47	556	256	8	0	875
N	8	10	73	125	11	0	0	227
NE	2	5	35	242	55	6	0	345
NNE	0	7	27	110	32	1	0	177
NNW	14	11	93	156	7	0	0	281
NW	9	13	85	188	12	2	0	309
S	0	5	84	106	21	3	0	219
SE	0	7	50	446	294	18	0	815
SSE	7	5	44	152	83	6	0	297
SSW	1	11	32	88	9	3	0	144
SW	9	7	47	136	29	6	1	235
W	4	8	45	109	18	1	1	186
WNW	7	10	67	117	14	1	0	216
WSW	2	7	44	126	16	0	0	195
Total	70	118	861	3,475	1,108	61	2	5,695

Notes:
Source: Derived from hourly Orlando, Florida (Station No. 12815). Period: 1999-2003.

[a]Calms = 0 knots
Categories are grouped by the following scheme: 0 - 3 means greater than 0 knots and less than or equal to 3 knots, 3 - 7 means greater than 3 knots and less than or equal to 7 knots, etc.

Table 2.3-19
Distribution of Hours of Occurrence of Wind Speed
and Wind Direction for Stability Class D

Direction Sector	Wind Speed Categories[a] (knots)							Total Hours
	Calms	0-3	3-7	7-12	12-18	18-24	>24	
E	2	4	105	1,346	1,561	186	6	3,210
ENE	1	1	84	965	1,218	171	7	2,447
ESE	3	3	144	1,250	1,461	113	3	2,977
N	6	17	138	365	282	20	0	828
NE	0	6	77	622	735	81	0	1,521
NNE	2	5	65	290	291	16	1	670
NNW	10	12	234	681	400	26	1	1,364
NW	16	19	252	650	454	31	0	1,422
S	4	9	167	381	271	29	4	865
SE	1	7	188	1,206	1,517	114	8	3,041
SSE	4	10	143	524	656	104	1	1,442
SSW	4	8	157	254	165	33	5	626
SW	8	9	181	248	162	32	8	648
W	9	8	120	219	163	22	3	544
WNW	7	11	165	282	182	14	5	666
WSW	1	10	135	252	152	21	3	574
Total	78	139	2,355	9,535	9,670	1,013	55	22,845

Notes:
Source: Derived from hourly Orlando, Florida (Station No. 12815). Period: 1999-2003.

[a]Calms = 0 knots
Categories are grouped by the following scheme: 0 - 3 means greater than 0 knots and less than or equal to 3 knots, 3 - 7 means greater than 3 knots and less than or equal to 7 knots, etc.

Table 2.3-20
Distribution of Hours of Occurrence of Wind Speed and Wind Direction for Stability Class E

Direction Sector	Wind Speed Categories(a) (knots)							Total Hours
	Calms	0-3	3-7	7-12	12-18	18-24	>24	
E	4	3	160	464	1	0	0	632
ENE	2	2	126	372	1	0	0	503
ESE	4	4	284	553	2	0	0	847
N	7	19	178	84	1	0	0	289
NE	3	3	98	148	0	0	0	252
NNE	0	8	74	57	0	0	0	139
NNW	17	19	402	291	1	0	0	730
NW	25	30	410	346	2	0	0	813
S	7	16	308	192	2	0	0	525
SE	7	9	365	531	4	0	0	916
SSE	9	11	222	194	0	0	0	436
SSW	10	8	218	94	2	0	0	332
SW	9	14	245	105	0	0	0	373
W	8	18	214	115	0	0	0	355
WNW	8	17	219	134	0	0	0	378
WSW	17	8	264	142	0	0	0	431
Total	137	189	3,787	3,822	16	0	0	7,951

Notes:
Source: Derived from hourly Orlando, Florida (Station No. 12815). Period: 1999-2003.

(a)Calms = 0 knots
Categories are grouped by the following scheme: 0 - 3 means greater than 0 knots and less than or equal to 3 knots, 3 - 7 means greater than 3 knots and less than or equal to 7 knots, etc.

Table 2.3-21
Distribution of Hours of Occurrence of Wind Speed and Wind Direction for Stability Class F

Direction Sector	Wind Speed Categories[a] (knots)							Total Hours
	Calms	0-3	3-7	7-12	12-18	18-24	>24	
E	9	8	108	2	0	0	0	127
ENE	5	6	53	0	0	0	0	64
ESE	15	13	184	1	0	0	0	213
N	7	16	154	1	0	0	0	178
NE	4	7	70	0	0	0	0	81
NNE	4	15	63	0	0	0	0	82
NNW	26	40	499	1	0	0	0	566
NW	32	40	496	4	1	0	0	573
S	27	25	293	1	0	0	0	346
SE	23	18	307	3	0	0	0	351
SSE	12	28	258	0	0	0	0	298
SSW	18	21	277	1	0	0	0	317
SW	15	35	291	2	0	0	0	343
W	14	27	268	0	0	0	0	309
WNW	19	50	260	0	0	0	0	329
WSW	31	45	366	1	0	0	0	443
Total	261	394	3,947	17	1	0	0	4,620

Notes:
Source: Derived from hourly Orlando, Florida (Station No. 12815). Period: 1999-2003.

[a]Calms = 0 knots
Categories are grouped by the following scheme: 0 - 3 means greater than 0 knots and less than or equal to 3 knots, 3 - 7 means greater than 3 knots and less than or equal to 7 knots, etc.

Table 2.3-22
Distribution of Hours of Occurrence of Wind Speed
and Wind Direction for Stability Class G

Direction Sector	Wind Speed Categories[a] (knots)							Total Hours
	Calms	0-3	3-7	7-12	12-18	18-24	>24	
E	17	6	0	0	0	0	0	23
ENE	8	11	0	0	0	0	0	19
ESE	28	12	0	0	0	0	0	40
N	21	32	0	0	0	0	0	53
NE	4	9	0	0	0	0	0	13
NNE	4	13	0	0	0	0	0	17
NNW	77	102	0	0	0	0	0	179
NW	45	112	0	0	0	0	0	157
S	44	53	0	0	0	0	0	97
SE	61	35	0	0	0	0	0	96
SSE	44	29	0	0	0	0	0	73
SSW	37	40	0	0	0	0	0	77
SW	55	67	0	0	0	0	0	122
W	51	85	0	0	0	0	0	136
WNW	33	81	0	0	0	0	0	114
WSW	78	79	0	0	0	0	0	157
Total	607	766	0	0	0	0	0	1,373

Notes:
Source: Derived from hourly Orlando, Florida (Station No. 12815). Period: 1999-2003.

[a]Calms = 0 knots
Categories are grouped by the following scheme: 0 - 3 means greater than 0 knots and less than or equal to 3 knots, 3 - 7 means greater than 3 knots and less than or equal to 7 knots, etc.

Table 2.3-23
Ambient Air Quality Standards

Pollutant	Less Than 24 Hour Average	24 Hour Average	Annual Average
Carbon Monoxide ($\mu g/m^3$)			
Federal primary and secondary	10,000 (8 hour)[(a)]	--	--
Federal primary and secondary	40,000 (1 hour)[(a)]	--	--
Florida	Same as Federal	--	--
Lead (Pb) ($\mu g/m^3$)			
Federal primary and secondary	--	--	1.5 (3 mo)[(b)]
Florida	--	--	1.5 (3 mo)[(b)]
Nitrogen Dioxide ($\mu g/m^3$)			
Federal primary and secondary	--	--	100[(b)]
Florida	--	--	100[(b)]
Particulate Matter (PM_{10}) ($\mu g/m^3$)			
Federal primary and secondary	--	150[(c)]	50[(b, g)]
Florida	--	150[(c)]	50[(b)]
Particulate Matter ($PM_{2.5}$) ($\mu g/m^3$)			
Federal primary and secondary	--	35[(d)]	15[(e)]
Ozone ($\mu g/m^3$)			
Federal primary and secondary	157 (8-hour)[(f)]	--	--
Florida	235 (1-hour)[(c)]	--	--
Sulfur Dioxide ($\mu g/m^3$)			
Federal primary	--	365[(a)]	80[(b)]
Federal secondary	1,300 (3-hour)[(a)]	--	--
Florida	1,300 (3-hour)[(a)]	260[(a)]	60[(b)]

Notes:
[(a)]Not to be exceeded more than once per year.
[(b)]Arithmetic mean.
[(c)]Not to be exceeded an average of more than 1 day per year over a 3 year period.
[(d)]Not to be exceeded by the 3 year average of the 98th percentile of 24 hour concentrations.
[(e)]Not to be exceeded by the 3 year average of the annual arithmetic mean.
[(f)]Not to be exceeded by the 3 year average of 4th highest daily maximum 8 hour concentration.
[(g)] EPA's 1997 interim $PM_{2.5}$ implementation policy for New source Review (NSR) instructs that PM_{10} should be used as a surrogate for $PM_{2.5}$ until the EPA sets a final implementation rule for $PM_{2.5}$.

$\mu g/m^3$ -- micrograms per cubic meter (at 25° C and 760 mm Hg)

Table 2.3-24
Background Ambient Air Quality

Standard	Background Concentration[a] ($\mu g/m^3$) 2007	Maximum	Year	Location	AIRS Site ID
CO				Orlando	120951005
8 hour	2.3	5.5[b]	1997		
1 hour	4.2	8.7[b]	1997		
Lead				Tampa	120571066
Calendar quarter	1.65	2.01[b]	2000		
Nitrogen Dioxide				Winter Park	120952002
Annual	0.0058	0.144[b]	2001		
PM_{10}				Orlando	120951004
Annual	20	23[b]	1999		
24 hour	56	56[b]	2007		
$PM_{2.5}$				Orlando	120951004
Annual	9	12[c]	2000		
24 hour	80	80[c]	2007		
Ozone				Kissimmee	120972002
8 hour	0.083	0.094[b]	1998		
1 hour	0.092	0.127[b]	1998		
SO_2				Winter Park	120952002
Annual	0.001	0.003[b]	2000		
24 hour	0.003	0.014[b]	2001		
3 hour	0.009	0.042[b]	2000		

Notes:
[a]Source: USEPA AIRS Data. Data is conservative and represents the 1st highest concentration. http://www.epa.gov/air/data/.
[b]Represents maximum reported values for the period 1997 – 2007.
[c]Represents maximum reported values for the period 1999 – 2007.

2.3.8 Existing Acoustical Environment

In order to characterize the existing acoustical environment surrounding the CIPP, an ambient sound level survey was conducted. This subsection describes the results of the survey and the nature of the existing acoustical environment surrounding the project site.

2.3.8.1 Acoustical Terminology. A variety of terms are used in the field of acoustics. In order to familiarize the reader with the terminology included in this report, this subsection briefly introduces general acoustical terminology and describes basic acoustical parameters.

Sound Energy. Sound is generated by the propagation of energy in the form of pressure waves. Being a wave phenomenon, sound is characterized by amplitude (sound level) and frequency (pitch). Sound amplitude is measured in decibels (dB). The decibel is the logarithmic ratio of a sound pressure to a reference sound pressure. Typically, 0 dB corresponds to the threshold of human hearing. A 3 dB change in a continuous broadband noise is generally considered “just barely perceptible” to the average listener. A 5 dB change is generally considered “clearly noticeable,” and a 10 dB change is generally considered a doubling (or halving) of the apparent loudness. For reference, the sound pressure levels and subjective loudness associated with common noise sources are shown in Table 2.3-25.

Frequency is measured in hertz (Hz) (cycles per second). Most sound sources (except those with pure tones) contain sound energy over a wide range of frequencies. In order to analyze sound energy over the range of frequencies, the sound energy is typically divided into sections called octave bands. Octave bands are identified by their center frequencies including 31.5, 63, 125, 250, 500, 1,000, 2,000, 4,000, and 8,000 Hz. For more detailed analyses, narrow bands such as one-third octave band or one-twelfth octave bands are employed. The sum of the sound energy in all of the octave bands for a source represents the overall sound level of the source.

A person with normal hearing can hear frequencies ranging from 20 Hz to 20,000 Hz. At typical sound pressure levels, the human ear is more sensitive to sounds in the middle and high frequencies (1,000 to 8,000 Hz) than sounds in the low frequencies. Various weighting networks have been developed to simulate the frequency response of the human ear. The A-weighting network was developed to simulate the frequency response of the human ear to sounds at typical environmental levels. The A-weighting network emphasizes sounds in the middle to high frequencies and deemphasizes sounds in the low frequencies. Most sound level instruments can apply these weighting networks automatically. Any sound level to which the A-weighting network has been applied is expressed in A-weighted decibels, (dBA).

Table 2.3-25
Typical Sound Pressure Levels Associated with Some Common Noise Sources

Sound Pressure Level (dBA)	Subjective Evaluation	Common Noise Source and/or Environment	
		Outdoor	Indoor
140	Deafening	Jet aircraft at 75 feet	
130	Threshold of Pain	Jet aircraft during takeoff at a distance of 300 feet	
120	Threshold of Feeling	Elevated train	Hard rock band
110	Extremely Loud	Jet flyover at 1,000 feet	Inside propeller plane
100	Very Loud	Power mower, motorcycle at 25 feet, auto horn at 10 feet	
90	Very Loud	Propeller plane flyover at 1,000 feet, noisy urban street	Full symphony or band, food blender, noisy factory
80	Moderately Loud	Diesel truck (40 mph) at 50 feet	Inside auto at high speed, garbage disposal, dishwasher
70	Loud	B-757 cabin during flight	Close conversation, vacuum cleaner, electric typewriter
60	Moderate	Air-conditioner condenser at 15 feet, near highway traffic	General office
50	Quiet		Private office
40	Quiet	Farm field with light breeze, birdcalls	Soft stereo music in residence
30	Very Quiet	Quiet residential neighborhood	Bedroom, average residence (without TV and stereo)
20	Very Quiet	Rustling leaves	Quiet theater, whisper
10	Just Audible		Human breathing
0	Threshold of Hearing		

Environmental Noise Metrics. Noise in the environment is constantly fluctuating, such as when a car drives by, a dog barks, or a plane passes overhead. Several noise metrics have been developed to quantify fluctuating noise levels. These metrics include the equivalent-continuous sound level and the exceedance sound levels.

The equivalent-continuous sound level, Leq, is the level of a hypothetical steady sound that has the equivalent sound energy as the actual fluctuating sound over a given time duration. For example, Leq (1h) is the equivalent-continuous sound level measured over a 1 hour period and provides an indication of the average (mean) sound energy over the 1 hour period.

The exceedance sound level, Lx, is the sound level exceeded "x" percent of the sampling period and is referred to as a statistical sound level. The most common Lx values are L90, L50, and L10. L90 is the sound level exceeded 90 percent of the sampling period. L90 is referred to as the residual sound level because it measures the background sound level without the influence of loud, transient noise sources. L50 is the sound level exceeded 50 percent of the sampling period or the median sound level. L10 is the sound level exceeded 10 percent of the sampling period. L10 is often referred to as the intrusive sound level because it measures the occasional louder noises. Typical background (residual) sound levels in various types of communities are outlined in Table 2.3-26 for reference. However, it is important to remember that each community is unique with regard to the sources of noise that contribute to the background sound levels.

The variation between the L90, L50, and L10 sound levels can provide an indication of the variability and distribution of the noise environment. If the noise environment were perfectly steady, all values would be identical. A large variation between the values would indicate a large range of sound levels within the environment. For instance, measurements near a roadway with frequent (but not constant) passing vehicles would cause a large variation in the statistical sound levels.

Human Response to Sound. Human response to sound is highly individualized. Annoyance is the most common issue regarding community noise. The percentage of people claiming to be annoyed by noise will generally increase as environmental sound levels increase. However, many other factors will also influence people's response to noise. These factors can include the character of the noise, the variability of the sound level, the presence of tones or impulses, and the time of day of the occurrence. Additionally, nonacoustical factors, such as the person's opinion of the noise source, the ability to adapt to the noise, the attitude towards the noise and those associated with it, and the predictability of the noise can also influence people's response.

Table 2.3.26
Typical Daytime Residual (Background) Sound Levels
in Various Types of Communities

Type of Community	Typical Daytime Residual (Background) Sound Pressure Level
Very Quiet Rural Areas	31 to 35 dBA
Quiet Suburban Residential	36 to 40 dBA
Normal Suburban Residential	41 to 45 dBA
Urban Residential	46 to 50 dBA
Noisy Urban Residential	51 to 55 dBA
Very Noisy Urban Residential	56 to 60 dBA
Adjacent Freeway or Major Airport	>> 60 dBA

2.3.8.2 General Community Noise. The environment around the CIPP site is characterized as a predominantly rural area with major traffic arterials. Noise sensitive areas within the vicinity include residential areas located south of the CIPP property along Old Tampa Highway and southeast along Wooten Road. The primary sources of noise include traffic on South Orange Blossom Trail (Highway 17) and Old Tampa Highway. Other primary sources of noise include natural sounds such as insects, birds, and dogs. Secondary noise sources include occasional aircraft and rail traffic. Significant noise sources located approximately 2 miles southeast of the CIPP site include light industrial noise from the Pepsi/Gatorade plant and semi-truck related noise from the various industrial parks.

2.3.8.3 Survey Procedure and Conditions. An ambient sound level survey was conducted on February 4 and 5, 2008, to characterize the existing acoustical environment at nearby noise sensitive receptors. The ambient sound level survey procedure was based on general industry test standards including American National Standards Institute (ANSI) S12.9, ANSI S12.18, and ANSI S1.13. The sound level survey was conducted at three locations surrounding the project site. These locations were selected to capture acoustical environments representative of the nearby noise-sensitive receptors (i.e., residences). Each measurement location is identified on Figure 2.3-23.

Weather conditions during the February 4 and 5, 2008, survey were favorable for sound level measurements. Temperatures ranged from approximately 60° F to 87° F, and the relative humidity ranged from approximately 47 to 97 percent. Winds were calm ranging from 0 to 6 mph, and skies were mostly clear.

Figure 2.3-23
Noise Measurement Locations NML1, NML2, and NML3

All sound level measurements were conducted using Type 1 or Type 2 sound level meters that met the requirements of ANSI S1.4. The sound level meters had integrating capabilities to determine the average and statistical sound levels over the measurement duration. The microphones were equipped with windscreens provided by the manufacturer. The equipment used for the survey is listed in Table 2.3-27. Calibration certificates are kept on file, and copies can be made available upon request.

Table 2.3-27
Noise Survey Test Equipment

Model	Serial Number	Last Calibration Date
Rion Model NA-27	01191119	8/10/2007
Rion Type UC-53A Microphone	99858	8/10/2007
Norsonic Type 1251 Acoustic Calibrator	25762	8/10/2007
Rion Model NL-22	00362605	8/10/2007
Rion Model NL-22	01110133	8/10/2007
Rion Model NL-22	01110135	8/10/2007
Rion Model NC-73 Acoustic Calibrator	10527795	8/10/2007

Existing Facility Operation. Simultaneous operation of the existing CIPP Units 1, 2, and 3 are typically limited to peak summer periods. Additionally, CIPP Unit 2 operation depends upon the operation of other facilities in the power pool. From 2003 through 2006, Units 1, 2, and 3 were in operation for an average of 2 percent, 22 percent, and 58 percent of the year, respectively. Only CIPP Unit 3 was operating at the time of the ambient noise survey, which is typical of the operating characteristics. However, Unit 3 was not audible at any period during the ambient sound level survey. Figure 2.3-24 shows a summary of the load trend data for the existing CIPP Unit 3 in operation during the survey period.

Continuous Monitoring. Continuous noise monitoring was conducted at locations NML1, NML2, and NML3 to capture typical ambient daytime and nighttime sound levels. Several sound level metrics were used to quantify the fluctuating noise levels. The measurements included the Leq, L1, L10, L50, and L90 sound pressure levels, which provided an indication of the daily trends in the ambient sound level.

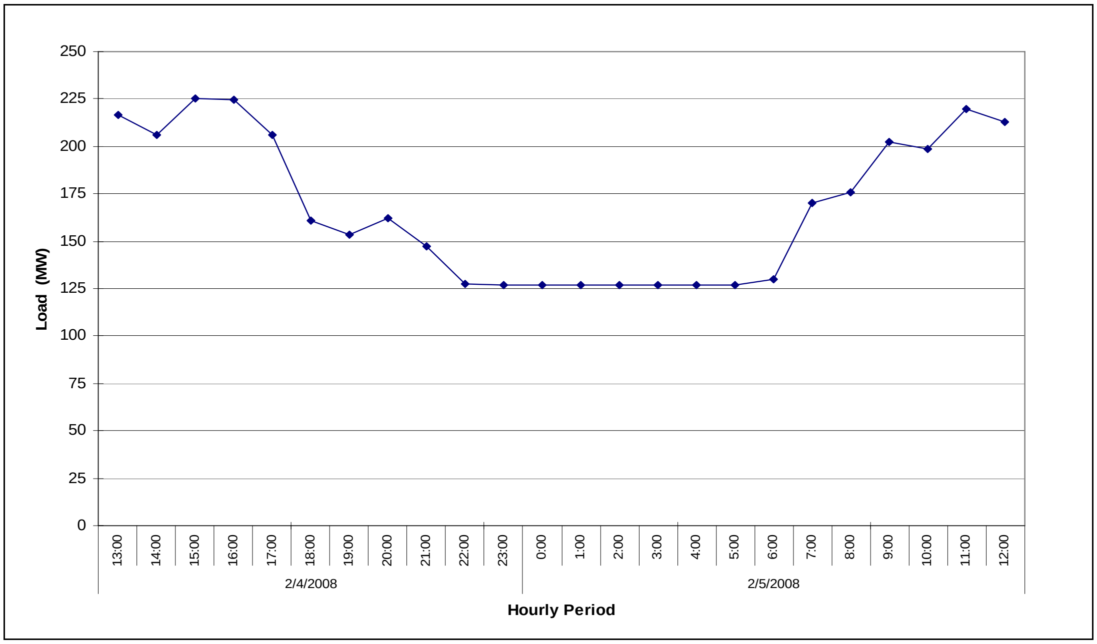


Figure 2.3-24
CIPP Unit 3 Load Trend Data During Ambient Survey

The continuous noise monitoring results are summarized in Table 2.3-28 as the range of hourly L90 sound levels and on Figure 2.3-24. As previously discussed, the L90 sound level is generally considered representative of the residual or background sound level (e.g., absent of discrete noise events such as occasional traffic, aircraft, dogs, etc.).

The continuous monitoring results indicated that the quietest times of the day occur during very early morning hours when predominant noise sources are at a minimum (e.g., traffic), as expected. At the three monitoring locations, the average hourly background sound levels (L90) ranged from 33 dBA to 54 dBA. Each location was primarily influenced by traffic noise and insect noise. As would be expected, sound levels increased during daytime hours and decreased during nighttime hours.

Location 1 (NML1). NML1 is representative of the residential properties located along South Orange Blossom Trail and provides an indication of traffic-related noise experienced at these residences. As shown on Figure 2.3-24, the quietest background periods occurred during the early morning hours from 12:53 a.m. to 2:53 a.m. The acoustical environment at this location is primarily influenced by traffic on South Orange Blossom Trail and natural sounds (e.g., insects). The existing CIPP units were not audible at this location. Traffic-related noise is represented on Figure 2.3-24 as the periods of elevated *background* sound levels (L90) centered at typical rush hour periods around 5:00 p.m. and 6:00 a.m. It should be noted that South Orange Blossom Trail includes heavy commercial truck traffic. The existing CIPP units were not audible at this location.

Table 2.3-28
Summary of Continuous Monitoring Results

Location	Range of Hourly L_{90} Background Sound Levels, dBA	
	Daytime[(a)]	Nightime[(b)]
NML1	49 - 54	35 - 54
NML2	37 - 42	33 - 43
NML3	36 - 43	33 - 41

Notes:
Daytime : 7:00 a.m. to Sunset (7:00 p.m.) per the Osceola Code of Ordinances
Nighttime: One minute after Sunset (7:01 p.m.) to 6:59 a.m. per the Osceola Code of Ordinances

Location 2 (NML2). NML2 is representative of the nearest residences located south of the CIPP site along Old Tampa Highway. As shown on Figure 2.3-25, the quietest background periods occurred from 1:13 a.m. to 3:12 a.m. This location was primarily influenced by noise from traffic on South Orange Blossom Trail, occasional traffic on Old Tampa Highway, and natural sounds (e.g., insects, dogs). The existing CIPP units were not audible at this location. Traffic noise influence at this location was less than NML1 and, as a result, the *background* sound levels (L90) shown on Figure 2.3-25 fluctuate less at the typical rush hour periods.

Location 3 (NML3). NML3 is representative of the nearest residences located south of the project site along Montzen Road. As shown on Figure 2.3-25, the quietest background periods occurred between 12:30 a.m. and 3:30 a.m. This location was primarily influenced by traffic on the South Orange Blossom Trail, occasional traffic along Old Tampa Highway, and insects. The existing CIPP units were not audible at this location. The small variation between the L90, L50, and L10 sound levels seen on Figure 2.3-26 suggest that the noise environment is fairly steady and the traffic-related noise influence is minimal, as compared to NML1. The acoustical environment at NML 3 is similar to that at NML2.

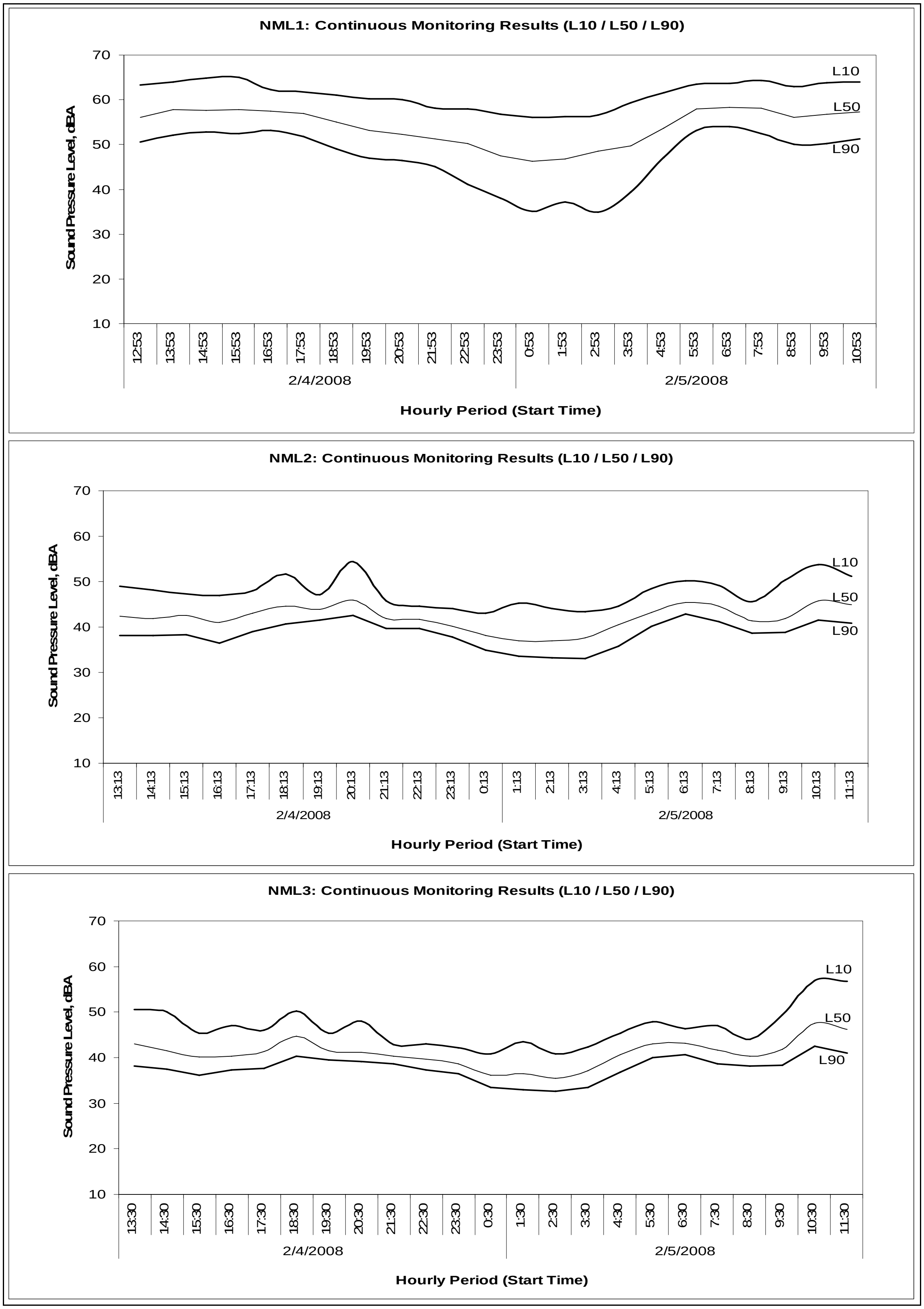


Figure 2.3-25
Results of Continuous Noise Monitoring

Short-Term Measurements. In addition to the continuous monitoring, manned, short-term noise measurements were conducted at each of the three monitoring locations. The short-term measurements were conducted to supplement the monitoring results and provide additional information. Specifically, these measurements helped to qualify the surrounding noise sources and provide an indication of the spectral content of the existing acoustical environment. Each measurement period lasted 20 minutes in order to capture sound levels representative of each location during different time periods throughout the day.

The short-term measurement results for each location are listed in Table 2.3-29 and are detailed on Figures 2.3-26 through 2.3-28. The results listed in Table 2.3-29 are consistent with the continuous monitoring results previously discussed. The figures show the background (L90) octave band sound pressure levels for each location at varying times throughout the day.

2.3.9 Other Environmental Features

Ultimate CIPP development was delineated during the permitting of Units 1 and 2; mitigation was provided for the access road and natural gas pipeline corridor, ultimate power block area, and Clay Street transmission lines impacts. As a result, development areas have been restricted to approximately 167 acres of the total 1,027 CIPP acres. The remaining 860 acres have been granted to the SFWMD and FGFWFC (now FFWCC) as conservation easements, which are actively managed by KUA for the benefit of wildlife. In addition, the CIPP habitats were identified as a “regionally significant resource” by the SFWMD. KUA is committed to preserving, monitoring, and managing these habitats to provide an environmentally safe and responsible project.

Table 2.3-29
Short-Term Measurement Results

Location	Time	Duration (min)	Measured Sound Levels, dBA			Audible Sources
			L_{90}	L_{50}	L_{10}	
NML1	2:22 p.m.	20	54	60	66	Traffic on S. Orange Blossom Trail (approx. 1,000 cars/hr), idling semi
	8:12 p.m.	20	48	55	61	Traffic on S. Orange Blossom Trail (approx. 400 cars/hr), insects, aircraft
	2:30 a.m.	20	41	50	57	Traffic on S. Orange Blossom Trail (approx. 120 cars/hr) *mostly heavy truck traffic*, insects
NML2	1:58 p.m.	20	40	43	48	Traffic, aircraft, insects, CIPP gate operation, T-line crackle
	8:38 p.m.	20	45	46	49	Traffic, Insects, T-line crackle (faint), CIPP gate operation, aircraft, dogs barking
	2:56 a.m.	20	34	38	44	Traffic, Insects, T-line crackle
NML3	1:32 p.m.	20	39	44	50	Traffic, Birds, Aircraft, Train (x2), Train crossing warning
	9:06 p.m.	20	41	43	55	Train (65 dBA max), traffic, dogs barking, aircraft
	3:21 a.m.	20	33	36	42	Traffic, insects, dogs barking, rooster crowing

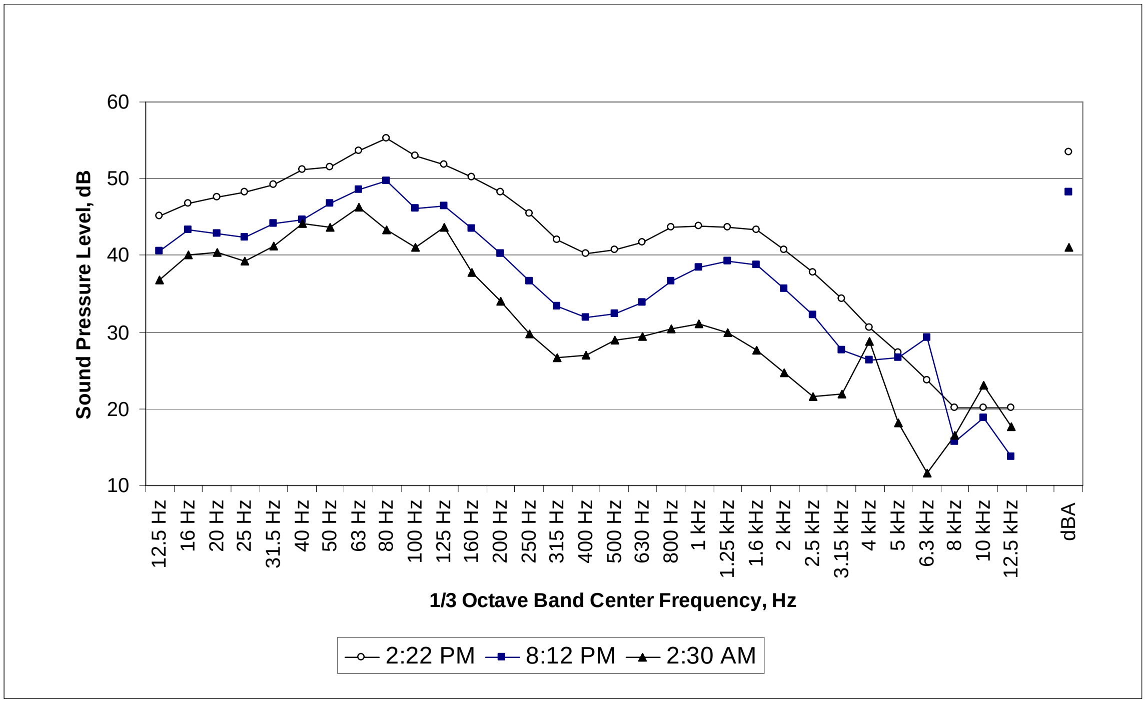


Figure 2.3-26
NML1: Measured Background One-Third Octave Band Sound Pressure Levels

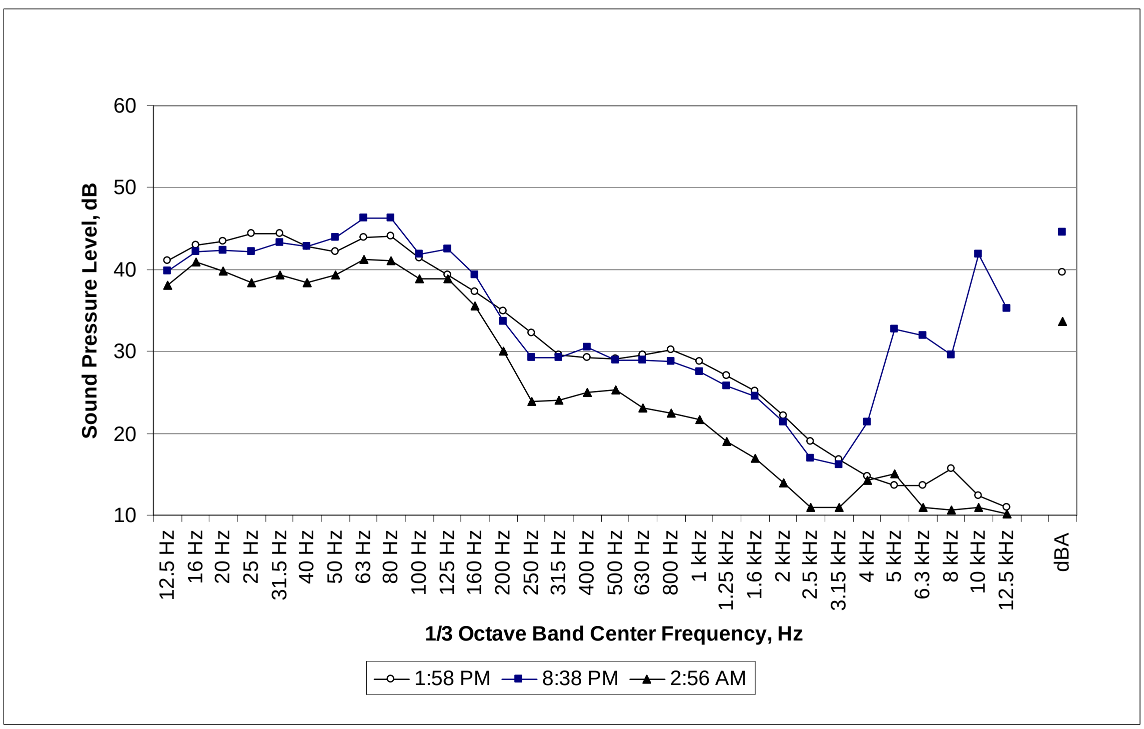


Figure 2.3-27
NML2: Measured Background One-Third Octave Band Sound Pressure Levels

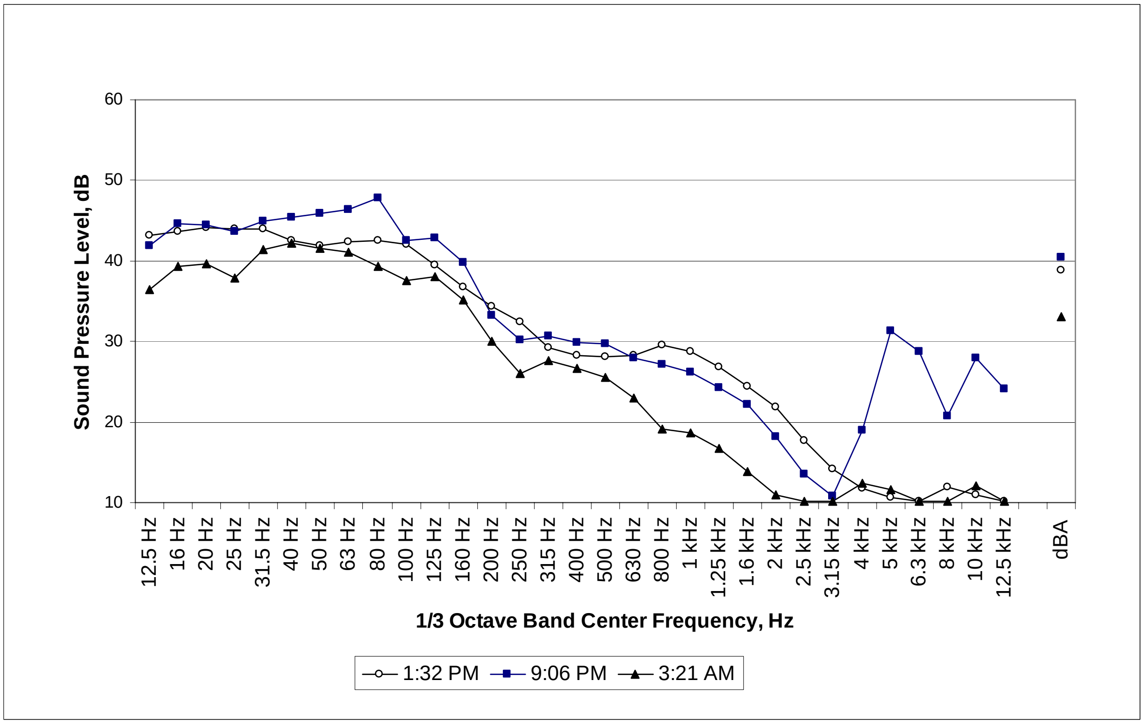


Figure 2.3-28
NML3: Measured Background One-Third Octave Band Sound Pressure Levels

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3.0 The Plant and Directly Associated Facilities

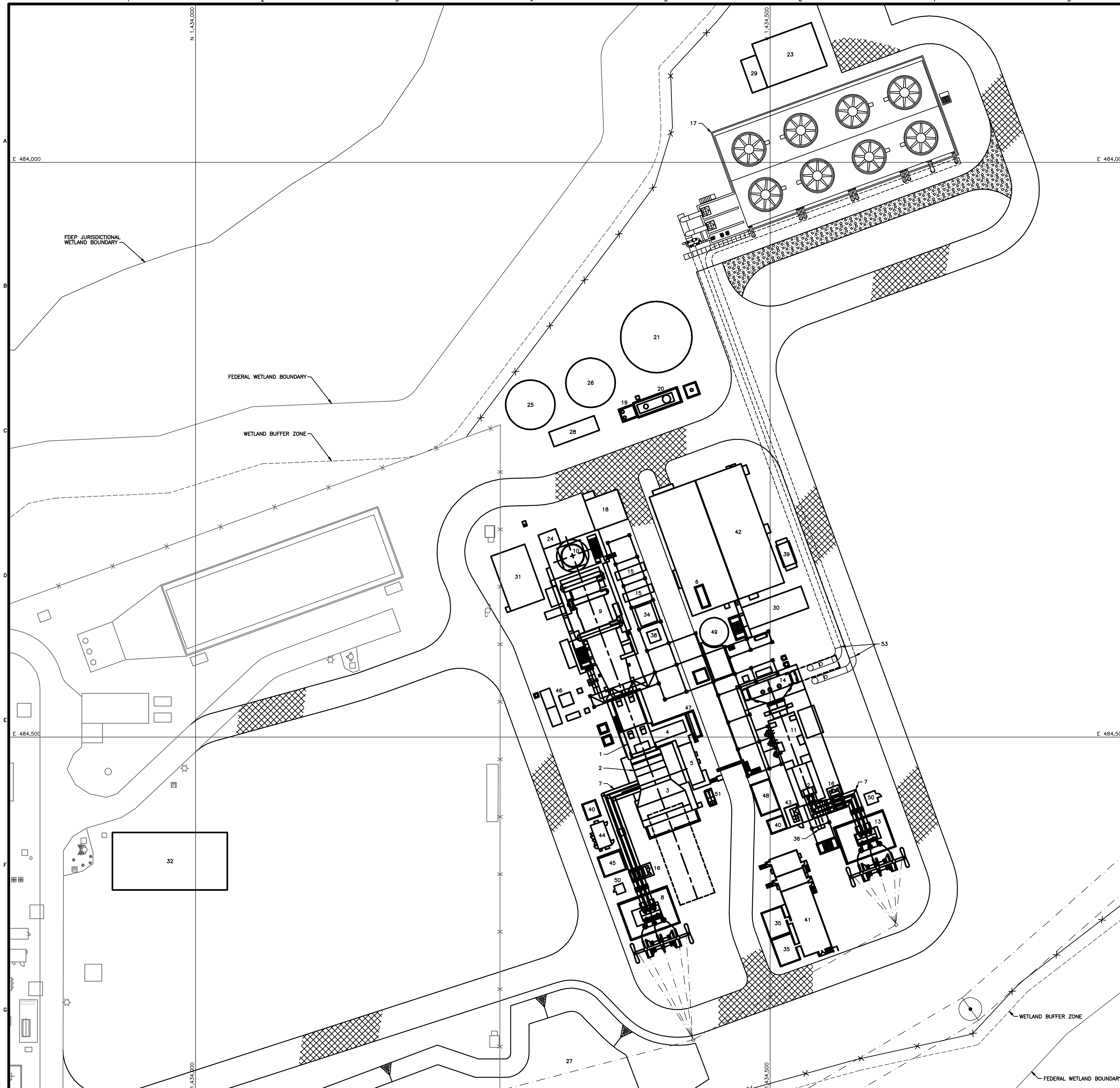
3.1 General Plant Description

The CIPP currently includes three existing units (Units 1, 2, and 3) and support facilities as shown on the site plan (Figure 2.1-3). The proposed location and detailed arrangement of Unit 4 is shown on Figure 3.1-1.

CIPP Unit 4 (Unit 4) will be a one-on-one F-class combined cycle unit with a nominal rating of 300 MW at average temperature conditions. Unit 4 will include a natural gas fueled CTG, HRSG, STG, a condenser cooled by a mechanical draft cooling tower, and associated facilities typical for a combined cycle unit. Table 3.1-1 presents the conceptual site design conditions for the CIPP site.

Table 3.1-1
Conceptual Design Conditions for the CIPP Site

Condition	Value or Range	Reference
Maximum Temperature Coincident Relative Humidity	102° F 33%	National Climatic Data Center
Minimum Temperature Coincident Relative Humidity	19° F 58%	National Climatic Data Center
Average Temperature Coincident Relative Humidity	73° F 80%	National Climatic Data Center
Wind Loading	Basic Wind Speed: 110 mph, Windborne Debris Region, Importance Factor (Iw): 1.15, Exposure C	ASCE 7-05
Seismic Zone	Seismic Use Group/Seismic Design Category III A, Site Classification (stiff soil): D,S_{ds}=0.089g, S_{d1}=0.056g	Florida Building Code does not consider seismic loads for building codes. Seismic design criteria in accordance with ASCE 7-98.
Site Elevation	Average 82.0 feet above msl	Site Arrangement Drawing
Location	Outdoors, Corrosive Environment	Site Arrangement Drawing



FACILITIES LEGEND

ID	FACILITY
1	COMBUSTION TURBINE
2	COMBUSTION TURBINE GENERATOR
3	COMBUSTION TURBINE INLET AIR FILTER
4	COMBUSTION TURBINE ACCESSORY MODULE
5	COMBUSTION TURBINE ELECTRICAL PACKAGE
6	COMBUSTION TURBINE WASH WATER SKID
7	ISOLATED PHASE BUS DUCT
8	CT GENERATOR STEPUP TRANSFORMER
9	HEAT RECOVERY STEAM GENERATOR
10	HEAT RECOVERY STEAM GENERATOR EXHAUST STACK
11	STEAM TURBINE
12	STEAM TURBINE GENERATOR
13	STEAM TURBINE GENERATOR STEPUP TRANSFORMER
14	CONDENSER
15	BOILER FEED PUMPS
16	GENERATOR BREAKER
17	COOLING TOWER
18	CO2, HYDROGEN, & NITROGEN STORAGE
19	WASTEWATER COLLECTION SUMP
20	OIL/WATER SEPARATOR
21	DEMINERALIZED WATER TANK
23	COOLING TOWER CYCLE CHEMICAL FEED STRUCTURE
24	CEMS ENCLOSURE
25	FIRE PROTECTION/SERVICE WATER TANK
26	FIRE PROTECTION/SERVICE WATER TANK
27	DETENTION POND
28	FIRE PUMP ENCLOSURE
29	COOLING TOWER ELECTRICAL ENCLOSURE
30	CLOSED CYCLE COOLING WATER PUMPS/HEAT EXCHANGER
31	AMMONIA STORAGE TANK
32	GAS METERING & AIR PRESSURE REGULATION STATION
34	HRSG BLOWDOWN TANK
35	UNIT AUXILIARY TRANSFORMER
36	STEAM TURBINE GENERATOR ROTOR REMOVAL
37	EMERGENCY MAKE-UP WELL
38	BLOWDOWN TANK SUMP & PUMPS
39	SAFE SHUTDOWN DIESEL GENERATOR
40	EXCITATION TRANSFORMER
41	POWER DISTRIBUTION CENTER
42	MISCELLANEOUS SERVICES BUILDING
43	STATIC EXCITATION ENCLOSURE
44	LOAD COMMUTATED INVERTER (LCI)
45	ISOLATION TRANSFORMER
46	FUEL GAS CONDITIONING EQUIPMENT
47	ACCESSORY MODULE CONTAINMENT TRENCH AND VAULT
48	STEAM TURBINE LUBE OIL SKID AREA
49	CONDENSATE STORAGE TANK
50	DELUGE HOUSE
51	CO2 FIRE PROTECTION SKID
53	CIRCULATING WATER PIPE

LEGEND

- WETLAND BUFFER ZONE
- OVERHEAD TRANSMISSION LINE
- FDEP JURISDICTIONAL WETLAND BOUNDARY
- FENCE LINE
- GOPHER TORTOISE HABITAT

NOTES

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0	04/01/2008	ISSUED FOR CONSTRUCTION	MRR	JMS	MJS	MJS	SAA

SCALE: 1"=30'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED ______
DATE ______ REG NO. ______

BLACK & VEATCH CORPORATION
ENGINEER JMS | DRAWN MRR | CHECKED MJS | DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4
UNIT 4 SITE ARRANGEMENT

PROJECT / DRAWING NUMBER: 147651-4STA-S1001 | REV 0
CODE
AREA
FIGURE 3.1-1

3.1.1 Mode of Operation

Unit 4 will be designed, subject to FDEP PSD permit approval, for unlimited operation on natural gas and LNG, including an unlimited number of starts annually. The new unit will be designed for cycling load operation. The STG will be selected in combination with the HRSG to provide a reasonable design throttle pressure to ensure satisfactory cycling operation. The HRSG will be designed with duct burners for peaking power operation. The CTG will have an evaporative cooler to increase warm weather power generation by increasing the CTG inlet air density. Power augmentation systems for the CTG are not included. Unit 4 will be designed to allow CTG operation with the STG out of service by providing a means for the steam from the HRSG to bypass the steam turbine and flow directly to the condenser.

3.1.2 Combustion Turbine Generator

The CTG will be a General Electric PG7241FA enhanced CTG. The CTG will have enclosures for installation outdoors and will include the following major features:

- Dry low NO_x combustion system.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system with silencers and evaporative coolers.
- Lube oil systems.
- Static starting system.
- Fire detection/carbon dioxide fire protection systems.
- Mark VIe control system with remote work station.
- Off-line/on-line water wash system.
- Package electrical and electronics control compartment.

3.1.3 Heat Recovery Steam Generator

The HRSG will be installed outdoors and will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG will be a natural circulation, three-pressure, reheat unit with supplemental duct firing to maximize unit output. Cycle operating pressure will be a nominal 2,100 pounds per square inch, gauge (psig). SCR for NO_x control is included within the HRSG. The HRSG will discharge to a metal exhaust stack. A stack damper will be included to minimize heat loss during shutdowns. Two 100 percent capacity condensate pumps and boiler feedwater pumps will be included. The design includes natural gas and LNG heating, utilizing HRSG intermediate-pressure feedwater as the heating source during normal operation and an electric heater for startup.

3.1.4 Steam Turbine Generator

The steam turbine will be a tandem-compound, single reheat, condensing turbine operating at 3,600 rpm. The steam turbine will have one high-pressure section with a nominal 2,100 psig throttle pressure, one intermediate-pressure section, and one low-pressure section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems will be utilized. A surface condenser will be provided for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. The condenser will be designed for full steam flow bypass around the steam turbine. A blanking plate will be provided to allow isolation of the steam turbine from the condenser, to allow operation of the combustion turbine during an extended steam turbine outage. A single synchronous generator will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and static excitation system will be utilized. The steam turbine will be provided with enclosures as required for outdoor installation.

3.1.5 Cooling Tower

A multiple cell, mechanical draft, counterflow cooling tower will be used for plant cooling. The cooling tower will be of fiberglass construction and installed on a reinforced concrete basin that will include a pump intake structure housing two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. A circulating water chemical feed system will be included. Makeup water to the cooling tower will be treated sewage plant effluent (reuse water) provided by Toho regional pipeline. Ground water will be requested as an emergency source of cooling tower makeup. The cooling tower will be equipped with drift eliminators with a design drift rate of 0.0005 percent. The Unit 4 cooling tower will be approximately 1,500 feet from the nearest CIPP property line.

A new (second) reuse supply pipeline from Toho to the CIPP may be required if the existing pipeline is inadequate to supply all units. Detailed design and supply information from Toho will determine the need for this second pipeline.

3.1.6 Control System

The unit will be designed for control through a plant distributed control and information system (DCIS). Mark VIe control systems for control of the CTG and STG will also be included. The DCIS control screens will be located in the existing main plant control room.

3.1.7 Transmission Interconnection

Unit 4 will be interconnected to the existing CIPP substation. The CIPP substation is connected to the KUA, Orlando Utilities Commission (OUC), Tampa Electric Company, and Progress Energy 230 kV transmission systems through four existing transmission lines. The CTG and STG will each connect to separate 18 kV/ 230 kV generator step-up transformers. The CTG and the STG will each have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each generator's 18 kV isolated phase bus duct. A new 230 kV breaker and one-half bay will be constructed in the CIPP substation to interconnect, via a collector bus, the combustion turbine and steam turbine to the substation. The existing transmission lines in the proposed Unit 4 location will be rerouted in the power block area to accommodate the new unit

3.2 Site Layout

The site plan depicts the proposed Unit 4, construction laydown/parking for Unit 4, and the existing Units 1, 2, and 3 (Figure 2.1-3). Figure 3.1-1 depicts the proposed arrangement of Unit 4. The site profile, shown on Figure 3.2-1, is based on preliminary elevations and dimensions and may change during detailed design and equipment selection. Figures 3.2-2 and 3.2-3 present computer generated renderings of the entire Unit 4 imposed on a photograph of the existing CIPP facility. Figure 3.2-4 depicts the proposed locations and elevations for the Unit 4 gaseous and liquid release points.

The site is an existing, certified site that has been cleared for construction and operation of the existing three units. FMPA proposes to clear and develop an additional 24 acres onsite, including a new wastewater percolation basin and construction laydown/parking for Unit 4.

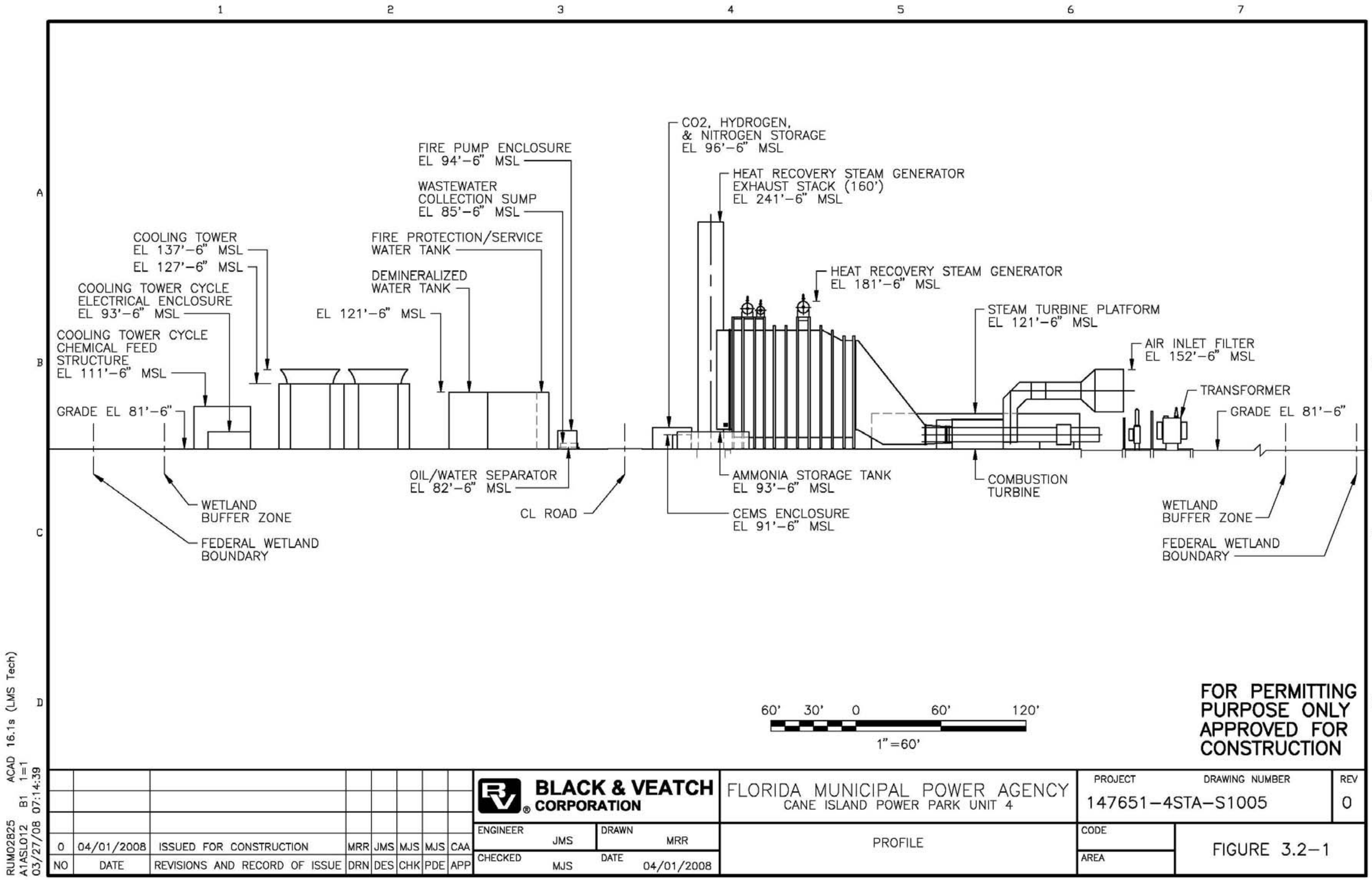


Figure 3.2-1
Unit 4 Site Profile

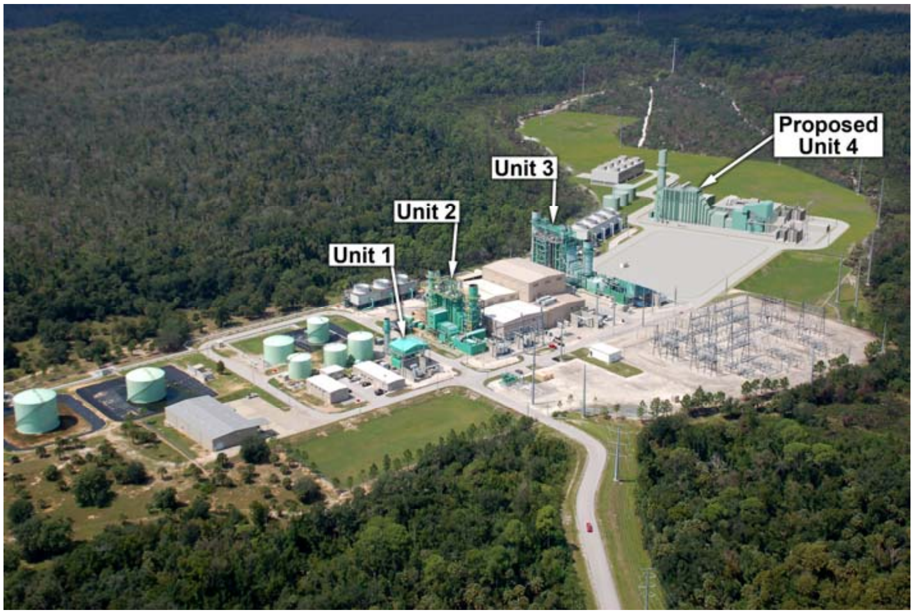
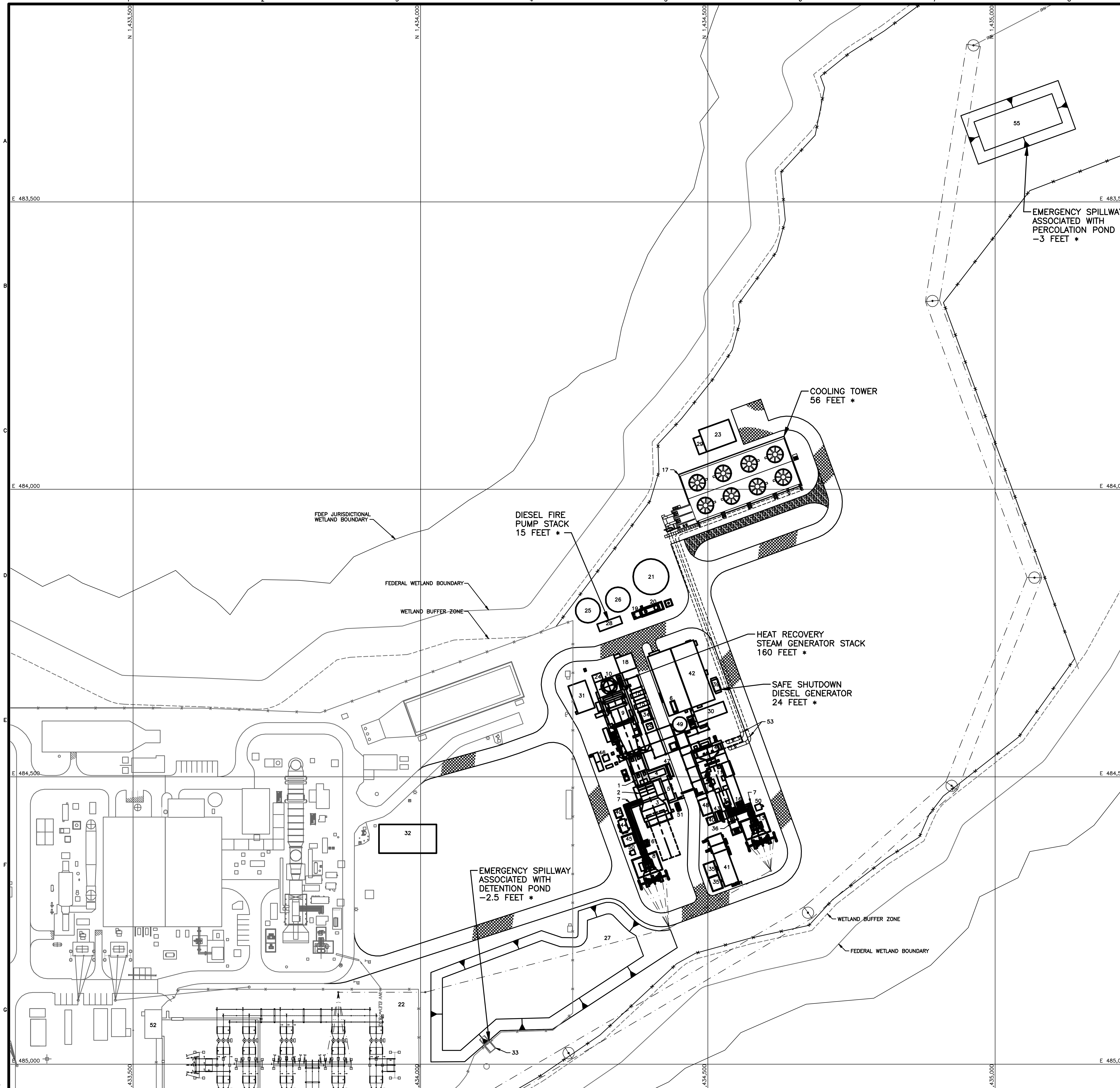


Figure 3.2-2
Computer Generated Rendering of the CIPP Four-Unit Facility

Figure 3.2-3
Computer Generated Rendering of CIPP Unit 4



FACILITIES LEGEND

ID	FACILITY
1	COMBUSTION TURBINE
2	COMBUSTION TURBINE GENERATOR
3	COMBUSTION TURBINE INLET AIR FILTER
4	COMBUSTION TURBINE ACCESSORY MODULE
5	COMBUSTION TURBINE ELECTRICAL PACKAGE
6	COMBUSTION TURBINE WASH WATER SKID
7	ISOLATED PHASE BUS DUCT
8	CT GENERATOR STEPUP TRANSFORMER
9	HEAT RECOVERY STEAM GENERATOR
10	HEAT RECOVERY STEAM GENERATOR EXHAUST STACK
11	STEAM TURBINE
12	STEAM TURBINE GENERATOR
13	STEAM TURBINE GENERATOR STEPUP TRANSFORMER
14	CONDENSER
15	BOILER FEED PUMPS
16	GENERATOR BREAKER
17	COOLING TOWER
18	CO2, HYDROGEN, & NITROGEN STORAGE
19	WASTEWATER COLLECTION SUMP
20	OIL/WATER SEPARATOR
21	DEMINERALIZED WATER TANK
22	SUBSTATION
23	COOLING TOWER CYCLE CHEMICAL FEED STRUCTURE
24	CEMS ENCLOSURE
25	FIRE PROTECTION/SERVICE WATER TANK
26	FIRE PROTECTION/SERVICE WATER TANK
27	DETENTION POND
28	FIRE PUMP ENCLOSURE
29	COOLING TOWER ELECTRICAL ENCLOSURE
30	CLOSED CYCLE COOLING WATER PUMPS/HEAT EXCHANGER
31	AMMONIA STORAGE TANK
32	GAS METERING & AIR PRESSURE REGULATION STATION
33	DETENTION POND DISCHARGE
34	HRSG BLOWDOWN TANK
35	UNIT AUXILIARY TRANSFORMER
36	STEAM TURBINE GENERATOR ROTOR REMOVAL
37	EMERGENCY MAKE-UP WELL
38	BLOWDOWN TANK SUMP & PUMPS
39	SAFE SHUTDOWN DIESEL GENERATOR
40	EXCITATION TRANSFORMER
41	POWER DISTRIBUTION CENTER
42	MISCELLANEOUS SERVICES BUILDING
43	STATIC EXCITATION ENCLOSURE
44	LOAD COMMUTATED INVERTER (LCI)
45	ISOLATION TRANSFORMER
46	FUEL GAS CONDITIONING EQUIPMENT
47	ACCESSORY MODULE CONTAINMENT TRENCH AND VAULT
48	STEAM TURBINE LUBE OIL SKID AREA
49	CONDENSATE STORAGE TANK
50	DELUGE HOUSE
51	CO2 FIRE PROTECTION SKID
52	SWITCHYARD CONTROL BUILDING (EXISTING)
53	CIRCULATING WATER PIPE
55	PERC POND

LEGEND

------	WETLAND BUFFER ZONE
—·—·—	OVERHEAD TRANSMISSION LINE
———	FDEP JURISDICTIONAL WETLAND BOUNDARY
—X—X—	FENCE LINE
*	INDICATES ELEVATION REFERENCE ABOVE OR BELOW POWER BLOCK ELEVATION OF 81.50 FT.

NOTES

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60' 30' 0 60' 120'
SCALE: 1"=60'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE REG NO.

BLACK & VEATCH CORPORATION
ENGINEER JMS DRAWN MRR
CHECKED MJS DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4

UNIT 4 RELEASE POINTS FOR LIQUID AND GASEOUS POINTS

PROJECT DRAWING NUMBER 147651-4STA-S1004 REV 0
CODE
AREA
FIGURE 3.2-4

3.3 Fuel

3.3.1 Fuel Types and Qualities

The primary fuel for Unit 4 will be natural gas from existing Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System L.L.C (Gulfstream) pipelines. These pipelines may also include vaporized LNG, which is similar to natural gas except that it has been refrigerated to minus 259° F. At this temperature, natural gas becomes a clear, colorless, and odorless liquid. LNG occupies only a fraction of its gaseous volume and can be transported economically between regions in special tankers. Table 3.3-1 presents typical natural gas properties.

Table 3.3-1
Natural Gas Properties

Parameter	Mole, %
C 6 +	0.054
Propane	0.506
I-Butane	0.110
N-Butane	0.100
I-Pentane	0.036
N-Pentane	0.022
Nitrogen	0.356
Methane	95.513
CO_2	0.853
Ethane	2.450
Totals	100.0

Note: Heating Value, Btu/cubic foot (HHV) is 1,037.

3.3.2 Fuel Quantities

Hourly fuel consumption rates will depend on plant load, ambient conditions, and whether supplemental firing is being used. Table 3.3-2 provides indicative estimates of average fuel consumption rates.

Table 3.3-2
Indicative Hourly Fuel Consumption Rates

Description of Operating Mode	Million MBtu/h
Average ambient, natural gas fuel, supplemental firing off, full load.	1,743
Average ambient, natural gas fuel, supplemental firing on, full load.	2,308

MBtu = Million British thermal units per hour.

3.3.3 Fuel Transportation, Delivery, and Metering

Natural gas will be delivered to the site by existing pipelines from FGT and Gulfstream and will be regulated, metered, and conditioned onsite. The gas supply pipelines are of adequate size. An existing onsite stub-up for Unit 4 is present to the north of Unit 3. The natural gas conditioning equipment includes a fuel gas scrubber, coalescing gas filters, and a performance fuel gas heater.

3.3.4 Alternate Fuel Types

FMPA has determined that combustion turbines firing natural gas will be the most efficient technology for power generation at the CIPP. Natural gas does not require delivery vehicles, storage facilities, secondary containment structures, or large dedicated acreages. Natural gas is also the cleanest burning fossil fuel available and its use results in minimal air quality impacts. Incremental additions of natural gas fired combustion turbine capacity are also more flexible than additions of oil or coal fired capacity. The CIPP is not suitable to accommodate coal fired generating units with coal storage and handling systems.

3.4 Air Emissions and Control

Unit 4 will be considered a major source by the FDEP. Subject to regulatory approval, emission control for NO_x will be by use of combustion turbine dry low NO_x burners and SCR when firing natural gas (no other fuels are proposed for this unit). Control of other pollutants will be by good combustion control and use of natural gas. The anticipated air emissions and proposed control technologies are fully described and presented in Volume 3, the PSD Application, which is included with this SCA under separate cover.

3.4.1 Air Emissions Types and Sources

Air pollutants will be emitted from the combustion turbine/HRSG when firing natural gas (no other fuels are proposed for this unit). Air emissions result from either the combustion process or impurities in the fuel. Fuel combustion generally results in the emissions of NO_x, CO, SO_2, VOC, PM/PM_{10}, sulfuric acid mist (SAM), and small amounts of hazardous air pollutants (HAPs). During combustion, two primary types of NO_x emissions are formed: fuel NO_x and thermal NO_x. Fuel NO_x emissions are formed through the oxidation of a portion of the nitrogen contained in the fuel. Thermal NO_x emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. SO_2 and SAM emissions result from conversion of sulfur in the fuel and are minimized by the very low sulfur content in the fuels proposed for the Project.

Potential annual emissions are based on emissions expected for baseload operation while firing natural gas at International Organization for Standardization (ISO) conditions of 59° F and 60 percent relative humidity. The potential annual emissions also include emissions from firing natural gas in the HRSG duct burner and with the evaporative cooling. Volume 3, the PSD Application, presents the basis for the emission rates and potential annual emissions.

Particulate emissions from the mechanical draft cooling tower result from dissolved solids contained in water drift from the cooling tower. High efficiency mist eliminators will be used to minimize PM/PM_{10} emissions from the mechanical draft cooling tower.

Combustion emissions will also result from the operation of an emergency generator and an emergency fire pump. While the use of these pieces of equipment will be infrequent given their purpose, emissions will further be controlled by good combustion control and use of ultra-low sulfur fuel oil (ULSFO). These controls are considered BACT for these two sources; given their small and infrequent nature of operation, these units are not discussed further in this section.

Table 3.4-1 presents the annual potential emissions for the Project compared to the PSD significant emission rates, which are thresholds for PSD review. If a project is located at an existing major source, then PSD review is required for any pollutant with emissions that are greater than the listed PSD significant emission rate for that pollutant. PSD review requires a determination of BACT, an ambient air quality impact analysis (AAQIA), and an additional impact analysis.

Table 3.4-1
PSD Applicability

Pollutant	Project Potential to Emit (PTE)[a] (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NO_x	78.1	40	Yes
SO_2	45.3 [b]	40	Yes
CO	178.8	100	Yes
PM	176.8 [c, d]	25	Yes
PM_{10}	176.8 [c, d]	15	Yes
VOC	23.3	40	No
SAM	24.3 [b, e]	7	Yes
Total Reduced Sulfur	Negligible	10	No
Hydrogen Sulfide	Negligible	10	No
Vinyl Chloride	Negligible	1	No
Total Fluorides	Negligible	3	No
Mercury	Negligible	0.1	No
Lead	Negligible	0.6	No

[a]Combustion turbine emissions are based on operation of the combustion turbine at 100 percent load and at ISO conditions of 59° F and 60 percent relative humidity and include emissions from the duct burner. PTE also includes emissions from the operation of the emergency generator and the emergency fire pump.
[b]Based on a natural gas sulfur content of 2 grains/100 standard cubic feet (scf).
[c]Includes the effects of SO_2 oxidation and formation of ammonium sulfates.
[d]Includes front and back half PM/PM_{10} emissions from Unit 4. In addition, includes the noncombustion particulate emissions from the operation of the cooling tower.
[e]Includes the effects of SO_2 oxidation and assumes 100 percent conversion of SO_3 to SAM.

Note: PTE calculations are provided in a spreadsheet included in Appendix C of Volume 3.

3.4.2 Air Emission Controls for the Combustion Turbine

The use of clean fuel (i.e., natural gas) and combustion controls will minimize air emissions and ensure compliance with applicable emission-limiting standards. The use of natural gas will also minimize emissions of SO_2, SAM, PM/PM_{10}, and other fuel-bound contaminants. Combustion controls will minimize the formation of NO_x and the formation of CO and VOCs by combustor design. Further NO_x reduction will be achieved by use of an SCR system. The combination of these techniques are proposed for Unit 4 and have been determined to represent BACT, based on an evaluation of economic, energy, and environmental impacts. The following subsection summarizes the Air Pollution Control Technology and BACT analysis, which is presented in the PSD permit application, located in Volume 3.

3.4.3 Best Available Control Technology Summary for the Combustion Turbine

BACT review is required under FDEP and US Environmental Protection Agency (EPA) regulations pertaining to PSD. BACT is applicable to all pollutants for which PSD review is required and is pollutant specific. It is an emission limitation that is based on the maximum degree of reduction for each regulated pollutant, which is determined to be appropriate after taking into account energy, environmental, economic impacts, and other costs. BACT cannot be any less stringent than the federal New Source Performance Standards (NSPS) applicable to the source under evaluation. For Unit 4, BACT is applicable for emissions of NO_x, CO, PM, PM_{10}, SO_2, and SAM. The emissions of VOC did not exceed the thresholds for PSD review, and therefore, do not warrant a BACT analysis.

3.4.3.1 Nitrogen Oxides. Dry low NO_x combustor technology has been offered and installed by combustion turbine manufacturers to reduce NO_x emissions by inhibiting thermal NO_x formation by premixing fuel and air prior to combustion and providing pre-mix combustion to reduce flame temperatures. The GE PG7241FA DLN combustion turbine produces NO_x emissions of 9.0 parts per million by volume dry (ppmvd), corrected to 15 percent O_2 for new combustion turbines firing natural gas.

NO_x emissions from Unit 4 will be controlled using state-of-the-art dry, low NO_x combustors in the combustion turbines when firing natural gas. To further reduce emissions of NO_x, an SCR system will be installed within the HRSG. The SCR system is designed for reduction of flue gas NO_x emissions to 2.0 ppmvd at 15 percent O_2.

Ammonia will be required for use in the SCR. Vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed, which is installed in the HRSG. The onsite ammonia system will include unloading facilities, an ammonia storage tank, forwarding system, and vaporizing facilities.

Aqueous ammonia will be used, and delivered to the site by tanker trucks that include integral unloading pumps. The aqueous ammonia (19 percent solution) will be stored as a liquid in a nominal 40,000 gallon tank large enough for four full tanker truck deliveries. The liquid ammonia will be forwarded to the HRSG, vaporized, and injected upstream of the catalyst.

3.4.3.2 Carbon Monoxide. The combustion turbine will utilize advanced combustion technology and good combustion control to minimize CO emissions. Proposed CO emission rates are consistent with those recently established as BACT.

3.4.3.3 Sulfur Oxides (SO_2 and H_2SO_4 Mist). The only reasonable SO_2 and SAM control method for combined cycle facilities is the use of clean fuels (i.e., natural gas).

3.4.3.4 Particulate Matter and Other Regulated Pollutants. Clean-burning fuel (i.e., natural gas) having low PM and trace contaminant contents is being proposed as BACT for Unit 4. PM emissions will be emitted from the mechanical draft cooling tower in the form of drift. Cooling tower drift will be controlled through the use of high efficiency mist eliminators designed to limit drift to 0.0005 percent of the circulating water flow rate of the cooling tower.

3.4.4 Design Data for Control Equipment

Design data for the air pollution control equipment is presented in Volume 3 (PSD Application). Emissions of other pollutants from Unit 4 are expected to be minimal and require no additional control technology. Therefore, analysis of alternative emission controls for these other pollutants is not necessary.

3.4.5 Design Philosophy

Unit 4 minimizes air pollutant emissions by using efficient generating and pollution prevention technologies. This concept has been incorporated with the selection of a combined cycle process utilizing advanced combustion turbines. Combined cycle plants can be expected to achieve fuel conversion rates on the order of 7,000 British thermal units (Btu)/kilowatt-hours (kWh), as opposed to values in the 9,000 to 10,000 Btu/kWh range for more conventional generating plants. This is an improvement of about 30 percent. Thus, by maximizing the MW output per unit of fuel consumed, the air pollutant emissions per MW output are minimized. Pollution prevention is incorporated in the design by the use of clean fuels, efficient combustion technology, and post-combustion control. Natural gas will be used at the facility for the Unit 4, and ULSFO for the emergency equipment. Moreover, advanced dry low NO_x combustion technology will minimize NO_x emissions during the combustion process while ensuring that CO emissions are within accepted limits. SCR will be installed post-combustion to further reduce NO_x emissions. Taken together, these design features will make Unit 4 one of the most efficient and least polluting power producers in the state of Florida.

3.5 Plant Water Use

In an effort to use Florida's water resources efficiently and minimize the quantity of ground water withdrawals requested for Unit 4, FMPA and KUA propose to use water from several sources. Treated sewage effluent (reuse water) will be used as the primary source for cooling tower makeup water, the largest single use of water for Unit 4 and facility operation. KUA has an agreement with Toho for the delivery, use, and return of this reuse water. The existing Toho reuse water supply pipeline in the CIPP area has adequate capacity to provide the required makeup water flow. The existing onsite pipelines appear to have adequate capacity, but a new supply line along the plant access road may be required. If a new supply line is installed, the existing supply line may be converted to a return line.

Unit 4 potable, service, and fire protection water will be supplied from the existing and proposed wells located on the CIPP site. Upgrades to the existing chlorination equipment will be required.

FMPA and KUA request the use of 2.786 mgd of ground water as an emergency source of cooling tower makeup for a total of 30 days per year in the event Toho is unable to supply reuse water. Although this scenario is unlikely, and has occurred only rarely in the past, the ground water withdrawals will be used to maintain power generation. Four new 500 gpm onsite wells are requested to provide the emergency water supply for cooling tower makeup. The wells will be sized so that all of the wells will be required to provide the required water flow at full load conditions. The CIPP site is currently authorized for maximum withdrawal of 2.865 mgd for 30 days for emergency makeup to the existing Unit 2 and 3 cooling towers. These new wells, in combination with the existing four wells, will be used to supply the presently authorized withdrawals and the requested withdrawal needs for Unit 4, which together total 5.651 mgd for CIPP Units 2 through 4. The cooling water is used to condense steam from the STGs. The STG of Unit 4 is slightly larger in capacity than the combined capacity of Units 2 and 3.

Process water demand for Unit 4, excluding cooling tower makeup, will be approximately 134,000 gpd. The site is currently authorized a maximum withdrawal of 780,000 gpd for 30 days. A new 250 gpm well, in combination with the existing two 200 gpm wells, will supply the present authorized withdrawals and the maximum withdrawal needs for Unit 4, which total 914,000 gpd for CIPP Units 1 through 4.

Maximum reuse water demand for Unit 4 cooling tower makeup will be approximately 2.8 gpd. Typical water quality of the reuse water is provided in Table 3.5-1 which meets all of the requirements of Chapter 62-610, Part III, of the FAC. Floridan Aquifer ground water is requested as the source of cooling tower makeup emergency supply for up to 30 days per year in the event that reuse water is unavailable due to events such as disruptions in the water supply from the sewage treatment plant, water quality upsets, or outages in the transfer pump and piping system.

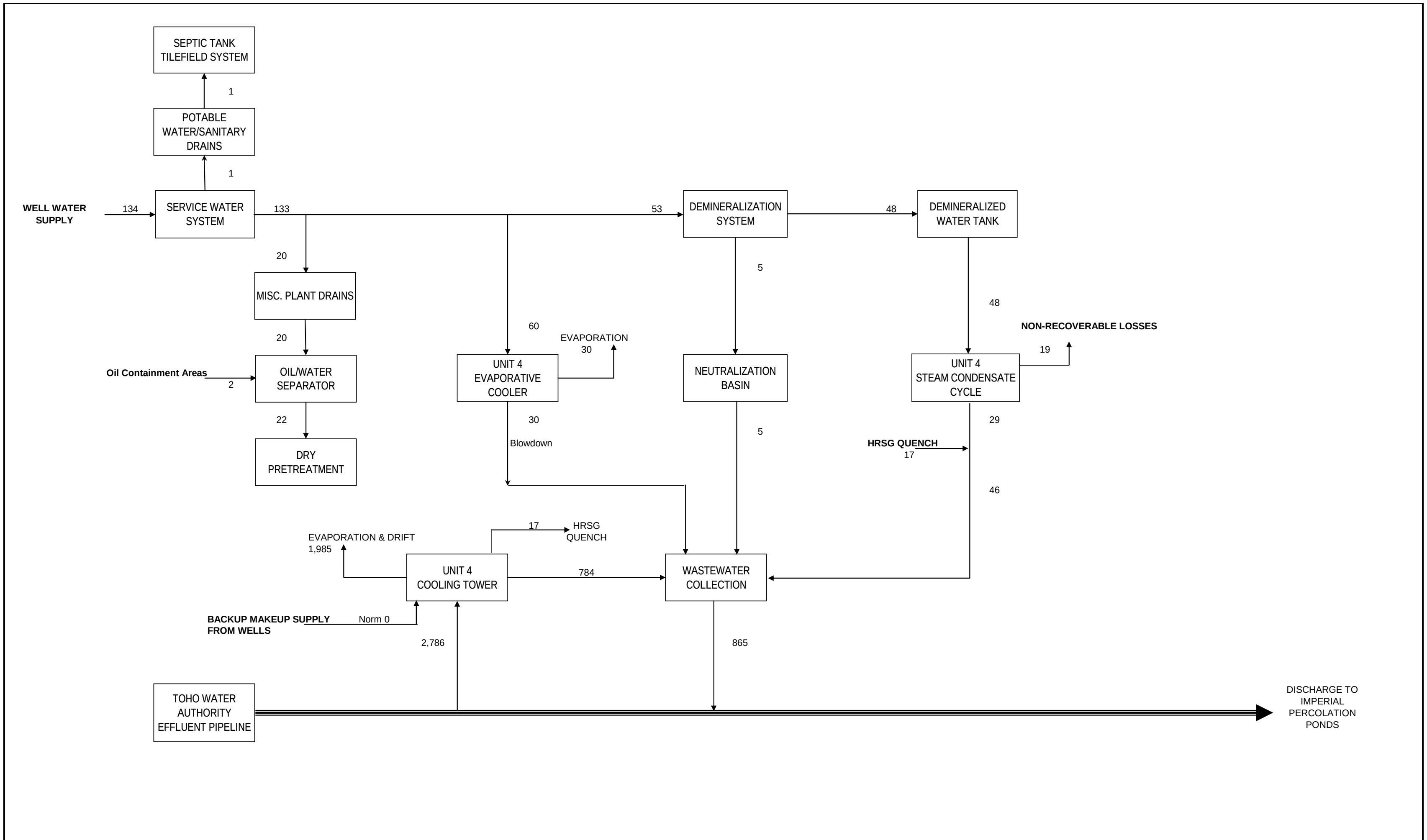
Table 3.5-1
Typical Water Quality of
Reuse Water and Well Water Supplies

Constituent	Reuse Water*	Well Water**
Calcium, mg/L as Calcium Carbonate ($CaCO_3$)	115	68
Magnesium, mg/L as $CaCO_3$	43	29
Sodium, mg/L as $CaCO_3$	156	6
Potassium, mg/L as $CaCO_3$	22	1
Alkalinity, mg/L as $CaCO_3$	131	70
Sulfate, mg/L as $CaCO_3$	35	6
Chloride, mg/L as $CaCO_3$	116	10
Silica, mg/L as SiO_2	21	14
Total Dissolved Solids, mg/L	417	119

*Based on samples taking of the present reuse water inflow to CIPP during June 2007.
**Based on data from existing Floridan Aquifer Wells 1 and 2 onsite.

In addition to the reuse water and well water sources, a tie-in may be made to the Toho raw water pipeline supplying the CIPP site. In accordance with the Toho and KUA agreement, this water may also be used for the service water/fire water system, cooling water system, and a short-term emergency supply to the cooling water makeup system.

Water mass balance diagrams depicting the natural gas case that results in average water consumption for Unit 4 and all units are shown on Figures 3.5-1 and 3.5-2, respectively. Figure 3.5-3 shows the expected water usage with Unit 4 operating on natural gas and Units 1 to 3 operating on fuel oil to show the maximum expected water usages at full load and average ambient conditions.



NOTE:	COMBUSTION TURBINE FUEL	Natural Gas			BLACK & VEATCH LLP		KISSIMMEE UTILITY AUTHORITY	Project	Drawing	Rev
1. FLOWS ARE IN 1000 GALLONS PER Day (gpd).	GROSS UNIT 4 OUTPUT (MW)	327.4	DEMINERALIZER EFFICIENCY	90%			CANE ISLAND POWER PARK	147651	WMB-1	0
2. FLOWS DO NOT INCLUDE UNITS 1-3	UNIT 4 TURBINE CONFIGURATION	1 x 1	CYCLE MAKEUP RATE	2.00%			UNIT 4 WATER MASS BALANCE			
	AMBIENT TEMP (ºF)	73	LOAD FACTOR	100%	Eng: KRW	Dwg: KRW				
	DUCT FIRING UNIT 4	On	CYCLES OF CONCENTRATION	3.5	Check:	Date:	73 ºF AMBIENT, FIRED, 100% LOAD, Gas			

Figure 3.5-1
Water Mass Balance – Unit 4 Operation

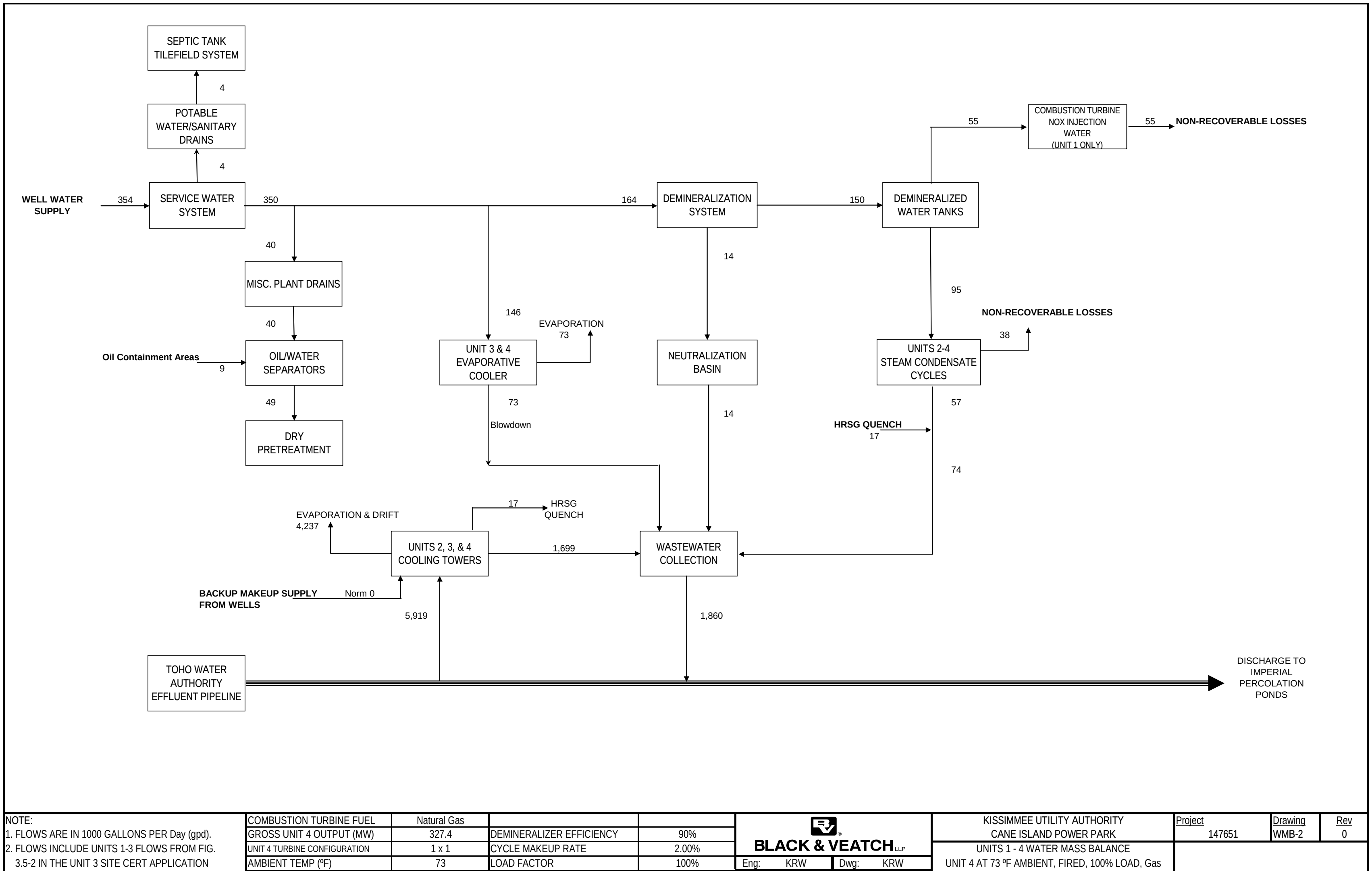
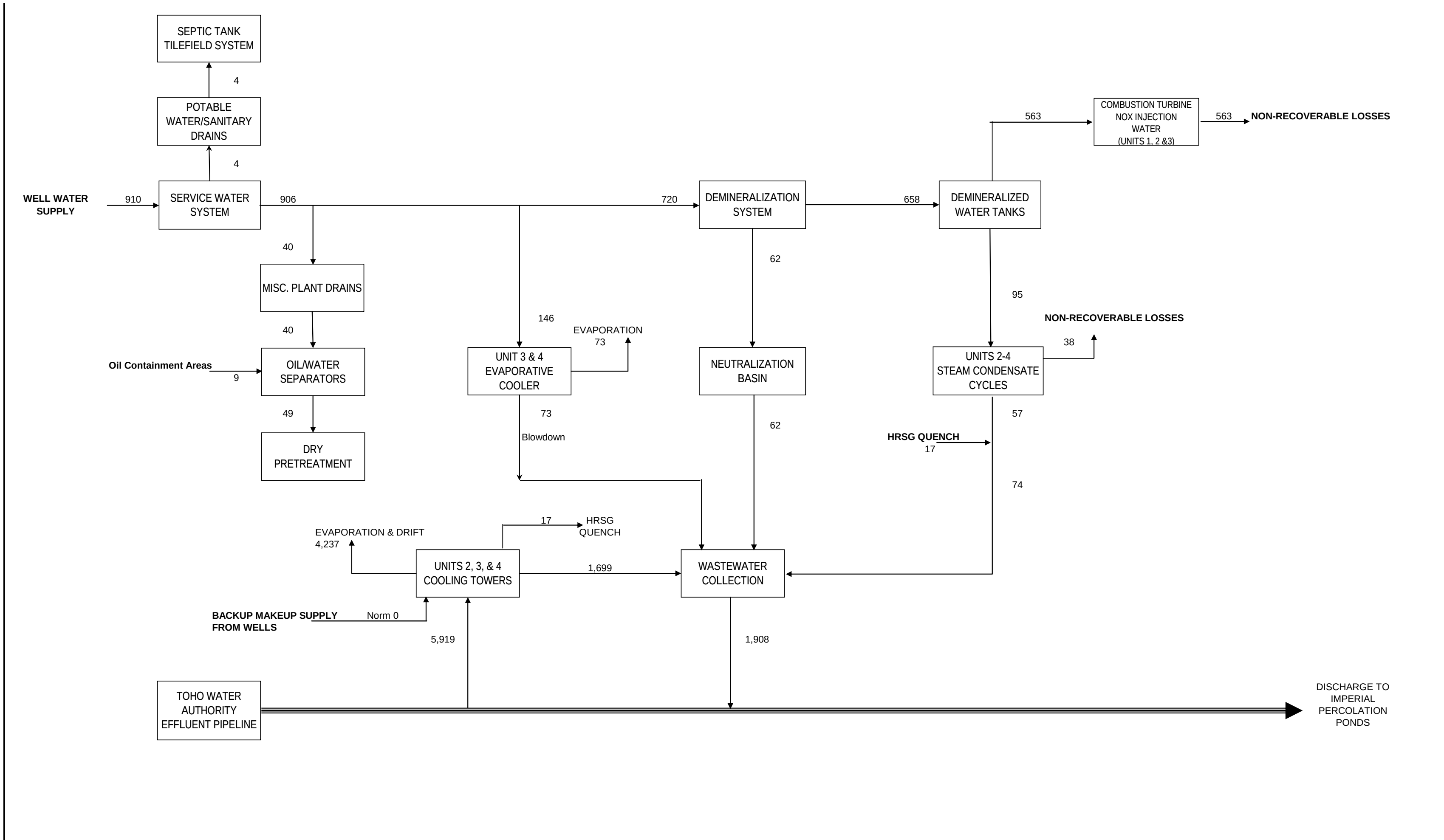


Figure 3.5-2
Water Mass Balance – All Units Operating on Natural Gas



NOTE:								Project	Drawing	Rev
1. FLOWS ARE IN 1000 GALLONS PER Day (gpd).	COMBUSTION TURBINE FUEL	Units 1-3 Oil, Unit 4 Natural Gas			BLACK & VEATCH LLP		KISSIMMEE UTILITY AUTHORITY			
2. FLOWS INCLUDE UNITS 1-3 FLOWS FROM FIG.	GROSS UNIT 4 OUTPUT (MW)	327.4	DEMINERALIZER EFFICIENCY	90%			CANE ISLAND POWER PARK	147651	WMB-3	0
3.5-4 IN THE UNIT 3 SITE CERT APPLICATION	UNIT 4 TURBINE CONFIGURATION	1 x 1	CYCLE MAKEUP RATE	2.00%			UNITS 1 - 4 WATER MASS BALANCE			
EXCEPT CLG TWR CYCLES ADJUSTED TO 3.5	AMBIENT TEMP (ºF)	73	LOAD FACTOR	100%	Eng: KRW	Dwg: KRW	UNIT 4 AT 73 ºF AMBIENT, FIRED, 100% LOAD, Gas			
	DUCT FIRING UNIT 4	On	CYCLES OF CONCENTRATION	3.5	Check:	Date: 2/13/2007	UNITS 1, 2, & 3 OIL FIRED			

Figure 3.5-3
Water Mass Balance – Unit 4 Operating on Natural Gas, Units 1 to 3 on Fuel Oil

The water mass balances represent operation at 100 percent load conditions during average temperatures. Actual average annual flows will be less, dependent upon the electrical loading of the generators and ambient temperature. Maximum flows for cooling tower makeup will be more (up to approximately 10 percent) depending on the ambient temperature and humidity.

3.5.1 Heat Dissipation System (Cooling Towers)

Waste heat from the Unit 4 steam turbine condenser and auxiliary cooling system will be rejected to the atmosphere by a cooling cycle using linear mechanical draft cooling towers. The primary source of cooling water makeup will be reuse water from Toho. The estimated maximum cooling water makeup to Unit 4 is approximately 2.8 mgd at full load and average ambient conditions.

Cooling tower blowdown will be returned to the Toho reuse water pipeline for downsteam reuse or disposal. The wastewater return to the Toho system from Unit 4 is estimated to be 865,000 gpd at full load and average ambient conditions.

3.5.1.1 Dilution System. The CIPP Unit 4 project does not propose the use of a cooling water stream dilution system.

3.5.1.2 Blowdown, Screened Organisms, and Trash Disposal. Cooling tower blowdown will be returned to Toho reuse water pipeline. No biological organisms or trash will be present in the blowdown.

3.5.1.3 Injection Wells. The CIPP Unit 4 project will not install any injection wells.

3.5.2 Domestic/Sanitary Wastewater

Domestic/sanitary wastewater is generated by showers, lavatories, sinks, toilets, urinals, and drinking fountains. It is estimated that there will be two new permanent Unit 4 employees at the site who will generate approximately 80 gpd of sanitary wastewater. Sanitary wastes will be routed to an existing septic tank/tile field system on the CIPP site.

3.5.3 Potable Water System

Potable water uses will include showers, lavatories, sinks, toilets, urinals, eye wash stations, and drinking fountains. The existing potable water treatment system will be modified to treat the additional water from the new well. Onsite facilities will be in accordance with Chapter 62-555, FAC. The typical well water chemical analysis from the existing wells is indicated in Table 3.5-1. An extension of the potable water system will be provided to the new Miscellaneous Services Building and Power Distribution Center to supply eye wash stations.

3.5.4 Process Water Systems

Service/process water will be obtained from the service/fire water tank for washdown purposes, pump and equipment seal water and flushing, evaporative cooler makeup, and cycle makeup treatment system water supply. The major systems and uses are indicated on the water mass balances.

Demineralized water will be required for use as makeup to the steam-condensate-feedwater cycle associated with the HRSGs. The makeup is required to replace cycle losses and boiler blowdown. Demineralized water will be supplied by the existing demineralization system. The present system is an ion exchange demineralizer system that treats service water. As water passes through the system, it is progressively demineralized until the effluent contains essentially no dissolved solids. Exhausted ion exchange is regenerated using sulfuric acid and sodium hydroxide. The resulting chemical wastewater flows are treated as described in Section 3.6. A new 1 million gallon demineralized water storage tank will be installed for Unit 4. The tank will be filled from the existing demineralized water storage and supply system.

Fire water will be obtained from well water via the existing service water system. There will be two new 500,000 fire/service water storage tanks, with 300,000 gallons dedicated to fire water in each tank. Two new fire water pumps (one electric motor driven and one diesel engine driven) will provide water by means of an underground piping loop which serves fire hydrants, hose racks and reels, and automatic suppression systems. The Unit 4 underground piping loop will be interconnected to the existing underground loop piping.

3.5.5 Water Use Variations

All water requirements described in the preceding sections are based on operation of the facility at 100 percent load and average annual ambient conditions. When the units operate at less than 100 percent load, the evaporation rate from the cooling towers, and consequently the cooling tower makeup and blowdown rates, will vary proportionately. There are also smaller variations in cooling tower evaporation resulting from ambient conditions such as temperature and humidity. Cooling tower makeup (reuse water) is the major water use.

Demineralized water used as makeup to the steam cycle also generally varies proportionately to unit loading. Evaporative cooler operation is dependent upon the ambient temperature and humidity conditions as well as unit load. The balance of water uses will be basically independent of the operating load.

In the event of temporary unit shutdown, no main cooling tower or steam cycle makeup will be required, but other systems may continue to operate.

3.6 Chemical and Biocide Waste

The Unit 4 startup and operations will require the use of different chemical and biocides. Chemicals are used in the steam cycle water treatment, the cycle makeup water treatment, and as cleaning agents. Biocides are used in the cooling tower to prevent bacterial growth. Chemicals or biocides may be present in the sanitary wastewater, the oil/water separator effluent, evaporative cooler blowdown, and the cooling tower blowdown. These waste streams are shown on the water mass balances.

3.6.1 Cooling Tower Blowdown

The cooling tower blowdown will be transferred via the existing pipeline to the Toho reuse water pipeline. Chemicals used in cooling tower water treatment will include sulfuric acid for alkalinity reduction (pH adjustment), sodium hypochlorite solution for biological control, and feed of a commercial scale inhibitor. Capability is also included for feed of a commercial non-oxidizing biocide to supplement chlorination for biological control.

3.6.2 Sanitary Wastes

Sanitary wastes will be collected and treated by an existing septic tank/tile field system on the CIPP site.

3.6.3 Steam Cycle Water Treatment

The steam cycle water will be treated with an oxygen scavenger for dissolved oxygen control and with an amine, such as ammonia solution, for pH control. The oxygen scavenger will break down to ammonia at the system operating temperature. A phosphate solution will be fed to the HRSG for control scaling, corrosion, and boiling water pH in the steam generator. The phosphate will react with any calcium hardness in the steam generators to form a non-adherent precipitate.

Boiler blowdown will be relatively high purity water with small amounts of suspended solids and phosphate. Boiler blowdown will be routed to a sump, where it will be quenched using cooling tower water, and then routed along with the cooling tower blowdown to the existing pipeline to the Toho reuse water pipeline.

A condensate polisher will be installed in the condensate system to reduce the time needed to achieve the required water quality during startups. The polisher with be of the powdered resin type. The resin will be renewed through a precoat process. Wastewater from the process will consist of condensate quality water with spent precoat material and will be filtered and then routed to blowdown sump for return to the Toho pipeline.

3.6.4 Cycle Makeup Water Treatment

As discussed in Subsection 3.5.4, the makeup water to the steam cycle will be generated by additional operation of the existing demineralization system which consists of ion exchange resin beds. The demineralization system uses sulfuric acid for cation resin regeneration and sodium hydroxide for anion resin regeneration. The sulfuric acid and sodium hydroxide are stored in tanks located in curbed concrete containment areas in or near the treatment areas. Any spillage of chemicals in the curbed areas is routed to the neutralization basin for treatment. The use of these chemicals is dependent on demineralized water requirements.

Wastewater from the cation resin regeneration includes regenerant water containing unreacted sulfuric acid and dissolved sulfate salts of cations removed from the resin during regeneration. Wastewater from anion resin regeneration includes regenerant water containing unreacted sodium hydroxide and dissolved sodium salts of anions removed from the resin during regeneration.

The estimated increase in regenerate waste with the addition of Unit 4 will be a maximum of approximately 5,000 gpd. The additional demineralizer regenerant wastes will be routed to the existing neutralization basin, as described in Subsection 3.6.7, for pH adjustment prior to discharge to the Toho reuse pipeline.

3.6.5 Chemical Cleaning Wastes

The Unit 4 HRSG and preboiler piping will be chemically cleaned during commissioning. The steam generator will also be cleaned infrequently during the life of the unit. Chemicals used for these cleanings will not be stored onsite and will be administered utilizing a temporary system. The chemical cleaning solutions to be used for cleaning of the HRSG will be dependent to a limited extent on the HRSG manufacturer. Chemicals typically used in HRSG and preboiler piping chemical cleaning include the following:

- Inhibited citric acid.
- Disodium phosphate.
- Trisodium phosphate.
- Nonfoaming wetting agents.
- Foam inhibitors.
- Chelates, such as EDTA (ethylenediaminetetraacetic acid).

Chemical cleaning wastewaters will consist of the cleaning solutions and material removed during the cleaning process. Since chemical cleaning is a maintenance operation, it will not contribute to the liquid wastes produced by the normal operation of the plant. Cleaning solutions will be neutralized onsite if required and transported offsite by a licensed waste disposal contractor.

3.6.6 Miscellaneous Chemical Drains

Chemical wastewater can result from draining a chemical storage tank, overflowing a chemical tank during filling, or from maintenance operations such as hosing down chemical storage areas. Any additional miscellaneous chemical drains will be contained for neutralization, if necessary, and disposed to the existing plant wastewater system. Large chemical leaks will be scavenged and disposed offsite by a licensed commercial service. Flows from miscellaneous chemical drains will be intermittent and will not normally contribute to the wastewater flows.

3.6.7 Neutralization Basin

An existing neutralization basin provides for treatment of chemical wastes prior to discharge to the Toho reuse pipeline. The basin accommodates the wastewaters produced during the regeneration of the makeup demineralizer. The neutralization basin is constructed of reinforced concrete with chemical resistant liner. A chemical waste mixer, mounted on a walkway spanning the basin, is provided to hasten the pH adjustment of the chemical wastes. Sulfuric acid and sodium hydroxide, as required for neutralization, are available from the makeup demineralizer regeneration equipment. Neutralized water is directed to the Toho reuse pipeline.

3.7 Solid and Hazardous Waste

Unit 4 will not generate any solid waste, such as combustion ash or flue gas desulfurization scrubber waste, from the electric generation process. The firing of natural gas does not create significant combustion byproducts. CIPP operations will not require any onsite landfills or solid waste disposal areas. The existing commercial trash services will be contracted to haul off typical solid wastes that result from plant operations, such as increased office debris.

Waste oil is the major potentially hazardous substance generated by plant operation. Two processes generate waste oil: combustion turbine cleaning and oil/water separator operation. The internal components of the combustion turbines are periodically cleaned using a solvent solution. This wash water may contain oily residues and metal particles. The wash water is collected in an underground combustion turbine drain tank and hauled offsite as needed by a licensed contractor for ultimate disposal.

Oily wastewaters that are generated will be conveyed to the oil/water separator. Waste oil collected in the oil/water separators will be hauled offsite as needed by a licensed contractor for ultimate disposal.

Small quantities of other hazardous wastes, such as paints and cleaners, are used in maintenance and will be segregated from the plant drainage system and disposed offsite to a licensed contractor.

Spent SCR modules will be removed from the CIPP by a licensed contractor.

3.8 Onsite Drainage System

3.8.1 Uncontaminated Areas

The existing geographic feature known as Cane Island is fairly flat and is crowned in the center. Generally, the existing drainage is directed in easterly and westerly directions into Reedy Creek Swamp. Storm water runoff from the existing Units 1 and 2 area is directed to an existing storm water pond. Storm water runoff from existing Unit 3 and Unit 4 will be directed to a separate, modified storm water pond.

The onsite drainage facilities will be designed in accordance with the requirements of the SFWMD Chapter 40 E-4 and Basis of Review, Chapter 7.0 Water Management System Design and Construction Criteria and the FDEP regulations in Chapter 62-621, FAC. Open channels and drainage structures (culverts, trench drains) will be designed to collect and direct the runoff resulting from a 25 year, 72 hour storm event. Site runoff facilities (i.e., ditches, detention basin) will provide storage to satisfy criteria for maintenance of water quality and quantity, and to provide storage to attenuate peak discharge rates.

The requirements for quality treatment include retention of the first inch of runoff from the developed portions of the site. This volume will be provided in the onsite storm water detention basin. The 1/2 inch of the retained runoff and direct precipitation on the onsite storm water detention basin will percolate from the basin in less than 24 hours due to the highly permeable soils.

The requirements for quantity treatment include the limitation that the post-development peak discharge does not exceed the predevelopment peak discharge. The detention basin will assist in attenuating the peak discharge flows from the developed site to meet this requirement.

Runoff from areas of the site not disturbed by construction activities or plant operations will be maintained in the existing state to the greatest extent possible. Runoff from areas of the site disturbed by construction activities or plant operations will be collected in a ditch system and directed to the onsite detention basin as described below. Drainage systems will be designed for gravity flow wherever site conditions allow. Generally, the drainage in the areas of the new unit will be directed away from the structures and routed to the onsite storm water detention basin. Figure 3.8-1 indicates the general flow paths at the CIPP site once construction is completed.

3.8.2 Drainage Areas

Limited construction will be required in the existing Unit 3 area. In this area, the existing drainage facilities will be used as much as possible; storm water runoff will continue to be directed to the east to the modified Unit 3 storm water detention basin, now the Units 3 and 4 basin. The existing facilities will be reviewed to ensure that capacities are sufficient to handle any additional impact from the new construction.

Most of the construction will occur in the Unit 4 power block area. A construction lay-down/staging area to the south of the power block will also be used during construction. These areas and the Unit 3 power block will drain into the modified 1.41 acre onsite runoff basin during construction and operation of Unit 4. The combined area of the Unit 3 power block, Unit 4 power block, construction lay-down/staging area, and storm water facilities is approximately 24.2 acres.

The new runoff basin will serve as a dry detention basin to provide both quality and quantity treatment to the storm water. The quality treatment will be accomplished by detention and reduction of suspended solids load. The basin will also provide quantity treatment by providing surge capacity to attenuate the maximum discharge rate into Reedy Creek Swamp.

Again, there will be no source of leachate associated with the CIPP or Unit 4, thereby eliminating this potential pollution source.

3.8.3 Design Criteria

The surface water management and storage of surface waters system will be designed in accordance with the regulations and requirements of Chapter 40E-4, FAC, the SFWMD's *Environmental Resource Permit Information Manual Volume IV (including the Basis of Review)*, and the FDEP's *The Florida Manual--A Guide to Sound Land and Water Management Land Development.* Areas subject to potential contamination of storm water runoff will be designed for zero discharge.

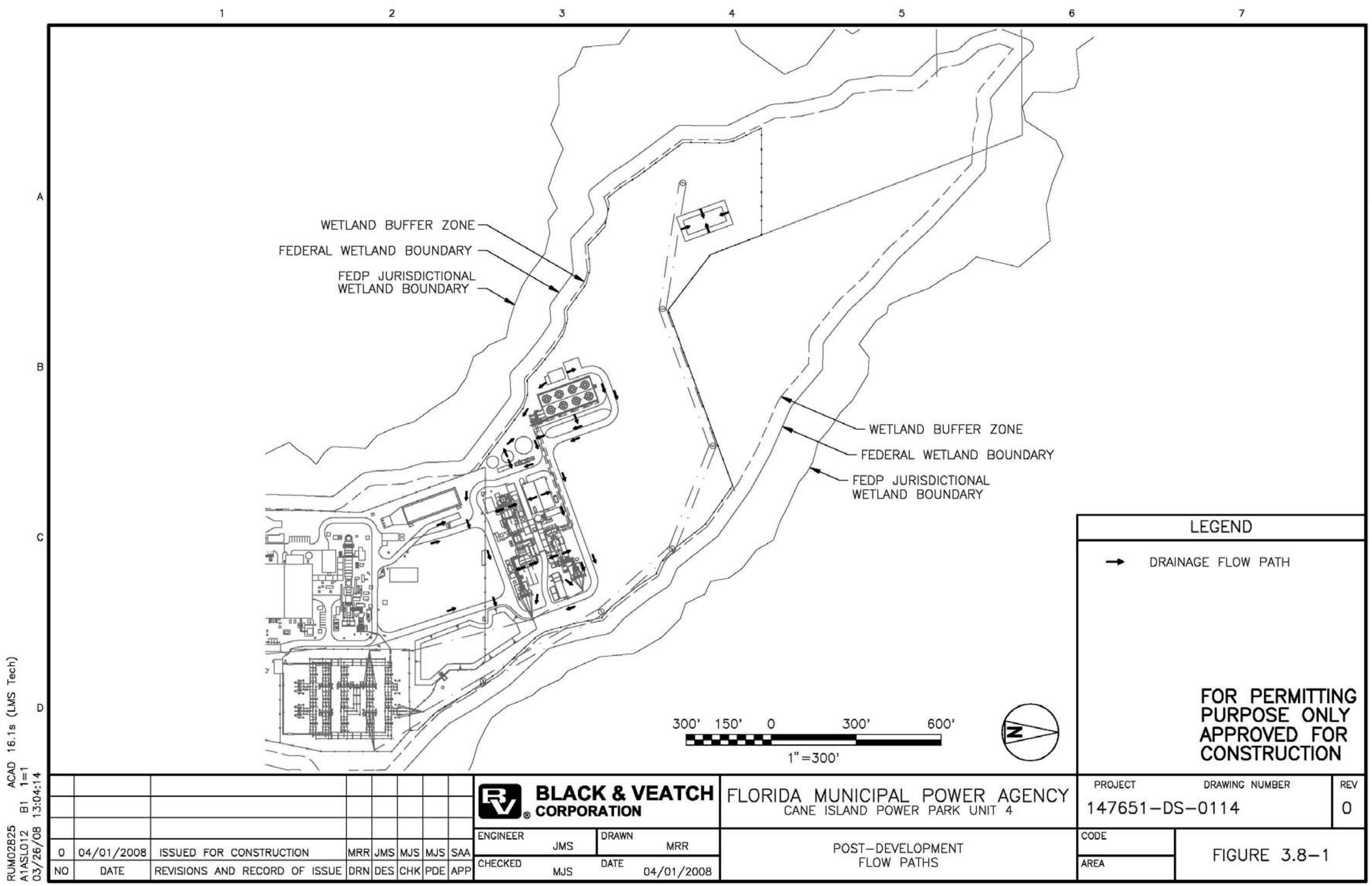


Figure 3.8-1
Preliminary Grading and Drainage

The surface water management system at the site is designed to maintain the existing drainage patterns wherever possible. The existing drainage patterns generally flow to the east or west from the units.

The surface water management system for the developed areas of the CIPP will be designed to ensure that the post-development peak discharge will not exceed that of the predevelopment peak discharge at the project site boundary.

The following design criteria are specified in the SFWMD Permit Manual:

- Design Storm: 25 year, 72 hour.
- Rainfall frequencies obtained from the SFWMD Permit Manual are as follows:
  - 10 year, 24 hour--5.48 inches.
  - 10 year, 72 hour--7.59 inches.
  - 25 year, 24 hour--6.57 inches.
  - 25 year, 72 hour--10.29 inches.
  - 100 year, 72 hour--11.27 inches.
- Rainfall Distribution: SFWMD 72 Hour Synthetic Storm Distribution.
- Outlet structures:
  - Emergency spillways are designed to pass the 100 year recurrence interval storm event.
  - Existing grading and drainage in Units 1, 2 and 3 areas have been permitted by SFWMD.

3.8.4 Runoff Analysis

The area associated with the Unit 3 power block, Unit 4 power block, and construction lay-down/staging area consists of approximately 5.0 acres of aggregate area and 7.9 acres of impervious area. These areas will drain into the modified Unit 3 storm water detention basin. The 25 year, 72 hour rainfall event was used to size the onsite runoff detention basin. The predevelopment curve number (CN) was estimated to be 45.0, with a predevelopment time of concentration of 0.41 hours. The post-development CN and time of concentration were estimated to be 89.5 and 0.13 hours, respectively. The post-development time lag is estimated at 0.08 hour. The curve numbers and time of concentrations were determined using the methods outlined in the Soil Conservation Service TR-55 manual.

The storm water collection system will consist of ditches, drainage structures, and a site runoff detention basin. This system will function as a storm water quality and quantity treatment facility. The quality treatment of runoff will be accomplished through percolation and detention in the site detention basin. Grading and drainage plans (storm water management system) are shown on Figures 3.8-2 through 3.8-5.

KEY PLAN

GENERAL NOTES

1. GENERAL NOTES APPLICABLE TO ALL S3000 SERIES DRAWINGS.
2. THE PLANT GRID SYSTEM USED FOR HORIZONTAL CONTROL IS STATE PLANE COORDINATE SYSTEM, FLORIDA EAST ZONE 901, NAD83.
3. INTERSECTIONS OF PAVED ROADS SHALL HAVE A 40 FOOT TURNING RADIUS MEASURED FROM THE EDGE OF PAVEMENT UNLESS NOTED OTHERWISE. A SMOOTH VERTICAL TRANSITION SHALL BE PROVIDED AT ROAD INTERSECTIONS.
4. THE LOCATIONS OF THE EXISTING FACILITIES AND UNDERGROUND UTILITIES SHOWN ON THIS SERIES OF DRAWINGS REPRESENT THE BEST KNOWLEDGE OF THE ENGINEER. BEFORE ANY WORK IS STARTED IN THE AREA OF THE EXISTING FACILITIES AND UNDERGROUND UTILITIES, THE SUBCONTRACTOR SHALL CONFIRM THEIR LOCATION AND NOTIFY THE OWNER THAT WORK IS PLANNED IN THIS AREA.
5. CONSTRUCTION SEQUENCE SHALL BE SCHEDULED TO MINIMIZE UNCONTROLLED RUNOFF AND OFFSITE SEDIMENTATION DURING GRADING OPERATIONS. SEDIMENTATION BARRIERS SHALL BE INSTALLED IN EACH AREA BEFORE GRADING OPERATIONS BEGIN. GRADED AREAS SHALL BE SEEDED IMMEDIATELY FOLLOWING COMPLETION OF FINAL GRADING IN EACH AREA.
6. SPOT ELEVATION AND CONTOURS ON THESE DRAWINGS ARE TOP OF FINISHED GRADE. SUBTRACT FINISHED SURFACING MATERIAL THICKNESS TO OBTAIN TOP OF SUBRGRADE.
7. GRADE SHALL SLOPE UNIFORMLY BETWEEN SPOT ELEVATIONS AND CONTOURS SHOWN ON THE PLANS. SLOPE GRADE TO DRAIN IN THE DIRECTION OF FLOW ARROWS.
8. THE FINISHED GRADE SHALL BE SET 6 INCHES BELOW TOP OF CONCRETE UNLESS NOTED OTHERWISE. FINISHED GRADE SHOULD SLOPE AWAY FROM THE STRUCTURE AT A MINIMUM SLOPE OF 1% FOR THE FIRST 10 FEET.
9. ALL CUT AND FILL SLOPES SHALL BE 3 HORIZONTAL TO 1 VERTICAL OR FLATTER, UNLESS NOTED OTHERWISE.
10. BUMPER POSTS ARE TO BE FIELD LOCATED.
11. SEE DWG 147651–4STF–S3050 FOR GRADING AND DRAINAGE SECTIONS AND DETAILS.
12. SEE 147651–4STF–S3100 SERIES DRAWINGS FOR THE EROSION CONTROL PLAN AND DETAILS.
13. SEE DWGS 147651–4STA–S1000 AND S1001 FOR SITE ARRANGEMENT.

LEGEND APPLICABLE TO ALL S3000 DRAWINGS

- PROPERTY LINE
- R/W — LIMIT OF RIGHT–OF–WAY
- NEW SECURITY FENCE
- 99 — NEW CONTOUR
- AREA INLET
- NEW STORM WATER SYSTEM
- NEW CULVERT
- GRADE SURFACE FLOW INDICATOR
- 123.45 + — NEW SPOT ELEVATION
- SURVEY CONTROL MONUMENT
- NEW TRENCH DRAIN
- EXISTING FENCE
- 99 — EXISTING CONTOUR
- WETLAND BUFFER ZONE
- OVERHEAD TRANSMISSION LINE
- FDEP JURISDICTIONAL WETLAND BOUNDARY
- ASPHALT SURFACING
- AGGREGATE SURFACING
- CONCRETE
- EARTH
- RIPRAP
- SAND/BEDDING MAT'L
- GRASS
- WETLANDS
- 1 — SECTION OR DETAIL NUMBER
- S3000 — DRAWING DESIGNATION NUMBER

ABBREVIATIONS APPLICABLE TO ALL S3000 DRAWINGS

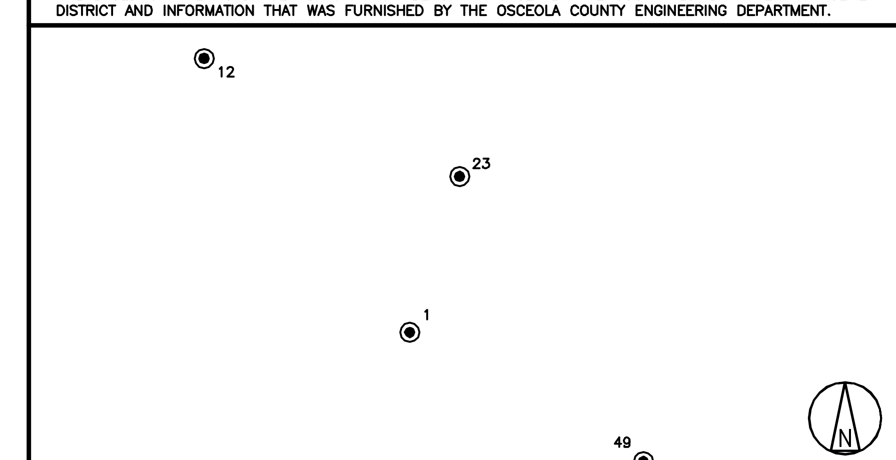
A – ARC LENGTH
AGG – AGGREGATE
APPROX – APPROXIMATE
ASPH – ASPHALT
AVG – AVERAGE
BLDG – BUILDING
B/MH – BOTTOM OF MANHOLE ELEVATION
BOD – BOTTOM OF ELECTRICAL DUCT BANK
BOP – BOTTOM OF PIPE
BU – BELL UP
CHDPE – CORRUGATED HIGH DENSITY POLYETHYLENE PIPE
CJ – CONTRACTION JOINT
CL – CENTERLINE
CMP – CORRUGATED METAL PIPE
CO – CLEAN OUT
D – DEGREE OF CURVE
Δ – DELTA ANGLE OF HORIZONTAL CURVE
DI – DUCTILE IRON
DIA – DIAMETER
DIM – DIMENSION
DWG – DRAWING
E – EAST
EA – EACH
EF – EACH FACE
EGP – EDGE OF PAVEMENT
EGS – EDGE OF SHOULDER
EHH – ELECTRICAL HANDHOLE
EL – ELEVATION
EJ – EXPANSION JOINT
EW – EACH WAY
EXP – EXPANSION
FD – FLOOR DRAIN
FDN – FOUNDATION
FF – FINISHED FLOOR
FG – FINISHED GRADE
FRP – FIBER REINFORCED PIPE
FT – FOOT
HC – HANDICAPPED
HDPE – HIGH DENSITY POLYETHYLENE
HVCM – HORIZ & VERT CONTROL MONUMENT
HP – HIGH POINT
ID – INSIDE DIAMETER
IN – INCH
INV – INVERT
L – LENGTH
LC – LENGTH OF VERTICAL CURVE
LS – LIFT STATION
LTR – LATER
MATL – MATERIAL
MH – MANHOLE
MSL – MEAN SEA LEVEL
MW – MONITORING WELL
N – NORTH
NO. – NUMBER
NTS – NOT TO SCALE
OD – OUTSIDE DIAMETER
OWS – OIL/WATER SEPARATOR
PC – POINT OF CURVATURE
PE – PLAIN END
PI – POINT OF INTERSECTION
PL – PROPERTY LINE
PLCS – PLACES
PRC – POINT OF REVERSE CURVE
PT – POINT OF TANGENT
PVC – POINT OF VERTICAL CURVE
PVI – POINT OF VERTICAL INTERSECTION
PVT – POINT OF VERTICAL TANGENT
R – RADIUS
RCP – REINFORCED CONCRETE PIPE
RD – ROOF DRAIN
RED – REDUCER
REQ'D – REQUIRED
REV – REVISION
R/W – RIGHT–OF–WAY
S – SOUTH
SE – SUPERELEVATION
SIM – SIMILAR
STA – STATION
T – TANGENT LENGTH
TMH – TOP OF MANHOLE
TOC – TOP OF CONCRETE
TOG – TOP OF GRATING
TOP – TOP OF PAVEMENT
TYP – TYPICAL
UNO – UNLESS NOTED OTHERWISE
V – DESIGN SPEED
VERT – VERTICAL
W – WEST
W/ – WITH
W/O – WITHOUT
WP – WORK POINT

PROJECT SURVEY CONTROL

CONTROL MONUMENT LOCATIONS

MONUMENT NO.	STATE PLANE COORDINATES		ELEVATION
	EASTING	NORTHING	
1	484,953.765	1,432,348.949	78.05
12	482,882.646	1,435,905.858	73.59
23	485,217.602	1,433,848.406	74.15
49	487,224.814	1,430,143.646	71.39

NOTE:
BENCHMARKS ARE 5' x 12"Ø CONCRETE MONUMENTS WITH BRASS DISC IN THE TOP. HORIZONTAL CONTROL IS BASED ON THE FLORIDA STATE PLANE COORDINATE – EAST ZONE (1983/90 N.A.D.) SYSTEM. THE ELEVATIONS ARE BASED ON THE NGVD 1929 DATUM FROM BENCHMARKS SET BY THE SOUTH FLORIDA WATER MANAGEMENT DISTRICT AND INFORMATION THAT WAS FURNISHED BY THE OSCEOLA COUNTY ENGINEERING DEPARTMENT.



FOR PERMITTING PURPOSE ONLY APPROVED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0	04/01/2008	ISSUED FOR CONSTRUCTION	MRR	JMS	MJS	MJS	SAA

N

100' 50' 0 100' 200'
SCALE: 1"=100'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED ______
DATE ______ REG NO. ______

BLACK & VEATCH CORPORATION
ENGINEER JMS | DRAWN MRR
CHECKED MJS | DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4

GRADING AND DRAINAGE – SITE
GENERAL NOTES, ABBREVIATIONS AND LEGEND

PROJECT DRAWING NUMBER 147651–4STF–S3000 | REV 0
CODE
AREA

FIGURE 3.8–2

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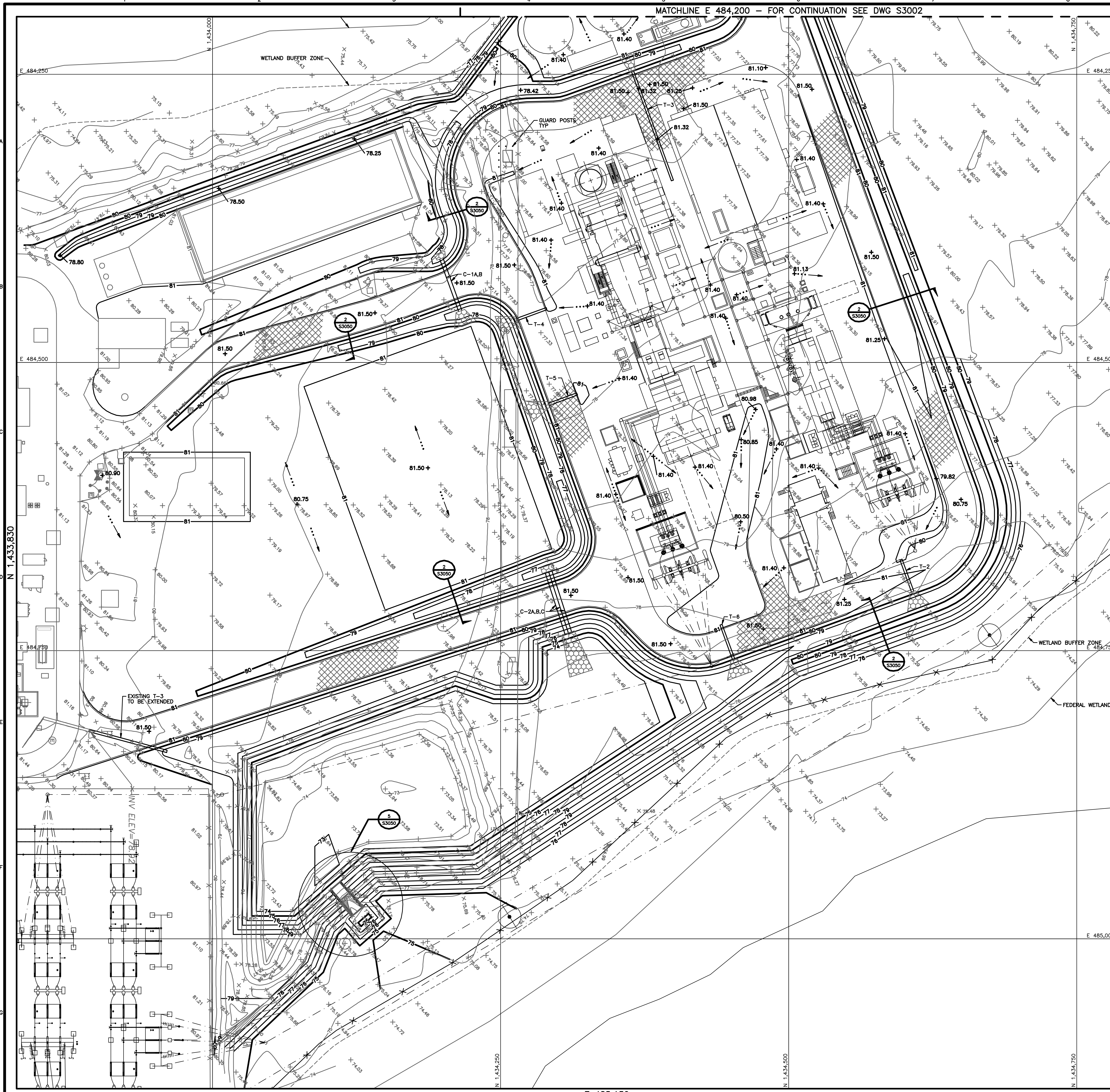
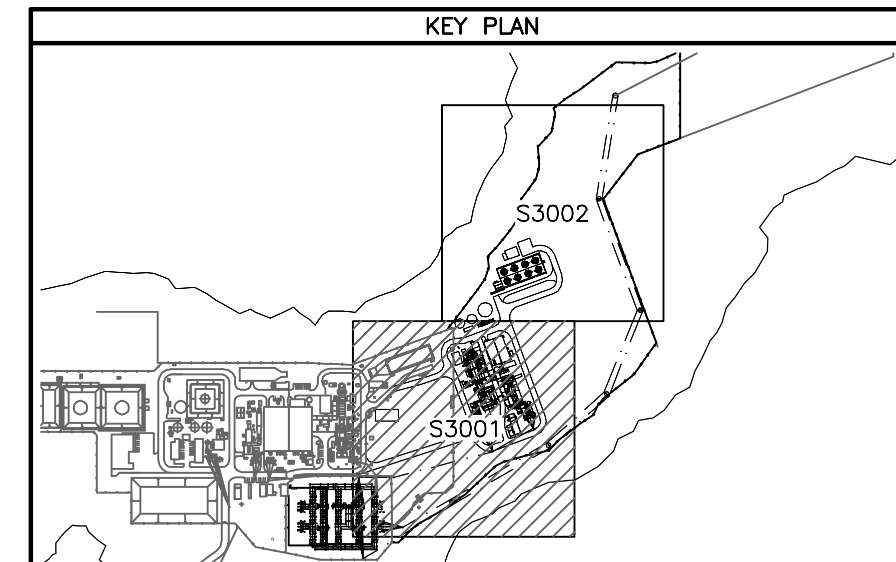




NOTES

1. SEE DWG S3000 FOR GENERAL NOTES, LEGEND, ABBREVIATIONS AND KEY PLAN.

FOR PERMITTING PURPOSE ONLY
APPROVED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0	04/01/2008	ISSUED FOR CONSTRUCTION	MRR	JMS	MJS	MJS	SAA

SCALE: 1"=30'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE REG NO.

BLACK & VEATCH CORPORATION

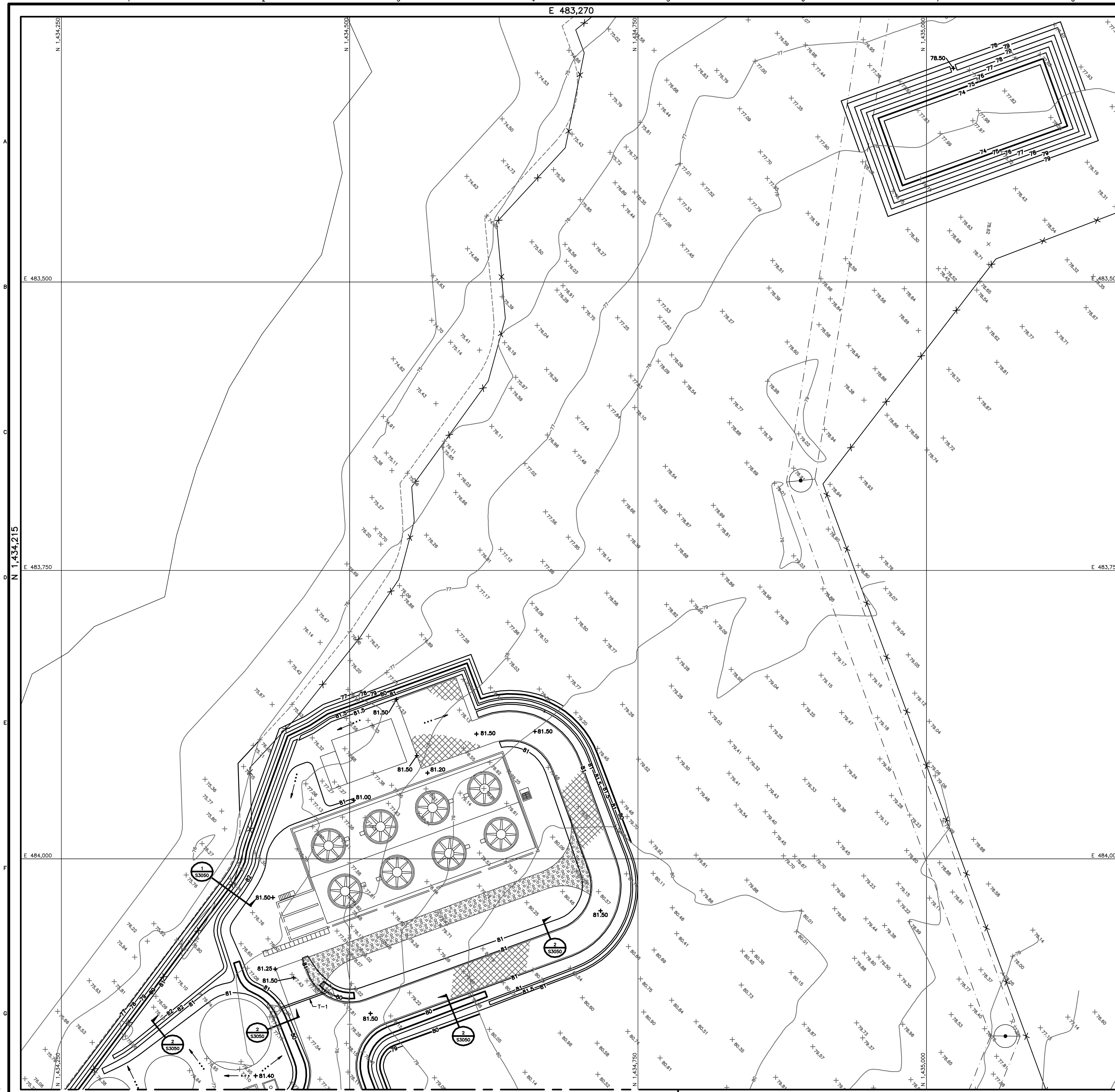
ENGINEER JMS | DRAWN MRR
CHECKED MJS | DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4

GRADING AND DRAINAGE – SITE
SHEET 1

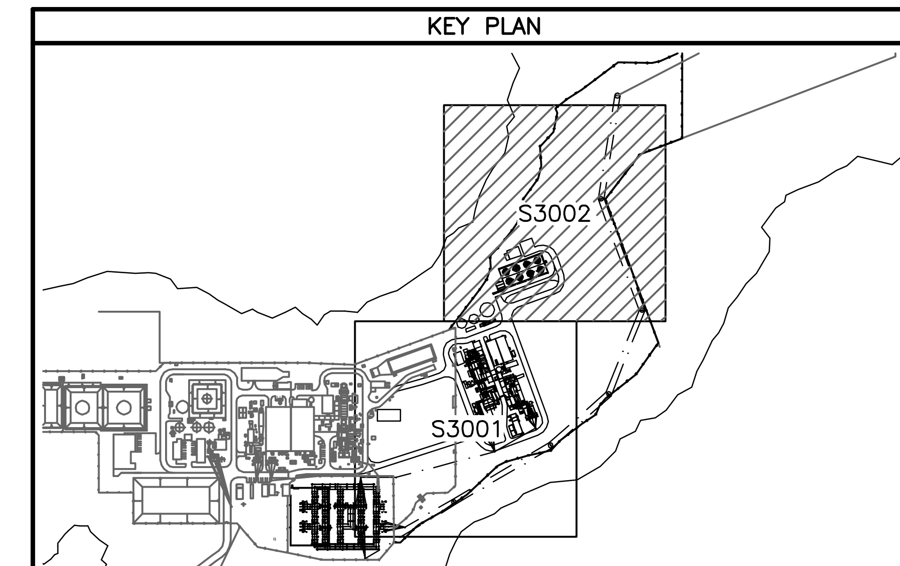
PROJECT / DRAWING NUMBER: 147651-4STF-S3001 REV 0

FIGURE 3.8-3



MATCHLINE E 484,200 – FOR CONTINUATION SEE DWG S3001

KEY PLAN



NOTES

1. SEE DWG S3000 FOR GENERAL NOTES, LEGEND, ABBREVIATIONS AND KEY PLAN.

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NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
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SCALE: 1"=30'

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DATE ______ REG NO. ______

BLACK & VEATCH CORPORATION

ENGINEER JMS | DRAWN MRR
CHECKED MJS | DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4

GRADING AND DRAINAGE – SITE
SHEET 2

PROJECT / DRAWING NUMBER: 147651-4STF-S3002 | REV 0

CODE
AREA

FIGURE 3.8-4

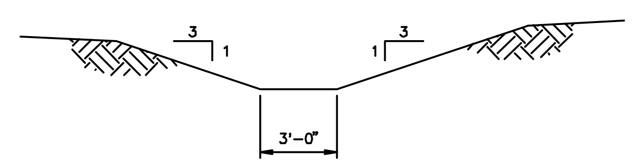
RUM02825 E1 ACAD 16.1s (LMS Tech)
A1ASL017 1=1
03/26/08 08:59:35

CULVERT TABLE

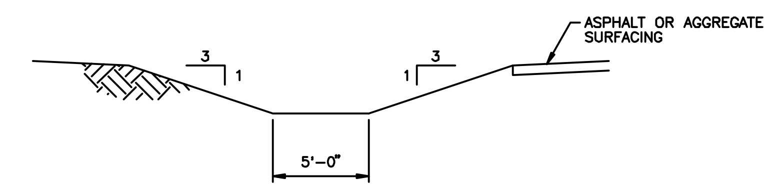
CULVERT NO.	CENTERLINE COORDINATES – INLET END – NORTH	CENTERLINE COORDINATES – INLET END – EAST	CENTERLINE COORDINATES – OUTLET END – NORTH	CENTERLINE COORDINATES – OUTLET END – EAST	LENGTH	INLET INV ELEVATION	OUTLET INV ELEVATION	END TYPE	PIPE DIAMETER	NUMBER OF BARRELS	PIPE MATERIAL
C-1A	1434199.95	484409.35	1434216.50	484454.82	48.4'	77.75	77.50	PROJECTING	24"	1	CHDPE
C-1B	1434197.13	484410.38	1434213.68	484455.85	48.4'	77.75	77.50	PROJECTING	24"	1	CHDPE
C-2A	1434294.38	484680.29	1434311.58	484733.58	56.0'	76.75	76.33	PROJECTING	24"	1	CHDPE
C-2B	1434291.52	484681.21	1434308.72	484734.50	56.0'	76.75	76.33	PROJECTING	24"	1	CHDPE
C-2C	1434288.67	484682.13	1434305.87	484735.42	56.0'	76.75	76.33	PROJECTING	24"	1	CHDPE

DRAINAGE TRENCH TABLE

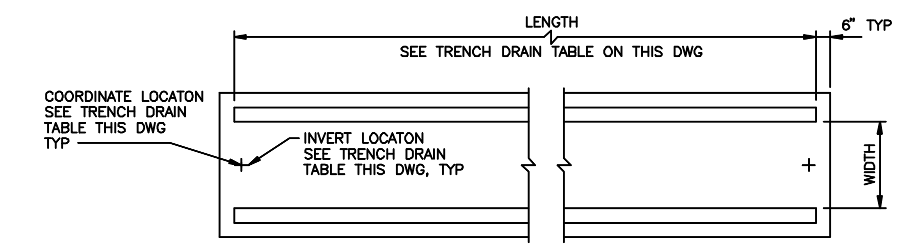
TRENCH DRAIN NO.	DRAWING NO.	CENTERLINE COORDINATES – INLET END – NORTH	CENTERLINE COORDINATES – INLET END – EAST	CENTERLINE COORDINATES – OUTLET END – NORTH	CENTERLINE COORDINATES – OUTLET END – EAST	LENGTH	INSIDE TRENCH WIDTH "A"	INLET TRENCH INV ELEVATION	OUTLET TRENCH INV ELEVATION	TOP OF CONCRETE ELEVATION	REMARKS
T-1	S3002	1434480.42	484114.96	1434439.91	484129.71	43.12	1'-6"	79.88	79.66	81.50	–
T-2	S3001	1434597.44	484671.00	1434608.86	484702.38	33.40	2'-0"	79.60	79.42	81.00	–
T-3	S3001	1434399.02	484342.22	1434364.49	484247.35	100.95	2'-0"	80.50	80.00	81.50	–
T-4	S3001	1434291.54	484452.77	1434262.24	484463.44	31.19	2'-0"	80.27	80.10	81.50	–
T-5	S3001	1434316.56	484527.31	1434291.09	484536.58	27.10	2'-0"	80.85	80.70	81.50	–
T-6	S3001	1434441.36	484727.53	1434452.43	484757.93	32.36	2'-0"	80.03	79.85	81.50	–
EXIST. T-3	S3001	–	–	1433960.44	484837.42	70.08	1'-0"	78.92	78.55	MATCH EXISTING	EXISTING TRENCH DRAIN TO BE EXTENDED



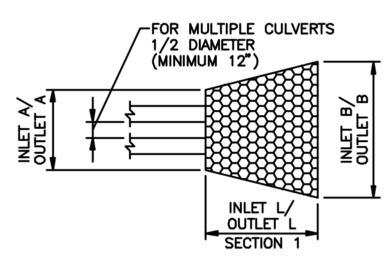
SECTION 1
NO SCALE
SEE DWG S3002



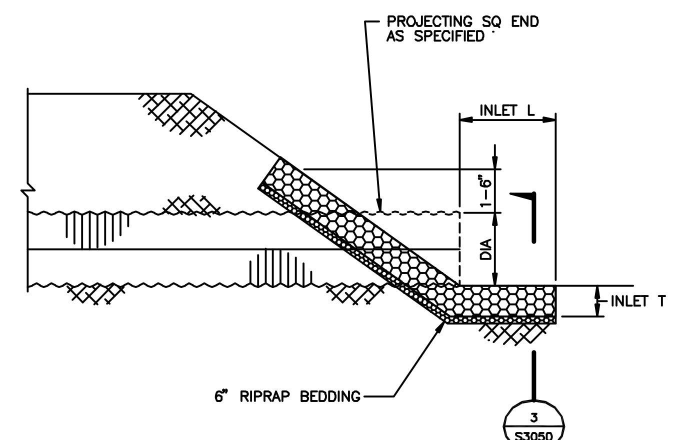
SECTION 2
NO SCALE
SEE DWGS S3001 & S3002



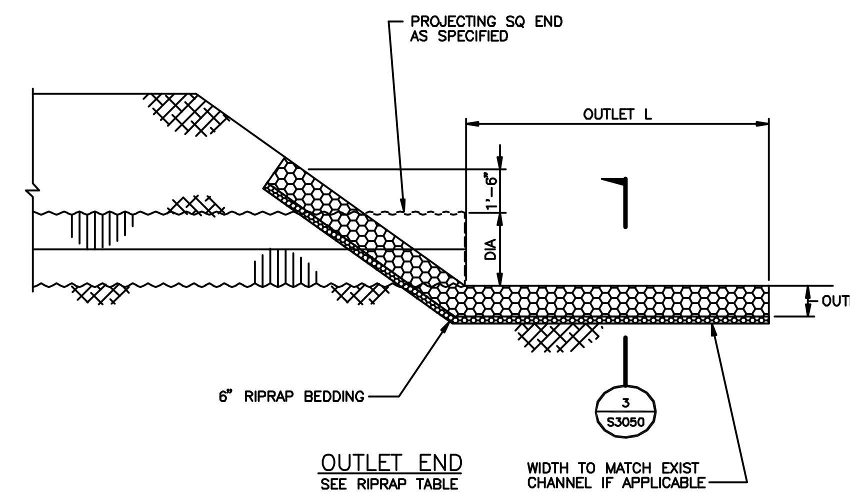
PLAN



SECTION 3
CULVERT RIPRAP PLAN
NO SCALE

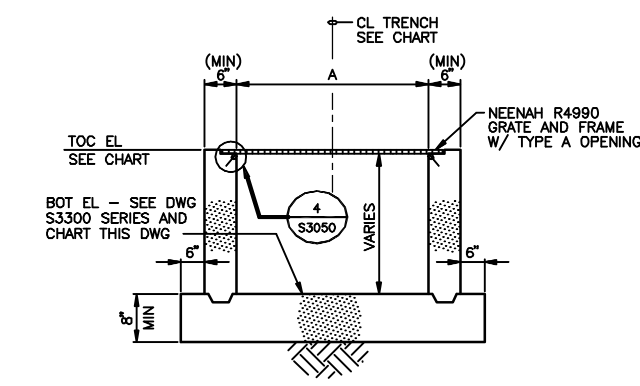


INLET END
SEE RIPRAP TABLE



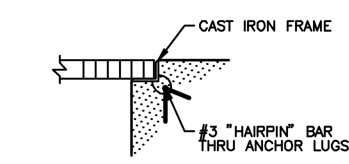
OUTLET END
SEE RIPRAP TABLE

TYPICAL CULVERT RIPRAP
NO SCALE



SECTION

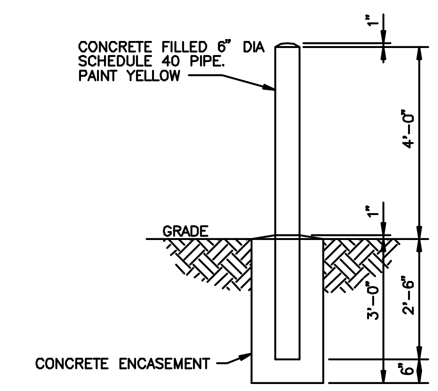
TYPICAL DRAINAGE TRENCH DETAIL
NO SCALE
SEE DWGS S3001 & S3002



DETAIL 4
NO SCALE
SEE THIS DWG

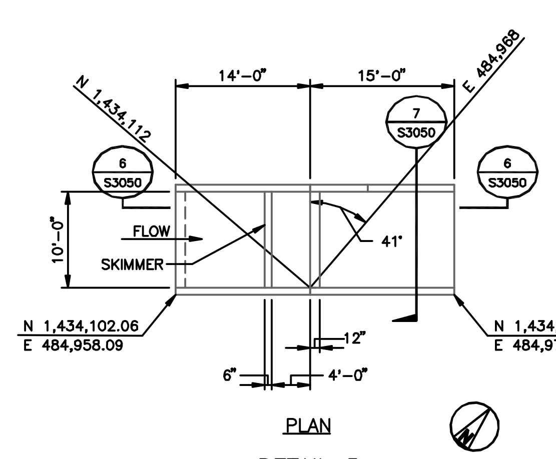
RIPRAP TABLE

CULVERT NO.	INLET L	OUTLET L	INLET A	INLET B	OUTLET A	OUTLET B	INLET T	OUTLET T	INLET D50	OUTLET D50	REMARKS
C-1	5	12.67	8	10	8	20	9"	9"	6"	6"	SEE DWG 147651-4STF-S3001 FOR PLAN
C-2	5	37	11	11	11	24.25	9"	9"	6"	6"	SEE DWG 147651-4STF-S3001 FOR PLAN
T-1	5	9.5	4.5	10	4.5	10	9"	9"	6"	6"	SEE DWG 147651-4STF-S3002 FOR PLAN
T-2	–	10	–	–	5	20	–	9"	–	6"	SEE DWG 147651-4STF-S3001 FOR PLAN
T-3	–	6.38	–	–	5	12.75	–	9"	–	6"	SEE DWG 147651-4STF-S3001 FOR PLAN
T-4	–	9	–	–	5	18	–	9"	–	6"	SEE DWG 147651-4STF-S3001 FOR PLAN
T-5	–	10	–	–	5	20	–	9"	–	6"	SEE DWG 147651-4STF-S3001 FOR PLAN
T-6	–	11	–	–	5	22	–	9"	–	6"	SEE DWG 147651-4STF-S3001 FOR PLAN
T-7	–	10	–	–	5	20	–	9"	–	6"	SEE DWG 147651-4STF-S3001 FOR PLAN
T-8	–	11.5	–	–	5	23	–	9"	–	6"	SEE DWG 147651-4STF-S3001 FOR PLAN



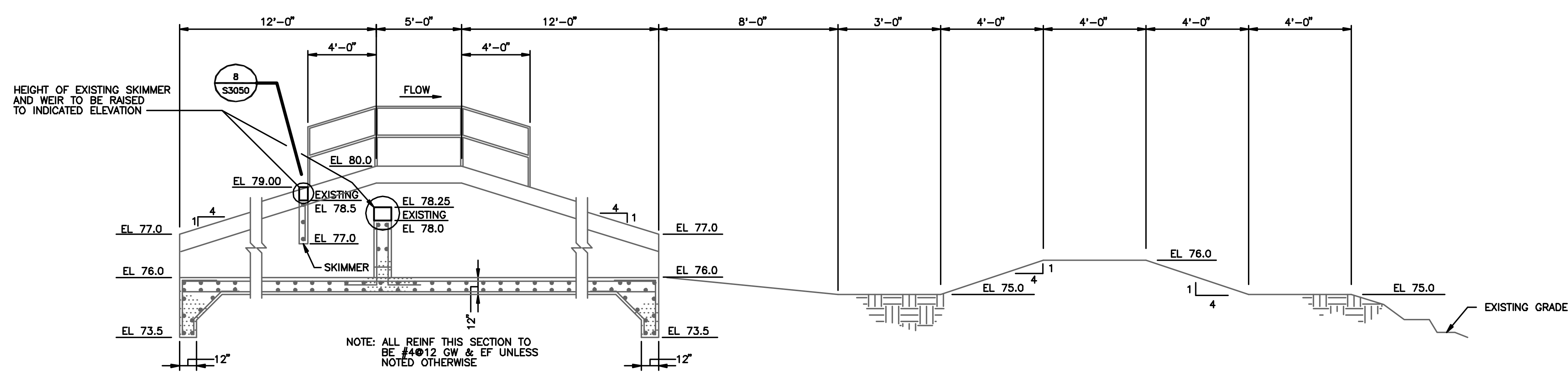
NOTE: ALL WORK BY CONTRACT 72.0201

TYPICAL GUARD POST
NO SCALE

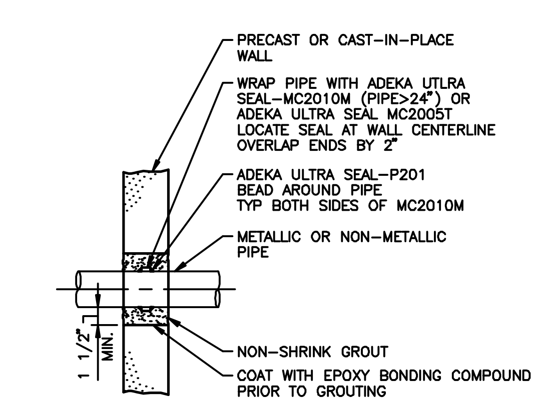


PLAN

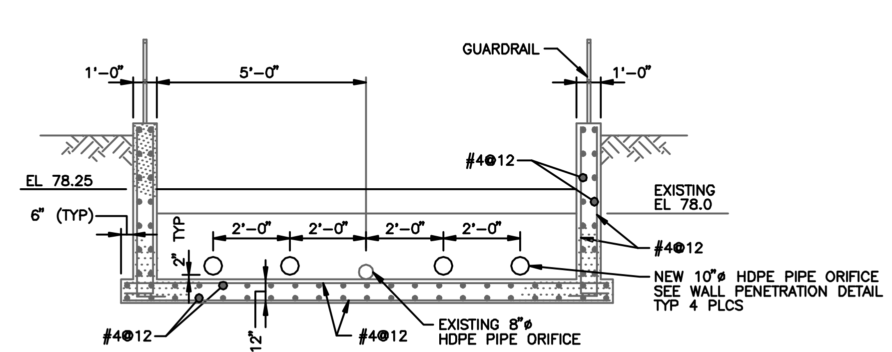
DETAIL 5
EXISTING DISCHARGE STRUCTURE NO. 2
SCALE:1"=10'
SEE DWG S3003



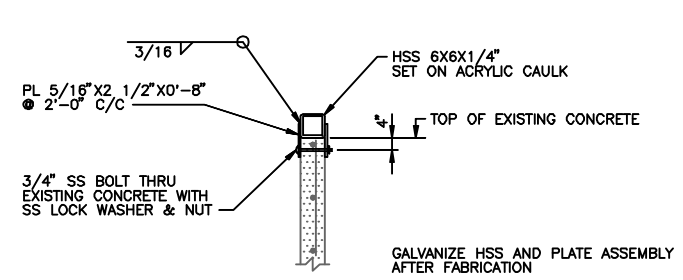
SECTION 6
NO SCALE
SEE THIS DWG



WALL PENETRATION DETAIL
NO SCALE



SECTION 7
NO SCALE
SEE THIS DWG



SECTION 8
NO SCALE
SEE THIS DWG

NOTES

1. SEE DWG S3000 FOR GENERAL NOTES, LEGEND, ABBREVIATIONS AND KEY PLAN.

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SIGNED ______________

DATE __________ REG NO. __________

BLACK & VEATCH CORPORATION

ENGINEER JMS | DRAWN MRR | CHECKED MJS | DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4

GRADING AND DRAINAGE – SITE
SECTIONS AND DETAILS

PROJECT DRAWING NUMBER 147651-4STF-S3050 | REV 0

CODE

AREA

FIGURE 3.8-5

RUN02825 E1 1=1
ACAD 16.1s (LMS Tech)
A1ASLOT7 12:54:43
03/26/08

The discharge structure of the detention basin is designed for the 25 year, 72 hour event peak flow. The discharge structure will also safely pass the 100 year, 72 hour storm event without overtopping the detention basin perimeter berms. The storm water detention basin and discharge structure are sized to meet the design criteria outlined in Subsection 3.8.3. Storm water enters the detention basin through direct precipitation and from ditches conveying runoff from the Unit 3 power block, Unit 4 power block and construction staging/lay-down areas.

The predevelopment discharge in response to the 25 year, 72 hour storm event is approximately 31 cfs. The post-development discharge in response to the 25 year, 72 hour storm event is approximately 18 cfs. Storm water discharges will enter Reedy Creek Swamp through a spreader swale that will distribute the flow and prevent erosion.

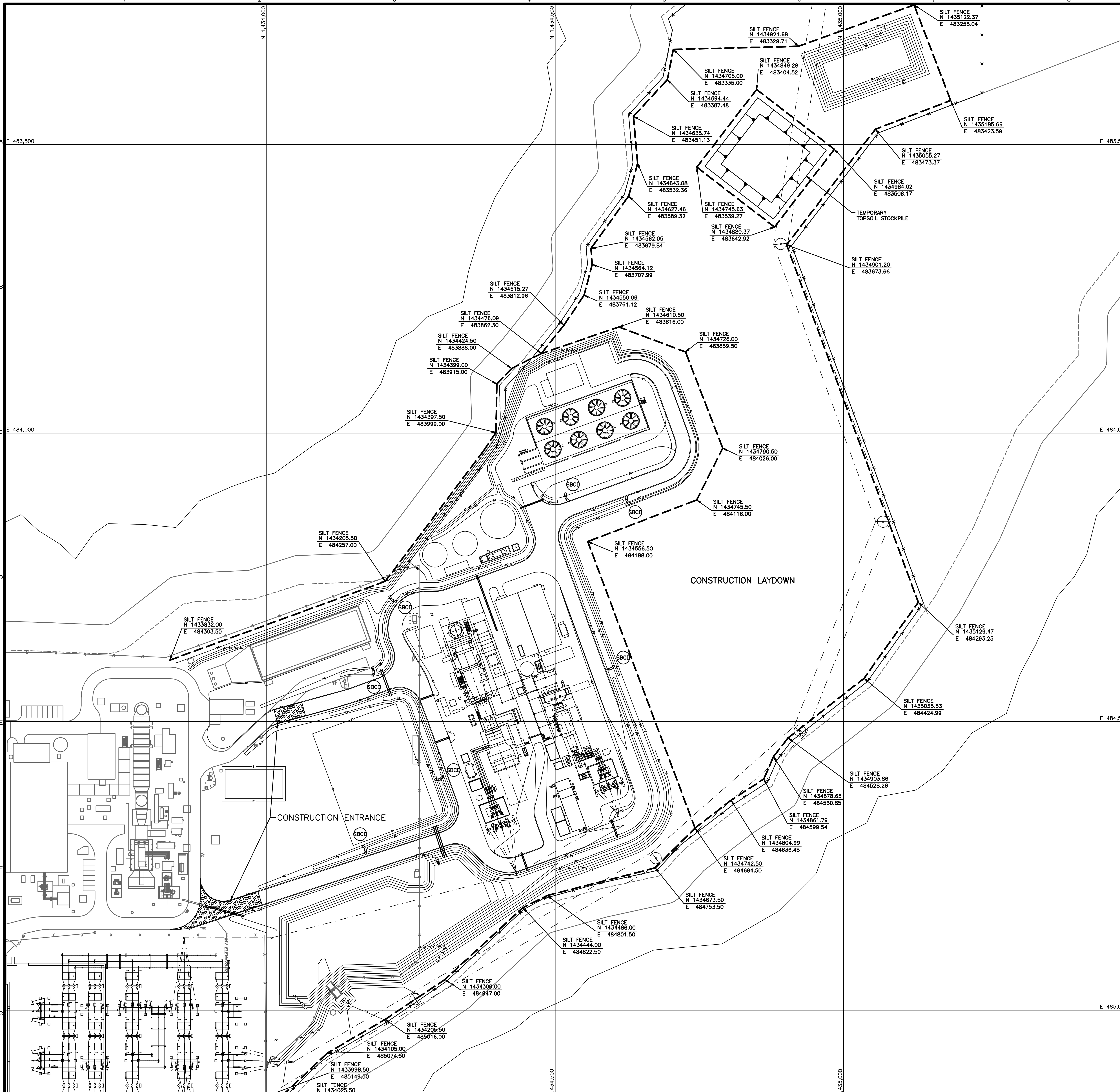
HEC-1 hydrologic analytic model was completed to predict runoff rates, storm water detention basin size, and site storm water drainage facilities. The predictive results from this analytic model are included in Subsection 10.5.1.

3.8.5 Erosion and Sediment Control Measures

Erosion and sediment control measures will be installed as necessary during construction to control sediment disposition. The primary destination of construction runoff will be to the Unit 3 and 4 storm water detention basin. The Unit 3 and 4 storm water detention basin will provide reduction of suspended solids load through detention.

Before construction begins, a silt fence or other appropriate control measures will be installed around the perimeter of construction areas. Figures 3.8-6 and 3.8-7 show erosion control plans and details. Diversion ditches will be equipped with straw bale dikes to aid in minimizing the amount of sediments flowing into the onsite runoff basin and offsite. Construction accessways and parking areas will be surfaced with aggregate to provide a stabilized subgrade. Erosion control measures will also include minimizing fugitive dust through the periodic spraying of water.

3.8.5.1 Staging of Earthmoving Activities. Initial construction will remove all significant vegetation (trees and brush). If possible, some trees will be retained in the construction lay-down/staging area. The runoff basin and associated drainageways will be constructed concurrently with initial clearing activities. Topsoil will be removed and stockpiled for finished grading and site restoration after construction is completed. Once the topsoil has been removed, site preparation will be directly related to the construction of specific power plant facilities. Once the earthmoving and construction are completed, the stockpiled topsoil will be used for finished grading. Seeding and mulching activities will begin immediately upon completion of construction.



GENERAL NOTES APPLICABLE TO ALL S3100 DRAWINGS

1. FOR GENERAL NOTES, LEGEND, AND ABBREVIATIONS SEE DWG S3000.
2. ALL EROSION CONTROL WORK SHALL BE IN ACCORDANCE WITH THE CONSTRUCTION SITE EROSION CONTROL PLAN.
3. SILT FENCE SHALL BE LOCATED AND INSTALLED IN ACCORDANCE WITH THE REQUIREMENTS OF THE CONSTRUCTION SITE EROSION CONTROL PLAN.
4. SEE DWG S3150 FOR EROSION CONTROL SECTIONS AND DETAILS.
5. STRAW BALE CHECK DAMS SHALL BE USED IN ALL DITCHES PER DETAIL ON DWG S3150.
6. SILT FENCE INLET PROTECTION SHALL BE USED AT ALL CULVERT AND TRENCH DRAIN INLETS.

LEGEND APPLICABLE TO ALL S3100 DRAWINGS

SBCD — STRAW BALE CHECK DAM
250 — EXISTING CONTOUR
250 — NEW CONTOUR
SILT FENCE
STORM WATER FLOW INDICATOR
PROPERTY BOUNDARY
CONSTRUCTION ENTRANCE

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SCALE: 1"=60'

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ENGINEER JMS DRAWN MRR
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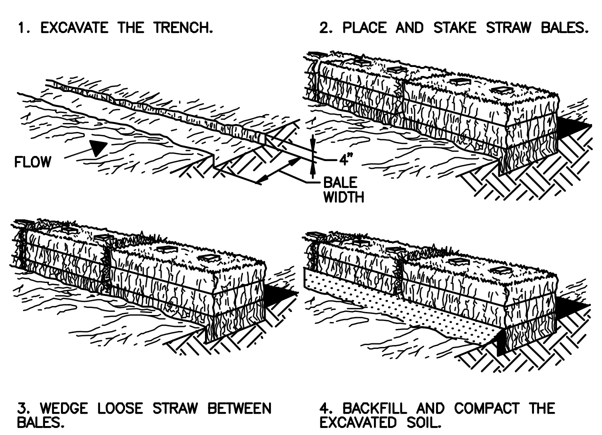
FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4

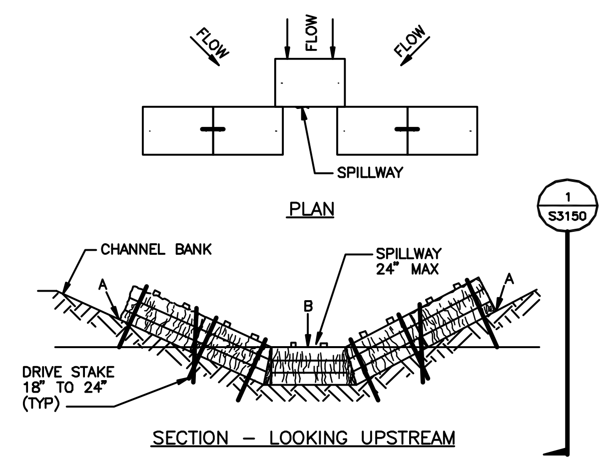
EROSION CONTROL
PLAN SHEET

PROJECT / DRAWING NUMBER: 147651-4STE-S3100 REV 0
CODE
AREA

FIGURE 3.8-6

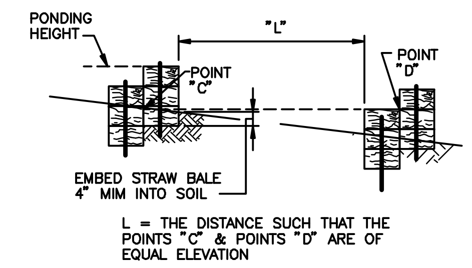


STRAW BALE BARRIER CONSTRUCTION DETAIL
NO SCALE

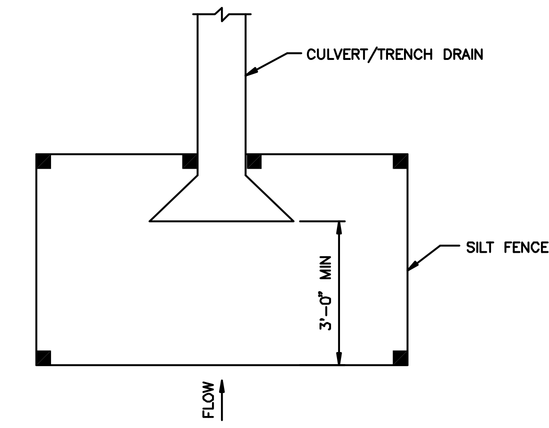


NOTES:
1. EMBED BALES 4" INTO SOIL AND "KEY" BALES INTO CHANNEL BANKS.
2. POINT "A" MUST BE HIGHER THAN POINT "B" (SPILLWAY HEIGHT)
3. PLACE BALES PERPENDICULAR TO THE FLOW WITH ENDS TIGHTLY ABUTTING.
4. SPILLWAY HEIGHT SHALL NOT EXCEED 24".
5. INSPECT AFTER EACH SIGNIFICANT STORM, MAINTAIN AND REPAIR PROMPTLY.

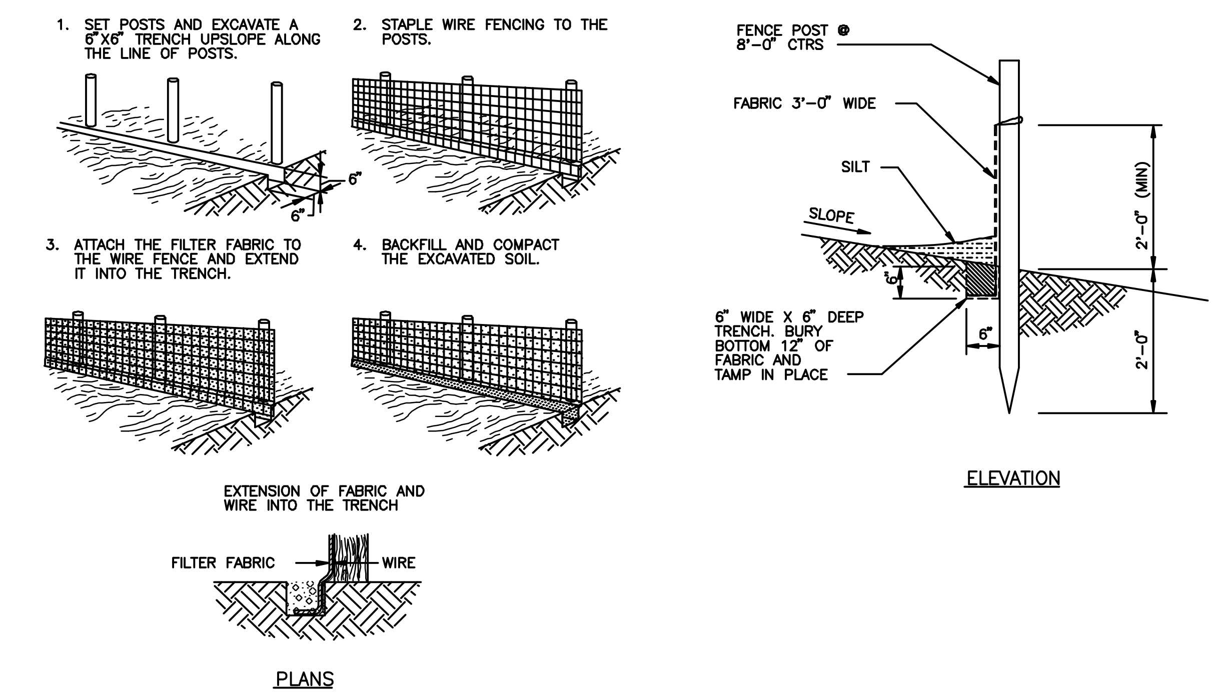
STRAW BALE CHECK DAM
IN DRAINAGE WAY
NO SCALE



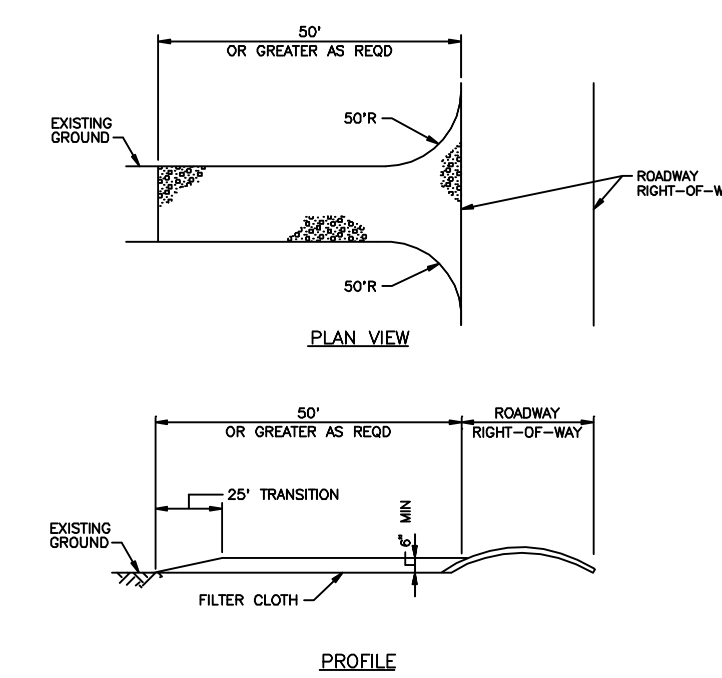
SPACING BETWEEN CHECK DAMS
NO SCALE



SILT FENCE
CULVERT/TRENCH DRAIN
INLET PROTECTION
NO SCALE



SILT FENCE DETAIL
NO SCALE



TYPICAL STABILIZED CONSTRUCTION ENTRANCE
NO SCALE
SEE NOTES 2 & 3

NOTES

1. SEE DWG S3000 FOR GENERAL NOTES, LEGEND, AND ABBREVIATIONS.
2. PROVIDE APPROPRIATE TRANSITION BETWEEN STABILIZED CONSTRUCTION ENTRANCE AND PUBLIC R.O.W.
3. DESIGN CRITERIA FOR STABILIZED CONSTRUCTION ENTRANCE.
   A. STONE SIZE – USE ASTM C-33, SIZE NO 2 OR 3, USE CRUSHED STONE.
   B. THICKNESS – NOT LESS THAN 8 INCHES.
   C. WIDTH – NOT LESS THAN FULL WIDTH OF POINTS OF INGRESS OR EGRESS.
   D. LENGTH – 50 FEET MINIMUM WHERE THE SOILS ARE SANDS OR GRAVEL OR 100 FEET MINIMUM WHERE SOILS ARE CLAYS OR SILTS, EXCEPT WHERE THE TRAVELED LENGTH IS LESS THAN 50 OR 100 FEET RESPECTIVELY. THESE LENGTHS MAY BE INCREASED WHERE FIELD CONDITIONS DICTATE.
   E. FILTER CLOTH – WILL BE PLACED OVER ENTIRE AREA PRIOR TO PLACING OF STONE.
   F. MAINTENANCE – THE ENTRANCE SHALL BE MAINTAINED IN A CONDITION WHICH WILL PREVENT TRACKING OR FLOWING OF SEDIMENT ON TO PUBLIC RIGHT-OF-WAY THIS MAY REQUIRE PERIODIC TOP DRESSING WITH ADDITIONAL STONE OR ADDITIONAL LENGTH AS CONDITIONS DEMAND AND REPAIR AND/OR CLEANOUT OF ANY MEASURES USED TO TRAP SEDIMENT. ALL SEDIMENT SPILLED, DROPPED, WASHED OR TRACKED ONTO PUBLIC RIGHT-OF-WAY MUST BE REMOVED IMMEDIATELY.

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SIGNED
DATE REG NO.

BLACK & VEATCH CORPORATION
ENGINEER JMS | DRAWN MRR
CHECKED MJS | DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4

EROSION CONTROL
SECTIONS AND DETAILS

PROJECT / DRAWING NUMBER: 147651-4STE-S3150 | REV 0
CODE
AREA
FIGURE 3.8-7

3.8.5.2 Construction Monitoring and Maintenance. In general, all erosion and sedimentation control measures will be checked weekly and after each significant rainfall event. Items, including the following, will be checked:

- Silt fences and straw bale dikes will be inspected after each significant rainfall and during prolonged periods of rainfall. Required repairs will be made within 24 hours.
- Sediment deposits at barriers will be removed when the deposit depth reaches approximately one-half the height of the barrier.

An FDEP issued, but federally required, National Pollution Discharge Elimination System (NPDES) General Permit for construction storm water discharges and accompanying Storm Water Pollution Prevention Plan will be required. A partially completed NOI is included in Subsection 10.2.1.2.

3.8.5.3 Permanent Control Measures. Permanent erosion and sedimentation control measures within the CIPP will include the runoff collection system (i.e., ditches, culverts, and trenches), surfaced traffic and work areas, nonworking areas with established vegetation, and the site runoff detention basin. These measures will minimize erosion and potential sedimentation into Reedy Creek Swamp.

The permanent erosion and sediment control system will be installed as early as possible during construction and will remain in service throughout the life of the project. The primary components of this system will be established vegetation, surfacing, aggregate and concrete ditches, culverts, and trenches that will collect the site runoff and direct it to the site runoff basin. The system will be maintained and monitored during construction and operation. When Unit 4 is constructed, uncontaminated storm water will flow into the storm water detention basin. In the event that the storm water detention basin overflows, the overflow will be directed through a weir and the storm water will then be allowed to sheet flow.

The drainage system will require periodic inspection, maintenance, cleaning, and occasional repair work. Inspection will be completed on a seasonal basis and after any severe rainfall event. The condition of the ditches, culverts, and weirs will be noted. Cleaning or repair of the drainage structures will be completed as required.

The existing Storm Water Pollution Prevention Plan prepared for Units 1, 2, and 3 operations will be amended to include Unit 4 facilities.

3.8.6 Potentially Contaminated Areas

Flows originating from potentially contaminated areas, and any storm water runoff generated in these areas, will not be collected in the surface water management system. These flows, which include miscellaneous plant drains and drainage from oil containment areas, will be routed through the oil/water separators for treatment prior to discharge.

After passing through the separator, these flows are routed to an onsite percolation pond. Operation of the percolation pond is discussed in detail in Section 5.3 Impacts for Water Supplies.

The following potentially contaminated areas currently exist and will be added with the construction of Unit 4:

- Steam Turbine Step-up Transformer.
- Combustion Turbine Step-up Transformer.
- Auxiliary Transformers.
- CTG and STG Lube Oil Pumping Units.
- Circulating Water Acid Storage Tank.

All of the transformers will be constructed with a curbed secondary containment area. The containment area will be sized to confine 110 percent of the volume of oil stored within the equipment and a sufficient allowance for the design rainfall storm event. The discharge from the containment areas will be conveyed to a new oil/water separator.

The secondary containment associated with the circulating water acid storage tank will be designed in accordance with Chapter 62-762, FAC, aboveground storage tank systems. The containment area will discharge all rainwater to the neutralization basin. Refer to Subsection 3.6.6 for descriptions of the miscellaneous chemical drains and neutralization basin.

The lube oil pumping units secondary containment areas are designed such that all of the rainwater is collected and conveyed to the oil/water separator for treatment prior to discharge. The containment areas are sloped to a drainage collection point (a gate valved discharge pipe). The discharge pipe from each containment area is interconnected and routed to the oil/water separator by gravity.

An oil/water separator is provided for separation of any oil and grease from contaminated wastewaters and storm waters. Treated separator effluent (water) will be discharged to an onsite percolation pond. The oil phase will be periodically pumped from the separator and disposed offsite by a licensed waste management contractor. The effluent from the separator will be low in the structure to allow the water to underflow while the oil is retained for later removal. The separator is sized to contain the volume of oil produced by the total failure of the single largest source served by the separator, with the exception of the valved step-up transformer and lube oil pumping unit containment areas.

3.9 Construction Materials and Equipment Handling

The major components associated with the Unit 4 installation include the following:

- CTG.
- HRSG.
- Generator Step-up Transformers.
- Cooling Tower.
- STG.
- Miscellaneous Services Building.
- Power Distribution Center.
- Water Storage Tanks.

The major components and all other required equipment and materials will be delivered to the CIPP by truck. All deliveries associated with construction and operation will utilize the site access road that connects to Old Tampa Highway. All deliveries will be cleared through a call-box at the main gate. Once onsite, construction materials and equipment will be directed to the construction lay-down area or its permanent location for offloading.

3.10 References

United States Department of Agriculture; Soil Conservation Service, *Urban Hydrology for Small Watersheds*, Technical Release 55, Washington, D.C., June 1986.

US Department of Commerce; Weather Bureau, *Rainfall Intensity-Duration-Frequency Curves*, Technical Paper No. 25, Washington D.C., December 1955.

United States Weather Bureau, *Rainfall Frequency Atlas of the United States for Durations from 30 Minutes to 24-Hour and Return Periods from 1 to 100 Years*, Technical Paper No. 40, Washington, D.C., May 1961.

South Florida Water Management District, *Environmental Resources Permit Information Manual Volume IV,* West Palm Beach, Florida, 2000.

4.0 Effects of Site Preparation and Plant and Associated Facilities Construction

This section identifies and describes the potential impacts from construction of the proposed CIPP Unit 4 Project (Unit 4) and site development on the social, physical, and natural resources of the site and vicinity. The potential impacts of Unit 4 and site development are assessed on the basis of the existing site and vicinity conditions described in Section 2.0, as well as in terms of compliance with applicable regulations and standards.

4.1 Land Impact

Construction of Unit 4 will occur entirely within the previously permitted 47 acre power block area on the central portion of Cane Island. Approximately 24.2 acres of this area will be temporarily impacted during construction of Unit 4; 9 acres will be permanently impacted. As discussed in Section 6.0, no new offsite transmission facilities will be required for construction or operation of Unit 4, which will be interconnected to the existing CIPP substation, approximately 500 feet southeast of the new unit.

4.1.1 General Construction Impacts

The power block facilities will be located on 9 acres, which will include several buildings and equipment pads. Concrete or aggregate surfacing will be used around the unit, with asphalt paved roads around the perimeter. The cooling tower, demineralized water tank, fire protection/service water tanks, and surrounding equipment are within an aggregate surfaced area. The area between the Unit 3 cooling tower and the storm water detention basin will be converted from a grass/lawn-like cover to aggregate surface. The storm water detention basin will be located southeast of Unit 4 and will occupy 1.41 acres. The area north of Unit 4 and the new cooling tower will be used for construction laydown and parking. This area will be seeded when construction is complete. As discussed in Section 6.0, no new offsite transmission facilities will be required for construction or operation of Unit 4, which will be interconnected to the existing CIPP substation. A few of the existing transmission poles in the power block area will be relocated to accommodate Unit 4.

The area proposed for the Unit 4 facilities is, for the most part, the construction equipment/materials lay-down area that was used during construction of Unit 3. This area is generally grassland with scattered trees located north of Unit 3. The 1.41 acre storm water pond associated with Units 3 and 4 will be located immediately north of the existing switchyard and will encroach into the sand pine scrub area. A new 12.5 acre construction equipment/materials lay-down area for Unit 4 will be located immediately north of the Unit 4 power block and cooling tower. The area of the existing transmission line corridor along the southern part of the CIPP, outside of the conservation area, may also be used for construction parking. Facility locations are shown on Figure 2.1-3 in Section 2.0.

No explosives will be used during construction. No paved roads will be required for Unit 4 construction access. Unimproved trails are available in the construction area so that new roads will not be needed for CIPP or Unit 4 construction area access. No railroad spur will be required. The CSX Railroad operates a track adjacent to the southern property boundary that could be used for deliveries.

Construction of Unit 4 will modify the existing terrain. The Unit 4 facilities areas will be cleared and grubbed. The power block area will be raised to the minimum floor elevation of 82 feet NGVD. The Units 3 and 4 storm water pond will require modification to accommodate Unit 4 runoff. Construction materials, such as concrete, steel, and aggregate, will be delivered to the site by trucks.

4.1.2 Roads

No new roads connecting to state roads will be required for Unit 4 construction or operation. Therefore, the “Utility Accommodation Guide” assessment is not required.

A new paved road will be constructed around the Unit 4 power block and connected to the existing plant road system as shown on Figure 2.1-3 in Section 2.0.

4.1.3 Flood Zones

The plant access road and Units 1, 2, and 3 buildings were placed above the 10 year, 24 hour and 100 year, 72 hour design rainfall events, respectively, as required by the SFWMD regulations. Unit 4 buildings will also be placed above the 100 year, 72 hour design rainfall event. Compensating storage volume to offset the loss of flood storage capacity from Unit 4 will be provided by expanding the Unit 3 storm water detention pond.

4.1.4 Topography and Soils

As described in Subsection 4.1.1 above, the proposed construction area is, for the most part, the construction lay-down area used during construction of Unit 3. This area is a relatively flat, grassland with scattered trees. The storm water detention basin associated with Units 3 and 4 will be located in a relatively flat sand pine scrub area. The soils in both of these areas are generally sandy.

Construction will begin with the installation of erosion and sedimentation control structures at the perimeter of the construction areas. The construction areas will then be cleared, grubbed, and prepared for buildings and foundations. The storm water detention basin will be excavated early to collect storm water runoff from the construction area and provide fill material. Additional offsite fill will be required to facilitate drainage. A minimal amount of fill will be required in the construction area to match elevations and facilitate drainage. Final paving, grading, and landscaping will complete Unit 4 construction. In addition to the erosion and sedimentation control measures, water sprays will be used to control fugitive dust.

Subsurface modifications may also be required in the power block area, after testing, because of the karst topography of the project area. Modification techniques may include vibroflotation, vibroreplacement, or possibly, sinkhole grouting. The purpose of these modifications is to increase the load bearing strength of the in situ soils and subsoils.

The modifications will minimize the potential for sinkhole formation in the power block area. The results of the modifications and construction will increase the amount of impervious area, reduce the permeability and percolation rates of the site, and increase the site runoff rate. As described above, the purpose of the storm water detention basin is to compensate for the loss of pervious area and provide runoff/flood storage capacity. These modifications will not alter the aesthetics or viewshed features of the project area because of the flat terrain and extensive buffer surrounding the power block.

4.1.5 Solid Wastes and Wastewater Disposal

Waste oils, greases, hydraulic fluids, construction wastes, and garbage will be collected, stored, and removed for disposal at a properly licensed landfill or resource recovery facility by the general contractor or individual construction contractors. Such activities will be supervised and controlled by the Construction Manager. Table 4.1-1 indicates the treatment and disposal methods of these wastes and wastewaters generated during construction.

Clearing existing vegetation will generate vegetation wastes that will be disposed of by the construction contractor in either a permitted solid waste landfill, a permitted composting facility, or burned in accordance with state and local requirements.

Table 4.1-1
Waste Streams and Wastewater Streams Associated with Construction

Potential Waste Streams	Quantity	Quality	Discharge Point	Treatment Prior to Discharge	Hazardous
Stone Column Pile Installation Water	11,000,000 gallons	Well water	Infiltration into surficial aquifer where piles install with some runoff to storm water pond or general construction area drainage	Best management practices used for construction storm water	No[(a)]
Well Development and Test Water	15,000,000 gallons	Well water	Storm water runoff pond and existing cooling towers	None	No
HRSG Hydro	200,000 gallons	Ammoniated demin water (pH 9-10) 2 ppm ammonia	Toho Water Authority reclaim water line or percolation pond	pH adjustment	No[(b)]
Condenser Hydro	200,000 gallons	Demin water (pH 6-8)	Storm water detention basin	Filter before discharge	No[(a)]
Misc. Hydro and Flush Water	5,000,000 gallons	Service or well water with trace oil/grease	Percolation pond or Storm water detention basin	Filter before discharge	No[(a)]
Cooling Tower Drain and Clean	800,000 gallons	Service or well water	Storm water detention basin	None	No[(a)]
Cooling System Water Flush	50,000 gallons	Demin water	Storm water detention basin	Filter before discharge	No[(a)]
Steam Blow Quench Water	300,000 gallons	Service or well water	Storm water detention basin	Filter before discharge	No[(a)]
HRSG and Preboiler Piping Chem Cleaning	250,000 gallons	Demin water; expected to be nonhazardous	Offsite	Perform toxicity characteristic leaching procedure (TCLP) test. If non-hazardous, to percolation pond. If hazardous, hauled off by a licensed contractor.	No[(b)]
Service/Fire Water Tank Hydro	1,000,000 gallons	Well or Service water	Storm water detention basin	Filter before discharge	No[(a)]
Demin Storage Tank Hydro	1,000,000 gallons	Service or well water	Storm water detention basin	Filter before discharge	No[(a)]
Preservatives in Tubes	150,000 gallons	Water soluble corrosion inhibitor	Offsite	Labeled, sealed container properly stored for disposal by licensed contractor	Yes[(c)]

Table 4.1-1 (Continued)
Waste Streams and Wastewater Streams Associated with Construction

Potential Waste Streams	Quantity	Quality	Discharge Point	Treatment Prior to Discharge	Hazardous
Oily Solid Wastes	Conditionally Exempt SQG	Hazardous	Offsite	Labeled, sealed container properly stored for disposal by licensed contractor	Yes[c]
Oily Rags	Conditionally Exempt Small Quantity Generator (SQG)	Hazardous	Offsite	Labeled, sealed container properly stored for disposal by licensed contractor	Yes[c]
Non-Oily Rags	Conditionally Exempt SQG	Hazardous	Offsite	Labeled, sealed container properly stored for disposal by licensed contractor	Yes[c]
Punctured Aerosol Cans	Varies	Empty cans	Offsite by approved scrap metal contractor	Metal recycling container	No[c]
Captured Paint Residues from Punctured Aerosol Cans	Conditionally Exempt SQG	Hazardous	As hazardous waste in accordance with 40 CFR 261	Labeled, sealed container properly stored for disposal by licensed contractor	Yes[c]
Fluorescent Bulbs and Batteries	Conditionally Exempt SQG	Not applicable	Offsite	Contained onsite; recycled as universal waste	No[a]
Wood	Varies	Not applicable	Offsite	Contained onsite: recycled or disposed in landfill	No[a]
Metals	Varies	Not applicable	Offsite	Contained onsite; approved scrap metal contractor	No[a]
Plastics	Varies	Not applicable	Offsite	Contained onsite; transported offsite by an FDEP approved recycle facility or disposal facility	No[a]

[a]Assessment based on process knowledge.
[b]Assessment based on analytical test.
[c]Assessment based on regulation, material safety data sheets (MSDSs), or manufacturer’s recommendation.

Vegetative matter removed during site clearing may be burned onsite after receiving the proper authorizations from Osceola County. The majority of the uncleared area will be totally cleared. In the very northern part of the site, some trees may be removed from the proposed construction/lay-down area, but this area may not require total clearing.

Wastewater will be generated from vibroflotation and vibroreplacement of the site soils from hydrostatic testing and cleaning of various items of equipment, such as the HRSG, piping, and tanks and from well water development and testing. Most of these wastewaters will be nonhazardous and will be released to either the storm water detention basin or conveyed to the onsite percolation pond. The well test water may be used as cooling tower makeup for the existing units. Waste and wastewater stream information is presented in Table 4.1-1. Any wastewater streams determined to be hazardous will be transported offsite by a licensed contractor. Many of the processes that generate wastewater during construction are the same wastewater streams identified on Figure 3.5-1, Water Mass Balance - Unit 4 Operation. However, construction will generate additional wastewater streams and solid wastes that are identified in Table 4.1-1. FMPA requests approval of these wastewaters and solid waste disposal methods during Unit 4 construction.

The well water or plant service water system will provide water for chemical cleaning of the HRSG and steam piping, as well as for the steam blow processes. Chemical cleaning involves cleaning the HRSG and piping systems prior to operation. The steam blow process involves cleaning steam piping systems to remove accumulated weld spatter, slag, filings, and other debris. If this material is not removed prior to steam turbine operation, the steam turbine will be damaged by the metal particles, which would strike the blades and steam path at very high velocities. Blowing through the piping system with steam removes these materials, rust, grease, and other fabrication and construction residues prior to commencement of combined cycle operation. The steam blow process requires treated water from the existing demineralization system and may require an additional portable demineralization unit for a short period of time. Chemical cleaning residuals will be hauled offsite by a licensed transporter and disposed of accordingly. Potable demineralization units generate spent resins that will be regenerated offsite. The wastewater generated from the existing demineralization system will be treated and discharge to the Toho reclaim water line south of the site as during normal plant operation.

4.2 Impact on Surface Water Bodies and Uses

Reedy Creek crosses the southwest portion of the CIPP, more than 1/2 mile from the power block area. The Bonnet Creek Canal is adjacent to the CIPP on the north and west, 1/2 mile from the power block area at its nearest point. Reedy Creek Swamp wetlands buffer these surface waters from the power block area.

4.2.1 Impact Assessment

Construction of Unit 4 will have no adverse impact on Reedy Creek, the Bonnet Creek Canal, or the onsite wetlands. The erosion and sedimentation control measures will control and minimize such impacts beyond the 15.2 acre construction zone. The Units 3 and 4 storm water pond and temporary drainage ditches will be developed early in the construction sequence to serve as the construction drainage system, providing treatment of storm waters and dewatering discharges through detention. In the event of storm water pond overflow, treated waters could enter the wetlands surrounding Cane Island.

4.2.2 Measuring and Monitoring Programs

If required during construction, water quality grab samples will be collected from storm water pond overflow discharges. The sample will be tested in accordance with FDEP standards.

The size of the construction area will require an NPDES Storm Water General Permit for storm water discharges associated with construction activity. One condition of this permit is the preparation and implementation of a pollution prevention plan specific to the construction site. In addition to a description of the project, potential pollutant sources, and the storm water management control plan, the pollution prevention plan must include spill prevention and system maintenance/inspection procedures.

4.3 Ground Water Impacts

Construction of various facilities for Unit 4 will involve dewatering excavated areas to support construction activities.

4.3.1 Impact Assessment

Ground water impact during construction will result from dewatering activities and the use of ground water during construction.

4.3.1.1 Dewatering. During Unit 4 construction, numerous facilities will be constructed below the surface of the upper unconfined ground water system in the power block area. It will be necessary to dewater the excavations for construction of the new oil/water separator, wastewater sump, circulating water lines, circulating water pump pit, blowdown tank pit and sump, Miscellaneous Services Building vault, accessory module containment sump, wash water collection sump, power distribution center vault, and other minor structures. The locations of these facilities are shown on Figure 3.1-1.

The majority of the underground utilities, miscellaneous pits, and sumps will be constructed above the ground water surface and will have no impact on the ground water at the site.

Dewatering for the above noted structures will be completed with a series of well points installed around the perimeter of the excavation. The dewatering activity duration will be short term, less than 6 months. The dewatering will be to a depth of approximately 15 feet below ground surface in some areas and 10 feet in others. Total withdrawal volumes will be less than 1.3 mgd during the initial 2 week dewatering period. After this period, flows should drop to less than 0.6 mgd. Discharge from the dewatering activities will be directed to the Units 3 and 4 storm water pond and possibly to the Units 1 and 2 storm water pond. Much of the discharge into the storm water pond is expected to percolate through the base of the pond.

The dewatering effects will be temporary and limited to the power block area. The ground water system will return to its original state after completion of the dewatering.

4.3.1.2 Well Water Usage. Water from the existing wells and the new wells will be used to support construction activities. Well water will be used for dust suppression, installation of stone column piles, hydrostatic testing of piping systems, tanks and equipment, flushing/cleaning activities, tank filling, and other miscellaneous usages. It is expected that 20 to 25 million gallons of well water will be used during the construction and commissioning of Unit 4. Maximum usage rate should be less than 1 mgd. During construction, this water usage is requested from the Unit 4 emergency cooling water allocation.

In addition, the development and testing of the new wells will require pumping of water from the Upper Floridan Aquifer. The wells will be developed and tested as they are completed. Pumping from each well should not exceed 1 mgd during the development and testing.

The above well water usages will have insignificant impacts to the ground water as shown on the operational modeling presented in Section 5.3, which has much higher usage rates and insignificant impacts.

4.4 Ecological Impacts

Site preparation and construction of Unit 4 facilities will impact upland habitats and resident wildlife. Site preparation and construction of Units 1, 2, and 3 previously impacted upland and wetland habitats, and resident wildlife. No wetlands impacts are anticipated, nor are any adverse impacts to federal or state threatened or endangered species. Black & Veatch, at the request of KUA and as required by resource agencies, acquired the necessary permits for Units 1 and 2 construction and prepared and implemented the *Cane Island Project Mitigation Plan* (1993) to mitigate and compensate for ecological impacts associated with ultimate site development. Upon certification of Unit 3, many of the environmental and ecological conditions from these permits were transferred to the CIPP Site Certification and remain in effect today.

4.4.1 Impact Assessment

Site preparation for construction of the Unit 4 facilities will permanently impact wildlife and wildlife habitat. All vegetation will be permanently removed from the Unit 4 power block and construction lay-down area location during site preparation. As a result, there will be a decrease of wildlife habitat, which will reduce the primary productivity at CIPP and displace wildlife from the impact areas. Additionally, wildlife species may also be temporarily displaced from adjacent communities by the noise, fugitive dust, and activity caused by construction.

Unit 4 construction will clear 24.2 acres within the permitted ultimate development area on Cane Island. Gopher tortoises may require relocation during site preparation and construction of Unit 4 and associated facilities. The FGFWFC, now the FFWCC, issued Permit No. OSC-6 for the incidental "take" of gopher tortoises and their burrows during Units 1 and 2 construction. The FFWCC has confirmed that this permit is still valid, which allows the CIPP staff to relocate tortoises to the appropriate management areas onsite. A copy of this permit is included in Subsection 10.5.7.

4.4.2 Measuring and Monitoring Programs

Vegetation, wildlife, and wetlands monitoring and management is required by the resource agencies as mitigation for CIPP development and operation. These efforts are conducted in compliance with the *Cane Island Project Mitigation Plan* (1993) and subsequent approved modifications to the plan. Qualitative habitat monitoring efforts began in 2005 and will be conducted once every 5 years for the life of the project. Wildlife and vegetation are now sampled at CIPP by opportunistic observations. Prescribed burns and treatment of exotic vegetation are the major habitat management programs used at the CIPP. Annual management and monitoring reports are submitted to the SFWMD and FFWCC.

4.5 Air Impacts

During the Unit 4 construction phase, atmospheric dust (i.e., particulate matter) will be generated from the mechanical disturbance of granular material that becomes exposed to the wind at the construction site. This material is often referred to as fugitive dust, as its source is particulate matter that cannot be reasonably discharged to the atmosphere in a confined flow stream.

4.5.1 Sources of Construction Fugitive Dust

Construction activities, including material moving activities, site preparation, and vehicle traffic, if not properly monitored and controlled, have the potential to generate large amounts of fugitive dust. The construction activities at CIPP may be generally broken down into the following three phases as related to generating fugitive dust:

- Phase 1 - Debris Removal--Debris removal consists of removing any manmade or natural obstructions from the site. Under extreme circumstances, this phase of construction may require blasting, explosion, or mechanical dismemberment of the obstructions to clear the site. However, this level of debris removal is not anticipated and will likely be limited to material loading/unloading, small disturbed areas, and vehicular travel on unpaved surfaces.
- Phase 2 - Site Preparation--Site development includes the general site grading and soil stabilization techniques used to bring the site to a final or near final grade. These techniques will typically include cut and fill as well as aggregate surfacing operations. Typical fugitive dust emission sources of this phase include movement of large earth moving equipment (e.g., scrapers and dozers) over disturbed surfaces, material/aggregate loading and unloading, and vehicular travel on unpaved surfaces.
- Phase 3 - General Construction--The construction phase is the final, but generally the longest, phase of the construction activities. This phase includes everything from foundation work, structural and reinforcing steel erection, exterior/interior operations, to piping/electrical work and final landscaping. In contrast to Phases 1 and 2, fugitive dust emissions during Phase 3 are somewhat sporadic in nature, depending on the delivery schedule of parts and materials, with many simultaneous operations throughout the construction site.

Within each of the major construction phases described above, there may be one or more specific construction activities occurring during that phase that can be a source(s) of fugitive dust. The fugitive dust emission sources resulting from these construction activities are typically assigned into one of four categories that include: disturbed surface areas, open storage piles, earth moving, and vehicular traffic. The following sections describe each of these fugitive dust emission sources as applicable to the Unit 4 construction site.

4.5.1.1 Disturbed Surface Areas. Many of the construction activities will result in disturbed surface areas in the power block area that may be subject to wind erosion. A disturbed surface refers to a portion of the earth's surface which has been physically moved, uncovered, destabilized, or otherwise modified from its undisturbed natural soil condition, thereby increasing the potential for emissions of fugitive dust. Disturbed surfaces do not include those areas which have been restored to a natural state such that the vegetative ground cover is similar to any adjacent natural conditions, or which have been paved or covered by a permanent structure.

4.5.1.2 Storage Piles. A storage pile is any accumulation of bulk material, generally with a 5 percent or greater silt content, that is not fully enclosed or otherwise covered or chemically stabilized. The storage pile may be composed of soil, stored temporarily during cut and fill operations, or may be composed of aggregate used in foundation work and construction materials. Storage piles of this nature are typically left uncovered because of the frequent need to transfer material into and out of storage. Fugitive dust emissions may occur at several points in the storage pile cycle, including material loading or unloading (material handing), and dust entrainment in wind currents on the exposed slopes of the storage pile.

4.5.1.3 Earth Moving. Earth moving refers to a broad range of construction activities using heavy equipment to clear land, excavate, cut and fill, etc. The activities may directly expose material to wind erosion through excavation, scraping, hauling, loading, transferring, and other material moving activities.

4.5.1.4 Vehicular Traffic. Vehicular traffic associated with the construction activities will include worker vehicles, equipment deliveries, and heavy construction vehicle traffic over unpaved surfaces. When a vehicle travels on an unpaved surface, the force of the wheels on the surface causes the material on the road to become lifted, dropped, and then entrained into the turbulent air currents caused by the velocity of the vehicle. As such, the vehicle's speed and size, silt content of the road surface, and material moisture content all play a role in determining the magnitude of the fugitive dust emissions from unpaved roads.

4.5.2 Available Control Methods

Fugitive dust emissions may result from a variety of activities that can require a multitude of different emission control alternatives. Additionally, the relatively short-term nature of construction activities makes some fugitive dust control methods more cost-effective and practical than others. Tables 4.5-1 through 4.5-4 describe several available fugitive dust control methods and practices associated with disturbed surfaces, storage piles, earth moving, and vehicular traffic that may be employed to control fugitive dust during construction. The available control methods identified in each table are summarized in the following subsections. The control methods ultimately used will be agreed upon by the Contractor and Construction Manager.

4.5.2.1 Watering. Watering is an effective stabilizing tool that controls fugitive dust by using water (or water combined with a surfactant) as a binder by either maintaining soil moisture content or establishing a crust that prevents soil movement under windy conditions. The water can be applied by any suitable means such as trucks, hoses, and/or sprinklers appropriate for site characteristics and size. Watering is most effective when an area or road surface is prewatered, with frequent reapplication as necessary.

4.5.2.2 Chemical Stabilizers. Chemical stabilizers are commercially available and contain approved chemical soil binding agents to artificially crust soil and prevent soil movement during windy conditions. Stabilizers are effective for temporary periods. Depending on the application rates and/or materials involved, stabilizer use may extend the durability and longevity of the artificial soil crust for longer periods. As such, stabilizers are best suited for areas not subject to daily disturbance.

4.5.2.3 Physical Barriers. Physical barriers provide a sheltered region behind the barrier to allow gravitational settling of larger fugitive dust particles, as well as a reduction in the wind’s erosion potential. Physical barriers reduce the mechanical turbulence generated by the ambient winds for a downwind distance proportional to the height of the barrier and porosity. Physical barriers include portable wind screens and fences, partial enclosures, straw bales, tree lines, and terraces. Wind screens and fences can be used to control a wide variety of fugitive dust sources at a construction site, including disturbed areas and storage piles, and to provide shelter for material handling operations such as storage pile loading or unloading. Furthermore, fences and screens are portable and, thus, capable of being relocated around the construction site as necessary.

Table 4.5-1
Available Fugitive Dust Control Methods for Disturbed Surface Areas

Control Method	Description/Remarks
Work Practice Controls	Paving identified roads and access points early in the construction process, phasing of earth moving activities to reduce disturbed surface extent, compaction and/or stabilization of disturbed surfaces as quickly as practical. Onsite traffic control program to direct, control, and restrict unnecessary traffic.
Watering	Use of water or water plus a wetting agent to suppress fugitive dust over disturbed areas. Typically applied with spray nozzles attached to a special truck adapted for this purpose. Temporary in nature, but cost-effective even with frequent reapplication.
Graveling	Graveling of high volume traffic areas within the disturbed area of the construction site provides a physical stabilization of the exposed surface and covers the surface with a material having a lower silt content.
Wind Fencing	Wind fencing provides a sheltered region behind the fence line, which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence around the disturbed surface.
Physical Stabilization	Physical stabilization methods involve the application of materials such as rock, bark, wood chips, straw, or other suitable materials to cover the exposed surface, thus preventing the wind from disturbing the surface particles. Graveling is one example of physical stabilization.
Vegetative Stabilization	Vegetative cover provides a physical stabilization and wind shelter of the disturbed surface. However, it is effective only on inactive areas of the disturbed surfaces where frequent mechanical (i.e., earth moving) activities are not anticipated. As such, it is typically not implemented during short-term construction activities.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities does not warrant their use as they are not cost-effective over such a small scale of application and reapplication.

Table 4.5-2
Available Fugitive Dust Control Methods for Storage Piles

Control Method	Description/Remarks
Work Practice Controls	Minimize temporary material storage pile(s) size and number by utilizing phased earth moving activities. Minimize drop height when adding material to the pile(s) and perform loading and unloading operations on the leeward (down wind) side of the pile. Cleanup spillage and maintain material to the confines of the pile.
Watering	Use of water or water plus a wetting agent to suppress fugitive dust from the storage pile. Temporary in nature, but cost-effective even with frequent reapplication.
Wind Fencing/ Barriers	Wind fencing or partial temporary barriers or enclosures provide a sheltered region in the vicinity of the storage pile, which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence or barrier.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities does not warrant their use as they are not cost-effective over such a small scale of application and reapplication.

Table 4.5-3
Available Fugitive Dust Control Methods for Earthmoving

Control Method	Description/Remarks
Work Practice Control	Onsite traffic control program to direct, control speed, and restrict unnecessary traffic. Reduce offsite hauling with balanced cut and fill operations and construction management. Cover truck beds during material hauling operations.
Watering	Preapplication of water or water plus a wetting agent to suppress fugitive dust prior to and, to the extent possible, during earth moving operations. Temporary in nature, but cost-effective even with frequent reapplication.
Wheel Washing	Water washing of heavy construction equipment wheels and undercarriages at construction site egress points to prevent material trackout and deposition outside of the construction site. System may include automatic or manual sprayers and/or drive-though wheel washing basins.
Wind Fencing/ Barriers	Wind fencing or partial temporary barriers or enclosures provide a sheltered region in the vicinity of the earth moving, which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence or barrier.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities does not warrant their use as they are not cost-effective over such a small scale of application and reapplication.

Table 4.5-4
Available Fugitive Dust Control Methods for Vehicular Traffic

Control Method	Description/Remarks
Work Practice Controls	Onsite traffic control program to direct, control speed, and restrict unnecessary traffic. Reduce offsite hauling with balanced cut and fill operations and construction management. Cover truck beds during material hauling operations.
	Unpaved Roads
Watering	Application of water or water plus a wetting agent to suppress fugitive dust prior to, and to the extent possible, during earth moving operations. Temporary in nature, but cost-effective even with frequent reapplication.
Graveling	Graveling of high volume unpaved traffic areas provides a physical stabilization of the exposed surface and covers the surface with a material having a lower silt content.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities does not warrant their use as they are not cost-effective over such a small scale of application and reapplication.

4.5.2.4 Vegetative Stabilization. Vegetative stabilization uses established cover or locally recommended varieties and seeding rates that approximate native cover to stabilize soil against wind erosion and emission of fugitive dust. Either temporary or permanent cover can be established using standard agricultural methods, hydroseeding, or hand seeding. Temporary cover, for areas that will be disturbed again after a short period, is best established by using rapidly emerging varieties of vegetation with rapid initial growth. Maintenance of the original vegetative cover and opportunistic vegetation such as weeds and native species are also options, but may require some watering to establish.

Vegetative stabilization as a fugitive dust control method is most effective only on inactive areas of the disturbed surfaces where frequent mechanical (i.e., earth moving) activities are not anticipated. As such, it is typically not implemented on a large scale for control of fugitive dust emissions during short-term construction activities.

4.5.2.5 Work Practice Controls. There are a number of work practice controls that can be applied to reduce the fugitive dust emissions during construction activities. These work practices include both active and preventive fugitive dust control methods, which are typically integrated into a comprehensive construction management plan. The following list contains several common work practice activities that may be applied to reduce fugitive dust emissions during construction:

- Pave designated roads, construction parking areas, and site access points early on in the construction project.
- Compact or stabilize disturbed areas as quickly as practical.
- Phase earth moving activities to reduce disturbed surface extent.
- Maintain original vegetative ground cover as long as practical.
- Establish a traffic control plan to decrease disturbance of soil and fugitive dust generated from unnecessary vehicle traffic by posting speed limit signs (generally less than 10 mph), erecting fencing and/or placing barriers to direct traffic, designating specific haul and/or access roads, designating offsite or limited access onsite parking for construction workers, and limiting public vehicle access.
- Reduce offsite hauling via balanced cut and fill operations.

4.5.2.6 Physical Stabilization. Physical stabilization methods, which involve covering a disturbed surface with a material that prevents the wind from entraining the surface particles, may be used during many phases of the construction project. Common physical stabilizing materials include rock, gravel, crushed or granulated slag, bark, wood chips, straw, or hay that are harrowed into the top few inches of the disturbed surface.

4.6 Impact on Human Populations

This section evaluates the impact on human population because of the construction of Unit 4. Areas of potential impact include those on land use, employment, traffic, housing, and public facilities and services. The assumed construction period for the 300 MW unit is from July 2009 through April 2011, a 22 month construction period.

4.6.1 Land Use Impacts

The CIPP is an existing site and is well suited for power generation. The project renderings in Section 3.2 illustrate that the site is surrounded by dense forest and is generally not visible from offsite areas.

Unit 4 will not require an expansion of the CIPP site and will not impact the land use of the surrounding area, which consists of hardwood swamp, rendering commercial or residential development unlikely in the foreseeable future. This is especially true since the land north, northeast, and west of the project site has been reserved for nature conservation. Furthermore, no alternative land uses have been proposed for the site.

No housing units will be affected by the site expansion. No lost income will result from any reduction of regional products or productivity whether due to displacement of persons from the land proposed for the site or otherwise.

4.6.2 Construction Employment and Income

The construction of Unit 4 will provide direct employment and wage benefits to the area through the significant construction workforce required at the site. Figure 4.6-1 shows the projected Unit 4 monthly workforce during the 22 month construction period. At peak, a total of 313 construction workers are projected to be onsite, and this figure includes 280 direct laborers and 33 construction management and utility personnel. This peak is expected to occur in month 15 of construction, which is projected to occur in September 2010. Over the 22 month construction period, an average of 160 direct craft construction workers and an average total workforce (also including indirect craft workers, construction management, and local utility staff) of 182 workers is expected. In all, a total of 4,010 man-months (334 man-years) of construction employment are expected, and 3,526 man-months (294 man-years) are expected to be direct craft employment.

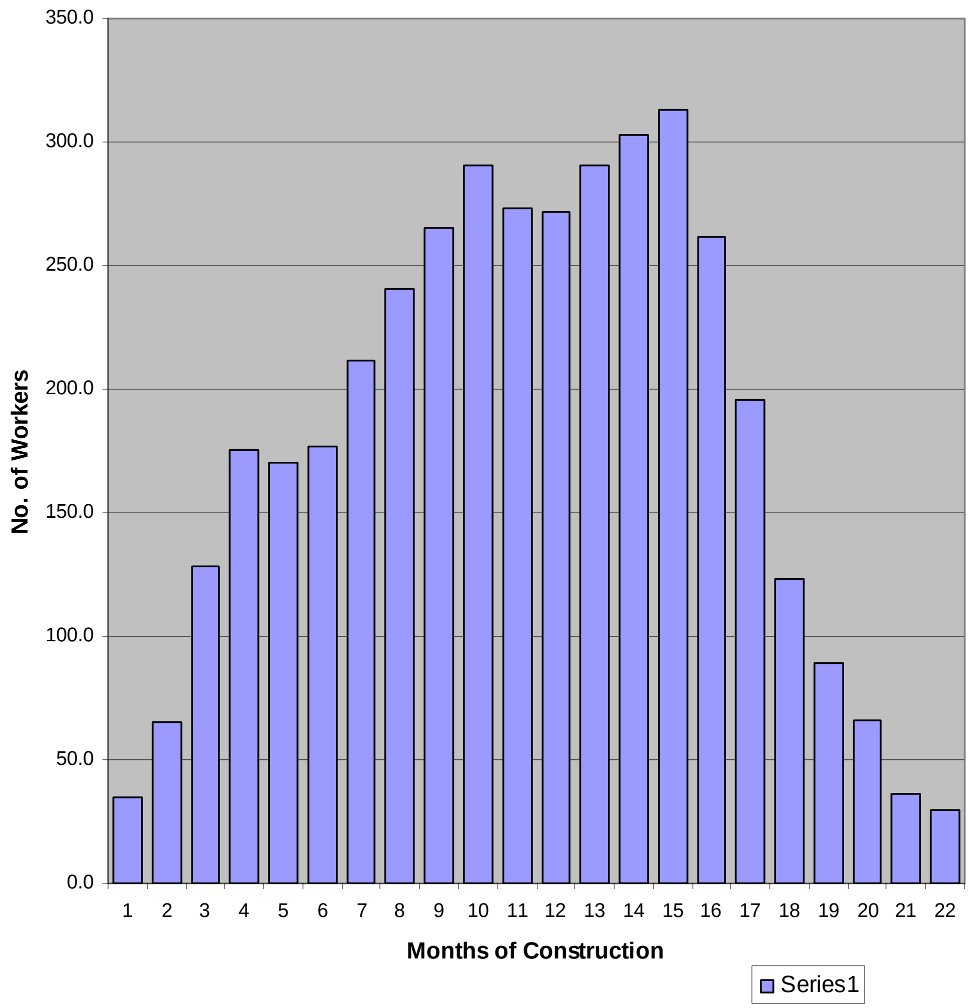

Figure 4.6-1
Unit 4 Site Manpower by Month

The wage benefits caused by Unit 4 construction are significant, given the 4,010 man-months of employment that will be required and the relatively high hourly wages paid to skilled construction workers and construction management staff. Total Unit 4 construction wages are budgeted at $42.75 million, of which $36.90 million is expected to be for direct labor. The multiplier impacts expected to result from these employment and income benefits are outlined in Section 7.0.

4.6.3 Construction Traffic

The CIPP is located off of Old Tampa Highway, 1 mile northwest of Intercession City. The CIPP is near Interstate 4, which will facilitate quick and easy access during the construction period. Other nearby routes include State Roads 535, 528 (Beachline Expressway), 408 (the East-West Expressway), and 417 (the GreeneWay). US 17/92, and 441 are also major highways in the area, and the likely commuting routes to the site are described in Section 2.0. Given the proximity of the CIPP to Orlando and Kissimmee, the entire Orlando-Kissimmee MSA is considered to be within easy commuting distance of the site.

Figure 4.6-2 shows the projected number of round trips that are anticipated to the site during construction. Included in the total round trips are those made by the construction workforce, as well as those needed to deliver supplies and equipment to the lay-down area, which will be entirely onsite. During the anticipated peak month of worker construction (month 15), it is anticipated that 7,076 round trips will be made to the site. This is equal to approximately 337 trips per day, on average, assuming 21 work days in the peak month. The additional trips to the site will present a small and temporary increase in the traffic flow near the site. Deliveries will be dispersed throughout the day, while worker trips will be linked to the morning and evening commute.

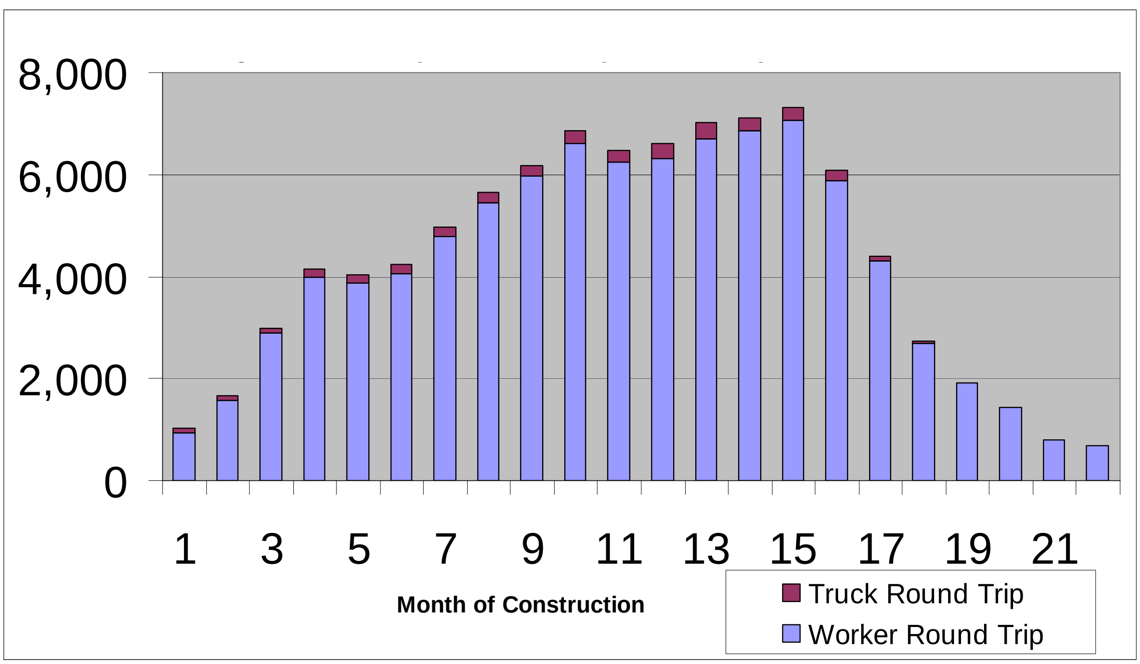

Figure 4.6-2
Projected Monthly Round Trips to the Site

4.6.4 Housing Impacts

Power plant construction can have the potential to impact area housing. Potential impacts could include the direct removal of housing units, visual impacts due to the location of the project near residential areas, and a housing shortage if an influx of workers requires long-term lodging during construction. As explained below, however, none of these potential impacts will occur because of the construction of the Unit 4 project.

The Unit 4 facility will not require any housing units to be removed at the site because the site is already used for power generation. Incremental visual impacts will also be minor because of the remote location of the site, which is surrounded by a significant tree buffer.

The potential for housing shortages has historically been an issue with large coal plant construction in sparsely populated areas of the western United States. However, experience has shown that smaller (i.e., noncoal plant) projects located in or around urban areas typically do not have a noticeable impact on the housing market. This is because housing impacts are mainly a function of the size of the construction workforce and its need for relocation throughout construction. The need to relocate is a function of the workforce available within a reasonable commuting distance of the work site. The Electric Power Research Institute (EPRI) has found that the construction workforce for a power plant project can be reasonably expected to commute without relocating during construction from a distance of over 70 miles, with instances of more than 100 miles commuting distance found in each of the construction projects studied. When a radius of 70 miles around the CIPP is considered, the large metropolitan areas of Kissimmee, Orlando, Palm Bay, Deltona, Lakeland, and portions of Tampa are within commuting distance of the site. Given these relatively large nearby population areas and the size of the construction force in the nine counties adjacent to the site, it is likely that nearly all craft workers will remain residing in their permanent residences during the 22 month construction period.

This conclusion is supported by the fact that most workers will not be onsite for the entire 22 month construction time frame, which further reduces the likelihood that relocation of a significant number of workers will occur. If occasional or short-term lodging is needed by some of the workforce, Osceola County has several hotels or other short-term lodging options, because it is a destination for vacationers and recreational enthusiasts. The Orlando area also has dozens of lodging options, and the Census data in Subsection 2.2.6.10 indicate a rental vacancy rate of 8.53 percent (in 2000). Assuming this vacancy pattern has remained fairly consistent, there would be ample housing rental options available should some of the craft workforce choose to relocate during construction. There may be a small number of specialized construction management staff that would relocate to the area on a temporary basis during construction, but there will be ample accommodations for this small number, and the economic benefits to the community will be positive.

4.6.5 Public Facilities and Services

Potential areas of impact from construction of Unit 4 may include fire and police protection, hospital services, the demand for water, wastewater, electricity, and natural gas supplies, the demand for landfill and trash removal services, and impacts on school facilities. Overall, however, construction practices will be planned to minimize or eliminate negative impacts on community facilities and services. Furthermore, the cost of services that are likely to be required is included in the construction budget and will be paid for on a user fee basis.

A construction safety plan will be developed for the site. This plan will help to ensure a safe working environment for the construction workforce. The safety plan will comply with all Occupational Safety and Health Administration (OSHA) requirements, and workers will have training to familiarize themselves with the training plan. Each member of the construction workforce will be required to abide by the requirements. Examples of proven safety measures include the use of hard hats in construction areas, and the required use of hard hats for people working at elevated heights.

Controlled access to the CIPP, Unit 4 footprint and lay-down area for equipment and supplies will be provided. This will include a badge system to control staff access and a security guard onsite. The facility will also have security lighting, some security fencing, and fire suppression equipment. First aid stations will be established and maintained throughout the construction area. Selected individuals in the construction workforce will receive first aid training. Standard procedures will also be adopted for spill prevention and containment, injury response, and requests for assistance for local police, fire, and ambulance service.

The construction safety plan is expected to mitigate safety risks, creating a minimal need for police, fire, and hospital support or services. Should a worker require hospitalization as a result of an onsite injury, the Orlando-Kissimmee area has complete hospital care facilities capable of handling almost any type of medical need, as described in Subsection 2.2.6.15.

The primary emergency responders to the CIPP will be the Osceola County Sheriff and the Intercession City Fire Department. The backup emergency responders to the site will be from the Osceola County Fire Department based in Kissimmee, approximately 9 miles from the CIPP.

The educational system is not expected to feel any impacts from the construction of the facility. Construction workers are expected to commute to their existing residences instead of relocating to the area. Therefore, area school enrollment should not rise significantly because of Unit 4 construction.

Water requirements during the construction will be supplied from onsite wells. The site will also reduce the need for an interconnected wastewater system through the use of portable restrooms for construction workers.

Waste produced by Unit 4 construction will be placed in large industrial dumpsters that will be obtained from and serviced by a contracted provider. The dumpsters will be emptied on a schedule that will avoid overfilling during the construction phase, and fees will be paid to cover all disposal costs.

4.6.6 Impacts from Construction Noise

Noise emissions attributable to construction activities are highly variable, depending on the location and operating load of the construction equipment and the construction phase activities. The following subsections discuss the methodology for estimating the construction activity noise emissions, the offsite noise levels associated with Unit 4 construction, and the evaluation of the noise levels and potential impacts to nearby receptors.

4.6.6.1 Construction Activities. Major construction phases will consist of site preparation, foundation construction, building and equipment erection, and site clean-up/facility startup. Noise emissions will vary with each phase of construction depending on the construction activity and the associated equipment required for each phase.

Site preparation will require the use of heavy diesel-powered earth moving equipment. Examples of this equipment include bulldozers, scrapers, dump trucks, graders, and front-end loaders. Noise emissions during site preparation will be dominated by the diesel engine noise.

Foundation construction primarily will involve concrete handling equipment such as concrete trucks, mixers, vibrators, pumps, and pile installation (if necessary) equipment. Some earth moving equipment will also be required to backfill the foundations. Foundation construction activities will primarily be centered at the power block and cooling tower equipment areas.

The equipment and building installation will involve diesel-powered earth moving equipment, mobile cranes, equipment delivery, impact wrenches, saws, drills, and air compressors. Again, these activities will primarily be centered at the power block and cooling tower equipment areas.

Site cleanup and facility startup will generally result in lower noise emissions than the preceding construction phases with the exception of steam blowout of the HRSG and steam lines. At the end of construction, low-pressure steam is passed through the HRSG to remove any debris within the steam lines prior to connecting with the steam turbine. Noise is produced when the steam is vented to the atmosphere. Typical steam blow schedules will involve several steam releases lasting several hours each, occurring within a 2 week period. While vent silencers are often employed, the steam blow noise is still easily discernable at offsite locations.

4.6.6.2 Construction Noise Ordinance. The Osceola County noise ordinance includes an exemption for noise resulting from construction activities occurring during daytime hours (7:00 a.m. to sunset). Construction activities resulting in offsite noise emissions during nighttime hours (1 minute after sunset to 6:59 a.m.) are subject to a sound level limit of 45 dBA at the CIPP property boundary. Construction activities will be scheduled during daytime periods (7:00 a.m. to sunset) to the fullest extent possible. Some activities will require extended hours of operation because of scheduling constraints or to maintain structural integrity of concrete pours. Nighttime construction will be limited to low-noise activities to the fullest extent possible. All construction activities will be conducted in accordance with the applicable local noise regulations.

At the end of construction, low-pressure steam is passed through the HRSG to remove any debris within the steam lines prior to connecting to the steam turbine. Noise is produced when the steam is vented to the atmosphere. Typical steam blow schedules will involve several steam releases lasting several hours each, occurring within a 2 week period. While vent silencers are often employed, the steam blow noise is still easily discernable at offsite locations. Local residents will be notified through correspondence sent through the U.S. Postal Service by FMPA, in advance of the steam blow period, to minimize adverse impacts related to steam blows.

4.6.6.3 Construction Noise Impacts. The variable nature of construction noise is best represented by an average noise level. The average noise levels account for the type and quantity of equipment, the typical usage of each piece of equipment, and typical noise levels of the equipment used during each phase of construction. The typical types of equipment, equipment usage, and equipment noise emissions for each phase of construction are listed in Table 4.6-1. Estimates of the construction equipment usage and noise levels are based on information provided in the EPA Document PB-250 430, Noise Emission Standards for Construction Equipment (EPA 1975) and the Power Plant Construction Noise Guide, Report No. 3321, prepared by Bolt Beranek and Newman Inc. (1977).

Table 4.6-1
Typical Construction Equipment Noise Emissions

Phase	Equipment	Lp[a] (50 ft) (dBA)	Qty	Usage[b]	Usage Factor[b]	Acoustic Max Factor[b]	L_{av}[c] (50 ft) (dBA)
Road Construction/ Site Preparation	Backhoe	82	1	0.04	-14	-5	63
	Concrete Vibrator	70	2	0.16	-8	-3	62
	Drill	83	1	0.16	-8	-3	72
	Grader	86	1	0.30	-5	-7	74
	Diesel Generator	76	1	0.16	-8	-3	65
	Trencher	86	1	0.21	-7	-3	76
	Mobile Crane	80	1	0.16	-8	-11	61
	Dozer	77	2	0.60	-2	-6	72
	Front End Loader	77	2	0.33	-5	-6	69
	Compactor/Roller	79	1	0.50	-3	-4	72
	Truck, Large	84	3	0.16	-8	-10	71
	Water Truck	84	1	0.35	-5	-10	69
Foundation	Mobile Crane	80	1	0.16	-8	-11	61
	Front End Loader	77	2	0.33	-5	-6	69
	Concrete Vibrator	70	3	0.16	-8	-3	64
	Pile Driver	81	2	0.04	-14	-3	67
	Drill	83	1	0.16	-8	-3	72
	Saw	70	2	0.21	-7	-3	63
	Torque Wrench	78	2	0.05	-12	-3	66
	Concrete Deliv. Truck	81	3	0.25	-6	-10	70
	Concrete Pump	74	1	0.08	-12	-3	59
	Concrete Saw	96	1	0.04	-14	-3	79
	Chop Saw	82	1	0.04	-14	-3	65
	Bush Hammer	85	1	0.25	-6	-3	76
	Dozer	77	1	0.50	-3	-6	68
	Stationary Crane	79	2	0.33	-5	-15	62
	Backhoe	82	2	0.40	-4	-5	76
	Truck, Large	84	3	0.16	-8	-10	71
	Diesel Generator	76	1	0.16	-8	-3	65
	Compactor/Roller	79	2	0.35	-5	-4	73
	Air Compressor	82	1	0.25	-6	-9	67
Equipment Erection	Mobile Crane	80	2	0.50	-3	-11	69
	Backhoe	82	1	0.20	-7	-5	70
	Truck, Large	84	2	0.16	-8	-10	69
	Stationary Crane	86	2	0.50	-3	-15	71
	Diesel Generator	76	1	0.33	-5	-3	68
	Welder, Diesel	81	1	0.65	-2	-3	76
	Grinder	80	1	0.25	-6	-3	71
	Chop Saw	82	1	1.00	0	-3	79
	Drill	83	1	0.16	-8	-3	72
	Torque Wrench	78	3	0.16	-8	-3	72
	Air Compressor	82	1	0.25	-6	-9	67

Table 4.6-1 (Continued)
Typical Construction Equipment Noise Emissions

Phase	Equipment	L_p[a] (50 ft) (dBA)	Qty	Usage[b]	Usage Factor[b]	Acoustic Max Factor[b]	L_{av}[c] (50 ft) (dBA)
Startup	Grader	86	1	0.10	-10	-7	69
	Trencher	86	1	0.10	-10	-3	73
	Drill	83	1	0.16	-8	-3	72
	Torque Wrench	78	5	0.16	-8	-3	74
	Diesel Generator	76	1	0.16	-8	-3	65
	Truck, Large	84	4	0.05	-12	-10	68
	Mobile Crane	80	1	0.05	-12	-11	57
	Air Compressor	82	1	0.25	-6	-9	67

Notes:
(a)Average sound pressure level at 50 feet (15 m) horizontal distance from the equipment.
(b)Based on information provided in the Power Plant Construction Noise Guide prepared by Bolt Beranek and Newman Inc. and information available from previous similar projects.
(c)Energy average sound pressure level at 50 feet (15 m) horizontal distance from the equipment for work shift of 7 to 10 hours.

Sources:
Power Plant Construction Noise Guide, 1977.
US EPA, *Noise emission standards for construction equipment*, 1975.

Table 4.6-2 shows the potential sound level increase caused by construction activities at each of the three nearest noise sensitive locations shown in Figure 4.6-3. In general, noise emissions associated with the construction of Unit 4 may cause short-term (temporary) increases in the daytime sound levels at the nearest noise sensitive locations of 0 to 5 dBA. While these sound level increases are typically considered "imperceptible" to "clearly noticeable," the construction noise is temporary in nature and these impacts are anticipated to be less than significant, particularly after sunset.

Table 4.6-2
Estimated Average Construction Noise at
Receptor Location for Each Construction Phase

Construction Phase	Nearest Receptor	Estimated Construction Noise Level L_{av}, dBA	Measured Average Daytime Background Sound Level L_{90}, dBA[(a)]	Estimated Future Background Sound Level During Construction, dBA[(b)]	Potential Temporary Sound Level Increase, dBA
Site Preparation	R1	40	52	52	0
	R2	40	39	43	4
	R3	40	38	42	4
Foundation	R1	41	52	52	0
	R2	41	39	43	4
	R3	41	38	43	5
Equipment Erection	R1	40	52	52	0
	R2	40	39	43	4
	R3	40	38	42	4
Startup[(a)]	R1	38	52	52	0
	R2	38	39	42	3
	R3	38	38	41	3

[(a)]Based on the median sound level recorded between the hours of 7:00 a.m. and 7:00 p.m.
[(b)]Sound level estimates do not include the influence of steam blows.

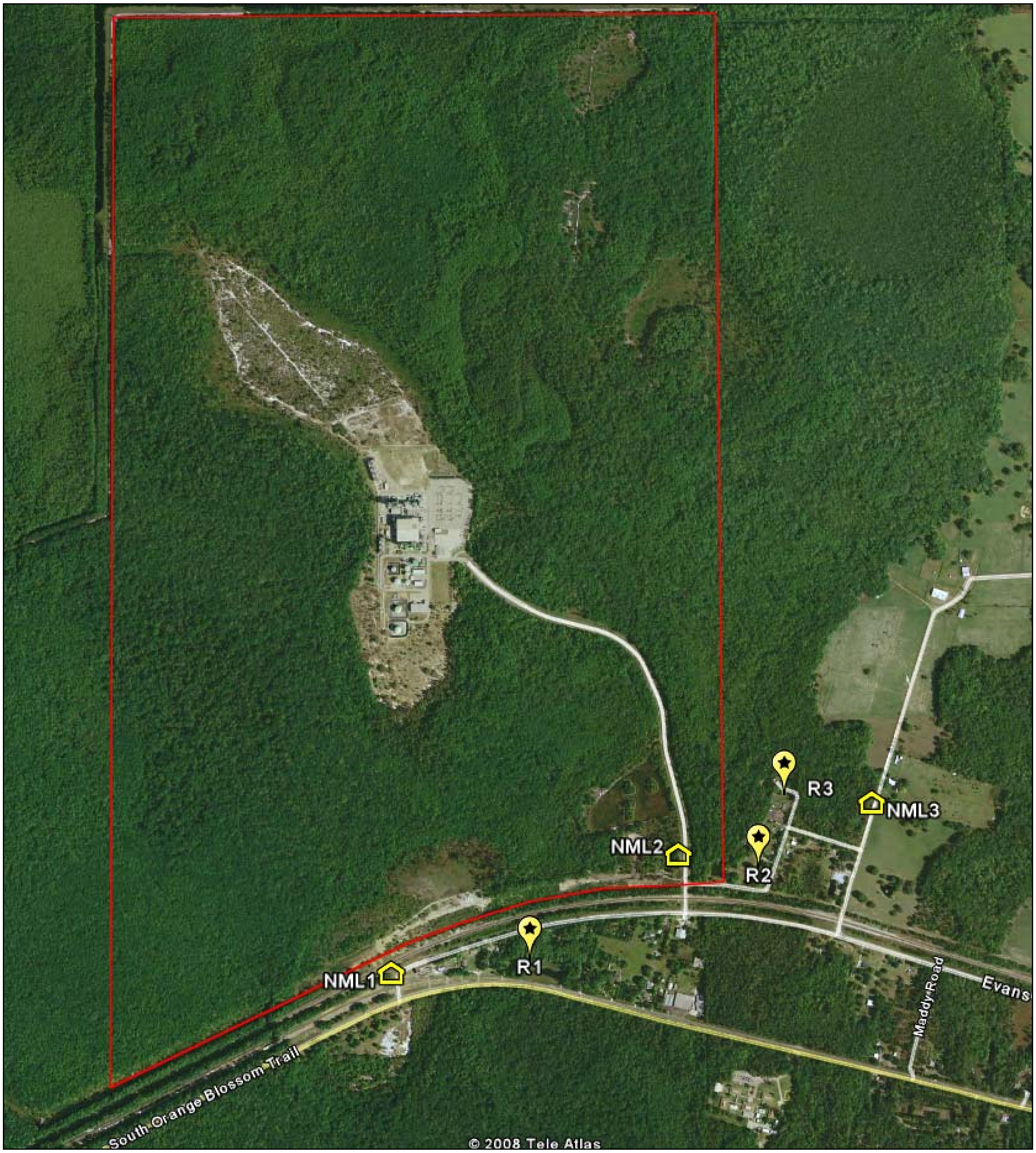

Figure 4.6-3
Nearest Noise Sensitive Receptors R1, R2, and R3

4.6.7 Storm Water Impacts

The construction phase will disturb more than 5 acres of land and will alter the amount of storm water discharged from the site. However, the amount of additional runoff from the construction site is not expected to be sufficient to negatively affect any of the nearby residences. This is due to the fact that storm water runoff control efforts will be designed and installed, including grading, a storm water detention pond, and strategically placed barriers of silt fences and/or straw bales to control runoff speeds and avenues. Even without control efforts, the distance to the nearest residence and the intervening swamp would prevent any additional runoff from the construction site from creating any negative impact on residents.

4.6.8 Visual Impacts

No adverse visual impacts are anticipated from the Unit 4 construction project. The new combined cycle unit will be located entirely within the established CIPP boundaries. Heavy forest vegetation exists between the power block area and Old Tampa Highway, the closest public thoroughfare, and the location of the nearest residences. The combination of the setback distance and the type and density of the buffer vegetation renders the power block nearly invisible from public view. The heights and locations of the Unit 4 facilities will not significantly alter the aesthetics of CIPP or the region.

Potentially, the most visible aspect of the Unit 4 project will be the stack. The HRSG stack will be approximately 160 feet tall and will be located in the north end of the power block. With the 100 foot Unit 2 and 130 foot Unit 3 stacks already in this area, the net visual effect is not expected to be significant. However, the top of the stack may be visible from Old Tampa Highway or US-17/92 directly south of the CIPP. No fogging or visible plume is anticipated from the new Unit 4 cooling tower under normal operating conditions. Exhaust stack plume visibility is expected to be minimal.

Trees will need to be removed for Unit 4 construction. In compliance with Osceola County Ordinance 87-15, which is designed to preserve and maintain a minimum amount of tree canopy, the CIPP received a tree removal permit during construction of Units 1 and 2 for ultimate site development. Therefore, a tree removal permit is not required for Unit 4 or future unit development.

4.7 Impact on Landmarks and Sensitive Areas

There are four recorded sensitive areas within 5 miles of the CIPP. These areas include Parcel 3 of the FDEP/Disney Conservation Easement north and west of the site, the playground/park in Intercession City, and the SOR properties south of Highway 92 and north of the CIPP. The location of the Intercession City playground is shown on Figures 2.2-1 and 2.2-2.

The Fletcher Park Monument and the South OBT Bridge occur within 1 mile of the CIPP as shown on Figure 2.2-2. The Rodgers House and the Homely Cow Dip area are within 5 miles of the CIPP as shown on Figure 2.2-1. In addition, the Disney 5000 13 Bridge in Intercession City, the Lake Wilson Boy Scout Camp in Kissimmee, and the Homestead Cemetery in Davenport are also within 5 miles of the CIPP. Sixteen historic residences occur along the South Orange Blossom Trail, four residences occur along the Old Tampa Highway, one residence occurs along Tallahassee Boulevard, and one residence occurs along Tomoka Road.

There should be no significant impacts on the FDEP/Disney Conservation Easement or the SOR properties resulting from construction of Unit 4. The distances, buffer zones, and onsite measures to control erosion, sedimentation, fugitive dust, and noise will effectively mitigate potential impacts. The construction workforce traffic may have a minimal impact on traffic through Intercession City, particularly during the rush hours. Although the playground/park in Intercession City fronts the Old Tampa Highway, construction traffic will be requested to use Highway 17/92 to avoid travel on the secondary streets of Intercession City.

The historic landmarks in the project area will not be impacted by project construction. Construction traffic will be requested to use Highway 17/92 to avoid travel on secondary streets and bridges in Intercession City. Therefore, these landmarks will be avoided.

4.8 Impact on Archaeological and Historic Sites

A Phase I cultural resources investigation of the CIPP property was conducted in May 1992, as described in Subsection 2.2.5. None of the discovered sites were considered eligible for listing on the *National Register of Historic Places.* The FDHR concurred and indicated that project construction could proceed without further involvement from the FDHR. Therefore, construction of Unit 4 is not expected to impact any known or recorded archeological or historic resources. If any such resources are discovered during construction, work in that area will stop, and the FDHR will be contacted within 24 hours for an appropriate plan of action.

4.9 Special Features

Construction debris, trash, and garbage will be collected in appropriate containers and removed from the site by a contractor for disposal at an approved landfill or resource recovery facility.

4.10 Benefits from Construction

The benefits associated with the construction of Unit 4 will include increased employment for regional workers. Attendant to this employment will be the benefits of increased sales tax revenue for Osceola County and the City of Kissimmee.

Increased income due to economic activity will also accrue to the region. Among these benefits are the increased revenue that will be enjoyed by the owners/operators of temporary housing facilities in the area. Although most of the construction employees are expected to commute daily from their established, permanent residences within the impact areas, some workers will be traveling into the impact area from more distant residences. Even though EPRI studies have indicated that these workers travel without their families, their individual housing needs will have to be satisfied. They will predictably patronize the hotels and recreation vehicle campgrounds that already exist in the area. Although this theoretically could cause a shortage of short-term housing, this situation is more optimistically interpreted as meaning that the owners of short-term housing will enjoy an increase in business. Realistically, a shortage of short-term housing is not anticipated since the area is a major tourist destination that has a tremendous amount of short-term housing capacity.

A detailed and comprehensive analysis of the benefits created by the site preparation, plant construction, and operation of the proposed CIPP expansion is contained in Section 7.0 of this application.

4.11 Variances

No variances from applicable codes or standards are requested for or during construction of Unit 4.

5.0 Effects of Plant Operation

5.1 Effects of the Operation of the Heat Dissipation System

Unit 4 will use a mechanical draft cooling tower as the major equipment heat dissipation/cooling method. Cooling tower makeup water is taken from, and blowdown is returned to, the Toho reuse water pipeline adjacent to the site.

5.1.1 Temperature Effect on Receiving Body of Water

Cooling towers are used to dissipate heat produced during power generation. There will be no discharge of cooling waters from the heat dissipation system to surface waters or wetlands. Blowdown from the heat dissipation system is combined with evaporative cooler blowdown, neutralization basin effluent, and steam cycle blowdown and returned to the Toho reuse water pipeline. The pipeline provides water to other downstream users and ultimately discharges to the Imperial site regional percolation pond treatment facility. Temperature of effluent from the CIPP is not anticipated to affect the regional percolation ponds.

5.1.2 Effect on Aquatic Life

There will be no discharge of effluent from the site into surface waters; no impacts to aquatic life are expected.

5.1.3 Biological Effects of Modified Circulation

Unit 4 will use municipal reuse water for cooling water. Modified circulation of a water body will not occur; therefore, there will be no biological effects.

5.1.4 Effects of Offstream Cooling

The purpose of this section is to assess the potential environmental impacts associated with the operation of the new eight-cell mechanical draft cooling tower associated with Unit 4. Potential impacts from the cooling towers include plume induced fogging and icing, deposition from circulating water drift, and visible plume formation. The following subsections describe the new cooling tower, explain the methodology and assumptions used to quantify the magnitude and extent of the impacts, present the results of the modeling, and discuss the potential environmental effects.

5.1.4.1 Cooling Tower Description. The new proposed combined cycle unit necessitates the construction and operation of a new cooling tower. The proposed cooling tower will be a mechanical draft, counterflow, wet design cooling tower incorporating plume abatement features. The preliminary design consists of one tower consisting of eight cells arranged along a north-northwest/south-southeast axis.

5.1.4.2 Technical Approach. A computer modeling analysis was performed to evaluate the magnitude and extent of the potential environmental impacts resulting from the operation of the new cooling tower. The Electric Power Research Institute (EPRI)-sponsored Seasonal/Annual Cooling Tower Plume Impact (SACTI, Version 11-1-90) model was used to quantify the cooling tower impacts. This computer code is an outgrowth of an earlier model evaluation study carried out by A. J. Policastro of the Argonne National Laboratory (ANL). Improved plume and drift models in the code have been calibrated with existing field and laboratory data and then subsequently verified with new data not included in the calibration process. The SACTI model has been widely used by electric utilities and their consultants to assess cooling tower plume impacts for incorporation into various types of environmental impact studies.

The methodology used in the SACTI model is based on the assumption that up to 35 distinct plume categories, based on the local ambient meteorological conditions and cooling tower design characteristics, can be identified at any given site. For mechanical draft cooling tower designs, the SACTI code assumes that 10 additional distinct plume categories may exist which are characteristic of plume induced ground level fogging and icing. In other words, depending on the type of cooling tower and the specific site conditions, a cooling tower plume may exhibit up to 45 distinctly different sets of plume characteristics (e.g., plume height, plume spread, plume downwash, and plume dispersion). In the case of mechanical draft cooling tower arrangements, the effects of the orientation of the tower with respect to merging cell plumes and structure induced downwash are simulated through the use of representative wind directions and the specific tower configuration.

The cooling tower plume in each of the aforementioned categories is produced by a different set of ambient meteorological conditions. Hourly meteorological data are used by the SACTI model to compute frequency distributions of the meteorological conditions responsible for each plume type within the assumed plume category. The SACTI model performs the following computational functions in a sequential manner to determine the representative plume categories and plume impacts:

- <u>Meteorological Data Preprocessor</u>--The meteorological data preprocessor performs three subtasks to delineate plume categories and calculate representative parameters for each category. In the first subtask, hourly surface meteorological data are read and invalid or missing parameters and hours are discarded. For each valid record, the model uses cooling tower parameters such as tower height, tower effective exit diameter, tower effective heat rejection, and tower effective air flow to calculate additional exit parameters including temperature and velocity, and some nondimensional parameters which characterize the buoyancy of the plume and the stability and saturation of the ambient air.

The second subtask generates frequency distribution tables for ranges of tower, meteorological, and nondimensional parameters as a function of the standard 16 wind directions. These meteorological variables represent the full range of atmospheric conditions affecting plume dispersion and drift deposition. For example, the SACTI model selects temperature ranges from -49° F to 113° F in 9° F intervals. The frequency of actual dry-bulb temperatures occurring in each of those ranges for each of the standard 16 wind directions is tabulated. Likewise, the model tabulates relative humidity values falling between 0 and 100 percent in intervals of 10 percent.

Subtask three uses the frequency distributions from Subtask two to delineate the distinctly different plume categories that could occur from cooling tower operation. Categories are selected so that all categories are roughly equally populated. A single set of representative tower and ambient conditions is then calculated from the range of conditions in each category, and then reassigned to each category.

- <u>Plume Calculations</u>--Using the preprocessor's representative conditions and cooling tower design data (e.g., tower orientation, number of cells, drift droplet spectrum, and salt concentrations), the plume code calculates fogging/icing and the plume's dimensions and depositional characteristics for each plume category and each representative wind direction. For example, assuming 45 total drift and fogging categories and four representative wind directions, a total of 225 plume cases are simulated.

  As previously stated, the representative wind directions are used to simulate tower-induced downwash. Therefore, specific output showing the nature and extent of the downwash is not generated by the program. Rather, output is generated for each representative wind direction, and the downwash effects can be inferred from the deposition/fogging/icing gradients.

- Impact Calculations--The various plume code prediction results are used in conjunction with the meteorological data preprocessor's frequency distribution of plume categories and actual wind directions to calculate impacts. The resulting cumulative impacts from all plume categories are tabulated and plotted in the SACTI model output as a function of wind direction and distance from the cooling tower.

5.1.4.2.1 Cooling tower plume model input. The SACTI cooling tower model requires certain site-specific, tower-specific, and circulating water-specific data as input. The input data used in this SACTI cooling tower modeling analysis are discussed below and summarized in Table 5.1-1 with the documented source of the data:

- Site-specific data includes the site's latitude and longitude, time zone, surface roughness height, monthly clearness indices, daily solar insolation values, representative hourly recorded surface meteorological data, and seasonal average morning and afternoon mixing heights.
- Tower-specific data includes information pertaining to the type of cooling tower, dimensions of the tower housing, cell exhaust diameter, heat load, drift rate, design air flow rate, and orientation of the cooling tower cells with respect to the 16 representative wind directions.
- Water-specific data includes the circulating water salt concentration, salt density, and the size distribution of the water droplets in the cooling tower drift.

The latitude, longitude, time zone, and surface roughness height were either directly measured or estimated. The monthly clearness indices and solar insolation values were obtained from Appendix B of the User's Manual for the SACTI Computer Code for a representative location at approximately the same latitude (EPRI 1984).

Five years (1999-2003) of surface meteorological data from Orlando, Florida, collected by the National Weather Service (NWS) and distributed by the National Climatic Data Center (NCDC) were used in the SACTI modeling analysis. These data contained the complete set of surface meteorological parameters (originally in ISH format; subsequently converted to TD-1440 format) necessary to conduct the cooling tower modeling analysis, and are considered representative of the site.

The type of cooling tower, dimensions of the tower housing, cell exhaust diameter, heat load, drift rate, design air flow rate, and orientation of the cooling tower cells were all based on design data.

Table 5.1-1
SACTI Cooling Tower Modeling Input Parameters

		Data Source/Notes
Site-Specific Data		
Site Latitude	28.28 ° N	Measured
Site Longitude	81.53 ° E	Measured
Time Zone	5	Measured
Surface Roughness Height	10 cm	Estimated
Monthly Clearness Indices (K_T)	0.61, 0.61, 0.62, 0.62, 0.63, 0.59, 0.56, 0.55, 0.56, 0.60, 0.64, 0.60	SACTI User's Manual for Tampa, FL
Monthly Average Daily Total Solar Flux (MJ/m^2)	13.76, 16.35, 19.95, 22.79, 24.88, 23.96, 22.29, 20.70, 18.99, 16.94, 14.93, 12.63	SACTI User's Manual for Tampa, FL
Meteorological Data (hourly surface data)	Orlando (1999-2003)	NCDC
Seasonal Average Mixing Heights	436 m (Winter morning) 1,079 m (Winter afternoon) 526 m (Spring morning) 1,524 m (Spring afternoon) 439 m (Summer morning) 1,429 m (Summer afternoon) 436 m (Fall morning) 1,079 m (Fall afternoon)	SACTI User's Manual for Tampa, FL
Wind Instrument Reference Height	10 m (anemometer height)	NCDC
Tower-Specific Data		
Tower Type	Linear Mechanical Draft	Design Criteria
Number of Towers	1	Design Criteria
Total Number of Cells	8	Design Criteria
Effective Exhaust Diameter	25.86 m	Note 1
Tower Height	17.07 m	Design Criteria
Tower Width	25.70 m	Design Criteria
Tower Length	58.60 m	Design Criteria
Total Heat Dissipation Rate	252 MW	Design Criteria
Total Circulating Water	126,000 gpm	Note 2
Total Drift Loss Rate	39.72 g/s	Note 2, based on 0.0005% drift rate.
Total Airflow Rate	4,346.60 kg/s	Note 2

Table 5.1-1 (Continued)
SACTI Cooling Tower Modeling Input Parameters

			Data Source/Notes
Water-Specific Data			
Cooling Tower Salt Concentration	0.002380 g Salt/g Soln		Preliminary Design
Salt Density	2.17 g/cm^3		Estimated
Drift Droplet Spectrum	Drop Size (µm)	Mass Fraction	Estimated, based on EPRI Study *Calculating Realistic PM$_{10}$ from Cooling Towers*.
	0-10	0.0000	
	10-20	0.0020	
	20-30	0.0003	
	30-40	0.0029	
	40-50	0.0130	
	50-60	0.0389	
	60-70	0.1565	
	70-90	0.2846	
	90-110	0.2070	
	110-130	0.1151	
	Drop Size (µm)	Mass Fraction	
	130-150	0.0599	
	150-180	0.0302	
	180-210	0.0144	
	210-240	0.0162	
	240-270	0.0060	
	270-300	0.0160	
	300-350	0.0072	
	350-400	0.0133	
	400-450	0.0073	
	450-500	0.0000	
	500-600	0.0093	

Note 1: Effective exhaust diameter is calculated using an equation from the SACTI User's Manual where the square-root of the total number of cells is multiplied by the actual diameter of a single cell. The total number of cells is eight. The actual diameter of a single cell is 9.14 meters.
Note 2: These values represent the total from the tower and not individual cells as required by the SACTI model.

The size distribution of drift droplets from the cooling tower is required as input to the SACTI model. The size distribution of drift droplets depends on the details of the interior construction, air and water flow through the fill, and the efficiency of the drift eliminators. The cooling tower drift droplet size spectrum data used in this study are based on representative data of other towers with similar drift eliminators. These drift droplet size data are representative of best available technology (BAT) currently utilized in cooling tower drift eliminator design. The concentration of total dissolved solids (TDS) in the cooling tower circulating water was based on using the Toho reuse water as the water supply with the cooling tower operating at 5 cycles of concentration.

5.1.4.3 Cooling Tower Impact Modeling Results. The SACTI cooling tower model was used to predict the magnitude of the cooling tower induced fogging and icing, deposition, and plume length frequency of occurrence while conservatively assuming the cooling tower is operating the entire year under peak conditions. The cooling tower system will dissipate waste heat by evaporating water and releasing the water vapor into the atmosphere. If the ambient air is cold and/or moist, a portion of the emitted water vapor will condense to form small water droplets. This condition is seen as a visible white plume emanating from the cooling tower.

Potential environmental impacts such as fogging, icing, and deposition associated with the cooling tower plumes may arise depending on the meteorological conditions and the environmental setting.

5.1.4.3.1 Plume fogging modeling results. Ground level fogging occurs when the visible plume from a cooling tower contacts the ground. Meteorological conditions favorable for ground level fogging from a mechanical draft cooling tower are generally associated with strong winds (generally greater than 20 mph) which bend the plume to intercept the ground, and high relative humidity (small dew point depression) for easy plume saturation. The cooling tower fogging results are calculated by the SACTI cooling tower model as the maximum number of hours plume induced fogging from a cooling tower could occur for each wind direction. Table 5.1-2 presents the total hours (based on the 5 year meteorological database) of predicted plume fogging associated with the cooling tower. The 16 wind direction labels in the columns of the table represent the direction from the cooling towers that the plume is headed. The data represent the total hours (over the 5 year data base) that the cooling tower plume could induce fogging conditions for a particular direction and distance from the cooling tower.

Table 5.1-2
Total Hours of Predicted Plume Induced Fogging

Distance From Tower (m)	Fogging in the Direction Plume is Headed (Hours)*																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	0.1	0.0	0.1	0.8	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.8	0.1	0.0	0.1	0.8	2.8
200.	0.0	0.0	0.5	0.7	0.0	0.0	0.0	0.0	0.0	1.0	0.5	0.7	0.0	1.0	0.5	1.0	5.9
300.	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.5	0.0	0.0	0.7	0.5	0.6	3.8
400.	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	0.0	0.0	0.5	0.5
500.	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	0.0	0.0	0.5	0.5
600.	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	0.0	0.0	0.5	0.5
700.	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	0.0	0.0	0.2	0.2
800.	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	0.0	0.0	0.0	0.0
900.	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	0.0	0.0	0.0	0.0
1000.	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	0.0	0.0	0.0	0.0
1100.	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	0.0	0.0	0.0	0.0
1200.	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	0.0	0.0	0.0	0.0
1300.	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	0.0	0.0	0.0	0.0
1400.	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	0.0	0.0	0.0	0.0
1500.	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	0.0	0.0	0.0	0.0
1600.	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	0.0	0.0	0.0	0.0

*Total hours of fogging over 5 years. Average annual hours of cooling tower induced fogging is obtained by dividing the table value by 5.

Source: SACTI cooling tower model.

As the data in Table 5.1-2 indicate, the SACTI model predicts that, on average, fogging would occur approximately 1 hour per year regardless of wind direction and would not extend past 700 meters (2,297 ft) in any direction from the cooling towers. The closest property boundary to the new cooling tower is approximately 615 meters indicating that the small fraction of hours predicted at 700 meters barely reaches past the nearest property boundary.

5.1.4.3.2 Plume icing modeling results. Ground level plume icing (fog ice) is a semi-opaque coating of small granules of ice formed when small water droplets in the visible cooling tower fog freeze rapidly on the ground during conditions of high relative humidity and below freezing temperatures. The SACTI cooling tower model predicted no occurrences of cooling tower plume induced icing based on the 5 year meteorological database. This is consistent with the climate of the area, as records indicate that freezing temperatures occur less than 1 percent of the year on average.

5.1.4.3.3 Water deposition modeling results. Water deposition from a cooling tower occurs when the airborne water droplets coalesce and precipitate downwind of the cooling tower. The pattern of water deposition and the distance of maximum water deposition from the cooling tower are a function of the physical size of the water droplets in the drift, prevailing wind direction, orientation of the cooling tower cells, and the airflow rate.

Table 5.1-3 presents the SACTI model predicted average monthly (based on the 5 year meteorological database) water deposition rate in scientific notation in units of kg/km^2/month associated with the proposed cooling tower. The 16 wind direction labels in the columns of the table represent the direction from the cooling towers that the water deposition is predicted to occur.

Table 5.1-3
Average Monthly Predicted Cooling Tower Water Deposition

Distance From Tower (m)	Water Deposition in the Direction Plume is Headed (kg/km2-month)																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	.48E+03	.13E+03	.65E+02	.28E+02	.42E+02	.24E+03	.26E+03	.34E+03	.56E+03	.31E+03	.21E+03	.23E+02	.23E+02	.12E+03	.12E+03	.99E+02	.19E+03
200.	.79E+04	.43E+04	.41E+04	.32E+04	.69E+04	.58E+04	.45E+04	.34E+04	.62E+04	.38E+04	.35E+04	.25E+04	.42E+04	.37E+04	.30E+04	.23E+04	.43E+04
300.	.71E+04	.31E+04	.25E+04	.53E+04	.97E+04	.32E+04	.27E+04	.24E+04	.45E+04	.27E+04	.24E+04	.31E+04	.54E+04	.20E+04	.19E+04	.19E+04	.37E+04
400.	.12E+04	.89E+03	.10E+04	.79E+03	.16E+04	.17E+04	.13E+04	.71E+03	.12E+04	.90E+03	.86E+03	.48E+03	.89E+03	.11E+04	.73E+03	.37E+03	.98E+03
500.	.22E+04	.11E+04	.10E+04	.13E+04	.22E+04	.14E+04	.10E+04	.81E+03	.15E+04	.98E+03	.82E+03	.70E+03	.11E+04	.79E+03	.70E+03	.56E+03	.12E+04
600.	.19E+04	.87E+03	.73E+03	.12E+04	.20E+04	.90E+03	.71E+03	.68E+03	.13E+04	.71E+03	.62E+03	.67E+03	.11E+04	.55E+03	.51E+03	.50E+03	.94E+03
700.	.14E+04	.63E+03	.47E+03	.84E+03	.14E+04	.58E+03	.49E+03	.42E+03	.83E+03	.54E+03	.46E+03	.45E+03	.71E+03	.37E+03	.37E+03	.32E+03	.64E+03
800.	.11E+04	.45E+03	.33E+03	.69E+03	.12E+04	.41E+03	.36E+03	.32E+03	.62E+03	.38E+03	.32E+03	.37E+03	.58E+03	.25E+03	.25E+03	.25E+03	.49E+03
900.	.97E+03	.39E+03	.27E+03	.37E+03	.71E+03	.33E+03	.30E+03	.28E+03	.54E+03	.33E+03	.28E+03	.24E+03	.34E+03	.20E+03	.21E+03	.21E+03	.37E+03
1000.	.84E+03	.28E+03	.19E+03	.16E+03	.36E+03	.26E+03	.23E+03	.24E+03	.47E+03	.26E+03	.21E+03	.11E+03	.16E+03	.15E+03	.16E+03	.17E+03	.27E+03
1100.	.48E+03	.18E+03	.13E+03	.15E+03	.33E+03	.20E+03	.17E+03	.17E+03	.33E+03	.20E+03	.16E+03	.98E+02	.14E+03	.10E+03	.11E+03	.95E+02	.19E+03
1200.	.37E+03	.13E+03	.86E+02	.12E+03	.24E+03	.15E+03	.13E+03	.14E+03	.27E+03	.16E+03	.12E+03	.71E+02	.11E+03	.68E+02	.76E+02	.67E+02	.14E+03
1300.	.28E+03	.99E+02	.59E+02	.11E+03	.22E+03	.11E+03	.10E+03	.11E+03	.22E+03	.14E+03	.98E+02	.66E+02	.10E+03	.46E+02	.59E+02	.53E+02	.12E+03
1400.	.18E+03	.68E+02	.43E+02	.90E+02	.19E+03	.66E+02	.60E+02	.64E+02	.12E+03	.84E+02	.61E+02	.59E+02	.90E+02	.33E+02	.39E+02	.35E+02	.81E+02
1500.	.17E+03	.61E+02	.38E+02	.89E+02	.19E+03	.57E+02	.51E+02	.59E+02	.12E+03	.72E+02	.54E+02	.58E+02	.88E+02	.30E+02	.34E+02	.31E+02	.75E+02
1600.	.18E+03	.61E+02	.37E+02	.83E+02	.18E+03	.56E+02	.50E+02	.59E+02	.12E+03	.72E+02	.54E+02	.55E+02	.82E+02	.29E+02	.34E+02	.31E+02	.74E+02
1700.	.18E+03	.54E+02	.29E+02	.52E+02	.99E+02	.50E+02	.48E+02	.58E+02	.12E+03	.68E+02	.50E+02	.33E+02	.50E+02	.23E+02	.30E+02	.30E+02	.61E+02
1800.	.17E+03	.50E+02	.26E+02	.33E+02	.73E+02	.47E+02	.46E+02	.57E+02	.12E+03	.67E+02	.48E+02	.24E+02	.32E+02	.20E+02	.28E+02	.29E+02	.54E+02
1900.	.16E+03	.47E+02	.24E+02	.33E+02	.73E+02	.45E+02	.44E+02	.55E+02	.11E+03	.65E+02	.46E+02	.24E+02	.32E+02	.19E+02	.27E+02	.26E+02	.52E+02
2000.	.95E+02	.40E+02	.21E+02	.33E+02	.73E+02	.36E+02	.35E+02	.24E+02	.53E+02	.50E+02	.37E+02	.24E+02	.32E+02	.16E+02	.22E+02	.15E+02	.38E+02
2100.	.92E+02	.29E+02	.15E+02	.33E+02	.73E+02	.21E+02	.20E+02	.24E+02	.52E+02	.29E+02	.24E+02	.24E+02	.32E+02	.11E+02	.15E+02	.14E+02	.32E+02
2200.	.92E+02	.29E+02	.15E+02	.32E+02	.71E+02	.21E+02	.20E+02	.23E+02	.52E+02	.28E+02	.24E+02	.23E+02	.31E+02	.11E+02	.15E+02	.14E+02	.31E+02
2300.	.87E+02	.28E+02	.14E+02	.31E+02	.71E+02	.19E+02	.18E+02	.22E+02	.48E+02	.27E+02	.23E+02	.23E+02	.31E+02	.10E+02	.14E+02	.13E+02	.30E+02
2400.	.85E+02	.27E+02	.14E+02	.31E+02	.70E+02	.19E+02	.18E+02	.21E+02	.47E+02	.27E+02	.22E+02	.23E+02	.31E+02	.98E+01	.13E+02	.12E+02	.29E+02
2500.	.84E+02	.25E+02	.13E+02	.26E+02	.61E+02	.19E+02	.17E+02	.21E+02	.46E+02	.26E+02	.21E+02	.20E+02	.26E+02	.97E+01	.13E+02	.12E+02	.28E+02
2600.	.78E+02	.25E+02	.13E+02	.21E+02	.52E+02	.18E+02	.17E+02	.21E+02	.44E+02	.26E+02	.21E+02	.16E+02	.22E+02	.96E+01	.13E+02	.12E+02	.26E+02
2700.	.77E+02	.25E+02	.13E+02	.17E+02	.47E+02	.18E+02	.17E+02	.20E+02	.43E+02	.25E+02	.20E+02	.14E+02	.18E+02	.95E+01	.12E+02	.12E+02	.24E+02
2800.	.77E+02	.23E+02	.12E+02	.11E+02	.26E+02	.17E+02	.16E+02	.20E+02	.43E+02	.24E+02	.20E+02	.80E+01	.11E+02	.89E+01	.12E+02	.12E+02	.21E+02
2900.	.74E+02	.21E+02	.11E+02	.78E+01	.17E+02	.16E+02	.15E+02	.20E+02	.42E+02	.23E+02	.18E+02	.52E+01	.82E+01	.82E+01	.11E+02	.11E+02	.19E+02
3000.	.61E+02	.15E+02	.78E+01	.76E+01	.16E+02	.13E+02	.12E+02	.17E+02	.37E+02	.19E+02	.15E+02	.50E+01	.80E+01	.58E+01	.83E+01	.88E+01	.16E+02
3100.	.49E+02	.16E+02	.77E+01	.72E+01	.16E+02	.13E+02	.12E+02	.15E+02	.33E+02	.19E+02	.16E+02	.49E+01	.76E+01	.56E+01	.81E+01	.65E+01	.15E+02
3200.	.49E+02	.14E+02	.69E+01	.63E+01	.14E+02	.12E+02	.11E+02	.14E+02	.33E+02	.18E+02	.15E+02	.44E+01	.66E+01	.48E+01	.74E+01	.60E+01	.14E+02
3300.	.49E+02	.13E+02	.59E+01	.50E+01	.11E+02	.11E+02	.11E+02	.14E+02	.32E+02	.17E+02	.14E+02	.27E+01	.49E+01	.39E+01	.66E+01	.60E+01	.13E+02
3400.	.46E+02	.13E+02	.59E+01	.41E+01	.96E+01	.11E+02	.11E+02	.13E+02	.30E+02	.17E+02	.14E+02	.24E+01	.43E+01	.39E+01	.66E+01	.54E+01	.12E+02
3500.	.32E+02	.11E+02	.52E+01	.39E+01	.93E+01	.11E+02	.10E+02	.68E+01	.18E+02	.16E+02	.12E+02	.23E+01	.41E+01	.37E+01	.60E+01	.35E+01	.97E+01
3600.	.25E+02	.72E+01	.33E+01	.39E+01	.93E+01	.50E+01	.46E+01	.57E+01	.14E+02	.76E+01	.72E+01	.23E+01	.41E+01	.21E+01	.34E+01	.29E+01	.67E+01
3700.	.23E+02	.70E+01	.31E+01	.39E+01	.93E+01	.48E+01	.44E+01	.50E+01	.13E+02	.75E+01	.70E+01	.23E+01	.41E+01	.20E+01	.32E+01	.23E+01	.63E+01
3800.	.22E+02	.64E+01	.27E+01	.39E+01	.93E+01	.41E+01	.36E+01	.49E+01	.13E+02	.67E+01	.63E+01	.23E+01	.41E+01	.15E+01	.26E+01	.21E+01	.59E+01
3900.	.22E+02	.61E+01	.25E+01	.32E+01	.81E+01	.37E+01	.33E+01	.48E+01	.13E+02	.64E+01	.60E+01	.21E+01	.35E+01	.13E+01	.24E+01	.21E+01	.56E+01
4000.	.22E+02	.61E+01	.25E+01	.32E+01	.81E+01	.37E+01	.33E+01	.48E+01	.13E+02	.64E+01	.60E+01	.21E+01	.35E+01	.13E+01	.24E+01	.21E+01	.56E+01
4100.	.22E+02	.61E+01	.25E+01	.32E+01	.81E+01	.37E+01	.33E+01	.48E+01	.13E+02	.64E+01	.60E+01	.21E+01	.35E+01	.13E+01	.24E+01	.21E+01	.56E+01
4200.	.22E+02	.61E+01	.25E+01	.32E+01	.81E+01	.37E+01	.33E+01	.48E+01	.13E+02	.64E+01	.60E+01	.21E+01	.35E+01	.13E+01	.24E+01	.21E+01	.56E+01
4300.	.22E+02	.50E+01	.21E+01	.32E+01	.81E+01	.34E+01	.31E+01	.48E+01	.13E+02	.57E+01	.50E+01	.21E+01	.34E+01	.12E+01	.21E+01	.21E+01	.54E+01
4400.	.20E+02	.46E+01	.20E+01	.30E+01	.78E+01	.33E+01	.31E+01	.46E+01	.11E+02	.54E+01	.46E+01	.20E+01	.33E+01	.12E+01	.20E+01	.20E+01	.50E+01
4500.	.17E+02	.46E+01	.20E+01	.30E+01	.77E+01	.33E+01	.31E+01	.43E+01	.10E+02	.54E+01	.46E+01	.20E+01	.33E+01	.12E+01	.20E+01	.18E+01	.47E+01
4600.	.17E+02	.46E+01	.20E+01	.30E+01	.77E+01	.33E+01	.31E+01	.43E+01	.10E+02	.54E+01	.46E+01	.20E+01	.33E+01	.12E+01	.20E+01	.18E+01	.47E+01
4700.	.17E+02	.46E+01	.20E+01	.30E+01	.77E+01	.33E+01	.31E+01	.43E+01	.10E+02	.54E+01	.46E+01	.20E+01	.33E+01	.12E+01	.20E+01	.18E+01	.47E+01
4800.	.17E+02	.46E+01	.20E+01	.26E+01	.71E+01	.33E+01	.31E+01	.43E+01	.10E+02	.54E+01	.46E+01	.19E+01	.29E+01	.12E+01	.20E+01	.18E+01	.46E+01
4900.	.13E+02	.46E+01	.20E+01	.25E+01	.70E+01	.33E+01	.31E+01	.35E+01	.86E+01	.54E+01	.46E+01	.19E+01	.28E+01	.12E+01	.20E+01	.13E+01	.42E+01
5000.	.13E+02	.46E+01	.20E+01	.25E+01	.70E+01	.33E+01	.31E+01	.35E+01	.84E+01	.54E+01	.46E+01	.19E+01	.28E+01	.12E+01	.20E+01	.13E+01	.42E+01

Source: SACTI cooling tower model.

The SACTI model predicted that the maximum cooling tower water deposition will occur approximately 300 meters (984 ft) west of the cooling tower at a rate of 9,700 kg/km^2/month. The average water deposition at a 300 meters (984 ft) radius from the cooling tower (considering all directions of plume travel) is predicted to be 3,700 kg/km^2/month.

5.1.4.3.4 Salt deposition modeling results. Salt deposition is primarily a function of the salt concentration in the circulating cooling water and the water deposition rate. Table 5.1-4 presents the SACTI model predicted average monthly (based on the 5 year meteorological database) salt deposition rate in units of kg/km^2/month associated with the proposed cooling tower. The 16 wind direction labels in the columns of the table represent the direction from the proposed cooling tower that the salt deposition is predicted to occur.

The maximum salt deposition occurs approximately 300 meters (984 ft) west of the cooling tower at a rate of 26.41 kg/km^2/month. The average salt deposition at a radius of 300 meters (984 ft) from the cooling tower (considering all directions of plume travel) is predicted to be 9.79 kg/km^2/month. Beyond 300 meters (984 ft) from the cooling towers, the salt deposition significantly decreases. In fact, the average salt deposition beyond 300 meters (984 ft) from the cooling towers in all directions is less than 4 kg/km^2/month.

5.1.4.3.5 Plume length modeling results. The cooling tower plume lengths are calculated by the SACTI model as the frequency of occurrence of a given plume length from the cooling tower for each wind direction. Table 5.1-5 presents the average annual (based on the 5 year meteorological database) predicted plume length frequency of occurrence associated with the cooling tower. The 16 wind direction labels in the columns of the table represent the direction from the cooling tower that the plume is headed. The data represent the probability (by percent of the year) that the cooling tower plume will be as long or longer than the length defined in the table for a particular direction and distance from the cooling tower.

As the data in Table 5.1-5 indicates, the SACTI model predicts the plume length to be less than 300 meters (984 ft) 95 percent of the year considering all directions of plume travel. The median plume length, or that length which the plume is predicted to be longer or shorter than for 50 percent of the year considering all directions of plume travel, is approximately 153 meters (502 ft).

Table 5.1-4
Average Monthly Predicted Cooling Tower Salt Deposition

Distance From Tower	Salt Deposition in the Direction Plume is Headed (kg/km2-month)																
(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	1.18	0.31	0.16	0.07	0.10	0.59	0.64	0.87	1.42	0.74	0.51	0.06	0.06	0.30	0.29	0.25	0.47
200.	20.04	10.98	10.48	8.21	17.70	14.92	11.56	8.99	16.22	9.69	9.03	6.33	10.90	9.46	7.71	6.14	11.15
300.	17.95	7.92	6.36	13.69	26.41	8.18	6.91	6.33	11.70	6.99	6.13	8.21	14.81	5.22	4.99	4.80	9.79
400.	3.49	2.58	2.95	2.23	5.14	5.34	4.30	2.25	3.78	2.68	2.75	1.50	3.00	3.63	2.32	1.13	3.07
500.	6.22	3.34	3.19	3.75	6.67	4.51	3.29	2.52	4.58	2.87	2.50	2.13	3.47	2.57	2.16	1.70	3.47
600.	5.55	2.63	2.31	3.68	6.19	3.03	2.38	2.11	3.84	2.20	1.99	2.02	3.34	1.92	1.67	1.55	2.90
700.	4.07	1.97	1.60	2.67	4.61	2.04	1.66	1.40	2.66	1.69	1.48	1.43	2.34	1.31	1.22	1.05	2.07
800.	3.27	1.48	1.20	2.19	3.91	1.57	1.31	1.14	2.13	1.29	1.10	1.18	1.92	0.96	0.91	0.85	1.65
900.	2.85	1.34	1.07	1.19	2.34	1.40	1.14	0.91	1.70	1.09	0.93	0.76	1.15	0.83	0.78	0.67	1.26
1000.	2.52	1.01	0.83	0.55	1.25	1.18	0.92	0.81	1.52	0.88	0.74	0.37	0.58	0.66	0.63	0.57	0.94
1100.	1.59	0.71	0.62	0.51	1.17	0.97	0.75	0.63	1.19	0.72	0.58	0.33	0.53	0.50	0.47	0.38	0.73
1200.	1.24	0.53	0.44	0.46	1.01	0.71	0.57	0.50	0.93	0.59	0.45	0.28	0.47	0.36	0.34	0.27	0.57
1300.	1.01	0.35	0.23	0.45	0.97	0.37	0.34	0.44	0.80	0.45	0.32	0.27	0.46	0.19	0.21	0.23	0.44
1400.	0.75	0.27	0.19	0.35	0.84	0.28	0.25	0.29	0.54	0.32	0.24	0.24	0.40	0.15	0.16	0.16	0.34
1500.	0.68	0.26	0.18	0.34	0.77	0.26	0.22	0.25	0.47	0.30	0.22	0.22	0.35	0.14	0.15	0.13	0.31
1600.	0.69	0.25	0.17	0.33	0.72	0.25	0.22	0.25	0.48	0.29	0.22	0.21	0.32	0.14	0.15	0.13	0.30
1700.	0.68	0.21	0.12	0.26	0.53	0.21	0.21	0.24	0.47	0.27	0.20	0.16	0.24	0.11	0.13	0.13	0.26
1800.	0.67	0.21	0.12	0.22	0.48	0.21	0.21	0.24	0.47	0.27	0.19	0.14	0.21	0.10	0.12	0.12	0.25
1900.	0.64	0.20	0.12	0.22	0.48	0.20	0.20	0.23	0.45	0.27	0.19	0.14	0.21	0.10	0.12	0.11	0.24
2000.	0.45	0.19	0.11	0.22	0.48	0.18	0.18	0.14	0.28	0.23	0.17	0.14	0.21	0.09	0.11	0.08	0.20
2100.	0.46	0.16	0.10	0.22	0.48	0.14	0.14	0.15	0.28	0.16	0.13	0.14	0.21	0.08	0.09	0.08	0.19
2200.	0.46	0.16	0.10	0.21	0.47	0.14	0.14	0.15	0.28	0.16	0.13	0.14	0.20	0.08	0.09	0.08	0.19
2300.	0.46	0.16	0.09	0.21	0.47	0.14	0.14	0.15	0.28	0.16	0.13	0.14	0.20	0.08	0.09	0.08	0.19
2400.	0.45	0.15	0.09	0.21	0.47	0.13	0.13	0.14	0.28	0.16	0.13	0.14	0.20	0.07	0.08	0.08	0.18
2500.	0.45	0.14	0.08	0.19	0.42	0.13	0.13	0.14	0.28	0.16	0.12	0.12	0.18	0.07	0.08	0.08	0.17
2600.	0.44	0.14	0.08	0.16	0.37	0.13	0.13	0.14	0.27	0.16	0.12	0.11	0.15	0.07	0.08	0.08	0.17
2700.	0.43	0.14	0.08	0.14	0.34	0.13	0.13	0.14	0.27	0.15	0.12	0.09	0.13	0.07	0.08	0.08	0.16
2800.	0.42	0.14	0.08	0.09	0.20	0.12	0.12	0.14	0.26	0.15	0.12	0.06	0.08	0.07	0.08	0.08	0.14
2900.	0.41	0.12	0.07	0.07	0.14	0.12	0.12	0.13	0.25	0.14	0.11	0.04	0.06	0.06	0.07	0.07	0.13
3000.	0.36	0.10	0.06	0.07	0.14	0.10	0.10	0.12	0.23	0.13	0.10	0.04	0.06	0.05	0.06	0.06	0.11
3100.	0.29	0.09	0.06	0.06	0.14	0.10	0.10	0.11	0.20	0.12	0.10	0.04	0.06	0.05	0.06	0.05	0.10
3200.	0.26	0.08	0.05	0.06	0.13	0.10	0.10	0.10	0.19	0.12	0.09	0.04	0.06	0.05	0.05	0.04	0.09
3300.	0.26	0.07	0.04	0.06	0.12	0.09	0.09	0.10	0.19	0.11	0.08	0.03	0.05	0.04	0.05	0.04	0.09
3400.	0.23	0.07	0.04	0.03	0.08	0.09	0.09	0.09	0.17	0.11	0.08	0.02	0.03	0.04	0.05	0.04	0.08
3500.	0.14	0.07	0.04	0.03	0.07	0.09	0.08	0.05	0.10	0.11	0.08	0.02	0.03	0.04	0.05	0.02	0.06
3600.	0.11	0.04	0.02	0.03	0.07	0.04	0.04	0.04	0.08	0.05	0.04	0.02	0.03	0.02	0.02	0.02	0.04
3700.	0.10	0.03	0.02	0.03	0.07	0.04	0.04	0.04	0.07	0.05	0.04	0.02	0.03	0.02	0.02	0.02	0.04
3800.	0.09	0.03	0.02	0.03	0.07	0.03	0.03	0.03	0.07	0.04	0.03	0.02	0.03	0.01	0.02	0.01	0.03
3900.	0.09	0.03	0.01	0.03	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4000.	0.09	0.03	0.01	0.03	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4100.	0.09	0.03	0.01	0.03	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4200.	0.09	0.03	0.01	0.03	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4300.	0.09	0.03	0.01	0.03	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4400.	0.09	0.02	0.01	0.02	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4500.	0.09	0.02	0.01	0.02	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4600.	0.09	0.02	0.01	0.02	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4700.	0.09	0.02	0.01	0.02	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4800.	0.08	0.02	0.01	0.02	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
4900.	0.07	0.02	0.01	0.02	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03
5000.	0.07	0.02	0.01	0.02	0.07	0.03	0.03	0.03	0.06	0.04	0.03	0.02	0.03	0.01	0.01	0.01	0.03

Source: SACTI cooling tower model.

Table 5.1-5
Average Annual Predicted Plume Length Frequency of Occurrence

Distance From Tower (m)	Probability the Plume is Longer in a Given Direction Than the Distance Indicated (percent)																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	SUM
100.	12.48	5.92	5.12	6.61	11.99	6.76	5.54	4.70	8.67	5.05	4.66	4.05	6.57	4.43	3.90	3.56	100.00
200.	0.43	0.27	0.21	0.64	1.33	0.11	0.14	0.10	0.29	0.24	0.16	0.61	0.71	0.08	0.11	0.04	5.48
300.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
400.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
500.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
600.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
700.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
800.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
900.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1000.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1100.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1200.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1300.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1400.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1500.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1600.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1700.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1800.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
1900.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2000.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2100.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2200.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2300.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2400.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2500.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2600.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2700.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2800.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
2900.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3000.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3100.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3200.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3300.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3400.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3500.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3600.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3700.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3800.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
3900.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4000.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4100.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4200.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4300.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4400.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4500.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4600.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4700.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4800.	0.43	0.18	0.10	0.53	0.98	0.05	0.09	0.10	0.29	0.21	0.13	0.52	0.58	0.03	0.07	0.04	4.31
4900.	0.08	0.18	0.10	0.32	0.58	0.05	0.09	0.01	0.04	0.21	0.13	0.28	0.35	0.03	0.07	0.00	2.52
5000.	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	0.00	0.00

Source: SACTI cooling tower model.

As indicated in Table 5.1-5, the percent frequency of occurrence of long cooling tower plumes in any particular direction is very small. The highest probability of a visible plume over a particular location is approximately 12.48 percent of the year in an area 100 meters (328 ft) south of the cooling tower. Neither the most frequent plume length (less than 300 meters), nor the median plume length (153 meters), nor the highest probability plume length (100 meters) is predicted to extend beyond the nearest property boundary to the new cooling tower.

5.1.4.4 Environmental Impact. The following subsections discuss the potential environmental impacts associated with the operation of the new cooling tower. The relative magnitudes of the impacts are based on the results of the numerical modeling studies presented in Subsection 5.1.4.3. The environmental impacts are assessed with respect to the transportation arteries, vegetation, aesthetics, and land use.

In addition to assessing the environmental impacts associated with each of the aforementioned categories, this subsection also discusses many naturally occurring meteorological and atmospheric phenomena such as fog, cloud cover, and precipitation that may tend to mitigate the actual or perceived environmental impacts resulting from the operation of the cooling towers.

5.1.4.4.1 Impact on transportation arteries. Cooling towers may at times produce plume induced fogging and icing in the vicinity of the cooling tower structures which may have an affect on nearby transportation arteries such as roads, highways, bridges, airports, or navigable waters. Several factors influence the cooling tower plume as it leaves the tower, which to varying degrees, determine the location and magnitude of these phenomena.

The cooling tower plume will have thermal buoyancy and momentum as it is exhausted from the cooling tower. Under calm conditions, the plume will ascend vertically due to these forces. However, prolonged periods of calm and stable conditions do not frequently occur in the atmosphere, and are somewhat infrequent along the central Florida peninsula. In fact, winds in the vicinity of Cane Island are calm for a small percentage of the year, and the subtropical humid climate is frequently unstable. As such, the cooling tower plume's trajectory becomes modified almost immediately as it leaves the cooling tower by persistent winds and atmospheric instability.

As the wind speed increases, the cooling tower plume begins to assume a trajectory that is sloped in the direction of the wind vector, bringing the plume closer to the ground. The plume will likely undergo further trajectory modification as the result of turbulent airflow over and around terrain features, buildings, or the cooling tower structure itself. This effect, known as structure or building induced downwash, occurs when the trajectory modification is such that the plume is forced to the ground in the vicinity of the cooling tower. If the plume becomes supersaturated during this process (i.e., becomes visible), then the result is a phenomenon known as cooling tower induced ground level fogging (Ovard and Reisman).

Cooling tower induced fogging can occur at any time during the year, but it is most commonplace during periods of moderate wind speeds (which bend the plume to intercept the ground), high relative humidity, and cool temperatures. These meteorological conditions frequently occur during the late evening and early morning periods of the day.

A topographic map of the area was reviewed to determine the major transportation arteries in the vicinity of the site. Apart from the entrance road, which is mostly restricted from public access, the nearest transportation arteries include portions of Old Tampa Highway, South Orange Blossom Trail, and the CSX Railroad immediately south of the CIPP boundary. While these arteries are nearly adjacent to the southern property boundary, these facilities are located approximately 1,421 meters (4,662 ft) from the new cooling tower. As discussed in Subsection 5.1.4.3.1, on average fogging is predicted to occur approximately 1 hour per year and no amount of fogging is predicted to extend beyond a radius of 700 meters feet (2,297 ft) from the new cooling tower.

Figure 5.1-1 illustrates the minimal extent and duration of the predicted cooling tower induced fogging. The outermost contour represents 0.05 hours per year of possible plume fogging, with increasing contours of fogging at 0.5 hour per year intervals. Based on the results of the modeling, the cooling tower plume induced fogging is not predicted to extend beyond the property boundary, and is not predicted to cause fogging conditions near the transportation corridors that lie to the south.

Many of the meteorological conditions that are favorable for the occurrence of cooling tower plume induced fogging are conducive to natural fog. As such, the two events may occur simultaneously and thereby mitigate the relative impact potentially caused by cooling tower plume induced events. Climatologically, natural fog (that which restricts visibility to less than 1/4 of a mile) occurs an average of 18 days a year based on meteorological data from Orlando. This means that there are, at a minimum, 18 hours of naturally occurring fog in the vicinity of the CIPP (conservatively assuming that reported fogging events last for only 1 hour per day). This indicates that the area sees more naturally occurring fog events than predicted to be initiated by the cooling tower. Therefore, if these events occur simultaneously due to the meteorological conditions conducive to fog, then no additional fogging over what the area experiences normally is expected due to operation of the cooling tower.

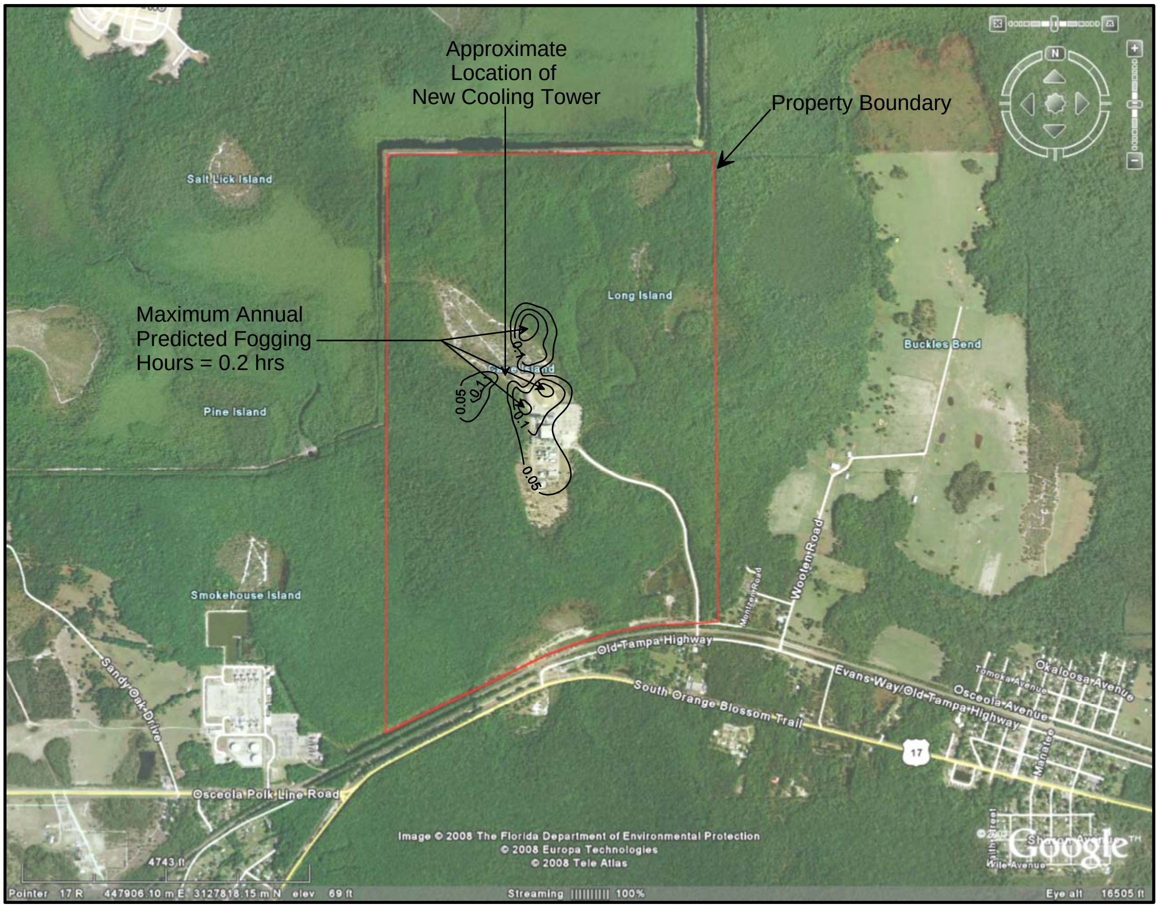

Figure 5.1-1
SACTI Annual Predicted Hours of Cooling Tower Induced Fogging

A secondary effect of cooling tower fogging is the formation of cooling tower induced ground level icing. However, as temperatures rarely fall below freezing in the area, no cooling tower plume induced icing is predicted to occur.

5.1.4.4.2 Impact on vegetation. The plume exhaust from cooling towers may affect the vegetation in the vicinity as the result of drift deposition. Drift deposition from a cooling tower occurs when airborne water droplets, caused by cooling tower drift, coalesce and precipitate in the vicinity of the cooling tower. The pattern of drift deposition and the distance from the cooling tower to the areas of maximum deposition concentrations are a function of many variables, which include: cooling tower type, prevailing wind direction and speed, orientation of the cooling tower, airflow rate, drift rate, water chemistry, and the physical size of the water droplets (drift droplet size spectrum) in the cooling tower drift. The potential effects associated with cooling tower drift deposition are primarily associated with water and salt deposition. The response of the vegetation to salt and water deposition will vary from year to year depending on the rate of deposit and precipitation patterns during the growing season.

An area map depicting the project location overlaid with an isopleth analysis of the SACTI predicted average monthly water deposition rate is presented on Figure 5.1-2. The predicted location of the maximum water deposition rate occurs approximately 300 meters (984 ft) west of the cooling tower at a deposition rate of 9,700 kg/km^2/month.

A potential effect of water deposition on vegetation species is the increased threat of plant fungal diseases associated with the increased precipitation. Based on historical meteorological data for Orlando, the average monthly rainfalls for the driest month (December) and the wettest month (June) are 59 and 187 mm, respectively. If one conservatively assumes no evaporation of the falling cooling tower drift droplets, then the precipitation rate equivalent of the maximum SACTI model predicted water deposition rate (9,700 kg/km^2/month) is approximately 0.01 mm per month. By comparison, this precipitation rate is less than 0.02 percent of the average monthly rainfall of the driest month.

Dr. Walter Stevenson, a crop pathologist at the University of Wisconsin has experience with plant disease prediction models that consider precipitation and leaf wetness. Dr. Stevenson's research shows that a slight increase in disease occurrence is sometimes observed by US Midwestern potato growers when irrigation at a rate of approximately 50 mm per week is applied. A 50 mm per week irrigation rate is equivalent to a water deposition rate of approximately 2 x 10^8 kg/km^2/month, which is more than 20,000 times greater than the maximum water deposition rate predicted by the SACTI model. This suggests that the water deposition from the new cooling tower on vegetation and crops species is insignificant when compared to normal wetting associated

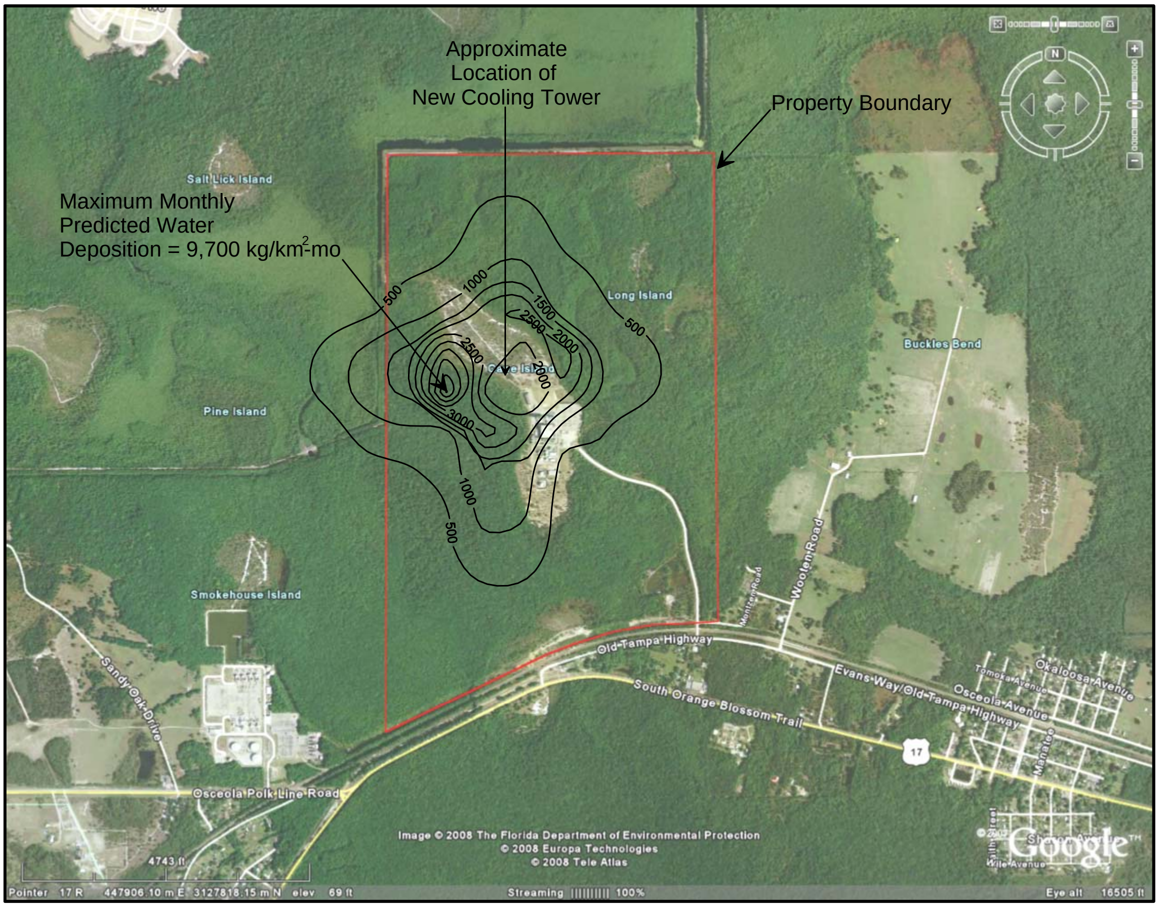

Figure 5.1-2
SACTI Predicted Average Monthly Water Deposition Rate (kg/km^2/month)

with dew, precipitation, and irrigation. Furthermore, because water deposition will occur in conjunction with salt deposition, the additional deposition of salt may be toxic to any pathogenic microorganisms or fungi, and thus negate the effects of water deposition by itself.

An area map overlaid with an isopleth analysis of the SACTI predicted average monthly salt deposition rate is presented on Figure 5.1-3. The predicted location of the maximum salt deposition rate occurs 300 meters (984 ft) west of the cooling tower at a deposition rate of 26.41 kg/km^2/month.

Research studies on salt deposition effects have been conducted in response to known or observed cases of vegetation damage. From these studies, it is known that the local climate plays a significant role in increasing or reducing the stress that such deposition can have on vegetation. For example, a species growing in an area with high rainfall during the growing season tends to be less stressed from salt deposition than the same species growing in an area with less rainfall due to the dilution of the deposited salt on the leaf surface. Additionally, vegetation species growing along coastal regions have a higher tolerance for salt deposition because of the relatively high ambient airborne concentration of sea salts in the marine environment.

As salinity levels increase, growth of intolerant plants declines, and yields are reduced. Some plant families tend to show either high or low limits of salt survival. The limit is low in legumes, (pea, beans), medium in cereal grasses (rye, oats, wheat barley), and high in some forage and other crop plants (alfalfa, sunflower, sugar beet, forage beet) (Maianu et al. 1965). Growth suppression is sometimes accompanied by leaf injury. Leaves become smaller and deeper blue-green than normal, and leaf tips or margins become bleached, tan, or brownish in proportion to the degree of salt deposition. Bronzing and early defoliation may also be prominent. Leaf injury may be the most prominent symptom of salt deposition, but is not nearly important to yield reductions as the growth suppression (Treshow 1970).

Dr. Charles Mulchi of the University of Maryland at College Park has conducted extensive research on cooling tower salt deposition effects and toxicity levels in several vegetation species. According to Dr. Mulchi (1991), a salt deposition rate of 400 kg/km^2/month or greater is sufficient to cause damage to vegetation. The amount and type of damage is dependent on the species involved. For example, one species of pine may show signs of damage while another species may show no signs of damage. The 400 kg/km^2/month salt deposition rate is the threshold level for most vegetation species and has been used in many environmental assessments as a screening or trigger level of potentially significant salt deposition rates. Salt deposition rates less than

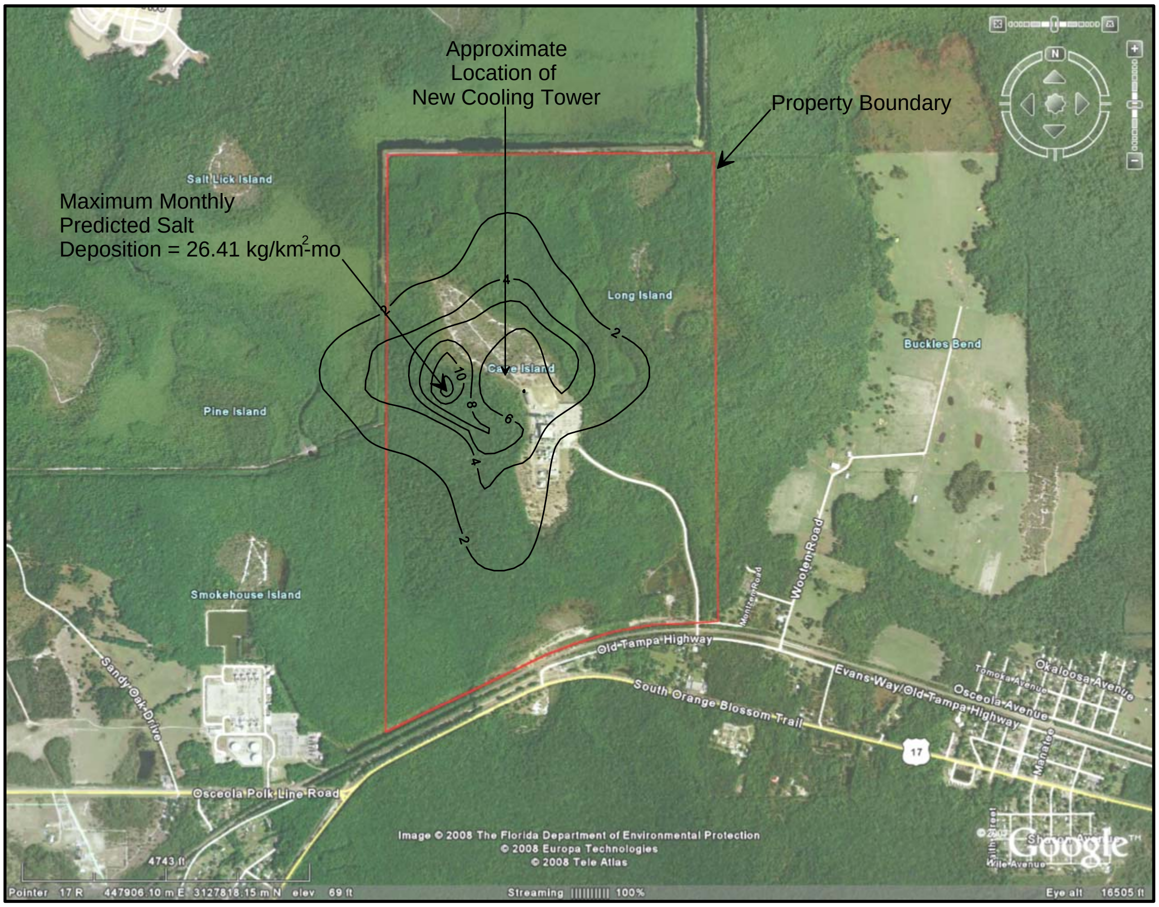

Figure 5.1-3
SACTI Predicted Average Monthly Salt Deposition Rate (kg/km^2/month)

400 kg/km^2/month are generally not considered to have a significant impact on vegetation. The maximum predicted salt deposition rate from the new cooling tower is 26.41 kg/km^2/month. Therefore, salt deposition from the cooling tower is expected to have a negligible impact on vegetation.

5.1.4.4.3 Impact on aesthetics and land use. A cooling tower contributes to the impacts on the aesthetics of an area by forming a visible, at times completely opaque, vapor condensate plume emanating from the cooling tower exhaust. The presence of a visible plume and cooling tower are often perceived as a distraction or debasement to the otherwise scenic quality or functional use of an area. This is particularly true if the cooling tower plume and tower structure are in the background or foreground of a view with a particular scenic quality or land use type. The potential impacts on aesthetics and land use as the result of visible plume formation and the cooling tower structure are discussed below.

Perhaps the most obvious environmental impact from a cooling tower is the formation of a visible plume extending out from the cooling tower cell exhaust ports. The visible plume may extend several hundred yards downwind, potentially obstructing visibility on the site and at nearby locations. The factors that affect visible cooling tower plume formation are discussed in the following paragraphs.

Cooling towers are simple fluid heat exchange systems that dissipate waste heat to the atmosphere through mass and convective heat transfer of water vapor. The exhaust from a cooling tower is essentially a saturated air-water vapor mixture which is warmer than the ambient air as it leaves the tower. Depending on the ambient air temperature and the wet-bulb temperature, a portion of the saturated air-water vapor mixture will become supersaturated and begin to condense into small water droplets as heat transfer with the atmosphere begins to cool the plume. With time, more small water droplets continue to form and grow through condensation and coalescence until the cooling tower exhaust becomes visible as a white plume emanating from the tower. The cooling tower plume will continue to be visible until it is dispersed and evaporated, or until meteorological conditions are no longer favorable for its formation. In the former case, the visible cooling tower plume is transported downwind until turbulent mixing in the atmosphere with the abundant and relatively dryer ambient air causes the small water droplets to disperse and evaporate. As the visible plume becomes thoroughly mixed with the ambient air, the small water droplets completely disperse and evaporate until the plume is no longer visible and becomes transparent.

The frequency, persistence, and size of the visible cooling tower plume depends primarily on the cooling tower type, heat load, orientation of the cooling tower, and the prevailing meteorological conditions. Mechanical draft towers typically present less of a visual distraction because of the relatively low plume exhaust height and profile.

Visible plume formation from cooling towers is more frequent during the cooler seasons when ambient air conditions are capable of rapidly condensing the cooling tower exhaust and allowing only minimal evaporation of the condensed water droplets. Similar conditions exist on a diurnal scale that are also more suitable for visible plume formation. These periods occur during the early morning hours, shortly before and after sunrise, when relatively low ambient air temperatures and high relative humidity make the environment particularly conducive to visible plume formation.

Figure 5.1-3 illustrates the site location overlaid with an isopleth analysis of the average annual predicted plume length frequency of occurrence. The highest probability of a visible plume is predicted to occur in the area just south of the new cooling tower for approximately 12 percent of the year on average. Over the remaining portions of the site and the immediate vicinity, the frequency of occurrence of a visible plume for a particular location generally ranges from about 1 to 9 percent of the year. Based on these results, it is concluded that the presence of a visible plume from the cooling tower will only minimally contribute to the visible and aesthetic impacts in the area.

As given in the SACTI output presented back in Table 5.1-5, the visible plume from the cooling tower is also predicted to periodically extend offsite. However, as shown on Figure 5.1-3, this is predicted to occur only less than 1 percent of the year on average, and therefore will have little or no impact on nearby businesses, residences, or transportation facilities.

It should be noted that the probability of visible plume lengths predicted by the SACTI model are conservative overestimates of actual plume lengths. This is primarily because the SACTI model does not distinguish prevailing meteorological conditions such as haze, overcast skies, fog, and precipitation, which may render the cooling tower plume indiscernible. In certain cases, especially as the distance from the cooling tower increases, the model may predict saturation (thus a visible plume by modeling standards), but due to spreading of the plume it may only be visible as a slight haze. If this is the case, then from an aesthetic perspective, the plume may not be discernible against the background haze that may already exist due to the high humidity, smog, or suspended particulate matter. In other cases, the plume may be dense, but it would not be discernable against the existing cloud deck.

5.1.5 Measurement Program

The CIPP Conditions of Certification authorize the discharge of wastewaters from the heat dissipation system to the Toho pipeline. The FDEP has set limits for effluent discharges and requires the monitoring of discharges. Monitoring parameters and the frequency and sample type are listed in Table 5.1-6. No monitoring of surface waters is required.

Table 5.1-6
Monitoring Requirements for Effluent Discharges

Parameters (Units)	Frequency of Sampling	Sample Type
Flow (mdg)	Daily	Metered
TDS (mg/L)	2/Month	Grab
Chlorides (mg/L)	2/Month	Grab
Nitrates as N (mg/l)	Weekly	Grab
Nitrates as N (#/day)	Weekly	Grab
Total Nitrogen (mg/L)	Weekly	Grab
Total Nitrogen (#/day)	Weekly	Grab
Sodium (mg/L)	2/Month	Grab
Sulfates (mg/L)	2/Month	Grab
TRPH (mg/L)	Monthly	Grab
pH (Std. Units)	2/Week	Grab

5.2 Effects of Chemical and Biocide Discharges

5.2.1 Industrial Wastewater Discharge

As shown on the water mass balances (Figures 3.5-1 through 3.5-3) in Section 3.0, and as described below, there will be one new industrial wastewater discharge point from operations at CIPP due to Unit 4: a new percolation pond. There are no discharges to wetlands or surface waters under normal operating conditions.

Unit 4 wastewaters potentially contaminated with grease or oil from the plant floor drain system and oil containment areas are treated by an oil/water separator and dry pretreatment (percolation pond) prior to onsite discharge to ground water. Effluent from the oil/water separators will contain no more than 10 ppm oil/grease.

5.2.2 Cooling Tower Blowdown

Cooling tower blowdown, boiler blowdown, evaporative cooler blowdown, condensate polisher backwash, and neutralization basin effluent will be collected in a sump and returned to the Toho pipeline for additional reuse or ultimate disposal at the regional Imperial percolation pond facility. Unit 4 water quantity estimates are provided on the water mass balance (Figure 3.5-1). No violation of water quality standards are expected at the Imperial site due to the CIPP facilities.

Potential effluent delivery emergency situations include disruption of effluent delivery due to an upstream treatment facility or pipeline problem, or low effluent supply; therefore, approval to use ground water as cooling tower makeup under emergency conditions is requested. If the Toho pipeline is not available, blowdown during such an emergency will be directed to the onsite storm water ponds. In the unlikely event that the storm water pond capacities are exceeded, the wastewaters will be discharged into the Reedy Creek swamp. FMPA and KUA will apply for an NPDES Wastewater Discharge Permit for this emergency situation. The impacts of this discharge scenario are described in Subsection 5.3.2 below. The CIPP will not require cooling water during non-operating periods such as for maintenance or repair.

5.2.3 Measurement Program

The Conditions of Certification require the monitoring of inflows, discharges, and ground water. It is anticipated that similar monitoring will be required with the addition of Unit 4.

Samples must be collected from the Toho pipeline and the well water supply system prior to use. Wastewater samples must be collected prior to return to the Toho pipeline and discharge to the percolation pond.

5.3 Impacts for Water Supplies

5.3.1 Surface Water

Surface waters in the CIPP area include Reedy Creek and the Bonnet Creek Canal. Reedy Creek discharges into Lake Russell approximately 13 miles downstream of the CIPP. The Bonnet Creek Canal discharges into Reedy Creek near the west CIPP boundary. There are no natural surface water bodies onsite. CIPP operations do not withdraw or discharge to these waters; therefore, no impacts to these surface waters are expected as a result of CIPP operations.

The CIPP drainage system will be designed to comply with all applicable federal, state, and local regulations regarding discharge into surface waters. Runoff from areas not disturbed by construction or operations will be directed to natural drainage systems within the area. Runoff from disturbed areas will be collected and directed into a drainage system consisting of ditches, swales, and runoff basins for treatment. The runoff from uncontaminated areas will be directed through a detention basin for reduction of the suspended solids load and equalization of peak flows. At the property boundary, the post development peak flow rate will not exceed the predevelopment peak discharge rate during the applicable design storm event. A detailed description of the onsite drainage system is provided in Section 3.8.

CIPP operations are not expected to affect surface water quality within the area. Undisturbed areas will remain in its existing state. Runoff water quality should at least remain unchanged and is expected to be improved as a result of detention in the storm water pond. CIPP water use and consumption are described in Section 3.5.

5.3.2 Ground Water

The following describes the effects of plant operations on the aquifers underlying the CIPP.

5.3.2.1 Surficial Aquifer. Under normal operating conditions, the CIPP will not have a significant effect on the surficial aquifer quality. No water will be withdrawn from this water table zone. Wastewaters are treated prior to ground water discharge as described in Subsection 5.3.4.

In the event that the Toho effluent pipeline is disabled, the combined cooling tower blowdown, neutralization basin effluent, evaporative cooler blowdown, and boiler blowdown will be temporarily discharged to the storm water runoff ponds. Total discharge is estimated to be 1,039,000 gpd, for a duration of 3 days. The 3 day period is assumed to be the maximum duration that the Toho effluent pipeline could be out of operation.

The two ponds are currently sized for storm water runoff and have a weir overflow structure to control the discharge of water. The discharge structure for the Unit 1 and 2 pond provides a 2.5 feet storage capacity from the bottom of the pond to the overflow structure. The structure has a 4 inch diameter orifice located at the base of the structure meant to dampen the discharge of storm water from the facility to predevelopment conditions. The Unit 3 and 4 pond will have approximately 4.25 feet storage capacity from the bottom of the pond to the overflow structure and has one 8 inch and four 10 inch diameter orifices. A detailed description of the storm water runoff pond operation is presented in Section 3.8. The orifices will be closed in the case that the pond must be utilized as a storage facility for emergency cooling tower blowdown. After closure of the orifices, the ponds will be used as a storage facility that allows percolation through the pond bottom. This disposal method is preferred over release of the blowdown to wetlands adjacent to the power block.

The ponds will be able to store and percolate the total volume for a period of 3 days of discharge. Storage volumes and percolation rates are estimated as follows:

Facility	Storage Volume	Percolation Rate Through Pond Bottom	Total for 3 Day Period
Unit 1 and 2 Storm Water Runoff Pond	734,210 gal	118,120 gal/day	1,088,800 gal
Unit 3 and 4 Storm Water Runoff Pond	1,522,500 gal	371,400 gal/day	2,636,700 gal
Total capacity for 3 days.			3,725,500 gal

Total discharge for 3 days at 1,039,000 gpd is 3.1 million gallons which is less than the available storage and percolation capacity for the two ponds. The two storm water ponds are capable of holding and percolating the total blowdown volume for a period of 4 days. If the effluent line is out of service for longer than 4 days, the daily flow of 1,039,000 gpd, minus the 489,520 gpd percolation capacity of the two storm water ponds, will be discharged over the ponds' overflow structures into Reedy Creek Swamp. However, the effluent line has only been out of service twice, for less than 24 hours each time, since the CIPP has been in operation.

During these rare events when there is an interruption in the effluent flow, ground water from the UFA will be used as cooling tower makeup. The ground water quality is better than the effluent quality, and therefore, the cooling tower can be operated at additional cycles of concentration. The blowdown water quality is estimated as follows:

	Typical Well Water (ppm)	Cooling Tower Blowdown at Six Cycles (ppm)
Ca, as $CaCO_3$	68	408
MG, as $CaCO_3$	29	174
Na, as $CaCO_3$	6	36
K, as $CaCO_3$	1	6
Alkalinity, as $CaCO_3$	70	150
SO_4, as $CaCO_3$	6	306
Cl, as $CaCO_3$	10	60
SiO_2, as such	14	84
TDS, as such	119	836

5.3.2.2 Floridan Aquifer. Water for service water, demineralizer water, miscellaneous drains, emergency cooling tower makeup, and potable water requirements will be supplied by the UFA system. The FAS, as defined for CIPP, comprises two confined units, the Upper and the Lower Floridan aquifers. Hydrogeological data for the FAS are presented in Subsection 2.3.2.

5.3.2.2.1 Floridan Aquifer Ground Water Model Selection and Development. An existing numerical transient ground water flow model known as the STOPR model (Parsons Brinckerhoff 2006) was utilized to assess impacts of ground water withdrawals from the UFA. The STOPR model is a calibrated model created using the widely accepted MODFLOW code developed by the USGS (McDonald and Harbaugh 1988). The STOPR model was developed in support of water use permitting for the SFWMD and has been accepted by the SFWMD as a calibrated model.

The STOPR model is based on the existing SJRWMD ECF regional steady-state ground water flow model (McGurk and Presley 2002). It covers parts or all of Orange, Osceola, Seminole, Lake, Polk, and Brevard counties. The calibrated numerical STOPR model conceptualizes the fresh ground water flow field as three horizontal aquifers: the surficial aquifer, the UFA, and the Lower Floridan Aquifer (LFA) separated by two semi-confining units, with the LFA underlain by a confining unit (Parsons Brinckerhoff 2006). The conceptualization and input parameters used in the STOPR and ECF models have been extensively reviewed and used in several studies and permitting impact assessments. The STOPR model completely encompasses the CIPP as shown on Figure 5.3-1. For these reasons, the STOPR model was deemed appropriate to be utilized as the modeling tool for impact assessment. The SFWMD provided the model and indicated it should be used to model the impacts of new wells at CIPP.

The STOPR model uses a model grid size of 2,500 feet by 2,500 feet. To appropriately represent the drawdown at and around the CIPP, horizontal grid spacing was refined in and around the area of interest. Grid refinement was performed approximately in an area of 16 square miles covering eight grid cells in the east-west direction and eight grid cells in the north-south direction. The minimum grid size used for impact assessment of ground water extraction is 125 feet by 125 feet. The STOPR model was first run with the refined grid to verify that the model with the refined grid is consistent with the model with the original grid. It was found that the simulation results based on the refined grid were almost identical to those generated by the STOPR model with the original grid spacing.

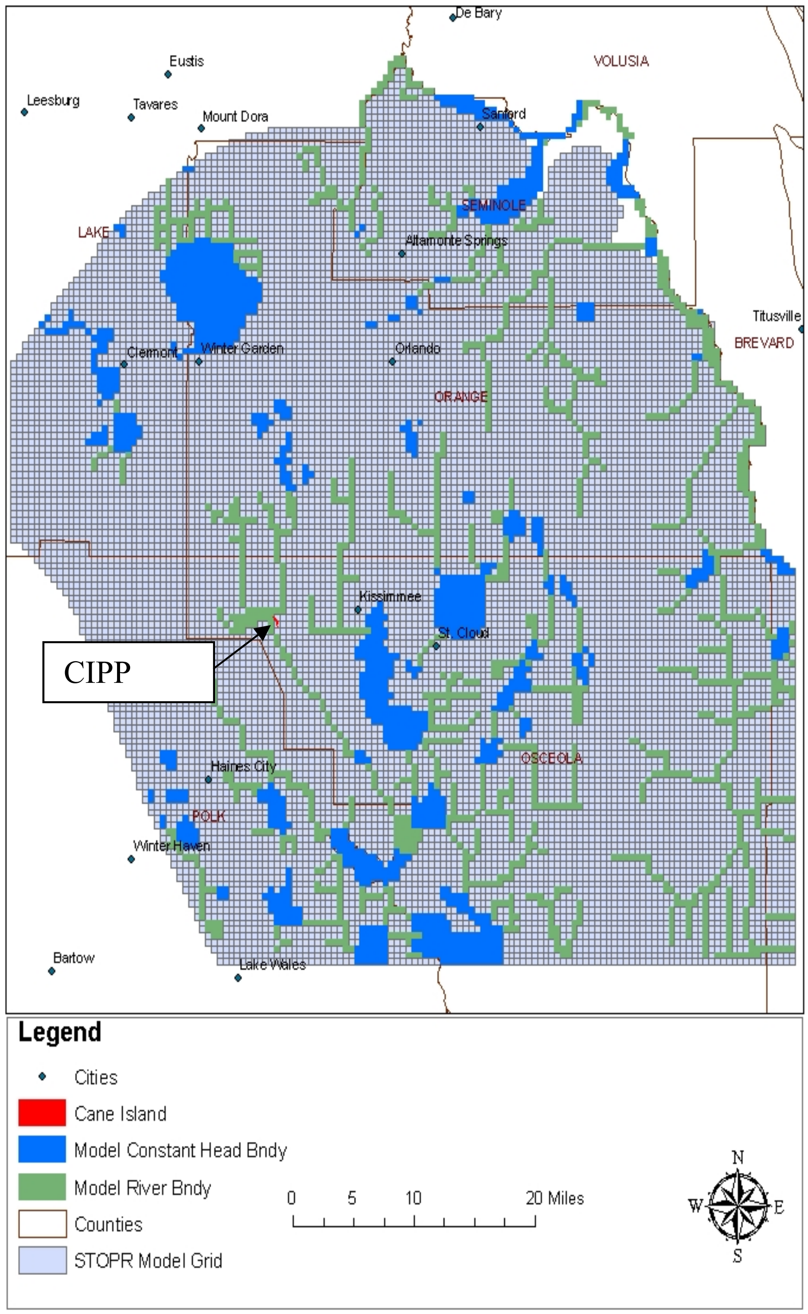

Figure 5.3-1
Location of the CIPP within the STOPR Model Domain

The STOPR model was utilized to assess the change in hydraulic head and associated radius of influence in response to anticipated additional ground water withdrawals required for Unit 4. The present permitted ground water withdrawals authorizations have annual limits with sub-limits of certain rates for a certain number of days in a calendar year for certain operating conditions. It is expected that the revised permit will contain similar limits. The present permitted limits and proposed revised limits are presented in Table 5.3-1. The potential current operating conditions under these limits in eight sequential periods covering 21 months for the currently permitted Wells 1 to 6 are shown in Table 5.3-2. The proposed incremental pumping rates during the same sequential operational periods as in Table 5.3-2 for a new well for Unit 4 are given in Table 5.3-3. It should be noted that in the tables, the total pumping rates during the first three periods are relatively small (below 1 mgd) compared to the fourth and fifth periods between Days 336 to 395, during which the combined pumping rate is 6.565 mgd (of which 2.92 mgd will be extracted from the hypothetical Unit 4 well).

Three different scenarios were used for impact assessment purposes. The three scenarios are listed below:

- Pre-CIPP Scenario--Pre-CIPP pumping based on the existing wells in the STOPR model
- Baseline Scenario--Pre-CIPP pumping and all water withdrawals for Units 1 through 3 from the UFA.
- Scenario 1--Baseline Scenario and all water withdrawal for Unit 4 from the UFA.

The Baseline Scenario was established by superposing the pumping rates and sequence in Table 5.3-2 on the existing STOPR model, which is based on the 1995 average recharge and pumping conditions (the Pre-CIPP Scenario). Scenario 1 was simulated by superposing the pumping conditions in Table 5.3-3 to the Baseline Scenario.

The ground water simulations were performed in accordance with the Basis of Review (BOR) for Water Use Applications within the SFWMD (2008). As required by the SFWMD BOR, all predictive scenarios were simulated under the following conditions:

- 3 months of average conditions.
- 12 months of 1 in 10 year drought conditions.
- 6 months of average conditions.

The monthly drought recharge rates were determined by Parsons Brinckerhoff (2006) utilizing the SFWMD, Part B Water Use Management System Design and Evaluation Aids, Part V, Supplemental Crop Requirement and Withdrawal Calculation, which is within Volume 3, Permit Information Manual for Water Use Permit

Table 5.3-1
Present Permit and Proposed Revised Permit Limits on Authorized Withdrawals*

Operating Conditions**	Number of Days per Year	Unit 1 through 3 Daily Flow, mgd	Unit 4 Daily Flow, mgd	New Total Daily Flow, mgd
Process Flows				
1	323	0.22	0.134	0.354
2	12	0.55	0.134	0.684
3	30	0.78	0.134	0.914
Emergency Cooling Flows				
4	30	2.865	2.786	5.651

*Present annual withdrawal limit is 186.8 mgy and proposed new limit is 319.8 mgy.
**Operating Conditions:

1. Operation of all units on natural gas.
2. Operation of Units 1 and 2 on fuel oil and Units 3 and 4 on natural gas.
3. Operation of Units 1, 2, and 3 on fuel oil and Unit 4 on natural gas.
4. Operation of Unit 2, 3, and 4 cooling tower with well water as makeup. This can occur with any of the Process Flow operating conditions.

Table 5.3-2
Pumping Rates for Wells Associated with Units 1, 2, and 3

Operating Conditions	Days	Well 1 (mgd)	Well 2 (mgd)	Well 3 (mgd)	Well 4 (mgd)	Well 5 (mgd)	Well 6 (mgd)	Total for Units 1-3 (mgd)
All Units Running, Units 1 and 2 on Oil, Unit 3 on Gas, No Emergency Cooling Tower Makeup Used	1 to 12	0.275	0.275	0	0	0	0	0.55
All Units Running on Gas, No Emergency Cooling Tower Makeup Used	13 to 90	0.11	0.11	0	0	0	0	0.22
All Units Running on Gas, No Emergency Cooling Tower Makeup Used	91 to 335	0.11	0.11	0	0	0	0	0.22
All Units Running, Units 1 to 3 on Oil, Emergency Cooling Tower Makeup Used	336 to 365	0.39	0.39	0.71625	0.71625	0.71625	0.71625	3.645
All Units Running, Units 1 to 3 on Oil, Emergency Cooling Tower Makeup Used	366 to 395* (1 to 30)**	0.39	0.39	0.71625	0.71625	0.71625	0.71625	3.645
All Units Running, Units 1 and 2 on Oil, Unit 3 on Gas, No Emergency Cooling Tower Makeup Used	396 to 407 (31 to 42)	0.275	0.275	0	0	0	0	0.55
All Units Running on Gas, No Emergency Cooling Tower Makeup Used	408 to 455 (43 to 90)	0.11	0.11	0	0	0	0	0.22
All Units Running on Gas, No Emergency Cooling Tower Makeup Used	456 to 638 (91 to 273)	0.11	0.11	0	0	0	0	0.22

*Days in the second calendar year.
**Days in a calendar year.

Table 5.3-3
Pumping Rates for Wells Associated with Unit 4 Only

Operating Conditions	Days	Total Incremental Pumping for Unit 4 (mgd)
Unit 4 Running on Gas, No Emergency Cooling Tower Makeup Used	1 to 12	0.134
Unit 4 Running on Gas, No Emergency Cooling Tower Makeup Used	13 to 90	0.134
Unit 4 Running on Gas, No Emergency Cooling Tower Makeup Used	91 to 335	0.134
Unit 4 Running on Gas, Emergency Cooling Tower Makeup Used	336 to 365	2.92
Unit 4 Running on Gas, Emergency Cooling Tower Makeup Used	366 to 395* (1 to 30)**	2.92
Unit 4 Running on Gas, No Emergency Cooling Tower Makeup Used	396 to 407 (31 to 42)	0.134
Unit 4 Running on Gas, No Emergency Cooling Tower Makeup Used	408 to 455 (43 to 90)	0.134
Unit 4 Running on Gas, No Emergency Cooling Tower Makeup Used	456 to 638 (91 to 273)	0.134

*Days in the second calendar year.
**Days in a calendar year.

Applications (refer to Section 1.7.5.2, SFWMD, 2008). The method in the manual was employed to determine the 1 in 10 year drought and average rainfall conditions for the purpose of evaluating monthly drought recharge rates. The average and drought recharge rate distributions were available as part of the STOPR model package developed by Parsons Brinckerhoff (2006).

To satisfy the BOR requirements, all scenarios were simulated for 21 months. For the Baseline Scenario, the first 12 month pumping (based on a calendar year authorized maximum withdrawals) follows the schedule presented in Table 5.3-2, Rows 1 through 4, and the pumping schedule of the following 9 months is presented in Table 5.3-2, Rows 5 through 8. Similarly, the pumping schedules for the first 12 months and the following 9 months for Scenario 1 are given in Table 5.3-3, Rows 1 through 4 and 5 through 8, respectively. The simulations in both scenarios were designed to capture the maximum impact due to heavy pumping. In both scenarios, the heavy pumping periods were conservatively assumed to occur consecutively during the 12th and 13th months (Days 336 to 365 and Days 366 to 395 of Tables 5.3-2 and 5.3-3) which, based on the above mentioned sequence of average and drought conditions, are within the 1 in 10 year drought period.

Impacts in terms of drawdown for both scenarios were estimated using the difference between the STOPR model 1995 potentiometric elevation and simulated ground water elevations from respective scenarios. Details of impacts are discussed below.

5.3.2.2.2 Baseline Impact Due to Pumping from the Existing Wells. Presented in Figure 5.3-2a is the maximum drawdown in the UFA resulting from pumping at Wells 1 to 6 over the entire simulation period of 638 days. The maximum drawdown at any point in time was always observed in the UFA at Well 4, which is one of the existing wells (refer to Figure 5.3-3a for its location). For the first 335 days of the year, the maximum drawdown remains small at approximately 0.5 foot, reflecting relatively light pumping rates (0.22 to 0.55 mgd) during this period. As shown in Figure 5.3-2a, the maximum drawdown, which occurs on the 395th day, is approximately 4.9 feet. In the figure, it can be seen that large drawdown is confined to the last 60 day period of heavy pumping within the entire simulation period of 638 days. After the heavy pumping period, the drawdown decreases to a near-constant value of 0.5 foot at the end of the simulation period of 638 days.

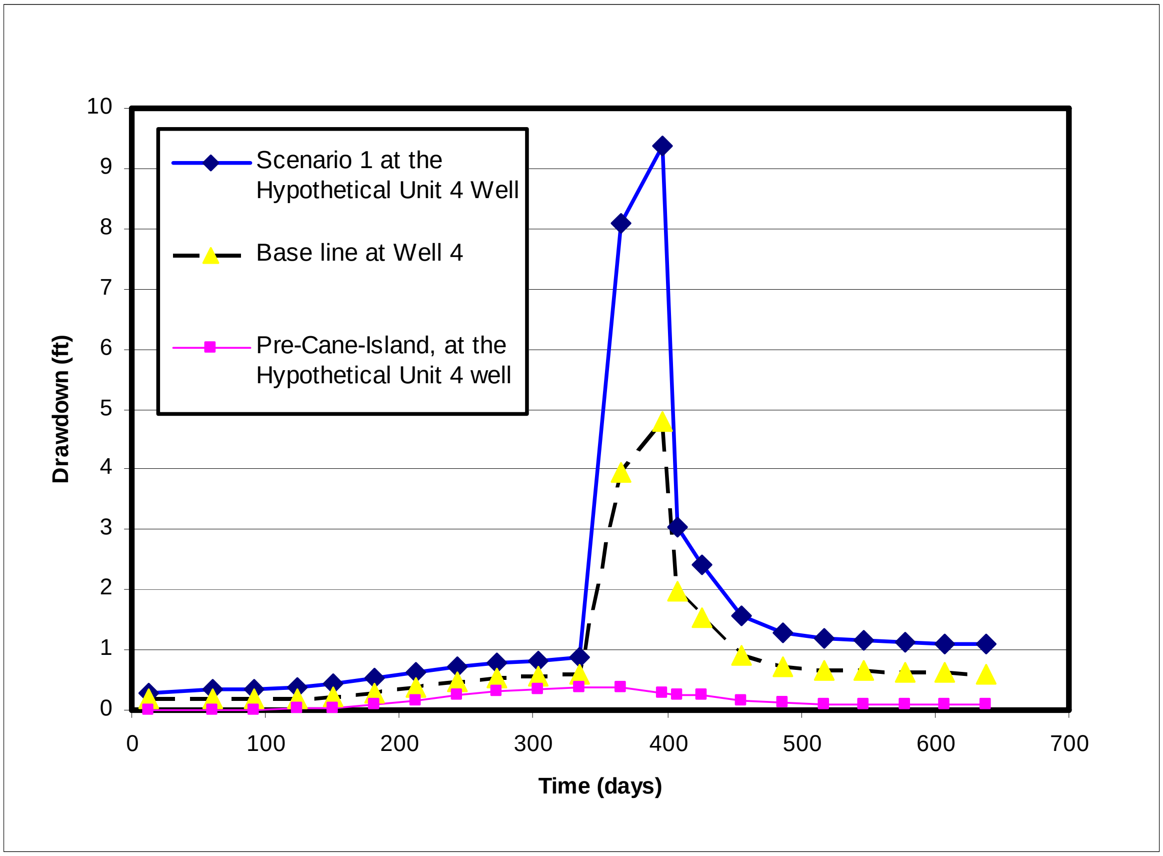

Figure 5.3-2a
Maximum Drawdowns Observed in the UFA (at Well 4 for the Baseline Scenario and at the Proposed Unit 4 Well for Scenario 1)

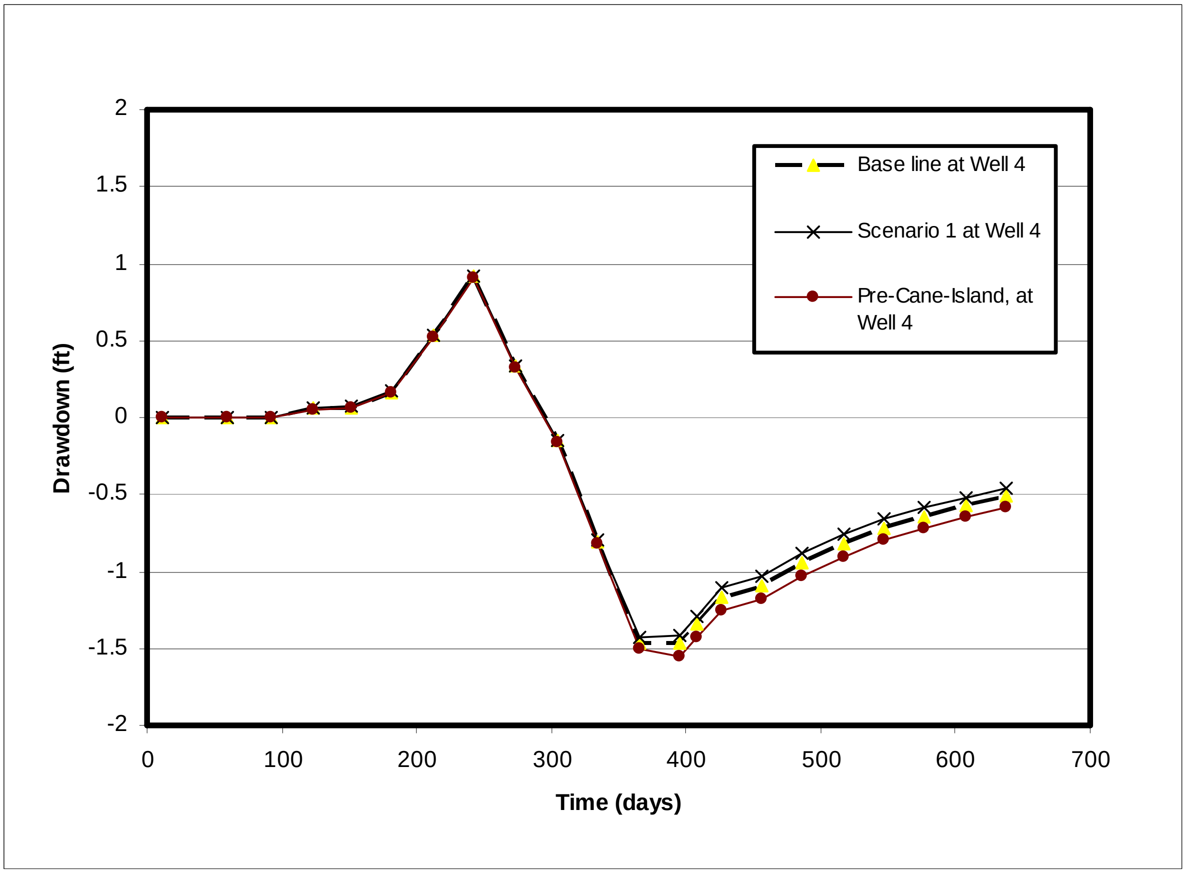

Figure 5.3-2b
Drawdowns Observed in the SAS at the location above Well 4

Presented on Figures 5.3-2b and 5.3-2c are drawdowns in the SAS at the locations above Well 4 and the hypothetical well for Unit 4 (refer to Figure 5.3-3a for their locations), respectively. As shown, the time variation of drawdowns in the SAS does not correspond to that of the UFA drawdown on Figure 5.3-2a. This observation indicates that lowering of water level in the SAS is in response not to the pumping for Units 1 to 3 in the UFA, but to the drought conditions (recharge and other surficial conditions). In fact, the ground water in the SAS rises in response to the change in recharge (drawdown is negative) during the period that maximum drawdown in observed in the UFA. Note that recharge increases and decreases according to precipitation during the drought period (Parsons and Brinkerhoff, 2006). As shown on Figure 5.3-3a, the maximum drawdown, which occurs on the 243rd day of the simulation period, is approximately 1 foot and regionally pervasive, indicating that the changes in ground water level in the SAS are in response to the drought conditions and that pumping in the UFA has negligible impact on the SAS. For comparison purposes, drawdown curves for the SAS above Well 4 and the hypothetical Unit 4 well from the Pre-Cane Island Scenario are also shown on Figures 5.3-2b and 5.3-2c, respectively. In the figures, it can be seen that the additional impact due to pumping for Units 1-3 is on the order of 0.05 foot near the two pumping wells.

The distribution of drawdown in the UFA on the 395th day is shown on Figure 5.3-3b. As can be observed in the figure, the cone of depression (defined by the 1 foot drawdown contour) is confined to within a 1 mile radius from the site center.
The distribution of drawdown in the LFA on the 395 day is shown on Figure 5.3-3c. The maximum UFA pumping-induced drawdown in the LFA is on the order of 0.6 foot. The drawdown in the LFA, compared to the drawdown in the UFA, shown on Figure 5.3 3b, appears to skew slightly to the west of the site area. The apparent skewness is due to the fact that pumping in the UFA diverts ground water, which would otherwise recharge the LFA, toward the wells, especially from the upgradient side or west of the site area (ground water flow in both the UFA and the LFA is from west to east). Because of the diversion of ground water flow in the UFA west of site area, the drawdown in the LFA tends to skew slightly toward the upgradient part of the regional ground water flow or west of the site area.

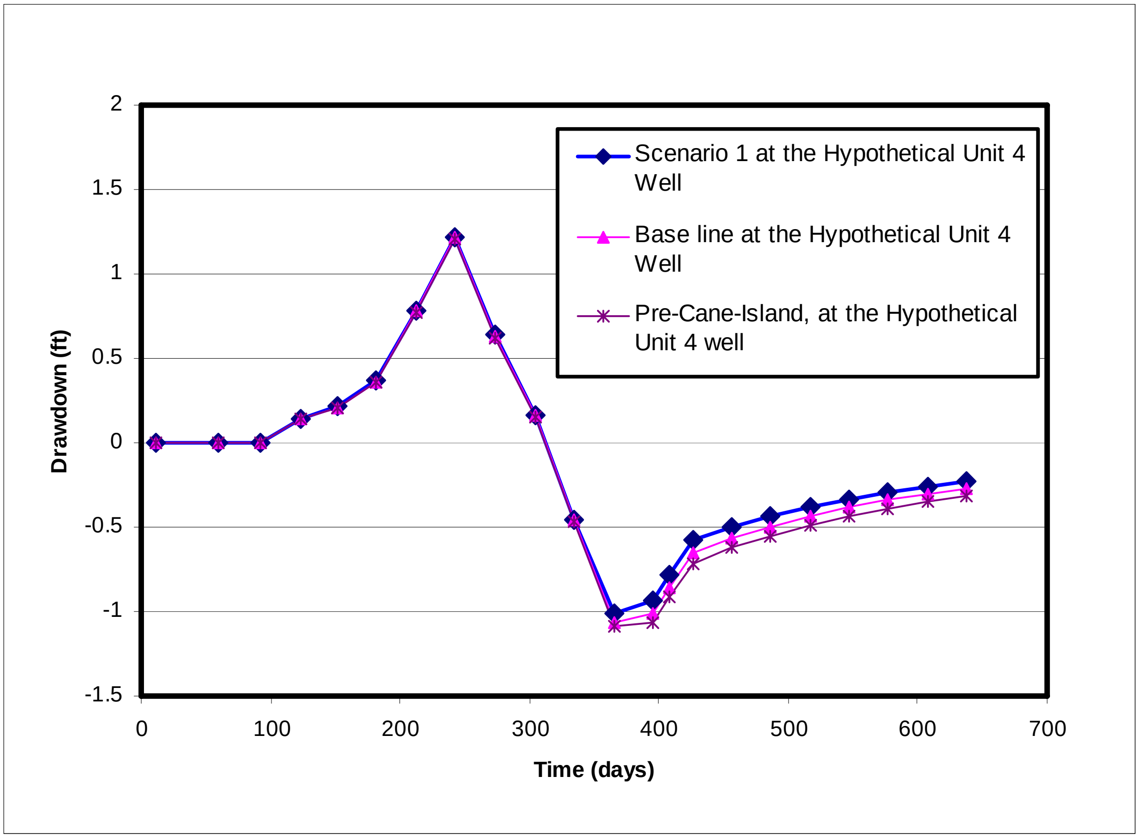

Figure 5.3-2c
Drawdowns Observed in the SAS at the location above the Hypothetical Unit 4 Well

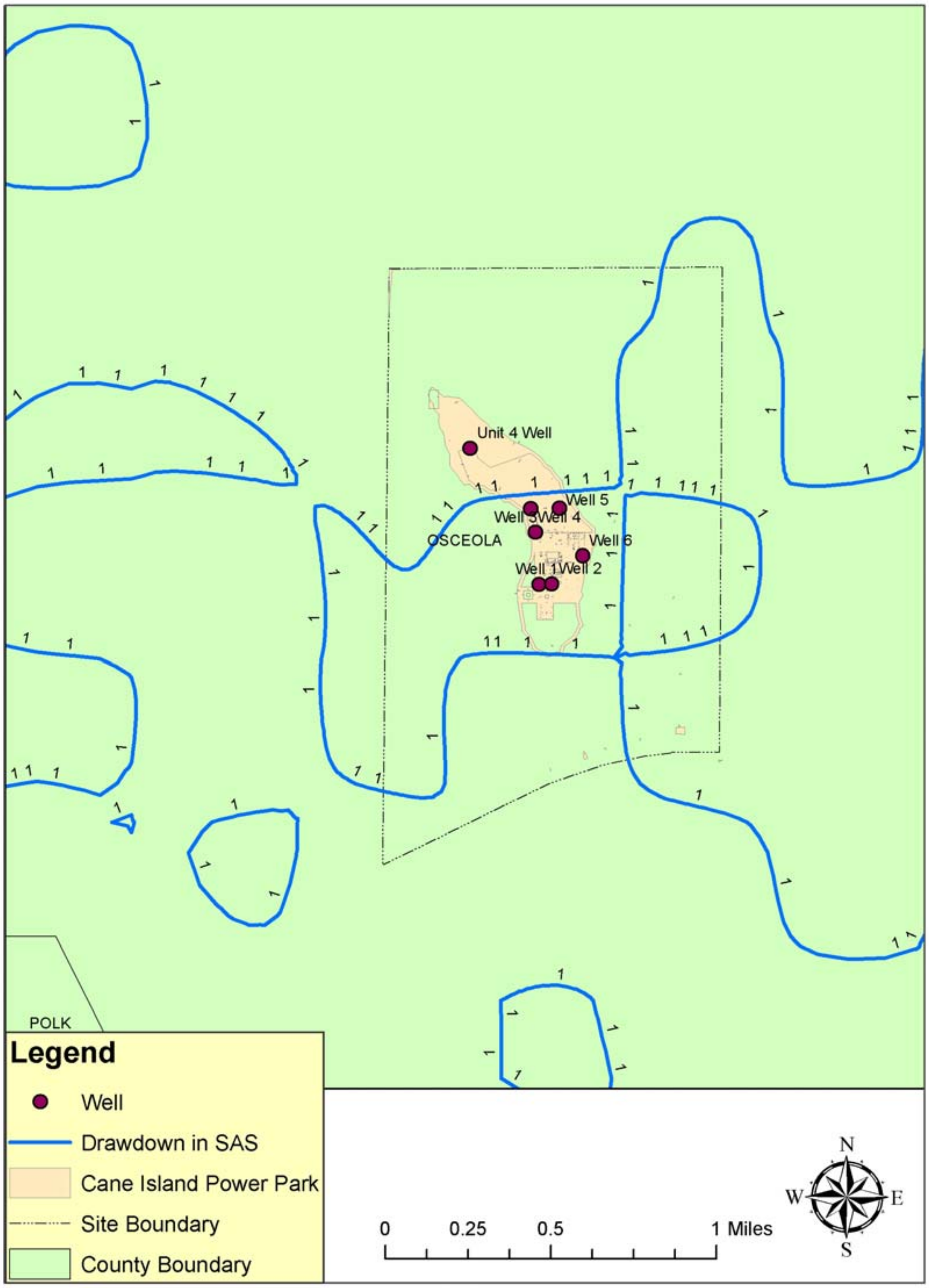

Figure 5.3-3a
Drawdown in the SAS on Day 243: Baseline Scenario

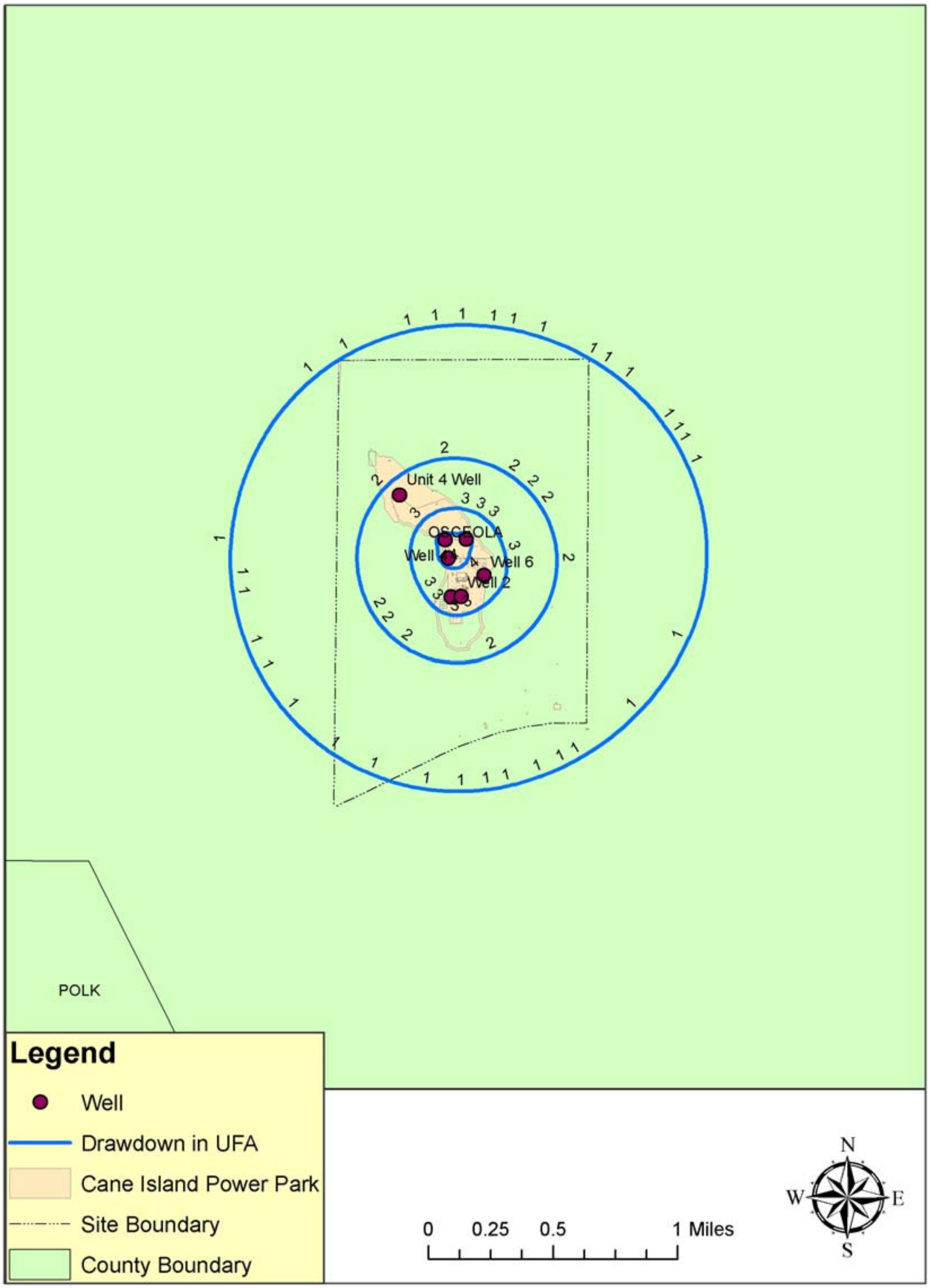

Figure 5.3-3b
Drawdown in the UFA on day 395: Baseline Scenario

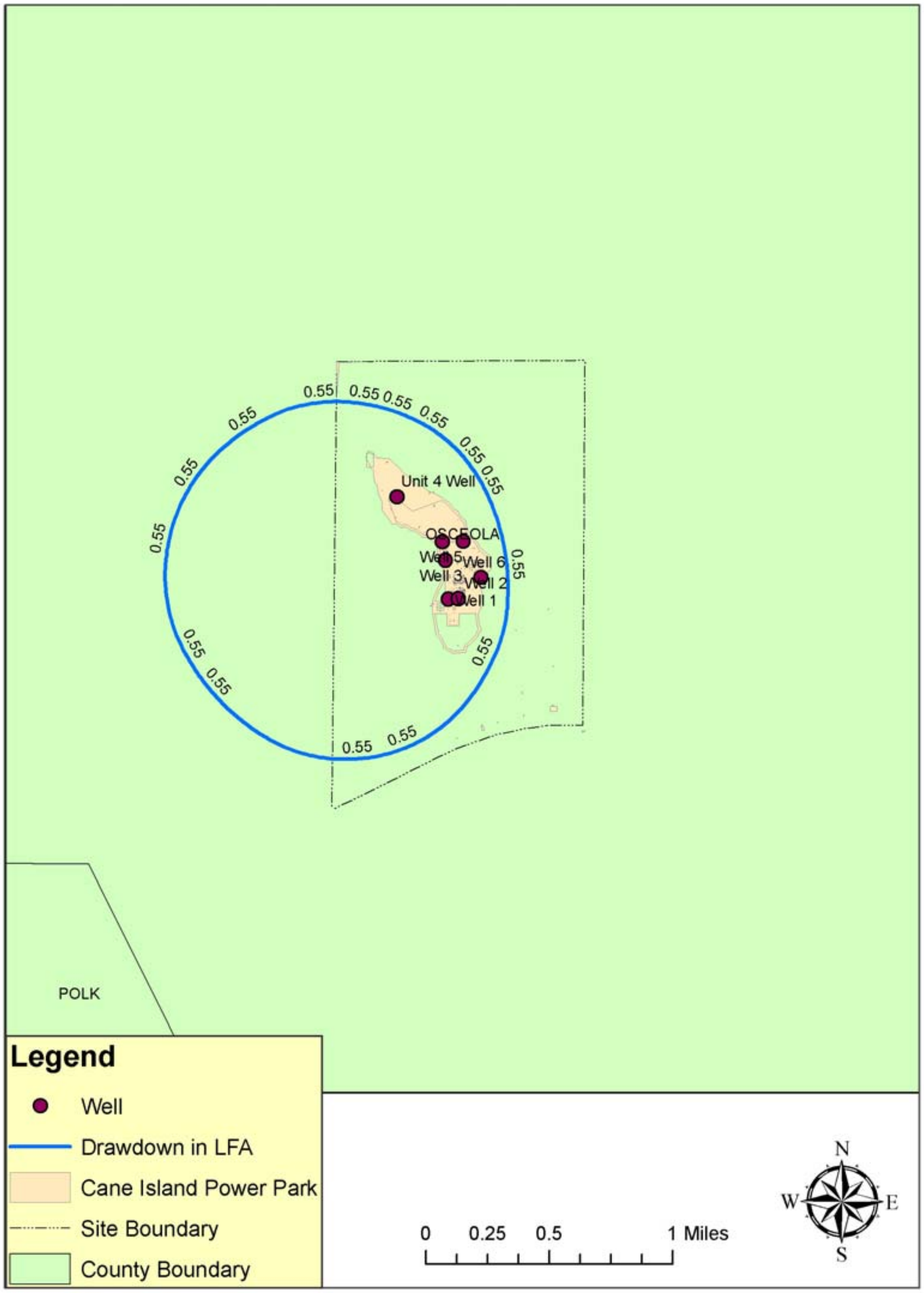

Figure 5.3-3c
Drawdown in the LFA on Day 395: Baseline Scenario
(Maximum drawdown is below 1 ft)

5.3.2.2.3 Impact Due to Units 1 to 4 Pumping with Existing and New Wells.

Presented on Figure 5.3-2a is the maximum drawdown in the UFA resulting from pumping at Wells 1 to 6 and the hypothetical well for Unit 4 (refer to Figure 5.3-3a for their locations) over the entire simulation period of 638 days. The maximum drawdown at any point in time was always observed in the UFA at the hypothetical Unit 4 well. For the first 335 days of the year, the maximum drawdown remains less than 1 foot, reflecting relatively light pumping rates (0.35 to 0.68 mgd) during this period. As shown on Figure 5.3-2a, the maximum drawdown, which occurs on the 395th day, is approximately 9.5 feet. In the figure, it can be seen that large drawdown is confined to the 60 day period of heavy pumping within the entire simulation period of 638 days. After the heavy pumping period, the drawdown decreases to a near-constant value of 1 foot at the end of the simulation period of 638 days. For comparison purposes, a drawdown curve at the hypothetical Unit 4 well for the Pre-CIPP Scenario is also shown on Figure 5.3-2a. In the figure, it can be seen that the drought conditions have small effects on the UFA as they result in lowering the UFA water level by less than 1/2 foot.

Presented on Figures 5.3-2b, and 5.3-2c are drawdowns in the SAS at the locations above Well 4 and the hypothetical well for Unit 4, respectively. Similar to the Baseline Scenario, the time variation of drawdowns in the SAS does not mimic that of the corresponding UFA drawdown on Figure 5.3-2a. As shown on Figure 5.3-4a, the maximum drawdown, which occurs on the 243rd day of the simulation period, is approximately 1 foot and regionally pervasive, indicating that the changes in ground water level in the SAS is in response to the drought conditions and that pumping in the UFA has negligible impact on the SAS. For comparison purposes, drawdown curves for the SAS above Well 4 and the hypothetical Unit 4 well from the Pre-CIPP Scenario are also shown on Figures 5.3-2b and 5.3-2c, respectively. In the figures, it can be seen that the additional impact due to pumping for Units 1 to 4 is on the order of 0.1 foot near the two pumping wells. The distribution SAS impact above the Pre-CIPP Scenario was found to be on the order of 0.02 to 0.04 foot within a 1/2 mile radius from the site center and is considered negligible.

The distribution of drawdown in the UFA on the 395th day is shown on Figure 5.3-4b. As can be observed in the figure, the cone of depression (defined by the 1 foot drawdown contour) is confined to within a 1.75 mile radius from the site center.

The distribution of drawdown in the LFA on the 365th day is shown on Figure 5.3-4c. The maximum UFA pumping-induced drawdown in the LFA is on the order of 0.7 foot. Similar to the drawdown shown on Figure 5.3-3c, the drawdown in the LFA shown on Figure 5.3-4c, also skews slightly to the west of the site area. The reason for the skewness is given and discussed in Subsection 5.3.2.2.2.

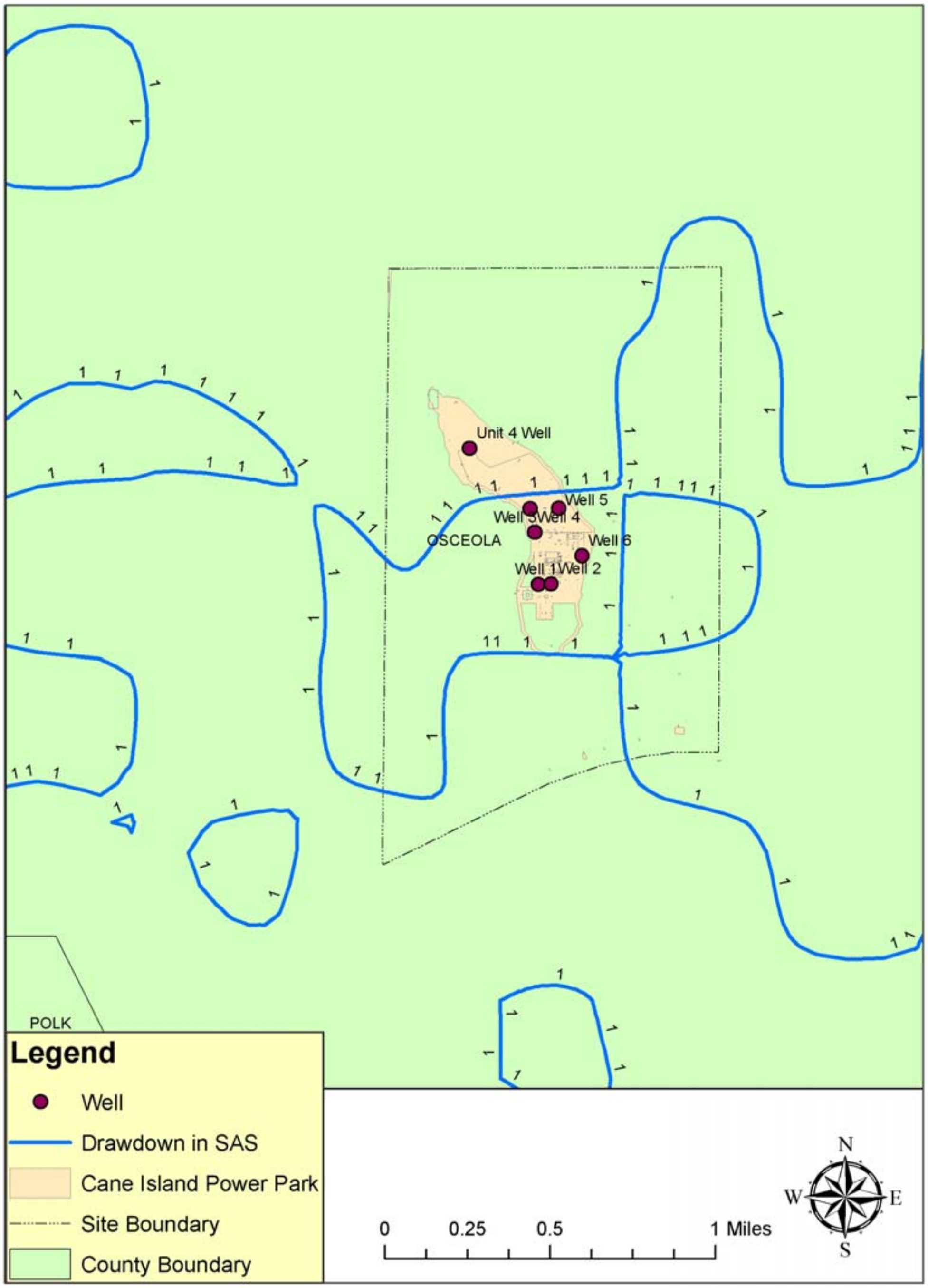

Figure 5.3-4a
Drawdown in the SAS on Day 243: Scenario 1 - Incremental Pumping in the UFA
(Maximum drawdown is below 0.1 ft)

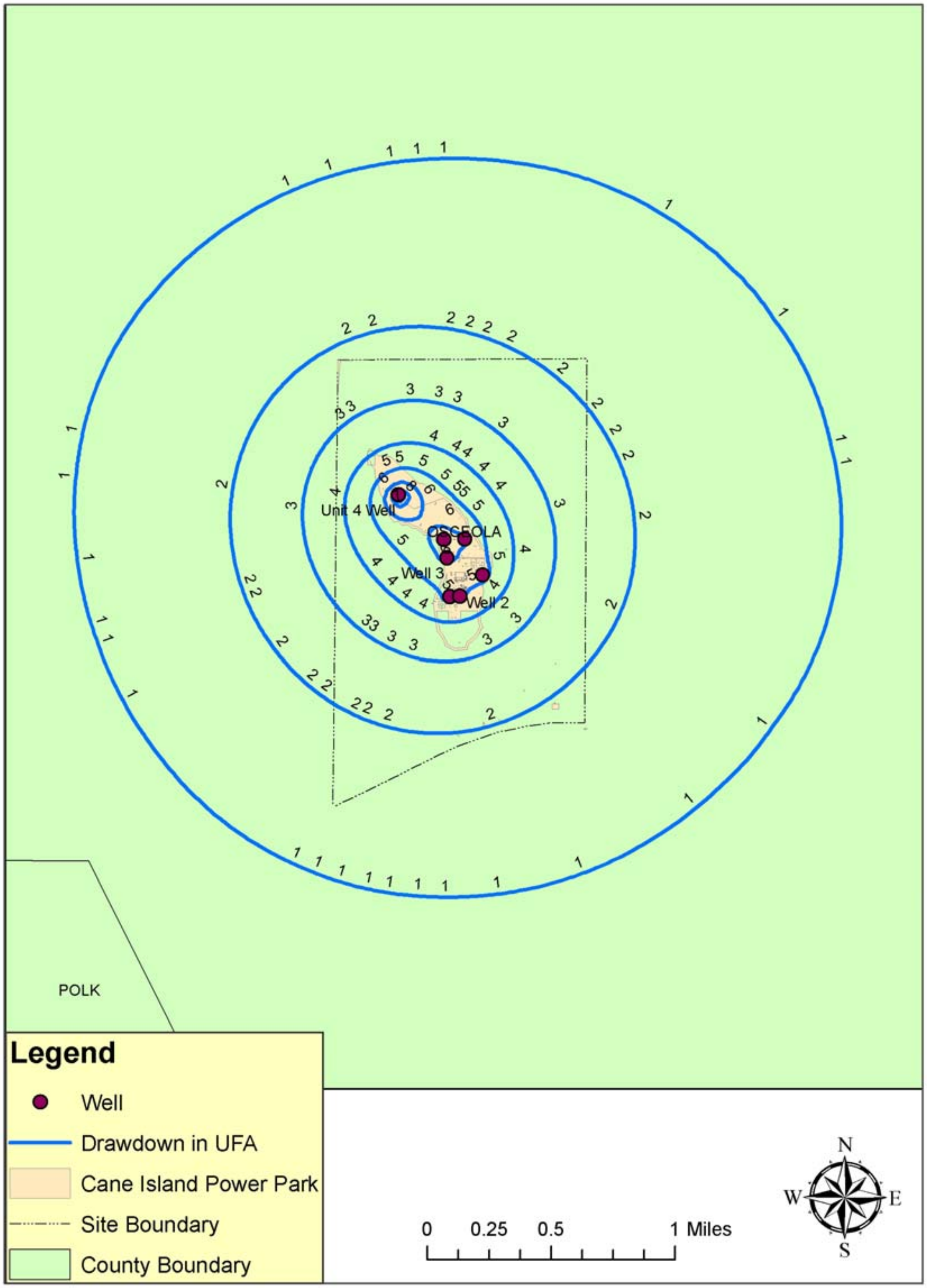

Figure 5.3-4b
Drawdown in the UFA on Day 395:
Scenario 1 - Incremental Pumping in the UFA

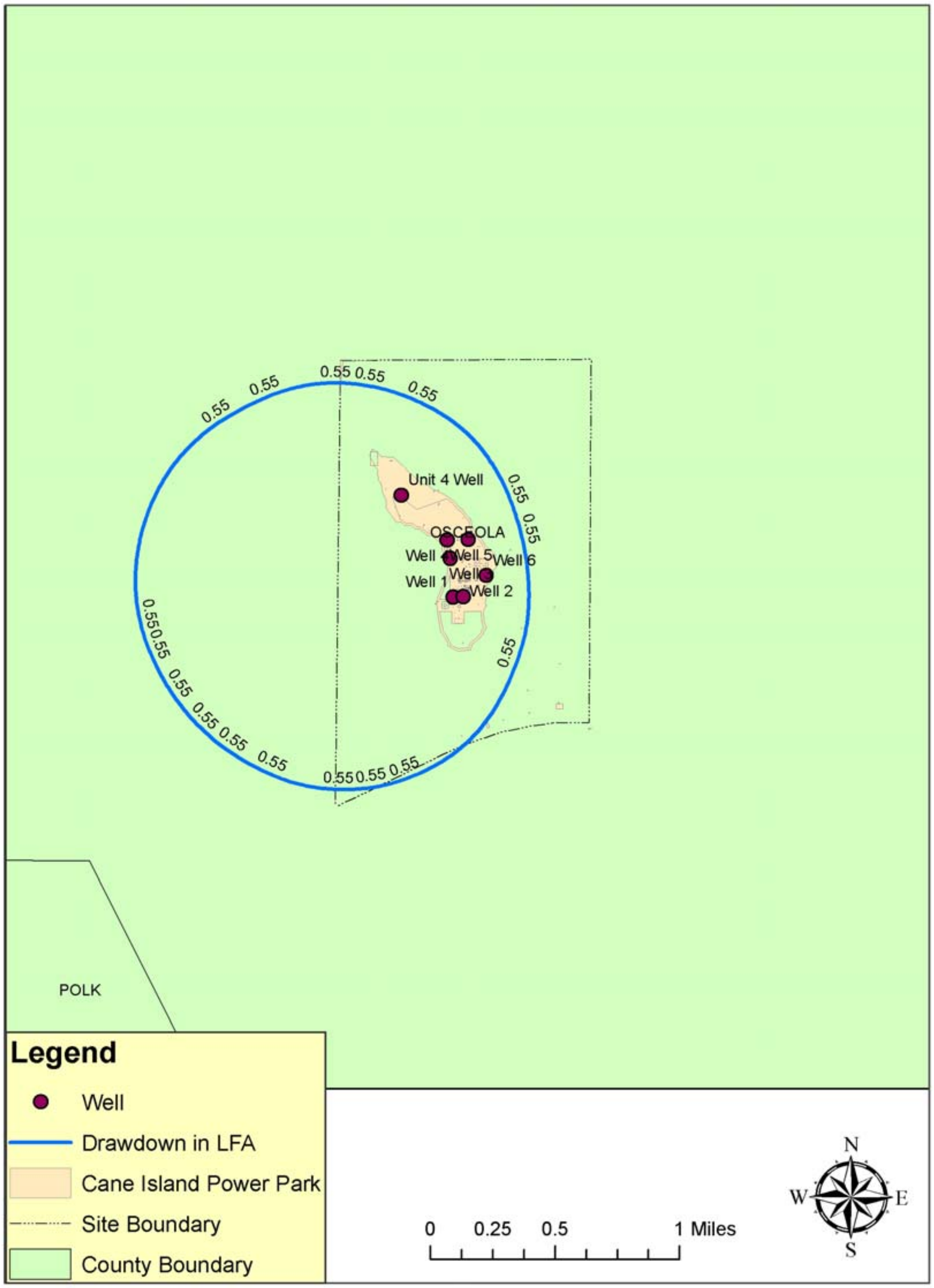

Figure 5.3-4c
Drawdown in the LFA on Day 395:
Scenario 1 - Incremental Pumping in the UFA (Maximum drawdown is below 1 ft)

5.3.2.2.4 Ground Water Impacts. The approach presented and discussed in Subsections 5.3.2.1, 5.3.2.2, and 5.3.2.3 is conservative, because of the following:

- Ground water for Unit 4 is assumed to be extracted from a single well. This type of analysis yields worst-case local drawdowns in all aquifers within the site area. Refer to Figure 2.1-3 for the proposed location of five new wells to provide the Unit 4 added water requirements.
- The analysis is designed to show the maximum impact. In the Baseline Scenario and Scenario 1, the heavy pumping periods were conservatively assumed to occur consecutively during the 12th and 13th months (Days 336 to 395 in Tables 5.3-2 and 5.3-3), which, based on the above-mentioned sequence of average and drought conditions, are within the 1 in 10 year drought period.

The cumulative impact on the surficial aquifer is relatively negligible and overwhelmed by the surficial conditions during the drought period. The maximum impact above the Pre-CIPP Scenario is expected to be from 0.02 to 0.06 foot within a 1 mile radius from the site center. The maximum drawdown in the UFA is expected to be approximately a foot close to the pumping wells and under a foot outside the pumping area, during light pumping periods (335 days of a calendar year). During two consecutive heavy pumping periods, under the 1 in 10 year drought conditions, the cone of depression as defined by a 1 foot drawdown contour is approximately within a 1.75 mile radius from the site center.

As indicated earlier, the impact due to pumping during the light pumping periods is expected to be very small for 335 days in a year. Even with the maximum impact during the heavy pumping periods, the predicted drawdown in the vicinity of the wells indicates that pumping from the existing wells for Units 1 to 3 and the proposed incremental pumping for Unit 4 will have no effects on existing domestic, irrigation, or other public water supply wells due to ground water withdrawal.

5.3.3 Drinking Water

The effects of CIPP ground water withdrawals during operation on drinking water supplies are discussed in Subsection 5.3.2. The effects of leachate and runoff are discussed in Subsection 5.3.4.

5.3.4 Leachate and Runoff

Effluent from the oil/water separators is routed to a new percolation pond dedicated for Unit 4 for discharge to the surficial aquifer. The percolation pond will operate as a single cell, dry pretreatment pond with berms to prevent overflow and divert general site runoff. The pond will be used to collect water that has been routed to the oil/water separators for treatment. Water sources includes rainfall water collected in secondary containment areas, plant and equipment drains, and nonchemical floor drains. Oil/water separator effluent quality is not to exceed 10 ppm of oil and grease. Collected waters will percolate down to the surficial aquifer below the pond. Water will also percolate into the surficial ground water from the storm water detention pond. The location of the new percolation pond, the detention pond, and surrounding structures is shown on Figure 5.3-5.

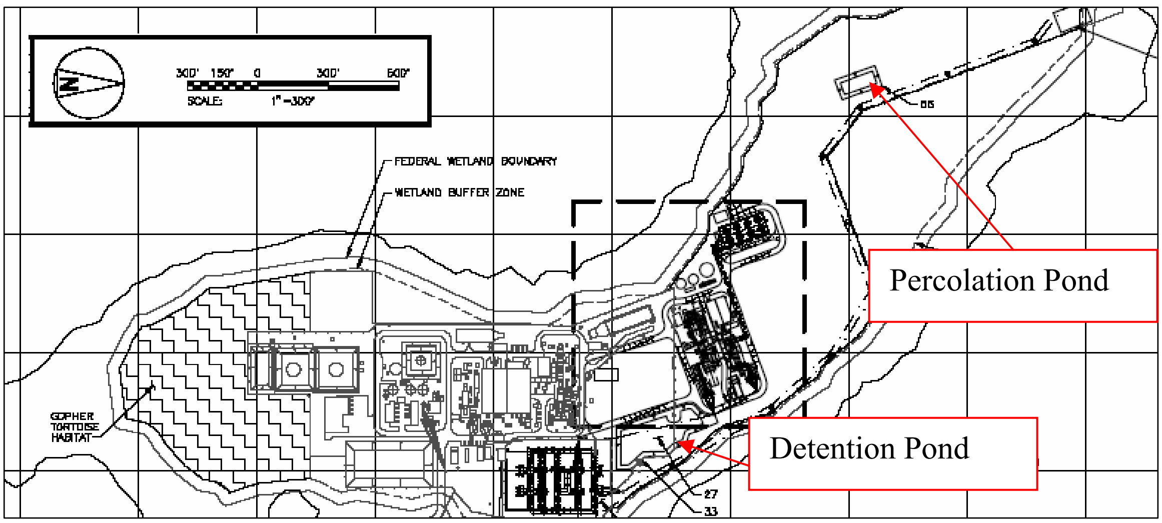

Figure 5.3-5
Locations of New Percolation Pond and Detention Pond

5.3.4.1 Mounding Study. A mounding study was performed to determine the impact of the operations of the percolation and the detention ponds to the water table in the underlying surficial aquifer. The mounding study was performed to simulate the daily flow as well as the maximum flow conditions predicted to occur at the percolation pond. Maximum daily flow condition includes storm water runoff from the secondary containment areas for a 24 hour, 10 year storm event including the average daily flow from the plant and equipment drain. Maximum flow also includes the rainfall occurring on the percolation pond.

The base of the percolation pond as well as the detention pond is at Elevation 74.0 feet above mean sea level (amsl). Maximum berm height is at Elevation 79.0 feet amsl for the two ponds. Effective size of the percolation pond at Elevation 74.0 feet is 90 feet by 180 feet. The total storage capacity for the new percolation pond, with a 1 foot design freeboard, is approximately 621,618 gallons. Storage volumes and areas for the detention pond at different elevations are presented in Table 5.3-4.

Table 5.3-4
Depth Versus Area Relation for Detention Pond

Stage	Pond Area (sq ft)	Total Area (acres)	Pond Incremental Detention volume (cu yd)	Accumulative Detention volume (cu yd)	Accumulative Detention volume (ac ft)
74	38,490	0.884	0.0	0.0	0.000
75	42,793	0.982	1,505.2	1,505.2	0.940
76	47,210	1.084	1,666.7	3,171.9	1.970
77	51,777	1.189	1,833.1	5,005.0	3.110
78	56,500	1.297	2,005.1	7,010.1	4.350
78.25	57,647	1.323	528.5	7,538.6	4.680
78.5	58,801	1.350	539.1	8,077.7	5.010
78.75	59,962	1.377	549.8	8,627.5	5.350
79	71,519	1.642	608.7	9,236.2	5.730

The maximum flow condition accounts for an average daily flow of 20,000 gpd from the plant and equipment drain; 10 year, 24 hour rainfall runoff of 28,806 gpd from containment areas; and 10 year, 24 hour rainfall amounting to 97,694 gpd occurring on the percolation pond. Total flow from the storm event collected by the percolation pond is 146,500 gpd. Based on the same 10 year, 24 hour precipitation event, the detention pond was analyzed for a given percolation rate of 193,868 gpd.

As discussed in Subsection 2.3.2.1 of this report, various infiltrometer tests were conducted at the Cane Island site. Based on the recent double ring infiltrometer tests (Ardaman and Associates 2007), a conservative value of 6.5 inches per hour was used as the infiltration rate for calculating the time it would take for both ponds to lose the estimated amount of water to the surficial aquifer.

The total maximum daily flow into the percolation pond is estimated at 146,500 gpd. It will take about 2.3 hours to percolate this amount of water. The detention pond storage capacity is approximately 1,866,999 gallons. It will take approximately 1.2 hours to percolate the water entering the detention pond. The inflow volumes entering the percolation and the detention ponds are much smaller than the storage capacity of the respective ponds.

Based on recent water level observations presented in Subsection 2.3.2, the highest ground water table encountered during the 2007-2008 investigation was in Boring B4-9 at Elevation +73.8 feet amsl. The lowest ground water table was encountered in Boring B4-7 at Elevation +70 feet amsl. The average ground water level was estimated as Elevation +72 feet amsl or approximately 6 feet bgs.

5.3.4.2 Mounding Simulations. An existing numerical transient ground water flow model known as the STOPR model (Parsons Brinckerhoff 2006) was utilized to assess impacts of percolation on the SAS. The STOPR model is a calibrated model created using the widely accepted MODFLOW code developed by the USGS (McDonald and Harbaugh 1988). The STOPR model was developed in support of water use permitting for the SFWMD and has been accepted by the SFWMD as a calibrated model. The STOPR model is based on the existing SJRWMD ECF regional steady-state ground water flow model (McGurk and Presley 2002).

The STOPR model uses a model grid size of 2,500 feet by 2,500 feet. To appropriately represent the mounding resulting from percolation from the percolation and the detention ponds, horizontal grid spacing was refined in and around the area of interest. Grid refinement was performed in an area of approximately 16 square miles covering eight grid cells in the east-west direction and eight grid cells in the north-south direction. The minimum grid size used for impact assessment of percolation from the percolation and detention ponds is 62.5 feet by 125 feet. The STOPR model was first run with the refined grid to verify that the model with refined grid is consistent with the model with the original grid. It was found that the simulation results based on the refined grid were almost identical to those generated by the STOPR model with the original grid spacing.

Three transient simulations were performed to assess the impacts of percolation from the percolation and the detention ponds into the SAS. The first simulation, the baseline scenario, was simulated with the average 1995 recharge and well pumping conditions (based on the 1995 calibrated conditions) applied to all stress periods. The baseline scenario hydraulic head distribution was then used to compute the mounding resulting from percolation in subsequent simulations. The remaining two simulations, representing the mounding scenarios, were also simulated with the recharge and pumping conditions identical to those in the first simulation. The first mounding scenario was simulated to assess the impacts due to loading from average daily conditions by adding average daily percolation rates, anticipated to occur for the percolation pond, to the recharge rates applied on to the grid cells that represent the percolation pond. The second mounding scenario was simulated to assess the impacts of percolation for maximum flow conditions resulting from a 10 year, 24 hour rainfall event. The maximum flow conditions were simulated for the percolation pond as well as the detention pond. Initial conditions used in all simulations represent the 1995 steady-state conditions. Mounding simulation performed for daily flow conditions was carried out until the hydraulic head achieved a steady-state condition. In the case of the maximum flow condition, the simulation was performed for a period of 1 day to detect the maximum rise. After the occurrence of the maximum rise, the mound would dissipate laterally subsequent to the mounding.

The percolation pond in the model is represented by one grid cell of size 125 feet by 125 feet and an area of approximately 15,625 square feet representing the area of the base of the percolation pond. The base of the percolation pond is 90 feet by 180 feet, an area of 16,200 square feet. The detention pond is represented by two grid cells of size 125 feet by 125 feet and one grid cell of size 125 feet by 62.5 feet, for a total area of 39,062.5 square feet. The area at the base of the detention pond is approximately 39,147 square feet. The maximum daily flow is based on the 10 year, 24 hour precipitation event. The rainfall collected by the percolation pond occurs during the day of the event.

Mounding was calculated by subtracting the hydraulic head results obtained from the baseline scenario from the hydraulic head results obtained from the mounding scenarios to assess the impact of percolation on the SAS ground water levels. Predicted mounding contours due to the average daily flow conditions are shown on Figure 5.3-6 and those for the maximum flow conditions are shown on Figure 5.3-7. In this analysis, which involves the unconfined SAS, the extent of the ground water mound caused by pond percolation is defined by the 0.1 foot contour.

The maximum rise of 1.0 foot was noted to occur underneath the percolation pond for the daily flow conditions. In the case of maximum flow conditions (without the daily flow), a maximum mounding of 1.4 feet is predicted for the SAS hydraulic head under the percolation pond, and a maximum mounding of 1.2 feet is predicted for the SAS hydraulic head under the detention pond. The combined impact in the event of maximum and average daily loadings is 2.4 feet (1.0 foot from average daily loading and 1.4 feet from the precipitation event) and may cause the ground water table to be in direct hydraulic communication with the water in the percolation pond because the average water table elevation, prior to the operation of the pond, is approximately 2 feet below the bottom of the percolation pond. During the wet season, after a 10 year, 24 hour precipitation event, the percolation pond may remain wet for a few days.

Figure 5.3-6
Surficial Aquifer Mounding For Average Daily Flow Conditions

Figure 5.3-7
Surficial Aquifer Mounding After 1 Day Maximum Flow Condition

The contours of ground water rises due to average daily loading and precipitation events are presented on Figures 5.3-6 and 5.3-7, respectively. As shown on Figure 5.3-6, the rise decreases radially away from the percolation pond. Near to the pond, the rise is approximately 0.5 foot on average. Beyond the site boundary, the rise is less than 0.2 foot. On Figure 5.3-7, it can be observed that the rise due to the precipitation event is relatively small (on the order of 0.5 foot on average) and confined to areas around the two ponds. After the cessation of precipitation, the additional rise caused by the precipitation event at the two ponds will eventually decay completely, and the total ground water rise will revert to that due to the long-term average daily loading shown on Figure 5.3-6. As shown in the two figures, ground water rise is not expected to exceed 1 foot beyond the ponds and 0.2 foot outside the site boundary.

5.3.4.3 Conclusion. The mounding study demonstrates that the Unit 4 percolation pond design has sufficient capacity to percolate the maximum design flow. There will be no surface water discharges (“daylighting”) due to ground water mounding. There will be no significant impacts to the surficial aquifer. Discharge to the percolation pond will not affect the adjacent surface water bodies.

5.3.5 Measurement Programs

5.3.5.1 Surface Water Monitoring. The general site runoff will be monitored during a rainfall event that causes discharge from the site runoff collection system at the site runoff detention overflow weir. A grab sample will be collected during the event in the vicinity of the basin overflow. The sample will be tested in accordance with applicable local, state, and federal requirements.

5.3.5.2 Ground Water Monitoring. No monitoring program is proposed for the new groundwater discharge through the new percolation pond. The existing percolation pond is operating as designed and has had no violations of ground water quality standards. The wastewater going to the new percolation pond will be essentially the same as that going to the existing percolation pond: same source water, same use/operation, same pre-treatment, similar pond design.

5.4 Solid/Hazardous Waste Disposal Impacts

Operation as a combustion turbine facility burning natural gas will not generate solid or hazardous wastes through the combustion process. Consequently, there are no onsite landfills or disposal areas.

Limited amounts of hazardous wastes (acidic and caustic wastes) from the regeneration of the demineralizers will be treated by pH adjustment in the neutralization basin prior to return to the Toho pipeline. A licensed contractor will be provided for the disposal of boiler cleaning wastes, wash waters collected in the combustion turbine drain tank, and spent SCR catalysts.

Miscellaneous office trash and maintenance wastes are collected in dumpsters and removed from the site by a licensed contractor. Small amounts of paints, cleaners, and solvents used in maintenance will be segregated and disposed using licensed contractors.

5.5 Sanitary and Other Waste Discharges

Sanitary wastes are collected and treated by an onsite septic tank/tile field system approved by the Osceola County Health Department. Unit 4 operations will increase the staff at the site, from approximately 30 to 32 people. However, the existing septic system is oversized, and capable of treating the additional load due to Unit 4 staff. The staff numbers and septic system capacity will be confirmed during detailed design, and in the unlikely event that it is determined that the existing system cannot handle the additional load, a second septic system will be incorporated in the Unit 4 design.

There are no other wastes or wastewater discharges from the site other than those previously described.

5.6 Air Quality Impacts

The air quality impacts associated with the addition of Unit 4 and ancillary equipment are addressed in detail in the PSD Air Permit Application attached to this Site Certification Application as Volume 3 under separate cover. The estimated air quality impacts associated with Unit 4 and the associated Florida Ambient Air Quality Standards (FAAQS) are shown in Table 5.6-1. As indicated in Table 5.6-1, the Unit 4 maximum model-predicted concentrations are less than the PSD Class II SILs for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and Ambient Air Quality Standards analyses) are required.

Furthermore, as discussed in the PSD application (Volume 3), the Unit 4 modeled air quality impacts are well below the monitoring de minimis concentrations. Therefore, no pre-construction or post-construction air quality monitoring is required.

Table 5.6-1 AERMOD Model-Predicted Class II Impacts				
Pollutant	Averaging Period	Model-Predicted Impact* ($\mu g/m^3$)	FAAQS ($\mu g/m^3$)	Predicted FAAQS Exceedance
NO_x	Annual	0.90	100	NO
SO_2	Annual	0.08	60	NO
	24 Hour	0.95	260	NO
	3 Hour	2.10	1,300	NO
PM/PM_{10}	Annual	0.31	50	NO
	24 Hour	4.92	150	NO
CO	8 Hour	33.78	10,000	NO
	1 Hour	103.38	40,000	NO

*Impacts represent the highest first high model-predicted concentration from all five years of meteorological data modeled and includes the operation of the combustion turbine/HRSG, cooling tower, safe shutdown generator, and emergency fire pump.

5.7 Noise

This section describes the potential facility noise emissions associated with the normal operation of Unit 4. In addition, a discussion of the potential impacts and compliance with local noise regulations related to Unit 4 operation, as well as mitigation, is included.

5.7.1 Noise Impact Significance Thresholds

Unit 4 will include the installation of a combustion turbine combined cycle arrangement. Specifically, the major equipment will include one frame 7FA CTG, one HRSG, one STG, and one eight-cell mechanical draft cooling tower. These major equipment components are expected to be the primary noise contributors to Unit 4 noise emissions. Secondary noise sources are expected to include generator step-up transformers, major pumps (e.g., boiler feedwater, circulating water, condensate, closed-cycle cooling water), and other associated equipment. Equipment sound levels were based on available data.

5.7.2 Noise Emissions Modeling

Unit 4 environmental noise emissions were modeled using noise prediction software (CadnaA version 3.6.119). The model simulated the outdoor propagation of sound from each noise source and accounted for sound wave divergence, atmospheric and ground sound absorption, sound directivity, and sound attenuation due to interceding barriers. A database was developed that specified the location, octave band sound levels, and sound directivity of each noise source. A receptor grid was specified that covered the entire area of interest. The model calculated the overall A-weighted sound pressure levels and the octave band sound levels within the receptor grid based on the octave band sound level contribution of each noise source. Finally, a noise contour plot was produced based on the overall sound pressure levels within the receptor grid, including specific receptor locations.

The environmental noise emissions are modeled to simulate normal Unit 4 operation, which excludes intermittent activities such as startup, shutdown, and any other abnormal or upset operating conditions. Also, these levels represent only the noise associated with Unit 4 and do not include the influence of any nonproject-related background noise.

The predicted facility noise emissions are presented on Figure 5.7-1 as overall, A-weighted noise contours. Unit 4 noise emissions are at or below 45 dBA at the facility property boundary. Also shown on Figure 5.7-1 are the nearest noise sensitive receptors, R1, R2, and R3. As shown, the overall sound pressure levels at the nearest noise sensitive receptors due to the normal operation of the project range from approximately 37 dBA to 38 dBA.

5.7.3 Project Noise Impacts

As referenced in CU/SDP 92-86, the Cane Island electrical generation facility has been approved as a Conditional Use. Due to this classification, sound limits are goverened under Special Condition 15 of CU/SDP 92-86. According to Special Condition 15, the maximum sound level measured at the facility property boundary cannot exceed 55 dBA.

5.7.3.1 CU/SDP 92-86 Special Condition 15 Compliance. As shown on Figure 5.7-1, the maximum predicted sound level at the property boundary is expected to be 45 dBA. Unit 4 is expected to be in compliance with Special Condition 15 with a margin of at least 10 dBA at all facility property boundaries. Additionally, the highest property boundary sound levels are predicted to occur along the west property line among areas where forested wetlands preclude the possibility of development.

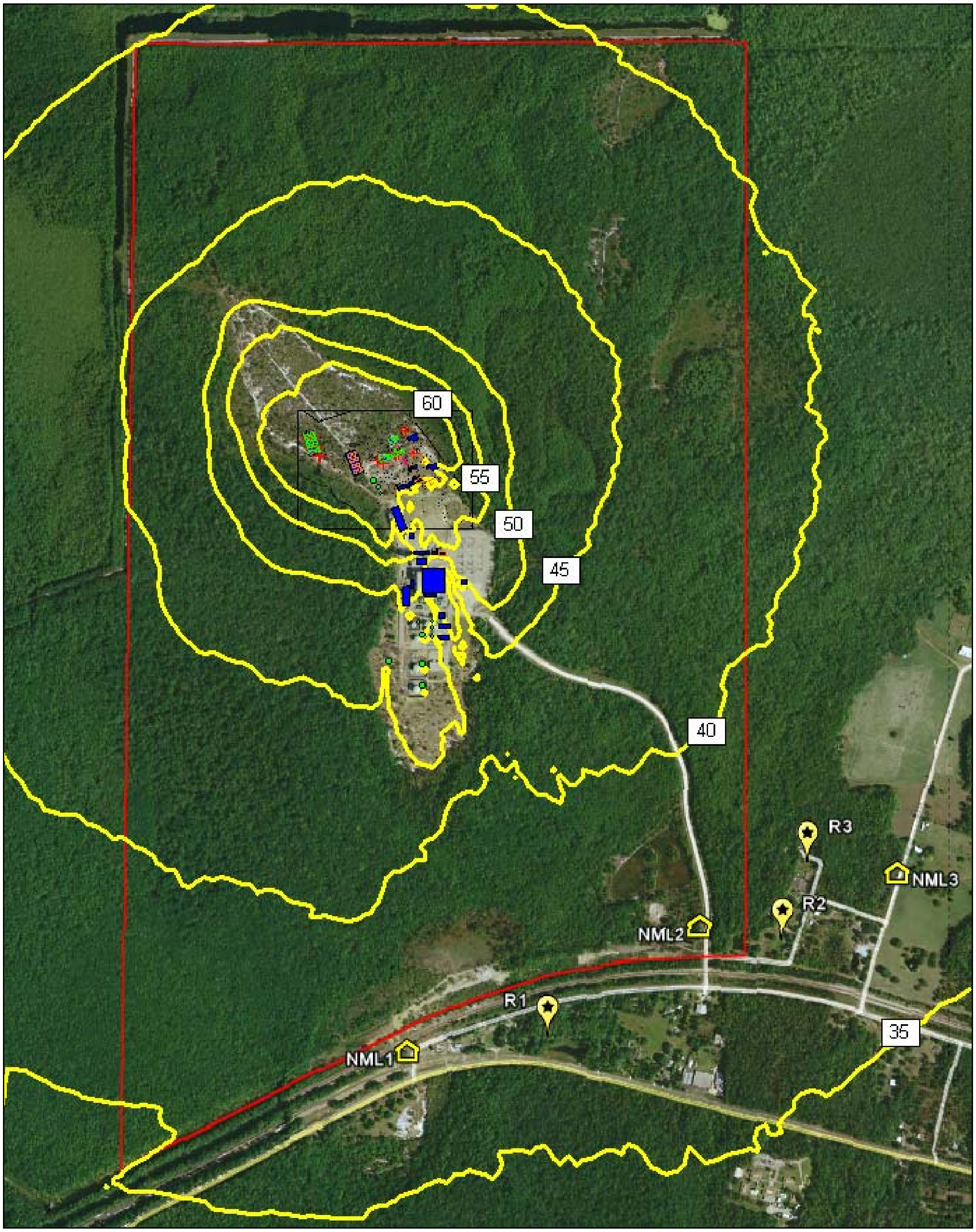

Figure 5.7-1
Predicted Unit 4 Project Noise Emissions

The property boundary sound levels shown on Figure 5.7-1 only represent the expected sound levels associated with the operation of Unit 4 and exclude the influence of background noise and noise generated from the existing facility (Units 1, 2, and 3). However, since Unit 4 sound levels at the property boundary have a margin of at least 10 dBA, it is anticipated that the overall facility sound levels (i.e., Units 1, 2, 3, and 4) will also be compliant with the 55 dBA property boundary limits.

In addition to regulatory limits, potential impacts to nearby receptors can also be evaluated against the existing background sound levels measured during the ambient noise survey to qualify the relative increase in background sound levels. It is important to note that evaluating the potential increase to background sound levels due to project noise emissions is subjective in nature and, therefore, lacks the measurable regulatory criteria previously discussed. However, such an evaluation provides additional criteria that can identify potential impacts that may occur despite compliance with regulatory limits. For reference, a 3 dB increase to the background sound level is generally considered "just barely perceptible" and a 5 dB increase to the background sound level is generally considered "clearly noticeable." Similarly, a 10 dB change in the background sound level is generally considered to be a doubling (or halving) of the apparent loudness. Typically, an increase in the background sound level of 5 dB or less is generally not considered to be a significant increase.

The increase in the existing background sound level due to the operation of Unit 4 is provided in Table 5.7-1. As shown, the increase is expected to range from 0 to 3 dB at the nearest noise sensitive receptors based on the measured background sound levels.

Table 5.7-1
Increase in Ambient Sound Level due to the Operation of Unit 4

Noise Sensitive Receptor	Measured Average Daytime Background Sound Level (Hourly L_{90}), dBA[1]	Predicted Project Sound Levels, dBA	Future Background Sound Levels with the Project, dBA	Future Background Sound Level Increase due to the Project
R1	52	38	52	0
R2	39	37	41	2
R3	38	38	41	3

[1]Based on the median sound level recorded between the hours of 7:00 a.m. and 7:00 p.m. during the operation of CIPP Unit 3.

The future sound levels presented in Table 5.7-1 are based on combining the existing background sound level measured during the survey with the predicted Unit 4 sound level. The future background sound levels are based on the median sound level measured during the ambient sound level survey detailed in Subsection 2.3.8; the actual future sound level will fluctuate throughout the day depending on variation in significant nonfacility noise sources (i.e., traffic). Furthermore, it is expected the project will not be audible at the nearest receptor locations, R1, R2, and R3, due to the existing nonfacility (i.e., background) noise.

5.7.4 Noise Impact Summary and Mitigation

The noise emissions associated with the normal operation of the project are expected to comply with the property boundary sound levels specified in Special Condition 15 of CU/SDP 92-86. The project is expected to meet these requirements by including standard equipment packages.

Although not required by noise regulations applicable to CIPP, potential impacts to nearby receptors were evaluated by comparing the existing background sound level with the new background sound level expected to result from operation of Unit 4. The new future background sound level is expected to be below a level that is typically considered “clearly noticeable.” As such, significant impacts to nearby receptors are not expected.

5.8 Changes in Nonaquatic Species Populations

5.8.1 Impacts

The operation of Unit 4 may potentially decrease the relative abundance of non-aquatic species in the vicinity of these facilities. Wildlife habitat will be permanently removed from the facility locations, and there may be some loss of individual animals. The activity and noise of plant operation may also temporarily or permanently displace wildlife. Therefore, changes in species diversity, composition, and dominance may occur, but no long-term changes in populations will result from operation of Unit 4 or its associated facilities.

5.8.2 Monitoring

The monitoring plan currently used, as described in Subsection 2.3.5.3 for monitoring vegetation and wildlife at the CIPP, will be sufficient to monitor impacts in the nonaquatic species populations near the Unit 4 power generation facility. No changes in the monitoring plan are proposed.

5.9 Other Plant Operation Effects

The primary effect of operating Unit 4 will be the additional energy capability it will provide to all FMPA members, including KUA. Other positive results of the plant will be the continued stable employment in well paying jobs for plant operations staff. Two full-time staff positions will be created in anticipation of Unit 4 operation. The annual salary of these operating personnel is estimated to be $133,000 per person, all inclusive of benefits and operations. This will be in addition to the roughly 30 staff members currently at the CIPP. Local purchases of certain site services and plant supplies made by these employees will in turn provide additional community employment and income benefits. There will also be maintenance personnel brought in for scheduled outages. The fixed operations and maintenance (O&M) budget for Unit 4 is approximately $1.4 million per year (2008 dollars), and the variable O&M purchases of water, wastewater, contract maintenance, various site services, as well as office supplies and consumables are expected to be approximately $5.8 million per year, assuming a 65 percent unit capacity factor (2008 dollars).

As further outlined below, Unit 4 will have minimal, if any, negative operational effects on the local community in terms of traffic, water and wastewater requirements, housing, labor force, and community facilities and services.

5.9.1 Traffic Impacts

Usual vehicular traffic to the site will consist of only two more operation staff members. In addition, there will also be occasional plant supply deliveries and support services associated with Unit 4. Plant access will not back up normal traffic flows in this rural area.

Natural gas, the only fuel for the plant, will be delivered through an underground natural gas pipeline. There will not be any increase in fuel deliveries by truck as the unit will not be dual fueled. The existing transmission system will be utilized and no increase in traffic will be associated with maintaining the transmission network now in place.

5.9.2 Water

Unit 4 will use reuse water (treated wastewater) for cooling tower makeup. This water will be supplied by Toho via an existing pipeline. In addition, five new onsite wells are requested for process/service water supply and backup cooling tower makeup supply. Approximately 2.8 mgd will be required for the cooling tower, with an additional 134,000 gpd of well water for process and service uses.

5.9.3 Wastewater

Wastewaters will be created from sanitary waste, oil/water separator effluent, cooling tower blowdown, treated chemical wastewaters, and evaporative cooler blowdown. Sanitary waste will be routed to an existing site septic system; oil/water separator effluent will be directed to a new onsite percolation pond; and, other wastewaters will returned to the Toho pipeline.

5.9.4 Power

The operation of Unit 4 will supply FMPA and its members with a safe, adequate, and reliable source of energy in an acceptable, environmental manner. This will be achieved with minimal impacts on the surrounding land uses and community, while creating employment in Osceola County.

5.9.5 Landfill

A negligible amount of landfill waste will be generated during the unit's operation. The waste that is created will come from standard office operations, packaging of supplies and materials. The overall amount of landfill waste should not be significant given the small incremental staff associated with Unit 4. It is likely that the existing dumpster capacity will suffice, with an additional dumpster or more frequent servicing as an option to handle any increased waste generation. FMPA will pay user fees for all site services instead of creating external costs to the surrounding community.

5.10 Landmarks, Sensitive Areas, and Archaeological Sites

No landmark, sensitive areas, or archaeological site will be adversely impacted by the operation of Unit 4.

The previous cultural resources investigation of the CIPP site revealed no significant historical or archaeological resources. The distances and buffer zones between the power block and the sensitive areas (i.e., FDEP/Disney Conservation Easement, the SOR properties, and the Intercession City playground), mitigation and pollution control measures will effectively minimize any impacts from project operation. Operations staff will be requested to use US Highway 17/92 to avoid travel on secondary streets in Intercession City.

5.11 Resources Committed

The CIPP site includes 1,027 acres of Reedy Creek Swamp wetlands and uplands. However, 860 acres onsite have been impressed with conservation easements, preserving valuable wildlife habitat. Plant and associated onsite facilities have 167 acres permitted for power development. The developed land may be mostly returned to its original use after the plant ceases operations.

The materials used to construct Unit 4 are, and will be, dedicated resources. It is possible that some of the materials may be reclaimed after plant closure.

The natural gas burned as fuel will be a permanent commitment of resources. It is estimated that approximately 792 billion cubic feet of natural gas will be consumed annually over the 30 year operating period.

5.12 Variances

No variances are requested.

5.13 References

Ardaman & Associates, Inc. 2007. Double Ring Infiltration Test Results. Private Consulting Report Prepared for Black & Veatch, Kansas City, Missouri.

McDonald, M. G. and Harbaugh, A. W., 1988. A Modular Three-Dimensional Finite-Difference Ground-Water Flow Model: US Geological Survey Techniques of Water Resources Investigations, Book 6, Chapter A1, 586 p.

McGurk, B., P. Presley. 2002. Simulation of the Effects of Groundwater Withdrawals on the Floridan Aquifer System in East - Central Florida: Model Expansion and Revision. Technical Publication No. SJ2002-3, St. Johns Water Management District, Palatka, Florida. November 2002. 196 pp.

Parsons Brinckerhoff, 2006. Documentation of Regional Transient Groundwater Flow Modeling in Support of SFWMD Water Use Permitting for the STOPR Group, Orlando, Florida.

SFWMD, 2008. Basis of Review for Water Use Applications within the South Florida Water Management District. Rules of the South Florida Water Management District, February 13, 2008.

6.0 Transmission Lines and Other Linear Facilities

6.1 Transmission Lines

No new offsite transmission facilities will be required for construction or operation of Unit 4. Unit 4 will be interconnected to the existing CIPP substation, approximately 500 feet from the new unit. A few of the existing transmission poles in the power block area will be relocated in the power block area to accommodate Unit 4. A portion of the relocated lines will cross (i.e., aerial crossing) approximately 400 feet of the wetland buffer zone upland of federal and state wetlands (Reedy Creek Swamp) as shown on the Site Plan Drawing. Trees in this upland buffer area will be trimmed to maintain required electrical safety code clearances. These impacts to the buffer zone will require modification of the SFWMD Conservation Easement.

6.2 Associated Linear Facilities

No new offsite linear facilities will be required for construction or operation of Unit 4.

7.0 Economic and Social Effects of Plant Construction and Operation

7.1 Socioeconomic Benefits

7.1.1 Creation of Temporary and Permanent Jobs

Unit 4 will create a significant number of jobs for Osceola County and the surrounding area during construction and operation. As outlined in Subsection 4.6.3, benefits during the construction of Unit 4 include 4,010 man-months (334 man-years) of employment and $42.75 million in total wage benefits.

Osceola County and the region will not only benefit from direct project labor, but also from the purchase of materials and supplies used in construction. Local purchases associated with power plant construction typically include lumber, concrete and gravel, fuel for onsite motors and vehicles, office supplies and site services such as security, trash hauling, and the installation of security fencing. In addition, the construction workforce will purchase supplemental fuel, food, and other consumables as they commute during plant construction. The overall impacts of these indirect benefits are estimated as part of the multiplier impact analysis in Subsection 7.1.2.

During operation, Unit 4 will have a minor direct employment impact, because it will employ two additional operational staff members. The annual anticipated payroll for Unit 4 operators is estimated at a total of $266,000, inclusive of all benefits and operations, because these are part of the fixed O&M costs of Unit 4. Other benefits will be generated when contract maintenance workers are brought into the area to maintain the unit, and operation of Unit 4 will generate further advantages in the form of continued purchases of consumables for onsite use. These variable O&M purchases include expenditures for water, wastewater, contract maintenance, various site services, as well as office supplies and consumables. Total fixed O&M for Unit 4 is estimated to be about $1.4 million per year (2008 dollars), and variable O&M is estimated to be approximately $5.8 million (2008 dollars) based on an assumed 65 percent capacity factor.

7.1.2 Additional Job Creation/Stimulation of Local Economies

A multiplier effect will be created in the local economy as a result of the additional employment, income, and output associated with the construction and operation of Unit 4. Osceola County and the Orlando area will experience the most impact because these areas will supply much of the Unit 4 workforce. This subsection estimates the multiplier impacts associated with Unit 4.

One method of estimating the multiplier impact of a new investment in a region is through the use of a regional input-output model, which can estimate an expected industry multiplier to be applied to the direct impact estimates. Input-output models typically use an accounting matrix that shows the change in output, earnings, or employment in all industries due to a change in investment in one industry. For estimating the impact of Unit 4, the Regional Input-Output Modeling System (RIMS II model) developed and maintained by the US BEA was used. The RIMS II model also includes multipliers for roughly 500 industry classifications and, as a static equilibrium model, can predict the total impact associated with an initial investment, though it does not predict the timing of impacts.

The RIMS II model requires the user to select a geographical area of study for which multipliers will be estimated. Typically, this will consist of contiguous counties near the investment location, sometimes referred to as the primary impact area. For the Unit 4 analysis, the primary impact area was defined as including the counties of Osceola, Brevard, Highlands, Indian River, Lake, Okeechobee, Orange, and Polk and Seminole.

After the primary impact area was selected, the RIMS II model simulation produced direct-effect multipliers for earnings and employment. These multipliers can then be applied to the direct employment and earnings associated with the construction and operational phases, and the result will produce a projection of the total regional impact arising from the two phases.

The analysis of the multiplier results is summarized in Table 7.1-1. Listed within the table are the direct earnings and employment figures associated with Unit 4, the projected indirect effects on earnings and employment, and the total estimated impact on regional earnings and employment. In total, the $42.75 million in direct construction earnings is projected to generate $78.1 million in regional earnings, and the direct man-years of employment will help generate a total of 654 man-years of regional employment. During operation, if the yearly earnings are assumed to consist of the $1.4 million in annual fixed O&M expenses, total associated annual earnings would equal $2.3 million, and employment would equal a minimum of 5.6 job-years each year, applying the employment multiplier only to the two additional full-time staff at the site.

The indirect economic effect of a new, large investment is always difficult to project with certainty. However, it can be safely concluded that the construction and operation of Unit 4 will create substantial economic benefits to the primary impact area in the form of added earnings and employment. A majority of these benefits will impact those not directly involved with the plant’s construction and operation. This is an important factor when weighing the overall costs and benefits from the project to the region. The projected regional economic benefits outlined above are in addition to the already stated benefit that the Cane Island facility has been determined as the best option for the project. Its attractiveness as a future plant site is based on its prime ability to provide a safe and reliable electricity supply for FMPA and KUA members at the lowest reasonable cost and in an environmentally acceptable manner.

Table 7.1-1
Projected Multiplier Impacts Associated with Cane Island Unit 4

Period	Impact Category	Earnings ($ millions)	Employment (job-years)
Construction	Direct	$42.75	334
	Indirect	$35.4	320
	Total	**$78.1**	**654**
Operation (annual impacts based on fixed O&M expenditures)	Direct	$1.4	2.0
	Indirect	$0.9	3.6
	Total	**$2.3**	**5.6**

7.1.3 Revenue Generation for State and Local Governments

Unit 4 will be owned by FMPA for the benefit of its members. As a public/municipal tax exempt agency, FMPA will not be required to pay property taxes. The local economy and public agency revenues will gain from the additional well paying jobs within the community.

7.1.4 Creation or Improvement of Local Roads, Waterways, or Other Local Transportation Facilities

No new or upgraded public roadways or other transportation facilities will be needed for Unit 4, given CIPP's established infrastructure and minimal need for heavy, long-term traffic. The unit will utilize existing power transmission facilities and will not create significant disruptions to the transportation network offsite.

7.1.5 Increased Knowledge of the Environment

Unit 4 is not expected to significantly contribute to an increased knowledge of the environment. Its overall positive impact will be due the use of proven technology at an existing site.

7.1.6 Increased Land Use Efficiency

Unit 4 increases the efficiency of area land use. The increased productivity from a given parcel of land is especially beneficial in areas of high economic growth, such as the impact area, as this allows other parcels of land to remain available for other uses.

7.2 Socioeconomic Costs

7.2.1 Temporary External Costs

Section 4.6 outlined the possibility of short-term external costs during the period of construction. This section summarizes key points of that discussion.

7.2.1.1 Housing. There are no anticipated negative housing impacts during the Unit 4 construction or operation periods. The primary factor in determining the level of impact is the proximity of the construction workforce. Because there is a sizable construction workforce that is able to commute from Osceola County and the Orlando region, it is safe to conclude that most craft workforce requirements will be met through workers living within reasonable commuting distance for power plant construction. The potential for negative external impacts on many community facilities and services will be largely nonexistent since the construction workforce will be able to commute from existing residences.

7.2.1.2 Traffic. Traffic flow will increase temporarily near the site during Unit 4 construction. There will also be a minor increase in traffic through the operational period. These impacts should be manageable because the concentration of commuting vehicles at the site occurs in a rural area experiencing relatively low traffic levels.

7.2.1.3 Aesthetic Disturbances. Unit 4 will not result in noticeable aesthetic disturbances to Kissimmee or the Intercession City community. This site is located in a relatively remote area that is surrounded by trees. Other than the temporary elevation in traffic during construction, there should be very minimal aesthetic impacts.

7.2.1.4 Use of Water and Sewage Treatment Facilities. Unit 4 will use approximately 2.8 mgd of reuse water for cooling tower makeup supplied by Toho via an existing pipeline. In addition, five new onsite wells are proposed to the UFA for service/process water supply and backup cooling tower makeup water supply for Unit 4. Such uses include plant drains, evaporative cooler, demineralized water, potable water, and fire protection water for total of 134,000 gpd to be supplied from the new well system.

Wastewaters will be created from sanitary waste, oil/water separator effluent, cooling tower blowdown, treated chemical wastewaters, and evaporative cooler blowdown. Sanitary wastes will be routed to an existing septic system onsite; oil/water separator effluent will be directed to a new onsite percolation pond; and, other process wastewaters will be returned to the Toho reuse pipeline.

7.2.1.5 Crowding of Public Facilities and Services. The construction workforce for Unit 4 is expected to live within reasonable commuting distances of the CIPP. Consequently, there are no expected adverse effects on local schools or other public facilities as a result of the additional influx from the worker population.

Hospital and emergency service needs are also expected to be minimal because a safety plan will be developed for the construction and operation phase. Osceola County and the Orlando area have several hospitals and health care facilities capable of treating all levels of medical needs, should there become a need for these services. Unit 4 is not expected to otherwise demand a significant increase in the area's services and facilities but, instead, will add needed power infrastructure.

7.2.2 Long-Term External Costs

Unit 4 is not anticipated to create long-term external impairments to recreational values, restrictions of access to land or water areas preferred for recreational use; deterioration of aesthetic and scenic values; restrictions on access to areas of scenic, historic, cultural, natural, or archeological value; or the removal of land from present or contemplated alternative uses. Unit 4 will not create locally adverse meteorological conditions; reduction of regional products due to displacement of persons from the land proposed from the site; lost income from reduced tourism, commercial fishing, and real estate values in areas adjacent to the proposed facility; or increased costs to local government for services required by the permanently employed workers and their families.

8.0 Site and Plant Design Alternatives

This optional chapter of the SCA will not be submitted as part of this application. An alternatives analysis is not anticipated, because neither a Section 404 permit from the COE nor an EIS under the National Environmental Policy Act (NEPA) would be required for Unit 4.

The CIPP is an existing power plant site with area available for expansion. The Unit 4 systems will be similar to and use several of the existing facilities and systems onsite.

9.0 Coordination

The following is a list of individuals within federal, state, regional and local government agencies contacted for guidance or information concerning the Unit 4 project.

9.1 Federal

US Fish and Wildlife Service

Mr. Paul Souza
South Florida Ecological Services Office
Vero Beach, Florida

9.2 State

Department of Community Affairs, Tallahassee

Mr. Paul Darst
Ms. Kelly Martinson

Department of Environmental Protection

Power Plant Siting Coordination, Tallahassee
Mr. Michael Halpin, Administrator
Ms. Cindy Mulkey

Air Resources Management Division, Bureau of Air Regulation, Tallahassee
Ms. Trina Vielhauer, Bureau Chief
Mr. Al Linero
Ms. Debbie Nelson

Central District Office, Orlando
Ms. Vivian Garfein, Director
Mr. Ali Kazi
Mr. Jim Bradner
Ms. Caroline Shine

Fish and Wildlife Conservation Commission, Vero Beach

Ms. Chance Cowan

Department of Transportation, Tallahassee

Ms. Connie Mitchell

Department of State, Historic Preservation, Tallahassee

Ms. Laura Kammerer, Deputy State Historic Preservation Officer

South Florida Water Management District

Mr. Jim Golden, W. Palm Beach
Mr. Ed Yaun, Orlando Service Center
Mr. Marc Ady, Orlando Service Center
Mr. George Ogden, Orlando Service Center

East Central Florida Regional Planning Council, Maitland

Mr. Andrew Landis
Ms. Kimberly Loewen

9.3 Local

Osceola County Administration, Kissimmee

Mr. Mike Freilinger, County Manager
Mr. Jim Murray
Mr. Don Fisher
Mr. Richard Keck
Ms. Kate Stangle

Toho Water Authority, Kissimmee

Mr. Brian Wheeler, Executive Director

Florida Electrical Power Plant Siting Act
Site Certification Application

Volume 2 of 3

Cane Island Power Park – Unit 4

Submitted by:

Florida Municipal Power Agency
Kissimmee Utility Authority

April 2008

FMPA
Florida Municipal Power Agency
Community Power. Statewide Strength.

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10.0 Permit Applications

This section identifies the permits, approvals, and agreements that are required to construct and operate Unit 4. The permit applications for federal, state, and local authorizations are included for informational purposes and to support agency review of the Unit 4 Project. The site certification application and any final site certification constitute the sole license of the state and any regional or state agency for the construction and operation of Unit 4 in accordance with Section 403.511(1), Florida Statutes (FS).

10.1 Existing Federal Permits

10.1.1 Notice of Intent to Use Multi-Sector Generic Permit for Storm Water Discharge Associated with Industrial Activity

KUA holds a valid NPDES multi-sector permit for uncontaminated storm water discharges from the CIPP. A copy of that permit is included herein. The existing Storm Water Pollution Prevention Plan in effect at the CIPP will be revised to incorporate Unit 4. Copies of this plan are available from KUA.

10.1.2 Oil Pollution Prevention

The amount of reserve fuel oil stored at the CIPP requires KUA to comply with the EPA oil pollution prevention regulations. The existing CIPP Integrated Contingency Plan is in compliance with those regulations. This plan will be revised to incorporate Unit 4 facilities prior to operation. Copies of the plan are available from KUA.

10.2 Federal Permits Applications and Approvals

10.2.1 NPDES Applications

Florida has been delegated authority by the EPA to administer the NPDES wastewater and storm water programs in the state.

10.2.1.1 Wastewater Discharge to Surface Waters. In the event the Toho pipeline is out of service and unavailable for return of site wastewaters, FMPA and KUA request an NPDES wastewater permit to allow discharge of process wastewaters to the onsite storm water basins as a temporary disposal method. The discharge structures of the basins can be plugged to prevent the discharge of these wastewaters to the Reedy Creek Swamp; however, if the pipeline is out of service for any length of time (several days), the basins may require discharge. An NPDES permit application (Form 62-620.910(5) FAC; Form 2CS) for this emergency discharge is included herein.

10.2.1.2 Notice of Intent to Use Generic Permit for Storm Water Discharge from Large and Small Construction Activities. The Notice of Intent (NOI) form must be completed and submitted to the FDEP prior to Unit 4 construction activities at the CIPP site. A partially completed NOI [Form 62-621.300(4)(b), FAC] is included herein. FMPA will require the contractor responsible for the site earthwork to obtain this authorization prior to construction.

A Storm Water Pollution Prevention Plan for Storm Water Discharges from Construction Activities will be prepared by the contractor for Unit 4 construction. The Storm Water Pollution Prevention Plan is required to be onsite and implemented during the construction period.

10.2.2 Department of Energy Self-Certification

The primary and only fuel for Unit 4 is natural gas. FMPA has also requested LNG as a fuel for the existing units, Unit 4, and future units.

The Power Plant and Industrial Fuel Use Act requires FMPA to certify that, with the installation of additional equipment, Unit 4 would be capable of firing coal or another alternate fuel such as gasified coal or biomass as the primary energy source. A draft copy of the Self-Certification is included herein.

10.2.3 Federal Aviation Administration - Determination of No Hazard to Air Navigation

The FAA requires that structures over 200 feet in height or within a specified distance of an airport be marked and lighted in accordance with the standards of the FAA Advisory Circular AC 70/7460-1K Obstruction Marking and Lighting. Although the Unit 4 stack will be less than 200 feet in height, a construction crane, likely 200 feet or greater in height, will be onsite during construction. The application for a construction crane is completed on FAA Form 7460-1 is included herein.

10.2.4 Army Corps of Engineers and Fish and Wildlife Service Notification

The Corps of Engineers and the Fish and Wildlife Service were notified of the Unit 4 project in March 2008. Copies of the notification letters are included herein. No impacts to waters or wetlands, and no adverse impacts to threatened or endangered species are anticipated from construction or operation of Unit 4.

10.2.5 316 Demonstrations

Not required.

10.2.6 Hazardous Waste Disposal Application

Not required.

10.2.7 Environmental Resource Permit Application (Section 10 or 404 Permit)

The Corps of Engineers has the authority to review the potential environmental impacts associated with the construction and operation of Unit 4 and associated facilities. Although there will be no waters or wetlands impacts due to Unit 4 construction or operation, the Corps was notified of the project by letter in March 2008. A copy of this letter is included in Subsection 10.2.4 above.

10.2.8 Prevention of Significant Deterioration Permit Application

The construction and operation of Unit 4 will require a PSD air construction permit. The FDEP will review the PSD application in coordination with the EPA. The PSD Air Permit Application is attached under separate cover as Volume 3 of this SCA.

10.2.9 Title IV Acid Rain Part Application

Modification of the existing Title IV Permit will be required with the addition of Unit 4. Attachment 7 of Appendix A to SCA Volume 3 lists the Acid Rain Part Application.

10.3 Zoning Descriptions

A copy of the Osceola County Conditional Use/Site Development Plan Permit issued for Unit 3 and the zoning categories identified in the Osceola County Land Development Code applicable to the CIPP site are included herein.

10.3.1 Conditional Use/Site Development Plan

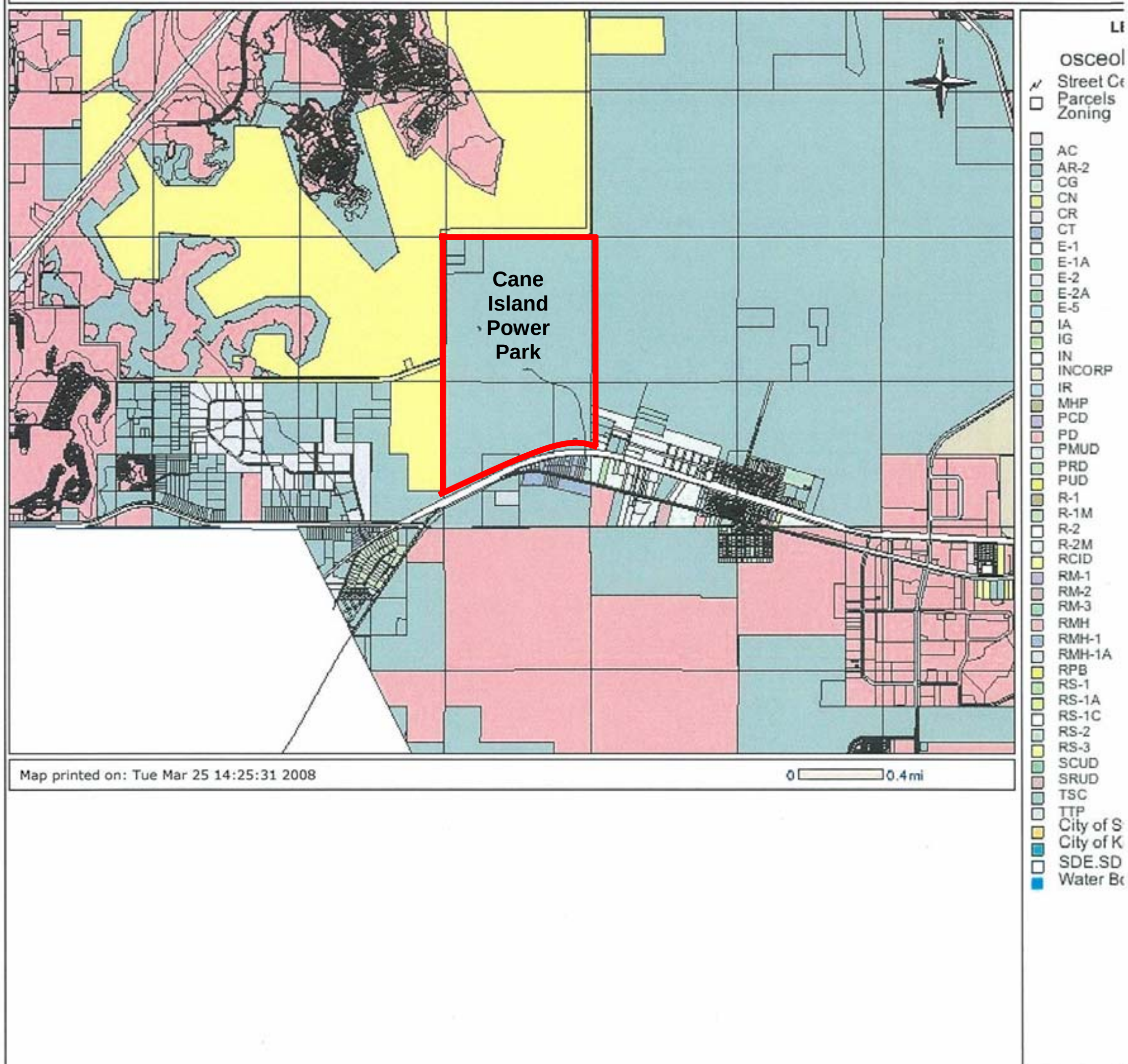
CU/SDP 92-86 was issued to KUA by the Osceola Board of County Commissioners for development of the property as a power generating station. A copy of this permit is included herein. A completed CU/SDP application to incorporate Unit 4 into the County records is also included herein.

10.3.2 Building Permit Exemption

A Building Permit would normally be required from Osceola County to construct several of the Unit 4 facilities. However, the Site Certification process exempts the project from the need to obtain a Building Permit. The project will still have to meet county codes and regulations. The construction contractor will be required to meet with county building officials to ascertain their requirements prior to start of construction.

PRINT:FMPA/KUA Cane Island Zoning Map Page 1 of 1

FMPA/KUA Cane Island Zoning Map



Disclaimer: .

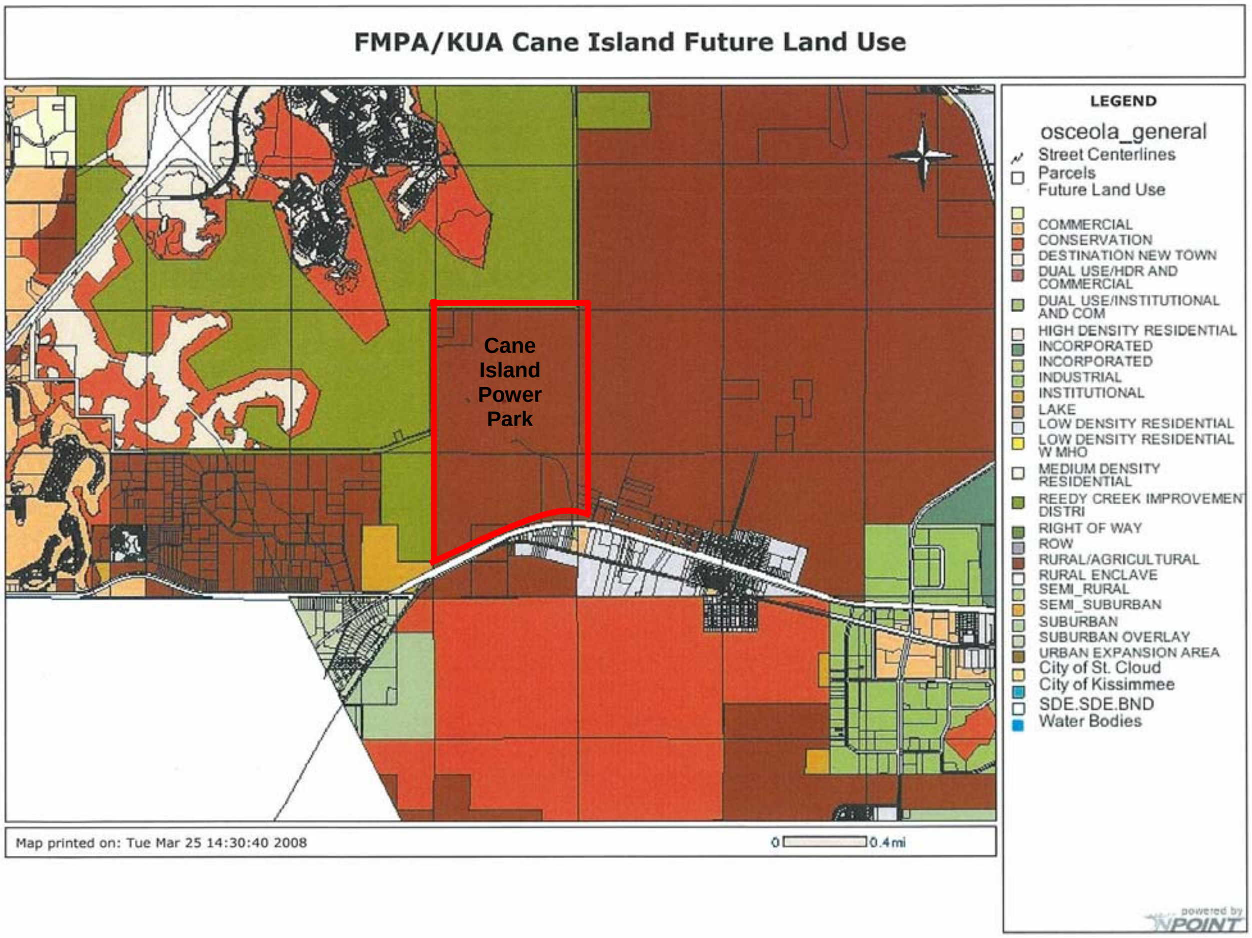
Comments: .

http://maps.osceola.org/public/onpoint 3/25/2008

10.4 Land Use Plan Descriptions

A copy of the Osceola County Future Land Use Designation element of the Comprehensive Plan of Osceola County applicable to the CIPP site is included herein.

PRINT:FMPA/KUA Cane Island Future Land Use



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Comments: .

http://maps.osceola.org/public/onpoint

10.5 State Permits and Applications

As an existing certified power plant site, KUA and FMPA hold an active Site Certification Order (PA 98-38) for the CIPP and associated facilities. Certification of Unit 4 and modification of the Conditions of Certification are required for installation and operation of Unit 4. The following applications have been prepared to support state agency reviews of these requests.

10.5.1 Environmental Resource Permit Application

FMPA and KUA will request that the construction, operation, and environmental impacts associated with Unit 4 be reviewed by SFWMD through interagency agreement with DEP during the certification process. The SFWMD has the complete storm water permitting history with the CIPP. An ERP Application demonstrating compliance with the state storm water permitting requirements is included herein to assist in this review.

No impacts to waters/wetlands, and no adverse impacts to threatened or endangered species are anticipated from construction or operation of Unit 4.

10.5.2 Application for Consumptive Uses of Water

Ground water withdrawals associated with operation of Unit 4 will be required for process/service water and emergency cooling water use. One new process service water well and four new emergency cooling water wells are requested to provide this water. These withdrawals and use will be reviewed through completion and review of SFWMD Application Form 0645-W01. This application is included herein.

10.5.3 Short-Term Dewatering Permit Application

Dewatering of ground water is considered a consumptive use of water and requires authorization from SFWMD. Dewatering will be required for the construction of Unit 4 including filling and stabilization of the site for placement of piping, electrical trenches, sumps, and foundations. Therefore, an Individual Dewatering Permit application has been prepared for review by the SFWMD. The permit application is prepared on SFWMD Form 0445 and is included herein. A detailed dewatering plan will be provided post-certification.

10.5.4 Florida Division of Historical Resources Review

In January 1992, in association with construction and operation of Units 1 and 2, the Florida Division of Historical Resources (DHR) was requested to review the CIPP site and project area for known or potential cultural resources. The DHR indicated in February 1992 that there were no known archeological or historical resources onsite or within the project area listed on the *National Register of Historic Place*, but requested a systematic survey of the site prior to any land disturbing activities.

A Phase I cultural resources investigation of the CIPP and associated corridors was conducted by Janus Research/Piper Archaeology of St. Petersburg, Florida, in May 1992. The investigation discovered 13 previously unrecorded sites: seven prehistoric and six historic. It was the consultant's opinion that none of the sites were eligible for listing on the *National Register of Historic Places*. All of the historic sites were outside of direct impact areas. The Phase I report was submitted to the DHR for review in June 1992. On July 23, 1992, the DHR issued a clearance letter concurring with the consultant's opinion and approving the site for construction. The DHR was notified of the Unit 4 project by letter in March 2008 (copy included herein).

10.5.5 Florida Natural Areas Inventory Review

The Florida Natural Areas Inventory (FNAI) was notified of the Unit 4 project in March 2008. A copy of this notification letter is included herein.

10.5.6 Permit Application to Construct, Repair, Modify, or Abandon a Well

FMPA and KUA propose to construct five new ground water wells on the CIPP site. The permit application for well construction will be reviewed by the SFWMD. At this time, the detailed well design and well drilling contractor have not been selected. The partially completed application is included herein. The final application will be submitted post-certification.

10.5.7 Florida Fish and Wildlife Conservation Commission Review

The FFWCC is a statutory party to the certification process.

Gopher tortoises are the only known state threatened or endangered species confirmed onsite. A copy of the previously issued gopher tortoise Incidental Take Permit OSC-6 is included in Appendix D of the ERP application, Subsection 10.5.1. The FFWCC confirmed in March 2008 that this permit is still valid, which allows the CIPP staff to relocate tortoises onsite.

10.5.8 Coastal Zone Management Certification

The Coastal Management Act of 1978 (Section 380.21-380.25, FS) requires that the Coastal Zone Management Section of FDEP be responsible for certification of consistency with the Florida Coastal Management Program (FCMP) for all federal licenses, permits, activities, and projects listed in Section 380.23 (3)(c), FS, when such activities are subject to federal consistency review and affect land or water use, are seaward of the jurisdiction of the state, or there is no state agency with sole jurisdiction for such consistency review. The requirements related to Section 10 of the Rivers and Harbors Act and Section 404 of the Clean Water Act are addressed in Appendix 10.1.4. Issuance of the final Site Certification will demonstrate consistency with Section 307 of the Coastal Zone Management Act.

10.5.9 Public Drinking Water System Extension Permit Application

The existing drinking water system will require an extension to the Miscellaneous Services Building and Power Distribution Center associated with Unit 4 to supply eye wash stations. This extension will be reviewed through completion of Form 62-555.900(7), FAC. A partially completed application is included herein. A complete application will be submitted post-certification.

10.5.10 Industrial Wastewater Treatment and Disposal System Permit

Process wastewaters from Unit 4 will be treated and conveyed to a new onsite percolation pond for discharge to groundwater. Form 62-620.910(4) FAC (Form 2CG), and supporting documentation are included herein.

Additional process wastewaters will be treated and returned to the Toho reuse water pipeline. KUA and FMPA will work with Toho to address Unit 4 wastewaters consistent with the Effluent Delivery and Use Agreement (refer to Subsection 10.7.1).

10.6 Monitoring Programs

Several monitoring programs are in effect at the CIPP site. Unit 4 will be incorporated into these programs. No new monitoring programs are proposed at this time.

KUA and FMPA also request modification of the groundwater monitoring program as described in the Conditions of Certification Section XVIII – Groundwater. The request is to reduce the sampling schedule from quarterly to semi-annually, based on demonstrated performance and compliance of the existing percolation pond.

10.7 Toho Water Authority Agreements

10.7.1 Effluent Delivery and Use Agreement

An agreement between KUA and Toho was executed in 1993 for the delivery, use, and return of treated sewage effluent. A copy of the agreement is included herein. The reuse agreement indicates that KUA has the right of first refusal to reuse water.

10.7.2 Well Installation and Well Water Supply Agreement

The well water agreement between KUA and Toho was executed in 2003 and allows Toho to install up to five wells on the CIPP site (two wells currently exist). With the installation of Unit 4, Toho has the obligation to deliver up to 330,000 gpd of raw well water to the Cane Island facility. Toho well water may also be used for emergency cooling, as available, if reuse supply is interrupted. A copy of the agreement is included herein.

10.8 Carbon Reduction Activities

On July 13, 2007, Governor Crist issued Executive Order 07-127, entitled "Immediate Action to Reduce Greenhouse Gas Emissions within Florida." This order directs the Department of Environmental Protection (DEP) to adopt rules requiring carbon dioxide (CO_2) emission reductions from electric utilities. Although DEP has not yet adopted any rules in response to the Governor's Order, the All-Requirements Project (ARP) is committed to responsibly reducing its CO_2 emissions. This Section summarizes the ARP's historical CO_2 emissions, as well as actions the ARP has taken or may take that will help reduce the ARP's CO_2 emissions. Specifically, Section 10.8.1 summarizes the ARP's carbon footprint. Section 10.8.2 summarizes actions the ARP has taken that will reduce the ARP's CO_2 emissions. Finally, Section 10.8.3 summarizes future planned actions, including the addition of Cane Island Unit 4, as well as other potential actions that would reduce the ARP's carbon footprint.

10.8.1 The ARP's Carbon Footprint

The Governor's Executive Order 07-127 sets goals for utilities to reduce their greenhouse gas emissions to 2000 levels by 2017, to 1990 levels by 2025, and by 80 percent of 1990 levels by 2050. This section describes the CO_2 emissions inventory developed for 1990 and 2000 to determine the baseline carbon footprint of the ARP in those years.

10.8.1.1 Methodology. Because DEP has not established any guidelines on reporting of greenhouse gases as of the date of this filing, the emissions inventory was performed using the guidelines set forth in the United States Department of Energy's (U.S. DOE) final "General Guidelines for Voluntary Reporting of Greenhouse Gases (1605(b)) Program" issued in April 2006, and "Technical Guidelines for Voluntary Reporting of Greenhouse Gases (1605(b)) Program" (the Technical Guidelines) issued in January 2007.[1]

The 1605(b) Guidelines categorize emissions for electric utilities as occurring from either direct or indirect sources. Direct emissions are those emissions that the utility is directly responsible for producing; that is, the utility produces these emissions through operation of its own generating units. Indirect emissions are those emissions associated with purchased power.

[1]The U.S. DOE initiated the Voluntary Reporting of Greenhouse Gases Program (the GHG Program) during 1994 in response to Section 1605(b) of the Energy Policy Act of 1992, which required the U.S. DOE to issue guidelines establishing such a program. The U.S. DOE developed both General Guidelines and Technical Guidelines for the GHG Program. The Technical Guidelines define the permissible methods of calculating and reporting emissions quantities and reductions under the GHG Program.

The collective 1990 and 2000 emissions for all 15 ARP Members[1] were developed using the equity share approach set forth in the 1605(b) Guidelines. Under this approach, a utility includes the percentage of the total emissions produced from a jointly owned facility that corresponds with its ownership percentage of that resource.

Where available, data from continuous emissions monitors (CEMs) were used to estimate direct emissions. However, as CEMS were not required to be installed on plants until after 1990, this data was not available for the 1990 computation. Additionally, some small generating units are not required to install CEMS, so CEMs data was not available for all generators for 2000. Where CEMs data was not available, emission factors provided in the 1605(b) Guidelines or other publicly available sources were used. Likewise, such publicly available emission factors were used to estimate emissions from purchase power.

10.8.1.2 Final Adjustments. The first step in determining the total emissions quantities for each year involved determining whether all energy sources had been captured for that year. The sum of all energy generated and purchased, net of wholesale energy sold to other entities, theoretically should be at least equal to the utility's energy requirements (some excess of energy sources above energy requirements may exist due to losses).

For computing total generation associated with direct emissions, the generation and consumption data from Global Energy Decisions' Velocity Suite was used for all units. This provided a consistent source of generation for all resources.

For both 1990 and 2000, however, the sum of the total energy sources amounted to less than the total energy requirements. For purposes of the analysis, CO_2 emissions were computed for the "missing" energy amount using the regional emissions factor for that year.

10.8.1.3 Emissions Totals. The total CO_2 emissions inventoried consist of the sum of the direct emissions, indirect emissions, and any adjustments. The computed total CO_2 emissions are shown in Table 10.8-1.

[1] The current ARP members are the City of Bushnell, the City of Clewiston, the City of Fort Meade, the Fort Pierce Utilities Authority, the City of Green Cove Springs, the Town of Havana, Beaches Energy Services (the electric department of the City of Jacksonville Beach), Keys Energy Services (also known as the Utility Board of the City of Key West), the Kissimmee Utility Authority, the City of Lake Worth, the City of Leesburg, the City of Newberry, the City of Ocala, the City of Starke, and the City of Vero Beach.

Table 10.8-1
Summary of ARP CO_2 Emissions in 1990 and 2000[1]

Item	Units	1990	2000
Total Energy Sources	GWh	3,142	6,426
Total Energy Requirements	GWh	4,663[2]	6,467
Surplus/(Shortfall)	GWh	(1,521)	(41)
Surplus/(Shortfall)	%	(32.6)	(0.6)
Direct CO_2 Emissions	000 Short Tons	1,442	2,538
Indirect CO_2 Emissions	000 Short Tons	836	2,139
Adjustments[3]	000 Short Tons	1,203	30
Total CO_2 Emissions	000 Short Tons	3,481	4,707

[1]Analysis performed as if all 15 current ARP Members were ARP Members in 1990 and 2000.
[2]Energy requirements estimated for 1990. Actual energy requirements for the ARP Members in 1990 were not available.
[3]Adjustments reflect CO_2 emissions computed for additional energy amounts necessary to balance total energy sources and total energy requirements and were computed using the regional emissions factor for Florida applicable to that year.

10.8.2 Historical Carbon Reduction Activities

10.8.2.1 Generation Efficiency. Historically, the ARP has consistently sought to improve the efficiency of its generating fleet, which can have the added benefit of reducing carbon intensity (quantity of CO_2 per unit of energy produced). The ARP's actions have displaced generation from older, Member-owned generating resources with newer, more efficient units. Table 10.8-2 contains a list of the units that either have been or are scheduled to be retired, the retirement year, and the average CO_2 emissions eliminated by retiring these resources. Additional member owned generation will be displaced with operation of Cane Island Unit 4.

Table 10.8-2
Recent and Scheduled Retirements of Member-Owned Generating Resources

Unit Name	Owner	Fuel Type	Retirement Year	Annual CO_2 Emissions (Short Tons)[1]
Hansel IC 8, 14-20	KUA	No. 2 Oil	2005	1,800
Big Pine Key IC 1	Keys Energy Services	No. 2 Oil	2006	400
Cudjoe Key IC 2-3	Keys Energy Services	No. 2 Oil	2006	1,500
H. D. King CC 5/9	Fort Pierce	Natural Gas	2008	11,100
H. D. King ST 7-8	Fort Pierce	Natural Gas	2008	20,400
H. D. King IC 1-2	Fort Pierce	No. 2 Oil	2008	200
Total				35,400

[1]Based on the average annual tons of CO_2 emitted during the years 2001 through 2005.

As appropriate and cost effective, FMPA has also sought to replace energy obtained from purchased power with more efficient means. Emissions for purchased power that are not tied to specific generating plants or units can be much higher than the carbon intensity of energy produced by efficient, natural gas-fired resources. As examples, FMPA has either recently replaced or is planning to replace energy from purchases from the City of Lakeland, Progress Energy Florida (PEF), and Florida Power & Light Company (FPL) with new generating resources or purchases from specific, gas-fired facilities.

FMPA has added several new generating resources in recent years through both ownership and facility-specific purchased power contracts. These new resources provide CO_2 emission reduction benefits to the ARP by allowing the ARP (1) to displace the operation of other, less efficient owned generating resources, and (2) to reduce the amount of more carbon-intensive energy it purchases from other entities. These new resources are described in more detail below.

- **Cane Island CC3**--Cane Island CC3 commenced operation in 2002. This 246 MW, natural-gas fired, combined cycle facility is jointly owned by Kissimmee Utility Authority (KUA) and FMPA, with all of its output going to the ARP. During its first five years of commercial operation, Cane Island CC3 emitted an average of approximately 0.21 short tons of CO_2 per MWh less than other ARP generating resources and approximately 0.22 short tons of CO_2 per MWh less than all energy sources for the ARP.

- **Stanton Energy Center CCA**--Stanton Energy Center CCA commenced operation in 2003. KUA and FMPA each owns a 3.5 percent share of this 600 MW, natural-gas fired, combined cycle facility, and each also purchases an additional 6.5 percent share from Southern Company with the total 20 percent share going to the ARP. During its first three complete years of commercial operation, Stanton Energy Center CCA emitted an average of approximately 0.26 short tons of CO_2 per MWh less than other ARP generating resources and approximately 0.28 short tons of CO_2 per MWh less than all other energy sources for the ARP.
- **Calpine (Osprey) Purchase**--FMPA has a contract with Calpine that provided 75 MW in 2006. The purchase increased to 100 MW in 2007 and expires in 2009. During 2006, each MWh of energy purchased from Calpine produced approximately 0.19 short tons of CO_2 less than the average of the ARP generating units and approximately 0.23 short tons of CO_2 less than other purchases.
- **Stock Island CT4**--In 2006, the ARP commenced operation of its Stock Island GT4 in Key West. If operating at full load, every MWh of energy generated from Stock Island CT4 in lieu of other on-island resources can reduce FMPA's CO_2 emissions output by up to 0.17 short tons.
- **Southern Purchase**--FMPA has a contract to purchase 156 MW of new peaking power from Southern Company's Oleander plant beginning in December 2007. Since the unit has only been in operation since December 2007, actual emission data is not yet available; however, as a new efficient General Electric 7FA simple cycle combustion turbine, the Oleander purchase will reduce CO_2 emissions compared to other less efficient FMPA peaking resources or purchased power.

FMPA also currently receives renewable energy from two renewable resources. These resources also provide CO_2 reduction benefits to the ARP, as described below.

- **U.S. Sugar**--Energy purchased from the U.S. Sugar Corporation is considered carbon neutral because it uses renewable, carbon-neutral bagasse as its primary fuel source. Over the period 2000 through 2006, the U.S. Sugar purchase is estimated to have reduced CO_2 emissions for the ARP by an average of approximately 1,300 short tons per year. As U.S. Sugar utilizes its generating facility to serve its own energy requirements, the ARP indirectly avoids having to serve the U.S. Sugar load using more carbon intensive generating resources.

- **Landfill Gas (Stanton Energy Center)**--The Stanton Energy Center utilizes landfill gas to supplement the fuel requirements for the coal-fired Units 1 and 2. The reportable CO_2 content for landfill gas/municipal solid waste (MSW) varies based on the plastic content of the underlying waste product. The national average CO_2 emissions factor for MSW as provided by the U.S. DOE is 92 pounds of CO_2 per MMBtu of MSW consumed and is based on a plastic content of 16 percent. As the plastic content of the landfill gas burned by Stanton Energy Center Units 1 and 2 could not be obtained, the default factor was assumed. Based on this factor, CO_2 emissions for the ARP were estimated to have been reduced by approximately 19,700 short tons per year over the period 2001 through 2006 by consuming landfill gas instead of coal.

10.8.2.2 Demand Side Management. FMPA is a wholesale supplier of electricity to the fifteen ARP Member cities. As such, FMPA does not directly implement demand-side management (DSM) to retail customers. The individual ARP Members actually provide the DSM programs to their customers. Several ARP members offer various DSM programs including the following:

- Energy Audits.
- Energy Savings Tips.
- Energy Star® Programs.
- Green Energy Programs.
- Solar Projects and Net Metering.
- Solar Promotion.
- Appliance Rebates.
- Compact Fluorescent Bulb Promotions.
- ESCO Projects.
- City-Wide Energy Conservation.
- LED Traffic Signals.
- Low Income Energy Assistance.
- Load Profiling for Commercial Customers.
- Fix-Up Programs for the Elderly and Handicapped.

To the extent these measures help to reduce FMPA's energy requirements, they have a corresponding CO_2 reduction benefit to the ARP.

10.8.3 Future Planned and Potential Carbon Reduction Activities

10.8.3.1 Treasure Coast Energy Center. FMPA's Treasure Coast Energy Center Unit 1 (TCEC Unit 1) is scheduled to commence operation in May 2008. This approximately 300 MW, natural gas-fired combined cycle unit represents FMPA's largest self-owned generating project to date. It is estimated that TCEC Unit 1 will reduce FMPA's CO_2 emissions by approximately 305,000 short tons in 2009, the first full year of commercial operation, as summarized in Table 10.8-3.

As shown in Table 10.8-3, the largest reduction in CO_2 results from a reduction in purchased power. It is also anticipated that TCEC Unit 1 will displace the operation of less efficient generating resources.

The projections shown in Table 10.8-3 were developed based on output from FMPA's production simulation model. To the extent that future conditions vary from the inputs included in the model, the actual CO_2 emissions reductions experienced may differ.

10.8.3.2 Cane Island 4. Cane Island 4 also will significantly reduce FMPA's total future CO_2 emissions. Cane Island 4 will displace the operation of less efficient generating resources. By operating this more efficient unit, FMPA will reduce the average CO_2 emitted per MWh produced for its system. Additionally, Cane Island 4 will reduce FMPA's purchase power requirements and associated higher CO_2 emissions. The addition of Cane Island 4 is estimated to reduce FMPA's CO_2 emissions by approximately 262,000 short tons in 2012, the first full year of commercial operation, as summarized in Table 10.8-4.

As shown in Table 10.8-4, the largest reduction in CO_2 results from a reduction in purchased power. It is also anticipated that Cane Island 4 will displace the operation of less efficient generating resources. Additionally, the need for Cane Island 4 resulted from the cancellation of the Taylor Energy Center (TEC), the coal-fired project that was jointly proposed by FMPA, JEA, Reedy Creek Improvement District, and the City of Tallahassee. The CO_2 emissions rate for the TEC was estimated between 200 and 215 lb/MMBtu, or between 0.92 and 0.99 short tons/MWh based on the average heat rate of 9,238 Btu/kWh, depending on the type of coal consumed. By contrast, the estimated CO_2 emissions rate for Cane Island 4 of approximately 115 lb/MMBtu, or 0.43 short tons/MWh based on the average heat rate of approximately 7,420 Btu/kWh (including duct firing), is significantly lower.

The projections shown in Table 10.8-4 were developed based on output from FMPA's production simulation model. To the extent that future conditions vary from the inputs included in the model, the actual CO_2 emissions reductions experienced may differ from the amounts shown in Table 10.8-4.

Table 10.8-3
Projected Impact of TCEC Unit 1 on ARP CO_2 Emissions in 2009

Energy Source	CO_2 Increase/ (Decrease) (000 Short Tons)[1]
Treasure Coast Energy Center	593
Stanton Energy Center Coal	(25)
Stanton CC A [2]	(24)
Cane Island Plant	(130)
Hansel Plant	(14)
Indian River CT A-D	(11)
H.D. King Plant	(18)
Tom G. Smith Plant	(9)
Stock Island Plant	10
Vero Beach Plant	(22)
Net Market Transactions	(500)
Other Purchases [3]	(155)
Net Increase/(Decrease)	(305)

(1) Represents the projected increase or decrease in CO_2 emissions for each energy source resulting from the operation of TCEC Unit 1.

(2) Includes the portion of Stanton A that is purchased power.

(3) Other purchases include purchases from PEF, FPL, Calpine, and Southern.

Table 10.8-4
Projected Impact of Cane Island 4 on ARP CO_2 Emissions in 2012

Energy Source	CO_2 Increase/ (Decrease) (000 Short Tons) [1]
Cane Island 4	640
Stanton Energy Center Coal	(58)
Stanton CC A [2]	(26)
Treasure Coast Energy Center	(10)
Cane Island Plant (excludes Unit 4)	(95)
Hansel Plant	(3)
Indian River CT A-D	(2)
Tom G. Smith Plant	(2)
Stock Island Plant	6
Net Market Transactions	(688)
Other Purchases [3]	(23)
Net Increase/(Decrease)	(262)

[1] Represents the projected increase or decrease in CO_2 emissions for each energy source resulting from the operation of Cane Island 4.
[2] Includes the portion of Stanton A that is purchased power.
[3] Other purchases include purchases from FPL and Southern.

10.8.3.3 Nuclear Uprates. FMPA's capacity shares of the Crystal River 3 and St. Lucie 2 nuclear units will increase as a result of upgrades to the facilities being undertaken by PEF and FPL, respectively. FMPA or Members that own shares of these facilities will receive proportional increases in their capacity allotments based on their ownership percentage. The total planned incremental capacity increase for each unit and the ARP Members' allocation of these capacity increases are shown below.

	Crystal River 3		St. Lucie 2	
	Total Uprate	ARP Allocation	Total Uprate	ARP Allocation
2008	12 MW	0.3 MW	--	--
2009	28 MW	0.8 MW	--	--
2010	--	--	--	--
2011	140 MW	4.0 MW	--	--
2012	--	--	100 MW	5.8 MW

This increase in nuclear capacity will provide a CO_2 emission reduction benefit to FMPA.

10.8.3.4 Future Nuclear Ownership. FMPA is currently investigating the feasibility of acquiring an ownership share in future nuclear resources proposed to be built in Florida. FMPA is currently in discussions with PEF concerning potential participation in the Levy County nuclear project. Since nuclear generation does not produce CO_2, acquiring additional nuclear ownership could bring significant CO_2 emission reduction benefits to the ARP as early as 2016.

10.8.3.5 System Loss Reduction. FMPA encourages the concept of asset management for both itself and Member utilities. Asset management involves investigating methods of utilizing existing assets to improve efficiency, lower costs, or improve revenue. CO_2 reductions can be obtained through management of the ARP's generating assets and aggregated electrical load.

Losses are an aggregated component of the electric load of the Member utilities. As losses are controlled and reduced, so is the need for additional electrical generation. Therefore, reducing losses reduces CO_2 emissions and can reduce or delay the need for additional generating resources to be constructed. FMPA is leading an effort among the Members to investigate losses and for Members to invest in loss reduction.

10.8.3.6 Potential Future Renewable Resources.

10.8.3.6.1 Potential Biomass Generation. As part of its efforts to reduce its overall CO_2 emissions, FMPA has issued requests for proposals (RFPs) for renewable resources. Based on the results of the RFPs, FMPA has decided to enter into negotiations for a purchase from a biomass facility. The biomass unit, which would utilize renewable, carbon-neutral resources, would reduce FMPA's CO_2 emissions by approximately 190,000 short tons per year. Because the cost of biomass energy is higher than FMPA's avoided cost, before committing to a biomass purchase, FMPA will need to examine the biomass resource to ensure that the costs are within a reasonably acceptable margin higher than FMPA's avoided cost. Furthermore, FMPA's ultimate commitment to utilizing biomass energy at its attendant higher cost as a means of its meeting CO_2 reduction targets will depend on whether the emissions inventory guidelines to be developed by FDEP confirm biomass as a carbon-neutral resource in Florida. FMPA will also need to examine the actions of other utilities in Florida in meeting their CO_2 reduction targets to ensure that FMPA's rates remain cost competitive. The time frame for implementation of the biomass resource would depend on the time necessary to complete negotiations and obtain all required regulatory approvals and permits.

10.8.3.6.2 Potential Solar Photovoltaic Project. FMPA has decided to enter into negotiations for the installation of 10 MW of solar photovoltaic (PV) technology on its Member systems. FMPA will additionally explore the feasibility of acquiring up to an additional 90 MW of PV systems. The average amount of CO_2 that could be reduced each year through PV resources ranges from approximately 9,000 short tons for 10 MW to 61,000 short tons for 100 MW. Before committing to the 10 MW PV project, FMPA will need to examine the PV resources to ensure that the costs are within a reasonably acceptable margin higher than FMPA's avoided cost. FMPA will also need to examine the actions of other utilities in Florida in meeting their CO_2 reduction targets to ensure that FMPA's rates remain cost competitive. FMPA's decision to pursue additional solar capacity beyond the initial 10 MW would depend on successful negotiation for and implementation of the initial 10 MW project. The time frame for implementation of solar capacity would depend on the time necessary to complete negotiations and obtain all required regulatory approvals and permits.

10.8.3.6.3 Potential Use of Bio-Fuels at Stock Island. FMPA is currently investigating the feasibility of operating several of the generating units at the Stock Island facility in Key West using bio-diesel fuel. These units currently operate using fuel oil. If ultimately implemented, the switch from fuel oil to bio-diesel fuel for these units could reduce FMPA's CO_2 emissions.

10.8.3.7 Potential Future Conservation Programs.

10.8.3.7.1 DSM Request for Proposals. In July 2007, FMPA issued an RFP for DSM activities. Four proposals were received, and three of the proposals have been short-listed for further evaluation. Discussions are proceeding with the proposers to examine the possibility of implementing demand-side programs. To the extent any of these measures, if ultimately implemented, help to reduce FMPA's future energy requirements, they would have a corresponding CO_2 reduction benefit to the ARP.

10.8.3.7.2 Potential ARP-Funded Energy Conservation Program. As a wholesale energy provider, FMPA does not directly implement demand-side conservation measures. However, FMPA is considering undertaking a program to assist its Members in implementing energy conservation measures. Under this program, FMPA could collect funds through its rates that would be allocated among the ARP Members. As an example, the Members could utilize these funds to purchase compact fluorescent light bulbs that could be distributed to retail customers at reduced or no cost. These measures would help to reduce FMPA's energy requirements, which would have a corresponding CO_2 reduction benefit to the ARP.

10.8.4 Conclusion

The ARP has demonstrated a strong track record in improving the efficiency of its generating fleet and it is committed to exploring new ways to improve efficiency and to reduce CO_2 emissions in a cost-effective manner. Because Cane Island Unit 4 will be one of the most efficient generating units in the state, it will enable the ARP to displace generation from less efficient units. As such, along with FMPA's other efforts, Cane Island Unit 4 will help the ARP to reduce CO_2 emissions consistent with the state's goals.

Florida Electrical Power Plant Siting Act
Site Certification Application

Volume 3 of 3

Cane Island Power Park – Unit 4

Submitted by:

Florida Municipal Power Agency
Kissimmee Utility Authority

April 2008

Florida Municipal Power Agency
Community Power. Statewide Strength.

KISSIMMEE
UTILITY
AUTHORITY

FMPA – Cane Island Power Park
Unit 4
Combined Cycle Combustion Turbine

Prevention of Significant Deterioration
Air Permit Application

April 2008

Prepared for:
Florida Municipal Power Agency
Orlando, Florida

Florida Municipal Power Agency
Community Power. Statewide Strength.

Prepared by:
Black & Veatch
Overland Park, Kansas

BLACK & VEATCH
Building a world of difference.

Table of Contents

Table of Contents (Continued)

Table of Contents (Continued)

Tables

Figures

Acronym List

AAQIA	Ambient Air Quality Impact Analysis
AAQS	Ambient Air Quality Standards
AERMIC	AMS/EPA Regulatory Model Improvement Committee
AMS/EPA	American Meteorological Society/Environmental Protection Agency
AQIA	Air Quality Impact Analysis
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
bhp	Brake Horsepower
BPIPPRM	Building Profile Input Program Prime
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CALPUFF	California Puff
CCCT	Combined Cycle Combustion Turbine
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CIPP	Cane Island Power Park
CO	Carbon Monoxide
CTG	Combustion Turbine Generator
CWA	Chassahowitzka Wilderness Area
DAT	Deposition Analysis Threshold
DEM	Digital Elevation Model
DLN	Dry Low NO_x
dv	Deciview
EC	Elemental Carbon
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FGT	Florida Gas Transmission Company
FMPA	Florida Municipal Power Agency
FWS	Fish and Wildlife Service
GE	General Electric
GEP	Good Engineering Practice
Gulfstream	Gulfstream Natural Gas System L.L.C.

H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid Mist
ha	Hectares
HAP	Hazardous Air Pollutant
Hg	Mercury
HRSG	Heat Recovery Steam Generator
ISC	Industrial Source Complex
ISO	International Organization for Standardization
IWAQM	Interagency Workgroup on Air Quality Modeling
kW	Kilowatt
lb/h	Pound per Hour
LCC	Lambert Conformal Conic
LMDCT	Linear Mechanical Draft Cooling Tower
LNG	Liquefied Natural Gas
MBtu	Million British Thermal Unit
MM5	Mesoscale Meteorological Data - Generation 5
MSA	Metropolitan Statistical Area
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
ng/J	Nanogram per Joule
NO_x	Nitrogen Oxides
NPS	National Parks Service
NSPS	New Source Performance Standard
NSR	New Source Review
NWS	National Weather Service
O3	Ozone
OC	Organic Carbon
Pb	Lead
PG/MP	Pasquill Gifford/McElroy Pooler
PM/PM10	Particulate Matter/Particulate Matter Less than 10 Microns
ppm	Parts per Million
ppmvd	Parts per Million Volumetric Dry
PRIME	Plume Rise Model Enhancement
PSD	Prevention of Significant Deterioration
psig	Pounds Per Square Inch Gauge
PTE	Potential To Emit

RICE	Reciprocating Internal Combustion Engine
RH	Relative Humidity
rpm	Revolutions Per Minute
scf	Standard Cubic Feet
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
SOA	Secondary Organic Aerosols
STG	Steam Turbine Generator
TCEC	Treasure Coast Energy Center
tpy	Tons per Year
ULSFO	Ultra-Low Sulfur Fuel Oil
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	Volatile Organic Compound
vr	Visual Range
WGS	World Geodetic System

1.0 Introduction

Florida Municipal Power Agency (FMPA) is proposing to construct and operate a new natural gas fired combined cycle combustion turbine (CCCT) (Unit 4) at its existing Cane Island Power Park (CIPP) located near Kissimmee, Florida. The natural gas pipelines may also include vaporized liquefied natural gas (LNG), which is essentially no different from natural gas. The proposed CIPP Unit 4 and supporting ancillary equipment will join the existing units (Units 1, 2, and 3) at the CIPP. Pursuant to the requirements of Florida Rule 62-212.400, Florida Administrative Code (F.A.C.), FMPA is hereby submitting this Prevention of Significant Deterioration (PSD) Air Permit Application for the construction and initial operation of CIPP Unit 4 and associated equipment. The applicable air permit application forms are included in Appendix A of this volume.

The proposed Unit 4 will be a CCCT unit rated at approximately 300 megawatts (MW), firing natural gas as the fuel. Unit 4 will occupy approximately 9 acres adjacent to and north of Unit 3. New major support facilities for Unit 4 will include a diesel engine driven fire pump, a safe shutdown generator, and an eight-cell linear mechanical draft cooling tower (LMDCT).

This report is a technical support document for the PSD Air Permit Application. The following sections contain a project characterization, best available control technology (BACT) determination, air quality impact analysis (AQIA), and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's (FDEP) preparation of an air construction permit for the Project.

2.0 Project Characterization

The following sections briefly characterize the Project, including a general description of the location, facility, and potential emission units, as well as a summary of the estimated emissions and a discussion of New Source Review (NSR) applicability.

2.1 Project Location

The CIPP is located in rural northwest Osceola County, Florida. Figure 2-1 shows the specific location of the Project, which is approximately 20 miles southwest of Orlando, 5 miles west of Kissimmee, and 1 mile northwest of Intercession City. The CIPP is situated on a slightly elevated ridge of dry sand surrounded by the wetlands of the Reedy Creek Swamp. The topography of the area is unpronounced and considered relatively flat.

2.2 Project Description

2.2.1 Existing Cane Island Power Park

The CIPP currently includes a nominal 40 MW simple cycle combustion turbine (SCCT) unit (Unit 1), a nominal 120 MW CCCT with a heat recovery steam generator (HRSG) and steam turbine (Unit 2), and a nominal 250 MW CCCT with an HRSG and steam turbine (Unit 3).

No modifications to CIPP's existing emission sources are proposed as part of this Project.

2.2.2 Proposed CIPP Unit 4

The Project installation will be a 1x1 combined cycle unit (Unit 4), which will include a General Electric (GE) 7FA combustion turbine generator (CTG), a duct fired HRSG, and a steam turbine generator (STG), and will be equipped with an evaporative cooler. Unit 4 will have a nominal rating of approximately 300 MW and will fire pipeline grade natural gas, exclusively. New major support facilities include a diesel engine driven fire pump, a safe shutdown generator, and an eight-cell LMDCT.

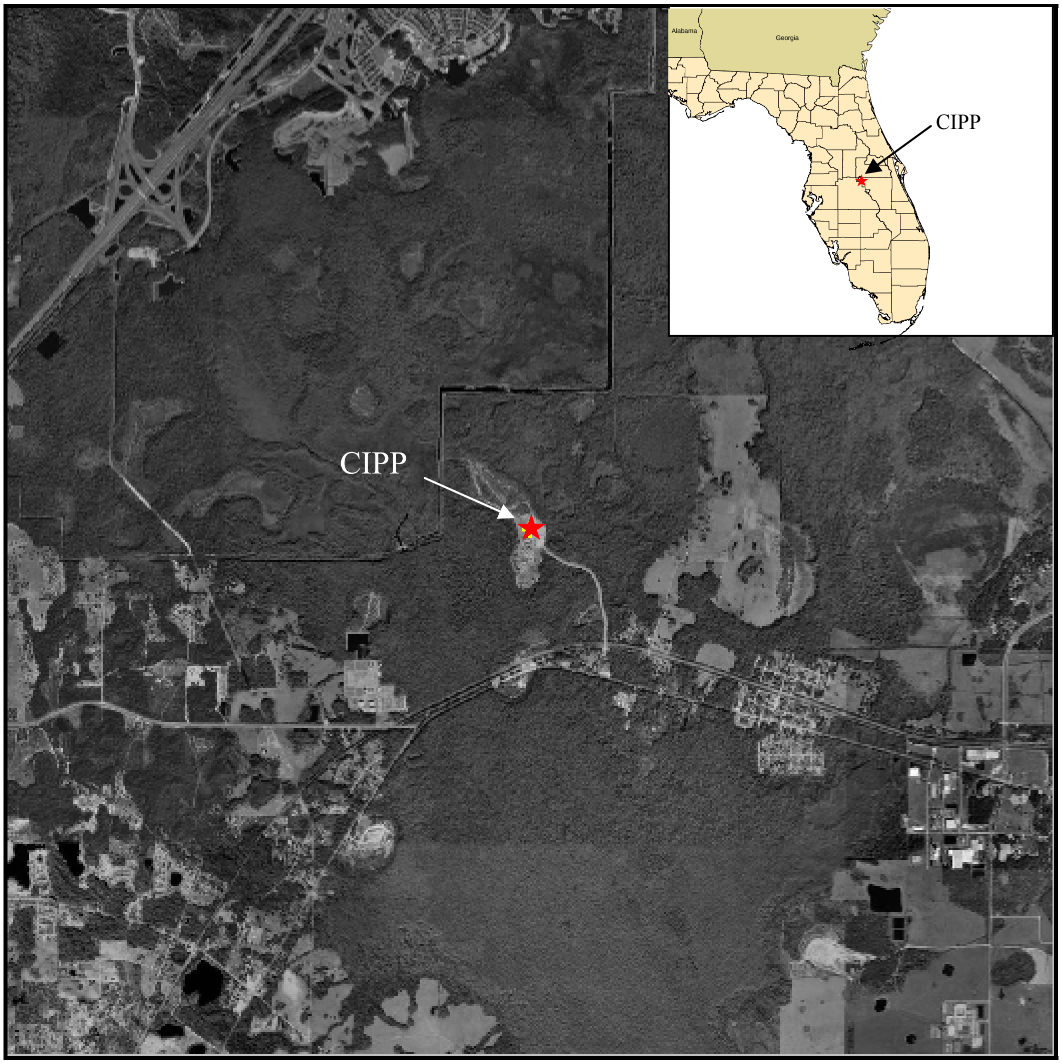


Figure 2-1
Proposed Project Location

Combustion Turbine Generator

The PSD application is based on a GE PG7241 FA enhanced CTG with modulating inlet guide vanes installed outdoors. The CTG unit will include the following major features:

- Single fuel firing system using pipeline-grade natural gas.
- Dry low NO_x (nitrogen oxides) combustion system.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system with silencers and evaporative coolers.
- Lube oil systems.
- Static starting system.
- Fire detection/carbon dioxide fire protection systems.
- Mark VIe control system.
- Off-line/on-line water wash system.
- Package electrical and electronics control compartment.

Heat Recovery Steam Generator

The HRSG will convert waste heat from the CTG exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three pressure, reheat unit with supplemental duct firing (593 MBtu/h) by natural gas only to maximize unit output. Selective catalytic reduction (SCR) for NO_x control is included (refer to Section 3.0 for further details). The HRSG will discharge to a metal exhaust stack approximately 160 feet tall. A stack damper will be included to minimize heat loss during unit shutdowns.

Steam Turbine Generator

The STG is expected to be a tandem-compound single reheat condensing turbine operating at 3,600 revolutions per minute (rpm). The steam turbine will have one high-pressure section with a nominal 2,100 pounds per square inch gauge (psig) throttle pressure, one intermediate-pressure section, and one low-pressure section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems are included. A surface condenser is included for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. A single synchronous generator is included that will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and static excitation system are included.

2.2.3 Mode of Operation

The Unit 4 CCCT is designed for unlimited operation on natural gas, including an unlimited number of starts annually. However, approximately 300 starts are expected annually, with an expected breakdown of 50 cold starts, 200 warm starts, and 50 hot starts. The gas turbine/HRSG system may also operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser.

2.2.4 Fuel

The primary fuel for Unit 4 will be natural gas from existing Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System L.L.C. (Gulfsteam) pipelines.

2.2.5 Air Quality Control

Based on the BACT analysis, emission control for NO_x will be by the use of combustion turbine dry low NO_x (DLN) burners and SCR. Control of other pollutants will be by good combustion control and use of natural gas. Please refer to Section 3.0 for further details.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from the Project. Emissions from the Project will be generated from the following emissions units:

- One GE CCCT/HRSG with supplemental duct firing (Unit 4).
- One diesel engine driven fire pump with associated 500 gallon ultra-low sulfur fuel oil (ULSFO) day storage tank.
- One safe shutdown generator with associated 1,000 gallon ULSFO day storage tank.
- One eight-cell LMDCT.

The emissions for each of these emission sources are presented in Table 2-1. Emissions from the ULSFO day tanks are insignificant. Detailed spreadsheets used to estimate these emissions are presented in Appendix C. In Table 2-2, the Project's aggregate annual PTE is presented and compared to the applicable PSD significant emission rates (SERs) to determine which of the Project's criteria pollutants are subject to PSD review, as further discussed in Subsection 2.4.1.2. The following sections briefly describe the basis for the emission calculations.

Table 2-1
Project Potential to Emit

Pollutant	Unit 4 (lb/h)[a]	Diesel Engine Fire Pump (lb/h)	Safe Shutdown Generator (lb/h)	Project PTE[b] (tons/yr)
CO	40.80	0.33	1.12	178.82
NO_x	17.60	3.47	9.65	78.10
PM/PM_{10}[c]	39.70	0.08	0.29	176.82
SO_2[d]	10.34	0.00	0.01	45.29
VOC	5.30	0.66	0.66	23.30
H_2SO_4[e]	5.54	0.00	0.02	24.27
Lead[f]	0.00	0.00	0.00	0.00
Mercury[f]	0.00	0.00	0.00	0.00
Fluorides	0.00	0.00	0.00	0.00
H_2S	0.00	0.00	0.00	0.00
Total Reduced Sulfur	0.00	0.00	0.00	0.00

[a]Regardless of operating mode, emissions are based on operation of the combustion turbine at 100 percent load, 8,760 hours per year, and at an ambient temperature at ISO conditions and includes emissions from the duct burner.
[b]Includes emissions from the diesel engine fire pump, safe shutdown generator, and the cooling tower (PM/PM_{10} [particulate matter/particulate matter less than 10 microns] emissions).
[c]Includes front and back half emissions from the CTG.
[d]Based on a natural gas sulfur content of 2 grains/100 scf. Emissions from the diesel engine fire pump and safe shutdown generator are based on firing ULSFO.
[e]Includes the effects of SO_2 oxidation and assumes 100 percent conversion of SO_3 to H_2SO_4.
[f]Based on AP-42 emission factors.

Note: Detailed calculations are contained in Appendix C.

Table 2-2
Comparison of Potential Annual Emissions from the Project to PSD SERs

Pollutant	Total Project Potential Annual Emissions[a] (ton/yr)	PSD SERs (tons/h)	PSD Review Required? (Yes/No)
CO	178.82	100	Yes
NO_x	78.10	40	Yes
PM/PM_{10}[b]	176.82	25/15	Yes
SO_2[c]	45.29	40	Yes
VOC	23.30	40	No
H_2SO_4[d]	24.27	7	Yes
Lead[e]	0.00	0.6	No
Mercury[e]	0.00	0.1	No
Fluorides	0.00	3	No
H_2S	0.00	10	No
Total Reduced Sulfur	0.00	10	No

[a]Total project potential annual emissions are from Table 2-1.
[b]Includes front and back half emissions from the CTG.
[c]Based on a natural gas sulfur content of 2 grains/100 scf. Emissions from the diesel engine fire pump and safe shutdown generator are based on firing ULSFO.
[d]Includes the effects of SO_2 oxidation and assumes 100 percent conversion of SO_3 to H_2SO_4.
[e]Based on AP-42 emission factors.

Note: Detailed calculations are contained in Appendix C.

2.3.1 Unit 4 Emissions

Performance data for Unit 4 at loads of 40, 50, 75, and 100 percent, and ambient air temperatures of 19° F, 59° F, 73° F, and 102° F are provided in Appendix D of this volume.

Ambient temperature data were selected based on meteorological data from Orlando, Florida. An ambient temperature of 19° F represents the extreme site minimum temperature and corresponds to maximum heat input and power generation. An ambient temperature of 73° F represents the average annual site temperature, which is representative of the average heat input rate. An ambient temperature of 102° F represents the maximum site temperature and corresponds to the lowest heat input rate for the combustion turbine. An ambient temperature of 59° F and a relative humidity of 60 percent were also selected because they represent ISO (International Organization for Standardization) conditions.

PTE for Unit 4, which is presented in Table 2-1, was estimated based on the hourly emission rate for each pollutant at ISO conditions and 100 percent load, natural gas firing in the CTG and the duct burner, and evaporative cooling. The PTE for Unit 4 includes the use of BACT, which is discussed in Section 3.0.

2.3.2 Diesel Engine Fire Pump

A 290 brake horsepower (bhp) diesel engine fire pump is proposed to be installed. The manufacturer specification sheet for the diesel engine fire pump is provided in Appendix B. The emissions calculations for the diesel engine fire pump were derived from a combination of vendor data and in-house estimates with the unit firing ULSFO and are presented in Appendix C. Annual emissions from the diesel engine fire pump were based on 52 hours per year of operation for testing purposes.

2.3.3 Safe Shutdown Generator

The 750 kilowatt (kW) safe shutdown generator will fire only ULSFO. The generator will be subject to occasional testing to ensure operability and will be used for service only when the transmission connection is lost and the plant shuts down. When the transmission lines are lost (plant goes black), the generator would start to provide power to maintain the plant in a safe shutdown condition. It will only be run for short test periods when the plant is running, and will otherwise operate only when Unit 4 is down and auxiliary power is lost. It is estimated that the safe shutdown generator will operate approximately 200 hours per year. Potential emissions are based on vendor data and are presented in Appendix B of this volume. Detailed emissions calculations are presented in Appendix C.

2.3.4 Linear Mechanical Draft Cooling Tower

The Project will utilize a multiple cell, mechanical draft, counterflow cooling tower for plant cooling. The cooling tower will be of fiberglass construction and installed on a reinforced concrete basin, which will include a pump intake structure housing the two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. A circulating water chemical feed system will be included. Makeup water to the cooling tower is expected to be from treated sewage plant effluent (reclaimed water). Provisions will be included to utilize municipal water and ground water as emergency sources of cooling tower makeup. The cooling tower will be equipped with drift eliminators with a design drift rate of 0.0005 percent of the circulating water flow rate.

The basic principle behind all cooling towers is to cool water using ambient air. Circulating cooling water will remove heat from the steam, causing it to condense. The heated circulating cooling water is transported to the cooling tower to dissipate the heat into the atmosphere. The circulating water is sprayed into the cooling tower as a coarse mist that cascades down a fill material. As the circulating water falls, air contacts the water, allowing a transfer of heat from the water to the cooler atmospheric air. The draft, which causes the atmospheric air to pass through the cascading water, is created mechanically with fans. The cooled circulating water is then collected in the cooling tower basin, where it is pumped from the cooling tower back to the condenser water boxes, repeating the process.

During the cooling process, small water droplets, known as cooling tower drift, escape to the atmosphere through the cooling tower exhaust. To minimize this effect, the tower will be equipped with drift eliminators to provide multiple directional changes of airflow while preventing the escape of water droplets.

Dissolved solids found in cooling tower drift typically consist of naturally occurring mineral matter, chemicals for corrosion inhibition, etc. Particulate matter is emitted when the drift droplets dispersed in the atmosphere evaporate and leave airborne fine particulate matter formed by crystallizations of dissolved solids.

Based on the type and efficiency of drift eliminators, drift droplets of varying sizes containing dissolved solids can be generated. For the purpose of this project, it is assumed that 100 percent of the drift droplets are small enough so that all the drift generated will be dispersed and lose water due to evaporation, resulting in emissions of particulate matter. PM/PM_{10} emissions calculations for the LMDCT are presented in Appendix C.

2.4 Federal and State Air Quality Requirements

This section provides a review of rule applicability for the facility and the various emission units that are part of the Project.

2.4.1 Rule Applicability to the Facility

This section provides a review of the rule applicability for the facility.

2.4.1.1 New Source Review. The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications at existing major sources under two programs; the PSD program outlined in 40 Code of Federal Regulations (CFR) 52.21 for areas in attainment, and the NSR program outlined in 40 CFR 51 and 52 for areas considered nonattainment for certain pollutants. The Environmental Protection Agency (EPA) has approved Florida's NSR Program. Accordingly, Florida's regulations at Chapter 62-212, F.A.C., apply in Florida.

The air quality in a given area is generally designated as being in attainment for a pollutant if the monitored concentrations of that pollutant are less than the applicable National Ambient Air Quality Standards (NAAQS). Likewise, a given area is generally classified as nonattainment for a pollutant if the monitored concentrations of that pollutant in the area are above the NAAQS. A review of the air quality attainment status of Osceola County reveals that CIPP, and thus the proposed Project, is located in an attainment or unclassifiable area with respect to all pollutants. As such, the PSD program will apply to the proposed Project, as administered by the state of Florida under 62-212.400, F.A.C., *Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration*.

2.4.1.2 Prevention of Significant Deterioration. The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the NAAQS while providing a margin for future industrial and commercial growth. The primary provisions of the PSD regulations require that major modifications and new major stationary sources be carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirements to apply BACT to minimize the emissions of air pollutants.

A major stationary source is defined as any one of the listed major source categories that emits, or has the PTE, 100 tons per year (tpy) or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the stationary source does not fall under one of the listed major source categories. The CIPP is one of the 28 major source categories (i.e., fossil fuel fired steam electric plant) and has a PTE greater than 100 tpy for at least one regulated pollutant; therefore, it is considered an existing major PSD source.

Because the proposed Project is locating at an existing major stationary source, PSD applicability is determined on a pollutant-by-pollutant basis by comparing the emissions increase of each pollutant against the following PSD SERs:

- Nitrogen oxides (NO_x)--40 tpy.
- Sulfur dioxide (SO_2)--40 tpy.
- Particulate matter (PM)--25 tpy.
- Particulate matter less than 10 microns (PM_{10})--15 tpy.
- Carbon monoxide (CO)--100 tpy.
- Ozone (O_3)--NO_x or volatile organic compounds (VOCs)--40 tpy.
- Lead (Pb)--0.6 tpy.
- Mercury (Hg)--0.1 tpy.
- Fluorides--3 tpy.
- Sulfuric acid mist (H_2SO_4)--7 tpy.
- Hydrogen sulfide (H_2S)--10 tpy.
- Total reduced sulfur compounds--10 tpy.

As presented in Table 2-2, the estimated potential emissions of NO_x, SO_2, CO, PM/PM_{10}, and H_2SO_4 resulting from the proposed Project exceed the PSD SERs of 40, 40, 100, 25/15, and 7 tpy, respectively. Therefore, the Project's emissions of NO_x, SO_2, CO, PM/PM_{10}, and H_2SO_4 are subject to PSD review. Because emissions of VOCs are below the PSD SERs of 40 tpy, the Project is not subject to PSD review for VOCs. The PSD review includes a BACT analysis, an AQIA, and an assessment of the Project's total impact on general residential and commercial growth, soils and vegetation, and visibility, as well as a Class I area impact analysis. These analyses are included in Sections 3.0, 4.0, and 5.0, respectively.

2.4.2 Rule Applicability to Unit 4

The following sections include a discussion of the applicability of regulations to the Unit 4 combustion turbine and the duct burner.

2.4.2.1 New Source Performance Standards. The New Source Performance Standards (NSPSs) established in the 1970 CAA, were developed for specific industrial categories and are promulgated in 40 CFR 60 and adopted by reference in Rule 62-204.800(8)(b)39, F.A.C.

The combustion turbine and duct burner are both subject to *Standards of Performance for Stationary Combustion Turbines*. The NSPS are found at 40 CFR Part 60 Subpart KKKK and are adopted by reference in Rule 62-204.800(8)(b)77, F.A.C. Subpart KKKK includes standards for regulation of NO_x and SO_2 as follows:

- NO_x--15 ppm (parts per million) at 15 percent O_2 or 54 ng/J (nanogram per joule) of useful output (0.43 lb/MWh) – new turbines firing natural gas with > 850 MBtu/h heat input.
- NO_x--96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh) – turbines operating at less than 75 percent of peak load – turbines with > 30 MW output.
- SO_2--The rule includes a fuel emission standard or a fuel sulfur standard equivalent to potential SO_2 emissions of 0.060 lb SO_2/MBtu.

The criteria for this NSPS will be met or exceeded by the proposed project.

2.4.2.2 National Emission Standards for Hazardous Air Pollutants. On March 5, 2004, the United States Environmental Protection Agency (USEPA) published final National Emission Standards for Hazardous Air Pollutants (NESHAP) for stationary combustion turbines. This rule, found at 40 CFR Part 63 Subpart YYYY, is commonly referred to as the CT MACT. The CT MACT is applicable to stationary gas turbines located at major sources of hazardous air pollutants (HAPs). A major source of HAPs is a site that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAPs at a rate of 25 tons or more per year. The CIPP is an existing major source of HAP emissions. The proposed project will, therefore, be subject to the CT MACT. However, the proposed combustion turbine will fire only natural gas and meets the definition of a lean pre-mix natural gas fired turbine and, thus, is exempt from meeting the emission requirements of this rule. Only initial notification requirements will be applicable. It should be noted that the CT MACT considers duct burners and waste heat recovery units as steam generating units and, thus, are not considered as affected units under the CT MACT. However, the CT MACT recognizes that it is usually difficult to separately monitor emissions from the turbine and duct burner, so affected sources are allowed by the CT MACT to meet the required emission limitations for the combustion turbines with their duct burners in operation. Since there is no emission limitation that is applicable, it is assumed that the combined cycle system is in compliance with the MACT requirements.

2.4.3 Rule Applicability to the Diesel Engine Fire Pump and the Safe Shutdown Generator

Reciprocating internal combustion engines (RICEs) rated greater than 500 bhp and located at major HAP sources are regulated by the RICE MACT (40 CFR Part 63, Subpart ZZZZ). The diesel engine fire pump is rated at 290 bhp and is exempt from the requirements of RICE MACT. The safe shutdown generator is rated greater than the 500 bhp applicability threshold and, thus, is an affected unit under the RICE MACT. However, a new emergency stationary RICE located at a major source of HAPs is subject only to the initial notification requirements of 40 CFR 63.6645(d). Since the purpose of the safe shutdown generator will be for emergency situations when the normal source of power is not available to the facility, it will be considered as emergency stationary RICE and, therefore, subject only to the initial notification requirements of the RICE MACT.

The diesel engine fire pump and safe shutdown generator will also be subject to the manufacturer's certification requirements of compliance under the NSPS for RICE (40 CFR Part 60, Subpart IIII). The rule provides various emission standards based on the engine's classification, use, manufacture date, and engine size. The applicable standards associated with the safe shutdown generator will be dependent on the engine model year. Therefore, the exact emission standards applicable to the safe shutdown generator cannot be identified until the engine is purchased. The fire pump engines will need to meet the emission requirements listed in Table 4 of the regulation.

Regardless of the applicable emissions requirements imposed by this NSPS, beginning with engines manufactured in model year 2007 (for emergency engines) and 2008 (for fire pump engines), the onus of this rule falls on the manufacturer of these engines because they are required to manufacture engines that comply with the rule. The only requirement of this rule for owners and operators of these units is that they purchase certified engines. FMPA will purchase certified engines that will meet the appropriate emission limits.

2.4.4 Rule Applicability to the LMDCT

There are no MACT standards or NSPS that apply to the cooling tower. Additionally, none of the standards included in 62-296, F.A.C. apply to the cooling tower. The Cooling Tower MACT standard (40 CFR Part 63, Subpart Q), adopted by reference in Rule 62-204.800(11)(b)10, F.A.C., prohibits the use of chromium-based water treatment chemicals in industrial process cooling towers. FMPA does not and will not use such chemicals in the cooling tower.

2.4.5 Excess Emissions

As with other CCCTs of this size and type, excess emissions during startup, shutdown, and malfunction are likely to exceed the duration of excess emissions allowed in accordance with Rule 62-210.700(1), F.A.C. In accordance with Rule 62-210.700(5), F.A.C., FMPA is requesting that the air permit for the Project allow for excess emissions from startups and shutdowns greater than 2 hours per 24 hour period. Because Unit 4 is almost identical to the Treasure Coast Energy Center (TCEC) Unit 1, FMPA requests that a condition similar to Condition 18 of the Applicable Standards and Regulations Section of the TCEC Unit 1 permit issued by FDEP on May 17, 2006, be included in the Project permit. In general, it is requested that, in a 24 hour period, this condition allow for 6 hours of excess emissions during a cold start of the steam turbine/HRSG system, 4 hours of excess emissions during a warm start of the steam turbine/HRSG, and 3 hours of excess emissions for the shutdown of the combined cycle operation. It is also requested that, in the event there is a trip during a startup or during a 24 hour period that contains a startup, the permit allow for additional excess emissions during a startup subsequent to a unit trip (i.e., the allowable excess emissions clock starts over after a unit trip that results in the need to restart the unit).

2.4.6 Dry Low NO_x Burner Tuning

As allowed in the TCEC permit issued by FDEP on May 17, 2006, FMPA is requesting that the permit for this Project allow for exclusion of Continuous Emissions Monitoring System (CEMS) data collected during initial or other major DLN burner tuning sessions from the CEMS compliance demonstration. FMPA is requesting that a condition similar to Condition 20 of the Applicable Standards and Regulations Section of that permit issued by FDEP be included in the proposed CIPP Unit 4 permit.

3.0 Best Available Control Technology

A detailed BACT analysis for the Project has been included as Appendix D. Emissions for the BACT analysis are based on unlimited natural gas firing for Unit 4 at ISO conditions. The following is a summary of the BACT determination for Unit 4:

- NO_x emissions--BACT was determined to be the use of low NO_x burners and an SCR to achieve 2 ppmvd (parts per million volumetric dry) at 15 percent O_2.
- CO emissions--BACT was determined to be the use of good combustion practices.
- PM/PM_{10} emissions--BACT was determined to be the use of good combustion controls and the use of natural gas.
- VOC emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below the PSD major modification thresholds.
- SO_2 emissions--BACT was determined to be the use of natural gas.
- H_2SO_4 emissions--BACT was determined to be the use of natural gas.

4.0 Class II Ambient Air Quality Analysis

The following sections discuss the air dispersion modeling methodology and the modeling results from the Ambient Air Quality Impact Analysis (AAQIA) for the proposed Project. This AAQIA has been performed for those emitted criteria pollutants subject to PSD review for which an AAQS exists (i.e., NO_x, PM_{10}, SO_2, and CO). The AAQIA was conducted in accordance with the USEPA's Guideline on Air Quality Models (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon air dispersion modeling protocol submitted to FDEP on behalf of FMPA on January 11, 2008. The FDEP provided verbal approval of the protocol with minor changes during the project kickoff meeting on January 15, 2008. A copy of the updated protocol (based on requested changes by FDEP), is presented in Appendix E.

4.1 Class II Model Selection

Consistent with the Appendix W *Guideline on Air Quality Models*, the American Meteorological Society/Environmental Protection Agency (AMS/EPA) Regulatory Model (AERMOD, Version 07026) air dispersion model was used to predict maximum ground-level concentrations associated with the proposed Project's emissions. AERMOD is the product of AMS/EPA Regulatory Model Improvement Committee (AERMIC), formed to introduce state-of-the-art modeling concepts into the USEPA's air quality models. AERMOD incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain. The AERMOD model includes a wide range of options for modeling air quality impacts of pollution sources.

4.2 Model Inputs and Options

This section discusses the model input parameters, source and emission parameters, and the AERMOD model default options and input databases.

4.2.1 Model Input Source Parameters

The AERMOD model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios, and ambient temperatures. Performance data for the combustion turbine operating at several different loads (40, 50, 75, and 100 percent with duct firing) over a range of ambient temperatures (19, 59, 73, and 100° F) are included in Appendix B. The corresponding stack parameters and emission rates for each load and ambient temperature considered in the analysis are presented in Table 4-1. For all load cases, the parameters in Table 4-1 are "enveloped" over the different operating scenarios as provided in Appendix C. "Enveloping" is the process in which a representative set of stack parameters and pollutant emission rates are utilized to produce the worst-case plume dispersion conditions and highest model predicted concentrations (i.e., lowest exhaust temperature and exit velocity and the highest emission rate).

Emissions from the diesel engine fire pump, safe shutdown generator, and the cooling tower were also included in the modeling. Emissions data for these emission units are included in Appendix C. Because the diesel engine fire pump is only operated in emergency situations and for occasional testing to ensure operability, emissions from the emergency fire pump in the modeling are based on operating 1 hour per day and 52 hours per year. The safe shutdown generator is assumed to operate 24 hours per day up to a maximum of 200 hours per year.

4.2.2 Dispersion Coefficient

With the introduction of AERMOD, the choice of the use of the simple rural or urban dispersion coefficient is no longer available. The AERMOD model has the option of assigning specific sources to have an urban effect, thus enabling AERMOD to employ enhanced turbulent dispersion associated with anthropogenic heat flux, parameterized by population size of the urban area.

Section 8.2.3 of the *Guideline on Air Quality Models* (incorporated as Appendix W of 40 CFR 51) provides the basis for determining the urban/rural status of a source. It was determined that the land use procedure described in Section 8.2.3(c) was sufficient for determining the urban/rural status. The land use procedure is as follows:

- Classify the land use within the total area, A_o, circumscribed by a 3 km radius circle about the source using the meteorological land use typing scheme proposed by Auer.
- If land use Types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (single-family compact residential), and R3 (multi-family compact residential) account for 50 percent or more of A_o, use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

Based on a visual inspection of the United States Geological Survey (USGS) 7.5 minute topographic map of the proposed site location, it was concluded that over 50 percent of the area surrounding the proposed Project is rural. Since the proposed Project is not located in an urbanized area, urban boundary layer option will not be invoked.

**Table 4-1
Stack Parameters and Pollutant Emissions
Used in AERMOD Modeling Analysis**

CTG Load	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
					NO_x	CO	PM/PM_{10}	SO_2
100% with Duct Firing	160	18	57.63	165	18.50	42.80	40.10[(a)]	10.81
75%	160	18	47.73	166	11.20	25.00	22.10[(a)]	6.86
50%	160	18	40.08	157	8.90	20.40	21.30[(a)]	5.48
40%	160	18	36.67	154	7.90	18.40	20.90[(a)]	4.84
Fire Pump[(b)]	15.17	0.42	184.08	855	Ann - 2.06E-02	1 hr - 3.26E-01 8 hr - 4.08E-02	24 hr - 3.46E-03 Ann - 4.93E-04	3 hr - 9.51E-04 24 hr - 1.19E-04 Ann - 1.69E-05
Safe Shutdown Generator[(c)]	24	0.83	192.82	816	Ann - 2.20E-01	1 hr - 1.12E+00 8 hr - 1.12E+00	24 hr - 2.92E-01 Ann - 6.66E-03	3 hr - 1.11E-02 24 hr - 1.11E-02 Ann - 2.54E-04
Cooling Tower[(d)]	56	30	23.67	91.52	--	--	24 hr - 8.27E-02 Ann - 8.27E-02	--

[(a)] PM/PM_{10} emission rates represent both front and back half emissions including the effects of SO_2 oxidation.
[(b)] Emissions from the fire pump are based on operation for testing purposes. As such, the emissions for the above averaging periods are based on a ratio of the averaging period of concern to 1 hour of operation per day and 52 hours of operation per year.
[(c)] Emissions from the safe shutdown generator are based on 24 hours per day and 200 hours of operation per year.
[(d)] Emissions given are per cooling tower cell.

4.2.3 Good Engineering Practice and Building Downwash Evaluation

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR Part 51, Sections 51.100 and 51.118. GEP stack height is defined as the greater of the following:

1. 65 meters.
2. A height established by applying the formula:

$$Hg = H + 1.5\ L$$

   where:

   Hg = GEP stack height
   H = height of nearby structure(s)
   L = lesser dimension (height or projected width) of nearby structure(s).

3. A height demonstrated by a fluid model or a field study, which ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features.

Since a fluid model analysis or a field study will not be completed, the GEP stack height is defined by Definition 1 or 2. Subsequently, the term *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.

For these analyses, the buildings and structures of the CIPP facility and the new Unit 4 addition were analyzed to determine the potential to influence the plume dispersion from the combustion turbine and ancillary sources stacks. Structure dimensions and relative locations were entered into the USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program Prime (BPIPPRM, Version 04274) to produce an AERMOD input file with direction-specific building downwash parameters. The BPIPPRM formula GEP height for the combined cycle Unit 4 stack is 60.29 meters (197.80 ft). The proposed Project stack height is 48.77 meters (160 ft). As such, direction-specific downwash parameters from the BPIPPRM program were included in the AERMOD air dispersion modeling analysis.

4.2.4 Model Default Options

Since the AERMOD model is especially designed to support the USEPA's regulatory modeling programs, the regulatory modeling options are considered the default mode of operation for the model. These options include the use of stack-tip downwash and a routine for processing averages when calm winds or missing meteorological data occur.

4.2.5 AERMOD Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends out 10 km from the center of the proposed location was used. The nested rectangular grid network consists of four tiers: the first tier extends from the center of the site to 1 km with 100 meter spacing; the second tier extends from 1 km to 2.5 km with 250 meter spacing; the third tier extends from 2.5 km to 5 km with 500 meter spacing; and the fourth tier extends from 5 km to 10 km with 1,000 meter spacing. Receptors were placed at 50 meter intervals along the property boundary (i.e., that area to which public access is physically restricted).

Terrain elevations at receptors were obtained from 7.5 minute USGS Digital Elevation Model (DEM) files and incorporated into the AERMOD model. There is no distinction in AERMOD between elevated terrain below release height and terrain above release height, as with earlier regulatory models that distinguished between simple terrain and complex terrain. For applications involving elevated terrain, the user must now also input a hill height scale along with the receptor elevation. To facilitate the generation of hill height scales for AERMOD, a terrain preprocessor, called AERMAP, has been developed by the USEPA. For each receptor, AERMAP searches for the terrain height and location that has the greatest influence on dispersion. In order to calculate the hill height scale, the DEM array and domain boundary must include all terrain features that exceed a 10 percent elevation slope from any given receptor. A visual inspection of the surrounding DEM files was performed to ensure that all such terrain nodes are covered in the computation of the hill height scale. Using AERMAP (Version 06341), terrain elevations were determined using a method that locates interpolated terrain elevation near each receptor. This method ensures that the most representative elevation of the surrounding nearby terrain points in the DEM files are used for each receptor.

4.2.6 Meteorological Data

The AERMOD model utilizes a file of surface boundary layer parameters and a file of profile variables including wind speed, wind direction, and turbulence parameters. These two types of meteorological inputs are generated by the meteorological preprocessor for AERMOD, which is called AERMET (Version 06341). AERMET includes three stages of preprocessing of the meteorological data. The first two stages extract, quality check, and merge the available meteorological data. The third stage requires input of certain surface characteristics (surface roughness, Bowen ratio, and Albedo) from the area of concern.

AERMET requires hourly input of specific surface and upper air meteorological data. These data, at a minimum, include the wind flow vector, wind speed, ambient temperature, cloud cover, and morning radiosonde observation, including height, pressure, and temperature. Surface characteristics in the vicinity of the proposed emissions sources are important in determining the boundary layer parameter estimates. Obstacles to the wind flow, amount of moisture at the surface, and reflectivity of the surface affect the calculations of the boundary layer parameters and are quantified by the following variables: surface roughness length, surface Albedo, and Bowen ratio, respectively.

Representative Hourly Meteorological Data

The *Appendix W – Guideline on Air Quality Models* (November 2005), the *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (EPA-454/R-99-005, Feb 2000), and the *Draft New Source Review Workshop Manual* (October 1990) indicate that when site-specific data are not available, 5 years of *adequately representative* data from a nearby National Weather Service station may be used. The analyses presented herein utilize 5 years (1999 – 2003) of meteorological data from the Orlando International Airport (MCO) as data representative of the Project location.

Representativeness of meteorological data is dependent on the following four factors:

- Spatial--The proximity of the meteorological monitoring site to the area under consideration.
- Temporal--The period of time during which the data is collected.
- Exposure--The siting of the meteorological instruments at the monitoring site.
- Geographic--The geographic features and land use cover in the vicinity of the monitoring site.

Spatial

The spatial representativeness of the meteorological data can be adversely affected by large distances between the source and the monitoring site. As, such, spatial representativeness is best achieved by using meteorological data in close proximity to the area under consideration. MCO is certainly in close proximity to the facility being located only 16 miles northeast. Additionally, the elevation of MCO (106 ft) is similar to that of the facility (82 ft).

Temporal

Temporal representativeness of the meteorological data refers to year-to-year variations or climatological accuracy of the data. The period or record of meteorological data should be sufficient to ensure that the worst-case meteorological dispersion conditions are adequately captured and provide a stable distribution of meteorological conditions. Too short of record may cause excessive variability in the model predicted concentrations.

The *Guideline on Air Quality Models* concludes that the variability of model estimates is adequately reduced if a 5-year period of record of meteorological data is used. The *Draft New Source Review Workshop Manual* indicates that the "5-year period is used to ensure that the model results adequately reflect meteorological conditions conducive to the prediction of maximum ambient concentrations." By using 5 years of meteorological data, the model contains 35,040 more hourly observations with which to predict concentrations than a single year of site-specific observations.

MCO has numerous years of data available for use in air dispersion modeling. The simulations presented here use the 5-year data set from 1999 through 2003 as received by the FDEP for use in air dispersion modeling demonstrations.

Exposure

As given in the document *Meteorological Data Representivity Analysis* (http://www.iowadnr.gov/air/prof/tech/files/representivity_analysis.pdf), produced by the Iowa Department of Natural Resources:

> *Instrument exposure refers to the ability of the instruments to measure meteorological conditions without the influence of manmade or natural obstructions. If obstructions are present, they can influence the measurements of the meteorological monitoring site.*

The meteorological data observations at MCO are derived from an Automated Surface Observing Station (ASOS), which are located at all major airports. The *Federal Standard for Siting Meteorological Sensors at Airports* requires that sensors be installed in appropriate locations to assure that the resultant observations are representative of the meteorological conditions. Because of this, it is determined that instrument exposure does not affect the representativeness of MCO meteorological data.

Geographic

Geographic representativeness refers to the degree surface parameters and characteristics differ between the area of interest and the meteorological monitoring site and can thus influence atmospheric dispersion. The effects of geographic features and land cover on representativeness require a degree of professional judgment. There are no significant geographic terrain features in the area that would greatly influence the wind flow in the area. Additionally, MCO is one of the few major meteorological stations in Florida that is located inland, distanced from the immediate effects of the Gulf of Mexico or Atlantic Ocean.

As mentioned previously, geographic representativeness also includes the degree surface parameters and characteristics differ between the area of interest and the meteorological monitoring site. AERMOD uses three landuse-based surface characteristics in its dispersion algorithms: 1) surface roughness (z_o), 2) Bowen ratio (B_o), and 3) albedo (r). The USEPA's *AERMOD Implementation Guide* (updated October 2007) provides a indication of how one may determine representativeness.

> *When using National Weather Service (NWS) data for AERMOD, data representativeness can be thought of in terms of constructing realistic planetary boundary layer (PBL) similarity profiles. As such, the determination of representativeness should include a comparison of the surface characteristics (i.e., z_o, B_o and r) between the NWS measurement site and the source location, coupled with a determination of the importance of those differences relative to predicted concentration.*

The recently released AERSURFACE tool (Version 08009), was used to process land cover data to determine the surface characteristics for both the facility location and MCO. The results of the AERSURFACE simulation are given below.

Location	Albedo	Bowen Ratio	Surface Roughness
Facility	0.15	0.34	0.61
MCO	0.16	0.59	0.09

Potential values range as follows:
1. Albedo: 0.1 – 0.6.
2. Bowen ratio: 0.1 – 6.0.
3. Surface roughness: 0.0001 – 1.3.

Sensitivity runs performed by the USEPA and presented at the 8th Modeling Conference (held September 2005 at Research Triangle Park) demonstrate that resulting model-predicted concentrations from buoyant and very buoyant stacks between 35 and 50 meters in height (similar to the stacks proposed herein) remain nearly flat as the three surface characteristics are altered within their potential range of values. Given the results of the USEPA sensitivity analysis and the fact the resulting values of the three site characteristics lie in close proximity to one another given the range of potential values, the values presented here are in good agreement with one another as to deem MCO representative from a landuse standpoint.

Conclusion

The above demonstration, including the four factor test and a comparison of landuse surface characteristics concludes that the use of existing adequately representative meteorological data from MCO in the AERMOD model is protective of air quality standards (including PSD Increment) and thereby acceptable for use in the AAQIA.

4.3 Model Predicted Impacts

As presented in Section 2.0, the Project's PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, PM/PM_{10}, and CO. In accordance with the approved modeling protocol, AERMOD air dispersion modeling was performed (as described in the preceding sections). Table 4-2 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels (SILs) and the preconstruction monitoring requirements. As Table 4-2 indicates, the Project's maximum model-predicted concentrations are less than the PSD Class II SILs for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and Ambient Air Quality Standards [AAQS] analyses) are required.

If any of the maximum impact source groups, from each pollutant and averaging period, occurred at the edge of or beyond the 100 meter fine grid, a 100 meter refined receptor grid would be placed around the impact to ensure that an absolute maximum concentration was obtained from the model. This procedure was not required for any pollutants, because all of the maximum impacts were within the 100 meter fine grid.

Table 4-2
AERMOD Model-Predicted Class II Impacts

Pollutant	Averaging Period	Model-Predicted Impact[a] ($\mu g/m^3$)				PSD Class II SIL[b] ($\mu g/m^3$)	Exceed SILs?	De Minimis Monitoring Level[c] ($\mu g/m^3$)	Preconstruction Monitoring Required?
		100%	75%	50%	40%				
NO_x	Annual	0.90	0.90	0.90	0.90	1	NO	14	No
SO_2	Annual	0.08	0.06	0.06	0.05	1	NO	--	No
	24 Hour	0.95	0.71	0.67	0.63	5	NO	13	No
	3 Hour	2.10	1.58	1.50	1.42	25	NO	--	No
PM/PM_{10}[d]	Annual	0.31	0.21	0.25	0.27	1	NO	--	No
	24 Hour	4.92	4.92	4.92	4.92	5	NO	10	No
CO	8 Hour	33.78	33.78	33.78	33.78	500	NO	575	No
	1 Hour	103.38	103.38	103.38	103.38	2,000	NO	--	No

[a]Impacts represent the highest first high model-predicted concentration from all 5 years of meteorological data: 1999, 2000, 2001, 2002, and 2003 modeled at each corresponding load.
[b]Predicted impacts that are below the specified level indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
[c]This criteria is used to determine if preconstruction ambient air monitoring is required to assess current and future compliance with AAQS.
[d]Note that the PM_{10} impacts are below the PSD Class II SILs, and the AAQS for $PM_{2.5}$ are significantly greater than the PM_{10} SILs. Therefore, if one were to conservatively assume that $PM_{2.5}$ impacts would be the same as the PM_{10} impacts (in accordance with the USEPA's guidance memorandum related to the interim implementation of NSR for $PM_{2.5}$), then the impacts would be significantly below the $PM_{2.5}$ AAQS.

Additionally, the maximum predicted concentrations are less than the preconstruction monitoring de minimis levels for each pollutant and applicable averaging period. As given in rule 62-212.400(3)(e)1.e, F.A.C., no de minimis air quality level is provided for ozone. However, as allowed by that rule, since the project's PTE of both NO_x and VOC are each below 100 tpy, the requirements for monitoring of ozone shall not apply. Therefore, by this application, the applicant requests an exemption from the PSD preconstruction monitoring requirements. Electronic copies of all Class II modeling input and output files are included in Attachment F.

5.0 Class I Ambient Air Quality Analysis

As part of the air impact evaluation for the addition to the CIPP site, analyses of the proposed Project's effect on all Class I areas within 200 km was performed. Specifically, the Chassahowitzka Wilderness Area (CWA) is the only Class I area of concern for this Project. The CWA is a PSD Class I area located in central Florida along the Gulf of Mexico coast, approximately 113 km northwest of the proposed project site. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this analysis are regional haze and deposition. Additionally, Class I SILs were evaluated and compared to the recommended thresholds. Figure 5-1 presents the location of the proposed Project site with respect to the CWA.

The methodology of the refined California Puff (CALPUFF) analysis followed those procedures recommended in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II* report dated December 1998 and the *Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG)* report dated December 2000, and an air dispersion modeling protocol sent to FDEP on January 11, 2008 (Appendix E). The following sections include discussions of the air modeling approach to assess impacts at CWA as well as the model-predicted impacts from the Project onto the CWA.

5.1 Class I Model Selection and Inputs

5.1.1 Model Selection

The CALPUFF (Version 5.8, Level 070623) air modeling system was used to model the proposed Project and assess the AQRVs at CWA. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model (Version 5.8, Level 070623), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. However, VISTAS, the Regional Planning Organization responsible for assisting with regional haze issues in the southeast, contracted Earth Tech to produce CALPUFF ready, CALMET meteorological data files, thus bypassing the need to run the resources intensive CALMET processor. VISTAS has provided 2001-2003 CALMET files for five 4 km sub-regional domains as illustrated on Figure 5-2. This modeling analysis used the CALMET files prepared for sub-domain 2.

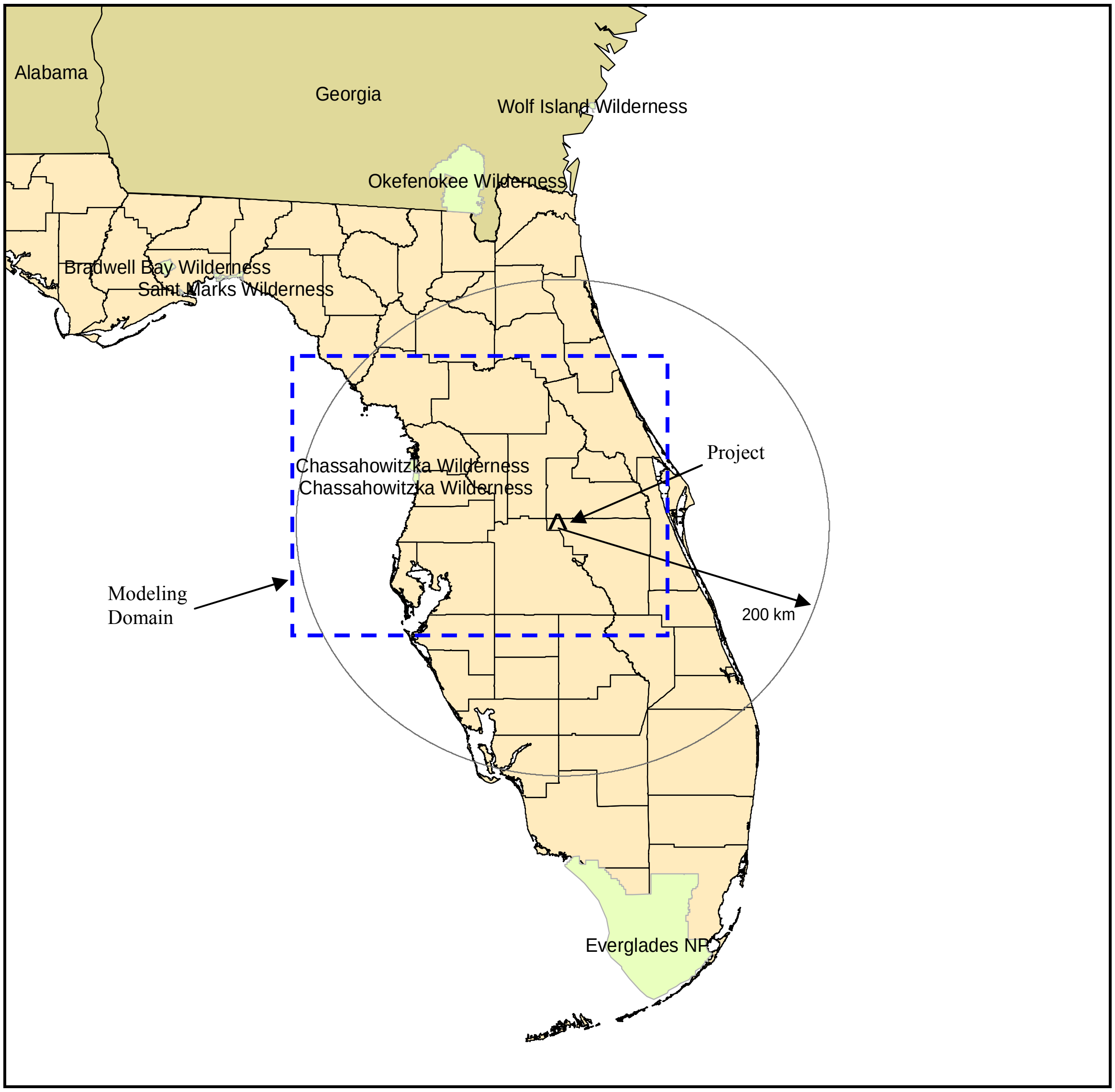


Figure 5-1
Proposed Project Location and Class I Areas

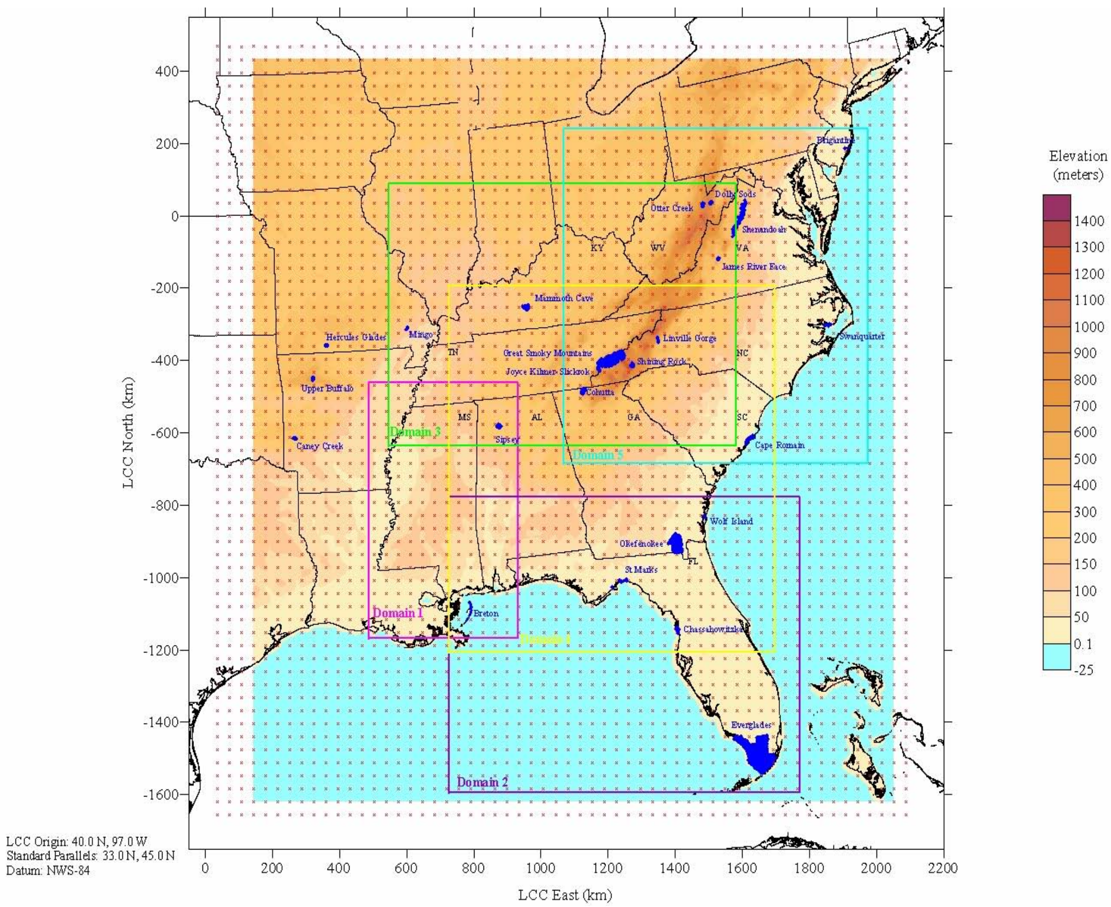


Figure 5-2
VISTAS 4 km CALMET Sub-Domains

5.1.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 5-1 were used for the modeling analyses.

5.1.3 Building Wake Effects

The CALPUFF analysis included the facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the USEPA's PRIME version of Building Profile Input Program (BPIPPRM, Version 04274), and included in the CALPUFF model input.

5.1.4 Receptor Locations

The CALPUFF analyses used an array of discrete receptors over the Class I area, which were created and distributed by the National Parks Service (NPS). Specifically, the array consists of receptors spaced to cover the extent of the Class I area. Receptor elevations are included in the same NPS-provided receptor files.

5.1.5 Meteorological Data Processing

The refined 4 km grid resolution VISTAS CALMET files from sub-domain 2 were used as the meteorological and geophysical data for input to CALPUFF. These high resolution, CALPUFF-ready, CALMET files were composed of available surface and upper air observations in addition to the highest resolution Mesoscale Meteorological Data - Generation 5 (MM5) data available for each year (i.e., 12 km MM5 data for 2001 and 2002 and 36 km MM5 data for 2003). A 4 km grid resolution is assumed to be adequate given the lack of significant terrain features in central Florida.

The VISTAS 2001-2003 meteorological data was recently re-processed by the Fish and Wildlife Service (FWS) using the current EPA regulatory version of CALMET (i.e., Version 5.8 Level 070623). Black & Veatch obtained this re-processed fine-grid CALMET data set for the entire VISTAS region from the North Carolina Department of Environment and Natural Resources.

Table 5-1
CALPUFF Model Settings

Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}, and speciated particulates.
Chemical Transformation	MESOPUFF II scheme.
Deposition	Include both dry and wet deposition, plume depletion.
Meteorological/Land Use Input	VISTAS CALMET files.
Plume Rise	Transitional plume rise, stack-tip downwash, partial plume penetration.
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, PRIME building downwash scheme.
Terrain Effects	Partial plume path adjustment.
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24 hour change as processed by CALPOST. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD SERs. Deposition: Annual total nitrogen and total sulfur deposition flux (including both wet and dry deposition).
Background Values	Ammonia: 0.5 ppb (monthly). Ozone: Hourly ozone data files provided by TRC for use in VISTAS's BART modeling analyses will be utilized. Monthly values were calculated using monthly averages from Everglades National Park, Indian River Lagoon, and the Sumatra ozone monitors. These values are substituted by the CALPUFF model should there be missing hourly values in the VISTAS ozone files.

PG/MP = Pasquill Gifford/McElroy Pooler.
ISC = Industrial Source Complex.

CALMET Settings

The major features of CALMET used by Earth Tech to develop the CALMET files are listed below:

- Modeling period: 3 years (2001 – 2003).
- Meteorological inputs: MM5 data provide initial guess fields in CALMET. Meteorological observation data are used in the Step 2 calculations. Buoy data, hourly surface meteorological observations, precipitation observations, and twice-daily upper air sounding data were used.
- CALMET grid resolution: 4 km.
- CALMET vertical layers: 10 layers. Cell face heights (meters): 0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000.
- CALMET mode: Refined mode with all available observational data included in the Step 2.
- Diagnostic options: Interagency Workgroup on Air Quality Modeling (IWAQM) default values.
- CALMET options dealing with radius of influence parameters (R1 = 5 km, R2 = 5 km, RMAX1 = 40 km, RMAX2 = 40 km, RMAX3 = 100 km), BIAS(NZ) = 10*0, ICALM = 0 parameters were predetermined by Earth Tech.
- TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments, which were used for all years. Value of 15 km used.
- Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water). This feature allows the temperature field over large bodies of water such as the Atlantic Ocean and the Great Lakes to be properly characterized by buoy observations.
- Mixing height averaging parameter (MNMDAV = 1) was determined by Earth Tech for the regional simulations based on sensitivity tests.
- Geophysical data for regional runs: USGS 3 arcsec terrain data, and Composite Theme Grid USGS 200 meter land use data set.
- References for these and other CALMET data sets can be found on the CALPUFF data page of the official CALPUFF site (www.src.com).

5.1.6 Modeling Domain

The CALPUFF modeling domain was a subset of the larger CALMET meteorological domain. The size of the domain used for the modeling was based on the distances needed to cover the area from the proposed project to the receptors at the

Class I area with at least an 80 km buffer zone in each direction. The modeling analysis was performed in the Lambert Conformal Conic (LCC) coordinate system with standard parallels of 33 and 45 degrees north latitude and reference latitude and longitude of 40.0 and 97.0 degrees, respectively. A rectangular modeling domain extending 292 km in the east-west (x) direction and 204 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is located at 1,317.995 km Easting and -1,254 km Northing (LCC, National Weather Service [NWS]-84, 6,370 km Radius Global Sphere). The grid resolution for the domain was 4 km. A grid spacing of 4 km yields 73 grid cells in the x-direction and 51 grid cells in the y-direction. The size and location of the modeling domain was illustrated on Figure 5-1.

5.1.7 Project Emissions

The worst-case representative stack parameters and pollutants emission rates at 100 percent operating load were used in the CALPUFF analyses. This was accomplished by representing the 100 percent operating load with a worst-case set of stack parameters and pollutant emission rates that were conservatively selected from performance data over a range of ambient temperatures (i.e., 19, 59, 73, and 102° F) to produce worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping."

Those pollutants modeled include NO_x, PM/PM_{10} (filterable and condensable), SO_2, and SO_4 (as H_2SO_4). Table 5-2 contains the stack parameters and emission rates modeled in CALPUFF. Furthermore, in accordance with guidance from the NPS, the PM/PM_{10} emissions were speciated based on size and composition and, therefore, were broken into the following constituents: elemental carbon (EC) and organic carbon (OC) for the regional haze analysis. Specifically, guidance from the NPS on PM speciation was found in the Emissions & Control Technology area of their Web site. In accordance with the NPS, for natural gas fired combustion turbines, all the filterable portion of PM/PM_{10} emissions are considered EC and all non-$(NH_4)_2SO_4$ condensables are considered to be OC.

The EC and OC emissions were further speciated based on size. In accordance with NPS guidance, all particles were assumed to be 1 micron or less for combustion turbines. Table 5-3 presents size distribution for EC and OC particulates as recommended by the NPS along with the Project's emission rates for each category and size.

Table 5-2
Stack Parameters and Pollutant Emissions
Used in CALPUFF Modeling Analysis

Cane Island Unit 4								
					Pollutant Emission Rate (lb/h)			
CTG Load	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	NO_x	PM/PM_{10}[a]	SO_2	H_2SO_4[b]
100% with Duct Firing	160	18	57.63	165	18.50	40.10	10.81	5.85

[a]PM/PM_{10} emission rates represent both front and back half emissions including the effects of SO_2 oxidation.
[b]Assumes a percentage conversion of SO_2 to SO_3; then 100 percent of SO_3 conversion to H_2SO_4.

Table 5-3
Particle Size Distribution

			Emission Rate (lb/hr)	
Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Filterable EC Emissions[a]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[b]
PM1P00	1.00	11	1.639	2.772
PM0P25	0.25	11	1.639	2.772
PM0P20	0.20	15	2.235	3.780
PM0P15	0.15	23	3.427	5.796
PM0P10	0.10	25	3.725	6.300
PM0P05	0.05	15	2.235	3.780
Subtotals			14.90	25.20

[a]EC includes all filterable emissions.
[b]OC includes all condensable emissions.

5.2 CALPUFF Analyses Performed

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses on the CWA, including regional haze, deposition, and Class I SILs. Electronic copies of Class I modeling input and output files are included in Attachment F.

5.2.1 Regional Haze Analysis

A regional haze analysis was performed for the CWA, for ammonium sulfates, ammonium nitrates, and PM, by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations. PM_{10} emissions were speciated into filterable and condensable PM size categories using NPS speciation spreadsheets.

Visibility

Visibility is an AQRV for the CWA. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the CWA lies beyond 50 km from the proposed Project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}\,(Mm^{-1}) = 3912 / vr\,(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as the following:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where:

b_{exts} = Extinction coefficient calculated for the source.

b_{extb} = Background extinction coefficient.

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the dv that simply quantifies the percent change in visibility due to the operation of a source is calculated as follows:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the CWA. The background visual range, or constituents thereof, for the CWA was obtained from the Phase I FLAG Report, December 2000. The average relative humidity (RH) factor for each day was computed by determining the RH factor for each hour's RH for the 24 hour period that the impact occurred. This factor, based on each hour's RH can be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a RH factor for each hour of RH) were then used to determine the average RH factor for that day (24 hour period). All of this was accomplished with the use of the CALPOST post-processor.

Interagency Workgroup on Air Quality Modeling Guidelines

The CALPUFF air modeling analysis followed the recommendations contained in the IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts, (EPA, 12/98), where appropriate. Table 5-4 summarizes the IWAQM Phase II recommendations. The methodology in Table 5-4 was used to compute the results of the regional haze analysis; however, CALPOST now possesses the ability to post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. The post-processing selection was made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze was calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly RH adjustments for observed and modeled sulfate and nitrates, which will be zero. The RH was capped at 95 percent. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Table 5-4
Outline of IWAQM Refined Modeling Analyses Recommendations

Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS will provide the modeling receptors.
Dispersion	CALPUFF with default dispersion settings. Use MESOPUFF II chemistry with wet and dry deposition. Define background values for ozone and ammonia for area.
Processing	Use highest predicted 24 hour SO_4, PM_{10}, and NO_3 value; compute a day-average RH factor (f(RH)) for the worst day for the predicted species, calculate extinction coefficients, and compute percent change in extinction using the FLAG supplied background extinction where appropriate. This can all now be accomplished with the use of Method 2 in the CALPOST post-processor.

Based on the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98).

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24 hour SO_4, NO_3, and PM speciated (EC and OC) impacts, in units of micrograms per cubic meter (μg/m^3).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:
   $(NH_4)_2SO_4$ (μg/m^3) = SO_4 (μg/m^3) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4
   $(NH_4)_2SO_4$ (μg/m^3) = SO_4 (μg/m^3) x 132/96 = SO_4 (μg/m^3) x 1.375
3. Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 (μg/m^3) = NO_3 (μg/m^3) x molecular weight NH_4NO_3 / molecular weight NO_3
   NH_4NO_3 (μg/m^3) = NO_3 (μg/m^3) x 80/62 = NO_3 (μg/m^3) x 1.29
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:
   $b_{exts} = 3[NH_4NO_3]f(RH) + 3[(NH_4)_2SO_4]f(RH) + 4[OC] + 10[EC] + 4[PMC] + 1[PMF]$
5. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:
   b_{extb} = 3.912 / visual range (km)
6. Compute the change in extinction coefficients:
   in terms of dv:
   $dv = 10 \ln (1 + b_{exts} / b_{extb})$
   in terms of percent change of visibility:
   $\Delta\% = (b_{exts} / b_{extb}) \times 100$

Based on the predicted SO_4, NO_3, and speciated PM concentrations, the proposed Project's emissions were compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in dv of 0.5. As illustrated in Table 5-5, the regional haze results are less than the 5 percent change in extinction threshold for the CWA and, as such, no further analysis is necessary.

Table 5-5
Regional Haze Results

Class I Area	Change in Extinction[a] (%)			Recommended Threshold (%)
	2001	2002	2003	
CWA	2.23	2.26	1.37	5

[a]Change in extinction was compared against the natural conditions presented in the FLAG 2000 document.

5.2.2 Deposition Analysis

Deposition analyses were performed for CWA for both total sulfur and total nitrogen. The analyses followed those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses were performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 5.1 (including output of both dry and wet deposition).
2. Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass, and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
3. Apply the appropriate scaling factors to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), and seconds to a year to achieve CALPOST results in kg/ha/yr.

The model-predicted results were compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the US FWS for Class I areas located east of the Mississippi River. The results of the deposition analysis for CWA are presented in Table 5-6. As illustrated in the table, the deposition results for the CWA are less than the 0.01 DAT and, as such, no further analysis is necessary.

5.2.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) at the CWA were calculated for NO_x, SO_2, and PM/PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis were compared with the Class I SILs calculated as 4 percent of the Class I Increment values. Table 5-7 presents the maximum results of the Class I analysis for the 3 year period that was modeled. As illustrated in the table, there are no impacts above the Class I SILs at the CWA and, as such, no further analysis is necessary.

Table 5-6
Deposition Results

Class I Area	Total Nitrogen Deposition[a] (kg/ha/yr)			Total Sulfur Deposition[b] (kg/ha/yr)			Deposition Analysis Threshold[c]
	2001	2002	2003	2001	2002	2003	
CWA	3.87E-04	5.14E-04	5.10E-04	6.06E-04	8.22E-04	7.64E-04	0.01

[a]Includes both wet and dry deposition with SO_4, NO_x, HNO_3, and NO_3 contributing to the nitrogen mass.
[b]Includes both wet and dry deposition with SO_2 and SO_4 contributing sulfur mass.
[c]For all areas east of the Mississippi River.

Table 5-7
Class I Significant Impact Levels Modeling Results

Pollutant	Averaging Period	Model-Predicted Impact[a] ($\mu g/m^3$)	PSD Class I SIL[b] ($\mu g/m^3$)	Exceed SILs?
Chassahowitzka Wilderness Area				
NO_x	Annual	8.68E-04	0.10	NO
SO_2	Annual	6.92E-04	0.08	NO
	24 Hour	9.39E-03	0.20	NO
	3 Hour	3.06E-02	1.0	NO
PM/PM_{10}	Annual	2.90E-03	0.16	NO
	24 Hour	4.24E-02	0.32	NO

[a]Model-predicted impacts are maximum predicted impacts for the 3 year period of 2001, 2002, and 2003.
[b]Class I SILs are calculated as 4 percent of the PSD Class I Increment values.

6.0 Additional Impact Analysis

A requirement of the PSD regulations is the need for an additional impact analysis as governed by Rule 62-212.400(4)(e), F.A.C., pertaining to the air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth that has occurred since August 7, 1977, in the area the Project would affect. A characterization of the population trend of the area can be a surrogate for general growth. An evaluation of the growth as it relates to the August 7, 1977 date, as well as a projection of growth indicators related to the Project with respect to workforce, housing, and commercial/industrial growth and their potential impact to air quality are presented below in Sections 6.1 through 6.4.

Additionally, Rule 62-212.400(8)(a), F.A.C., requires that an analysis that considers the impairment to visibility, soils, and vegetation that would occur as a result of the Project be performed. A visibility analysis was performed on the CWA and was provided in Section 5.0. Analyses for soils and vegetation were performed and are discussed in Section 6.5.

6.1 Growth Analysis

The proposed Project will be located within the CIPP in Osceola County, Florida, which is approximately 20 miles southwest of Orlando, 5 miles west of Kissimmee, and 1 mile northwest of Intercession City. The proposed Project will occupy approximately 9 acres of the existing site. The site was previously zoned for agricultural use, but was approved for industrial use in 1993. Osceola County future land use maps indicate no change in the anticipated zoning pattern for the Power Park site or the adjacent land area in the future, confirming that the Power Park site will continue to be compatible with the predominant land use in the immediate project vicinity.

The two major cities in Osceola County are Kissimmee and St. Cloud. The City of Kissimmee, the county seat, is 18 miles due south of Orlando. Well known for its year-round desirable climate and abundant recreational opportunities, Kissimmee covers roughly 17 square miles and has become the fourth fastest growing county in the United States. Its current population of 59,364 makes it the largest city in Osceola County although it is relatively small when compared to Florida's largest municipalities.

The population trends of Osceola County may be used as a surrogate growth indicator of the extent of air quality impacts related to general commercial, residential, and industrial growth since August 7, 1977. The US Census Bureau estimated that Osceola County had a population of 41,700 persons in 1977. The population of Osceola County was estimated to be 235,153 in 2005 by the University of Florida's Florida

Housing Data Clearinghouse. Osceola County's population constituted roughly 1.3 percent of the estimated 2005 state population of 17,918,453. The Osceola County population increased by 36.3 percent between 2000 and 2005, compared to a 12.1 percent growth for Florida. The respective 1990 to 2000 growth rate was 60.1 percent for Osceola County compared to 23.5 percent at the state level. The 2005 population estimate given above is a growth of 464 percent since 1977.

Since 1977, Osceola County has successfully balanced growth and economic development with the preservation of unique environmental and recreational areas. The County has anticipated and planned for this additional growth while continuing to demonstrate compliance with the air quality standards (Osceola County is in attainment for all criteria pollutants) and preserving the amenities offered to the county population and its visitors. Because the maximum predicted air pollutant concentrations for the proposed Project are well below the NSR/PSD significant impact levels, air concentrations in the region are expected to fully comply with the ambient air quality standards when the proposed Project becomes operational. Therefore, from an air quality impact standpoint, the proposed facility is consistent with the balanced growth demonstrated by the county to date.

6.2 Workforce

Labor force statistics show that as of September 2007 Osceola County had a total employment of 126,946 persons. Employment figures by occupation are available for the Orlando-Kissimmee Metropolitan Statistical Area (MSA). This MSA includes not only Orlando and Kissimmee, but also towns from Osceola, Orange, Seminole, and Lake counties. As of May 2006, there were 1,019,280 people employed among all occupations within this MSA; the largest occupation category was in the office and administrative support occupation (191,350 or 18.8 percent). This category was followed by sales and related occupation (132,160 or 13.0 percent), and the food preparation and serving occupation (110,350 or 10.8 percent). Major employment sectors in the county included the leisure and hospitality sector (21.6 percent) as well as the trade, transportation and utilities sector (21.4 percent). Education and health services (11.1 percent), construction (9.0 percent), professional and business services (8.9 percent) also made up a significant portion of the Osceola County employment by industry in 2006.

Compared to the state, Osceola County had a relatively higher concentration of employment in the leisure and hospitality sector (21.6 percent versus 11.5 percent). The county was well below the state percentage in the professional and business services sector (8.9 percent versus the state's 17.1 percent), and education and health services (11.1 percent for the county versus 18.4 percent in the state).

County business data for Osceola County for 1977 show the total employment to be 10,538 persons. The largest occupational category was in the services division (3,782, or 35.9 percent). This category was followed by the retail trade division (2,307, or 21.9 percent) and the government division (1,731, or 16.4 percent). Other major employment divisions in the county included manufacturing (10.5 percent), wholesale trade (5.1 percent), finance, insurance, real estate (3.8 percent), construction (3.6), and transportation/communications/utilities (2.0 percent). Agriculture (0.8 percent) made up the remainder of the occupational categories.

6.2.1 Workforce Growth Associated with the Project

The proposed Project will require a substantial construction workforce during the 23 month construction period, scheduled to span the July 2009 through May 2011 time frame. During this period, an average of 160 direct craft construction workers and a total workforce (that also includes indirect craft workers, construction management, and local utility staff) average of 182 personnel are expected. The peak construction workforce is projected to occur during the fifteenth month of construction, when 280 direct craft workers, and a total of 313 workers, are expected onsite. However, the construction labor force increase and associated secondary air emissions increase will be temporary and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the proposed Project.

The net number of new, permanent jobs that will be created by Unit 4 is estimated at two. The secondary residential, commercial, and industrial growth associated with this small operation staff, which will be divided into shifts to provide around-the-clock operation, is not expected to have a significant impact on air quality.

6.3 Housing

According to the US Census Bureau, there were 89,902 occupied housing units in Osceola County in 2006; this was approximately 1.0 percent of the 8,533,419 units in the state. Osceola County's total number of housing units in 2006 grew by 52 percent in the 6 years between the 2000 census, when 72,293 units were reported. Approximately 82 percent of the 2006 housing units were built in 1980 or later, with 5.5 percent built before 1960. Approximately 69 percent of residents moved into units after 2000; nearly 91 percent have moved to their residence in 1990 or later. The Orlando-Kissimmee MSA had a total of 749,928 housing units in 2006 and this constituted 8.8 percent of the total state's overall units.

The housing unit stock around Orlando and Kissimmee is relatively young, reflecting the recent population growth. Approximately 68 percent of the housing stock in 2006 was built in 1980 or later, and only 10 percent of the housing units were built before 1960. Approximately 64 percent of the 2006 population moved into their housing unit in 2000 or later, and approximately 86 percent moved into the unit in 1990 or later.

Building activity for Osceola County has continued at a rapid pace during the recent past, as reflected in the number of housing unit building permits issued. According to the US Department of Housing and Urban Development, in 2006, a total of 8,006 permits were issued for the county, and this was equal to approximately 2.6 percent of the 2002 existing housing stock. During 2002 through 2006, the type of housing unit for which a building permit was issued was primarily for single family structures, although 5+ unit multi-family structures also comprised a significant percentage in 2002 (32 percent) and in other years.

6.3.1 Housing Growth Associated with the Project

The potential for housing shortages and, thus, the possibility of housing related growth and secondary air quality impacts have been an issue historically for the construction of large coal plants in sparsely populated areas. However, experience has also shown that smaller projects (non-coal plants) like the Unit 4 project located in or near urban areas typically have no noticeable impacts on the housing market. The reason is that impacts are primarily a function of the size of the construction workforce and the need for the workforce to relocate during construction.

The need to relocate is a function of the available workforce within a reasonable commuting distance of the work site. Research by the Electric Power Research Institute (EPRI) has indicated that the construction workforce for a power plant project can reasonably be expected to commute without relocating during construction from a distance of more than 70 miles, with instances of a commuting distance of more than 100 miles found in each of the construction projects studied. When a 70 mile radius around the CIPP site is considered, large metropolitan areas including Orlando, Tampa, and Melbourne are within commuting distance to the site, and a 100 mile radius includes cities like Saint Petersburg and Clearwater.

In addition to the previously discussed housing and rental stock, Orlando and Kissimmee offer a wide variety of temporary lodging, reflecting the area's status as a destination for recreational seekers. The Kissimmee Convention and Visitors' Bureau Web site lists 144 motels, inns, hotels, RV parks, and short-term apartments in the area. Given the expected population of the commuting workforce, the fact that during the 23 month construction period most workers will be onsite for less than the total construction period, an abundance of hotel and other short-term lodging options, it is unlikely that a substantial number of the Unit 4 construction workforce would choose to relocate during the 23 month construction period. Therefore, the anticipated housing growth will be minimal or nonexistent, and is not expected to have a significant impact on the air quality.

6.4 Commercial/Industrial Growth

The Project is proposed to meet the existing and current projected electrical demands of the surrounding area. It is anticipated that little commercial growth will be associated with its specific operation. Additionally, the electrical generating capacity created by Unit 4 will not have a significant effect upon the industrial growth in the immediate area, considering that the electrical generating capacity will be sold to the grid as opposed to a nearby industrial host. For these reasons, Unit 4 is not expected to have a significant impact on the air quality as the result of commercial or industrial growth.

6.5 Vegetation and Soils Analysis

Combustion turbine projects are typically considered “clean facilities” that have very low predicted ground level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust. Therefore, the Project’s impacts on soils and vegetation will be minimal.

The vegetation and soils analysis was based on predicted air pollutant concentrations derived from a comprehensive air dispersion modeling analysis of the stack emissions from the proposed Project. The model-predicted pollutant concentrations were compared to AAQS, which are designed to protect the public health, welfare, and the natural environment. These AAQS have been established by the USEPA for the six criteria air pollutants and include primary ambient air quality standards, which are designed to protect public health with an adequate margin of safety, and secondary AAQS, which are designed to protect public welfare-related values, including property, materials, and plant and animal life. Specifically, and as indicated in the *Draft New Source Review Workshop Manual* (EPA, 1990), ambient concentrations of pollutants below the secondary AAQS will not result in harmful effects for most types of soils and vegetation. In Florida, AAQS at least as stringent as the national secondary standards have been adopted by the Department.

As given in Section 4.3 of the application, the model-predicted ambient concentrations of SO_2, PM/PM_{10}, NO_x, and CO are not only one or more orders of magnitude less than the applicable AAQS, but are even less than the more stringent NSR/PSD significant impact levels and the USEPA recommended screening levels for air pollution impacts on plants, soils, and animals. Because the predicted air quality impacts are so much lower than the air quality standards designed to protect plant and animal life, it is reasonable to conclude that the proposed emissions of SO_2, PM/PM_{10}, NO_x, and CO will not significantly affect vegetation, soils, or wildlife.

The air quality impact to soils, vegetation, and wildlife from H_2SO_4 is also expected to be insignificant. There is no national or state air quality standard for H_2SO_4 to compare model-predicted impacts with, as a general measure of H_2SO_4's air quality impact potential, as there are for other PSD pollutants. However, based on the fact that the Project proposes to use two of the least sulfur bearing fuels available (i.e., natural gas and ULSFO) and that predicted SO_2 concentrations are orders of magnitude less than USEPA recommended screening concentrations, it is reasonable to assume that H_2SO_4 emissions will not significantly impact the air quality in a manner that is detrimental to soils or vegetation.

To further demonstrate that the proposed Project will have an insignificant impact upon vegetation, additional modeling analyses were performed. Those analyses consisted of evaluating the Project's two largest emitted PSD pollutants (NO_x and CO) against the sensitive vegetation thresholds found in the EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals*. In that document, the minimum NO_2 concentrations at which adverse growth effects or tissue injury occurred for the most sensitive vegetation are: 3,760 ug/m^3 (4 hour averaging period), 564 ug/m^3 (1 month averaging period), and 94 ug/m^3 (1 year averaging period). Similarly, the most sensitive vegetation threshold for CO is given as 1,800,000 ug/m^3 (1 week averaging period); potentially reducing the photosynthetic rate. The model-predicted impacts for these pollutants compared to the given thresholds are presented in Table 6-1. As illustrated in the table, the proposed Project's impacts are significantly below the aforementioned screening levels and as such, no adverse impacts to vegetation at or near the facility are expected from NO_x and CO emissions.

The literature about air quality impacts on wildlife generally focuses on acute exposure by wildlife to unusual or high concentrations of pollutants. Wildlife can be affected through three pathways: ingestion, dermal exposure, and inhalation of ambient air, with ingestion, which can result in bioaccumulation, being the most common means of exposure to high concentrations of pollutants. However, the project air emissions and impacts are predicted to be very low, and are highly unlikely to have any effects on wildlife in the vicinity of the project.

Table 6-1
Additional Modeling Results to Assess Impacts to Vegetation

Pollutant	Averaging Period	Model-Predicted Impact[(a)] (ug/m^3)	Screening Threshold[(b)] (ug/m^3)	Exceed Threshold?
NO_x	4 hour	3.63	3.760	No
	24 hour	1.62	564	No
	1 month	0.27	94	No
CO	1 hour	10.93	1,800,000[(c)]	No

[(a)]Impacts represent the highest first high model-predicted concentration from the operation of Unit 4 for all 5 years of meteorological data modeled at 100 percent load.
[(b)]Thresholds are taken from EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals.*
[(c)]Value is actually based on a 1 week averaging period. Model-predicted 1 hour impact is conservatively below this threshold.

Appendix A
FDEP Air Permit Application Forms

Department of
Environmental Protection
Division of Air Resource Management
APPLICATION FOR AIR PERMIT - LONG FORM
I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Florida Municipal Power Agency	
2. Site Name: Cane Island Power Park	
3. Facility Identification Number: 0970043	
4. Facility Location... Street Address or Other Locator: 6075 Old Tampa Highway City: Intercession City County: Osceola Zip Code: 33848	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: Susan Schumann
2. Application Contact Mailing Address... Organization/Firm: Florida Municipal Power Agency Street Address: 8553 Commodity Circle City: Orlando State: FL Zip Code: 32819
3. Application Contact Telephone Numbers... Telephone: (407) 355-7767 ext. Fax: (407) 355-5794
4. Application Contact Email Address: susan.schumann@fmpa.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

- [x] Air construction permit.
- [ ] Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- [ ] Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

- [ ] Initial Title V air operation permit.
- [ ] Title V air operation permit revision.
- [ ] Title V air operation permit renewal.
- [ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- [ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- [ ] Air construction permit and Title V permit revision, incorporating the proposed project.
- [ ] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- [ ] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Florida Municipal Power Agency (FMPA) is proposing to own and construct and Kissimmee Utility Authority (KUA) is proposing to operate a new natural gas-fired combined cycle combustion turbine (CCCT) (Unit 4) at the existing Cane Island Power Park (CIPP) located near Kissimmee, Florida. The proposed CIPP Unit 4 and supporting ancillary equipment will join the existing units (Units 1, 2, and 3) at the CIPP. The proposed Unit 4 is rated at approximately 300 MW (net), firing natural gas as the only fuel.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
	Unit 4 – GE PG7241 FA Combustion Turbine	AC1A	$7,500
	Diesel Engine Fire Pump	AC1A	NA
	Safe Shutdown Generator	AC1A	NA
	Mechanical Draft Cooling Tower	AC1A	NA

Application Processing Fee

Check one: [x] Attached - Amount: $ 7,500 [ ] Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : Roger Fontes – General Manager and CEO
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: Florida Municipal Power Agency Street Address: 8553 Commodity Circle City: Orlando State: FL Zip Code: 32819
3.	Owner/Authorized Representative Telephone Numbers... Telephone: (407) 355-7767 ext. Fax: (407) 355-5794
4.	Owner/Authorized Representative Email Address: roger.fontes@fmpa.com
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature: Roger A Fontes Date: 3/27/08

APPLICATION INFORMATION

<u>Application Responsible Official Certification</u>

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1.	Application Responsible Official Name:
2.	Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source, CAIR source, or Hg Budget source.
3.	Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4.	Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5.	Application Responsible Official E-mail Address:
6.	Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* ________________________ ________________ Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Stanley A. Armbruster, P.E.
   Registration Number: 30562
2. Professional Engineer Mailing Address...
   Organization/Firm: Black & Veatch
   Street Address: 11401 Lamar Avenue
   City: Overland Park State: KS Zip Code: 66211
3. Professional Engineer Telephone Numbers...
   Telephone: (913) 458-2763 ext. Fax: (913) 458-2934
4. Professional Engineer Email Address: ArmbrusterSA@bv.com
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here [x], if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here , if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature

(seal)

Date April 1, 2008

STANLEY A. ARMBRUSTER
LICENSE
30562
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

<table>
<tr><td colspan="2">1. Facility UTM Coordinates...
Zone 17 East (km) 447.5
North (km) 3128.0</td><td colspan="2">2. Facility Latitude/Longitude...
Latitude (DD/MM/SS)
Longitude (DD/MM/SS)</td></tr>
<tr><td>3. Governmental Facility Code:
4</td><td>4. Facility Status Code:
C</td><td>5. Facility Major Group SIC Code:
49</td><td>6. Facility SIC(s):
4911</td></tr>
<tr><td colspan="4">7. Facility Comment :</td></tr>
</table>

Facility Contact

1. Facility Contact Name Jay Butters
2. Facility Contact Mailing Address... Organization/Firm: Kissimmee Utility Authority Street Address: 6075 Old Tampa Highway City: Intercession City State: FL Zip Code: 33848
3. Facility Contact Telephone Numbers: Telephone: (407) 933-9853 ext. Fax: (407) 846-6485
4. Facility Contact Email Address: jbutters@kua.com

Facility Primary Responsible Official
Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO	A	N
NOX	A	N
PM	A	N
PM10	A	N
SO2	A	N
VOC	B	N
SAM	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Attach. 1 ☐ Previously Submitted, Date:________
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Attach. 2 ☐ Previously Submitted, Date:________
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Attach. 3 ☐ Previously Submitted, Date:________

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☐ Attached, Document ID:_______ ☒ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☐ Attached, Document ID: See Section 2.0 of Application Support Document
3.	Rule Applicability Analysis: ☒ Attached, Document ID: Attach. 4
4.	List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☐ Attached, Document ID:__________ ☒ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: See Sections 4, 5, 6 of the Application Support Document
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: See Sections 4, 5, 6 of the Application Support Document
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: See Section 6 of the Application Support Document
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: See Section 6 of the Application Support Document
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units:
   ☐ Attached, Document ID:___________ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities: (Required for initial/renewal applications only)
   ☐ Attached, Document ID:___________ ☐ Not Applicable (revision application)
2. Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought)
   ☐ Attached, Document ID:___________
   ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan: (Required for all initial/revision/renewal applications)
   ☐ Attached, Document ID:___________
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:___________
   ☐ Equipment/Activities Onsite but Not Required to be Individually Listed
   ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:___________ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit:
   ☐ Attached, Document ID:___________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   [x] Attached, Document ID: Attach. 7 [ ] Previously Submitted, Date:__________
   [ ] Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   [ ] Attached, Document ID:__________ [ ] Previously Submitted, Date:__________
   [x] Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   [ ] Attached, Document ID:__________ [ ] Previously Submitted, Date:__________
   [x] Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   [x] Attached, Document ID: Attach. 7 [ ] Previously Submitted, Date:__________
   [ ] Not Applicable (not a CAIR source)

3. Hg Budget Part (DEP Form No. 62-210.900(1)(c)):
   [x] Attached, Document ID: Attach. 7 [ ] Previously Submitted, Date:__________
   [ ] Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

A CD-ROM with air dispersion modeling files is included in the Application Support Document. Please see Appendix F of the application package.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Unit 1 – GE PG7241 FA Combustion Turbine.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	☒ Yes ☐ No

9. Package Unit:
Manufacturer: GE Model Number: PG7241 FA

10. Generator Nameplate Rating: 157 MW for the CT
153 MW for the STG

Above ratings are gross output. When auxiliary power is subtracted, nominal rating is 300 MW net for the combined cycle unit.

11. Emissions Unit Comment: The combined cycle combustion turbine will include HRSG duct firing capability.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: Dry low NO_x burners in conjunction with selective catalytic reduction will be used to control NO_x emissions when firing natural gas.
2. Control Device or Method Code(s): 205, 139

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:			
2. Maximum Production Rate:			
3. Maximum Heat Input Rate: 1975.2 million Btu/hr (HHV) – CT firing natural gas 593.2 million Btu/hr (HHV) – Duct Burner firing natural gas			
4. Maximum Incineration Rate: pounds/hr tons/day			
5. Requested Maximum Operating Schedule:			
CT firing natural gas	24 hours/day	7 days/week	
	52 weeks/year	8,760 hours/year	
Duct burner firing natural gas	24 hours/day	7 days/week	
	52 weeks/year	8,760 hours/year	
6. Operating Capacity/Schedule Comment: The unit will be operated between 40 and 100 percent of full load. The maximum heat input rate shown in Field 3 is with operation at 100% load at the site minimum ambient temperature of 19°F. Operation at 100 percent load and a 59°F (ISO conditions) is expected to have a corresponding maximum heat input of 1,860.4 MBtu/hr (HHV). Note that the heat input rate is a function of ambient temperature. We request inclusion of the standard permitting note that the heat input rates are provided for informational purposes only and are not intended to be enforceable limits.			

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Heat Recovery Steam Generator Exhaust Stack		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 18 feet
8. Exit Temperature: 167°F	9. Actual Volumetric Flow Rate: 990,556 acfm	10. Water Vapor: 11%
11. Maximum Dry Standard Flow Rate: 819,771 scfm		12. Nonstack Emission Point Height:
13. Emission Point UTM Coordinates... Zone: 17 East (km): 447.6239 North (km): 3127.9624		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: Emission point information given in Fields 8 through 11 are based on firing natural gas in the CTG and the duct burner with operation at 100% load, evaporative cooler on, and at ISO Conditions		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

<table>
<tr><td colspan="3">1. Segment Description (Process/Fuel Type):
Natural gas used in the combustion turbine</td></tr>
<tr><td colspan="2">2. Source Classification Code (SCC):
20100201</td><td>3. SCC Units:
Million Cubic Feet Burned</td></tr>
<tr><td>4. Maximum Hourly Rate:
2.03</td><td>5. Maximum Annual Rate:
17,838</td><td>6. Estimated Annual Activity Factor:</td></tr>
<tr><td>7. Maximum % Sulfur:</td><td>8. Maximum % Ash:</td><td>9. Million Btu per SCC Unit:
970 (HHV)</td></tr>
<tr><td colspan="3">10. Segment Comment: The maximum fuel input to the combustion turbine is a function of the ambient temperature. The maximum hourly rate given in Field 4 is based on operation at 100% load at the site minimum ambient temperature of 19°F. The maximum natural gas use rate given in Field 5 is based on 100 percent load operation for 8,760 hours per year at the site minimum ambient temperature of 19°F. The fuel use rates do not include duct burner. See next segment for duct burner. operation.</td></tr>
</table>

Segment Description and Rate: Segment 2 of 2

<table>
<tr><td colspan="3">1. Segment Description (Process/Fuel Type):
Natural gas used in duct burner.</td></tr>
<tr><td colspan="2">2. Source Classification Code (SCC):</td><td>3. SCC Units:
Million Cubic Feet Burned</td></tr>
<tr><td>4. Maximum Hourly Rate:
0.61</td><td>5. Maximum Annual Rate:
5,357</td><td>6. Estimated Annual Activity Factor:</td></tr>
<tr><td>7. Maximum % Sulfur:</td><td>8. Maximum % Ash:</td><td>9. Million Btu per SCC Unit:
970 (HHV)</td></tr>
<tr><td colspan="3">10. Segment Comment: The duct burner is fired only with natural gas.</td></tr>
</table>

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOX	**205, 139 (NG)**		**EL**
PM			
PM10			
SO2			**WP**
VOC			
SAM			**WP**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>
Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 40.8 lb/hour 178.70 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Potential emissions are based on vendor data.
The potential hourly CO emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions.

Annual emissions = (40.8 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 178.70 tons/year

11. Potential, Fugitive, and Actual Emissions Comment:

The potential hourly and annual emissions are for informational purposes only and do not constitute emission limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>Allowable Emissions</u> Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>Allowable Emissions</u> Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 17.6 lb/hour 77.09 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: Potential emissions are based on vendor data. The potential hourly NO_x emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (17.6 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 77.09 tons/year	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15 ppmvd	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is from NSPS Subpart KKKK and applies when Unit 4 is operating on natural gas at greater than 75 percent load. Equivalent allowable emissions are based on operation at 59°F ambient temperature (ISO) and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.0 ppmvd at 15% O_2 (combined cycle mode with natural gas firing)	4. Equivalent Allowable Emissions: 17.6 lb/hour 77.09 tons/year
5. Method of Compliance: CEMS.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly and annual emissions rates are based on operation at 100% load and at ISO conditions. The equivalent allowable emissions include emissions from HRSG duct burner firing. The allowable emissions from 40 CFR 60, Subpart KKKK are 0.39 lb/MW-hr when firing natural gas, based on a 4-hour rolling average. Compliance with the BACT levels will ensure compliance with the standard.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 39.7 lb/hour 173.89 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential emissions are based on vendor data.

The potential hourly PM/PM10 emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions.

Annual emissions = (39.7 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 173.89 tons/year

11. Potential, Fugitive, and Actual Emissions Comment:

The potential hourly and annual emissions are for informational purposes only and do not constitute emission limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 10.34 lb/hour 45.29 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential emissions are based on vendor data.

The potential hourly SO_2 emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions.

Annual emissions = (10.34 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 45.29 tons/year

11. Potential, Fugitive, and Actual Emissions Comment:

The potential hourly and annual emissions are for informational purposes only and do not constitute emission limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: Natural gas with less than 20 grains per 100 scf of natural gas	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Natural gas supplier tariff sheet.	
6. Allowable Emissions Comment (Description of Operating Method): The natural gas sulfur standard is associated with NSPS Subpart KKKK. Per 40 CFR 60.4365, FMPA is requesting that they be exempt from the requirement to monitor fuel sulfur content by demonstrating the fuel sulfur content through the natural gas tariff sheet.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2 grains sulfur per 100 scf in the natural gas	4. Equivalent Allowable Emissions: 10.34 lb/hour 45.29 tons/year
5. Method of Compliance: Compliance will be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas supplied from the pipeline for each month of operation.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions standard given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly and annual emissions rate is based on operation at 100% load in combined cycle mode, evaporative cooler on, duct firing and at ISO conditions. While the natural gas tariff does not guarantee a sulfur content of 2 grains per 100 scf, historical data indicates that this is a reasonable sulfur level. Therefore, if the permit is to include a natural gas sulfur content standard, it is requested that any such standard be based on a calendar month average.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.3 lb/hour 23.21 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: Potential emissions are based on vendor data. The potential hourly VOC emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (5.3 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 23.21 tons/year	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.54 lb/hour 24.27 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: Potential emissions are based on vendor data. The potential hourly SAM emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (5.54 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 24.27 tons/year	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2 grains sulfur per 100 scf in the natural gas	4. Equivalent Allowable Emissions: 5.54 lb/hour 24.27 tons/year
5. Method of Compliance: Fuel supplier tariff sheet	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are based on the estimated oxidation of SO_2 to SO_3 and assuming 100 percent conversion of SO_3 to sulfuric acid mist. Equivalent allowable emissions are given for informational purposes only and do not represent limits. They are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: To be determined Model Number: To be determined	Serial Number: To be determined
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEMS will be installed before operation of the emission source. CEMS is required as a condition of 40 CFR Parts 60 and 75.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: CO2 or O2	2. Pollutant(s):
3. CMS Requirement:	x Rule ☐ Other
4. Monitor Information... Manufacturer: To be determined Model Number: To be determined	Serial Number: To be determined
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEMS will be installed before operation of the emission source. CEMS is required as a condition of 40 CFR 75.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

<u>Continuous Monitoring System:</u> Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

<u>Continuous Monitoring System:</u> Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Attach. 2 ☐ Previously Submitted, Date ______
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: See Application Support Document .
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: see Section 3 in Application Support Document
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Attach. 5 ☐ Previously Submitted, Date ______ ☐ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: ______ Test Date(s)/Pollutant(s) Tested: ______ ☐ Previously Submitted, Date: ______ Test Date(s)/Pollutant(s) Tested: ______ ☐ To be Submitted, Date (if known): ______ Test Date(s)/Pollutant(s) Tested: ______ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☐ Attached, Document ID: ______ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☒ Attached, Document ID: See Section 3 of the Application Support Document
2.	Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☒ Attached, Document ID: See Section 4 of the Application Support Document
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: Attach.6 ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☐ Attached, Document ID: ___________
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☐ Not Applicable

Additional Requirements Comment

A CD-ROM with air dispersion modeling files is included in Appendix F of the application package.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: 290 BHP Diesel Engine Fire Pump.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	☐ Yes [x] No

9. Package Unit:
   Manufacturer: TBD Model Number: TBD

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:
2. Maximum Production Rate: 290 HP (approximate)
3. Maximum Heat Input Rate:
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule:
6. Operating Capacity/Schedule Comment: Based on National Fire Protection Association (NFPA) guidelines it is conservatively estimated that the diesel engine fire pump will operate approximately 52 hours per year. Because this is emergency fire equipment, a maximum operating schedule is not requested. Because a specific manufacturer and model has not been determined, the maximum production rate provided is an approximate value.

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Fire Pump Building		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 15.17 feet	7. Exit Diameter: 0.4167 feet
8. Exit Temperature: 855°F	9. Actual Volumetric Flow Rate: 1,506 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate:		12. Nonstack Emission Point Height:
13. Emission Point UTM Coordinates... Zone: 17 East (km): 447.589 North (km): 3127.965		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): ULSFO used in the diesel engine fire pump		
2. Source Classification Code (SCC): 20100301	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 0.0135	5. Maximum Annual Rate: 2.7	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 137 (HHV)
10. Segment Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters. The annual rate is based on an estimated 52 hours per year of operation.		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			**NS**
NOX			**EL**
PM			**EL**
PM10			**NS**
SO2			**NS**
VOC			**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.33 lb/hour 8.48 E-03 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly CO emission rate is 0.33 lb/hour. The maximum annual potential CO emissions are based on operating 52 hours per year. Annual emissions = 0.33 lb/hr x 52 hours/year x 1 ton/2,000 lb = 8.48 E-03 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 1.92 lb/hour 4.99 E-02 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly NO_x emission rate is 1.92 lb/hour. The maximum annual potential NO_x emissions are based on operating 52 hours per year. Annual emissions = 1.92 lb/hr x 52 hours/year x 1 ton/2,000 lb = 4.99 E-02 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential NO_x emissions are based on the NSPS Subpart IIII 2009 model year limit for NOx + non-methane HC of 3 g/hp-hr. As a worst case NO_x emissions were assumed to be 3 g/hp-hr. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3 g/hp-hr (NOX + NMHC) for 2009 model year engines	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.08 lb/hour 2.16 E-03 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM/PM10 emission rate is 0.083 lb/hour. The maximum annual potential PM emissions are based on operating 52 hours per year. Annual emissions = 0.083 lb/hr x 52 hours/year x 1 ton/2,000 lb = 2.16 E-03 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.0029 lb/hour 7.42 E-05 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data using fuel oil with 0.0015 percent sulfur content. The maximum hourly SO_2 emission rate is 0.003 lb/hour. The maximum annual potential SO_2 emissions are based on operating 52 hours per year. Annual emissions = 0.003 lb/hr x 52 hours/year x 1 ton/2,000 lb = 7.42 E-05 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on using fuel oil with 0.0015 percent sulfur content. The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.66 lb/hour 1.72E-02 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly VOC emission rate is 0.19 lb/hour. The maximum annual potential VOC emissions are based on operating 52 hours per year. Annual emissions = 0.66 lb/hr x 52 hours/year x 1 ton/2,000 lbs = 1.72 E-02 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE- NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3 g/hp-hr (NOX + NMHC)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

<u>Visible Emissions Limitation:</u> Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

<u>Visible Emissions Limitation:</u> Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor __ of __

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor __ of __

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ___________ ☐ Previously Submitted, Date _________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: See Application Support Document

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ___________ ☐ Previously Submitted, Date _________

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ___________ ☐ Previously Submitted, Date _________
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. 5 ☐ Previously Submitted, Date _________
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ___________
   Test Date(s)/Pollutant(s) Tested: ___________________________
   ☐ Previously Submitted, Date: ________
   Test Date(s)/Pollutant(s) Tested: ___________________________
   ____
   ☐ To be Submitted, Date (if known): ____________
   Test Date(s)/Pollutant(s) Tested: ___________________________
   ____
   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ___________ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: See Section 3 of Application Support Document
2.	Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: See Section 4 of Application Support Document
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:____________ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: ___________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: __________ [ ] Not Applicable

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Safe Shutdown Generator.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code: C	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes ☒ No

9. Package Unit:
   Manufacturer: TBD Model Number: TBD

10. Generator Nameplate Rating: 750 kW standby rating

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:
2. Maximum Production Rate: 1,102 HP (approximate)
3. Maximum Heat Input Rate:
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule:
6. Operating Capacity/Schedule Comment: It is conservatively estimated that the safe shutdown generator will operate approximately 200 hours per year. Because this is emergency equipment, a maximum operating schedule is not requested. Because a specific manufacturer and model has not been determined, the maximum production rate provided is an approximate value.

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Safe Shutdown Generator		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 24 feet	7. Exit Diameter: 0.83 feet
8. Exit Temperature: 816°F	9. Actual Volumetric Flow Rate: 6,310 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate:		12. Nonstack Emission Point Height:
13. Emission Point UTM Coordinates... Zone: 17 East (km): 447.623 North (km): 3128.018		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): ULSFO used in the safe shutdown generator		
2. Source Classification Code (SCC): 20100301	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 0.15	5. Maximum Annual Rate: 30	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 137 (HHV)
10. Segment Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters. The annual rate is based on an estimated 200 hours per year of operation.		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			**EL**
NOX			**EL**
PM			**EL**
PM10			**NS**
SO2			**NS**
VOC			**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 1.11 lb/hour 0.11 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly CO emission rate is 1.11 lb/hour. The maximum annual potential CO emissions are based on operating 200 hours per year. Annual emissions = 1.11 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.11 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE - NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.6 g/hp-hr	4. Equivalent Allowable Emissions:
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 9.64 lb/hour 0.96 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly NO_x emission rate is 9.64 lb/hour. The maximum annual potential NO_x emissions are based on operating 200 hours per year. Annual emissions = 9.64 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.96 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 4.8 g/hp-hr (NOX + NMHC)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.29 lb/hour 0.029 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM/PM10 emission rate is 0.29 lb/hour. The maximum annual potential PM emissions are based on operating 200 hours per year. Annual emissions = 0.29 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.029 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.011 lb/hour 0.0011 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data using fuel oil with 0.0015 percent sulfur content. The maximum hourly SO_2 emission rate is 0.11 lb/hour. The maximum annual potential SO_2 emissions are based on operating 200 hours per year. Annual emissions = 0.11 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.0011 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on using fuel oil with 0.0015 percent sulfur content. The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>Allowable Emissions</u> Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.66 lb/hour 0.066 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly VOC emission rate is 0.66 lb/hour. The maximum annual potential VOC emissions are based on operating 200 hours per year. Annual emissions = 0.66 lb/hr x 200 hours/year x 1 ton/2,000 lbs = 0.066 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE- NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 4.8 g/hp-hr (NOX + NMHC)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

<u>Visible Emissions Limitation:</u> Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

<u>Visible Emissions Limitation:</u> Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[x] Attached, Document ID: See Application Support Document

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
[x] Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[x] Attached, Document ID: Attach. 5 ☐ Previously Submitted, Date ________
☐ Not Applicable

6. Compliance Demonstration Reports/Records
☐ Attached, Document ID: ________
Test Date(s)/Pollutant(s) Tested: ________
☐ Previously Submitted, Date: ________
Test Date(s)/Pollutant(s) Tested: ________
____
☐ To be Submitted, Date (if known): ________
Test Date(s)/Pollutant(s) Tested: ________
____
[x] Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
☐ Attached, Document ID: ________ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: See Section 3 of Application Support Document
2.	Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: See Section 4 of Application Support Document
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:____________ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: ___________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: __________ [ ] Not Applicable

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one) ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent). ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions. [x] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.				
2. Description of Emissions Unit Addressed in this Section: Mechanical Draft Cooling Tower.				
3. Emissions Unit Identification Number:				
4. Emissions Unit Status Code: C	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes [x] No
9. Package Unit: Manufacturer: Model Number:				
10. Generator Nameplate Rating:				
11. Emissions Unit Comment:				

<u>Emissions Unit Control Equipment</u>

1. Control Equipment/Method(s) Description: Drift eliminators
2. Control Device or Method Code(s): 152

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: 111,130 gpm design water flow		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate:		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Cooling Tower		2. Emission Point Type Code: 3
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 56 ft	7. Exit Diameter: 30 ft
8. Exit Temperature: 91.52 F	9. Actual Volumetric Flow Rate: 1,003,756 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate:		12. Nonstack Emission Point Height:
13. Emission Point UTM Coordinates... Zone: 17 East (km): 447.516 North (km): 3128.009		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: The cooling tower design is an 8 cell mechanical draft cooling tower. The information given in fields 5 through 9 is for each cell.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Drift loss			
2. Source Classification Code (SCC): 38500101		3. SCC Units: Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate: 6,670	5. Maximum Annual Rate: 58,409,928		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment: The maximum hourly and annual rates shown in Fields 4 and 5 are the design water circulation rate.			

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment:			

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			**WS**
PM10			**WS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.66 lb/hour 2.89 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data, mass balance	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on the design cooling tower water flow, the design drift rate and the cycled water total dissolved solids. Design water flow = 111,130 gpm = 55,609,452 lb/hr Design drift rate = 0.0005% of design water flow Total dissolved solids = 2,380 ppm Hourly PM/PM10 emissions = 55,542,774 lb/hr x 0.0005/100 x 2,380 ppm/1,000,000 = 0.66 lb/hr The maximum annual PM/PM10 emissions = 0.66 lb/hr x 8,760 hr/yr x ton/2,000 lb = 2.89 tpy	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor __ of __

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor __ of __

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Attach. 2 [ ] Previously Submitted, Date ________
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: NA [ ] Previously Submitted, Date ________
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: See Section 3 of Application Support Document
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: ________ [ ] Previously Submitted, Date ________ [x] Not Applicable (construction application)
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: ________ [ ] Previously Submitted, Date ________ [x] Not Applicable
6.	Compliance Demonstration Reports/Records [ ] Attached, Document ID: ________ Test Date(s)/Pollutant(s) Tested: ________ [ ] Previously Submitted, Date: ________ Test Date(s)/Pollutant(s) Tested: ________ [ ] To be Submitted, Date (if known): ________ Test Date(s)/Pollutant(s) Tested: ________ [x] Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute [ ] Attached, Document ID: ________ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications

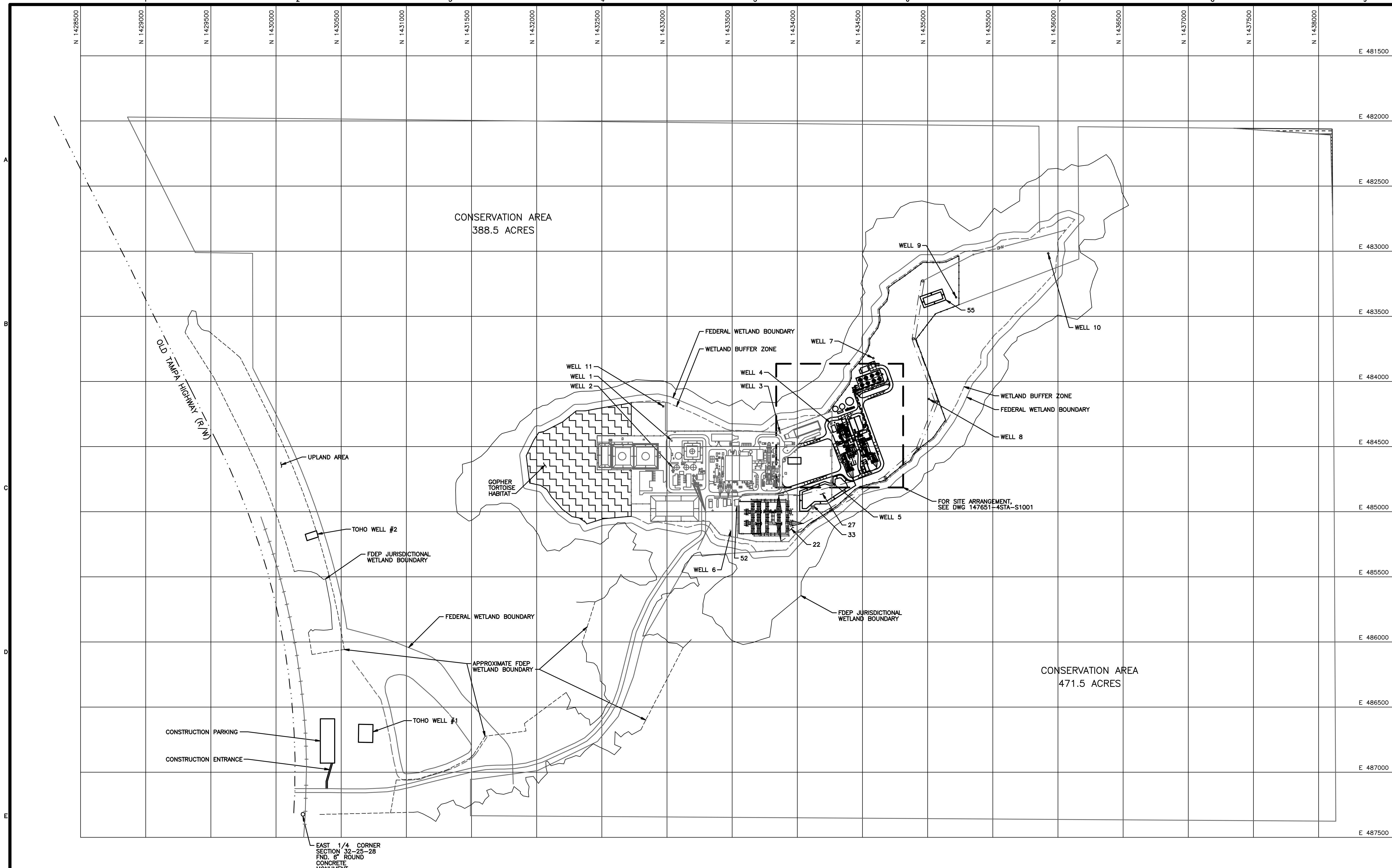
1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: See Section 3 of the Application Support Document
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: _See Section 4 of Application Support Document
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:____________ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: [ ] Attached, Document ID: ___________
2. Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3. Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: __________ [ ] Not Applicable

Additional Requirements Comment

Attachment 1
Facility Plot Plan



FACILITIES LEGEND	
ID	FACILITY
22	SUBSTATION
27	DETENTION POND
33	DETENTION POND DISCHARGE
52	SWITCHYARD CONTROL BUILDING (EXISTING)
55	PERC POND

LEGEND

- WETLAND BUFFER ZONE
- OVERHEAD TRANSMISSION LINE
- FDEP JURISDICTIONAL WETLAND BOUNDARY
- FENCE LINE
- GOPHER TORTOISE HABITAT

NOTES

FOR PERMITTING PURPOSE ONLY
APPROVED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0	04/01/2008	ISSUED FOR CONSTRUCTION	MRR	JMS	MJS	MJS	SAA

300' 150' 0 300' 600'
SCALE: 1"=300'

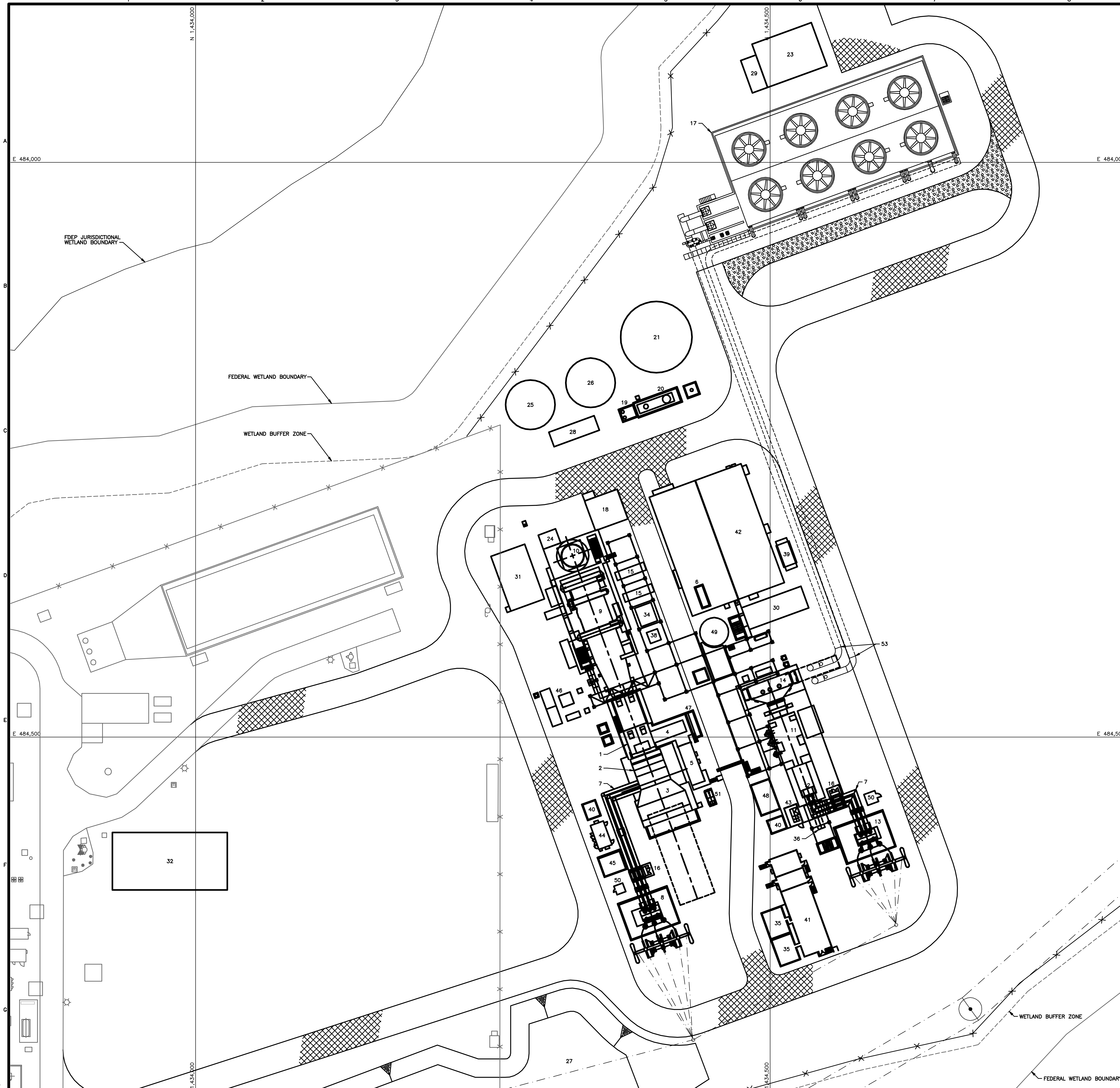
I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE REG NO.

BLACK & VEATCH CORPORATION
ENGINEER JMS DRAWN MRR
CHECKED MJS DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4

SITE PLAN

PROJECT DRAWING NUMBER 147651-4STA-S1000 REV 0
CODE
AREA
FIG 2.1-3



FACILITIES LEGEND

ID	FACILITY
1	COMBUSTION TURBINE
2	COMBUSTION TURBINE GENERATOR
3	COMBUSTION TURBINE INLET AIR FILTER
4	COMBUSTION TURBINE ACCESSORY MODULE
5	COMBUSTION TURBINE ELECTRICAL PACKAGE
6	COMBUSTION TURBINE WASH WATER SKID
7	ISOLATED PHASE BUS DUCT
8	CT GENERATOR STEPUP TRANSFORMER
9	HEAT RECOVERY STEAM GENERATOR
10	HEAT RECOVERY STEAM GENERATOR EXHAUST STACK
11	STEAM TURBINE
12	STEAM TURBINE GENERATOR
13	STEAM TURBINE GENERATOR STEPUP TRANSFORMER
14	CONDENSER
15	BOILER FEED PUMPS
16	GENERATOR BREAKER
17	COOLING TOWER
18	CO2, HYDROGEN, & NITROGEN STORAGE
19	WASTEWATER COLLECTION SUMP
20	OIL/WATER SEPARATOR
21	DEMINERALIZED WATER TANK
23	COOLING TOWER CYCLE CHEMICAL FEED STRUCTURE
24	CEMS ENCLOSURE
25	FIRE PROTECTION/SERVICE WATER TANK
26	FIRE PROTECTION/SERVICE WATER TANK
27	DETENTION POND
28	FIRE PUMP ENCLOSURE
29	COOLING TOWER ELECTRICAL ENCLOSURE
30	CLOSED CYCLE COOLING WATER PUMPS/HEAT EXCHANGER
31	AMMONIA STORAGE TANK
32	GAS METERING & AIR PRESSURE REGULATION STATION
34	HRSG BLOWDOWN TANK
35	UNIT AUXILIARY TRANSFORMER
36	STEAM TURBINE GENERATOR ROTOR REMOVAL
37	EMERGENCY MAKE-UP WELL
38	BLOWDOWN TANK SUMP & PUMPS
39	SAFE SHUTDOWN DIESEL GENERATOR
40	EXCITATION TRANSFORMER
41	POWER DISTRIBUTION CENTER
42	MISCELLANEOUS SERVICES BUILDING
43	STATIC EXCITATION ENCLOSURE
44	LOAD COMMUTATED INVERTER (LCI)
45	ISOLATION TRANSFORMER
46	FUEL GAS CONDITIONING EQUIPMENT
47	ACCESSORY MODULE CONTAINMENT TRENCH AND VAULT
48	STEAM TURBINE LUBE OIL SKID AREA
49	CONDENSATE STORAGE TANK
50	DELUGE HOUSE
51	CO2 FIRE PROTECTION SKID
53	CIRCULATING WATER PIPE

LEGEND

WETLAND BUFFER ZONE
OVERHEAD TRANSMISSION LINE
FDEP JURISDICTIONAL WETLAND BOUNDARY
FENCE LINE
GOPHER TORTOISE HABITAT

NOTES

FOR PERMITTING PURPOSE ONLY
APPROVED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0	04/01/2008	ISSUED FOR CONSTRUCTION	MRR	JMS	MJS	MJS	SAA

SCALE: 1"=30'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED ____________
DATE ____________ REG NO. ____________

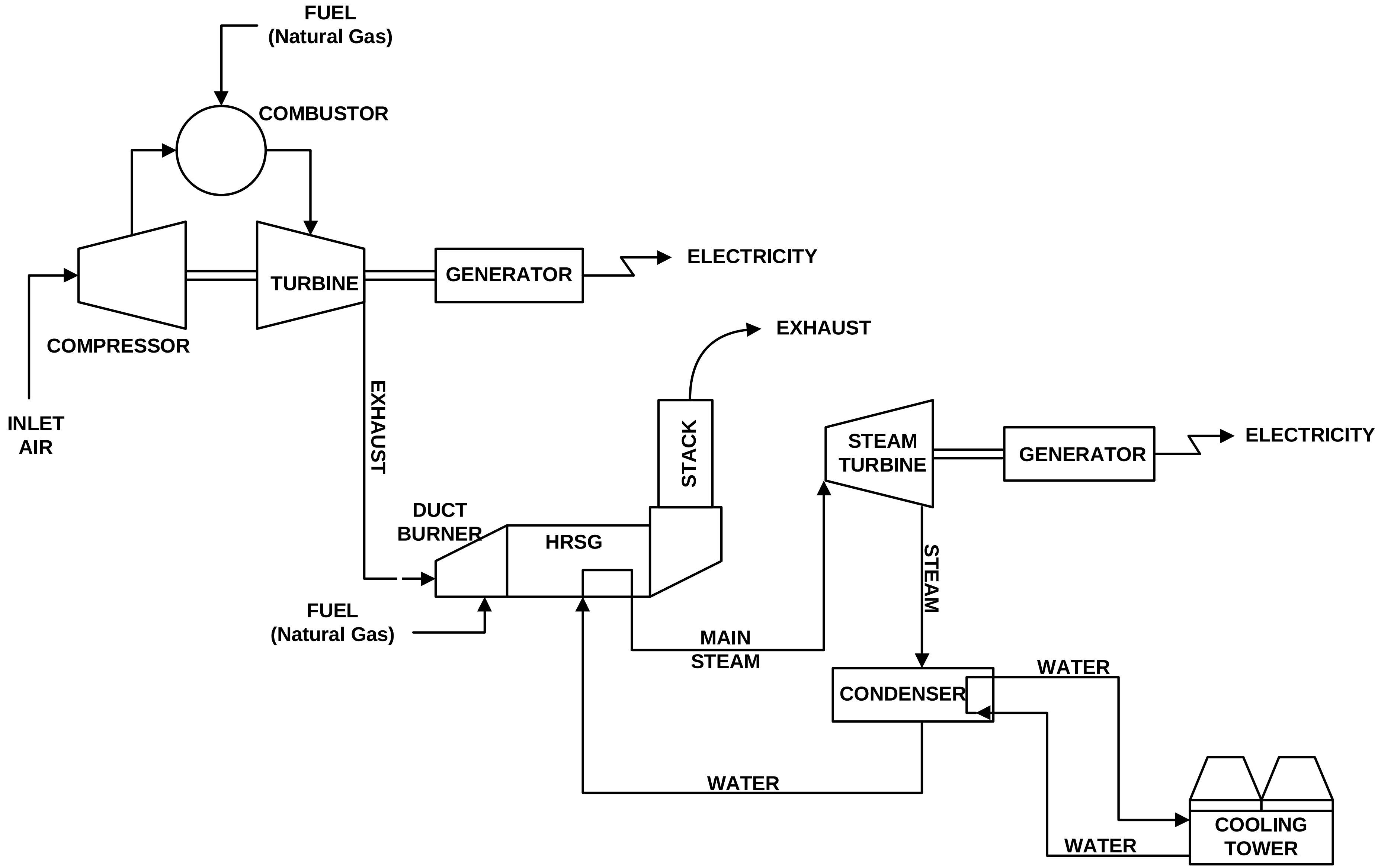
BLACK & VEATCH CORPORATION
ENGINEER JMS | DRAWN MRR | CHECKED MJS | DATE 04/01/2008

FLORIDA MUNICIPAL POWER AGENCY
CANE ISLAND POWER PARK UNIT 4
UNIT 4 SITE ARRANGEMENT

PROJECT / DRAWING NUMBER: 147651-4STA-S1001 | REV 0
CODE
AREA

FIGURE 3.1-1

Attachment 2
Process Flow Diagram



Cane Island Unit 4
Combined Cycle Combustion Turbine
Process Flow Diagram

Attachment 3

Precautions to Prevent Emissions of Unconfined Particulate Matter

Attachment 3
Precautions to Prevent Emissions of Unconfined Particulate Matter

Reasonable precautions to control unconfined emissions of particulate matter as listed in Rule 62-296.320(4), FAC will be employed as appropriate. Additionally, watering will be used as needed to prevent emissions from unpaved areas.

Attachment 4
Rule Applicability Analysis

Attachment 4
Rule Applicability Analysis

Rule Applicability Analysis for the Entire Facility

- State: Rule 62-4.070 – Standards for Issuing or Denying Permits.
- State: Rule 62-210.300 – Permits Required.
- State: Rule 62-212.300 – General Preconstruction Review Requirements.
- State: Rule 62-212.400 – Prevention of Significant Deterioration.

Rule Applicability Analysis for the GE 7FA Combined Cycle Combustion Turbine

Only Initial Notification Applicable - Federal: 40 CFR Part 63 Subpart YYYY, *National Emission Standards for Stationary Combustion Turbines*. This standard is applicable to combustion turbine units at a facility that is a major source of HAPs. Natural gas fired turbines are exempt from the emission limit requirements but will have to file initial notification.

- Applicable - Federal: 40 CFR Part 60 Subpart KKKK – *Standards of Performance for Stationary Gas Turbines* – This rule applies to Unit 1, including the duct burner.
- Federal: 40 CFR Part 60 Subpart A – *General Provisions*.
- Federal: 40 CFR Part 72 – *Permits Regulation (Acid Rain)*
- Federal: 40 CFR Part 75 – *Continuous Emissions Monitoring*
- State: Rule 62-204.800(8)(d) – *General Provisions Adopted – 40 CFR 60 Subpart A – General Provisions adopted by reference, with exceptions*.
- State: Rule 62-212.400 – *Prevention of Significant Deterioration* applies to CO, NO_x, SO_2, PM, PM_{10}, and sulfuric acid mist. See the technical support document accompanying this application for a more detailed discussion of PSD applicability.
- State: Rule 62-212.300 – *General Preconstruction Review Requirements*. Applies to applicable pollutants not subject to PSD review.
- State: Rule 62-297.310 – *General Compliance Test Requirements*.

Rule Applicability Analysis for the Emergency Diesel Fire Pump and the Safe Shutdown Generator

Rule Applicability Analysis for the Emergency Diesel Fire Pump

NOT APPLICABLE - Federal: 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Reciprocating Internal Combustion Engines*. This standard is only applicable to reciprocating internal combustion engines (RICE) rated greater than 500 BHP. The fire pump is rated at 290 BHP, thus 40 CFR 63 Subpart ZZZZ does not apply to the emergency diesel fire pump.

The following rules are APPLICABLE to the Emergency Diesel Fire Pump:
Federal: 40 CFR 60 Subpart IIII, *New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines*
The emergency diesel fire pump will be subject to the manufacturer's certification requirements of compliance under the NSPS for RICE (40 CFR Part 60, Subpart IIII). The rule provides various emission standards based on the engine's classification, use, manufacture date, and engine size. The fire pump engines will need to meet the emission requirements listed in Table 4 of the regulation.

State: Rule 62-212.400 – *Prevention of Significant Deterioration (PSD)*

Rule Applicability Analysis for the Safe Shutdown Generator

The following rules are APPLICABLE to the Safe Shutdown Generator:

Federal: 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Reciprocating Internal Combustion Engines*.
The safe shutdown generator is rated greater than the 500 BHP applicability threshold and thus is an affected unit under the RICE MACT. However, a new emergency stationary RICE located at a major source of HAPs is subject only to the initial notification requirements of 40 CFR 63.6645(d). Since the purpose of the safe shutdown generator will be for emergency situations when the normal source of power is not available to the facility, it will be considered as emergency stationary RICE and, therefore, subject only to the initial notification requirements of the RICE MACT.

Federal: 40 CFR 60 Subpart IIII, *New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines*
The safe shutdown generator will be subject to the manufacturer's certification requirements of compliance under the NSPS for RICE (40 CFR Part 60, Subpart IIII). The rule provides various emission standards based on the engine's classification, use, manufacture date, and engine size. The applicable standards associated with the safe shutdown generator will be dependent on the engine model year. Therefore, the exact emission standards applicable to the safe shutdown generator cannot be identified until the engine is purchased.

State: Rule 62-212.400 – Prevention of Significant Deterioration (PSD)

Attachment 5
Operation and Maintenance Plan

Attachment 5
Operation and Maintenance Plan

The emission units will be operated and maintained in accordance with manufacturer's recommendations, operations and maintenance experience, and technical guidance taking into account protection of equipment, safety of personnel and other factors as deemed necessary to maintain compliance with the permitted limits.

Attachment 6
Description of Stack Sampling Facilities

Attachment 6
Description of Stack Sampling Facilities

Unit 4 will be equipped with stack sampling facilities appropriate for performing required stack testing. A detailed description of stack sampling facilities is not available at this time. When available, if requested by the Department, the stack sampling facilities description will be supplied to the Department.

Attachment 7
Acid Rain/CAIR/CAMR Program Forms

Attachment 7
Acid Rain/CAIR/CAMR Program Forms

In accordance with 62-213.420 F.A.C., since Unit 4 is not covered by a Title V permit prior to May 1, 2008, a certified CAIR Part form and a certified Hg Budget Part form will be submitted to the Department prior to the unit commencing operation. FMPA understands that the forms will be incorporated into the Title V permit upon issuance of the revised, or renewal Title V permit, whichever comes first.

In accordance with 62-214.320, F.A.C., FMPA will submit a complete Acid Rain Part application governing Unit 4 operation to the Department at least 24 months before the date on which Unit 4 commences operation. Cane Island Unit 4 is expected to be operational May 1, 2011. The Acid Rain Part application will be submitted before May 1, 2009.

Appendix B

Combustion Turbine Performance Data and Ancillary Equipment Specification Sheets

Combustion Turbine Performance Data

24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	19	19	19	19	19	59	59	59	59	59	59	59
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Ambient Conditions												
Ambient Temperature, F	19.0	19.0	19.0	19.0	19.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
Ambient Relative Humidity, %	58.0	58.0	58.0	58.0	58.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Atmospheric Pressure, psia	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660
Combustion Turbine Performance												
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	85	85	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	19.0	19.0	19.0	19.0	19.0	59.0	59.0	52.6	52.6	59.0	59.0	59.0
CTG Compr. Inlet Relative Humidity, %	58.3	58.3	58.3	58.3	58.3	60.2	60.2	92.9	92.9	60.2	60.2	60.2
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	15.0	15.0	9.5	6.5	5.3	13.1	13.1	13.4	13.4	8.7	6.1	5.1
CTG Load Level (percent of Base Load)	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
Gross CTG Output, kW	190,700	190,700	143,000	95,400	76,300	173,500	173,500	176,800	176,800	130,200	86,800	69,400
Gross CTG Heat Rate, Btu/kWh (LHV)	9,337	9,337	9,775	11,720	12,960	9,522	9,522	9,486	9,486	10,070	12,090	13,360
Gross CTG Heat Rate, Btu/kWh (HHV)	10,357	10,357	10,843	13,001	14,376	10,563	10,563	10,523	10,523	11,171	13,411	14,820
CTG Heat Input, MBtu/h (LHV)	1,780.6	1,780.6	1,397.8	1,118.1	988.9	1,652.1	1,652.1	1,677.1	1,677.1	1,311.1	1,049.4	927.2
CTG Heat Input, MBtu/h (HHV)	1,975.2	1,975.2	1,550.6	1,240.3	1,096.9	1,832.6	1,832.6	1,860.4	1,860.4	1,454.4	1,164.1	1,028.5
CTG Water/Steam Injection Flow, lb/h	0	0	0	0	0	0	0	0	0	0	0	0
Injection Fluid/Fuel Ratio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTG Exhaust Flow, lb/h	3,867,000	3,867,000	3,042,000	2,489,000	2,248,000	3,590,000	3,590,000	3,634,000	3,634,000	2,895,000	2,395,000	2,190,000
CTG Exhaust Temperature, F	1,074	1,074	1,130	1,184	1,200	1,115	1,115	1,109	1,109	1,160	1,200	1,200
Combustion Turbine Fuel												
Total CTG Fuel Flow, lb/h	85,540	85,540	67,150	53,710	47,500	79,370	79,370	80,570	80,570	62,990	50,410	44,540
CTG Fuel Temperature, F	365	365	365	365	365	365	365	365	365	365	365	365
CTG Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
CTG Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091
HHV/LHV Ratio	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093
CTG Fuel Composition (Ultimate Analysis by Weight)												
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.78%	73.78%	73.78%	73.78%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%
H2	24.02%	24.02%	24.02%	24.02%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%
N2	0.59%	0.59%	0.59%	0.59%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00

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24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	19	19	19	19	19	59	59	59	59	59	59	59
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust												
CTG Exhaust Analysis (Volume Basis - Wet)												
Ar	0.94%	0.94%	0.94%	0.94%	0.94%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.94%
CO2	3.87%	3.87%	3.86%	3.78%	3.70%	3.86%	3.86%	3.86%	3.86%	3.80%	3.67%	3.55%
H2O	7.70%	7.70%	7.69%	7.52%	7.37%	8.46%	8.46%	8.70%	8.70%	8.35%	8.11%	7.88%
N2	74.92%	74.92%	74.93%	75.00%	75.06%	74.32%	74.32%	74.14%	74.14%	74.37%	74.46%	74.55%
O2	12.56%	12.56%	12.58%	12.76%	12.93%	12.43%	12.43%	12.36%	12.36%	12.56%	12.82%	13.09%
SO2, (after SO2 oxidation)	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00009%
SO3, (after SO2 oxidation)	0.00003%	0.00003%	0.00003%	0.00003%	0.00002%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00002%	0.00002%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.48	28.48	28.48	28.49	28.50	28.39	28.39	28.37	28.37	28.40	28.42	28.43
Specific Volume, ft^3/lb	38.01	38.01	39.92	41.56	42.07	39.32	39.32	39.18	39.18	40.86	42.11	42.20
Specific Volume, scf/lb	13.32	13.32	13.32	13.32	13.31	13.36	13.36	13.37	13.37	13.36	13.35	13.35
Exhaust Gas Flow, acfm	2,449,745	2,449,745	2,023,944	1,724,047	1,576,223	2,352,647	2,352,647	2,373,002	2,373,002	1,971,495	1,680,891	1,540,300
Exhaust Gas Flow, scfm	858,474	858,474	675,324	552,558	498,681	799,373	799,373	809,776	809,776	644,620	532,888	487,275
CTG NOx Emissions (Without Post Combustion Emissions Control)												
NOx, ppmvd (dry, 15% O2)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd (dry)	11.10	11.10	11.10	10.80	10.60	11.10	11.10	11.20	11.20	11.00	10.60	10.20
NOx, ppmvw (wet)	10.20	10.20	10.20	10.00	9.80	10.20	10.20	10.20	10.20	10.00	9.70	9.40
NOx, lb/h as NO2	63.9	63.9	50.2	40.2	35.5	59.3	59.3	60.2	60.2	47.1	37.7	33.3
NOx, lb/MBtu (LHV)	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359
NOx, lb/MBtu (HHV)	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324
CTG CO Emissions (Without Post Combustion Emissions Control)												
CO, ppmvd (dry, 15% O2)	4.40	4.10	7.30	7.50	7.70	4.10	4.10	4.20	4.10	7.40	7.70	7.90
CO, ppmvd (dry)	5.40	5.10	9.00	9.00	9.00	5.10	5.10	5.20	5.10	9.00	9.00	9.00
CO, ppmvw (wet)	5.00	4.70	8.30	8.30	8.30	4.70	4.60	4.80	4.70	8.20	8.30	8.30
CO, lb/h	19.0	17.7	25.0	20.4	18.4	16.6	16.5	17.1	16.7	24.0	20.0	17.9
CO, lb/MBtu (LHV)	0.0107	0.0100	0.0179	0.0182	0.0186	0.0101	0.0100	0.0102	0.0100	0.0183	0.0191	0.0193
CO, lb/MBtu (HHV)	0.0096	0.0090	0.0161	0.0164	0.0168	0.0091	0.0090	0.0092	0.0090	0.0165	0.0172	0.0174
CTG SO2 Emissions (After SO2 Oxidation, Without Post Combustion Emissions Control)												
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.9100	0.9100	0.9100	0.9100	0.9083	0.9083	0.9083	0.9083	0.9083	0.9083	0.9083	0.9083
SO2, ppmvd (dry)	1.1213	1.1213	1.1188	1.0922	1.0658	1.1243	1.1243	1.1294	1.1294	1.1053	1.0671	1.0290
SO2, ppmvw (wet)	1.0349	1.0349	1.0328	1.0100	0.9872	1.0291	1.0291	1.0311	1.0311	1.0130	0.9805	0.9479
SO2, lb/h	9.0027	9.0027	7.0672	5.6527	4.9885	8.3356	8.3356	8.4616	8.4616	6.6153	5.2941	4.6777
SO2, lb/MBtu (LHV)	0.0051	0.0051	0.0051	0.0051	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050
SO2, lb/MBtu (HHV)	0.0046	0.0046	0.0046	0.0046	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045

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24-Jan-08
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Black & Veatch Project 147651
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Case Number	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	19	19	19	19	19	59	59	59	59	59	59	59
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust - continued												
CTG UHC Emissions (Without Post Combustion Emissions Control)												
UHC, ppmvd (dry, 15% O2)	6.2	6.2	6.2	6.3	6.4	6.2	6.2	6.2	6.2	6.3	6.5	6.7
UHC, ppmvd (dry)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.7	7.7	7.6	7.6	7.6
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	15.2	15.2	12.0	10.0	8.9	14.2	14.2	14.4	14.4	11.4	9.5	8.7
UHC, lb/MBtu as CH4 (LHV)	0.0086	0.0086	0.0086	0.0089	0.0090	0.0086	0.0086	0.0086	0.0086	0.0087	0.0090	0.0093
UHC, lb/MBtu as CH4 (HHV)	0.0077	0.0077	0.0077	0.0081	0.0081	0.0077	0.0077	0.0077	0.0077	0.0079	0.0081	0.0084
CTG VOC Emissions (Without Post Combustion Emissions Control)												
VOC percentage of UHC	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
VOC, ppmvd (dry, 15% O2)	1.2	1.2	1.2	1.3	1.3	1.2	1.2	1.2	1.2	1.3	1.3	1.3
VOC, ppmvd (dry)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
VOC, ppmvw (wet)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	3.0	3.0	2.4	2.0	1.8	2.8	2.8	2.9	2.9	2.3	1.9	1.7
VOC, lb/MBtu as CH4 (LHV)	0.0017	0.0017	0.0017	0.0018	0.0018	0.0017	0.0017	0.0017	0.0017	0.0017	0.0018	0.0019
VOC, lb/MBtu as CH4 (HHV)	0.0015	0.0015	0.0015	0.0016	0.0016	0.0015	0.0015	0.0015	0.0015	0.0016	0.0016	0.0017
CTG PM10 Emissions (without the Effects of SO2 Oxidation)												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV)	0.0051	0.0051	0.0064	0.0080	0.0091	0.0054	0.0054	0.0054	0.0054	0.0069	0.0086	0.0097
PM10, lb/MBtu (HHV)	0.0046	0.0046	0.0058	0.0073	0.0082	0.0049	0.0049	0.0048	0.0048	0.0062	0.0077	0.0088
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV)	0.0101	0.0101	0.0129	0.0161	0.0182	0.0109	0.0109	0.0107	0.0107	0.0137	0.0172	0.0194
PM10, lb/MBtu (HHV)	0.0091	0.0091	0.0116	0.0145	0.0164	0.0098	0.0098	0.0097	0.0097	0.0124	0.0155	0.0175

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24-Jan-08
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Case Number	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	19	19	19	19	19	59	59	59	59	59	59	59
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
HRSG Duct Burners												
Duct Burner Fuel												
Duct Burner Heat Input, MBtu/h (LHV)	534.8	0.0	0.0	0.0	0.0	534.8	0.0	534.8	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	593.2	0.0	0.0	0.0	0.0	593.2	0.0	593.2	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	25,691	0	0	0	0	25,691	0	25,691	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)												
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%
H2	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%
N2	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Duct Burner Emissions												
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	0.0%	0.0%	0.0%	0.0%	10.0%	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	3.042	0.000	0.000	0.000	0.000	3.042	0.000	3.042	0.000	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.422	0.000	0.000	0.000	0.000	0.422	0.000	0.422	0.000	0.000	0.000	0.000
DB NOx, lb/h	47.50	0.00	0.00	0.00	0.00	47.50	0.00	47.50	0.00	0.00	0.00	0.00
DB CO, lb/h	23.70	0.00	0.00	0.00	0.00	23.70	0.00	23.70	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	35.60	0.00	0.00	0.00	0.00	35.60	0.00	35.60	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	2.40	0.00	0.00	0.00	0.00	2.40	0.00	2.40	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	5.90	0.00	0.00	0.00	0.00	5.90	0.00	5.90	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	14.20	0.00	0.00	0.00	0.00	14.20	0.00	14.20	0.00	0.00	0.00	0.00

Owner FMPA
Plant Cane Island Power Plant
Project No. 147651.0035
Title 1x1 Emissions Estimates, Revision 1

24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	19	19	19	19	19	59	59	59	59	59	59	59
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Stack Emissions												
Stack Exhaust Analysis - Volume Basis - Wet												
Ar	0.93%	0.94%	0.94%	0.94%	0.94%	0.92%	0.93%	0.92%	0.93%	0.93%	0.93%	0.94%
CO2	4.98%	3.87%	3.86%	3.78%	3.70%	5.04%	3.86%	5.03%	3.86%	3.80%	3.67%	3.55%
H2O	9.85%	7.70%	7.69%	7.52%	7.37%	10.75%	8.46%	10.96%	8.70%	8.35%	8.11%	7.88%
N2	74.08%	74.92%	74.93%	75.00%	75.06%	73.43%	74.32%	73.26%	74.14%	74.37%	74.46%	74.55%
O2	10.16%	12.56%	12.58%	12.76%	12.93%	9.86%	12.43%	9.83%	12.36%	12.56%	12.82%	13.09%
SO2 (after SO2 oxidation)	0.000120%	0.000100%	0.000100%	0.000100%	0.000100%	0.000120%	0.000100%	0.000120%	0.000100%	0.000100%	0.000100%	0.000090%
SO3 (after SO2 oxidation)	0.000040%	0.000030%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000030%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	166	178	166	157	154	166	180	167	180	169	161	158
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18	18	18	18	18	18
Stack Flow, lb/h	3,892,687	3,866,996	3,041,997	2,488,998	2,247,998	3,615,687	3,589,996	3,659,687	3,633,996	2,894,997	2,394,998	2,189,998
Stack Flow, scfm	868,719	858,474	675,324	552,558	498,681	809,312	799,373	819,771	809,776	644,620	532,888	487,275
Stack Flow, acfm	1,047,783	1,056,336	815,256	657,096	590,100	976,839	986,053	990,556	999,956	781,168	637,469	580,350
Stack Exit Velocity, ft/s	69.0	69.0	53.0	43.0	39.0	64.0	65.0	65.0	65.0	51.0	42.0	38.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)												
NOx, ppmvd (dry, 15% O2)	12.1	9.0	9.0	9.0	9.0	12.2	9.0	12.2	9.0	9.0	9.0	9.0
NOx, ppmvd (dry)	19.6	11.1	11.1	10.8	10.6	20.3	11.1	20.3	11.2	11.0	10.6	10.2
NOx, ppmvw (wet)	17.6	10.2	10.2	10.0	9.8	18.1	10.2	18.1	10.2	10.0	9.7	9.4
NOx, lb/h as NO2	111.4	63.9	50.2	40.2	35.5	106.8	59.3	107.7	60.2	47.1	37.7	33.3
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0481	0.0359	0.0359	0.0359	0.0359	0.0488	0.0359	0.0487	0.0359	0.0359	0.0359	0.0359
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0434	0.0324	0.0324	0.0324	0.0324	0.0440	0.0324	0.0439	0.0324	0.0324	0.0324	0.0324
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)												
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, ppmvd (dry)	3.2	2.5	2.5	2.4	2.3	3.3	2.5	3.3	2.5	2.4	2.3	2.3
NOx, ppmvw (wet)	2.9	2.3	2.3	2.2	2.2	3.0	2.3	3.0	2.3	2.2	2.2	2.1
NOx, lb/h as NO2	18.5	14.2	11.2	8.9	7.9	17.5	13.2	17.6	13.4	10.5	8.4	7.4
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
SCR NH3 slip, ppmvd (dry, 15% O2)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
SCR NH3 slip, lb/h	17.1	13.2	10.3	8.3	7.3	16.2	12.2	16.3	12.4	9.7	7.7	6.8
Stack CO Emissions												
CO, ppmvd (dry, 15% O2)	7.6	4.1	7.3	7.5	7.7	7.6	4.1	7.6	4.1	7.4	7.7	7.9
CO, ppmvd (dry)	12.3	5.1	9.0	9.0	9.0	12.6	5.1	12.6	5.1	9.0	9.0	9.0
CO, ppmvw (wet)	11.1	4.7	8.3	8.3	8.3	11.3	4.6	11.2	4.7	8.2	8.3	8.3
CO, lb/h	42.8	17.7	25.0	20.4	18.4	40.4	16.5	40.8	16.7	24.0	20.0	17.9
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0185	0.0100	0.0179	0.0182	0.0186	0.0185	0.0100	0.0185	0.0100	0.0183	0.0191	0.0193
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0166	0.0090	0.0161	0.0164	0.0168	0.0166	0.0090	0.0166	0.0090	0.0165	0.0172	0.0174
Stack SO2 Emissions, after SO2 Oxidation												
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO2, ppmvd (dry, 15% O2)	0.84	0.88	0.88	0.88	0.88	0.84	0.88	0.84	0.88	0.88	0.88	0.88
SO2, ppmvd (dry)	1.36	1.09	1.09	1.06	1.03	1.40	1.09	1.40	1.10	1.07	1.04	1.00
SO2, ppmvw (wet)	1.23	1.00	1.00	0.98	0.96	1.25	1.00	1.24	1.00	0.98	0.95	0.92
SO2, lb/h	10.81	8.73	6.86	5.48	4.84	10.23	8.09	10.34	8.21	6.42	5.14	4.54
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0047	0.0049	0.0049	0.0049	0.0049	0.0047	0.0049	0.0047	0.0049	0.0049	0.0049	0.0049
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0042	0.0044	0.0044	0.0044	0.0044	0.0042	0.0044	0.0042	0.0044	0.0044	0.0044	0.0044

Owner FMPA
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Project No. 147651.0035
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24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	19	19	19	19	19	59	59	59	59	59	59	59
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Stack Emissions - continued												
Stack UHC Emissions												
UHC, ppmvd (dry, 15% O2)	15.8	6.2	6.2	6.3	6.4	16.4	6.2	16.2	6.2	6.3	6.5	6.7
UHC, ppmvd	25.6	7.6	7.6	7.6	7.6	27.2	7.6	27.0	7.7	7.6	7.6	7.6
UHC, ppmvw	23.1	7.0	7.0	7.0	7.0	24.3	7.0	24.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	50.8	15.2	12.0	10.0	8.9	49.8	14.2	50.0	14.4	11.4	9.5	8.7
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0220	0.0086	0.0086	0.0089	0.0090	0.0228	0.0086	0.0226	0.0086	0.0087	0.0090	0.0093
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0198	0.0077	0.0077	0.0081	0.0081	0.0205	0.0077	0.0204	0.0077	0.0079	0.0081	0.0084
Stack VOC Emissions												
VOC, ppmvd (dry, 15% O2)	1.7	1.2	1.2	1.3	1.3	1.7	1.2	1.7	1.2	1.3	1.3	1.3
VOC, ppmvd (dry)	2.7	1.5	1.5	1.5	1.5	2.8	1.5	2.8	1.5	1.5	1.5	1.5
VOC, ppmvw (wet)	2.5	1.4	1.4	1.4	1.4	2.5	1.4	2.5	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	5.4	3.0	2.4	2.0	1.8	5.2	2.8	5.3	2.9	2.3	1.9	1.7
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0023	0.0017	0.0017	0.0018	0.0018	0.0024	0.0017	0.0024	0.0017	0.0017	0.0018	0.0019
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0021	0.0015	0.0015	0.0016	0.0016	0.0021	0.0015	0.0021	0.0015	0.0016	0.0016	0.0017
PM10 without the Effects of SO2 oxidation												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	14.9	9.0	9.0	9.0	9.0	14.9	9.0	14.9	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0064	0.0051	0.0064	0.0080	0.0091	0.0068	0.0054	0.0068	0.0054	0.0069	0.0086	0.0097
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0058	0.0046	0.0058	0.0073	0.0082	0.0062	0.0049	0.0061	0.0048	0.0062	0.0077	0.0088
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	32.2	18.0	18.0	18.0	18.0	32.2	18.0	32.2	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0139	0.0101	0.0129	0.0161	0.0182	0.0147	0.0109	0.0146	0.0107	0.0137	0.0172	0.0194
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0126	0.0091	0.0116	0.0145	0.0164	0.0133	0.0098	0.0131	0.0097	0.0124	0.0155	0.0175
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	14.9	9.0	9.0	9.0	9.0	14.9	9.0	14.9	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0064	0.0051	0.0064	0.0080	0.0091	0.0068	0.0054	0.0068	0.0054	0.0069	0.0086	0.0097
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0058	0.0046	0.0058	0.0073	0.0082	0.0062	0.0049	0.0061	0.0048	0.0062	0.0077	0.0088
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	40.1	23.2	22.1	21.3	20.9	39.6	22.8	39.7	22.9	21.8	21.1	20.7
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0173	0.0130	0.0158	0.0190	0.0211	0.0181	0.0138	0.0179	0.0136	0.0166	0.0201	0.0223
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0156	0.0117	0.0142	0.0171	0.0190	0.0163	0.0124	0.0162	0.0123	0.0150	0.0181	0.0201
Total Effects of SO2 Oxidation												
Total SO2 to SO3 conversion rate, %vol	26.1%	22.4%	22.4%	22.4%	22.4%	25.9%	22.4%	25.9%	22.4%	22.4%	22.4%	22.4%
Total Amount of SO2 converted to SO3, lb/h	3.82	2.52	1.98	1.58	1.40	3.57	2.33	3.62	2.37	1.85	1.48	1.31
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	7.89	5.20	4.08	3.26	2.88	7.37	4.81	7.47	4.89	3.82	3.06	2.70
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	5.85	3.86	3.03	2.42	2.14	5.47	3.57	5.54	3.63	2.84	2.27	2.01

Owner FMPA
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24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	19	19	19	19	19	59	59	59	59	59	59	59
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Post Combustion Emissions Control Equipment												
Selective Catalytic Reduction (SCR)												
NOx Removed in SCR, %wt	83.4%	77.8%	77.8%	77.8%	77.8%	83.7%	77.8%	83.6%	77.8%	77.8%	77.8%	77.8%
NOx removed in SCR, lb/h	92.9	49.7	39.0	31.2	27.6	89.3	46.1	90.0	46.8	36.6	29.3	25.9
Ammonia Slip, lb/h	17.1	13.2	10.3	8.3	7.3	16.2	12.2	16.3	12.4	9.7	7.7	6.8

Notes:

1. The emissions estimates shown in the table above are per stack.
2. These estimates are based on expected CTG/Duct Burner emission guarantees.
3. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
4. ISO conditions are defined as 59 F, 14.696 psia and RH of 60%, Norm conditions are defined as 0 C, 1.103 bar
5. All ppm values are based on CH4 calibration gas.
6. The CTG performance is from General Electric dated 11/13/2007.
7. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
8. The VOC/UHC ratios for NG were taken from the GE guarantee used in TCEC Unit 1.
9. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
10. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable.
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch.
12. As requested the SCR was designed to reduce the NOx stack emissions to 2 ppmvd@15%O2 when firing NG.
13. The emissions estimate is based on NG with a maximum sulfur content of 2.0 grains/100scf.
14. For the 100% load base and fired cases, a 3% margin on the heat rate was added while a 5% margin was added to the duct burner fuel flow on the fired cases.

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24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	13a	14a	15a	16a	17a	18a	19a	20a	21a	22a	23a	24a	25a	26a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	73	73	73	73	73	73	73	102	102	102	102	102	102	102
HRSG Duct Firing	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Ambient Conditions														
Ambient Temperature, F	73.0	73.0	73.0	73.0	73.0	73.0	73.0	102.0	102.0	102.0	102.0	102.0	102.0	102.0
Ambient Relative Humidity, %	80.0	80.0	80.0	80.0	80.0	80.0	80.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Atmospheric Pressure, psia	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660
Combustion Turbine Performance														
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	85	85	0	0	0	0	0	85	85	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	73.0	73.0	69.2	69.2	73.0	73.0	73.0	102.0	102.0	80.9	80.9	102.0	102.0	102.0
CTG Compr. Inlet Relative Humidity, %	80.1	80.1	96.7	96.7	80.1	80.1	80.1	33.1	33.1	84.8	84.8	33.1	33.1	33.1
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	12.4	12.4	12.5	12.5	8.4	5.9	4.9	10.8	10.8	11.9	11.9	7.6	5.5	4.6
CTG Load Level (percent of Base Load)	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
Gross CTG Output, kW	166,300	166,300	168,300	168,300	124,700	83,100	66,500	147,300	147,300	161,600	161,600	110,500	73,700	58,900
Gross CTG Heat Rate, Btu/kWh (LHV)	9,641	9,641	9,615	9,615	10,250	12,270	13,570	9,981	9,981	9,728	9,728	10,720	12,820	14,250
Gross CTG Heat Rate, Btu/kWh (HHV)	10,695	10,695	10,666	10,666	11,370	13,611	15,053	11,072	11,072	10,791	10,791	11,892	14,221	15,807
CTG Heat Input, MBtu/h (LHV)	1,603.3	1,603.3	1,618.2	1,618.2	1,278.2	1,019.6	902.4	1,470.2	1,470.2	1,572.0	1,572.0	1,184.6	944.8	839.3
CTG Heat Input, MBtu/h (HHV)	1,778.5	1,778.5	1,795.1	1,795.1	1,417.9	1,131.1	1,001.0	1,630.9	1,630.9	1,743.9	1,743.9	1,314.0	1,048.1	931.1
CTG Water/Steam Injection Flow, lb/h	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Injection Fluid/Fuel Ratio	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	0.0
CTG Exhaust Flow, lb/h	3,470,000	3,470,000	3,497,000	3,497,000	2,834,000	2,356,000	2,154,000	3,221,000	3,221,000	3,393,000	3,393,000	2,679,000	2,272,000	2,088,000
CTG Exhaust Temperature, F	1,131	1,131	1,127	1,127	1,171	1,200	1,200	1,163	1,163	1,141	1,141	1,198	1,200	1,200
Combustion Turbine Fuel														
Total CTG Fuel Flow, lb/h	77,020	77,020	77,740	77,740	61,400	48,980	43,350	70,630	70,630	75,520	75,520	56,910	45,390	40,320
CTG Fuel Temperature, F	365	365	365	365	365	365	365	365	365	365	365	365	365	365
CTG Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
CTG Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091
HHV/LHV Ratio	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093
CTG Fuel Composition (Ultimate Analysis by Weight)														
Ar	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%
C	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.76%	73.76%	73.76%	73.78%	73.78%	73.78%	73.78%	73.76%
H2	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.01%	24.01%	24.01%	24.02%	24.02%	24.02%	24.02%	24.01%
N2	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.61%	0.61%	0.61%	0.59%	0.59%	0.59%	0.59%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00657%	0.00657%	0.00657%	0.00658%	0.00658%	0.00658%	0.00658%	0.00657%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00

Owner FMPA
Plant Cane Island Power Plant
Project No. 147651.0035
Title 1x1 Emissions Estimates, Revision 1

24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	13a	14a	15a	16a	17a	18a	19a	20a	21a	22a	23a	24a	25a	26a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	73	73	73	73	73	73	73	102	102	102	102	102	102	102
HRSG Duct Firing	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust														
CTG Exhaust Analysis (Volume Basis - Wet)														
Ar	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%	0.93%	0.92%	0.92%	0.91%	0.91%	0.92%	0.92%	0.93%
CO2	3.85%	3.85%	3.86%	3.86%	3.76%	3.61%	3.50%	3.81%	3.81%	3.85%	3.85%	3.69%	3.47%	3.36%
H2O	9.61%	9.61%	9.75%	9.75%	9.44%	9.15%	8.93%	9.60%	9.60%	10.41%	10.41%	9.38%	8.96%	8.74%
N2	73.43%	73.43%	73.32%	73.32%	73.49%	73.60%	73.69%	73.40%	73.40%	72.80%	72.80%	73.48%	73.65%	73.73%
O2	12.19%	12.19%	12.15%	12.15%	12.38%	12.71%	12.96%	12.27%	12.27%	12.02%	12.02%	12.53%	12.99%	13.24%
SO2, (after SO2 oxidation)	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00009%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00009%	0.00009%
SO3, (after SO2 oxidation)	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00002%	0.00002%	0.00003%	0.00003%	0.00003%	0.00003%	0.00002%	0.00002%	0.00002%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.27	28.27	28.25	28.25	28.28	28.30	28.31	28.26	28.26	28.18	28.18	28.28	28.30	28.32
Specific Volume, ft^3/lb	39.96	39.96	39.87	39.87	41.35	42.31	42.39	40.93	40.93	40.39	40.39	42.11	42.34	42.41
Specific Volume, scf/lb	13.42	13.42	13.43	13.43	13.42	13.41	13.40	13.42	13.42	13.46	13.46	13.42	13.40	13.40
Exhaust Gas Flow, acfm	2,311,020	2,311,020	2,323,757	2,323,757	1,953,098	1,661,373	1,521,801	2,197,259	2,197,259	2,284,055	2,284,055	1,880,212	1,603,275	1,475,868
Exhaust Gas Flow, scfm	776,123	776,123	782,745	782,745	633,871	526,566	481,060	720,430	720,430	761,163	761,163	599,203	507,413	466,320
CTG NOx Emissions (Without Post Combustion Emissions Control)														
NOx, ppmvd (dry, 15% O2)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd (dry)	11.30	11.30	11.30	11.30	11.00	10.50	10.20	11.10	11.10	11.40	11.40	10.80	10.10	9.70
NOx, ppmvw (wet)	10.20	10.20	10.20	10.20	10.00	9.60	9.30	10.10	10.10	10.20	10.20	9.80	9.20	8.90
NOx, lb/h as NO2	57.6	57.6	58.1	58.1	46.0	36.6	32.4	52.8	52.8	56.5	56.5	42.5	33.9	30.1
NOx, lb/MBtu (LHV)	0.0359	0.0359	0.0359	0.0359	0.0360	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359
NOx, lb/MBtu (HHV)	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324
CTG CO Emissions (Without Post Combustion Emissions Control)														
CO, ppmvd (dry, 15% O2)	4.00	4.10	4.10	4.10	7.40	7.70	8.00	3.70	4.10	4.00	4.10	7.50	8.00	8.30
CO, ppmvd (dry)	5.10	5.10	5.10	5.20	9.00	9.00	9.00	4.60	5.10	5.00	5.20	9.00	9.00	9.00
CO, ppmvw (wet)	4.60	4.60	4.60	4.60	8.20	8.20	8.20	4.20	4.60	4.50	4.60	8.20	8.20	8.20
CO, lb/h	15.7	16.0	16.0	16.1	23.0	19.1	17.5	13.3	14.6	15.2	15.7	22.0	18.4	17.0
CO, lb/MBtu (LHV)	0.0098	0.0100	0.0099	0.0100	0.0180	0.0187	0.0194	0.0090	0.0100	0.0096	0.0100	0.0186	0.0195	0.0202
CO, lb/MBtu (HHV)	0.0089	0.0090	0.0089	0.0090	0.0162	0.0169	0.0175	0.0081	0.0090	0.0087	0.0090	0.0167	0.0176	0.0182
CTG SO2 Emissions (After SO2 Oxidation, Without Post Combustion Emissions Control)														
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.9100	0.9100	0.9100	0.9100	0.9100	0.9100	0.9083	0.9083	0.9083	0.9100	0.9100	0.9100	0.9100	0.9083
SO2, ppmvd (dry)	1.1404	1.1404	1.1433	1.1433	1.1114	1.0638	1.0256	1.1240	1.1240	1.1502	1.1502	1.0890	1.0204	0.9823
SO2, ppmvw (wet)	1.0308	1.0308	1.0319	1.0319	1.0065	0.9665	0.9340	1.0161	1.0161	1.0304	1.0304	0.9869	0.9290	0.8965
SO2, lb/h	8.1060	8.1060	8.1818	8.1818	6.4621	5.1549	4.5527	7.4177	7.4177	7.9481	7.9481	5.9895	4.7771	4.2345
SO2, lb/MBtu (LHV)	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0050	0.0050	0.0050	0.0051	0.0051	0.0051	0.0051	0.0050
SO2, lb/MBtu (HHV)	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0045	0.0045	0.0045	0.0046	0.0046	0.0046	0.0046	0.0045

24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	13a	14a	15a	16a	17a	18a	19a	20a	21a	22a	23a	24a	25a	26a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	73	73	73	73	73	73	73	102	102	102	102	102	102	102
HRSG Duct Firing	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust - continued														
CTG UHC Emissions (Without Post Combustion Emissions Control)														
UHC, ppmvd (dry, 15% O2)	6.2	6.2	6.2	6.2	6.3	6.6	6.8	6.3	6.3	6.2	6.2	6.5	6.9	7.1
UHC, ppmvd (dry)	7.7	7.7	7.8	7.8	7.7	7.7	7.7	7.7	7.7	7.8	7.8	7.7	7.7	7.7
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	13.8	13.8	13.9	13.9	11.3	9.4	8.5	12.8	12.8	13.5	13.5	11.0	9.0	8.3
UHC, lb/MBtu as CH4 (LHV)	0.0086	0.0086	0.0086	0.0086	0.0088	0.0092	0.0095	0.0087	0.0087	0.0086	0.0086	0.0093	0.0095	0.0099
UHC, lb/MBtu as CH4 (HHV)	0.0078	0.0078	0.0077	0.0077	0.0079	0.0083	0.0085	0.0078	0.0078	0.0078	0.0078	0.0084	0.0086	0.0089
CTG VOC Emissions (Without Post Combustion Emissions Control)														
VOC percentage of UHC	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
VOC, ppmvd (dry, 15% O2)	1.2	1.2	1.2	1.2	1.3	1.3	1.4	1.3	1.3	1.2	1.2	1.3	1.4	1.4
VOC, ppmvd (dry)	1.5	1.5	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.5	1.5	1.5
VOC, ppmvw (wet)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	2.8	2.8	2.8	2.8	2.3	1.9	1.7	2.6	2.6	2.7	2.7	2.2	1.8	1.7
VOC, lb/MBtu as CH4 (LHV)	0.0017	0.0017	0.0017	0.0017	0.0018	0.0018	0.0019	0.0017	0.0017	0.0017	0.0017	0.0019	0.0019	0.0020
VOC, lb/MBtu as CH4 (HHV)	0.0016	0.0016	0.0015	0.0015	0.0016	0.0017	0.0017	0.0016	0.0016	0.0016	0.0016	0.0017	0.0017	0.0018
CTG PM10 Emissions (without the Effects of SO2 Oxidation)														
PM10 Emissions - Front Half Catch Only														
PM10, lb/h	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV)	0.0056	0.0056	0.0056	0.0056	0.0070	0.0088	0.0100	0.0061	0.0061	0.0057	0.0057	0.0076	0.0095	0.0107
PM10, lb/MBtu (HHV)	0.0051	0.0051	0.0050	0.0050	0.0063	0.0080	0.0090	0.0055	0.0055	0.0052	0.0052	0.0068	0.0086	0.0097
PM10 Emissions - Front and Back Half Catch														
PM10, lb/h	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV)	0.0112	0.0112	0.0111	0.0111	0.0141	0.0177	0.0199	0.0122	0.0122	0.0115	0.0115	0.0152	0.0191	0.0214
PM10, lb/MBtu (HHV)	0.0101	0.0101	0.0100	0.0100	0.0127	0.0159	0.0180	0.0110	0.0110	0.0103	0.0103	0.0137	0.0172	0.0193

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Case Number	13a	14a	15a	16a	17a	18a	19a	20a	21a	22a	23a	24a	25a	26a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	73	73	73	73	73	73	73	102	102	102	102	102	102	102
HRSG Duct Firing	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
HRSG Duct Burners														
Duct Burner Fuel														
Duct Burner Heat Input, MBtu/h (LHV)	534.8	0.0	534.8	0.0	0.0	0.0	0.0	534.8	0.0	534.8	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	593.2	0.0	593.2	0.0	0.0	0.0	0.0	593.2	0.0	593.2	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	25,691	0	25,691	0	0	0	0	25,691	0	25,691	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)														
Ar	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%
C	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%
H2	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%
N2	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Duct Burner Emissions														
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%	10.0%	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	3.042	0.000	3.042	0.000	0.000	0.000	0.000	3.042	0.000	3.042	0.000	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.422	0.000	0.422	0.000	0.000	0.000	0.000	0.422	0.000	0.422	0.000	0.000	0.000	0.000
DB NOx, lb/h	47.50	0.00	47.50	0.00	0.00	0.00	0.00	47.50	0.00	47.50	0.00	0.00	0.00	0.00
DB CO, lb/h	23.70	0.00	23.70	0.00	0.00	0.00	0.00	23.70	0.00	23.70	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	35.60	0.00	35.60	0.00	0.00	0.00	0.00	35.60	0.00	35.60	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	2.40	0.00	2.40	0.00	0.00	0.00	0.00	2.40	0.00	2.40	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	5.90	0.00	5.90	0.00	0.00	0.00	0.00	5.90	0.00	5.90	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	14.20	0.00	14.20	0.00	0.00	0.00	0.00	14.20	0.00	14.20	0.00	0.00	0.00	0.00

Owner FMPA
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Title 1x1 Emissions Estimates, Revision 1

24-Jan-08
FMPA
Cane Island Power Plant
Black & Veatch Project 147651
1x1 Emissions Estimates, Revision 1

Case Number	13a	14a	15a	16a	17a	18a	19a	20a	21a	22a	23a	24a	25a	26a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	73	73	73	73	73	73	73	102	102	102	102	102	102	102
HRSG Duct Firing	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Stack Emissions														
Stack Exhaust Analysis - Volume Basis - Wet														
Ar	0.91%	0.92%	0.91%	0.92%	0.92%	0.92%	0.93%	0.91%	0.92%	0.90%	0.91%	0.92%	0.92%	0.93%
CO2	5.08%	3.85%	5.07%	3.86%	3.76%	3.61%	3.50%	5.12%	3.81%	5.10%	3.85%	3.69%	3.47%	3.36%
H2O	11.95%	9.61%	12.07%	9.75%	9.44%	9.15%	8.93%	12.12%	9.60%	12.79%	10.41%	9.38%	8.96%	8.74%
N2	72.52%	73.43%	72.42%	73.32%	73.49%	73.60%	73.69%	72.42%	73.40%	71.88%	72.80%	73.48%	73.65%	73.73%
O2	9.55%	12.19%	9.53%	12.15%	12.38%	12.71%	12.96%	9.43%	12.27%	9.33%	12.02%	12.53%	12.99%	13.24%
SO2 (after SO2 oxidation)	0.000130%	0.000100%	0.000130%	0.000100%	0.000100%	0.000090%	0.000090%	0.000130%	0.000100%	0.000130%	0.000100%	0.000100%	0.000090%	0.000090%
SO3 (after SO2 oxidation)	0.000040%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000030%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	167	182	167	182	172	164	162	165	180	168	183	171	165	163
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Stack Flow, lb/h	3,495,687	3,469,996	3,522,687	3,496,996	2,833,997	2,355,998	2,153,998	3,246,688	3,220,997	3,418,687	3,392,997	2,678,997	2,271,998	2,087,998
Stack Flow, scfm	785,948	776,123	792,606	782,745	633,871	526,566	481,060	730,506	720,430	770,915	761,163	599,203	507,413	466,320
Stack Flow, acfm	950,245	960,612	958,759	969,252	771,793	633,371	576,554	879,853	888,996	933,303	944,385	728,688	611,925	559,932
Stack Exit Velocity, ft/s	62.0	63.0	63.0	63.0	51.0	41.0	38.0	58.0	58.0	61.0	62.0	48.0	40.0	37.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)														
NOx, ppmvd (dry, 15% O2)	12.3	9.0	12.3	9.0	9.0	9.0	9.0	12.5	9.0	12.4	9.0	9.0	9.0	9.0
NOx, ppmvd (dry)	20.9	11.3	20.8	11.3	11.0	10.5	10.2	21.5	11.1	21.2	11.4	10.8	10.1	9.7
NOx, ppmvw (wet)	18.4	10.2	18.3	10.2	10.0	9.6	9.3	18.9	10.1	18.5	10.2	9.8	9.2	8.9
NOx, lb/h as NO2	105.0	57.6	105.6	58.1	46.0	36.6	32.4	100.2	52.8	103.9	56.5	42.5	33.9	30.1
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0491	0.0359	0.0490	0.0359	0.0360	0.0359	0.0359	0.0500	0.0359	0.0493	0.0359	0.0359	0.0359	0.0359
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0443	0.0324	0.0442	0.0324	0.0324	0.0324	0.0324	0.0451	0.0324	0.0445	0.0324	0.0324	0.0324	0.0324
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)														
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, ppmvd (dry)	3.4	2.5	3.4	2.5	2.4	2.3	2.3	3.4	2.5	3.4	2.5	2.4	2.2	2.2
NOx, ppmvw (wet)	3.0	2.3	3.0	2.3	2.2	2.1	2.1	3.0	2.2	3.0	2.3	2.2	2.0	2.0
NOx, lb/h as NO2	17.1	12.8	17.2	12.9	10.2	8.1	7.2	16.0	11.7	16.8	12.5	9.5	7.5	6.7
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
SCR NH3 slip, ppmvd (dry, 15% O2)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
SCR NH3 slip, lb/h	15.8	11.8	15.9	12.0	9.4	7.5	6.7	14.8	10.9	15.6	11.6	8.7	7.0	6.2
Stack CO Emissions														
CO, ppmvd (dry, 15% O2)	7.6	4.1	7.6	4.1	7.4	7.7	8.0	7.6	4.1	7.6	4.1	7.5	8.0	8.3
CO, ppmvd (dry)	12.9	5.1	12.9	5.2	9.0	9.0	9.0	13.0	5.1	13.1	5.2	9.0	9.0	9.0
CO, ppmvw (wet)	11.3	4.6	11.3	4.6	8.2	8.2	8.2	11.4	4.6	11.4	4.6	8.2	8.2	8.2
CO, lb/h	39.5	16.0	39.8	16.1	23.0	19.1	17.5	37.0	14.6	38.9	15.7	22.0	18.4	17.0
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0185	0.0100	0.0185	0.0100	0.0180	0.0187	0.0194	0.0185	0.0100	0.0185	0.0100	0.0186	0.0195	0.0202
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0166	0.0090	0.0166	0.0090	0.0162	0.0169	0.0175	0.0166	0.0090	0.0166	0.0090	0.0167	0.0176	0.0182
Stack SO2 Emissions, after SO2 Oxidation														
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO2, ppmvd (dry, 15% O2)	0.84	0.88	0.84	0.88	0.88	0.88	0.88	0.85	0.88	0.84	0.88	0.88	0.88	0.88
SO2, ppmvd (dry)	1.43	1.11	1.43	1.11	1.08	1.03	0.99	1.45	1.09	1.45	1.12	1.06	0.99	0.95
SO2, ppmvw (wet)	1.26	1.00	1.26	1.00	0.98	0.94	0.91	1.27	0.99	1.27	1.00	0.96	0.90	0.87
SO2, lb/h	10.03	7.86	10.09	7.94	6.27	5.00	4.42	9.43	7.20	9.89	7.71	5.81	4.63	4.11
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0047	0.0049	0.0047	0.0049	0.0049	0.0049	0.0049	0.0047	0.0049	0.0047	0.0049	0.0049	0.0049	0.0049
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0042	0.0044	0.0042	0.0044	0.0044	0.0044	0.0044	0.0042	0.0044	0.0042	0.0044	0.0044	0.0044	0.0044

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Case Number	13a	14a	15a	16a	17a	18a	19a	20a	21a	22a	23a	24a	25a	26a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	73	73	73	73	73	73	73	102	102	102	102	102	102	102
HRSG Duct Firing	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Stack Emissions - continued														
Stack UHC Emissions														
UHC, ppmvd (dry, 15% O2)	16.6	6.2	16.5	6.2	6.3	6.6	6.8	17.3	6.3	16.8	6.2	6.5	6.9	7.1
UHC, ppmvd	28.1	7.7	28.0	7.8	7.7	7.7	7.7	29.7	7.7	28.8	7.8	7.7	7.7	7.7
UHC, ppmvw	24.8	7.0	24.6	7.0	7.0	7.0	7.0	26.1	7.0	25.1	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	49.4	13.8	49.5	13.9	11.3	9.4	8.5	48.4	12.8	49.1	13.5	11.0	9.0	8.3
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0231	0.0086	0.0230	0.0086	0.0088	0.0092	0.0095	0.0241	0.0087	0.0233	0.0086	0.0093	0.0095	0.0099
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0208	0.0078	0.0207	0.0077	0.0079	0.0083	0.0085	0.0218	0.0078	0.0210	0.0078	0.0084	0.0086	0.0089
Stack VOC Emissions														
VOC, ppmvd (dry, 15% O2)	1.7	1.2	1.7	1.2	1.3	1.3	1.4	1.8	1.3	1.7	1.2	1.3	1.4	1.4
VOC, ppmvd (dry)	2.9	1.5	2.9	1.6	1.5	1.5	1.5	3.0	1.5	3.0	1.6	1.5	1.5	1.5
VOC, ppmvw (wet)	2.6	1.4	2.6	1.4	1.4	1.4	1.4	2.7	1.4	2.6	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	5.1	2.8	5.2	2.8	2.3	1.9	1.7	4.9	2.6	5.1	2.7	2.2	1.8	1.7
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0024	0.0017	0.0024	0.0017	0.0018	0.0018	0.0019	0.0025	0.0017	0.0024	0.0017	0.0019	0.0019	0.0020
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0022	0.0016	0.0022	0.0015	0.0016	0.0017	0.0017	0.0022	0.0016	0.0022	0.0016	0.0017	0.0017	0.0018
PM10 without the Effects of SO2 oxidation														
PM10 Emissions - Front Half Catch Only														
PM10, lb/h	14.9	9.0	14.9	9.0	9.0	9.0	9.0	14.9	9.0	14.9	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0070	0.0056	0.0069	0.0056	0.0070	0.0088	0.0100	0.0074	0.0061	0.0071	0.0057	0.0076	0.0095	0.0107
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0063	0.0051	0.0063	0.0050	0.0063	0.0080	0.0090	0.0067	0.0055	0.0064	0.0052	0.0068	0.0086	0.0097
PM10 Emissions - Front and Back Half Catch														
PM10, lb/h	32.2	18.0	32.2	18.0	18.0	18.0	18.0	32.2	18.0	32.2	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0151	0.0112	0.0150	0.0111	0.0141	0.0177	0.0199	0.0161	0.0122	0.0153	0.0115	0.0152	0.0191	0.0214
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0136	0.0101	0.0135	0.0100	0.0127	0.0159	0.0180	0.0145	0.0110	0.0138	0.0103	0.0137	0.0172	0.0193
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]														
PM10 Emissions - Front Half Catch Only														
PM10, lb/h	14.9	9.0	14.9	9.0	9.0	9.0	9.0	14.9	9.0	14.9	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0070	0.0056	0.0069	0.0056	0.0070	0.0088	0.0100	0.0074	0.0061	0.0071	0.0057	0.0076	0.0095	0.0107
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0063	0.0051	0.0063	0.0050	0.0063	0.0080	0.0090	0.0067	0.0055	0.0064	0.0052	0.0068	0.0086	0.0097
PM10 Emissions - Front and Back Half Catch														
PM10, lb/h	39.4	22.7	39.5	22.7	21.7	21.0	20.6	38.9	22.3	39.3	22.6	21.5	20.8	20.4
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0184	0.0141	0.0183	0.0140	0.0170	0.0206	0.0229	0.0194	0.0152	0.0187	0.0144	0.0181	0.0220	0.0244
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0166	0.0128	0.0165	0.0127	0.0153	0.0185	0.0206	0.0175	0.0137	0.0168	0.0130	0.0163	0.0198	0.0220
Total Effects of SO2 Oxidation														
Total SO2 to SO3 conversion rate, %vol	25.8%	22.4%	25.8%	22.4%	22.4%	22.4%	22.4%	25.5%	22.4%	25.7%	22.4%	22.4%	22.4%	22.4%
Total Amount of SO2 converted to SO3, lb/h	3.49	2.27	3.51	2.29	1.81	1.44	1.27	3.23	2.08	3.43	2.23	1.68	1.34	1.19
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	7.19	4.68	7.25	4.73	3.73	2.98	2.63	6.65	4.28	7.07	4.59	3.46	2.76	2.45
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	5.34	3.47	5.38	3.51	2.77	2.21	1.95	4.94	3.18	5.24	3.41	2.57	2.05	1.82

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1x1 Emissions Estimates, Revision 1

Case Number	13a	14a	15a	16a	17a	18a	19a	20a	21a	22a	23a	24a	25a	26a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	73	73	73	73	73	73	73	102	102	102	102	102	102	102
HRSG Duct Firing	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Post Combustion Emissions Control Equipment														
Selective Catalytic Reduction (SCR)														
NOx Removed in SCR, %wt	83.8%	77.8%	83.7%	77.8%	77.8%	77.8%	77.8%	84.0%	77.8%	83.8%	77.8%	77.8%	77.8%	77.8%
NOx removed in SCR, lb/h	88.0	44.8	88.4	45.2	35.8	28.5	25.2	84.2	41.1	87.1	43.9	33.1	26.4	23.4
Ammonia Slip, lb/h	15.8	11.8	15.9	12.0	9.4	7.5	6.7	14.8	10.9	15.6	11.6	8.7	7.0	6.2

Notes:

1. The emissions estimates shown in the table above are per stack.
2. These estimates are based on expected CTG/Duct Burner emission guarantees.
3. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
4. ISO conditions are defined as 59 F, 14.696 psia and RH of 60%, Norm conditions are defined as 0 C, 1.103 bar
5. All ppm values are based on CH4 calibration gas.
6. The CTG performance is from General Electric dated 11/13/2007.
7. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
8. The VOC/UHC ratios for NG were taken from the GE guarantee used in TCEC Unit 1.
9. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
10. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable.
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch.
12. As requested the SCR was designed to reduce the NOx stack emissions to 2 ppmvd@15%O2 when firing NG.
13. The emissions estimate is based on NG with a maximum sulfur content of 2.0 grains/100scf.
14. For the 100% load base and fired cases, a 3% margin on the heat rate was added while a 5% margin was added to the duct burner fuel flow on the fired cases.

Safe Shutdown Generator Manufacturer Data Sheet

Power Generation

EPA Tier 2 Exhaust Emission Compliance Statement 750DQFAA

60 Hz Diesel Generator Set

Compliance Information:

The engine used in this generator set complies with U.S. EPA and California emission regulations under the provisions of 40 CFR 89, Non-Road (Mobile Off Highway) Tier 2 emissions limits when tested per ISO 8178 D2.

Engine Manufacturer:	Cummins Inc
EPA Certificate Number:	CEX-NRCI-06-40
Effective Date:	12/30/2005
Date Issued:	12/30/2005
EPA Nonroad Diesel Engine Family:	6CEXL030.AAD
CARB Executive Order:	U-R-002-0335

Engine Information:

Model:	Cummins Inc QST30-G5 NR2	Bore:	5.51 in. (140 mm)
Engine Nameplate HP:	1490		
Type:	4 Cycle, 50°V, 12 Cylinder Diesel	Stroke:	6.5 in. (165 mm)
Aspiration:	Turbocharged and Low Temperature Aftercooled (Air-to-Air)	Displacement:	1860 cu. in. (30.5 liters)
Compression Ratio:	14.7:1		
Emission Control Device:	Turbocharged and Low Temperature Aftercooled(Air-to-Air)		

U.S. Environmental Protection Agency Non-Road Tier 2 Limits

COMPONENT	(All values are Grams per HP-Hour)
NOx + HC (Oxides of Nitrogen as NO2 + Total Unburned Hydrocarbons)	4.77
CO (Carbon Monoxide)	2.61
PM (Particulate Matter)	0.15

Engine operation with excessive air intake or exhaust restriction beyond published maximum limits, or with improper maintenance, may result in elevated emission levels.

Cummins Power Generation

Exhaust Emission Data Sheet
750DQFAA
60 Hz Diesel Generator Set

Engine Information:

Model:	Cummins Inc. QST30-G5 NR2	Bore:	5.51 in. (139 mm)
Type:	4 Cycle, 50°V, 12 Cylinder Diesel	Stroke:	6.5 in. (165 mm)
Aspiration:	Turbocharged and Low Temperature aftercooled	Displacement:	1860 cu. in. (30.4 liters)
Compression Ratio:	14.7:1		
Emission Control Device:	Aftercooled (Air-to-Air)		

PERFORMANCE DATA	1/4 Standby	1/2 Standby	3/4 Standby	Full Standby	Full Prime
BHP @ 1800 RPM (60 Hz)	276	551	827	1102	999
Fuel Consumption (gal/Hr)	14.8	27.1	39.8	52.7	47.9
Exhaust Gas Flow (CFM)	2350	3620	4930	6310	5880
Exhaust Gas Temperature (°F)	553	686	770	816	798
EXHAUST EMISSION DATA					
HC (Total Unburned Hydrocarbons)	0.22	0.11	0.10	0.09	0.09
NOx (Oxides of Nitrogen as NO2)	5.81	4.50	3.83	3.97	3.88
CO (carbon Monoxide)	1.38	0.48	0.37	0.46	0.43
PM (Particular Matter)	0.19	0.17	0.14	0.12	0.13
SO2 (Sulfur Dioxide)	0.12	0.11	0.10	0.10	0.10
Smoke (Bosch)	0.65	0.84	0.79	0.79	0.80

All Values are Grams/HP-Hour, Smoke is Bosch #

TEST CONDITIONS

Data was recorded during steady-state rated engine speed (± 25 RPM) with full load (±2%). Pressures, temperatures, and emission rates were stabilized.

Fuel Specification:	46.5 Cetane Number, 0.035 Wt.% Sulfur; Reference ISO8178-5, 40CFR86.1313-98 Type 2-D and ASTM D975 No. 2-D.
Fuel Temperature:	99 ± 9 °F (at fuel pump inlet)
Intake Air Temperature:	77 ± 9 °F
Barometric Pressure:	29.6 ± 1 in. Hg
Humidity:	NOx measurement corrected to 75 grains H2O/lb dry air
Reference Standard:	ISO 8178

The NOx, HC, CO and PM emission data tabulated here were taken from a single engine under the test conditions shown above. Data for the other components are estimated. These data are subjected to instrumentation and engine-to-engine variability. Field emission test data are not guaranteed to these levels. Actual field test results may vary due to test site conditions, installation, fuel specification, test procedures and instrumentation. Engine operation with excessive air intake or exhaust restriction beyond published maximum limits, or with improper maintenance, may results in elevated emission levels.

Fire Pump Manufacturer Data Sheets

JW6H-UF48
Stationary Fire Pump Engine Driver
EMISSION DATA
EPA 40 CFR Part 60

6 *Cylinders*
Four *Cycle*
Lean *Burn*
Turbocharged & Raw Water Aftercoolec

500 PPM SULFUR #2 DIESEL FUEL								
RPM	BHP (3)	FUEL GAL/HR (L/HR)	GRAMS / HP- HR				EXHAUST	
			NMHC	NOx	CO	PM (4)	°F (°C)	CFM (m^3/min)
1760	290	13.5 (51)	0.30	5.43	0.51	0.13	855 (443)	1506 (43)

Notes:

1) *6081HF001 Base Engine Model manufactured by John Deere Corporation. For John Deere Emissions Conformance to EPA 40 CFR Part 60 see Page 2 of 2.*
2) *The Emission Warranty for this engine is provided directly to the owner by John Deere Corporation. A copy of the John Deere Emission Warranty can be found in the Clarke Operation and Maintenance Manual.*
3) *Engines are rated at standard conditions of 29.61in. (7521 mm) Hg barometer and 77°F (25° C) inlet air temperature. (SAE J1349)*
4) *PM is a measure of total particulate matter, including PM_{10}.*

From: Cardinal, Michael
Sent: Wednesday, February 27, 2008 9:11 AM
To: Klote, Lawrence E.
Cc: Armbruster, Stanley A. (Stan)
Subject: Cane Island Fire Pump

Larry,

According to Clarke Fire Protection Products Americas Sales Manager Justin Strousse (513-771-2200 ext 2307), Clarke will be meeting EPA Stationary Fire Pump Requirements 40 CFR Part 60 Sub Part IIII Fed Reg June 28, 2006 standards for year 2009. That would be for NOx limit of 3.0 gm/HP-hr. The technology used would be advanced electronic controls. Clarke will not be able to provide a firm quote until about October due to uncertainty of price at this time.

Regards,

Mike Cardinal P.E.
Black & Veatch Corporation
Energy - Engineering & Construction
Consulting Engineering Services (CES)
11401 Lamar
Overland Park, KS 66211
Phone: (913) 458-6016
e-mail: cardinalm@bv.com

Appendix C
Emission Calculations

FMPA

Cane Island Unit 4 PSD Application

Summary of Potential to Emit for Criteria Pollutants

(Tons per year)

	CO	NO_x	TSP	PM_{10}	SO_2	VOC	H_2SO_4	Pb	Hg	Fluorides	H_2S	Total Reduced Sulfur
Unit 4 CCCT	178.704	77.088	173.886	173.886	45.289	23.214	24.265	0	0	0	0	0
Safe Shutdown Generator	0.112	0.965	0.029	0.029	0.001	0.066	0.002	0	0	0	0	0
Diesel Engine Fire Pump	0.008	0.050	0.002	0.002	0.000	0.017	0.000	0	0	0	0	0
Cooling Tower	--	--	2.898	2.898	--	--	--	--	--	--	--	--
TOTAL	178.824	78.102	176.816	176.816	45.290	23.298	24.267	0	0	0	0	0
SER	100	40	25	15	40	40	7	0.6	--	3	10	10
PSD Review Required?	YES	YES	YES	YES	YES	NO	YES	NO	--	NO	NO	NO

FMPA

Cane Island Unit 4

Unit 4 CCCT Parameters

Emissions Calculation

Basis:

Unit Type	GE 7FA	
Number of Turbines	1	
Fuel	Natural Gas	
Fuel Burn Rate	1,860.4	MBtu/hr [1]
Hours of Operations	8,760	hr/yr

Table C1 Unit 4 CCCT Emissions

Pollutant	Natural Gas		
	Mass Emission (lb/hr)	Potential to Emit (tpy)	[1]
CO	40.8	178.7	[2]
NO_x	17.6	77.1	[2]
PM_{10}	39.7	173.9	[2]
SO_2	10.3	45.3	[2]
VOC	5.3	23.2	[2]
H_2SO_4	5.5	24.3	[2]
Lead	0	0.0	[3a]
Mercury	0	0.0	[4]
Fluorides	0	0.0	[4]
H_2S	0	0.0	[4, 5]
Total Reduced Sulfur	0	0.0	[4, 5]

Notes [ ]:

1. Based on performance data at 100%, duct firing, evaporative cooling and ISO conditions (59 °F).
2. Performance data contained in Appendix B.
3. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines". April 2000.
   a. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
4. Emissions are insignificant and assumed to be zero.
5. All sulfur contained in the natural gas was assumed to be emitted as either SO_2 or H_2SO_4.

FMPA

Cane Island Unit 4 PSD Application

Safe Shutdown Generator Parameters

Emissions Calculation and Stack Parameters Information

Basis:

Power Rating	1,102 HP[1]		
Heat Input	7.38 MBtu/hr		
Heating Value	140,000 Btu/gal[2]		
Fuel Burn Rate	53 gal/hr[1]	10,540 gal/yr	
Hours of Operation	200 hrs/yr		

Stack Exit Conditions [1]:

Exhaust Flow Rate	6,310 acfm		
Exhaust Exit Velocity	192.82 ft/sec	58.77 m/sec	
Exhaust Temperature	816 °F	708.71 K	
Stack Diameter	10 in	0.83 ft	0.2540 m
Stack Height	24 ft	7.32 m	

Table C2 Safe Shutdown Diesel Generator Emissions

Pollutant	Outlet Conditions	Emission Rate			Potential to Emit (total)
	g/hp-hr	g/sec	lb/hr		ton/yr
CO	0.46	0.1408	1.1176	[1]	1.12E-01
NO_x	3.97	1.2153	9.6451	[1]	9.65E-01
PM/PM_{10}	0.12	0.0367	0.2915	[1]	2.92E-02
SO_2	4.58E-03	0.0014	0.0111	[3]	1.11E-03
VOC	0.09	0.0837	0.6640	[1]	6.64E-02
H_2SO_4	0.01	0.0021	0.0170	[5]	1.70E-03
Lead	0	0	0	[6]	0.00E+00
Mercury	0	0	0	[6]	0.00E+00
Fluorides	0	0	0	[6]	0.00E+00
H_2S	0	0	0	[6]	0.00E+00
Total Reduced Sulfur	0	0	0	[6]	0.00E+00

Operating Scenarios:

24-hr per day worst case operation assumed

Table C3 Emergency Generator Modeling Parameters

Pollutant	Emission Rate for the Applicable Averaging Period									
	1-hr		3-hr		8-hr		24-hr		Annual	
	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr
CO	1.408E-01	1.118E+00	--	--	1.408E-01	1.118E+00	--	--	--	--
NO_x	--	--	--	--	--	--	--	--	2.775E-02	2.202E-01
PM/PM_{10}	--	--	--	--	--	--	3.673E-02	2.915E-01	8.387E-04	6.656E-03
SO_2	--	--	1.403E-03	1.113E-02	--	--	1.403E-03	1.113E-02	3.203E-05	2.542E-04

Notes [ ]:

1. Vendor data - Cummins Model 750DQFAA
2. Assumed fuel oil heating value of 140,000 Btu/gal. USEPA, AP-42, Fifth Edition, Vol. I. Appendix A "Miscellaneous Data and Conversion Factors". September 1985.
3. Ultra low sulfur fuel oil, 0.0015%(wt).
4. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.4 "Large Stationary Diesel and All Stationary Dual-fuel Engines". October 1996.
   a. Table 3.4-1 "Gaseous Emission Factors for Large Stationary Diesel and All Stationary Dual-Fuel Engines".
5. Assumed 100% conversion of SO_2 to H_2SO_4.
6. Emissions are insignificant and assumed to be zero.

FMPA

Cane Island Unit 4 PSD Application

Diesel Engine Fire Pump Parameters

Emissions Calculation and Stack Parameters Information

Basis:

Power Rating	290	BHP[1]		
Heat Input	1.89	MBtu/hr		
Heating Value	140,000	Btu/gal[2]		
Fuel Burn Rate	13.5	gal/hr[1]	702	gal/yr
Hours of Operation	52	hrs/yr		

Stack Exit Conditions [1]:

Exhaust Flow Rate	1,506	acfm				
Exhaust Exit Velocity	184.08	ft/sec	56.11	m/sec		
Exhaust Temperature	855	°F	730.37	K		
Stack Diameter	5	in	0.42	ft	0.13	m
Stack Height	15.17	ft	4.62	m		

Table C4 Fire Pump Emissions

Pollutant	Outlet Conditions	Emission Rate			Potential to Emit
	g/bhp-hr	g/sec	lb/hr		ton/yr
CO	0.51	0.0411	0.3261	[1]	8.48E-03
NO_x	3.00	0.2417	1.9180	[1]	4.99E-02
PM/PM_{10}	0.13	0.0105	0.0831	[1]	2.16E-03
SO_2	4.46E-03	0.0004	0.0029	[3]	7.42E-05
VOC	1.03	0.0833	0.6615	[4a]	1.72E-02
H_2SO_4	0.01	0.0006	0.0044	[5]	1.14E-04
Lead	0	0	0	[6]	0.00E+00
Mercury	0	0	0	[6]	0.00E+00
Fluorides	0	0	0	[6]	0.00E+00
H_2S	0	0	0	[6]	0.00E+00
Total Reduced Sulfur	0	0	0	[6]	0.00E+00

Operating Scenarios:

1-hr per day operation (fire pump operating for testing purposes only)

Table C5 Emergency Fire Pump Modeling Parameters

Pollutant	Emission Rate for the Applicable Averaging Period									
	1-hr		3-hr		8-hr		24-hr		Annual	
	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr
CO	4.108E-02	3.261E-01	--	--	5.135E-03	4.076E-02	--	--	--	--
NO_x	--	--	--	--	--	--	--	--	1.435E-03	1.139E-02
PM/PM_{10}	--	--	--	--	--	--	4.363E-04	3.463E-03	6.216E-05	4.934E-04
SO_2	--	--	1.198E-04	9.508E-04	--	--	1.497E-05	1.188E-04	2.133E-06	1.693E-05

Notes [ ]:

1. Vendor data - Clarke Model JW6H-UF48 (1760 RPM).
2. Assumed fuel oil heating value of 140,000 Btu/gal. USEPA, AP-42, Fifth Edition, Vol. I. Appendix A "Miscellaneous Data and Conversion Factors". September 1985.
3. Ultra low sulfur fuel oil, 0.0015%(wt).
4. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.3 "Gasoline and Diesel Industrial Engines". October 1996.
   a. Table 3.3-1 "Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines".
5. Assumed 100% conversion of SO_2 to H_2SO_4.
6. Emissions are insignificant and assumed to be zero.

FMPA

Cane Island Unit 4 PSD Application
Cooling Tower - Linear Mechanical Draft

Cooling Tower Emissions

Basis (per Tower):

Total Dissolved Solids	476	mg/L	
Cycles of Concentration	5	No.	
Cycled Water TDS	2,380	ppmw	
Drift Rate	0.0005	%	
Cell Diameter	30	ft	
Stack Height	56	ft	
Circulating Water Flow	111,130	gpm	
Exhaust Air Flow (per cell)	1,003,756	cfm	4,374.08 kg/s
Number of Cells (per tower)	8	No.	
Number of Towers	1	No.	
Ambient Pressure	14.70	psia	
Relative Humidity	60	%	
Wet Bulb Temperature	69	°F	
Heat Dissipation Rate	861	MBtu/hr	
Enthalpy of air $_{in}$ (H_{in})	33.08	Btu/lb	
PM_{10}/TSP Fraction	1.000	dimensionless	[1]
$PM_{2.5}$/PM_{10} Fraction	0.600	dimensionless	[2a]

Calculations:

TSP Emission (lb/hr) = Circulating Water Flow Rate (gpm) x (Drift Rate(%)/100) x Density of Circulating Water (lb/gal) x TDS (ppmw) x 60 min/h
TSP Emission (tpy) = TSP Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

PM_{10} Emission (lb/hr) = TSP Emission (lb/hr) x PM_{10}/TSP Fraction
PM_{10} Emission (tpy) = PM_{10} Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

$PM_{2.5}$ Emission (lb/hr) = PM_{10} Emission (lb/hr) x $PM_{2.5}$/PM_{10} Fraction
$PM_{2.5}$ Emission (tpy) = $PM_{2.5}$ Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

Table C6 Cooling Tower Emissions

Activity	Number of Towers	Hours of Operation	Circulating Water Flow	Drift Rate	Density Circ Water	TDS	Potential Uncontrolled Emissions tpy			Control Method	Control Efficiency	Potential Controlled Emissions tpy		
	No.	hr/yr	gpm	%	lb/gal	ppmw	TSP	PM10	PM2.5		%	TSP	PM10	PM2.5
Cooling Tower - Mechanical Draft	1	8,760	111,130	0.0005	8.34	2,380	2.90	2.90	1.74	NA	0	2.90	2.90	1.74

Calculations (for modeling):

Exit Velocity (per cell)	23.67 ft/sec	=	7.21 m/sec			
Enthalpy of air $_{out}$ (H_{out})	57.89 Btu/lb					Guess Temp
Exit Temperature (dry bulb)	91.52 °F	=	33.07 °C	=	306.22 °K	91.5 °F

Table C7 Cooling Tower Modeling Parameters

EU Number	Activity	Cells per Tower	Controlled Emissions (per cell) lb/hr			Controlled Emissions (per cell) g/sec		
		No.	TSP	PM10	PM2.5	TSP	PM10	PM2.5
	Cooling Tower - Mechanical Draft	8	0.0827	0.0827	0.0496	0.0104	0.0104	0.0063

Notes [ ]:
1. Assumed all particulate emissions are less than 10 microns.
2. South Coast AQMD, Air Guidance Book "Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds". Final. October 2006.
   a. Table A "Updated CEIDARS Table with PM2.5 Fractions".

FMPA

Cane Island Unit 4 PSD Application

Unit 4 CCCT

Hazardous Air Pollutants (HAPs) Emissions Calculation

Basis:

Unit Type	GE 7FA	
Number of Turbines	1	
Fuel	Natural Gas	
Fuel Burn Rate	1,860.4	MBtu/hr [1]
Hours of Operations	8,760	hr/yr

Table C8 Unit 4 CCCT HAPs Emissions

Pollutant	Natural Gas			Potential to Emit
	Emission Factor (lb/MBtu)		Mass Emission (lb/hr)	(tpy)
Organic HAP Emissions				
1,3-Butadiene	4.3E-07	[2a]	8.0E-04	0.004
Acetaldehyde	4.0E-05	[2a]	7.4E-02	0.326
Acrolein	6.4E-06	[2a]	1.2E-02	0.052
Benzene	1.2E-05	[2a]	2.2E-02	0.098
Ethylbenzene	3.2E-05	[2a]	6.0E-02	0.261
Formaldehyde	7.1E-04	[2a]	1.3E+00	5.785
Naphthalene	1.3E-06	[2a]	2.4E-03	0.011
PAH	2.2E-06	[2a]	4.1E-03	0.018
Propylene Oxide	2.9E-05	[2a]	5.4E-02	0.236
Toluene	1.3E-04	[2a]	2.4E-01	1.059
Xylenes	6.4E-05	[2a]	1.2E-01	0.522
Total Organic HAP Emissions				8.371

Notes [ ]:

1. Based on performance data at 100% and ISO conditions (59 °F).
2. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines". April 2000.
   a. Table 3.1-3 "Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines".

FMPA

Cane Island Unit 4 PSD Application

Duct Burner

Hazardous Air Pollutants (HAPs) Emissions Calculation

Basis:

Fuel	Natural Gas	
Fuel Burn Rate	593.2	MBtu/hr [1]
Heating Value	1,020	Btu/scf
Hours of Operations	8,760	hr/yr
Number of Burners	1	

Table C9 Duct Burner HAPs Emissions

Pollutant	Natural Gas Emission Factor		Natural Gas Mass Emission (lb/hr)	Potential to Emit (tpy)
Organic HAP Emissions [2a]				
2-Methylnaphthalene	2.4E-05	lb/mmscf	1.4E-05	6.1E-05
3-Methylchloranthrene	1.8E-06	lb/mmscf	1.0E-06	4.6E-06
7,12-Dimethylbenz(a)anthracene	1.6E-05	lb/mmscf	9.3E-06	4.1E-05
Acenaphthene	1.8E-06	lb/mmscf	1.0E-06	4.6E-06
Acenaphthylene	1.8E-06	lb/mmscf	1.0E-06	4.6E-06
Anthracene	2.4E-06	lb/mmscf	1.4E-06	6.1E-06
Benz(a)anthracene	1.8E-06	lb/mmscf	1.0E-06	4.6E-06
Benzene	2.1E-03	lb/mmscf	1.2E-03	5.3E-03
Benzo(a)pyrene	1.2E-06	lb/mmscf	7.0E-07	3.1E-06
Benzo(b)fluoranthene	1.8E-06	lb/mmscf	1.0E-06	4.6E-06
Benzo(g,h,i)perylene	1.2E-06	lb/mmscf	7.0E-07	3.1E-06
Benzo(k)fluoranthene	1.8E-06	lb/mmscf	1.0E-06	4.6E-06
Chrysene	1.8E-06	lb/mmscf	1.0E-06	4.6E-06
Dibenzo(a,h)anthracene	1.2E-06	lb/mmscf	7.0E-07	3.1E-06
Dichlorobenzene	1.2E-03	lb/mmscf	7.0E-04	3.1E-03
Fluoranthene	3.0E-06	lb/mmscf	1.7E-06	7.6E-06
Fluorene	2.8E-06	lb/mmscf	1.6E-06	7.1E-06
Formaldehyde	7.5E-02	lb/mmscf	4.4E-02	1.9E-01
Hexane	1.8E+00	lb/mmscf	1.0E+00	4.6E+00
Indeno(1,2,3-cd)pyrene	1.8E-06	lb/mmscf	1.0E-06	4.6E-06
Naphthalene	6.1E-04	lb/mmscf	3.5E-04	1.6E-03
Phenanathrene	1.7E-05	lb/mmscf	9.9E-06	4.3E-05
Pyrene	5.0E-06	lb/mmscf	2.9E-06	1.3E-05
Toluene	3.4E-03	lb/mmscf	2.0E-03	8.7E-03
			Total Organic HAP Emissions	4.795
Metallic HAP Emissions [2b]				
Arsenic	2.0E-04	lb/mmscf	1.2E-04	0.001
Beryllium	1.2E-05	lb/mmscf	7.0E-06	0.000
Cadmium	1.1E-03	lb/mmscf	6.4E-04	0.003
Chromium	1.4E-03	lb/mmscf	8.1E-04	0.004
Cobalt	8.4E-05	lb/mmscf	4.9E-05	0.000
Manganese	3.8E-04	lb/mmscf	2.2E-04	0.001
Mercury	2.6E-04	lb/mmscf	1.5E-04	0.001
Nickel	2.1E-03	lb/mmscf	1.2E-03	0.005
Selenium	2.4E-05	lb/mmscf	1.4E-05	0.000
			Total Metallic HAP Emissions	0.014
			Total HAP Emissions	4.809

Notes [ ]:

1. Based on performance data at 100% and iso conditions (59 °F).
2. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 1 "External Combustion Sources", Section 1.4 "Natural Gas Combustion". July 1998.
   a. Table 1.4-3 "Emission Factors for Speciated Organic Compounds from Natural Gas Combustion".
   b. Table 1.4-4 "Emission Factors for Metals from Natural Gas Combustion".

FMPA

Cane Island Unit 4 PSD Application
Safe Shutdown Generator

Hazardous Air Pollutants (HAPs) Emissions Calculation

Basis:

Fuel	ULS Fuel Oil	
Fuel Burn Rate	7.4	MBtu/hr [1]
Hours of Operations	200	hr/yr
Number of Generators	1	

Table C10 Safe Shutdown Generator HAPs Emissions

Pollutant	ULSD Fuel Oil Emission Factor (lb/MBtu)		ULSD Fuel Oil Mass Emission (lb/hr)	Potential to Emit (tpy)
Organic HAP Emissions				
Acetaldehyde	2.52E-05	[2a]	1.9E-04	1.9E-05
Acrolein	7.88E-06	[2a]	5.8E-05	5.8E-06
Benzene	7.76E-04	[2a]	5.7E-03	5.7E-04
Formaldehyde	7.89E-05	[2a]	5.8E-04	5.8E-05
Toluene	2.81E-04	[2a]	2.1E-03	2.1E-04
Xylenes	1.93E-04	[2a]	1.4E-03	1.4E-04
PAH	2.12E-04	[3]	1.6E-03	1.6E-04
Acenaphthylene	9.23E-06	[2b]	--	--
Acenaphthene	4.68E-06	[2b]	--	--
Naphthalene	1.30E-04		--	--
Fluorene	1.28E-05	[2b]	--	--
Phenanthrene	4.08E-05	[2b]	--	--
Anthracene	1.23E-06	[2b]	--	--
Fluoranthene	4.03E-06	[2b]	--	--
Pyrene	3.71E-06	[2b]	--	--
Benz(a)anthracene	6.22E-07	[2b]	--	--
Chrysene	1.53E-06	[2b]	--	--
Benzo(b)fluoranthene	1.11E-06	[2b]	--	--
Benzo(k)fluoranthene	2.18E-07	[2b]	--	--
Benzo(a)pyrene	2.57E-07	[2b]	--	--
Indeno(1,2,3-cd)pyrene	4.14E-07	[2b]	--	--
Dibenz(a,h)anthracene	3.46E-07	[2b]	--	--
Benzo(g,h,l)perylene	5.56E-07	[2b]	--	--
			Total Organic HAP Emissions	1.16E-03

Notes [ ]:

1. Based on vendor data (52.7 gal/hr) and a heating value of 140,000 Btu/gal.
2. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.4 "Large Stationary Diesel and All Stationary Duel-fuel Engines". October 1996.
   a. Table 3.4-3 "Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Dies
   b. Table 3.4-4 "PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines".

FMPA

Cane Island Unit 4 PSD Application

Fire Pump

Hazardous Air Pollutants (HAPs) Emissions Calculation

Basis:

Fuel	ULS Fuel Oil
Fuel Burn Rate	1.89 MBtu/hr [1]
Hours of Operations	52 hr/yr
Number of Pumps	1

Table C11 Fire Pump HAPs Emissions

Pollutant	ULSD Fuel Oil Emission Factor (lb/MBtu)		ULSD Fuel Oil Mass Emission (lb/hr)	Potential to Emit (tpy)
Organic HAP Emissions				
1,3-Butadiene	3.91E-05	[2a]	7.4E-05	1.9E-06
Acetaldehyde	7.67E-04	[2a]	1.4E-03	3.8E-05
Acrolein	9.25E-05	[2a]	1.7E-04	4.5E-06
Benzene	9.33E-04	[2a]	1.8E-03	4.6E-05
Formaldehyde	1.18E-03	[2a]	2.2E-03	5.8E-05
Toluene	4.09E-04	[2a]	7.7E-04	2.0E-05
Xylenes	2.85E-04	[2a]	5.4E-04	1.4E-05
PAH	1.68E-04	[3]	3.2E-04	8.3E-06
Acenaphthene	1.42E-06	[2a]	--	--
Acenaphthylene	5.06E-06	[2a]	--	--
Anthracene	1.87E-06	[2a]	--	--
Benzo(a)anthracene	1.68E-06	[2a]	--	--
Benzo(a)pyrene	1.88E-07	[2a]	--	--
Benzo(b)fluoranthene	9.91E-08	[2a]	--	--
Benzo(g,h,l)perylene	4.89E-07	[2a]	--	--
Benzo(k)fluoranthene	1.55E-07	[2a]	--	--
Chrysene	3.53E-07	[2a]	--	--
Dibenz(a,h)anthracene	5.83E-07	[2a]	--	--
Fluoranthene	7.61E-06	[2a]	--	--
Fluorene	2.92E-05	[2a]	--	--
Indeno(1,2,3-cd)pyrene	3.75E-07	[2a]	--	--
Naphthalene	8.48E-05	[2a]	--	--
Phenanthrene	2.94E-05	[2a]	--	--
Pyrene	4.78E-06	[2a]	--	--
			Total Organic HAP Emissions	1.90E-04

Notes [ ]:

1. Based on vendor data (13.5 gal/hr) and a heating value of 140,000 Btu/gal.
2. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.3 "Gasoline and Diesel Industrial Engines". October 1996.
   a. Table 3.3-2 "Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines".
3. Summation of individual PAH chemicals.

FMPA

Cane Island Unit 4 PSD Application

Project Total

Hazardous Air Pollutants (HAPs) Emissions Calculation

Table C12 Project HAPs Emissions

Pollutant	Potential to Emit				
	Unit 4 CCCT	Duct Burner	Safe Shutdown Generator	Fire Pump	Project Total [1]
	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Organic HAP Emissions					
1,3-Butadiene	3.5E-03	--	--	1.9E-06	3.51E-03
2-Methylnaphthalene	--	6.1E-05	--	--	6.11E-05
3-Methylchloranthrene	--	4.6E-06	--	--	4.59E-06
7,12-Dimethylbenz(a)anthracene	--	4.1E-05	--	--	4.08E-05
Acenaphthene	--	4.6E-06	--	--	4.59E-06
Acenaphthylene	--	4.6E-06	--	--	4.59E-06
Acetaldehyde	3.3E-01	--	1.9E-05	3.8E-05	3.26E-01
Acrolein	5.2E-02	--	5.8E-06	4.5E-06	5.22E-02
Anthracene	--	6.1E-06	--	--	6.11E-06
Benz(a)anthracene	--	4.6E-06	--	--	4.59E-06
Benzene	9.8E-02	5.3E-03	5.7E-04	4.6E-05	1.04E-01
Benzo(a)pyrene	--	3.1E-06	--	--	3.06E-06
Benzo(b)fluoranthene	--	4.6E-06	--	--	4.59E-06
Benzo(g,h,i)perylene	--	3.1E-06	--	--	3.06E-06
Benzo(k)fluoranthene	--	4.6E-06	--	--	4.59E-06
Chrysene	--	4.6E-06	--	--	4.59E-06
Dibenzo(a,h)anthracene	--	3.1E-06	--	--	3.06E-06
Dichlorobenzene	--	3.1E-03	--	--	3.06E-03
Ethylbenzene	2.6E-01	--	--	--	2.61E-01
Fluoranthene	--	7.6E-06	--	--	7.64E-06
Fluorene	--	7.1E-06	--	--	7.13E-06
Formaldehyde	5.8E+00	1.9E-01	5.8E-05	5.8E-05	5.98E+00
Hexane	--	4.6E+00	--	--	4.59E+00
Indeno(1,2,3-cd)pyrene	--	4.6E-06	--	--	4.59E-06
Naphthalene	1.1E-02	1.6E-03	--	--	1.21E-02
PAH	1.8E-02	--	1.6E-04	8.3E-06	1.81E-02
Phenanathrene	--	4.3E-05	--	--	4.33E-05
Propylene Oxide	2.4E-01	--	--	--	2.36E-01
Pyrene	--	1.3E-05	--	--	1.27E-05
Toluene	1.1E+00	8.7E-03	2.1E-04	2.0E-05	1.07E+00
Xylenes	5.2E-01	--	1.4E-04	1.4E-05	5.22E-01
Total Organic HAP Emissions					13.168
Metallic HAP Emissions					
Arsenic	--	5.1E-04	--	--	5.09E-04
Beryllium	--	3.1E-05	--	--	3.06E-05
Cadmium	--	2.8E-03	--	--	2.80E-03
Chromium	--	3.6E-03	--	--	3.57E-03
Cobalt	--	2.1E-04	--	--	2.14E-04
Manganese	--	9.7E-04	--	--	9.68E-04
Mercury	--	6.6E-04	--	--	6.62E-04
Nickel	--	5.3E-03	--	--	5.35E-03
Selenium	--	6.1E-05	--	--	6.11E-05
Total Metallica HAP Emissions					0.014
Total HAP Emissions					13.182

Notes [ ]:

1. Total HAP emissions are the total HAP emissions from the combustion turbine, the duct burner operation, safe shutdown generator, and the fire pump.

Appendix D
BACT Analysis

Best Available Control Technology Analysis
for
FMPA – Cane Island Power Park
Unit 4
Combined Cycle Combustion Turbine

Submitted by

Florida Municipal Power Agency

April 2008
Project No. 147651

BLACK & VEATCH
Building a world of difference.

Table of Contents

Table of Contents (Continued)

Table of Contents (Continued)

Tables

Acronym List

AQC	Air Quality Control
BACT	Best Available Control Technology
bhp	Brake Horsepower
BOP	Balance-of-Plant
Btu	British Thermal Unit
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CCCT	Combined Cycle Combustion Turbine
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DB	Duct Burner
DLN	Dry Low NO_x Burner
FDEP	Florida Department of Environmental Protection
FGD	Flue Gas Desulfurization
FMPA	Florida Municipal Power Agency
FPL	Florida Power & Light Company
H_2	Hydrogen
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid Mist
h/yr	Hours per Year
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
in. wg	Inches Water Gauge
ISO	International Organization for Standardization
K_2CO_3	Potassium Carbonate
kW	Kilowatt
kWh	Kilowatt Hour
LAER	Lowest Achievable Emission Rate
Lb/h	Pound per Hour
LNB	Low NO_x Burner
MBtu	Million British Thermal Unit
MW	Megawatt
NESCAUM	Northeast States for Coordinated Air Use Management

ng/J	Nanogram per Joule
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O&M	Operations and Maintenance
OAQPS	Office of Air Quality Planning And Standards
Pb	Lead
PEC	Purchased Equipment Costs
PM/PM_{10}	Particulate Matter/Particulate Matter Less than 10 Microns
ppm	Parts per Million
ppmvd	Parts per Million Volumetric Dry
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RH	Relative Humidity
SARA	Superfund Amendments and Reauthorization Act of 1986
Scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STG	Steam Tubine Generator
TCI	Total Capital Investment
tpy	Tons per Year
ULSFO	Ultra-Low Sulfur Fuel Oil
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

1.0 Introduction and Executive Summary

Florida Municipal Power Agency (FMPA) proposes to expand the Cane Island Power Park by adding a new, high-efficiency, natural gas fired electric generating unit. The new electric generating unit, known as Cane Island Unit 4 (also referred to as the "Unit 4") will be located in Osceola County, southwest of Orlando, Florida, and west of Kissimmee, Florida. Unit 4 will consist of a 1x1 General Electric F-Class (PG7241FA) Combined Cycle Combustion Turbine (CCCT) and associated support facilities. Unit 4 will be fueled with natural gas as the primary fuel with no alternate backup fuel. Unit 4 will include a 150 megawatt (MW) (approximate) combustion turbine generator (CTG), a duct fired heat recovery steam generator (HRSG), and a 150 MW (approximate) steam turbine generator (STG). The Project includes Cane Island Unit 4, a diesel engine driven fire pump, a safe shutdown generator, and a mechanical draft cooling tower.

The Project is classified as a New Source Review/Prevention of Significant Deterioration (NSR/PSD) major modification to an existing major source, and as a result of the calculated emissions increases, is subject to a Best Available Control Technology (BACT) review for sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter/particulate matter less than 10 microns (PM)/PM_{10}, and sulfuric acid mist (H_2SO_4), as previously discussed in Section 2.4 of the air permit application document. The Project is not subject to review for volatile organic compounds (VOC), lead (Pb), hydrogen sulfide (H_2S), vinyl chloride, total fluorides, mercury, or total reduced sulfur compounds.

As required under the NSR/PSD regulations, the BACT analysis presented herein employed a "top-down," five-step analysis process to determine the appropriate emission control technologies and emissions limitations for the Project. The BACT analysis was conducted for the Cane Island Unit 4 CCCT, diesel engine driven fire pump, safe shutdown generator, and mechanical draft cooling tower. The BACT analysis was conducted in accordance with the United States Environmental Protection Agency's (USEPA's) recommended methodology:

- Step 1--Identify All Control Technologies.
- Step 2--Eliminate Technically Infeasible Options.
- Step 3--Rank Remaining Control Technologies by Control Effectiveness.
- Step 4--Evaluate Most Effective Controls.
- Step 5--Select BACT.

1.1 Step 1--Identify All Control Technologies

The first step in a top-down analysis is to identify all available control options for the emission unit in question. Identifying all the potential available control options consists of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. The potential available control technologies and techniques include lower emitting processes, practices, and post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques that are classified as pre-combustion controls. Post-combustion controls would be the various add-on controls for the pollutant being controlled.

1.2 Step 2--Eliminate Technically Infeasible Options

The second step of the top-down analysis is to identify the technical feasibility of the control options identified in Step 1, which are evaluated with respect to source-specific factors. A control option that is determined to be technically infeasible is eliminated. "Technically infeasible" is defined as a clearly documented case of a control option that has technical difficulties that would preclude the successful use of the control option because of physical, chemical, and engineering principles. After completion of this step, technically infeasible options are then eliminated from the BACT review process.

In Step 2, the control option is identified as technically feasible. A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size under review (demonstrated). If the control option cannot be demonstrated, the analysis gets more involved. When determining if a control option has not been demonstrated, two key concepts need to be analyzed. The first concept, "availability," is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. The second concept, "applicability," is defined as an available control option that can reasonably be installed and operated on the source type under consideration. In summary, the commercially available technology is applicable if it has been previously installed and operated at a similar type of source of comparable size, or a source with similar gas stream characteristics.

1.3 Step 3--Rank Remaining Control Technologies by Control Effectiveness

The third step of the top-down analysis is to rank all the remaining control alternatives not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information in regard to other control options that would provide less control.

1.4 Step 4--Evaluate Most Effective Controls

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed to make a BACT determination in Step 4. The impacts of the technology implementation on the viability of the control technology at the source are evaluated. The evaluation process of these impacts is also known as "Impact Analysis." The following impact analyses are performed:

- Energy evaluation of alternatives.
- Environmental evaluation of alternatives.
- Economic evaluation of alternatives.

The first impact analysis addresses the energy evaluation of alternatives. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which impacts the cost-effectiveness of the control technology.

The second impact analysis addresses the environmental evaluation of alternatives. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology. Examples of non-air quality environmental impacts include polluted water discharge and solids or waste generation. The procedure for conducting this analysis should be based on a consideration of site-specific circumstances.

The third and final impact analysis addresses the economic evaluation of alternatives. This analysis is performed to indicate the cost to purchase and operate the control technology. The capital and operating/annual cost is estimated based on the established design parameters. Information for the design parameters should be obtained from established sources that can be referenced. However, documented assumptions can be made in the absence of references for the design parameters. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost-effectiveness ($/tons) of the control technology is determined. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. The cost-effectiveness compares the potential technologies on an economical basis. Two types of cost-effectiveness are considered in a BACT analysis: average and incremental cost-effectiveness. Average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. It has a unit of (dollars/incremental ton removed). The incremental cost-effectiveness is a good measure of viability when comparing technologies that have similar removal efficiencies.

1.5 Step 5--Select BACT

The highest ranked control technology that is not eliminated in Step 4 is proposed as the BACT for the pollutant and emission unit under review.

As summarized in Table 1-1, the aforementioned BACT analysis process resulted in the following control technology and emissions level determinations for the Project's affected air emissions sources and pollutants. The ton per year (tpy) emissions presented in Appendix C are proposed as BACT emission caps.

Table 1-1
BACT Determination Summary

Emission Unit: Nominal 300 MW CCCT Unit B (1x1 F-Class PG7241FA)				
Pollutant	**Control Technology**	**Emission Basis**	**Compliance Method**	**CEMS Avg Period**
NO_x	DLN/SCR	2.0 ppmvd at 15% O_2	Stack Test, Three-Run Avg	24 hour block
CO	Good Combustion Controls	7.6 ppmvd at 15% O_2 with DBs 4.1 ppmvd at 15% O_2 w/o DBs	Stack Test, Three-Run Avg	
		8.0 ppmvd at 15% O_2 with and w/o DBs		24 hour block
PM/PM_{10}	Natural Gas (2.0 gr S/100 scf) Good Combustion Practices	10% Opacity	USEPA Method 9 Fuel Sulfur Records	NA
SO2	Natural Gas (2.0 gr S/100 scf)	NA	Fuel Sulfur Records	NA
H_2SO_4	Natural Gas (2.0 gr S/100 scf)	NA	Fuel Sulfur Records	NA

Emission Unit: Safe Shutdown Generator (750 kW)	
Pollutant	**Control Technology**
SO_2	Ultra low-sulfur fuel oil (ULSFO)
NO_x	Good Combustion Controls
PM/PM_{10}	ULSFO
CO	Good Combustion Controls
VOC	Good Combustion Controls
H_2SO_4	ULSFO

Emission Unit: Emergency Fire Pump (290 bhp)	
Pollutant	**Control Technology**
SO_2	ULSFO
NO_x	Good Combustion Controls
PM/PM_{10}	ULSFO
CO	Good Combustion Controls
VOC	Good Combustion Controls
H_2SO_4	ULSFO

Emission Unit: Cooling Tower		
Pollutant	**Control Technology**	**Emission Basis**
PM/PM_{10}	Drift Eliminators	0.0005 percent drift rate

CEMS = Continuous Emissions Monitoring System.
DB = Duct burners.
DLN = Dry low NO_x.
gr S/100 scf = Grains of sulfur/100 standard cubic feet.
MBtu = Million British Thermal Unit.
ppmvd = Parts per million volumetric dry.
SCR = Selective Catalytic Reduction.
ULSFO = Ultra-low sulfur fuel oil

2.0 BACT Analysis Basis

This section describes the basis of the Project, Cane Island Power Park Unit 4, BACT analysis. Information is provided on the BACT methodology and approach used as well as the parameters and factors used in developing the analysis. The BACT analysis for Cane Island Unit 4 is based on certain regulatory requirements and project assumptions. The following is a summary of the requirements and assumptions for which this BACT analysis is based.

2.1 Regulatory Basis

The Clean Air Act Amendments of 1990 (CAA) established revised conditions for the approval of pre-construction permit applications under the PSD program. One of these requirements is that BACT be installed to control all pollutants regulated under the Florida Electrical Power Plant Siting Act (Act) that are emitted in significant amounts from new major sources or major modifications.

The applicable state regulations governing this process define BACT in Rule 62-210.200(37), F.A.C. as follows:

> *"Best Available Control Technology" or "BACT" – An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes, and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant."*

However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS).

To bring consistency to the BACT process, the USEPA provides as guidance to the states the use of a top-down approach to BACT determinations, which utilizes the five-step analysis process previously summarized. In practice, the top-down BACT analysis determines the most stringent control technology and emissions limitation combination available for a similar source or source category of emission units. At the head of the list in the top-down analysis methodology are the control technologies and emissions limits that represent the Lowest Achievable Emission Rate (LAER) determinations, which, under NSR/PSD regulations, represent the most effective control alternative that must be considered under the BACT analysis process.

The following informational databases, clearinghouses, and documents were used to identify recent control technology determinations for similar source categories and emission units for this BACT analysis:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC).
- USEPA's National Combustion Turbine Projects Spreadsheet.
- Federal/State/Local new source review permits, permit applications, and associated inspection/test reports.
- Technical journals, newsletters, and reports.
- Information from air quality control (AQC) technology suppliers.
- Engineering design on other projects.

If it cannot be shown that the top level of control is infeasible (for a similar type source and fuel category) on the basis of technical, economic, energy, or environmental impact considerations, then that level of control must be declared to represent BACT for the respective pollutant and air emissions source. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site- and project-specific consideration of the aforementioned screening criteria (e.g., technical, economic, energy, and environmental considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration. BACT cannot be determined to be less stringent than the emissions limits established by an applicable NSPS for the affected air emissions source.

2.1.1 Applicable NSPS Emissions Limits

As previously discussed, a proposed BACT emissions limit, established in accordance with the top-down, five-step process, cannot be determined to be less stringent than the emissions limit(s) established by the applicable NSPS regulations found in 40 CFR (Code of Federal Regulations) Part 60. The following NSPS emissions limitations are applicable to the Project's air emissions sources.

2.1.1.1 NSPS Subpart KKKK – Standards of Performance for Stationary Combustion Turbines. As a new stationary CCCT, Unit 4 will be subject to NSPS Subpart KKKK. Additionally, because the Project is subject to Subpart KKKK, it is not subject to Subpart GG or Subpart Da for the combustion turbine (CT) and HRSG DBs, respectively. Applicable NSPS Subpart KKKK emissions limitations for the Project are as follows:

- NO_x--15 ppm (parts per million) at 15 percent O_2 or 54 ng/J (nanograms per joule) of useful output (0.43 lb/MWh [pound per megawatt-hour]) – new turbines firing natural gas with >850 MBtu/h heat input.

- NO_x--96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh) – turbines operating at less than 75 percent of peak load – turbines with > 30 MW output.
- SO_2--The rule includes a fuel emission standard or a fuel sulfur standard equivalent to potential SO_2 emissions of 0.060 lb SO_2/MBtu.

2.1.1.2 NSPS Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The Project's safe shutdown generator and emergency fire pump will be subject to the manufacturer's certification requirements of compliance to NSPS Subpart IIII. The rule provides various emissions standards based on the engine's use, manufacture date, and engine size. The applicable standards associated with the equipment will be dependent on the engine model year.

Beginning with engines manufactured in model year 2007, the onus of this rule falls on the engine manufacturers, since they are required to manufacture engines that comply with the rule. The requirement of this rule for owners and operators of these engines is that they purchase certified engines.

2.2 Unit Operations and Baseline Emissions Basis

The proposed operating scenario for the Project is a maximum of 8,760 full load operating hours per year (h/yr) while firing natural gas with or without DB firing on natural gas. This unit is expected to cycle with frequent startups and will be operated at 40 to 100 percent of full load for up to 8,760 h/yr.

2.2.1 CCCT Cane Island Unit 4

Table 2-1 presents the BACT design basis for the Project's CCCT. Table 2-2 shows the baseline emission rates for Cane Island Unit 4 at 100 percent base load at the International Organization for Standardization (ISO) inlet air temperature of 59° F for natural gas and 60 percent relative humidity (60 percent RH), hereinafter referred to as ISO conditions. The emissions shown in Table 2-2 are based on the use of DLN burners during natural gas firing with the operation of the natural gas fired DBs at 100 percent load. The DBs will fire only natural gas. The lb/MBtu values are based on the higher heating value (HHV) of the expected fuel to be fired and are based on the combined heat input to the CT and the DBs. Table 2-3 shows the uncontrolled emissions for Cane Island Unit 4.

Table 2-1 Combustion Turbine Design Basis[a]	
Size	Nominal 300 MW (combined cycle)
CTG	
Heat Input	1,860.4 MBtu/h[a]
HRSG DBs	
Heat Input	593.2 MBtu/h[a]
Operating Hours	8,760 h/yr
Fuel	Natural Gas

[a]Based on the HHV when firing natural gas, 100 percent load, duct firing, evaporative cooling, at ISO conditions.

Table 2-2
Baseline Emission Rates for Cane Island Unit 4

Emission Parameter	Unit 4[a] Natural Gas, 100% Load, Duct Firing, Evaporative Cooling at ISO Conditions
NO_x, ppmvd at 15% O_2	12.2
NO_x, lb/h	107.7
NO_x, lb/MBtu (HHV)	0.0439
CO, ppmvd at 15% O_2	7.6
CO, lb/h	40.8
CO, lb/MBtu (HHV)	0.0166
PM/PM_{10} (front and back), lb/h[b]	39.7
PM/PM_{10} (front and back), lb/MBtu (HHV)[c]	0.0162
SO_2, lb/h[c]	10.34
SO_2, lb/MBtu (HHV)[c]	0.0042
H_2SO_4, lb/h[b]	5.54
H_2SO_4, lb/MBtu[b]	0.00298

[a]Emissions are based on firing natural gas in the CT and HRSG DBs at 100 percent of base load with evaporative cooling at ISO conditions.
[b]PM/PM_{10} and H_2SO_4 values include the effects of 20 percent SO_2 oxidation in the CT and 10 percent SO_2 oxidation in the DBs.
[c]SO_2 values include the effects of 3 percent SO_2 oxidation in the SCR System. Based on a natural gas sulfur content of 2.0 grains/100 scf.

Table 2-3
Cane Island Unit 4 Baseline Uncontrolled Emissions

Emission Parameter	Natural Gas Firing[a]
NO_x, tpy	471.73
CO, tpy	178.8
PM/PM_{10} (front and back), tpy	173.89
SO_2, tpy	45.29
H_2SO_4, tpy	24.27

[a]Cane Island Unit 4 emissions are based on firing natural gas in the CT and HRSG DBs at 100 percent of base load with evaporative cooling at ISO conditions.

2.3 Economic Basis

The economic analyses used to determine the capital and annualized costs of the control technologies were based on USEPA methodologies shown in the USEPA "Best Available Control Technology Draft Guidance Document" (October 1990), "Top Down Best Available Control Technology Guidance Document" (March 1990), The Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (February 1996, Fifth Edition), internal owner cost factors, and vendor budgetary cost quotes.

Table 2-4 lists the economic criteria used in the analysis of BACT alternatives. The capital recovery factor was calculated based on the present worth discount rate and economic life of the equipment or the assumed catalyst life.

Table 2-4
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	10
Escalation, percent	2.3
Present Worth Discount Rate, percent	5.0
Economic Life, years	20
Capital Recovery Factor (20 years)	0.0802
SCR Catalyst Life, years	3
$SCONO_x$ Catalyst Life, years	5
CO Catalyst Life, years	3
Catalyst Capital Recovery Factor (3 years)	0.3672
$SCONO_x$ Catalyst Capital Recovery Factor (5 years)	0.2310
Labor Cost, $/man-hour (2008)	50
Natural Gas Cost, $/MBtu (2008)	8.05
Aqueous Ammonia Cost, $/ton (2008)	215
Energy Cost, $/kWh (2008)	0.063
Sales Tax, percent	NA

3.0 Cane Island Unit 4 NO_x and CO BACT Analysis

This section presents the top-down, five-step BACT process used to evaluate and determine the Project's NO_x and CO emissions limits for Cane Island Unit 4. As this analysis will demonstrate, the proposed NO_x BACT was determined to be the use of SCR to achieve an emission limit of 2 ppmvd at 15 percent O_2 while firing natural gas. The proposed CO BACT was determined to be the use of good combustion controls while firing natural gas.

3.1 Step 1--Identify All NO_x Control Technologies

The first step in a top-down analysis, according to the USEPA's October 1990, Draft New Source Review Workshop Manual, is to identify all available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission unit and the NO_x emissions limit that is being evaluated. The results of this search for all CCCTs are listed in Attachment 1: NO_x Control Technology Review List.

NO_x is defined as the combination of nitrogen oxide (NO) and nitrogen dioxide (NO_2). Typically, the NO_x that is formed in CTs consists of 60 percent NO, with the balance occurring as NO_2. NO_x emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

NO_x control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NO_x formed in the combustion process. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The six different types of emission controls reviewed by this BACT analysis are as noted below.

- In-Combustor Type:
  - Water/Steam Injection.
  - DLN Burners.
  - XONON.

- Post-Combustion Type:
  - Selective Noncatalytic Reduction (SNCR).
  - $SCONO_x$.
  - SCR.

The rationale behind whether the above technologies are evaluated as NO_x control for BACT is included in the following subsections.

3.1.1 Water or Steam Injection

NO_x emissions from Unit 4 can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the CT. A limit exists, however, on the amount of water that can be injected into the system before reliability of the CT is seriously degraded and operational life is affected. This type of control can also be counterproductive with regard to CO and VOC emissions that are formed as a result of incomplete combustion. Furthermore, this in-combustor control technology is typically used for fuel oil fired CTs or much smaller units.

3.1.2 Dry Low NO_x Burners

NO_x formation can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of DLN burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called DLN burners because, when firing natural gas, injecting water into the combustion chamber is not necessary to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion system as the state-of-the-art for NO_x controls in CTs. This method is exclusively utilized when firing natural gas.

3.1.3 XONON

Another form of in-combustor control is XONON. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2,700° F at full power generation, which significantly reduces NO_x emissions without raising, and possibly even lowering, emissions of CO and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine.

This emerging technology is being commercialized by several joint ventures that Catalytica has with turbine manufacturers.

3.1.4 Selective Noncatalytic Reduction

SNCR is one method of post-combustion control. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. SNCR systems can use either ammonia (Thermal DeNO_x) or urea (NO_xOUT) as reagents.

The SNCR system is dependent upon the reagent injector location and temperature to achieve proper reagent/flue gas mixing for maximum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x reduction efficiency. The optimum temperature range for injection of ammonia or urea is 1,550° to 1,900° F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Injection of reagent below this temperature window results in excessive ammonia emissions (ammonia slip). Injection of reagent above the temperature window results in increased NO_x emissions.

The exhaust temperature at the exit of the CT is between 1,074º to 1,200º F. Therefore, the exhaust temperature is less than the optimum temperature range for the application of this technology. It is not technically feasible to apply this technology to this Project, and it will be eliminated from further evaluation in this BACT analysis.

3.1.5 $SCONO_x$

A second, post-combustion technology from EmeraChem, LLC is EM_X^{TM} ($SCONO_x$), which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. EmeraChem purchased $SCONO_x$ from Goal Line Environmental Technologies and ABB Alstom Power.

The $SCONO_x$ system utilizes hydrogen (H_2) (which is created by reforming natural gas) as the basis for a proprietary catalyst regeneration process. The system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize both NO_x and CO, thereby reducing total plant emissions. CO emissions are decreased by the oxidation of CO to CO_2. The catalyst is installed in the flue gas at a point where the temperature is between 300° to 700° F. EmeraChem guarantees the performance of the catalyst for 3 years. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst.

The $SCONO_x$ catalyst is very susceptible to fouling by sulfur in the flue gas. The impact of sulfur can be minimized by a sulfur absorption $SCOSO_x$ catalyst. The $SCOSO_x$ catalyst is located upstream of the $SCONO_x$ catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the $SCOSO_x$ catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The $SCOSO_x$ catalyst is regenerated along with the $SCONO_x$ catalyst.

The $SCONO_x$ catalyst will require that it be re-coated or "washed" every 6 months to 1 year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the $SCOSO_x$ catalyst. The washing consists of removing the catalyst modules from the unit and placing each module in a K_2CO_3 reagent tank, which is the active ingredient of the catalyst. The $SCOSO_x$ catalyst will also require washing, but due to limited operating experience with the $SCOSO_x$ catalyst, it is uncertain how often this will be required. However, it is expected that the $SCOSO_x$ catalyst will require annual washing.

The current $SCONO_x$ catalyst technology is in its second generation. The first generation operated for approximately 10 months on a small LM-2500 CCCT unit before the $SCONO_x$ system was taken out of service because of poor regeneration gas distribution.

The USEPA has stated its concerns (November 19, 1999 letter from USEPA Region I) with the technical uncertainties of the $SCONO_x$ system and was apprehensive about applying $SCONO_x$ technology to large combined cycle turbines that burn primarily natural gas. The CT proposed for this project is approximately 150 MW, which is outside the operating range (32 MW) of the $SCONO_x$ system currently operating at the Federal Cold Storage Cogeneration facility in California.

3.1.6 Selective Catalytic Reduction

Another post-combustion method of NO_x control is SCR. SCR systems have been used quite extensively in CTG/HRSG projects for the past 10 years. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the CT exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades, ammonia slip will increase to approximately 5 to 10 ppmvd (dependent on system design), ultimately requiring catalyst replacement.

The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. Vanadium/titanium catalysts have been used on the majority of SCR system installations. The flue gas temperature range for optimum SCR operation using a conventional vanadium/titanium catalyst is approximately 600° to 750° F. At temperatures above 850° F permanent damage to the vanadium/titanium catalyst occurs. For Unit 4, the flue gas temperature in the HRSG of the CTG/HRSG would typically range from 600° to 800° F. Accordingly, a vanadium/titanium catalyst can be installed for Unit 4. Therefore, the vanadium/ titanium-based catalyst will be evaluated further for these units.

Because the SCR system requires the regulation of ammonia injection based on the NO_x emission monitors, the accuracy of the emission reading directly influences the amount of actual error in the ammonia injection rate. Therefore, erroneous emission readings can result in excess ammonia levels even when the actual NO_x value is below the permitted value. This may result in excessive ammonia "slip" being discharged to the atmosphere with little or no improvement in NO_x emissions. Reduction of the NO_x emission concentrations to levels below 2.0 ppmvd also raises concerns with the additional ammonia that may be emitted to obtain further reduced levels. Although SCR catalyst vendors have indicated that ammonia emissions will not be increased, these vendors are not solely responsible for guaranteeing ammonia slip. The distribution of the ammonia in the duct is the key parameter since localized maldistribution of the ammonia will cause the ammonia to pass through the catalyst without reacting with the NO_x. The proper distribution of the gas and ammonia is difficult to obtain when both reactants, NO_x and ammonia, are at such low concentrations. This distribution would be even more difficult, if not impossible, to maintain during transient operations, such as load changes, when flow patterns are changing. Changes in operation from one stable load to another stable load may present problems since the flow patterns and the loads may be different. Since the catalyst vendors are not responsible for the ammonia distribution, they typically limit their guarantees to some distribution level.

This SCR method of post-combustion control will be considered in this BACT analysis to control NO_x emissions.

3.2 Step 1--Identify All CO Control Technologies

The first step in a top-down analysis, according to the USEPA's October 1990, Draft New Source Review Workshop Manual, is to identify all available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission unit and the CO emission limit that is being evaluated. The results of this search for all CCCTs are listed in Attachment 2: CO Control Technology Review List.

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO. CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation is limited by ensuring complete and efficient combustion of the fuel in the CT. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions.

CO control methods may be divided into two categories: in-combustor CO formation control and post-combustion emission reduction. An in-combustor CO formation control process minimizes the quantity of CO formed in the combustion process. A post-combustion technology reduces the CO emissions in the flue gas stream after the CO has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of CO emissions required. The three different types of emission controls reviewed by this BACT analysis are as noted below.

- In-Combustor Type:
  - DLN Burners.
- Post-Combustion Type:
  - Oxidation Catalyst.
  - $SCONO_x$.

The rationale behind whether the above technologies are evaluated as CO control for BACT is included in the following subsections.

3.2.1 Dry Low NO_x Burners and Good Combustion Control

The development of good combustion practice improvements with state-of-the-art DLN burners has reduced CO emissions as compared to those previously obtained by the use of water injection as the main NO_x control method. These improved combustion characteristics have allowed minimization of CO emissions without sacrificing NO_x control performance. For this reason, the use of low NO_x burners (LNBs) that use good combustion practices is the standard method of also controlling CO emissions.

3.2.2 CO Oxidation Catalyst

A current CO reduction technology available that will not impact NO_x emissions is the use of an oxidation catalyst to convert the CO to CO_2. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic. No reagent injection is necessary, and oxidizing catalysts (dependent on the uncontrolled emission level), are capable of reducing a significant amount of the CO emissions. A 73.7 percent CO reduction rate (i.e., 7.6 ppm to 2.0 ppm) has been assumed for this BACT analysis.

3.2.3 *$SCONO_x$*

Another CO control technology that was previously discussed for NO_x control is the $SCONO_x$ process. The $SCONO_x$ system reduces CO emissions by oxidizing the CO to CO_2. The demonstrated application for this technology is currently limited to CCCT units under 40 MW. The CT proposed for this project is approximately 150 MW, which is outside the operating range (32 MW) of the $SCONO_x$ system currently operating at the Federal Cold Storage Cogeneration facility in California.

3.3 Step 2--Eliminate Technically Infeasible NO_x Options

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. The following subsections review the control technologies identified in Step 1 of the NO_x BACT analysis and determine if they are technically feasible. Table 3-1 summarizes the evaluation of the technically feasible NO_x options.

Table 3-1
Summary of Step 2--Eliminate Technically Infeasible Options

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Water or Steam Injection	Yes	No – Wet injection has limited NO_x removal. Not a primary control technology for natural gas fired turbines.
DLN Burners	Yes	Yes
XONON	Yes	No – There are no documented installations on utility sized CTs firing natural gas.
SNCR	Yes	No – The exhaust temperature of the CT is less than the SNCR's optimum temperature range.
$SCONO_x$	Yes	Yes
SCR	Yes	Yes

3.3.1 Water or Steam Injection

Water or steam injection can be an effective NO_x control method for a turbine burning natural gas or fuel oil. However, demineralized water must be used and additional capital cost is required because an onsite demineralized system must be built and the annual operation of this system can be a significant expense in the unit operation. The development of DLN burners has replaced the use of wet controls, except for certain cases, such as oil firing. New DLN burners can achieve lower levels of NO_x compared to wet controls. Since Unit 4 will only fire natural gas, water injection will not be considered further in this BACT analysis.

3.3.2 Dry Low NO_x Burners

DLN burners are a demonstrated technology for controlling NO_x emissions from a CCCT and are commercially available from several vendors. DLN burners are considered technically feasible and will be considered further.

3.3.3 XONON

Although XONON technology has been applied to small turbines, such as a Kawasaki M1A-13X (1.5 MW) CT, it has not been applied to utility size CTs such as proposed for Unit 4. It is expected that application of this technology to utility size CTs will require a period of “scale up” and testing before it can be determined that this technology can demonstrate in practice a given NO_x emission limit. Because this technology has not been applied to utility size CTs firing natural gas, it is not considered to be technically feasible for Unit 4. As such, this method of combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

3.3.4 Selective Noncatalytic Reduction

SNCR optimum temperature range for injection of ammonia or urea is 1,550° to 1,900° F. The exhaust temperature at the exit of the CT is between 1,074º to 1,200º F. Therefore, the exhaust temperature is less than the optimum temperature range for the application of this technology. It is not technically feasible to apply this technology to this Project, and it will be eliminated from further evaluation in this BACT analysis.

3.3.5 $SCONO_x$

The application of this technology is currently limited to natural gas CCCT units under 40 MW. However, EmeraChem, LLC is EM_X^{TM} ($SCONO_x$) offers their product for GE 7FAs, which makes it available. In addition, $SCONO_x$ has not been previously installed and operated at a similar type and size of turbine. However, in the interest of providing a complete technology analysis, $SCONO_x$ will be evaluated in the BACT for NO_x control.

3.3.6 Selective Catalytic Reduction

SCR systems are a demonstrated technology of controlling NO_x emissions from a CCCT and commercially available from several vendors. SCR systems are considered technically feasible and will be considered further.

3.4 Step 2--Eliminate Technically Infeasible CO Options

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. The following subsections review the control technologies identified in Step 1 of the CO BACT analysis and determine if they are technically feasible. Table 3-2 summarizes the evaluation of the technically feasible CO options.

3.4.1 Dry Low NO_x Burners and Good Combustion Control

The development of good combustion practice improvements with state-of-the-art DLN burners are a demonstrated technology of controlling CO emissions from a simple cycle CT and commercially available from several vendors. DLN burners and good combustion control are considered technically feasible and will be considered further.

3.4.2 CO Oxidation Catalyst

CO oxidation catalysts are a demonstrated technology of controlling CO emissions from a simple cycle CT and are commercially available from several vendors. CO oxidation catalysts are considered technically feasible and will be considered further.

Table 3-2 Summary of Step 2--Eliminate Technically Infeasible CO Options		
Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
DLN Burners and Good Combustion Control	Yes	Yes
CO Oxidation Catalyst	Yes	Yes
$SCONO_x$	Yes	Yes

3.4.3 $SCONO_X$

The application of this technology is currently limited to natural gas CCCT units under 40 MW. However, EmeraChem, LLC is EM_X^{TM} ($SCONO_x$) offers their product for GE 7FAs, which makes it available. In addition, $SCONO_x$ has not been previously installed and operated at a similar type and size of turbine. However, in the interest of providing a complete technology analysis, $SCONO_x$ will be evaluated in the BACT for CO control.

3.5 Step 3--Rank Combined NO_X and CO Control Technology Effectiveness

In-combustor NO_x and CO control by advanced combustion controls using DLN burners is the least stringent control technology considered for Cane Island Unit 4. However, the use of a combination SCR/oxidation catalyst system or the $SCONO_x$ system are technologies capable of achieving significantly lower emissions than the application of DLN burners alone. Because the $SCONO_x$ system is capable of reducing NO_x and CO, emissions, the NO_x and CO BACT analyses have been combined to avoid double counting the $SCONO_x$ technology, thus inflating its economic impacts. The following control technologies will be evaluated in this BACT analysis and are ranked in order of relative control effectiveness:

- In-combustor NO_x and CO control consisting of DLN combustors to limit outlet emissions during natural gas firing for all operating loads for Unit 4 is considered the base case scenario. All modern CTs of the type proposed for this Project include DLN combustors.

- The addition of an SCR system and oxidation catalyst to reduce outlet NO_x emissions from the natural gas fired CTG/HRSG with DB to the level of 2.0 ppmvd and CO to 2.0 ppmvd emissions for the natural gas fired CTG/HRSG with DBs.
- The addition of a $SCONO_x$ system to reduce outlet NO_x emissions from the natural gas fired CTG/HRSG with DBs to the NO_x level of 2.0 ppmvd and CO emissions to 2.0 ppmvd.

The following evaluation considers energy, environmental, and economic impacts for the NO_x and CO combined technology scenarios evaluated. Table 3-3 outlines the expected NO_x and CO emissions rates from the evaluated emissions control alternatives of DLN burners (i.e., good combustion controls), SCR/CO catalyst, and $SCONO_x$. SCR/CO catalyst and $SCONO_x$ are considered the most stringent NO_x and CO emissions control alternatives because they achieve the lowest outlet emission rate. Therefore, if $SCONO_x$ is not found viable via energy, environmental, or economic impacts for the combined emissions reduction, the $SCONO_x$ technology will be eliminated from consideration, and a BACT evaluation would be done for control of NO_x and CO emissions separately.

3.6 Step 4--Evaluate Most Effective Combined NO_X and CO Controls

In the following subsections, the NO_x and CO combined control technologies are evaluated in a comparative approach with respect to their energy, environmental, and economic impacts on Cane Island Unit 4. The following are the evaluated technologies: $SCONO_x$, SCR, and Oxidation Catalyst.

3.6.1 $SCONO_x$ Energy Impacts

The use of an $SCONO_x$ system will increase the energy requirements on the system compared to use of DLN burners alone. The $SCONO_x$ system will increase the back pressure on the CT by about 4 inches water gauge (in. wg). This will reduce the output of Cane Island Unit 4 by approximately 0.3 percent and increase the lost power generation. In addition, the period required for catalyst washing will result in increasing the lost power generation. Wahlco-Metroflex estimated the unit will be off-line for a 24 hour period once per year to accommodate the washing process. Furthermore, there will be an energy loss due to steam consumption from the regeneration system. Steam is used as the carrier medium for the regeneration gas for the $SCONO_x$ system. Wahlco-Metroflex estimated that approximately 5,000 lb/h of steam would be used in the regeneration production for each CT. These three effects will be added together to

Table 3-3
Estimated NO_x and CO Emissions from Alternate Control Technologies for Unit 4

	Control Technology Alternatives		
	LNB/Good Combustion Controls	SCR/CO Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	12.2	2.0	2.0
pounds per hour (lb/h)	107.7	17.6	17.6
tpy[a]	471.7	77.3	77.3
percent reduction	NA	83.6	83.6
NO_x Emission Reduction (tpy)	Base	394.4	394.4
CO Emissions			
ppmvd (at 15 percent O_2)	7.6	2.0	2.0
lb/h	40.8	10.7	10.7
tpy[a]	178.7	47.0	47.0
percent reduction	NA	73.7	73.7
CO Emission Reduction (tpy)	Base	131.7	131.7

[a]Total emissions are based on 8,760 h/yr firing natural gas, 100 percent load, duct firing, evaporative cooling, at ISO conditions.

determine the total lost power generation and are included in the annualized cost estimate. The $SCONO_x$ system will have minimal effect on power consumption that will be necessary to operate the damper actuators and regeneration system. Wahlco-Metroflex estimated that approximately 15 kW would be consumed during operation of each $SCONO_x$ system. This increase in power consumption will be included in the annualized cost estimate. The natural gas required for the production of the regeneration gas will increase the annualized cost associated with using the $SCONO_x$ system. The annualized cost of natural gas consumption is included in the annualized cost analysis.

3.6.2 $SCONO_x$ Environmental Impacts

The $SCONO_x$ catalyst is composed of precious metals coated with K_2CO_3. When the K_2CO_3 coating can no longer be regenerated, the precious metal content of the remaining catalyst can be recycled. Although recycling the K_2CO_3 is a positive aspect of this technology, the oxidation of CO and VOC that results from the application of this technology directly results in an increased production of CO_2, a greenhouse gas. There is currently a worldwide effort to reduce industrial emissions of CO_2 because of its contribution to global climate change. Installation of a $SCONO_x$ system would directly counter this initiative.

The $SCONO_x$ catalyst will oxidize approximately 1.0 percent of the SO_2 in the flue gas to SO_3. The SO_3 will then react with the moisture in the flue gas to form H_2SO_4 in the atmosphere. Any H_2SO_4 formed will increase the amount of PM emitted in the flue gas. The PM will predominately consist of PM_{10}.

3.6.3 SCR Energy Impacts

The use of an SCR system impacts the energy requirements of Cane Island Unit 4. An SCR system requires an ammonia storage, handling, and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. In addition, an SCR system catalyst would increase the back pressure on each CT. The SCR system would add about 2.6 in. wg back pressure to the unit for the NO_x reduction to 2.0 ppmvd. This would reduce the output of Cane Island Unit 4 by approximately 492 kilowatts (kW).

3.6.4 SCR Environmental Impacts

The vanadium content of the SCR catalyst contributes to its classification as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures. Because of this, recycling of SCR catalysts for vanadium has become common.

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes and is also regulated by USEPA's Chemical Accident Prevention Provisions. This BACT analysis is based on the use of aqueous ammonia that can be stored and used more safely than anhydrous ammonia. According to the Committee on Toxicology of the National Academy of Sciences and the Committee on Medical and Biological Effects of Environmental Pollutants (both of the National Research Council), the following threshold concentrations exist for ammonia:

Human Response	Concentration (ppm)
Immediate throat irritation	Equal to or greater than 400
Eye irritation	Equal to or greater than 700
Coughing	Equal to or greater than 1,700
Life threatening for short exposure	2,500 to 6,500
Rapidly fatal for short exposure	5,000 to 10,000

Some ammonia slip from the Cane Island Unit 4 stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd, unless that limit is shown to be inappropriate. Ammonia slip from an SCR system is one of the major design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictate associated catalyst replacement. Exceeding the NESCAUM's recommendation, Florida Department of Environmental Protection (FDEP) proposed an ammonia slip of 5 ppmvd for Treasure Coast, a CCCT unit utilizing SCR. Based on the recent Treasure Coast air permit, an ammonia slip design value of 5 ppmvd at 15 percent O_2 is used for this analysis.

The SCR catalyst will oxidize approximately 2 to 3 percent of the SO_2 in the flue gas to SO_3. Once the flue gas cools below approximately 600° F, the ammonia present in the flue gas may react with SO_3 to form ammonium sulfate and bisulfate salts. This formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge, which is dependent upon the temperature reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO_3 will react with the moisture in the flue gas to form H_2SO_4 in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the amount of PM emitted in the flue gas. The particulate material will predominately consist of matter less than PM_{10}. As the catalyst gradually deactivates, more ammonia must be injected to compensate and maintain the desired NO_x reduction. This results in an increased amount of ammonia slip for a given level of performance. Increased ammonia slip in turn results in additional ammonia salt formation which could result in increased opacity and particulate emissions from Cane Island Unit 4.

3.6.5 Oxidation Catalyst Energy Impacts

An oxidation catalyst reactor located downstream of the CT exhaust will increase the back pressure on the CT. The additional back pressure of about 1.2 in. wg, will reduce each CT output by approximately 227 kW. The cost of lost power revenue due to the back pressure is included in the economic analysis.

3.6.6 Oxidation Catalyst Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions is that a percentage of the SO_2 in the flue gas will oxidize to SO_3. The higher the operating temperature, the higher the SO_2 to SO_3 oxidation potential. It is estimated that approximately 20 percent of the SO_2 in the flue gas will oxidize to SO_3 as a result of the oxidation catalyst being installed after the CT outlet with high temperatures. The SO_3 will react with the moisture in the flue gas to form H_2SO_4. The increase in H_2SO_4 emissions would increase PM_{10} emissions.

Spent oxidation catalyst is made up of precious metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures. Because of the precious metal content of the catalyst, the oxidation catalyst can also be recycled to recover the precious metals.

As mentioned previously, the installation of an oxidation catalyst will also increase the back pressure on the turbine, thereby decreasing efficiency. This decrease in efficiency will lead to increased emissions of all pollutants on a unit power output basis. The oxidation of CO also directly results in increased production of CO_2, a greenhouse gas. There is currently a worldwide effort to reduce industrial emissions of CO_2 because of its contribution to global climate change. Installation of an oxidation catalyst would directly counter this initiative.

3.6.7 Economic Impacts for SCR (2.0 ppmvd)/Oxidation Catalyst Versus $SCONO_x$

The use of an SCR/oxidation catalyst or $SCONO_x$ has significant economic impacts to Cane Island Unit 4. An analysis of the economic impact is provided in this subsection.

3.6.7.1 Capital Costs for SCR (2.0 ppmvd)/Oxidation Catalyst and $SCONO_x$. Table 3-4 presents the capital costs for installing an SCR/oxidation catalyst and $SCONO_x$ system on Cane Island Unit 4 during natural gas firing to achieve an NO_x outlet emission level of 2.0 ppmvd and a CO outlet emission rate of 2.0 ppmvd. The cost of the SCR/oxidation catalyst system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing and ductwork; controls and instrumentation; and freight. The catalyst costs were not included in the total capital investment (TCI) cost but were assessed as an annual cost. The cost of the $SCONO_x$ system includes the catalyst, regenerative gas distribution system, catalytic reactor housing, controls and instrumentation, and freight. The balance-of-plant (BOP) cost for the SCR/oxidation catalyst and $SCONO_x$ system consists of 8 percent of the purchased equipment costs (PEC) for foundation and supports, 14 percent for handling and erection, 4 percent for electrical installation, 2 percent for piping, 1 percent for insulation, and 1 percent for painting. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates.

Quotations for the SCR and oxidation catalyst material were based on vanadium/titanium and precious metal type catalysts, respectively. The direct installation costs included the BOP items such as foundations, insulation and lagging, and painting and were calculated as percentages of the total purchased equipment costs. The TCI was calculated as the summation of the total direct cost and total indirect costs in accordance with OAQPS cost methods. The indirect capital costs for the SCR/oxidation catalyst systems are percentages of the total direct costs and are site specific. The indirect capital costs for the $SCONO_x$ system are percentages of the $SCONO_x$ system direct costs.

Table 3-4
NO_x/CO Combined Control Alternative Capital Cost ($) For Cane Island Unit 4

	DLN	$SCONO_x$ ($)	SCR/ Oxidation Catalyst ($)	Remarks
Direct Capital Cost				Cost based on emissions in Table 3-3.
Catalysts	NA	Included	1,289,000	Est. from BASF/CERAM.
Catalyst Reactor Housing /Ductwork	NA	Included	705,000	Estimated from Turner EnviroLogic.
$SCONO_x$ System	NA	16,000,000	0	Vendor Estimate.
Control/Instrumentation	NA	150,000	195,000	Estimated; includes controls and monitoring equipment.
Ammonia (Storage and Injection)	NA	N/A	985,000	Estimated from Turner EnviroLogic and previous projects.
PEC	**NA**	**16,150,000**	**3,174,000**	
Sales Tax		0	0	Not applicable to FMPA.
Freight	NA	1,615,000	318,000	10 percent of PEC.
BOP	NA	5,491,000	953,000	30 percent of PEC. Refer to text for background information on this item.
Total Direct Cost (DC)	**NA**	**23,256,000**	**4,445,000**	
Indirect Capital Costs				
Contingency	NA	2,326,000	445,000	10 percent of DC.
Engineering and Supervision	NA	2,326,000	445,000	10 percent of DC for $SCONO_x$. 10 percent of DC for SCR and 10 percent of DC for CO catalyst.
Construction and Field Expense	NA	1,163,000	223,000	5 percent of DC.
Construction Fee	NA	2,326,000	445,000	10 percent of DC.
Startup Assistance	NA	465,000	89,000	2 percent of DC.
Performance Test	NA	50,000	50,000	Assumed $50,000 emission test.
Total Indirect Capital Costs (IC)	**Base**	**8,656,000**	**1,697,000**	
Installed Costs (DC+IC)	**Base**	**31,912,000**	**6,142,000**	
Less Catalyst	Base	4,000,000	1,289,000	Catalyst is viewed as an operations and maintenance (O&M) value.
TCI	**Base**	**27,912,000**	**4,853,000**	TCI = DC + IC – Catalyst

There are many potential items and uncertainties that are not captured by the cost items included in the estimate, such as possible changes between cost quotes and contract values, changes in operating conditions, process contingency, increased equipment cost, scope changes, labor/wage increases, and schedule acceleration. In addition, the Electric Power Research Institute published the document titled, "NO_x Emissions: Best Available Control Technology, A Gas Turbine Permitting Guidebook," in November 1991 and lists under NO_x control cost (Page 5-5) the following text:

> "Based on experience with other cost methodology sources, the contingency factor recommended by the OAQPS Manual (3% of the total equipment cost) is a lower-bound estimate. Standard EPA guidance for pollution control costing is a contingency factor of 10 to 50% of the sum of direct and indirect costs.[1] A contingency factor of 20% of the sum of direct and indirect costs was used in the economic analyses conducted by the EPA in support of the NSPS for industrial and small boilers and municipal waste combustors.[2,3]. Based on this range of values, it is recommended that individual utilities use the contingency factor that would normally be used in-house in procurement or rate estimation procedures, and document the validity of the factor for the case in question. The factor recommended by OAQPS should be used as a default value when more appropriate information is not available."

Therefore, a 10 percent contingency factor has been assumed for this project.

Based on the analysis in this subsection, the TCI for the SCR/oxidation catalyst control system is calculated as the sum of the total direct and indirect capital costs in accordance with OAQPS cost methods. The TCI for Cane Island Unit 4 controlling NO_x and CO to 2.0 ppmvd and 2.0 ppmvd, respectively, is estimated to be $4,853,000.

The TCI for the $SCONO_x$ control system is calculated as the sum of the total direct and indirect capital costs in accordance with OAQPS cost methods. The TCI for Cane Island Unit 4 controlling NO_x and CO to 2.0 ppmvd and 2.0 ppmvd, respectively, is estimated to be $27,912,000.

[1] U.S. Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations: Volume I, EPA 600/8-79-018a, June 1979.

[2] U.S. Environmental Protection Agency, Industrial Boiler SO_2 Cost Report, EPA 450/3-85-011, November 1984.

[3] U.S. Environmental Protection Agency, Municipal Waste Combustors – Background Information for Proposed Standards: Control of NO_x Emissions, EPA 450/3-89-27d, August 1989.

3.6.7.2 Operating Costs for SCR/Oxidation Catalyst Versus SCONO$_x$. Table 3-5 presents the annualized operating costs using an SCR/oxidation catalyst and SCONO$_x$ system to achieve NO_x outlet emissions of 2.0 ppmvd and CO emissions of 2.0 ppmvd while firing natural gas for Unit 4. Annualized operating costs for the SCR/oxidation catalyst include catalyst replacement, energy impacts, operating personnel, maintenance, reagent, and heat rate penalty. Throughout the life of the plant, catalyst elements for both the SCR and the oxidation catalyst will require routine periodic replacement. As the SCR catalyst becomes deactivated, ammonia slip emissions will increase. At the point ammonia slip approaches 5 ppmvd the catalyst must be replaced. The oxidation catalyst will degrade from normal operation that will be evident by an increase in CO emissions, thereby requiring replacement of the oxidation catalyst. Currently, SCR and oxidation catalyst manufacturers are willing to guarantee a catalyst life of 3 years of equivalent operating hours.

Ammonia consumption rates were based on a stoichiometric ratio of 1.1 for reacting NO_x. The heat rate penalty cost (lost power generation) item reflects the cost due to the SCR and oxidation catalyst back-pressure losses. The additional back pressure will derate the CT resulting in lost electric sales revenue. The costs associated with these impacts are included in the annualized cost estimate.

The use of either an SCR/oxidation catalyst system or an SCONO$_x$ system increases the energy requirements of the project. The SCR system requires vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. SCONO$_x$ consumes power to open and close the catalyst dampers and to produce the regenerating gas. The maintenance costs will consist of routine system maintenance for each system. However, there is an additional annual maintenance cost for washing the SCONO$_x$/SCOSO$_x$ catalyst. Therefore, the SCONO$_x$ system will include the additional O&M cost for catalyst washing.

The indirect annual costs include capital recovery, overhead, administrative charges, and insurance. The overhead annual cost is estimated to be 60 percent of the O&M costs. According to the OAQPS Cost Manual there are two types of overhead: payroll and plant. Payroll overhead expenses include Workers' Compensation, social security, vacations, group insurance, and other fringe benefits. Plant overhead is not tied into O&M of the control system, but is related to plant protection, control labs, employee amenities, plant lighting, parking areas, and landscaping. The OAQPS Cost Manual allows for combining these overhead costs into one sum. The administrative cost covers sales, research and development, accounting, and other home office expenses. The insurance cost was based on 1 percent of the TCI for each system.

Table 3-5
NO_x/CO Combined Control Alternative Annualized Cost ($) For Cane Island Unit 4

	DLN	$SCONO_x$ ($)	SCR/ Oxidation Cataylst ($)	Remarks
Direct Annual Cost				Cost based on emissions in Table 3-3.
Catalyst Replacement	NA	1,116,000	536,000	Includes freight, installation, and 3 year capital recovery factor based on 3 year guaranteed catalyst life for SCR/oxidation catalyst and 5 year catalyst life for $SCONO_x$.
O&M	NA	64,000	37,000	Refer to text for background information on this item.
Maintenance Materials	NA	48,000	23,000	
Reagent Feed	NA	N/A	240,000	Assumes 1.1 stoichiometric ratio.
Natural Gas Consumption	NA	65,000	0	
Power Consumption	NA	110,000	285,000	Includes injection blower and vaporization of ammonia.
Lost Power Generation	NA	2,191,000	397,000	Back pressure on CT. Includes 7 days of lost power generation time for catalyst/system cleaning for $SCONO_x$.
Annual Distribution Check	NA	116,000	34,000	Estimated as 0.5 percent of the total direct cost for $SCONO_x$ and 1 percent for SCR.
Total Direct Annual Cost	**NA**	**3,710,000**	**1,552,000**	
Indirect Annual Costs				
Overhead	NA	38,000	22,000	60 percent of O&M cost.
Administrative Charges	NA	638,000	123,000	2 percent of installed cost.
Property Taxes	NA	0	0	Not included.
Insurance	NA	319,000	61,000	1 percent of installed cost.
Capital Recovery	NA	2,240,000	389,000	Capital recovery excluding catalyst.
Total Indirect Annual Costs	**NA**	**3,235,000**	**595,000**	
Total Annualized Cost	**NA**	**6,945,000**	**2,147,000**	

3.6.7.3 Total Annualized Costs for SCR (2 ppmvd)/Oxidation Catalyst Versus SCONO$_x$. Total annualized costs for the SCR and oxidation catalyst control systems are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor and the TCI. Table 3-5 shows that the total annualized cost for an SCR/oxidation catalyst system for Cane Island Unit 4 firing natural gas is estimated to be $2,147,000, which is approximately a third of the cost of an SCONO$_x$ system having a total annualized cost of $6,945,000.

3.6.7.4 Conclusions. Based on the fact that the SCR/oxidation catalyst system is a lower capital cost system and has lower annualized costs than the SCONO$_x$ system, the SCONOx system will not be further evaluated as part of the BACT analysis. The remainder of the BACT analysis will concentrate on evaluating technologies for the control of each pollutant separately.

3.7 Step 4--Evaluate Most Effective NO_X Controls

This section identifies economic impacts of the NO_x only BACT analysis. This section will not include a discussion of energy and environmental impacts, because they are the same as those discussed in the combined control BACT evaluation for NO_x and CO as listed in Section 3.6.

3.7.1 Economic Impacts for SCR

The control of NO_x emissions separate from CO emission control is possible through the application of an SCR to Cane Island Unit 4 without additional CO emission controls. To determine the BACT levels for NO_x controls without the influence of the CO emission controls, a separate economic analysis is required. An analysis of the economic impact of SCR as a separate control technology for NO_x emissions of 2.0 ppmvd firing natural gas is provided in this subsection. The BACT costs presented in this analysis are based on operating the CT, with duct firing, at 100 percent base load for 8,760 h/yr on natural gas.

3.7.2 Economic Impacts for SCR (2.0 ppmvd NO$_X$) System

The use of an SCR has significant economic impacts to the FMPA Project. The application of SCR on Cane Island Unit 4 must incorporate special design and operational/maintenance criteria, such as periodic catalyst replacements and increased associated plant outage costs. A detailed description of the economic impacts of SCR was provided previously in Subsection 3.6.7 and will not be repeated.

3.7.2.1 Capital Costs for SCR (2.0 ppmvd NO_x). Table 3-6 summarizes the economic capital cost for implementing SCR on Cane Island Unit 4 firing natural gas. Based on the analysis in this subsection, the total installed capital costs for the SCR control system is calculated as the sum of the total direct and indirect capital costs in accordance with OAQPS cost methods. The TCI cost of SCR for Cane Island Unit 4 controlling NO_x to 2.0 ppmvd is estimated to be $4,031,000.

3.7.2.2 Total Annualized Costs for SCR (2.0 ppmvd NO_x). Total annualized costs for the SCR control systems are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor and the TCI. Table 3-7 shows that the total annualized cost for SCR systems is estimated to be $1,676,000. This annualized cost for the Unit 4 SCR systems results in a cost-effectiveness of approximately $4,250 per ton of NO_x removed.

3.8 Step 4--Evaluate Most Effective CO Controls

This section identifies economic impacts of the CO only BACT analysis. This section will not include a discussion of energy and environmental impacts, because they are the same as those discussed in the combined control BACT evaluation for NO_x and CO as listed in Section 3.6.

3.8.1 Economic Impacts for Oxidation Catalyst

The use of an oxidation catalyst has significant economic impacts to the FMPA Project. An analysis of the economic impact is provided in this subsection. An analysis of the economic impact of oxidation catalyst as a separate control technology for CO emissions of 2.0 ppmvd firing natural gas is provided in this subsection. The BACT costs presented in this analysis are based on operating the CT, with duct firing, at 100 percent of base load for 8,760 h/yr on natural gas.

Table 3-6
NO_x Emission Control Alternative Capital Cost ($) for Cane Island Unit 4

	DLN	SCR ($)	Remarks
Direct Capital Cost			Cost based on emissions in Table 3-3.
Catalyst	N/A	674,000	Estimated from CERAM.
Catalyst Reactor Housing/Ductwork	N/A	630,000	Estimated from Turner EnviroLogic.
Control/Instrumentation	N/A	150,000	Estimated; includes controls and monitoring equipment.
Ammonia (Injection/Dilution/ Storage)	N/A	985,000	Estimated from Turner EnviroLogic.
PEC	**N/A**	**2,439,000**	
Sales Tax		0	Not applicable to FMPA.
Freight	N/A	244,000	10 percent of PEC.
BOP	N/A	732,000	30 percent of PEC. Refer to text for background information on this item.
Total Direct Cost (DC)	**Base**	**3,415,000**	
Indirect Capital Costs			
Contingency	N/A	342,000	10 percent of DC.
Engineering and Supervision	N/A	342,000	10 percent of DC.
Construction and Field Expense	N/A	171,000	5 percent of DC.
Construction Fee	N/A	342,000	10 percent of DC.
Startup Assistance	N/A	68,000	2 percent of DC.
Performance Test	N/A	25,000	Assumed $25,000.
Total Indirect Capital Costs (IC)	**Base**	**1,290,000**	
Installed Costs (DC + IC)		**4,705,000**	
Less SCR Catalyst Cost		674,000	Catalyst is viewed as an O&M value.
TCI	**Base**	**4,031,000**	

Table 3-7
NO_x Emissions Control Annualized Cost ($) for Cane Island Unit 4

	DLN	SCR ($)	Remarks
Direct Annual Cost			Cost based on emissions in Table 3-3.
Catalyst Replacement	NA	299,000	Includes freight, installation, and 3 year capital recovery factor based on 3 year guaranteed catalyst life.
O&M	NA	37,000	Refer to text for background information.
Maintenance Materials	NA	23,000	Refer to text for background information.
Reagent Feed	NA	240,000	Assumes 1.1 stoichiometric ratio.
Power Consumption	NA	285,000	Includes injection blowers and vaporization of ammonia.
Lost Power Generation	NA	272,000	Back pressure on CT.
Annual Distribution Check	NA	34,000	Estimated as 1 percent of the total direct cost.
Total Direct Annual Cost	NA	1,190,000	
Indirect Annual Costs	NA		
Overhead	NA	22,000	60 percent of O&M cost.
Administrative Charges	NA	94,000	2 percent of installed costs.
Property Taxes	NA	0	Not included.
Insurance	NA	47,000	1 percent of installed costs.
Capital Recovery	NA	323,000	Capital recovery excluding catalyst.
Total Indirect Annual Cost	NA	486,000	
Total Annualized Cost	NA	1,676,000	
NO_x Annual Emissions, tpy	471.3	77.3	Emissions taken from Table 3-3.
NO_x Emissions Reduction, tpy	NA	374.4	Emissions calculated in Table 3-3.
NO_x Total Cost Effectiveness, $/ton	NA	4,250	Total Analyzed Cost/Emissions Reduction.

3.8.2 Capital Cost for Oxidation Catalyst

Table 3-8 presents the capital cost for installing an oxidation catalyst on the units during natural gas firing to achieve a CO outlet emission level of 2.0. The capital costs for the systems include the oxidation catalyst, oxidation catalyst reactor housing, controls and instrumentation, sales taxes, and freight, and were based on budgetary quotations from equipment manufacturers and other engineering estimates. The direct installation costs included the BOP items such as foundations, insulation and lagging, and painting, and were calculated as percentages of the total PEC. The TCI was calculated as the summation of the total direct cost and total indirect costs in accordance with OAQPS cost methods. The indirect capital costs for the SCR/oxidation catalyst systems are percentages of the total direct cost and are site specific. The 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating, as discussed in Subsection 3.6.7.1.

Total capital cost for the oxidation catalyst control system to reduce CO is calculated as the sum of the direct and indirect installed costs. The TCI per unit for an oxidation catalyst system to reduce CO emissions from Cane Island Unit 4 firing natural gas is estimated to be $822,000.

3.8.3 Operating Costs for Oxidation Catalyst

Table 3-9 presents the annualized operating costs and emission rates using an oxidation catalyst to achieve a 74 percent reduction in CO emissions while firing natural gas on Cane Island Unit 4. Annualized operating costs for the system include catalyst replacement and lost power generation. Throughout the life of the plant, catalyst elements will require routine periodic replacement. Currently, catalyst manufacturers are willing to guarantee an oxidation catalyst life of 3 years of equivalent operating hours for an oxidation catalyst.

3.8.4 Total Annualized Costs for Oxidation Catalyst

Total annualized costs for the oxidation control system are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor and the total installed costs. Firing natural gas, the total annualized cost for a 2.0 ppmvd CO oxidation catalyst system for Cane Island Unit 4 is estimated to be $471,000. This annualized cost for Cane Island Unit 4 results in a cost-effectiveness of approximately $3,576 per ton of CO removed.

Table 3-8
CO Reduction System Capital Cost ($) For Cane Island Unit 4

	Good Combustion Controls/DLN	Oxidation Catalyst ($)	Remarks
Direct Capital Cost			Cost based on emissions in Tables 3-3.
Oxidation Catalyst	NA	615,000	Estimated from BASF.
Catalyst Reactor Housing	NA	75,000	
Control/Instrumentation	NA	45,000	Estimated; includes controls and monitoring equipment.
PEC	NA	735,000	
Sales Tax	NA	0	Not applicable to FMPA.
Freight	NA	74,000	10 percent of PEC.
BOP	NA	221,000	30 percent of PEC. Refer to text for background information on this item.
Total Direct Cost (DC)	**Base**	**1,030,000**	
Indirect Capital Costs	NA		
Contingency	NA	103,000	10 percent of DC.
Engineering and Supervision	NA	103,000	10 percent of DC.
Construction and Field Expense	NA	52,000	5 percent of DC.
Construction Fee	NA	103,000	10 percent of DC.
Startup Assistance	NA	21,000	2 percent of DC.
Performance Test	NA	25,000	Assumed value of $25,000.
Total Indirect Capital Costs (IC)	**Base**	**407,000**	
Installed Costs (DC +IC)		**1,437,000**	
Less Catalyst	NA	615,000	Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	**Base**	**822,000**	

Table 3-9
CO Control Annualized Cost ($) For Cane Island Unit 4

	Good Combustion Controls/DLN	Oxidation Catalyst ($)	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1.
Catalyst Replacement	NA	237,000	Includes freight, installation, and 3 year capital recovery factor based on 3 year guaranteed catalyst life.
O&M	NA	0	Not applicable for oxidation catalyst.
Lost Power Generation		125,000	Back pressure on CT.
Total Direct Annual Cost	**NA**	**362,000**	
Indirect Annual Costs			
Overhead	NA	0	Not applicable because of zero O&M.
Administrative Charges	NA	29,000	2 percent of installed costs.
Property Taxes	NA	0	Not included.
Insurance	NA	14,000	1 percent of installed costs.
Capital Recovery	NA	66,000	Capital recovery excluding catalyst.
Total Indirect Annual Costs	**NA**	**109,000**	
Total Annualized Cost	**Base**	**471,000**	
CO Annual Emissions, tpy	178.7	47.0	Emissions taken from Table 3-3.
CO Emissions Reduction, tpy	NA	131.7	Emissions taken from Table 3-3.
CO Total Cost Effectiveness, $/ton	**NA**	**3,576**	**Total Annualized Cost/Emissions Reduction**

3.9 Step 5--Select NO_x BACT

Based on the cost-effectiveness value for the SCR catalyst it is determined that add-on controls to further reduce NO_x emissions are warranted. FMPA has determined that the top NO_x control alternative when firing natural gas, DLN burners with SCR catalyst, represents NO_x BACT for Cane Island Unit 4, corresponding to an emissions limit of 2 ppmvd at 15 percent O_2 on a 24 hour average basis. Table 3-10 summarizes the Project's NO_x BACT determination for Cane Island Unit 4.

Table 3-10
Cane Island Unit 4 NO_x BACT Determination

Control Technology	Emission Limit
DLN Burners with SCR	2.0 ppmvd at 15 percent O_2 (24 hour average)

3.10 Step 5--Select CO BACT

Based on the high cost-effectiveness value for the oxidation catalyst it is determined that add-on controls to further reduce CO emissions are unwarranted given the low CO emission characteristics of Cane Island Unit 4 firing natural gas. As a basis for review, the cost-effectiveness guidelines are pollutant-specific, considering the control technology, environmental sensitivity, and determinations from similar BACT trends for that pollutant in the affected region and across the country. FMPA believes that an oxidation catalyst is not BACT for this project. This determination is independent of the NO_x control determination. The CO BACT assessment is firmly based on the energy, environmental, and economic impacts detailed in the application, as well as recent Department determinations for similar units at similar emission levels. In those determinations, the Department has found that add-on controls to further reduce CO emissions are unwarranted given the already low emissions characteristics of this particular gas turbine firing natural gas as the only fuel. A few of those particular determinations are Florida Power & Light's (FPL's) Turkey Point, TECO's Bayside Power Station, FMPA's Treasure Coast, and Progress Energy's Hines Power Block 4, which are all documented in Attachment 2. The CO BACT cost-effectiveness for FMPA has determined that the CO BACT for Cane Island Unit 4 during natural gas firing, with and without the operation of the natural gas fired DBs at 100 percent load, is good combustion controls. The CO BACT emission limit, with and without DBs operating, is a stack test limit of 7.6 ppmvd at 15 percent O_2 and 4.1 ppmvd at 15 percent O_2, respectively. The CEMS average limit is proposed as 8 ppmvd at 15 percent $O_{2,}$ and

24 hour block average. Table 3-11 summarizes the Project's CO BACT determination for Cane Island Unit 4.

Table 3-11
Cane Island Unit 4 CO BACT Determination

Control Technology	Emission Limit
Good Combustion Controls	7.6 ppmvd at 15 percent O_2 (stack test, three-run average) with DBs 4.1 ppmvd at 15 percent O_2 (stack test, three-run average) without DBs 8 ppmvd at 15 percent O_2 (CEMS, 24 hour block average)

4.0 Cane Island Unit 4 PM/PM_{10} BACT Analysis

The objective of this analysis was to determine BACT for PM/PM_{10} emissions from Cane Island Unit 4. This includes the CT and supplemental firing from DBs in the HRSG as a total unit.

PM/PM_{10} emissions from the CTs are a result of incomplete combustion and trace particulate parameters in the fuel. The emissions of PM from Cane Island Unit 4 will be controlled by ensuring as complete combustion of the fuel as possible. The NSPS for CTs does not establish a particulate emission limit. Natural gas contains only trace quantities of noncombustible material.

The manufacturer's standard operating procedures include filtering the turbine inlet air and combustion controls. The BACT/LAER Clearinghouse documents do not list any post-combustion PM control technologies being used on CTs. Consistent with the previous determinations as referenced by the State of Florida, such as the FPL West County, FMPA Treasure Coast, FPL Turkey Point, FPL Martin, FPL Manatee, FPL Fort Myers, Santa Rosa, and the City of Tallahassee projects, the use of combustion controls and natural gas (low sulfur fuel) is considered BACT for PM and is proposed for Cane Island Unit 4.

5.0 Cane Island Unit 4 SO_2 BACT Analysis

The objective of this analysis was to determine BACT for SO_2 emissions from Cane Island Unit 4. The SO_2 emissions are based on operating the CT with duct firing at 100 percent of baseload for a total of 8,760 hours while firing natural gas.

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. The selection of natural gas fuel provides inherently low SO_2 emissions.

Emissions of SO_2 can be controlled by limiting sulfur content in the fuel, limiting fuel oil usage, or by a post-combustion flue gas desulfurization (FGD) system. The fuel for this project is natural gas with a maximum expected sulfur content of 2.0 grains per 100 standard cubic feet.

To date, no supplemental SO_2 emission controls, such as FGD systems, have been imposed on simple cycle CTs. Such a system would be both technically and economically prohibitive.

Therefore, BACT for Cane Island Unit 4 is the use of natural gas. The basis of this determination is firing natural gas up to a maximum of 8,760 h/yr.

6.0 Cane Island Unit 4 H_2SO_4 BACT Analysis

The objective of this analysis was to determine BACT for H_2SO_4 emissions from Cane Island Unit 4. The H_2SO_4 emissions are based on operating the CT with duct firing at 100 percent of baseload for a total of 8,760 hours while firing natural gas.

Emissions of H_2SO_4 can be controlled by limiting sulfur content in the fuel. The natural gas to be utilized for Cane Island Unit 4 will contain less than 2 grains per 100 scf. The selection of low sulfur fuel (natural gas) provides inherently low SO_2 emissions, thus controlling the formation of H_2SO_4. In addition, no supplemental SO_3 emission controls, such as FGD systems or H_2SO_4 abatement systems, have been imposed on natural gas fired CTs by regulatory agencies.

Therefore, BACT for Cane Island Unit 4 is the use of good combustion controls while firing natural gas. The basis of this determination is firing natural gas up to a maximum of 8,760 h/yr.

7.0 Cane Island Unit 4
Safe Shutdown Generator and Fire Pump BACT Analysis

In the event of the loss of normal auxiliary power, ac power will be supplied by a new 750 kW, ULSFO fired safe shutdown generator. Additionally, a new emergency fire pump will supply emergency fire water to the Project using a 290 bhp diesel engine. The fire pump will be periodically tested for no more than 1 hour per week (up to 52 h/yr) to confirm their ready-to-start condition. The safe shutdown generator will be limited to no more than 200 hours per year of operation. Because of their small size, infrequent operation, and status as emergency equipment, the installation of post-combustion emission controls such as SCR and SNCR for NO_x, or FGD systems for SO_2, or oxidation catalyst for CO, while technically feasible for the safe shutdown generator and the fire pump, are far from cost-effective as control devices and are, therefore, not practical as BACT control alternatives. As such, FMPA has determined that BACT for the safe shutdown generator and fire pump is limited operation and good combustion controls while firing ULSFO. The proposed BACT determinations have no adverse environmental or energy impacts and are summarized below for each pollutant.

7.1 Select SO_2 BACT

The safe shutdown generator and fire pump will emit small quantities of SO_2 as a result of the oxidation of sulfur in the fuel. A review of the informational databases discussed in Section 2.1 indicates that ULSFO is the most stringent permitted control for similar types of units operated in the manner proposed. No post-combustion FGD system has ever been applied to a generator/fire pump this small that is firing a low sulfur fuel oil. Therefore, ULSFO is proposed as the BACT. The BACT control is good combustion control and combustion of ULSFO.

7.2 Select NO_x BACT

Further review of the informational databases discussed in Section 2.1 indicated that emergency generators and fire pumps have not been required to install additional NO_x controls because their operation is of an intermittent nature. As discussed in Subsection 2.1.1.4, the engines must meet the applicable NSPS, which will apply depending on the year of engine manufacture. The BACT control is good combustion control.

7.3 Select PM/PM_{10} BACT

The safe shutdown generator and fire pump will emit small quantities of particulates consisting of ash in the fuel and residual carbon and hydrocarbons caused from incomplete combustion. A review of the informational databases discussed in Section 2.1 indicated that good combustion control was the most stringent control permitted for similar units. Therefore, because of the very low operating hours of the safe shutdown generator and the fire pump, good combustion control and engine design are proposed as BACT.

As discussed in Subsection 2.1.1.4, the engines must meet the applicable NSPS, which will depend on the year of engine manufacture. The BACT control is good combustion control.

7.4 Select CO BACT

The control technologies for CO emissions evaluated for use on the safe shutdown generator and the fire pump are catalytic oxidation and proper design to minimize emissions. Because of the intermittent operation and low emissions, add-on controls would be prohibitively expensive. Thus, good combustion control is proposed as BACT for controlling the CO emissions from the safe shutdown generator.

As discussed in Subsection 2.1.1.4, the engines must meet the NSPS that will apply, depending on the year of engine manufacture. The BACT control is good combustion control.

7.5 Select H_2SO_4 BACT

The safe shutdown generator and the fire pump will emit small quantities of H_2SO_4 as a result of the oxidation of SO_2 in the exhaust. A review of the informational databases discussed in Section 2.1 indicated that ULSFO was the most stringent permitted control for similar types of units. Therefore, ULSFO is proposed as BACT. The BACT control is good combustion control and ULSFO.

8.0 Cane Island Unit 4 Cooling Tower

A new multicell linear mechanical draft cooling tower will be used to dissipate heat from the condensing water of the Project's main boiler. Particulate from cooling towers is generated by the presence of dissolved and suspended solids in the cooling tower circulation water, which is potentially lost as "drift" or moisture droplets that are suspended in the air moving out of the cooling tower. A portion of the water droplets emitted from the tower exhausts will evaporate, leaving the suspended or dissolved solids in the atmosphere.

The particulate emissions from the cooling towers can be controlled by minimizing the amount of water drift that occurs and/or minimizing the amount of dissolved solids in the water. This can be accomplished by using high efficiency drift eliminators, a decreased number of cycles of circulating water concentration, or a combination of both. The number of cycles of water concentration is limited by the amount of water available for use, since lower levels of concentration require increased cooling tower blowdown and more water intake to offset the blowdown.

A review of drift eliminators as particulate control technology for cooling towers concluded that they are technically feasible. There are no significant energy, environmental, or economic impacts that would preclude the use of drift eliminators as particulate control technologies as presented in this evaluation.

The proposed cooling tower BACT for this Project is the use of drift eliminators for particulate control, with a cooling tower design drift rate of 0.0005 percent.

Attachment 1
NO_x Control Technology Review List

NO_X Top Down RBLC Clearinghouse Review Results
Table A-1

FACILITY/COMPANY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Barton Shoals Energy, LLC	AL	NG	1,200	4	4	GE 7FA (170 MW)	2.5 ppm (0.0092 lb/mmbtu)		SCR	07/15/2002	EPA did not received application until 5/24/02	EPA Region 4 and 7 CT Spreadsheet
Dome Valley Energy Partners -- Wellton Mohawk Generation Station	AZ	NG	310	1	1	GE 7FA	2 ppm @ 15% O2	3-hr	DLN, SCR	12/01/2004	After 18 months, the 3-hour average changes to 1-hr average unless it is demonstrated it can not be met.	RBLC
Salt River Project -- Santan Generating Plant	AZ	NG	900	3	3	GE 7FA	2 ppm @ 15% O2	1-hr	SCR	03/07/2003		RBLC
Caithness Blythe II, LLC -- Blythe Energy Project II	CA	NG	580	2	2	GE 7FA (170 MW)	2.0 ppmdv @ 15% O2	3-hr	SCR	04/25/2007		RBLC
Calpine Western Regional -- Pastoria Energy Facility	CA	NG	750	3			2.5 ppm @ 15% O2	1-hr	DLN, SCR	12/23/2004		RBLC
Calpine Corp. -- Sutter Power Plant	CA	NG	500	2			2 ppm @ 15% O2	1-hr	SCR	08/16/2004		RBLC
Three Mountain Power, LLC	CA	NG		2	2	GE 7FA or SW 501F	2.5 ppm @ 15% O2	1-hr	SCR	10/10/2003		CARB BACT Clearinghouse
Western Midway Sunset Power Project	CA	NG		2		GE 7FA or SW 501F	2 ppm @ 15% O2	1-hr	SCR	12/12/2003		CARB BACT Clearinghouse
Elk Hills Power Project	CA	NG		2		GE 7FA	2.5 ppm @ 15% O2	1-hr	SCR	03/01/2003		CARB BACT Clearinghouse
Magnolia Power Project, SCPPA	CA	NG	181	1		GE 7FA	2 ppm @ 15% O2	1-hr	SCR	5/7/2003		CARB BACT Clearinghouse
Calpine Corp. -- Rocky Mountain Energy Center, LLC	CO	NG	300	1		F-class	3 ppm @ 15% O2	1-hr	DLN, SCR	05/02/2006	NO_X Limited To Max of 100 PPM @ 15% O2 during startup and shutdown.	RBLC
Jacksonville Electric Authority - Brandy Branch (revision)	FL	NG; FO	200	0	2	GE 7FA (170 MW)	3.5 ppm NG; 15 ppm FO	3-hr	SCR	03/29/2002	Conversion of 2 SC units to 2 CC units	EPA Region 4 and 7 CT Spreadsheet
TECO Bayside Power Station (repowering)	FL	NG	1,032	4	0	GE 7FA (170 MW)	3.5 ppm	24-hr	SCR	01/09/2002	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)	EPA Region 4 and 7 CT Spreadsheet
CPV Cana Power Generation Facility	FL	NG; FO	245	1	1	GE 7FA (170 MW)	2.5 ppm NG; 10 ppm FO	24-hr	SCR	01/17/2002	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load	EPA Region 4 and 7 CT Spreadsheet
FPC - Hines Energy Complex	FL	NG; FO	530	2	0	SW 501FD (170 MW)	2.5 ppm NG/10 ppm FO	24-hr	SCR	09/19/2003	SCONOx - $8,597/ton NOx;	EPA Region 4 and 7 CT Spreadsheet
FPL Turkey Point	FL	NG; FO	1,150	4	4	GE 7FA (170 MW)	2.0 ppm NG/8.0 ppm FO	24-hr	SCR	02/08/2005	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx	EPA Region 4 and 7 CT Spreadsheet
Progress Energy - Hines Energy Complex (Unit 4)	FL	NG; FO	530	2	0	GE 7FA (170 MW)	2.5 ppm NG/10 ppm FO	24-hr	SCR	06/08/2005		EPA Region 4 and 7 CT Spreadsheet/RBLC
Florida Municipal Power Agency --Treasure Coast Energy Center	FL	NG; FO	300	1		GE 7FA	2.0 ppm NG; 8.0 ppm FO	24-hr block	SCR	05/30/2006	180 km from the Everglades National Park	RBLC
Orlando Utilities Commission -- Curtis H. Stanton Energy Center, Unit B	FL	NG; FO	285	1	1	GE 7FA	2.0 ppm NG; 8.0 ppm FO	24-hr block	SCR	Application under Review		FDEP NSR/PSD Permits
FPL West County Energy Center	FL	NG; FO	2,500	6	6	Mitsbishi M501G	2.0 ppm NG (CT/CT and DB); 8.0 ppm FO	24-hr block	SCR	01/10/2007	SCR - $3,385/ton NO_X	FDEP NSR/PSD Permits
GenPower Rincon	GA	NG	528	2	2	GE 7FA (170 MW)	2.5 ppm		SCR	03/24/2003		EPA Region 4 and 7 CT Spreadsheet
Savannah Electric and Power - Plant McIntosh	GA	NG; FO	1,260	4	4	GE 7FA (170 MW)	2.5 ppm NG; 6 ppm FO		SCR	04/17/2003	After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)	EPA Region 4 and 7 CT Spreadsheet
Live Oak Co., LLC	GA	NG	600	2	2	SW 501FD (170 MW)	3.5 ppm		SCR	02/04/2004		EPA Region 4 and 7 CT Spreadsheet
Big River Power, LLC	GA	NG; FO	855	3	3	GE 7FA (170 MW)	3.0 ppm NG; 8.0 ppm FO		SCR/DLN; WI	applic. under review	SCR - $5,075/ton NOx; CatOx - $4,712/ton CO	EPA Region 4 and 7 CT Spreadsheet

NO_X Top Down RBLC Clearinghouse Review Results
Table A-1

FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Hawkeye Generation, LLC (a division of Entergy)	IA	NG	580	2	2	GE 7FA	SC-9 ppm, CC-3 ppm	3-hour	SC-DLN; CC-SCR	07/23/2002	Duct burning limited to 4,500 hours per year	EPA Region 4 and 7 CT Spreadsheet
Interstate Power and Light - Exira Station	IA	NG; FO	568	2	1	2- GE-7FA,1- HRSG w/aux firing @ 405MMBTU	SC-9 ppm (NG), 42 ppm (oil); CC-3 ppm (NG), 33 ppm (oil)	3-hour	SC-DLN, CC-SCR	12/20/2002		EPA Region 4 and 7 CT Spreadsheet
Kentucky Pioneer Energy	KY	syngas/NG	540	2	0	GE 7FA (197 MW)	15/20 ppm	3-hr	Steam Injection	06/08/2001		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Trimble	KY	NG; FO	1,240	4	4	GE 7FA (160 MW)	3.5 ppm		SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Duke Energy (Leavenworth County)	KS	NG	620	2	2	2 - GE-7FA (310 MW each)	4.5 ppm	24-hour	SCR, DLN	02/07/2002		EPA Region 4 and 7 CT Spreadsheet
Cresent City Power, LLC -- Cresent City Power	LA	NG	600	2	2		3 ppm	Annual	DLN, SCR	06/06/2005	Startup emissions is limited to 220 lbs/hr; Project-wide emissions is limited to 74.33 tpy.	RBLC
Crossroads Energy Center	MS	NG	580	2	2	GE 7FA (170 MW)	3.5 ppm		SCR	06/24/2002	SCONOx - $23,400/ton NOx; CatOx - $11,039/ton CO	EPA Region 4 and 7 CT Spreadsheet
Reliant Energy Choctaw County, LLC	MS	NG	920	3		F-class	3.5 ppm @ 15% O2	3-hr	SCR	11/23/2004	Limits apply at all times.	RBLC
Berrien Energy, LLC	MI	NG	1100	3	3		2.5 ppm @ 15% O2	24-hr	DLN, SCR	04/13/2005	Project-wide emissions is limited to 239.4 tpy.	RBLC
Nebraska Public Power District	NE		220	2		2 on 1 CC with 2 GE 7E CTs	3.5 ppm	3-hr	SCR	05/29/2003		EPA Region 4 and 7 CT Spreadsheet
El Dorado Energy, LLC	NV	NG	475	2	2		3.5 ppm @ 15% O2 (w/o DBs); 3.7 ppm @ 15% O2 (w DBs)		DLN, SCR	08/19/2004		RBLC
Sierra Pacific Power Company -- Tracy Substation Expansion Project	NV	NG	612	2	2		2 ppm @ 15% O2	3-hr	SCR w/Ammonia Inj.	08/16/2005		RBLC
Bessicorp - Empire Development Co., LLC	NJ	NG; FO	1,280	3	3	GE 7FA	2.5 ppm NG; 9 ppm FO	1 hour	DLN/SCR	08/24/2002		EPA Region 4 and 7 CT Spreadsheet
Bessicorp - Empire Development Co., LLC	NY	NG; FO	560	2	2	GE Frame 7FA		1 hour		09/23/2004		EPA Region 4 and 7 CT Spreadsheet
GenPower Earleys, LLC	NC	NG	528	2	2	GE 7FA (170 MW)	2.5/3.5 ppm		SCR	01/14/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level SCONOx - $21,942/ton NOx; CatOx - $3,246ton CO	EPA Region 4 and 7 CT Spreadsheet
Mirant Gastonia	NC	NG	1,200	4	4	"F" Class (175 MW)	2.5/3.5 ppm	24-hr block	SCR	05/28/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level	EPA Region 4 and 7 CT Spreadsheet
Mountain Creek - Granville Energy Center	NC	NG	911	3	3	GE 7FA (170 MW)	3.5 ppm		SCR	applic. under review	SCONOx - $22,600/ton NOx; CatOx - $3,560ton CO	EPA Region 4 and 7 CT Spreadsheet
Dominion Person, Inc.	NC	NG; FO	1,100	4	4	GE 7FA (172 MW)	3.5 ppm; 15 ppm FO		SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Forsyth Energy Projects, LLC -- Forsyth Energy Plant	NC	NG; FO	812	3	3	GE 7FA (170 MW)	2.5 ppmdv @ 15% O2 (first 500 hours); 3 ppmdv @ 15% O2 (after 500 hours)	24-hr	DLN, SCR	09/29/2005	The use of fuel oil is limited to 1,200 hours per year and only during the months of November through March.	RBLC/EPA Region 4 and 7 CT Spreadsheet
Duke Energy Hanging Rock, LLC -- Duke Energy Hanging Rock Energy Facility	OH	NG	1270	4	4	GE 7FA	3 ppm @ 15% O2	3-hr	DLN, SCR	12/28/2004	The maximum hours of operation of the duct burners shall not exceed 5500 hrs/12-month rolling avg. for each turbine.	RBLC
Port Westward (Portland General Electric)	OR, Permit 05-0008	NG	650	2	2	GE 7FB or SW 501S	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	01/16/2002	Not yet constructing. Source is expected to submit a request for permit extension given that construction is not expected to commence within 18 months of permit issuance. ODEQ - Northwest Region. Clatskanie, OR. Extension out for public comment.	EPA Region 4 and 7 CT Spreadsheet

NO_X Top Down RBLC Clearinghouse Review Results
Table A-1

FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Umatilla Generating (PG&E)	OR, Permit 30-0007	NG	580	2	2	GE 7FB	2.0 ppmdv @ 15% O2	3-hr	DLN, SCR	01/18/2002	Not yet constructing. 05/24/03 permit extension. ODEQ - Eastern Region. Hermiston, OR.	EPA Region 4 and 7 CT Spreadsheet
Turner Energy Center (Calpine)	OR	NG	620	2	2	GE 7FA			DLN, SCR	Public comment period - 7/30/04	Not yet constructing. Not yet permitted. Startup projected 2005. ODEQ - Western Region. Turner, OR.	EPA Region 4 and 7 CT Spreadsheet
California Oregon Border (Peoples Energy)	OR, Permit 18-0029	NG	1,150	4	4	F-class	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	12/30/2003	Not yet constructing. Not yet permitted. Air-cooled condensor. ODEQ - Eastern Region. Bonanza, OR.	EPA Region 4 and 7 CT Spreadsheet
Klamath Generation LLC (Pacific Power Energy Marketing)	OR, Permit 18-0026	NG	480	2	2	Various	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	03/14/2003	Constructing? ODEQ - Eastern Region. Klamath Falls, OR.	EPA Region 4 and 7 CT Spreadsheet
WANAPA Energy Center (Diamond Wanapa LLC)	OR, EPA	NG	1,200	4	4	F-class			DLN, SCR	Drafting	Not yet constructing. Not yet permitted. Construction projected to commence Spring '04, startup projected Summer '06. EPA Region 10. Umatilla, OR.	EPA Region 4 and 7 CT Spreadsheet
West Cascades Energy	OR, LRAPA	NG	900	2	2	F-class			DLN, SCR	Drafting	Lane County, OR.	EPA Region 4 and 7 CT Spreadsheet
Diamond Wanapa 1, L.P. -- Wanapa Energy Center	OR	NG	1200	4	4	GE 7FA	2 ppm @ 15% O2	3-hr	DLN, SCR	08/08/2005	The final permit was affirmed by EPA's Environmental Appeals Board on Feb. 9, 2006.	RBLC
Jasper County Generating Facility	SC	NG, FO	1,260	4	4	GE 7FA (170 MW)	2.5 ppm NG; 7.5 ppm FO	24-hr	SCR	05/28/2002	SCONOx - $19,870/ton NOx; CatOx - $3,320/ton CO	EPA Region 4 and 7 CT Spreadsheet
Fork Shoals Energy, LLC	SC	NG	1,150	2	2	"F" Class (175 MW)	3.5 ppm	24-hr	SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Palmetto Energy Center	SC	NG	970	3	3	GE 7FB (180 MW)	3.5 ppm		SCR	applic. under review	SCONOx - $18,789/ton NOx; CatOx - $2,111/ton CO	EPA Region 4 and 7 CT Spreadsheet
Haywood Energy Center (Calpine)	TN	NG; FO	900	3	3	SW, GE 7FA or GE F7B	3.5 ppm NG; 42 ppm FO		DLN/SCR; WI	02/01/2002		EPA Region 4 and 7 CT Spreadsheet
Duke Energy	TX		620	2		F7FA	5		SCR	07/23/2003		EPA Region 4 and 7 CT Spreadsheet
TX Petrochem	TX	NG	900	3		GE 7FA	5 ppm		SCR	10/08/2003		EPA Region 4 and 7 CT Spreadsheet
Pacificorp - Currant Creek Power Project	UT	NG	1,050	2	2	GE 7FA	9.0 ppm SC; 2.25 ppm CC; 25 ppm (transient load conditions)	18-HR SC; 3-hr CC; ERR	DLN - SC; SCR - CC	05/17/2004	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.	EPA Region 4 and 7 CT Spreadsheet
Summit Vineyard -- Lakeside Power Plant	UT	NG	560	2	2	SW 501FD	2 ppm @ 15% O2	3-hr	SCR	01/06/2005		RBLC
Tenaska Fluvanna	VA	NG/FO	900	3	3	GE 7FA	3.0 ppm		SCR	01/20/2002		EPA Region 4 and 7 CT Spreadsheet
CPV Warren	VA	NG	580	2	2	GE 7FA (170 MW)	2.0 ppmdv @ 15% O2	1-hr	DLN, SCR	06/05/2007		RBLC
Duke Energy Wythe, LLC	VA	NG	580	2	2	GE 7FA	2.5 ppm @ 15% O2		DLN, SCR	02/05/2004		RBLC
Frederickson Power II (West Coast Energy)	WA, PSCAA NOC 8695	NG; FO	290	1	0	GE Frame 7FA	2.5 / 6 ppmdv gas / oil @ 15% O2	1-hr	DLN, SCR	06/19/2003	Not built. Permit expires 01/01/05. Minor NSR BACT. PSCAA. Frederickson, WA.	EPA Region 4 and 7 CT Spreadsheet
BP Cherry Point Cogen	WA	NG	720	3	3	GE 7FA	2.5 ppmdv @ 15% O2	Annual	DLN, SCR	Public comment period is over.	Not constructing as permit not yet issued. EFSEC & EPA. Blaine, WA.	EPA Region 4 and 7 CT Spreadsheet
Wallula Power (Newport Northwest Generation)	WA	NG	1,300	4	4	GE 7FA	2.5 ppmdv @ 15% O2	3-hr	DLN, SCR	03/03/2003	Not constructing. Construction on hold due to market conditions. BPA anticipates new generation development within the next five years. EFSEC & EPA. Wallula, WA.	EPA Region 4 and 7 CT Spreadsheet
BP West Coast Products, LLC -- BP Cherry Point Cogeneration Project	WA	NG	720	3	3	GE 7FA	2.5 ppm @ 15% O2	3-hr	DLN, SCR	01/11/2005		RBLC

Color Code Legend
Data from EPA Regions 4 and 7 Combustion Turbine Spreadsheet
Data from EPA's RBLC Clearinghouse
Data from Florida Department of Environmental Protection NSR/PSD Construction Permits Website -- Power Plants
Data from CARB's BACT Clearinghouse

Attachment 2
CO Control Technology Review List

CO Top Down RBLC Clearinghouse Review Results
Table A-2

FACILITY/COMPANY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Barton Shoals Energy, LLC	AL	NG	1,200	4	4	GE 7FA (170 MW)	10 ppm (0.022 lb/mmbtu); 0.041 lb/mmbtu w/DB		GCP	07/15/2002	EPA did not received application until 5/24/02	EPA Region 4 and 7 CT Spreadsheet
Dome Valley Energy Partners -- Wellton Mohawk Generation Station	AZ	NG	310	1	1	GE 7FA	3 ppm @ 15% O2	3-hr	CatOx	12/01/2004		RBLC
Salt River Project -- Santan Generating Plant	AZ	NG	900	3	3	GE 7FA	3 ppm @ 15% O2	3-hr	CatOx	03/07/2003		RBLC
Caithness Blythe II, LLC -- Blythe Energy Project II	CA	NG	580	2	2	GE 7FA (170 MW)	4.0 ppmdv @ 15% O2	3-hr		04/25/2007		RBLC
Calpine Corp. -- Sutter Power Plant	CA	NG	500	2			4 ppm @ 15% O2	3-hr	CatOx	08/16/2004		RBLC
Three Mountain Power, LLC	CA	NG		2	2	GE 7FA or SW 501F	4 ppm @ 15% O2	3-hr	CatOx	10/10/2003		CARB BACT Clearinghouse
Western Midway Sunset Power Project	CA	NG		2		GE 7FA or SW 501F	4 ppm @ 15% O2	3-hr	CatOx	12/12/2003		CARB BACT Clearinghouse
Elk Hills Power Project	CA	NG		2		GE 7FA	4 ppm @ 15% O2	3-hr	CatOx	03/01/2003	CO limit was offered by catalyst vendor.	CARB BACT Clearinghouse
Magnolia Power Project, SCPPA	CA	NG	181	1		GE 7FA	2 ppm @ 15% O2	1-hr	CatOx	5/7/2003	CO limit was proposed by the applicant.	CARB BACT Clearinghouse
Calpine Corp. -- Rocky Mountain Energy Center, LLC	CO	NG	300	1		F-class	3 ppm @ 15% O2		GCP, CatOx	05/02/2006		RBLC
Jacksonville Electric Authority - Brandy Branch (revision)	FL	NG; FO	200	0	2	GE 7FA (170 MW)	14 ppm	24-hr	GCP	03/29/2002	Conversion of 2 SC units to 2 CC units	EPA Region 4 and 7 CT Spreadsheet
TECO Bayside Power Station (repowering)	FL	NG	1,032	4	0	GE 7FA (170 MW)	9 ppm (7.8 ppm test avg.)	24-hr	GCP	01/09/2002	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)	EPA Region 4 and 7 CT Spreadsheet
CPV Cana Power Generation Facility	FL	NG; FO	245	1	1	GE 7FA (170 MW)	8 ppm NG (13 ppm w/PA) ; 17/19/26 ppm FO	24-hr	GCP	01/17/2002	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load	EPA Region 4 and 7 CT Spreadsheet
FPC - Hines Energy Complex	FL	NG; FO	530	2	0	SW 501FD (170 MW)	10 ppm NG/20 ppm FO	24-hr	GCP	09/19/2003	SCONOx - $8,597/ton NOx;	EPA Region 4 and 7 CT Spreadsheet
FPL Turkey Point	FL	NG; FO	1,150	4	4	GE 7FA (170 MW)	4.1 ppm NG/7.6 ppm NG w/DB/8 ppm NG w/PA&DB/14ppm w/PK&DB; 8.0 ppm FO/ & 6.0 ppm (12-month avg.)All modes	24-hr/12-mo	GCP	02/08/2005	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx	EPA Region 4 and 7 CT Spreadsheet
Progress Energy - Hines Energy Complex (Unit 4)	FL	NG; FO	530	2	0	GE 7FA (170 MW)	8 ppm @ 15% O2 NG; 12 ppm FO	24-hr	GCP	06/08/2005		EPA Region 4 and 7 CT Spreadsheet/RBLC
Florida Municipal Power Agency --Treasure Coast Energy Center	FL	NG; FO	300	1		GE 7FA	6 ppm (12-month); 8 ppm FO (24-hr); 4.1 ppm NG w/o DBs (24-hr)	12-month or 24-hr	GCP	05/30/2006	Continuous compliance with ppm limit by CEMS	RBLC
Progress Energy -- P.L. Bartow Power Plant	FL	NG; FO	1,475	4	4	Siemens SGT6-5000F	FO: 8.0 ppm @ 15% O2 (CT); NG: 4.1 ppm @ 15% O2 (CT) and 7.6 ppm @ 15% O2 (CT + DB)	3-hr Stack Test	GCP	Draft Permit	CEMS Block Average for CO -- 8.0 ppm @ 15% O2 (24-hr avg.) / 6.0 ppm @ 15% O2 (12-month rolling avg.); Cat. Ox. -- $3,956/ton CO	FDEP NSR/PSD Permits
Orlando Utilities Commission -- Curtis H. Stanton Energy Center, Unit B	FL	NG; Syn. Gas	285	1	1	GE 7FA	Syn. Gas or NG: 4.1 ppm @ 15% O2 (between 21 and 27 months following the initial compliance tests)	24-hr rolling avg.	CatOx	12/22/2006		FDEP NSR/PSD Permits
FPL West County Energy Center	FL	NG; FO	2,500	6	6	Mitsbishi M501G	FO: 8.0 ppm @ 15% O2 (CT); NG: 4.1 ppm @ 15% O2 (CT) and 7.6 ppm @ 15% O2 (CT + DB)	3-hr Stack Test	GCP	01/10/2007	CEMS Block Average for CO -- 8.0 ppm @ 15% O2 (24-hr avg.) / 6.0 ppm @ 15% O2 (12-month rolling avg.)	FDEP NSR/PSD Permits
GenPower Rincon	GA	NG	528	2	2	GE 7FA (170 MW)	2.0 ppm		CatOx	03/24/2003		EPA Region 4 and 7 CT Spreadsheet
Savannah Electric and Power - Plant McIntosh	GA	NG; FO	1,260	4	4	GE 7FA (170 MW)	2.0 ppm		CatOx	04/17/2003	After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)	EPA Region 4 and 7 CT Spreadsheet
Live Oak Co., LLC	GA	NG	600	2	2	SW 501FD (170 MW)	10 ppm (17 ppm w/DB or PA)		GCP	02/04/2004		EPA Region 4 and 7 CT Spreadsheet
Big River Power, LLC	GA	NG; FO	855	3	3	GE 7FA (170 MW)	19.2 ppm (w/DB)/9.0 ppm (w/o DB) NG; 20.o ppm FO		GCP	applic. under review	SCR - $5,075/ton NOx; CatOx - $4,712/ton CO	EPA Region 4 and 7 CT Spreadsheet

CO Top Down RBLC Clearinghouse Review Results
Table A-2

FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Hawkeye Generation, LLC (a division of Entergy)	IA	NG	580	2	2	GE 7FA	SC-9 ppm, CC-5 ppm	3-hour	Oxidation Catalyst	07/23/2002	Duct burning limited to 4,500 hours per year	EPA Region 4 and 7 CT Spreadsheet
Interstate Power and Light - Exira Station	IA	NG; FO	568	2	1	2- GE-7FA,1- HRSG w/aux firing @ 405MMBTU	SC-9 ppm (NG), 20 ppm (oil); CC-5 ppm (NG), 7.1 ppm (oil)	3-hour	Oxidation Catalyst	12/20/2002		EPA Region 4 and 7 CT Spreadsheet
Kentucky Pioneer Energy	KY	syngas/NG	540	2	0	GE 7FA (197 MW)	15/20 ppm	3-hr	GCP	06/08/2001		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Trimble	KY	NG; FO	1,240	4	4	GE 7FA (160 MW)	9/13.9/20 ppm		GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Duke Energy (Leavenworth County)	KS	NG	620	2	2	2 - GE-7FA (310 MW each)	16.9 ppm	short-term	GCP	02/07/2002		EPA Region 4 and 7 CT Spreadsheet
Cresent City Power, LLC -- Cresent City Power	LA	NG	600	2	2		4 ppm @ 15% O2	Annual	GCP, CatOx	06/06/2005	Startup emissions is limited to 1,530 lbs/hr; Project-wide emissions is limited to 567.11 tpy.	RBLC
Nothernern States Power Co. DBA XCEL Energy -- Riverside Plant	MN	NG	528	2	0	GE 7FA (170 MW)	10.0 ppmdv @ 15% O2	3-hr	GCP	05/16/2006	Three existing coal-fired boilers being replaced by 2 GE 7FA CCCTs; CatOx rejected at $7,670/ton of CO	RBLC
Crossroads Energy Center	MS	NG	580	2	2	GE 7FA (170 MW)	10.4 ppm		GCP	06/24/2002	SCONOx - $23,400/ton NOx; CatOx - $11,039/ton CO	EPA Region 4 and 7 CT Spreadsheet
Reliant Energy Choctaw County, LLC	MS	NG	920	3		F-class	18.36 ppmv @ 15% O2	3-hr	GCP	11/23/2004		RBLC
Berrien Energy, LLC	MI	NG	1100	3	3		2 ppm @ 15% O2	3-hr	CatOx	04/13/2005	All 3 turbines and duct burners combined are limited to 165.5 tpy	RBLC
Nebraska Public Power District	NE		220	2		2 on 1 CC with 2 GE 7E CTs	10.8 lb/hr	Stack	CatOx	05/29/2003		EPA Region 4 and 7 CT Spreadsheet
Sierra Pacific Power Company -- Tracy Substation Expansion Project	NV	NG	612	2	2		0.03 lb/Mbtu	3-hr	GCP	08/16/2005		RBLC
El Dorado Energy, LLC	NV	NG	475	2	2		2.6 ppm @ 15% O2 (each CTG); 3.5 ppm @ 15% O2 (CTG + DB)		CatOx	08/19/2004		RBLC
Bessicorp - Empire Development Co., LLC	NJ	NG; FO	1,280	3	3	GE 7FA	4 ppm	1 hour	CatOx	08/24/2002		EPA Region 4 and 7 CT Spreadsheet
Bessicorp - Empire Development Co., LLC	NY	NG; FO	560	2	2	GE Frame 7FA				09/23/2004		EPA Region 4 and 7 CT Spreadsheet
GenPower Earleys, LLC	NC	NG	528	2	2	GE 7FA (170 MW)	9 ppm (14 ppm w/DB)		GCP	01/14/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level SCONOx - $21,942/ton NOx; CatOx - $3,246ton CO	EPA Region 4 and 7 CT Spreadsheet
Mirant Gastonia	NC	NG	1,200	4	4	"F" Class (175 MW)	15 or 30 ppm	24-hr block	GCP	05/28/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level	EPA Region 4 and 7 CT Spreadsheet
Mountain Creek - Granville Energy Center	NC	NG	911	3	3	GE 7FA (170 MW)	9 ppm (24.3 ppm w/DB)		GCP	applic. under review	SCONOx - $22,600/ton NOx; CatOx - $3,560ton CO	EPA Region 4 and 7 CT Spreadsheet
Dominion Person, Inc.	NC	NG; FO	1,100	4	4	GE 7FA (172 MW)	9 ppm NG (20 ppm w/DB) 20 ppm FO		GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Forsyth Energy Projects, LLC -- Forsyth Energy Plant	NC	NG; FO	812	3	3	GE 7FA (170 MW)	11.6 ppm NG (25.9 ppm w/DB); 15.7 ppm FO (25.1 ppm w/DB)	3-hr	GCP	01/23/2004	CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels	EPA Region 4 and 7 CT Spreadsheet
Duke Energy Hanging Rock, LLC -- Duke Energy Hanging Rock Energy Facility	OH	NG	1270	4	4	GE 7FA	9 ppm @ 15% O2	24-hr	GCP	12/28/2004	The maximum hours of operation of the duct burners shall not exceed 5500 hrs/12-month rolling avg. for each turbine. Each turbine has a limit of 278 tpy of CO.	RBLC
Port Westward (Portland General Electric)	OR, Permit 05-0008	NG	650	2	2	GE 7FB or SW 501S	4.9 ppmdv @ 15% O2	8-hr	CatOx	01/16/2002	Not yet constructing. Source is expected to submit a request for permit extension given that construction is not expected to commence within 18 months of permit issuance. ODEQ - Northwest Region. Clatskanie, OR. Extension out for public comment.	EPA Region 4 and 7 CT Spreadsheet

CO Top Down RBLC Clearinghouse Review Results
Table A-2

FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Umatilla Generating (PG&E)	OR, Permit 30-0007	NG	580	2	2	GE 7FB	6.0 ppmdv @ 15% O2	24-hr	CatOx	01/18/2002	Not yet constructing. 05/24/03 permit extension. ODEQ - Eastern Region. Hermiston, OR.	EPA Region 4 and 7 CT Spreadsheet
Turner Energy Center (Calpine)	OR	NG	620	2	2	GE 7FA			CatOx	Public comment period - 7/30/04	Not yet constructing. Not yet permitted. Startup projected 2005. ODEQ - Western Region. Turner, OR.	EPA Region 4 and 7 CT Spreadsheet
California Oregon Border (Peoples Energy)	OR, Permit 18-0029	NG	1,150	4	4	F-class	5.0 ppmdv @ 15% O2	8-hr	CatOx	12/30/2003	Not yet constructing. Not yet permitted. Air-cooled condensor. ODEQ - Eastern Region. Bonanza, OR.	EPA Region 4 and 7 CT Spreadsheet
Klamath Generation LLC (Pacific Power Energy Marketing)	OR, Permit 18-0026	NG	480	2	2	Various	5.0 ppmdv @ 15% O2	8-hr	CatOx	03/14/2003	Constructing? ODEQ - Eastern Region. Klamath Falls, OR.	EPA Region 4 and 7 CT Spreadsheet
WANAPA Energy Center (Diamond Wanapa LLC)	OR, EPA	NG	1,200	4	4	F-class			CatOx	Drafting	Not yet constructing. Not yet permitted. Construction projected to commence Spring '04, startup projected Summer '06. EPA Region 10. Umatilla, OR.	EPA Region 4 and 7 CT Spreadsheet
West Cascades Energy	OR, LRAPA	NG	900	2	2	F-class				Drafting	Lane County, OR.	EPA Region 4 and 7 CT Spreadsheet
Diamond Wanapa 1, L.P. -- Wanapa Energy Center	OR	NG	1200	4	4	GE 7FA	2 ppm @ 15% O2	3-hr	CatOx	08/08/2005	The final permit was affirmed by EPA's Environmental Appeals Board on Feb. 9, 2006.	RBLC
Jasper County Generating Facility	SC	NG, FO	1,260	4	4	GE 7FA (170 MW)	9 ppm NG (14 ppm w/DB); 20 ppm FO (22 ppm w/DB)		GCP	05/28/2002	SCONOx - $19,870/ton NOx; CatOx - $3,320/ton CO	EPA Region 4 and 7 CT Spreadsheet
Fork Shoals Energy, LLC	SC	NG	1,150	2	2	"F" Class (175 MW)	14 ppm (GE7FA/16 ppm (SW501F)	24-hr	GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Palmetto Energy Center	SC	NG	970	3	3	GE 7FB (180 MW)	15 ppm (31 ppm w/DB)		GCP	applic. under review	SCONOx - $18,789/ton NOx; CatOx - $2,111/ton CO	EPA Region 4 and 7 CT Spreadsheet
Haywood Energy Center (Calpine)	TN	NG; FO	900	3	3	SW, GE 7FA or GE F7B	varies from 7.4 to 50 ppm depending on CT type and load		GCP	02/01/2002		EPA Region 4 and 7 CT Spreadsheet
TX Petrochem	TX	NG	900	3		GE 7FA	15 ppm		GCP	10/08/2003		EPA Region 4 and 7 CT Spreadsheet
Duke Energy	TX		620	2		F7FA	20			07/23/2003		EPA Region 4 and 7 CT Spreadsheet
Pacificorp - Currant Creek Power Project	UT	NG	1,050	2	2	GE 7FA	7.8 ppm SC; 3.0 ppm CC	24-HR SC; 3-hr CC; ERR	Oxid Cat	05/17/2004	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.	EPA Region 4 and 7 CT Spreadsheet
Summit Vineyard -- Lakeside Power Plant	UT	NG	560	2	2	SW 501FD	3 ppm @ 15% O2	3-hr	CatOx	01/06/2005		RBLC
Tenaska Fluvanna	VA	NG/FO	900	3	3	GE 7FA	21 ppm		GCP	01/20/2002		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Wythe, LLC	VA	NG	580	2	2	GE 7FA	9 ppm @ 15% O2		DLN, SCR	02/05/2004		RBLC
CPV Warren	VA	NG	580	2	2	GE 7FA (170 MW)	2.5 ppmdv @ 15% O2 with Power Augmentation and DBs		CatOx and GCP	06/05/2007	CO Limit: 1.3 ppmvd @15% O2 w/o Power Aug., 1.8 ppmvd @ 15% O2 w/Power Aug. and w/o DBs	RBLC
Frederickson Power II (West Coast Energy)	WA, PSCAA NOC 8695	NG; FO	290	1	0	GE Frame 7FA	2.0 / 3.0 ppmdv @ 15% O2	1-hr	CatOx	06/19/2003	Not built. Permit expires 01/01/05. Minor NSR BACT. PSCAA. Frederickson, WA.	EPA Region 4 and 7 CT Spreadsheet
BP Cherry Point Cogen	WA	NG	720	3	3	GE 7FA	2.0 ppmdv @ 15% O2	Ann.	CatOx	Public comment period is over.	Not constructing as permit not yet issued. EFSEC & EPA. Blaine, WA.	EPA Region 4 and 7 CT Spreadsheet
Wallula Power (Newport Northwest Generation)	WA	NG	1,300	4	4	GE 7FA	2.0 ppmdv @ 15% O2	3-hr	CatOx	03/03/2003	Not constructing. Construction on hold due to market conditions. BPA anticipates new generation development within the next five years. EFSEC & EPA. Wallula, WA.	EPA Region 4 and 7 CT Spreadsheet
BP West Coast Products, LLC -- BP Cherry Point Cogeneration Project	WA	NG	720	3	3	GE 7FA	2 ppm @ 15% O2	3-hr	GCP, CatOx	01/11/2005		RBLC

Color Code Legend
Data from EPA Regions 4 and 7 Combustion Turbine Spreadsheet
Data from EPA's RBLC Clearinghouse
Data from Florida Department of Environmental Protection NSR/PSD Construction Permits Website -- Power Plants
Data from CARB's BACT Clearinghouse

Appendix E
Air Dispersion Modeling Protocol

Cane Island Power Park
Unit 4 Combustion Turbine

Class I and II Air Dispersion Modeling Protocol

January 2008

Prepared for:
Florida Municipal Power Agency
Orlando, Florida

Florida Municipal Power Agency
Community Power. Statewide Strength.

Prepared by:
Black & Veatch
Overland Park, Kansas

BLACK & VEATCH
Building a world of difference.

Table of Contents

List of Tables

List of Figures

1.0 Introduction

Florida Municipal Power Agency (FMPA) is proposing to construct and operate a new natural gas-fired combined cycle combustion turbine (CCCT) at their existing Cane Island Power Park (CIPP). This combustion turbine will be Unit 4 at the facility (hereinafter referred to as the Project).

FMPA anticipates that the potential emissions of the Project will trigger air permitting review requirements under the Prevention of Significant Deterioration (PSD) program of Florida Regulation 62-212.400. This Ambient Air Quality Impact Analysis Protocol (hereinafter referred to as the Protocol) describes the air quality impact analysis methodology for obtaining a Construction Permit for the proposed project under the PSD review program. After Florida Department of Environmental Protection (FDEP) review and approval, this Protocol will provide the basis of a mutually agreed upon procedure for the final ambient air quality impact analysis in support of the air construction permit application meeting PSD review requirements.

This Protocol describes site and source characteristics, determination of pollutants applicable to the air quality review, and the analytical procedures that will be used to conduct the ambient air quality impact analysis. The construction permit application and supporting ambient air quality impact analysis (AAQIA) will include a determination of compliance with the National Ambient Air Quality Standards (NAAQS), New Source Performance Standards (NSPS), the PSD increments, and an assessment of additional impacts.

2.0 Project Characterization

The following sections briefly characterize the Project including a general description of the facility, location, and potential emission units, as well as an overview of the local air quality status and NSR and NSPS applicability.

2.1 Project Location

The CIPP is located near Intercession City in Osceola County. The specific location of the project is illustrated in Figure 2-1. The site location has a sub-tropical climate with hot summers and mild winters.

2.2 Project Description

FMPA is proposing the installation of a new natural gas-fired, 1 x 1 combined cycle combustion turbine (Unit 4) at their existing CIPP near Intercession City, Florida. Unit 4 will have a nominal rating of 300 megawatts (MW) and will include a GE 7FA combustion turbine generator (CTG), a duct-fired heat recovery steam generator (HRSG), a steam turbine generator (STG), and will be equipped with an evaporative cooler. New major support facilities include a diesel engine driven fire pump, a safe shutdown generator, and a mechanical draft cooling tower.

2.3 Project Emissions

For the proposed Unit 4 CCCT, emissions and stack parameters will be developed from performance data for unit loads of 100, 75, 50, and 40 percent of maximum capacity over a range of representative ambient temperatures (19, 59, 73, and 102°F) for natural gas firing. This range of temperatures represents the site minimum, ISO, site average, and site maximum temperatures. The emissions included in the air dispersion modeling analysis for Unit 4 will be based on direct pound per hour emissions to the atmosphere.

Unit 4 will have the capability of operating in several configurations; including evaporative cooling and duct firing, along with different unit loads and at different ambient temperatures. A process called enveloping may be used in the modeling. Enveloping allows multiple operating scenarios to be conservatively considered in an AAQIA, while keeping the actual air dispersion modeling runs to a minimum. However, it is possible that because of the specific characteristics of the source, this analysis approach could result in overly conservative modeling impacts. In this case, the AAQIA may be performed for each individual load and ambient temperature combination.

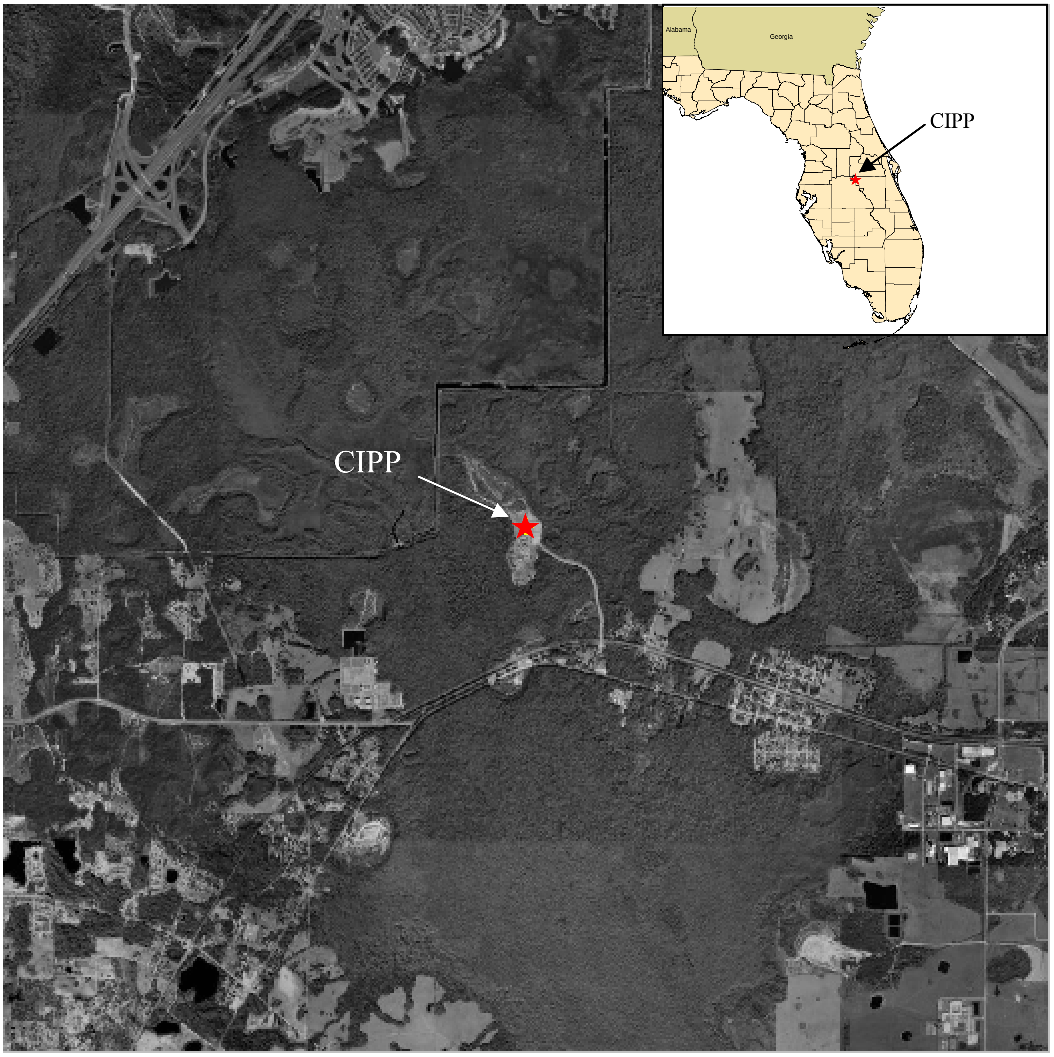

Figure 2-1
Proposed Project Location

The emissions and stack parameters for each of the ancillary equipment will be based on manufacturer data and these emission sources will only be included in the Class II AAQIA.

2.4 Local Air Quality Attainment/Nonattainment Status

The air quality in a given area is generally designated as being in attainment for a pollutant if the monitored concentrations of that pollutant are less than the applicable National Ambient Air Quality Standards (NAAQS). Likewise, a given area is generally classified as nonattainment for a pollutant if the monitored concentrations of that pollutant in the area are above the NAAQS. A review of the air quality status in the region reveals that Osceola County is in attainment or unclassifiable for all pollutants.

2.5 New Source Review/PSD Applicability

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications at existing major sources under two programs; the PSD program outlined in 40 CFR 52.21 for areas in attainment, and the NSR program outlined in 40 CFR 51 and 52 for areas considered nonattainment for certain pollutants. As noted in Section 2.4, the proposed Project is located in an attainment or unclassifiable area with respect to all pollutants. As such, the PSD program, as administered by the state of Florida under 62-212.400, F.A.C., will apply to the proposed project.

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the NAAQS while providing a margin for future industrial and commercial growth. The primary provisions of the PSD regulations require that major modifications and new major stationary sources be carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirements to apply Best Available Control Technology (BACT) to minimize the emissions of air pollutants.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit (PTE), 100 tons per year (tpy) or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the stationary source does not fall under one of the listed major source categories. The CIPP is one of the 28 major source categories (i.e., fossil fuel fired steam electric plant) which has a PTE greater than 100 tpy for at least one regulated pollutant; therefore, it is considered an existing major PSD source.

Because the proposed Project is locating at an existing major stationary source, PSD applicability is determined on a pollutant by pollutant basis by comparing the emissions increase of each pollutant against the PSD significant emission rates (SERs).

PSD SERs

- Nitrogen Oxides (NO_x)--40 tpy.
- Sulfur Dioxide (SO_2)--40 tpy.
- Particulate Matter (PM)--25 tpy.
- Particulate Matter less than 10 microns (PM_{10})--15 tpy.
- Carbon Monoxide (CO)--100 tpy.
- Ozone (O_3)--NO_x or Volatile Organic Compounds (VOC)--40 tpy.
- Lead (Pb)--0.6 tpy.
- Mercury (Hg)--0.1 tpy.
- Fluorides (F)--3 tpy.
- Sulfuric Acid Mist (H_2SO_4)--7 tpy.
- Hydrogen Sulfide (H_2S)--10 tpy.
- Total Reduced Sulfur Compounds--10 tpy.

The project emissions increase and the project net emissions increase must be above the PSD SER for PSD to apply to the project. This is determined on a pollutant by pollutant basis. It is expected that the emissions of NO_x, PM/PM_{10}, SO_2, CO, and sulfuric acid mist will exceed the PSD SER threshold for the proposed Project; therefore, the Project will be required to perform a BACT analysis along with an AAQIA.

2.6 New Source Performance Standards

The New Source Performance Standards (NSPS) established in the 1970 CAA, were developed for specific industrial categories and are promulgated in 40 CFR 60. The applicable category for the proposed project falls under Subpart KKKK of 40 CFR 60. Specifically, this category is the NSPS for stationary combustion turbines. The criteria for this NSPS will be met or exceeded by the proposed project.

3.0 Class I Ambient Air Quality Analysis

As part of the air impact evaluation for the addition to the CIPP site, analyses of the proposed project's effect on all Class I areas within 200 km will be performed. The Chassahowitzka (CW) Wilderness area is the only Class I area of concern for this project. The CW is a PSD Class I area located in Florida approximately 113 km northwest of the proposed project site. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this protocol are regional haze and deposition. Additionally, Class I Significant Impact Levels (SILs) will be evaluated and compared to the recommended thresholds. Figure 3-1 presents the location of the proposed project site with respect to the Class I area.

The methodology of the refined CALPUFF analysis will closely follow those procedures recommended in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II* report dated December 1998 and the *Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG)* report dated December 2000 where appropriate for model option selections. This protocol includes a discussion of the meteorological and geophysical databases to be used in the analysis, the preparation of those databases for introduction into the modeling system, and the air modeling approach to assess impacts at CW.

3.1 Class I Model Selection and Inputs

3.1.1 Model Selection

The California Puff (CALPUFF, Version 5.8, Level 070623) air modeling system will be used to model the proposed project and assess the AQRVs at the Class I area. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects, as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model (Version 5.8, Level 070623), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. However, VISTAS, the Regional Planning Organization responsible for assisting with regional haze issues in the southeast, contracted Earth Tech to produce CALPUFF-ready, CALMET meteorological data files, thus bypassing the need to run the resources intensive CALMET processor for this modeling analysis. VISTAS has provided 2001-2003 CALMET files for five 4-km sub-regional domains as illustrated in Figure 3-2. The modeling proposed in this protocol will use the CALMET files prepared for sub-domain 2.

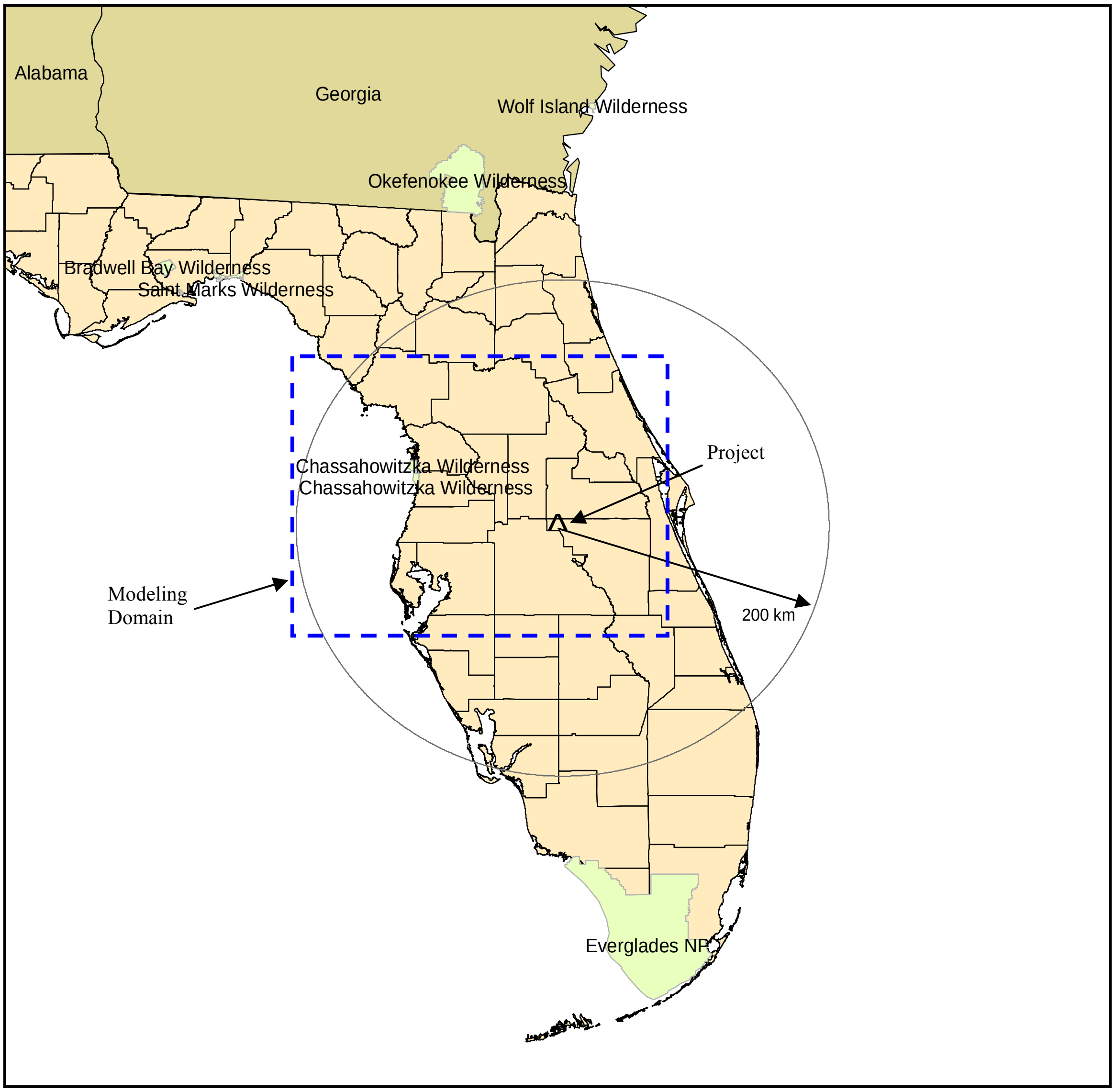

Figure 3-1
Proposed Project Location and Class I Areas

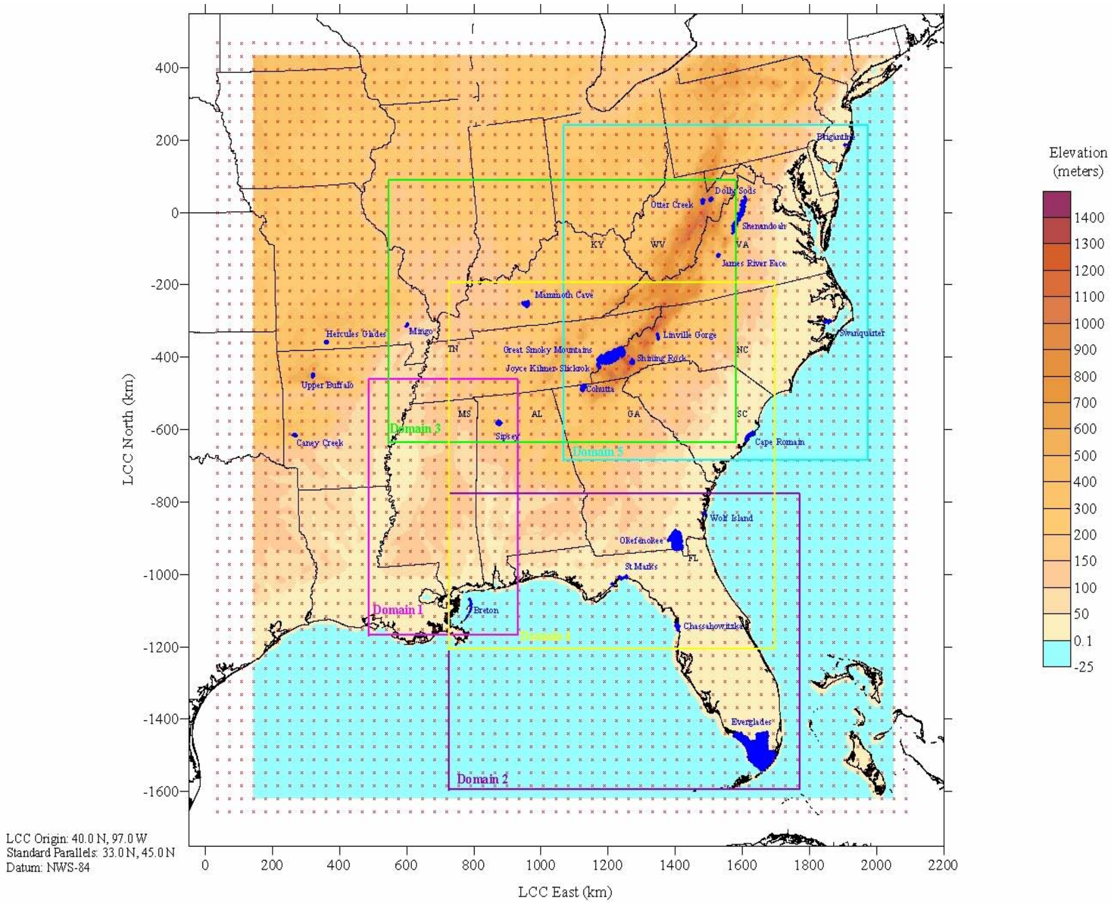

Figure 3-2
VISTAS 4-km CALMET Sub-Domains

3.1.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 3-1 will be used for the modeling analyses.

3.1.3 Project Emissions

The CALPUFF analysis will only include the emissions from Unit 4. The worst-case representative stack parameters and pollutants emission rates at 100% operating load will be used in the CALPUFF analyses. Per guidance from NPS, the PM/PM_{10} emissions will be speciated based on size and composition and therefore be broken into the following constituents: elemental carbon (EC), organic carbon (OC), and soils (SOIL) for the regional haze analysis.

3.1.4 Building Wake Effects

The CALPUFF analysis will include the facility's building dimensions to account for the effects of building-induced downwash on the emission source. Dimensions for all significant building structures will be processed with the USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program (BPIPPRM, Version 04274).

3.1.5 Receptor Locations

The CALPUFF analyses will use an array of discrete receptors over the Class I area, which were created and distributed by the National Park Service (NPS). Specifically, the array consists of receptors appropriately spaced to cover the extent of the Class I area. Receptor elevations are included in the same NPS- provided receptor files.

3.1.6 Meteorological Data Processing

The refined 4-km grid resolution VISTAS CALMET files from sub-domain 2 will be used as the meteorological and geophysical data for input to CALPUFF. These high resolution, CALPUFF-ready, CALMET files were composed of available surface and upper air observations in addition to the highest resolution MM5 data available for each year (i.e., 12-km MM5 data for 2001 and 2002 and 36-km MM5 data for 2003). A 4-km grid resolution is expected to be adequate given the lack of significant terrain features in central Florida

The VISTAS 2001-2003 meteorological data was recently re-processed by the Fish & Wildlife Service (FWS) using the current EPA regulatory version of CALMET, i.e., Version 5.8 Level 070623. Black & Veatch obtained this re-processed fine-grid CALMET dataset for the entire VISTAS region from the North Carolina Department of Environment and Natural Resources.

Table 3-1
CALPUFF Model Settings

Parameter	**Setting**
Pollutant Species Emitted	SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	VISTAS CALMET Files
Plume Rise	Transitional plume rise, stack-tip downwash, partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, PRIME building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24-hour change as processed by CALPOST Class I SILS: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Rates (SERs).
Background Values	Ammonia: 0.5 ppb (monthly); Ozone: Hourly ozone data files provided by TRC for use in VISTAS's BART modeling analyses will be utilized. A review of the CASTNET database will be performed to obtain monthly averages and these values will be substituted by the CALPUFF model should there be missing hourly values in the VISTAS ozone files.

3.1.6.1 CALMET Settings. The major features of CALMET used by Earth Tech to develop the CALMET files are listed below.

- Modeling period: 3 years (2001 – 2003).
- Meteorological inputs: MM5 data provide initial guess fields in CALMET, surface and upper air data.
- CALMET grid resolution: 4 km.
- CALMET vertical layers: 10 layers. Cell face heights (meters): 0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000.
- CALMET mode: MM5 data was used for initial guess field, in addition hourly surface data, twice daily upper air soundings, precipitation data, and over water data was used.
- Diagnostic options: IWAQM default values, except as follows: diagnostic terrain blocking and slope flow algorithms used for 2003 simulations (using 36 km MM5 data), but no diagnostic terrain adjustments in 2001 and 2002 simulation (using 12 km MM5 data).
- CALMET options dealing with radius of influence parameters (R1, R2, RMAX1, RMAX2, RMAX3), BIAS, ICALM parameters were predetermined by Earth Tech for each sub-domain.
- TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments (i.e., the 2003 simulations).
- Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water). This feature allows the temperature field over large bodies of water such as the Atlantic Ocean and the Great Lakes to be properly characterized by buoy observations.
- Mixing height averaging parameter (MNMDAV) was determined by Earth Tech for the regional simulations based on sensitivity tests.
- Geophysical data for regional runs: USGS 3-arcsec terrain data, Composite Theme Grid (CTG) USGS 200m land use dataset.
- References for these and other CALMET datasets can be found on the CALPUFF data page of the official CALPUFF site (www.src.com).

3.1.7 Modeling Domain

The CALPUFF modeling domain will be a subset of the previously discussed CALMET domain. The size of the domain used for the modeling will be based on the distances needed to cover the area from the proposed project to the receptors at the Class I area with at least a 80 km buffer zone in each direction. The modeling analysis will be performed in the Lambert Conformal Conic (LCC) coordinate system with standard parallels of 33 and 45 degrees north latitude and reference latitude and longitude of 40 and 97 degrees, respectively. A rectangular modeling domain extending 292 km in the east-west (x) direction and 204 km in the north-south (y) direction will be used for the refined modeling analysis. The southwest corner of the domain is located at 1,317.995 km Easting and -1,254 km Northing (LCC, World Geodetic System (WGS) 1984 coordinates). The grid resolution for the domain will be 4 km. A grid spacing of 4 km yields 73 grid cells in the x-direction and 51 grid cells in the y-direction. Figure 3-1 illustrates the size and location of the modeling domain.

3.2 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system will be used to complete the Class I analyses on the Class I area, including regional haze and Class I SILs.

3.2.1 Regional Haze Analysis

A regional haze analysis will be performed for the Class I area, for ammonium sulfates, ammonium nitrates, and particulate matter, by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations. PM_{10} emissions will be speciated into filterable and condensable PM size categories using NPS speciation spreadsheets.

3.2.1.1 Visibility. Visibility is an AQRV for the Class I areas. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the Class I area lies beyond 50 km from the proposed project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}\,(Mm^{-1}) = 3912 / vr\,(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where:

b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

3.2.1.2 Background Visual Ranges and Relative Humidity Factors. The background visual range is based on data representative of historical conditions at the Class I area. The background visual range, or constituents thereof, for the Class I area will be obtained from the Phase I FLAG Report, December 2000. The average relative humidity factor for each day will be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the impact occurred. This factor, based on each hour's relative humidity can be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a relative humidity factor for each hour of relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). All of this is accomplished with the use of the CALPOST post-processor.

3.2.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines. The CALPUFF air modeling analysis will closely follow the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts*, (EPA, 12/98) where appropriate. Table 3-2 summarizes the IWAQM Phase II recommendations. The methodology in Table 3-2 will be used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. The post-processing selection will be made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze will be calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly relative humidity adjustments for observed and modeled sulfate and nitrates. The relative humidity will be capped at 95 percent. Method 7, which eliminates hours during which visibility limiting weather events occur, may be explored as necessary. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Table 3-2
Outline of IWAQM Refined Modeling Analyses Recommendations

Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS will provide the modeling receptors.
Dispersion	CALPUFF with default dispersion settings. Use MESOPUFF II chemistry with wet and dry deposition. Define background values for ozone and ammonia for area.
Processing	Use highest predicted 24-hr SO_4, PM_{10}, and NO_3 value; compute a day-average relative humidity factor (f(RH)) for the worst day for the predicted specie, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate. This can all now be accomplished with the use of Method 2 in the CALPOST post-processor.

Based on the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98)

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM speciation (EC & OC) impacts, in units of micrograms per cubic meter (μg/m^3).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:
   $(NH_4)_2SO_4$ (μg/m^3) = SO_4 (μg/m^3) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4
   $(NH_4)_2SO_4$ (μg/m^3) = SO_4 (μg/m^3) x 132/96 = SO_4 (μg/m^3) x 1.375
3. Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 (μg/m^3) = NO_3 (μg/m^3) x molecular weight NH_4NO_3 / molecular weight NO_3
   NH_4NO_3 (μg/m^3) = NO_3 (μg/m^3) x 80/62 = NO_3 (μg/m^3) x 1.29
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:
   $b_{exts} = 3[NH_4NO_3]f(RH) + 3[(NH_4)_2SO_4]f(RH) + 4[OC] + 10[EC] + 4[PMC] + 1[PMF]$
5. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:
   $b_{extb} = 3.912$ / visual range (km)
6. Compute the change in extinction coefficients:
   in terms of deciviews:
   $dv = 10 \ln (1 + b_{exts} / b_{extb})$
   in terms of percent change of visibility:
   $\Delta\% = (b_{exts} / b_{extb}) \times 100$

Based on the predicted SO_4, NO_3, and speciated PM concentrations, the proposed project's emissions will be compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

3.2.2 Deposition Analyses

Deposition analyses will be performed for CW for both total sulfur and total nitrogen. The analyses will follow those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the USEPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses will be performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 3.1 (including output of both dry and wet deposition).
2. Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results are in kg/ha/yr.

The model-predicted results will be compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. Fish and Wildlife Service (FWS).

3.2.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) to the Class I area will be calculated for the appropriate criteria pollutants subject to PSD for each applicable averaging period. The results of this analysis will be compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Should the model predicted impacts onto the Class I area exceed the Class I SILs, an appropriately derived inventory of PSD increment consuming sources will be developed through FDEP and modeled with the CALPUFF modeling system for comparison to the Class I Increment values.

4.0 Class II Ambient Air Quality Analysis

Air Dispersion Model:	AERMOD (Latest version)
Model Options:	USEPA recommended regulatory default options.
GEP & Downwash:	USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program (BPIPPRM, Version 04274) will be used to determine GEP stack height and direction specific building downwash parameters for each 10-degree azimuth direction for each stack. Structures associated with the new site will be included in the downwash analysis.
Receptor Grids:	A 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 250 m spacing from 1 km to 2.5 km, 500 m spacing from 2.5 km to 5 km, and 1,000 m spacing from 5 km to 10 km. Fenceline receptors will be placed at 50 m intervals, and a 100 m fine grid will be placed at maximum impact locations.
Terrain Considerations:	Terrain elevations at receptors will be obtained from 7.5-minute United States Geological Survey (USGS) Digital Elevation Model (DEM) files. For applications involving elevated terrain, the user must now also input a hill height scale along with the receptor elevation. To facilitate the generation of hill height scales for AERMOD, a terrain preprocessor, called AERMAP, has been developed by USEPA. For each receptor AERMAP searches for the terrain height and location that has the greatest influence on dispersion. In order to calculate the hill height scale, the DEM array and domain boundary must include all terrain features that exceed a 10% elevation slope from any given receptor. A visual inspection of the surrounding DEM files will be performed to ensure all such terrain nodes are covered in the computation of the hill height scale. Using AERMAP (Version 06341), terrain elevations will be determined using a method that interpolates the terrain elevation near each receptor.
Dispersion Coefficients:	A key feature of AERMOD's formulation is the use of directly observed variables of the boundary layer to parameterize dispersion; therefore, the choice of the use of the simple rural or urban dispersion coefficient is no longer available. The AERMOD model has the option of assigning specific sources to have an urban effect, thus

enabling AERMOD to employ enhanced turbulent dispersion associated with anthropogenic heat flux, parameterized by population size of the urban area. Since the proposed Project is not located in an urbanized area, urban boundary layer option will not be invoked.

Meteorological Data: Sequential hourly meteorological data will consist of Orlando surface data and upper air data from Tampa/Ruskin for the data period of 1999-2003. This data set is provided by and processed by Florida Department of Environmental Protection (FDEP) and is AERMOD ready.

Pollutants to be Modeled: The pollutants that are currently expected to be modeled are PM/PM_{10}, NO_x, SO_2, and CO.

Source Modeling Parameters: Representative combustion turbine performance and emissions data for the several operating configurations; including natural gas firing, evaporative cooling, and duct firing. The performance and emission data will be determined across 40, 50, 75, and 100 percent load cases at ambient temperatures of 19, 59, 73, and 100 ^oF. Enveloping may be used to determine the worst-case hourly emission rates and operating parameters for each load case across ambient temperatures and operating scenarios that will be used for short-term modeling impacts. Emission rates and operating parameters for annual modeling impacts will be based on annual average ambient temperature data, at 100 percent load.

Significant Impact Area: It is anticipated that the maximum model predicted pollutant impacts will be less than their respective PSD SILs. However, if the predicted impact of one or more pollutants and applicable averaging periods are greater than the PSD SILs, then a significant impact area (SIA) will be determined and interactive cumulative source modeling will be performed for those pollutants to determine compliance with PSD increment limits. In this event, the proposed project will develop a methodology for compiling a cumulative source inventory and submit to the agency that methodology for approval.

Preconstruction Monitoring: It is anticipated that the maximum model predicted pollutant impacts will be less than the applicable PSD significant monitoring concentrations and VOC and NO_x emissions will each be less than 100 tpy, as such, an exemption from pre-application monitoring requirements is requested. However, in the event the maximum model predicted impacts exceed the applicable PSD significant monitoring concentration for a given pollutant, then the existing ambient air quality monitoring network will be evaluated for representativeness of these data to the site location pursuant to requesting a waiver from the pre-application monitoring requirements for that pollutant.

Additional Impacts: An analysis considering the impairment to soils and vegetation, as well as projected air quality impacts that may occur as the result of general commercial, residential, industrial, and other growth associated with the new major stationary source will be performed. The USEPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals* will serve as a basis for assessing the vegetation and soil impacts.

Toxics: No toxic modeling analysis is required.

Appendix F
Electronic Modeling Files