Applicant's Environmental Report – Operating License Renewal Stage St. Lucie Units 1 & 2

Florida Power & Light Company

Docket Nos. 50-335 and 50-389

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

APPENDICES

LIST OF TABLES

LIST OF FIGURES

ACRONYMS AND ABBREVIATIONS

°	degree(s)
>	greater than
<	less than
≤	less than or equal to
AB	Auxiliary Building
AC	alternating current
AEC	U.S. Atomic Energy Commission
AFW	Auxiliary Feedwater
ATWS	Anticipated Transient Without Scram
bcf	billion cubic feet
BGE	Baltimore Gas and Electric Company
Btu	British thermal unit
C	Celsius
CAA	Clean Air Act
CCNPP	Calvert Cliffs Nuclear Power Plant
CCW	component cooling water
CDF	core damage frequency
CE	Combustion Engineering Inc.
CEQ	Council on Environmental Quality
CFR	*Code of Federal Regulations*
cfs	cubic feet per second
cm	centimeter(s)
CO	carbon monoxide
CST	Condensate Storage Tank
CT	combustion turbine
CVCS	Chemical Volume Control System
CWA	Clean Water Act
DC	direct current
DECON	immediate decontamination and dismantlement

ACRONYMS AND ABBREVIATIONS (Continued)

DEP	(Florida) Department of Environmental Protection
DOE	U.S. Department of Energy
DSM	demand-side management
ea.	each
ECCS	Emergency Core Cooling System
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
F	Fahrenheit
FES	Final Environmental Statement
FGD	flue-gas desulfurization
FGT	Florida Gas Transmission
FL	Florida
FMPA	Florida Municipal Power Agency
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
ft^3	cubic foot (feet)
FWCC	(Florida) Fish and Wildlife Conservation Commission
FWS	U.S. Fish and Wildlife Service
g	gram(s)
gal	gallon(s)
GEIS	*Generic Environmental Impact Statement for License Renewal of Nuclear Plants*
gpm	gallon(s) per minute
HPSI	high-pressure safety injection
hr	hour(s)
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events
ISLOCA	interfacing system loss-of-coolant accident

ACRONYMS AND ABBREVIATIONS (Continued)

ISO	International Standards Organization
K	thousand
kg	kilogram(s)
kV	kilovolt(s)
kW	kilowatt
kWh	kilowatt hour(s)
lb	pound(s)
LOCA	loss-of-coolant accident
LOS	level of service
m	meter(s)
m^3	cubic meter(s)
mA	milliamperes
MAB	maximum attainable benefit
MACCS	Melcor Accident Consequence Code System
MFW	Main Feedwater
mi	mile(s)
mg	milligrams
mg/l	milligram(s) per liter
MM	million
MSIV	main steam isolation valve
MSL	mean sea level
MSLB	Main Steam Line Break
MW	megawatt(s)
MW(e)	megawatts (electric)
MW(t)	megawatts (thermal)
NA	not applicable; not available
NEPA	National Environmental Policy Act
NESC®	National Electrical Safety Code®
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxide(s)

ACRONYMS AND ABBREVIATIONS (Continued)

NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
OSHA	Occupational Safety and Health Act
OUC	Orlando Utilities Commission
PIT	passive integrated transponder
PM_{10}	particulates having diameter of less than 10 microns
PORV	power-operated relief valve
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
RAB	Reactor Auxiliaries Building
RCP	reactor coolant pump
RCS	Reactor Coolant System
Ref.	Reference
rem	roentgen equivalent man
RHR	residual heat removal
ROW	right-of-way
SAFSTOR	safe storage of the stabilized and defueled facility
SAMA	severe accident mitigation alternative
SAMDA	severe accident mitigation design alternative
SBO	station blackout
SFWMD	South Florida Water Management District
SG	steam generator
SGTR	steam generator tube rupture
SHPO	State Historic Preservation Officer
SI	safety injection
SMITTR	surveillance, (on-line) monitoring, inspections, testing, trending, and recordkeeping
SO_2	sulfur dioxide
SO_x	sulfur oxides
SSC	state species of special concern

ACRONYMS AND ABBREVIATIONS (Continued)

T2	reactor trip with PORV challenge
TSP	total suspended particulates
TVA	Tennessee Valley Authority
U1	St. Lucie Unit 1
U2	St. Lucie Unit 2
UFSAR	Updated Final Safety Analysis Report
UIDS	Underwater Intrusion Detection System
USC	United States Code
UTM	Universal Transverse Mercator
V	volt
WPA	Work Project Administration
wt	weight
yr	year(s)

1.0 INTRODUCTION

1.1 PURPOSE OF AND NEED FOR ACTION

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act and NRC implementing regulations. Florida Power & Light Company (FPL) operates St. Lucie Units 1 & 2 pursuant to NRC Operating Licenses DPR-67 and NPF-16, respectively. The Unit 1 license will expire March 1, 2016, and the Unit 2 license will expire April 6, 2023. FPL has prepared this environmental report in connection with its application to the NRC to renew the St. Lucie Units 1 & 2 licenses, as provided for by the following NRC regulations:

- Title 10, Energy, *Code of Federal Regulations*, Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, Section 54.23, Contents of Application—Environmental Information (10 CFR 54.23); and
- Title 10, Energy, *Code of Federal Regulations*, Part 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions, Section 51.53, Postconstruction Environmental Reports, Subsection 51.53(c), Operating License Renewal Stage [10 CFR 51.53(c)].

The NRC's regulations at 10 CFR 54.17(c) state that an application for a renewed license may not be submitted earlier than 20 years before the current operating license for a unit expires. However, FPL has obtained an exemption from this requirement for St. Lucie Unit 2 license renewal (Ref. 1.1-1), in accordance with provisions of 10 CFR 54.15. Therefore, as with other portions of this application, this environmental report addresses both of the St. Lucie Units.

The NRC has defined the purpose and need for the proposed action, the renewal of the operating licenses for nuclear power plants such as St. Lucie Units 1 & 2, as follows:

> ...The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized, Federal (other than NRC) decision makers.... (Ref. 1.1-2, page 28472).

The renewed operating licenses would allow 20 additional years of plant operation beyond the current St. Lucie Units 1 & 2 licensed operating periods of 40 years.

1.2 ENVIRONMENTAL SCOPE AND METHODOLOGY

NRC regulations for domestic licensing of nuclear power plants require environmental review of applications to renew operating licenses. The NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled *Applicant's Environmental Report - Operating License Renewal Stage*. In determining what information to include in the St. Lucie Units 1 & 2 environmental report, FPL has relied on NRC regulations and the following supporting documents that provide additional insight into the regulatory requirements:

- NRC supplemental information in the *Federal Register* (Ref. 1.1-2; Ref. 1.2-1; Ref. 1.2-2; Ref. 1.2-3)
- *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Ref. 1.2-4; Ref. 1.2-5)
- *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses* (Ref. 1.2-6)
- *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response* (Ref. 1.2-7)

FPL has prepared Table 1.2-1 to verify conformance with regulatory requirements. Table 1.2-1 indicates where the environmental report responds to each requirement of 10 CFR 51.53(c). In addition, each responsive section is prefaced by a boxed quote of the regulatory language and applicable supporting document language.

TABLE 1.2-1
ENVIRONMENTAL REPORT RESPONSES TO LICENSE RENEWAL ENVIRONMENTAL REGULATORY REQUIREMENTS

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(1)	Entire Document	
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0	Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.2.2	Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0	Alternatives to the Proposed Action
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5	Short-term Use versus Long-term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4	Irreversible or Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.2	Mitigation
	7.2.2	Environmental Impacts of Alternatives
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0	Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1	Introduction
10 CFR 51.53(c)(3)(ii)(B)	4.2	Entrainment of Fish and Shellfish in Early Life Stages
	4.3	Impingement of Fish and Shellfish
	4.4	Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.1	Introduction
10 CFR 51.53(c)(3)(ii)(D)	4.1	Introduction
10 CFR 51.53(c)(3)(ii)(E)	4.5	Impacts of Refurbishment on Terrestrial Resources
	4.6	Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.7	Air Quality During Refurbishment (Non-attainment or Maintenance Areas)
10 CFR 51.53(c)(3)(ii)(G)	4.1	Introduction
10 CFR 51.53(c)(3)(ii)(H)	4.8	Electric Shock from Transmission-line-induced Currents

TABLE 1.2-1 (continued)
ENVIRONMENTAL REPORT RESPONSES TO LICENSE RENEWAL ENVIRONMENTAL REGULATORY REQUIREMENTS

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(3)(ii)(I)	4.9	Housing Impacts
	4.10	Public Utilities: Public Water Supply Availability
	4.11	Education Impacts from Refurbishment
	4.12	Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.13	Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.14	Historic and Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.15	Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.2	Mitigation
10 CFR 51.53(c)(3)(iv)	5.0	Assessment of New and Significant Information
10 CFR 51, Appendix B, Table B-1, Footnote 6	4.16	Environmental Justice

1.3 ST. LUCIE UNITS 1 & 2 LICENSEE AND OWNERSHIP

St. Lucie Unit 1 is owned by FPL. St. Lucie Unit 2 is co-owned by FPL, Orlando Utilities Commission (OUC), and Florida Municipal Power Agency (FMPA). Together, OUC and FMPA own 14.9 percent of St. Lucie Unit 2. FPL built St. Lucie Units 1 & 2 and has had sole responsibility for operation of the Units since March 1, 1976, and April 6, 1983, respectively.

1.4 REFERENCES

1.1-1 Jabbour, K.N. (NRC) Letter to T.F. Plunkett (FPL). St. Lucie Plant, Unit No. 2, Exemption from the Requirements of 10 CFR 54.17, Section 54.17 (c) Regarding Schedule for License Renewal Application (TAC No. MB0418)." February 27, 2001.

1.1-2 U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." *Federal Register*. Vol. 61, No. 109. (June 5, 1996): 28467-97.

1.2-1 U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction." Federal Register. Vol. 61, No. 147. (July 30, 1996): 39555-6.

1.2-2 U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register. Vol. 61, No. 244. (December 18, 1996): 66537-54.

1.2-3 U.S. Nuclear Regulatory Commission. "Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rules." Federal Register. Vol. 64, No. 171. (September 3, 1999): 48496-507.

1.2-4 U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. NUREG-1437. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

1.2-5 U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Section 6.3, "Transportation," and Table 9-1, "Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants." NUREG-1437, Vol. 1, Addendum 1. Office of Nuclear Reactor Regulation. Washington, D.C. August 1999.

1.2-6 U.S. Nuclear Regulatory Commission. Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses. NUREG-1440. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

1.2-7 U.S. Nuclear Regulatory Commission. Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response. NUREG-1529. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 LOCATION AND FEATURES

Florida Power & Light Company's (FPL's) St. Lucie Units 1 & 2 are located on Hutchinson Island in St. Lucie County, Florida. The site is in Sections 8, 9, 15, 16, and 17, Township 36 South, Range 41 East. The nearest municipalities are Fort Pierce, approximately seven miles northwest of the plant; Port St. Lucie, approximately four and a half miles to the west; and Stuart, approximately eight miles to the south. Port St. Lucie is the largest city within 50 miles of St. Lucie Units 1 & 2. State Road A1A provides road access to the plant and transverses FPL property in a north-south direction approximately 1,000 feet east of St. Lucie Units 1 & 2 (Ref. 2.1-1, Section 2.1.1). Figures 2.1-1 and 2.1-2 show the site location and features within 50 and 6 miles, respectively. Figure 2.1-3 shows the site boundary in relation to the powerblock and adjacent features. The exclusion area for the plant, as defined in 10 CFR 100.3, corresponds to the area within 0.97 miles of the reactors and lies within the FPL property boundary (Ref. 2.1-1, Section 2.1.1).

The St. Lucie Units 1 & 2 site consists of approximately 1,130 acres of land on the widest section of Hutchinson Island in an area previously degraded by mosquito control projects. The plant site is bordered by the Atlantic Ocean to the east and the Indian River Lagoon to the west. The topography of the site is generally flat. The most prominent topographic feature of the site is the grade for State Road A1A, which passes through the eastern portion of FPL property. Between the dunes and State Road A1A, the principal feature is a series of mangrove-dominated mosquito impoundments interspersed with islands of natural coastal strand vegetation. St. Lucie Units 1 & 2 are located on the west side of State Road A1A in a relatively flat, sheltered area of the island. West of the facility, the land gradually slopes downward to a mangrove fringe bordering the intertidal shoreline of the Indian River Lagoon. East of the facility, land rises from the ocean shore to form dunes and ridges approximately 15 feet above mean low water (Ref. 2.1-2, Section 2.1). Two county parks with beach access, Blind Creek Pass Park and Walton Rocks Park, lie within the St. Lucie Units 1 & 2's property boundary. Recreational facilities for FPL employees and their families are also available within the site's property boundary (Ref. 2.1-1, Section 2.1.1).

The Indian River Lagoon is a long, shallow, tidally influenced estuary stretching along Florida's central east coast between the mainland and a series of offshore islands. At St. Lucie Units 1 & 2, the Indian River Lagoon is approximately 7,200 feet wide (Ref. 2.1-3, Section II-A). Blind Creek and Big Mud Creek, inlets off the Indian River Lagoon, are adjacent to the site. The stretch of lagoon adjacent to the site is designated as the Jensen Beach to Jupiter Inlet Aquatic Preserve. The North Fork St. Lucie River Aquatic Preserve is located on the north fork of the river as it parallels the coast north of where it flows into the St. Lucie River at Port St. Lucie. The St. Lucie Canal connects the St. Lucie River with Lake Okeechobee and parallels State Route 76, south of Stuart.

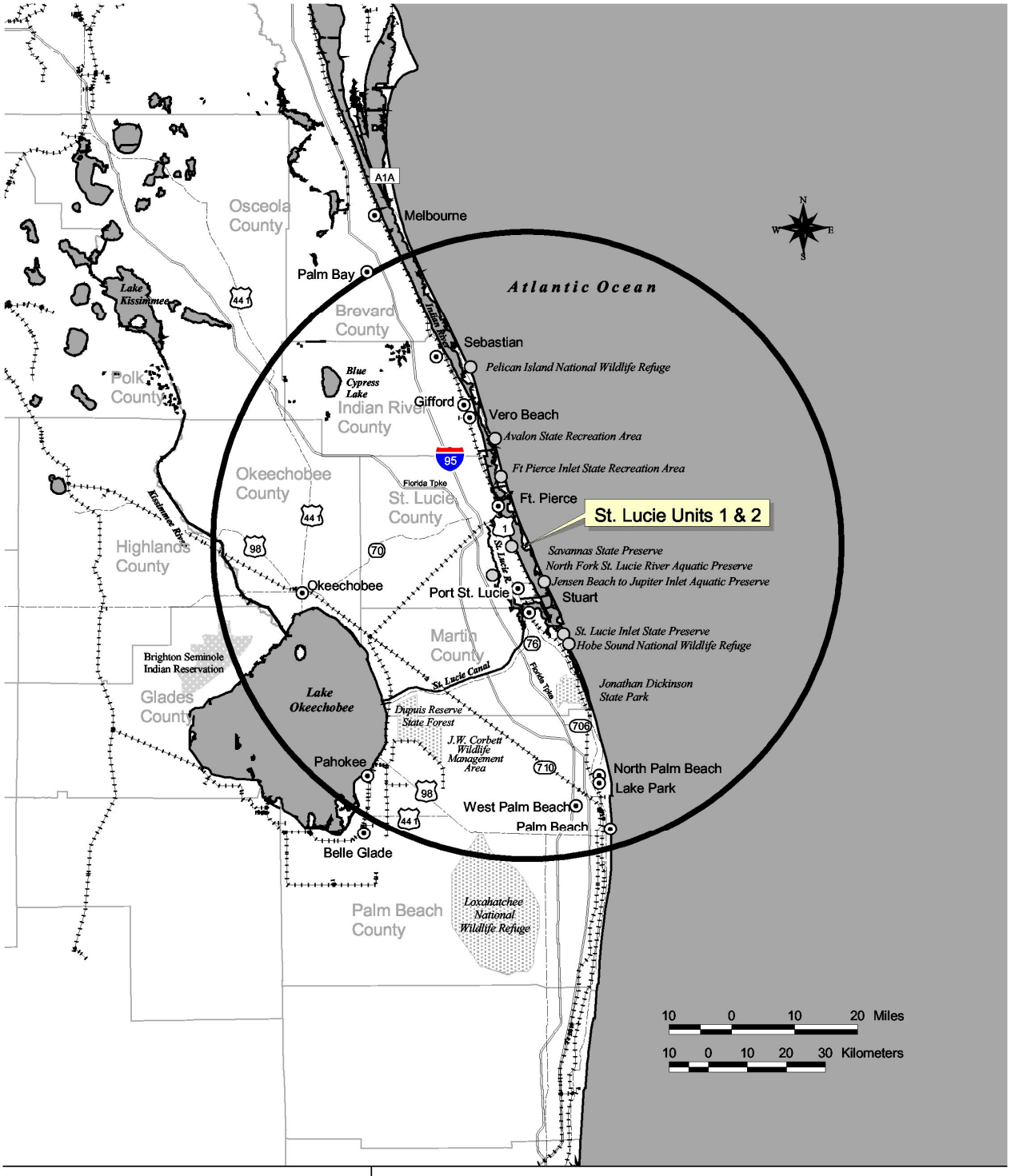
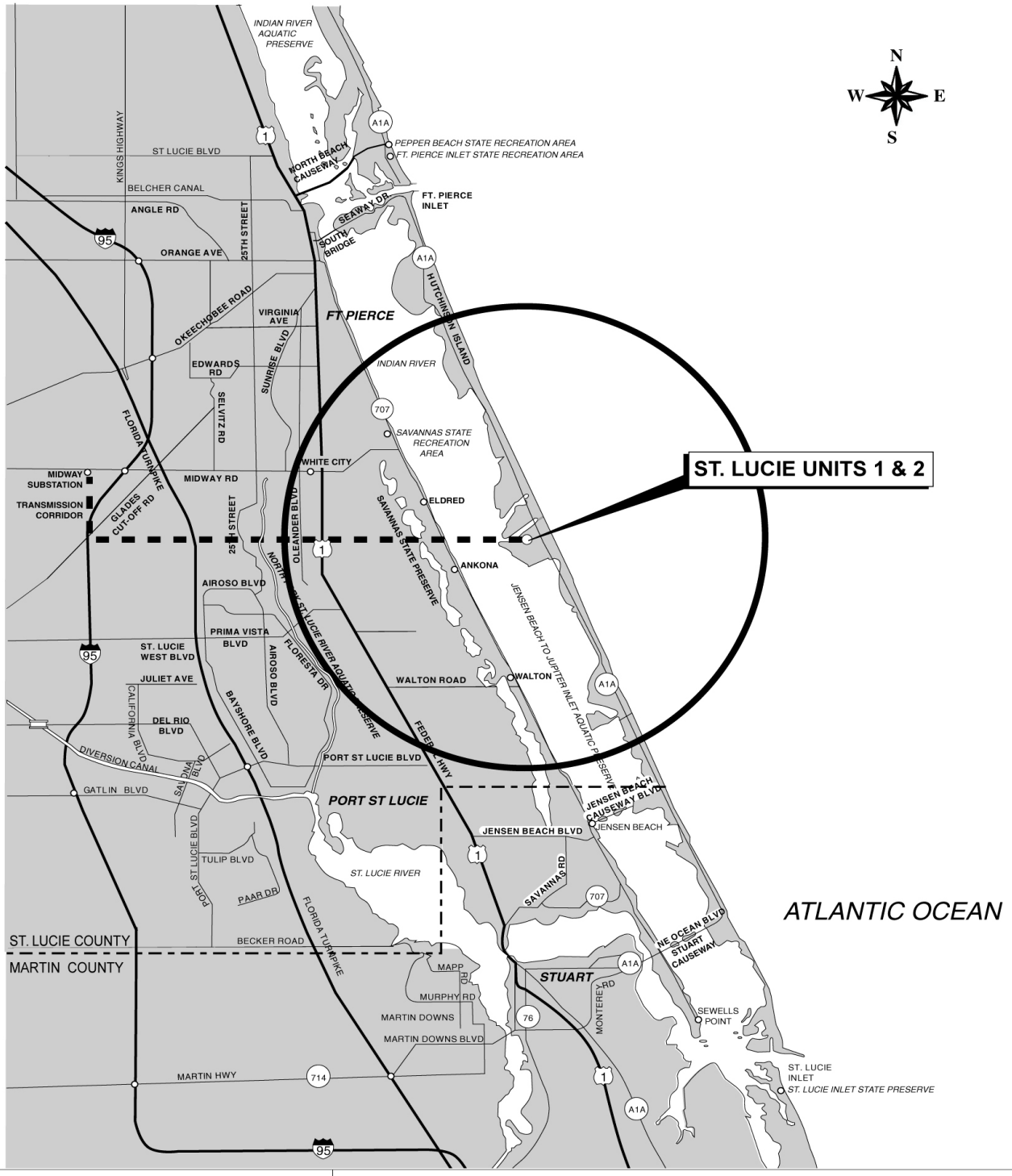


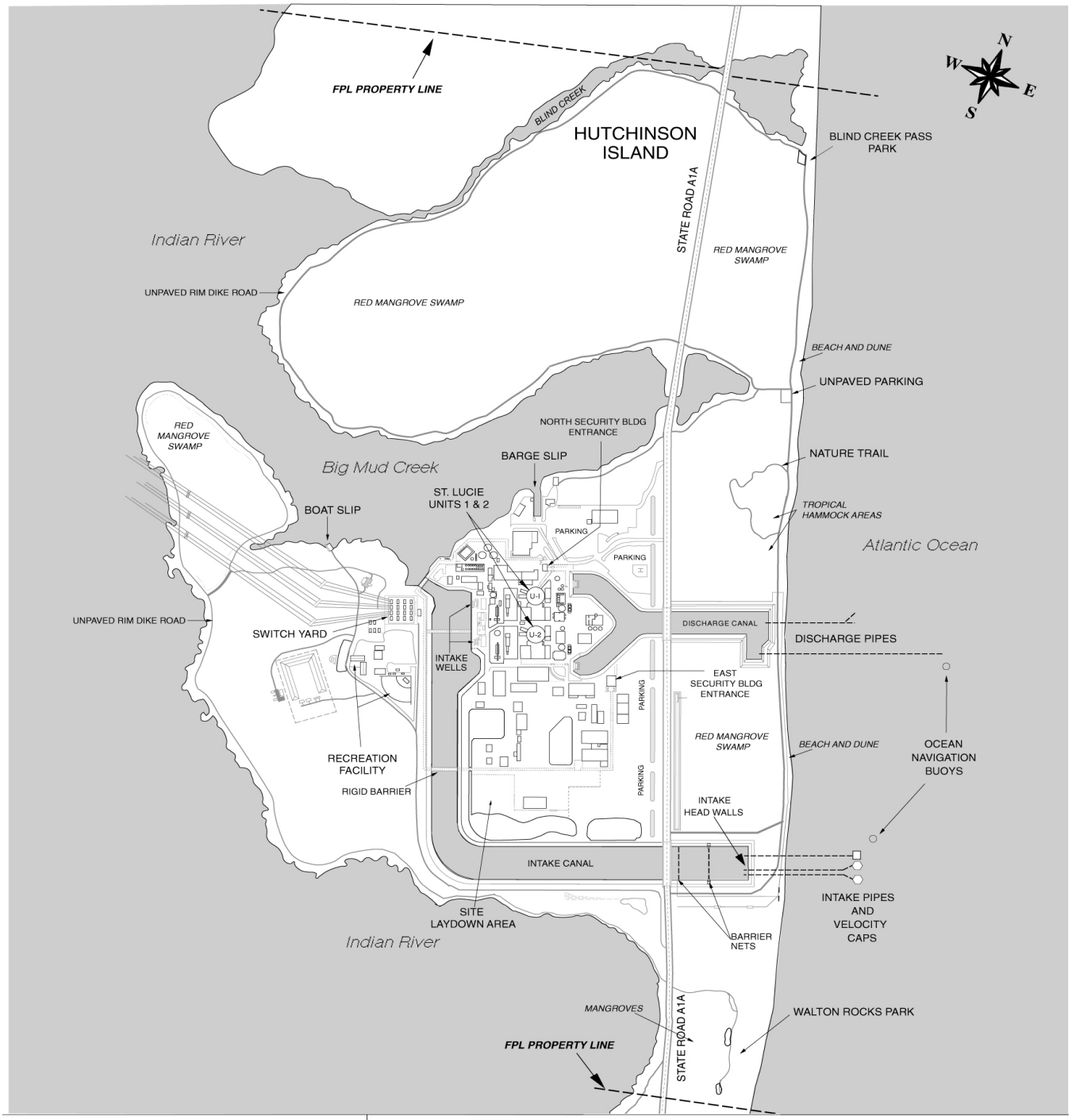
FIGURE 2.1-1
ST. LUCIE UNITS 1 & 2, 50-MILE REGION
LICENSE RENEWAL APPLICATION
ST. LUCIE UNITS 1 & 2



SCALE
0 2 MILES 4 MILES

County Boundary
Roads
Transmission Corridor
6-Mile Radius

FIGURE 2.1-2
ST. LUCIE UNITS 1 & 2, 6-MILE REGION
LICENSE RENEWAL APPLICATION
ST. LUCIE UNITS 1 & 2



SCALE
0 1/8 1/4 MILE

FIGURE 2.1-3
ST. LUCIE UNITS 1 & 2 SITE BOUNDARY
LICENSE RENEWAL APPLICATION
ST. LUCIE UNITS 1 & 2

Fort Pierce Inlet State Recreation Area is approximately nine miles north of St. Lucie Units 1 & 2 immediately north of the Fort Pierce Inlet (see Figure 2.1-2). Activities include beach access, swimming, picnicking, camping, and hiking (Ref. 2.1-4). Other state recreation areas include Avalon, Savannas, and Pepper Beach. The Savannas State Preserve, a freshwater lagoon, is located on the mainland approximately two miles west of St. Lucie Units 1 & 2, and offers fishing, hiking, picnicking, and other outdoor related activities (Ref. 2.1-5). Other prominent features within 50 miles of St. Lucie Units 1 & 2 include Lake Okeechobee, Blue Cypress Lake, Jonathan Dickinson State Park, the Dupuis Reserve State Forest, J. W. Corbett Wildlife Management Area, portions of the Brighton Seminole Indian Reservation, and the Hobe Sound, Pelican Island, and Loxahatchee National Wildlife Refuges (see Figure 2.1-1).

Section 3.1 describes the major features of St. Lucie Units 1 & 2, including reactor and containment systems; fuel configuration and refueling activities; cooling and auxiliary water systems; and power transmission systems.

2.2 AQUATIC ECOLOGICAL COMMUNITIES

The St. Lucie Units 1 & 2 location on Hutchinson Island places it between two major aquatic ecosystems: the Atlantic Ocean to the east and the Indian River Lagoon to the west. The plant uses a once-through cooling water system that withdraws from and discharges into the Atlantic Ocean via offshore intake and discharge structures. The plant is also equipped with an emergency cooling water intake that can withdraw water from the Indian River Lagoon via Big Mud Creek but this pathway is closed during normal operation (see Section 3.1.3). These areas contain markedly different habitats and biotic communities, as discussed below.

2.2.1 ATLANTIC OCEAN

Submerged coquinoid rock formations parallel much of Hutchinson Island. A notable beach frontage feature at the plant site, just south of the St. Lucie Units 1 & 2 Intake Canal, is an intertidal coquina-rock formation that protrudes through the sand at Walton Rocks Park. The hard substrate is colonized extensively by an encrusting tube-building polychaete worm. These worm rock communities in turn support a rich and diverse association of other invertebrates, algae, and fishes. Several studies of the worm rock communities were conducted at Walton Rocks Park. Studies performed to support the early operations of St. Lucie Unit 1 indicated that thermal effluents did not significantly alter the species composition of the worm rock communities.

The near shore area has no reef structures, grass beds, or rock outcroppings. Seaward, the ocean floor consists of unconsolidated sediments composed of quartz and calcareous sands, broken shell fragments, and negligible amounts of silts and clays. The sea floor gently slopes into a trough with a maximum depth of about 39 feet at about one nautical mile offshore. Continuing offshore, the sea floor rises to form the Pierce Shoal at about two miles.

The marine communities in the vicinity of St. Lucie Units 1 & 2 were studied in detail prior to startup of Unit 1 in 1976 (Ref. 2.1-2, Section 2.7.5). Phytoplankton were collected at five locations offshore of Hutchinson Island. Densities ranged from 1.0 to 35,532.9 cells/liter during the study period, but varied little from location to location. The community was dominated by diatoms, the most common of which were the genera *Nitzschia*, *Bellerochea*, and *Chaetoceros*, and the species *Thalassionema nitzschioides* and *Skeletonema costatum*. The data indicated the possibility of two blooms per year, one in September-October and one in January. Chlorophyll a concentrations ranged from 0.08 to 7.7 mg/m^3 and correlated well with the September-October phytoplankton bloom. The composition of the phytoplankton communities was typical of those described for other nearshore areas along the eastern seaboard of the United States.

Zooplankton were sampled at the same locations as phytoplankton, and ranged in density from 244 to 12,023 organisms/m^3. The zooplankton community was characterized primarily by neritic holoplanktonic species (species that spend their entire life cycle in the water column). Copepods dominated the collections with the genera *Acartia, Paracalamis, Oithona, Temora, Undinula, Corycaeus, Euterpina,* and *Labidocera* being common. Zooplankton density appeared to be broadly correlated with phytoplankton density.

Baseline monitoring established that there were three sub-tidal microhabitats offshore of the plant: shallow beach terrace, offshore shoal, and a deeper trough in between the two. Sediment composition differed among these zones. The biological composition of macroinvertebrate communities is largely influenced by sediment composition. Because of the sediment heterogeneity, the trough supports the most abundant fauna. It was characterized by high diversity and relatively rapid turnover of less abundant and more transient species. In the intertidal zone, the worm reef community provided yet another distinct habitat for macroinvertebrates. Patterns of fish abundance and diversity were also largely aligned along microhabitat boundaries. In addition to the habitats identified above, the surf zone harbored yet another distinct assemblage of fish.

Baseline studies identified 127 species of arthropods and nearly 300 species of mollusks. The diverse makeup of these groups, and to some extent their seasonal variability, was attributed to the transitional temperate, sub-tropical, and tropical mix of climate and water masses in the general vicinity of Hutchinson Island. Some estuarine affinities were also noted and attributed to water mass intrusions from the Indian River Lagoon by way of St. Lucie Inlet and prevailing northerly coastal currents. Among species of direct commercial value, the calico scallop was the only mollusk recorded. Arthropods of potential commercial value included penaeid shrimp and the blue crab. However, these species were generally collected in small numbers and infrequently.

Benthic studies were conducted through 1984 and produced remarkable databases for regional sediments, hydrology, and bottom dwelling organisms. A total of 934 taxa of benthic macroinvertebrates, many species new to science, were identified by the monitoring. The sediment, water quality, and biological data show that the combined operations of St. Lucie Units 1 & 2 had little impact on benthic environments in the vicinity of the discharge diffusers and within the boundaries of the thermal plume.

The fish communities offshore are transitional assemblages of temperate and tropical forms. Since oceanic icthyofauna are most diverse and abundant near reefs and other hard-bottom areas, FPL sited intake and discharge structures for St. Lucie Units 1 & 2 in areas devoid of these habitats.

Multi-year fisheries assessments were carried out in association with startup and operations of St. Lucie Units 1 & 2. Bottom trawls were used for several years, but produced few fish (Ref. 2.1-2, Section 2.7.5). For example, sampling every other month at five Hutchinson Island offshore locations from September 1971 to March 1972 produced only 39 individual fish among 13 species. The sheepshead (*Archosargus probatocephalus*) was most abundant in this small catch. Beach seines were deployed over this same time period. Ninety-eight percent of the catch of 11,598 fish was collected in November 1971, and consisted primarily of Cuban and longnose anchovies (*Anchoa cubana* and *Anchoa nasuta*) and 20 other much less abundant species. Ichthyoplankton was also sampled during the early monitoring studies (Ref. 2.2-1, Section 4.3.8.2.5). Larvae of herring and anchovies were most common, and generally abundant during spring and summer. This program yielded 5,570 individuals distributed among 49 species. The five most abundant species accounted for nearly 70 percent of the catch: Atlantic bumper (*Chloroscombrus chrysurus*), Spanish mackerel (*Scomberomorus maculatus*), Atlantic croaker (*Micropogonias undulatus*), spot (*Leiostomus xanthurus*), and bluefish (*Pomatomus saltatrix*). Catches were higher in fall and winter than spring and summer. In comparing eight years of monitoring data (1977-

1984), investigators found temporal and spatial distributions to be highly variable (Ref. 2.2-2, Section B).

Commercial and recreational fishing are important activities in the vicinity of St. Lucie Units 1 & 2. Commercial landing data for St. Lucie County were summarized for 1970-1972 (Ref. 2.1-2, Section 2.7.5.9). Their evaluation focused on three of the most abundant species in commercial catches at that time, the bluefish, Spanish mackerel, and king mackerel (*Scomberomorus cavalla*). All three species are highly migratory, spawn in coastal waters from late summer into winter (depending on species), and migrate northward along the East Coast during the warmer seasons. For the 1971 season, landed weights of bluefish, Spanish mackerel, and king mackerel from St. Lucie County were 228,663 lb, 679,110 lb, and 1,217,356 lb, respectively. These landings represented 10.7 percent, 6.8 percent, and 21.6 percent, respectively, of total Florida landings. These species were also prominent in the 1982 landings for St. Lucie County (Ref. 2.2-2, Section B), ranging from 236,146 lb of bluefish to 899,944 lb of Spanish mackerel. However, several other species were quite abundant in 1982, including tilefish (e.g., *Caulolatilus* spp.) (587,654 lb) and swordfish (*Xiphias gladius*) (451,503 lb).

FPL (Ref. 2.1-2, Section 2.7.5.9) reported that St. Lucie County is the northernmost county on Florida's east coast that has an extensive winter sport fishery. Ladyfish (*Elops saurus*), snook, and various billfish species were common in recreational catches. Pre-operational studies revealed that the three most important commercially valuable fish in local ocean fisheries (bluefish, Spanish mackerel, and king mackerel) occur farther offshore than where the intake and discharge lines now terminate (i.e., trough habitat). These species are only seasonally abundant during migrations in spring and fall.

2.2.2 INDIAN RIVER LAGOON

The Indian River Lagoon is a productive estuary that abuts the western edge of the St. Lucie Units 1 & 2 property. A number of environmental studies were conducted in the Lagoon from the late 1960s into the 1980s in association with siting, construction, and operation of St. Lucie Units 1 & 2. The results of these studies have previously been summarized in the St. Lucie Unit 2 Environmental Report (Ref. 2.1-2, Section 2.7.4) and the Final Environmental Statement for Unit 2 (Ref. 2.2-1, Section 4.3.8.1).

The Lagoon is characterized by extensive growths of manatee grass (*Syringodium filiforme)* and red algae such as the dominant form *Gracilaria.* In turn, the grass and algae are inhabited by a variety of gammarids, shrimp, isopods, crabs, and juvenile fish. A variety of microscopic organisms are supported by this vegetative community, including diatoms attached to the plant leaves.

Planktonic organisms are abundant and diverse in the Indian River Lagoon owing to constant deposition of organic matter from the plant community. The organic matter is decomposed by bacteria, releasing mineral nutrients that are utilized by algae (including phytoplankton). Zooplankton such as protozoa, rotifers, and copepods maintain abundant populations by feeding on the bacteria. More than 90 phytoplankton species have been reported from the Lagoon.

Benthic organisms are also abundant and include tube-dwelling worms and crustaceans, the latter including larger shellfish such as shrimp and blue crabs. Twenty-four decapod

species (e.g., shrimp, crabs) were collected from Big Mud Creek near St. Lucie Units 1 & 2 in the early 1970s.

Big Mud Creek, a backwater cove of the Indian River Lagoon, was dredged to a maximum depth of 46 feet during plant construction to provide deep-water access to the Intra-Coastal Waterway. Being some distance from both the Fort Pierce and St. Lucie inlets, Big Mud Creek receives little tidal influence and so has minimal water exchange with Indian River Lagoon. This results in water stratification in the summer and anoxic conditions on the bottom. During the winter months, the water masses turn over as the surface cools.

A diverse and abundant fish community of over 300 species has been identified in the southern portion of the Indian River Lagoon (Ref. 2.2-1, Section 4.3.8.1). Red drum (*Sciaenops ocellatus*), spotted seatrout (*Cynoscion nebulosus*), common snook (*Centropomus undecimalus*), sheepshead (*Archosargus probatocephalus*), and gray snapper (*Lutjanus griseus*) were commonly reported.

During the last 20 years, the increasing levels of human activities in its watershed have impacted the Lagoon's water, sediment, and habitat quality. As the construction of extensive agricultural and urban drainage projects have increased the watershed's size, the land use changes associated with increased residential, commercial, agricultural, and industrial development have altered the freshwater inputs to the Lagoon. Alteration of the normal patterns of freshwater inputs has contributed to changes in the biological communities in the Lagoon. Reductions in abundance and distribution of sea grasses and oysters are evidence of these changes.

2.3 CRITICAL AND IMPORTANT TERRESTRIAL HABITATS

As described in Section 2.1, Hutchinson Island is a typical Florida barrier island, separated from the mainland by the Indian River Lagoon. Its eastern side is composed of ocean beach and dunes to an approximate elevation of 15 feet above mean sea level (MSL). From the dunes westward, the topography slopes to about four feet above MSL forming a swale. This area is characterized by a mangrove community (Ref. 2.1-2, Section 2.7).

There are no designated critical terrestrial habitats for endangered species in the vicinity of St. Lucie Units 1 & 2 and the transmission corridor associated with the plant. The beach and dunes, mangrove, and tropical hammock habitats are important, however, in that they represent important coastal ecosystems that have historically been reduced by development. Also, these habitats support a variety of animal species.

At the St. Lucie Units 1 & 2 site, the beach and dune habitat consists of a narrow band along the Atlantic Ocean shoreline and is subject to significant wave erosion. The seaward side of the dunes currently has no vegetation. Vegetation on the inland side of the dunes includes sea oats (*Unida paniculata*), sea grape (*Coccoloba uvifera*), salt marsh hay (*Spartina patens*), Australian pine (*Casuarina equisetifolia*), marsh ox-eye (*Barrichia frutescens*), beach sunflower (*Helianthus debilis*), marsh elder (*Iva frutescens*), bay bean (*Canaualia rosea*), and railroad vine (*Ipomoea peseaprae*).

The mangrove habitat has been considerably altered from its former natural state (Ref. 2.1-2, Section 2.7). In the 1930s and 1940s, the mangrove forest was destroyed by trenching, diking, and flooding with seawater as part of a Work Project Administration (WPA) mosquito control program. Many trees were killed by hydrologic alterations, particularly the black mangrove (*Avicennia nitida*). Since that time there has been partial restoration, particularly of red mangrove (*Rhizophora mangle*), which tends to grow in lower, wetter portions of mangrove forests. Some black and white mangrove (*Laguncularia racemosa*), fish poison (*Dalbergia ecastophyllum*), and giant leather fern (*Acrostichum danceifolium*) have since been established at higher elevations.

The mangrove stands suffered freeze damage in 1989, and revegetation has not occurred in all areas. Currently the mangrove areas are either inundated or intertidal, and function as mud flat habitats for wildlife. The tropical hammock habitat occurs east of State Road A1A. The largest area of occurrence is located amid the mangrove stands north of the St. Lucie Units 1 & 2 Discharge Canal. Prominent species include gumbo-limbo (*Bursera simaruba*), paradise tree (*Simarouba glauca*), white and Spanish stoppers (*Eugenia axillaris and E. foetida*), wild lime (*Zanthoxylum fagara*), white indigo berry (*Randia aculeata*), mastic (*Mastichodendron foetidissimum*), and snow berry (*Chiococcoca alba*). The occurrence of tropical hammocks this far north on the Atlantic coast and with a distinct assemblage of tropical species is unusual.

Notwithstanding the debilitation of the mangrove habitat that occurred in the 1930s and 1940s, Hutchinson Island habitats support a variety of animal species. FPL (Ref. 2.1-2, Section 2.7) reported 24 mammals from Hutchinson Island, of which the Virginia opossum (*Didelphis virginiana*), raccoon (*Procyon lotor*), and beach mouse (*Peromyscus polionotus*) were most common. Nearly 160 bird species were reported to use Hutchinson Island, at least during part of their life cycles. Abundant resident species were typified by water-associated birds such as great egret (*Casmerodius albus*), American coot (*Fulica*

americana), ring-billed gull (*Larus delawarensis*), and fish crow (*Corvus ossifragus*). Many migratory species pass through the area such as warblers [e.g., black and white warbler (*Mniotilta varia*)], spotted sandpiper (*Actitis macularia*), and Forster's tern (*Sterna forsteri*). Gopher tortoise (*Gopherus polyphemus*) are present on the site and have active burrows in areas of soft soils that are not subject to flooding.

Habitat in the transmission line corridor is a mixture of man-altered areas, sand pine scrub, prairie/pine flatwoods, wet prairie, and isolated marshes. In the 1970s, most of the corridor was in agricultural usage such as orange groves and pastureland (Ref. 2.1-2, Section 3.9). Current land use in the man-altered areas includes pastures, abandoned agricultural lands, and areas disturbed by grading or clearing.

2.4 THREATENED OR ENDANGERED SPECIES

A list of threatened or endangered species, or state species of special concern (SSC) that have been observed on or near the St. Lucie Units 1 & 2 site, or could potentially occur in the vicinity or along the transmission line corridor, is provided in Table 2.4-1. Certain species, such as the Least Tern (*Sterna antillarum*), Black Skimmer (*Rynchops niger*), American Oystercatcher (*Haematopus palliateus*), several species of sea turtle, gopher tortoise (*Gopherus polyphemus*), and the Florida manatee (*Trichechas manatus*) have been documented at the St. Lucie Units 1 & 2 site. There are species on the list that could occur in St. Lucie County, but would not likely occur at the St. Lucie Units 1 & 2 site because of habitat requirements. For example, the American alligator (*Alligator mississippiensis*) would be very unlikely to occur in the high salinity waters of the Atlantic Ocean or the Indian River Lagoon, on either side of the plant. The Red-cockaded Woodpecker (*Picoides borealis*) requires mature pine or pine-oak woods (Ref. 2.4-1) and would be very unlikely to occur in the beach-dune or mangrove habitats of Hutchinson Island. The most common occurrences of threatened or endangered species at the site are several species of sea turtle that nest on Hutchinson Island beaches.

Five species of sea turtle have been reported from Hutchinson Island. The federally threatened loggerhead sea turtle (*Caretta caretta*) has historically been most common. Between 5,000 and 8,000 loggerhead nests have been reported on Hutchinson Island over the last 10 years (Ref. 2.4-2). The endangered green sea turtle (*Chelonia mydas mydas*) also nests on Hutchinson Island, but these nests are less abundant than those of the loggerhead. Juveniles of both species use the area near the St. Lucie Units 1 & 2 site as a developmental area. The endangered leatherback sea turtle (*Dermochelys coriacea*) infrequently nests on Hutchinson Island. Nest numbers have shown an upward trend in the last 20 years though they have varied widely. For the years 1996 through 2000, the number of leatherback nests has ranged from a low of 42 in 1997 to a high of 143 in 1999 (Ref. 2.4-3). The endangered Kemp's ridley sea turtle (*Lepidochelys kempi*) and hawksbill sea turtle (*Eretmochelys imbricccata*) do not nest on Hutchinson Island and have only infrequently been reported from the area.

A number of the protected bird species listed in Table 2.4-1 have been seen on Hutchinson Island, including Least Tern, Brown Pelican (*Pelacanus occidentalis*), Bald Eagle (*Haliaeetus leucocephalus*), Peregrine Falcon (*Falco peregrinus*), Wood Stork (*Mycteria americana*), Little Blue Heron (*Egretta caerulea*), Snowy Egret (*Egretta thula*), Reddish Egret (*Egretta rufescens*), and Louisiana Heron (*Egretta tricolor*) (Ref. 2.2-1). The latter five species all nest in mangroves. The Least Tern, a state threatened species, and the Black Skimmer, a state species of special concern, nest on the canal berms and building rooftops within the St. Lucie Units 1 & 2 property boundary. The American Oystercatcher, a state species of special concern, also nests on the canal berms. The Brown Pelican, White Ibis (*Eudocimus albus*), Little Blue Heron, and the Southeastern American Kestrel (*Falco sparverius paulus*) were observed on site in recent surveys.

Recent surveys indicate gopher tortoises, a state-listed species of special concern, occupy approximately 43 active burrows on the site. Burrows are located in the area east of State Road A1A in the vicinity of the Intake and Discharge canals in areas of soft soils that are not subject to flooding. Three active gopher tortoise burrows were also found in one area along

TABLE 2.4-1
ENDANGERED, THREATENED, OR SPECIAL CONCERN ANIMAL AND PLANT SPECIES THAT MAY OCCUR AT ST. LUCIE UNITS 1 & 2 OR ALONG ASSOCIATED TRANSMISSION LINES[a]

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Birds			
Ajaia ajaja	Roseate Spoonbill	–	SSC
Ammodramus savannarum floridanus	Florida Grasshopper Sparrow	E	E
Aphelocoma coerulescens	Florida Scrub-jay	T	T
Aramus guarauna	Limpkin	–	SSC
Charadrius melodus	Piping Plover	T	T
Egretta caerulea	Little Blue Heron	–	SSC
Egretta rufescens	Reddish Egret	–	SSC
Egretta thula	Snowy Egret	–	SSC
Egretta tricolor	Louisiana Heron	–	SSC
Eudocimus albus	White Ibis	–	SSC
Falco peregrinus	Peregrine Falcon	–	E
Falco sparverius paulus	Southeastern American Kestrel	–	T
Grus canadensis pratensis	Florida Sandhill Crane	–	T
Haematopus palliatus	American Oystercatcher	–	SSC
Haliaeetus leucocephalus	Bald Eagle	T	T
Mycteria americana	Wood Stork	E	E
Pelacanus occidentalis	Brown Pelican	–	SSC
Picoides borealis	Red-cockaded Woodpecker	E	T
Polyborus plancus audubonii	Audubon's Crested Caracara	T	T
Rostrhamus sociabilis	Everglades Snail Kite	E	E
Rynchops niger	Black Skimmer	–	SSC
Speotyto cunicularia	Burrowing Owl	–	SSC
Sterna antillarum	Least Tern	–	T
Reptiles			
Alligator mississippiensis	American alligator	SA	SSC
Caretta caretta	Loggerhead sea turtle	T	T
Chelonia mydas mydas	Green sea turtle	E	E
Dermochelys coriacea	Leatherback sea turtle	E	E

NOTES:

a. Sources: Ref. 2.4-4 and Ref. 2.4-5.

b. T = threatened; E = endangered, SSC = state species of special concern; SA = similarity of appearance (e.g., to the crocodile).

TABLE 2.4-1 (continued)
ENDANGERED, THREATENED, OR SPECIAL CONCERN ANIMAL AND PLANT SPECIES THAT MAY OCCUR AT ST. LUCIE UNITS 1 & 2 OR ALONG ASSOCIATED TRANSMISSION LINES[a]

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Reptiles (continued)			
Eretmochelys imbricata	Hawksbill sea turtle	E	E
Lepidochelys kempi	Kemp's ridley sea turtle	E	E
Gopherus polyphemus	Gopher tortoise	–	SSC
Drymarchon corias couperi	Eastern indigo snake	T	T
Nerodia fasciata taeniata	Atlantic salt marsh snake	T	T
Pituophis melanoleucus mugitus	Florida pine snake	–	SSC
Amphibians			
Rana capito aesopus	Florida gopher frog	–	SSC
Mammals			
Balaenoptera borealis	Sei whale	E	E
Balaenopteral phusalus	Finback whale	E	E
Eualaena glacialis	Right whale	E	E
Megaptera novaeanliae	Humpback whale	E	E
Physeter catodon	Sperm whale	E	E
Trichechus manatus	Florida manatee	E	E
Felis concolor coryi	Florida panther	E	E
Peromyscus polionotus niveiventris	Southeastern beach mouse	T	T
Podomys floridanus	Florida mouse	–	SSC
Sciurus niger shermani	Sherman's fox squirrel	–	SSC
Fish			
Acipenser oxyrhynchus	Atlantic sturgeon	–	SSC
Centropomus undecimalis	Common snook	–	SSC
Rivulus marmoratus	Mangrove rivulus	–	SSC
Plants			
Acanthocereus (Cereus) pentagonus	Barbed wire cactus	–	T
Argusia gnaphalodes	Sea lavender	–	E
Asclepias curtissii	Curtiss' milkweed	–	E
Asimina tetramera	Four-petal paw paw	E	E

NOTES:

a. Sources: Ref. 2.4-4 and Ref. 2.4-5.

b. T = threatened; E = endangered, SSC = state species of special concern; SA = similarity of appearance (e.g., to the crocodile).

TABLE 2.4-1 (continued)
ENDANGERED, THREATENED, OR SPECIAL CONCERN ANIMAL AND PLANT SPECIES THAT MAY OCCUR AT ST. LUCIE UNITS 1 & 2 OR ALONG ASSOCIATED TRANSMISSION LINES[a]

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Plants (continued)			
Caesalpinia major	Yellow nickerbean	–	E
Calopogon multiflorus	Many-flowered grass pink	–	E
Chamaesyce cumulicola	Sand dune spurge	–	E
Chrysophyllum oliviforme	Satinleaf	–	T
Cladonia perforata	Perforate reindeer lichen	E	E
Coelorachis tuberculosa	Piedmont jointgrass	–	T
Conradina grandiflora	Large-flowered rosemary	–	T
Dicerandra immaculate	Lakela's mint	E	E
Drypetes lateriflora	Guina plum	–	T
Encyclia boothiana	Dollar orchid	–	E
Erithalis fruticosa	Black torch	–	T
Ernodea littoralis	Beach creeper	–	T
Eulophia (Pteroglossaspis) ecristata	Non-crested coco	–	T
Halophila johnsonii	Johnson's seagrass	T	T
Harrisia (Cereus) eriophorus	Fragrant prickly apple	E	E
Harrisia (Cereus) gracilis var. simpsonii	Prickly applecactus	–	E
Jacquemontia reclinata	Beach clustervine	E	E
Lantana depressa	Pineland lantana	–	E
Lechea cernua	Nodding pinweed	–	T
Lechea divaricata	Pine pinweed	–	E
Lilium catesbaei	Catesby's lily	–	T
Linum carteri var. smallii	South Florida flax	–	E
Myrcianthes fragrans	Simpson's stopper	–	T
Nemastylis floridana	Celestial lily	–	E
Nephrolepis biserrata	Giant sword fern	–	T
Okenia hypogaea	Burrowing four-o'clock	–	E
Oncidium bahamensis	Dancing lady orchid	–	E
Ophioglossum palmatum	Hand fern	–	E

NOTES:

a. Sources: Ref. 2.4-4 and Ref. 2.4-5.

b. T = threatened; E = endangered, SSC = state species of special concern; SA = similarity of appearance (e.g., to the crocodile).

TABLE 2.4-1 (continued)
ENDANGERED, THREATENED, OR SPECIAL CONCERN ANIMAL AND PLANT SPECIES THAT MAY OCCUR AT ST. LUCIE UNITS 1 & 2 OR ALONG ASSOCIATED TRANSMISSION LINES[a]

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Plants (continued)			
Opuntia stricta	Common prickly pear	–	T
Peperomia humilis	Pepper	–	E
Pinguicula caerulea	Blue butterwort	–	T
Pinguicula lutea	Yellow butterwort	–	T
Pithecellobium keyense	Blackbead	–	T
Platanthera nivea	Snowy orchid	–	T
Pogonia ophioglossoides	Rose pogonia	–	T
Polygala smallii	Tiny milkwort	E	E
Polypodium (Pecluma) dispersa	Polypoda fern	–	E
Polypodium (Pecluma) plumula	Plume polypoda fern	–	E
Polypodium (Pecluma) ptilodon	Swamp plume polypoda fern	–	E
Polystachya concreta	Pale-flowered polystachya	–	E
Pteris bahamensis	Cretan brake cane	–	T
Remirea maritima	Beach star	–	E
Scaevola plumieri	Inkberry	–	T
Spermacoce terminalis	False buttonweed	–	T
Spiranthes lacinata	Lace-lipped ladies' tresses	–	T
Spiranthes tuberosa	Little pearl-twist	–	T
Stenorrhynchos lanceolatus	Leafless beaked orchid	–	T
Tephrosia angustissima var. curtissii	Hoary pea	–	E
Tillandsia balbisiana	Inflated wild pine	–	T
Tillandsia flexuosa	Twisted and banded airplant	–	T
Tillandsia valenzuelana	Soft leaved wild pine	–	T
Vanilla mexicana	Unscented vanilla	–	E
Verbena (Glandularia) maritima	Coastal vervain	–	E
Verbena (Glandularia) tampensis	Tampa vervain	–	E
Zephyranthes simpsonii	Simpson's zephyr lily	–	T

NOTES:

a. Sources: Ref. 2.4-4 and Ref. 2.4-5.

b. T = threatened; E = endangered, SSC = state species of special concern; SA = similarity of appearance (e.g., to the crocodile).

the transmission line corridor. Though none have been sighted, eastern indigo snakes (*Drymarchon corias couperi*) have been observed on Hutchinson Island and commonly inhabit gopher tortoise burrows.

Two protected plant-species were also observed in recent surveys, inkberry (*Scaevola plumieri*) and common prickly pear (*Opuntia stricta*). The potential impacts of operation of St. Lucie Units 1 & 2 on these and the other species listed in Table 2.4-1 are discussed in Section 4.6 of this Environmental Report.

2.5 REGIONAL DEMOGRAPHY

2.5.1 INTRODUCTION

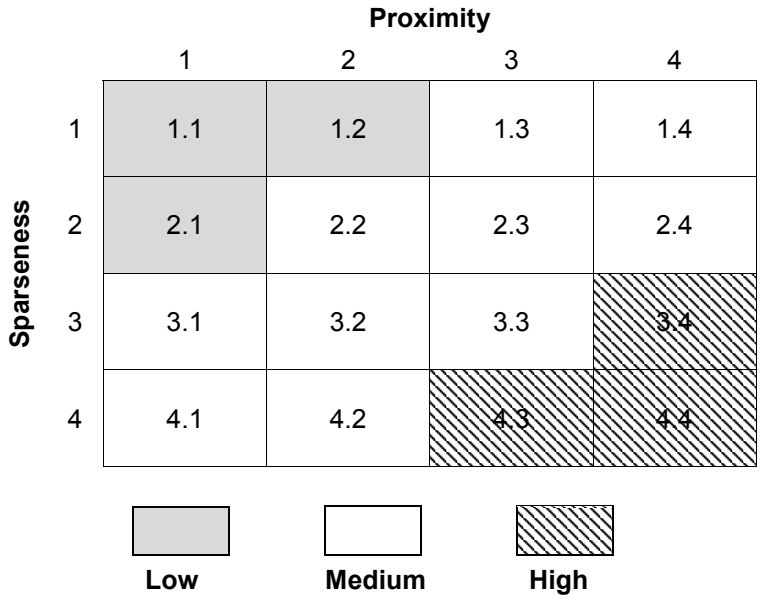
The U.S. Nuclear Regulatory Commission's (NRC's) *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) presents a population classification method using "sparseness" and "proximity" to characterize the remoteness of the area surrounding a site. Sparseness measures population density and city size within 20 miles of a site, while proximity measures population density and city size within 50 miles (Ref. 2.5-1, Section C.1.4). The GEIS model for population by sparseness and proximity measures is shown below:

Category		
Sparseness		
Most sparse	1.	Less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles
	2.	40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles
	3.	60 to 120 persons per square mile or less than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Least sparse	4.	Greater than or equal to 120 persons per square mile within 20 miles
Proximity		
Not in close proximity	1.	No city with 100,000 or more persons and less than 50 persons per square mile within 50 miles
	2.	No city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles
	3.	One or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles
In close proximity	4.	Greater than 190 persons per square mile within 50 miles

NOTES:

Source: Ref. 2.5-1, page C-159.

The GEIS then uses the following matrix to rank the population category as low, medium, or high:



NOTES:

Source: Ref. 2.5-1, page C-6.

FPL used 2000 census data from the U.S. Census Bureau to characterize the population in the vicinity of St. Lucie Units 1 & 2. The Census Bureau provides updated annual projections, in addition to decennial data, for selected portions of its demographic information. However, Section 2.5.2 uses 1990 minority and low-income population demographic information because year 2000 data for low-income populations were not published at the time of the analysis. Using Census Bureau year 2000 data, an estimated 345,000 people live within 20 miles of St. Lucie Units 1 & 2. Therefore, with a population density of 274.5 people per square mile within 20 miles, St. Lucie Units 1 & 2 falls into Category 4 (greater than or equal to 120 persons per square mile within 20 miles) of the GEIS sparseness classifications.

There are an estimated 1,180,000 people living within 50 miles of St. Lucie Units 1 & 2. This equates to a population density of 150.2 persons per square mile within 50 miles. Since there is no city with more than 100,000 persons within 50 miles of the site, St. Lucie Units 1 & 2 falls into Category 2 (no cities with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles) of the GEIS proximity classifications. According to the GEIS sparseness and proximity matrix, St. Lucie Units 1 & 2's sparseness Category 4 and proximity Category 2 result in the conclusion that the plant is located in a medium population area.

All or parts of nine counties are located within 50 miles of St. Lucie Units 1 & 2: Palm Beach, Martin, St. Lucie, Indian River, Brevard, Okeechobee, Glades, Osceola, and Highlands. Figure 2.1-1 shows the location of these counties. All of St. Lucie, Martin, and Indian River counties are within 50 miles of St. Lucie Units 1 & 2. The majority of Okeechobee County, approximately 40 percent of the land area of Palm Beach County, and a small percentage of Brevard lie within a 50-mile radius of the site. Only very small

fractions of land in Glades, Osceola, and Highlands counties are located within the 50-mile radius, and combined they account for less than half of a percent of the 2000 population within 50 miles of the plant. Dupuis Reserve State Forest, most of Lake Okeechobee and portions of Loxahatchee National Wildlife Refuge and the Brighton Seminole Indian Reservation fall within the 50-mile radius of St. Lucie Units 1 & 2.

Approximately 83 percent of St. Lucie Units 1 & 2 employees resides in St. Lucie and Martin counties (see Section 3.4). Table 2.5-1 presents estimated populations and annual growth rates for these two counties of interest.

TABLE 2.5-1
POPULATIONS AND ANNUAL GROWTH RATES IN ST. LUCIE AND MARTIN COUNTIES FROM 1980 TO 2040

Year	St. Lucie County		Martin County	
	Population	Growth Rate[a] (Percent)	Population	Growth Rate[a] (Percent)
1980	87,182[b]	7.2	64,014[b]	12.8
1990	150,171[b]	7.2	100,900[b]	5.8
2000	192,695[c]	2.7	126,731[c]	2.3
2010	232,000[d]	2.1	147,300[d]	1.9
2020	274,000[d]	1.8	171,400[d]	1.6
2030	315,100[d]	1.5	194,400[d]	1.3
2040	352,597[e]	1.2	202,176[e]	1.0

NOTES:

a. Annual growth rate over previous decade.
b. Source: Ref. 2.5-4.
c. Source: Ref. 2.5-2.
d. Source: Ref. 2.5-5.
e. Projection.

Florida's Treasure Coast, which includes Palm Beach, St. Lucie, Martin, and Indian River counties, has experienced growth over the past three decades. St. Lucie, Martin, and Indian River counties have not had the level of development and urban sprawl that the largely suburbanized Palm Beach County has. However, all four counties share a similar pattern of development, due mainly to their common economies and coastal proximity. County populations live in the coastal areas, with lands to the west dominated by agricultural uses and wetlands. According to 2000 Bureau of Census estimates, Port St. Lucie (population 88,769) and Fort Pierce (population 37,516) are the two largest cities in St. Lucie County (Ref. 2.5-2). An estimated 37.9 percent of St. Lucie County's total population lives in unincorporated areas. By comparison, 85.5 percent of Martin County's total population lives in unincorporated areas (Ref. 2.5-3). Stuart, the largest municipality in Martin County, has a 2000 population of 4,633 (Ref. 2.5-2).

The region experiences significant fluctuations in transient population throughout the year, particularly during the winter months, as thousands of seasonal residents live in the area for

several months before returning to their permanent residences in other states in the spring. The region also experiences a significant population influx from vacationing tourists in the winter and summer months (Ref. 2.1-1, Section 2.1.3.3).

Proportionally, the populations in both St. Lucie and Martin counties are older than that of the State of Florida and the Nation as a whole. This is primarily due to the immigration of elderly into the area. In Martin County, 28.3 percent of the population is over age 65. This compares to 22.8 percent in St. Lucie County, 17.6 percent in the State of Florida, and 12.7 percent for the Nation. Martin County has a particularly aged population, with a median age of 47.3, compared to a median age of 42.0 for St. Lucie County and a median age of 38.7 for the State of Florida (Ref. 2.5-2; Ref. 2.5-6).

2.5.2 MINORITY AND LOW-INCOME POPULATIONS

2.5.2.1 MINORITY POPULATIONS

The NRC guidance for performing environmental justice analyses defines "minority" as: American Indian or Alaskan Native; Asian or Pacific Islander; Black not of Hispanic origin, or Hispanic (Ref. 2.5-7, Attachment 4). The guidance indicates that a minority population exists if:

Exceeds 50 Percent – the minority population of the environmental impact site exceeds 50 percent, or

More than 20 Percent Greater – the minority population percentage of the environmental impact site is significantly greater (typically at least 20 percent) than the minority population percentage in the geographic area chosen for comparative analysis.

The NRC performed environmental justice analyses for the Calvert Cliffs Nuclear Power Plant and Oconee Nuclear Station license renewals (Ref. 2.5-8, Section 4.4-6; Ref. 2.5-9, Section 4.4.6). In doing so, the NRC used a 50-mile radius as the environmental impact site and the state as the geographic area for comparative analysis. FPL has adopted this approach for the St. Lucie Units 1 & 2 environmental justice analysis.

The NRC guidance calls for use of the most recent U.S. Census Bureau decennial census data. FPL used 1990 census data from the U.S. Census Bureau website in determining the percentage of the total population within the State of Florida for each minority category and in identifying minority (Ref. 2.5-10) and low-income (Ref. 2.5-11) populations within 50 miles of St. Lucie Units 1 & 2. The U.S. Census Bureau provides updated annual population projections for selected portions of its demographic information; however, the updated projections are not available for census-tract levels of analysis. FPL used ArcView® software to combine U.S. Census Bureau tract data with Environmental Systems Research Institute tract-boundary spatial data to produce tract-by-tract data and associated figures. The 50-mile radius (geographic area) includes 194 census tracts. The total number of census tracts was determined by superimposing a 50-mile radius grid, using ArcView® software by Environmental Systems Research Institute spatial data, with U.S. Census Bureau tract data. Tracts were included if 50 percent or greater of their area lay within the 50-mile radius grid.

FPL divided U.S. Census Bureau population numbers for each minority by the total population for the State of Florida to obtain the percentage of the total represented by each

minority. Table 2.5-2 shows the results of this calculation and the threshold for determining whether a minority population exists. Because the state percentages are low, the "more than 20 percent greater" criterion is more encompassing than the "exceeds 50 percent" criterion. For example, if 40 percent of a Florida tract were Black, it would not contain a minority population under the "exceeds 50 percent" criterion. However, because 13 percent of the Florida population is Black, the tract would contain a minority population under the "more than 20 percent greater" criterion because 40 percent does exceed 33 percent (13 percent plus 20 percent).

For each of the 194 census tracts within 50 miles of St. Lucie Units 1 & 2, FPL calculated the percentage of the population in each minority category and compared the results to the corresponding threshold percentages to determine whether minority populations exist. The 50-mile radius surrounding St. Lucie Units 1 & 2 encompasses in whole or in part nine counties: St. Lucie, Indian River, Brevard, Okeechobee, Martin, Palm Beach, Osceola, Highlands, and Glades (see Figure 2.5-1). Only six counties, St. Lucie, Indian River, Brevard, Okeechobee, Martin, and Palm Beach, have census tracts that have 50 percent or greater of their area within the 50-mile radius. These six counties were evaluated in the environmental justice analysis. Table 2.5-2 indicates how many census tracts within each county exceed the threshold for determining the presence of a minority population.

Based on the "more than 20 percent greater" criterion, St. Lucie County has Black minority populations in five tracts. There are no tracts with American Indian minority populations, Asian minority populations, or Hispanic minority populations in St. Lucie County. Indian River County has Black minority populations in two tracts and no tracts with American Indian minority populations, Asian minority populations, or Hispanic minority populations. Brevard County has no tracts with Black minority populations, American Indian minority populations, Asian minority populations, or Hispanic minority populations. Okeechobee County has a Black minority population in one tract and no tracts with American Indian minority populations, Asian minority populations, or Hispanic minority populations. Martin County has a Black minority population in one tract and no tracts with American Indian minority populations, Asian minority populations, or Hispanic minority populations. Palm Beach County has Black minority populations in 15 tracts and no tracts with American Indian minority populations, Asian minority populations, or Hispanic minority populations.

Figure 2.5-1 depicts the locations of Black minority populations that occur in St. Lucie, Indian River, Palm Beach, and Okeechobee Counties.

2.5.2.2 LOW-INCOME POPULATIONS

NRC guidance defines "low-income" using U.S. Census Bureau statistical poverty thresholds (Ref. 2.5-7, Attachment 4). The guidance indicates that a low-income population is present if the percentage of households below the poverty level in an environmental impact site is significantly greater (typically at least 20 percent) than the low-income population percentage in the geographical area chosen for comparative analysis. U.S. Census Bureau data (Ref. 2.5-11) characterizes 12 percent of Florida households as low-income. Applying the NRC criterion (at least 20 percent greater than the State), two St. Lucie County census tracts, one Indian River County census tracts, no Brevard County census tracts, no Okeechobee County census tract, no Martin County census tracts, and four Palm Beach County census tracts have low-income populations (see Table 2.5-2). Figure 2.5-2 shows locations of the low-income population census tracts.

TABLE 2.5-2
MINORITY AND LOW-INCOME POPULATION CENSUS TRACTS

Category[a]	State Average (percent)	Threshold for Minority Population (percent)[b]	Number of Census Tracts Exceeding Threshold					
			St. Lucie	Indian River	Brevard	Okeechobee	Martin	Palm Beach
American Indian or Alaskan Native[c]	<1	20	0	0	0	0	0	0
Asian or Pacific Islander[c]	1	21	0	0	0	0	0	0
Black (Non-Hispanic origin)[c]	13	33	5	2	0	1	1	15
Hispanic[c]	12	32	0	0	0	0	0	0
Low-Income[d]	12.1	32.1	2	1	0	0	0	4

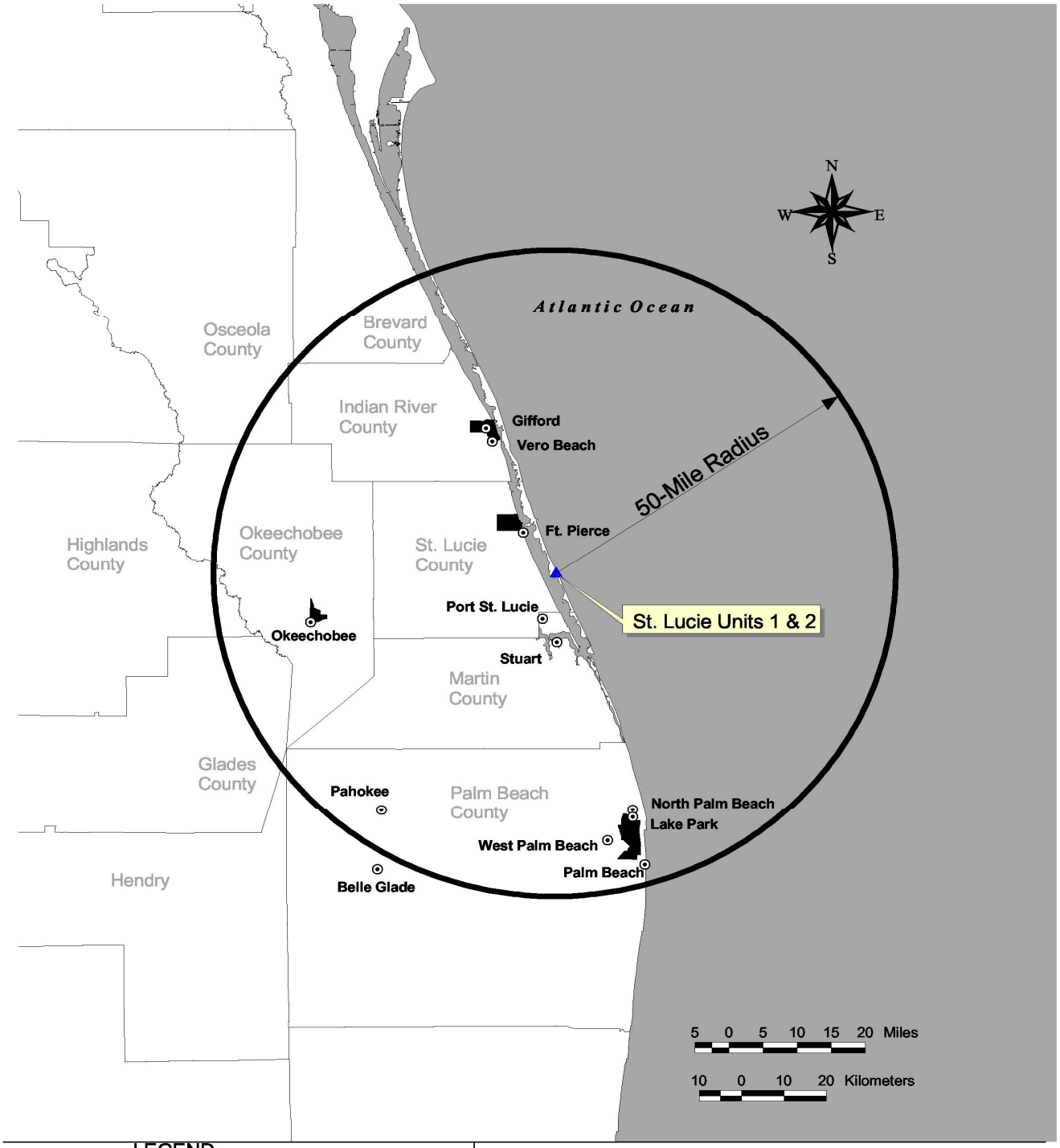
NOTES:

a. As defined by Ref. 2.5-7, Attachment 4.

b. At least 20 percent greater than state average (Ref. 2.5-7, Attachment 4).

c. Source: U.S. Census Bureau website (Ref. 2.5-10).

d. Source: U.S. Census Bureau website (Ref. 2.5-11).

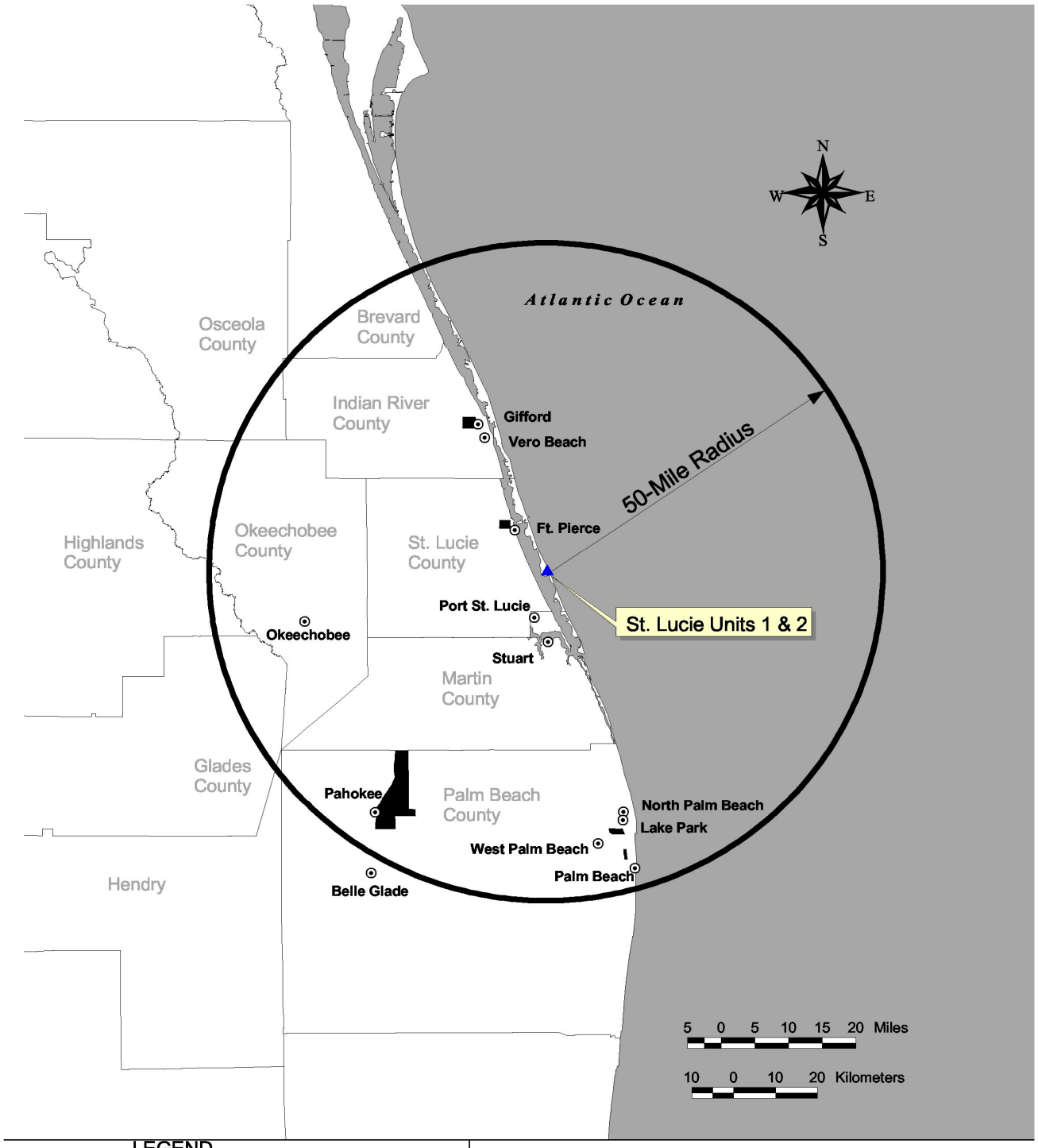


LEGEND

50-mile radius
1990 Black Minority Population
County

Tracts are designated as Black minority population if the percentage of Black population is at least 20 percent greater than the Black percentage of 13 percent for the State of Florida.

FIGURE 2.5-1
BLACK MINORITY POPULATIONS WITHIN 50 MILES OF ST. LUCIE UNITS 1 & 2
LICENSE RENEWAL APPLICATION
ST. LUCIE UNITS 1 & 2



LEGEND

50-mile radius
1990 Low-Income Population
County

Tracts are designated as Low-income population if the percentage of Low-income population is at least 20 percent greater than the Low-income percentage of 12 percent for the State of Florida.

FIGURE 2.5-2
LOW-INCOME POPULATION WITHIN 50 MILES OF ST. LUCIE UNITS 1 & 2
LICENSE RENEWAL APPLICATION
ST. LUCIE UNITS 1 & 2

2.5.2.3 MIGRANT FARM WORKERS

Migrant farm workers are those whose employment requires travel that prevents the employee from returning to his or her permanent place of residence the same day (Ref. 2.5-12). Migrant farm workers can be members of minority or low-income populations, but their travel could prevent them from being available for census data gathering. In addition, migrant farm workers can spend a significant amount of time in an area without being residents. These factors could result in migrant farm worker numbers being under-represented in minority and low-income population analyses based on U.S. Census Bureau data.

Citrus groves, orchards, and row crops are important land-use categories in the vicinity of St. Lucie Units 1 & 2, and migrant farm workers are frequently present at these locations. However, FPL is unaware of any reliable estimate of the number of migrant farm workers that might be present. In 1997, there were 2,159 hired farm workers in St. Lucie County, 1,848 in Indian River County, 924 in Brevard County, 1,479 in Okeechobee County, 2,653 in Martin County, and 10,707 in Palm Beach County (Ref. 2.5-12). Using the 12.5 percent National average of hired farm workers who meet the definition of migrant workers (Ref. 2.5-12), there may be as many as 2,471 migrant workers present at any time within 50 miles of St. Lucie Units 1 & 2.

A large number of farms in the vicinity hire farm workers: 215 in St. Lucie County, 201 in Indian River County, 180 in Brevard County, 165 in Okeechobee County, 144 in Martin County, and 528 in Palm Beach County (Ref. 2.5-13). These farms cover a large geographic area; therefore, FPL assumes that migrant farm workers are located throughout the region's agricultural areas and not clustered in a single location. Due to their small number compared to the overall population, FPL does not expect the migrant farm worker population to change the population characteristics of any particular census tract.

2.6 ECONOMIC BASE

Traditionally, tourism and in-migration have been key contributors to the overall growth of the region's economy, while retail trade and services are becoming increasingly important economic sectors. Visitors are attracted to the region's warm weather and the recreational activities found at public beaches, Lake Okeechobee, the Indian River, the Loxahatchee River, golf courses, parks, and natural habitats. Often in-migrating residents relocate to the region after first arriving as a tourist or seasonal resident (Ref. 2.6-1).

While supporting a relatively small work force, agriculture contributes significantly to the economies in both St. Lucie and Martin counties, as St. Lucie County leads Florida in citrus production (Ref. 2.6-2), and Martin County is fifth in both vegetable and citrus production (Ref. 2.6-3).

St. Lucie County has an estimated labor force of 78,757, and Martin County has an estimated labor force of 49,480. Services is currently the largest employment sector in both St. Lucie and Martin counties, accounting for 24.7 percent of total employment in St. Lucie County and 35.2 percent of total employment in Martin County. Retail trade accounts for 20.6 percent of total employment in St. Lucie County, and 23.3 percent of total employment in Martin County (Ref. 2.6-4). The region's transportation network includes rail and trucking terminals, the St. Lucie County International Airport, and a deep-water seaport at Fort Pierce that provides access to domestic and international markets. Two major interstates, the Florida Turnpike and Interstate 95, intersect with State Road 70 and State Road 76, giving the region access to east-west and north-south corridors (Ref. 2.6-5). The Fort Pierce-Port St. Lucie area is the 31st fastest growing metropolitan statistical area in the United States, according to U.S. Census Bureau estimates (Ref. 2.6-6).

Since the early 1980s, unemployment rates in St. Lucie County have generally been higher than the state average. Unemployment rates in Martin County have generally exceeded the state average since the mid-1980s. Employment in tourism and agriculture is stronger during winter months, resulting in employment fluctuations throughout the year (Ref. 2.6-1). In 2000, St. Lucie County had a 7.7 percent unemployment rate, and Martin County a 4.4 percent unemployment rate (Ref. 2.6-4). Florida's unemployment rate was 3.6 percent during the same year (Ref. 2.6-7).

2.7 TAXES

FPL pays annual property taxes to St. Lucie County for St. Lucie Units 1 & 2. Property taxes paid to the County are distributed among such entities as the County school district, the County Board of Commissioners, the County fire district, and the South Florida Water Management District. For the years 1990 to 2000, St. Lucie Units 1 & 2 property taxes comprised about 10.6 percent of St. Lucie County's total property tax revenues. For the years 1997 to 2000, St. Lucie Units 1 & 2 property taxes comprised about 8.1 percent of St. Lucie County's total annual revenues (Table 2.7-1).

If the Operating Licenses for St. Lucie Units 1 & 2 are renewed, the annual property taxes for the plant would continue throughout the period of extended operation.

TABLE 2.7-1
ST. LUCIE UNITS 1 & 2 CONTRIBUTION TO COUNTY PROPERTY TAX REVENUES

Year	Total St. Lucie County Property Tax Revenues[a]	Property Tax Paid to St. Lucie County for St. Lucie Units 1 & 2	Percentage of Total Property Taxes	Total Annual Revenue St. Lucie County[b]	Percentage of Total Annual Revenues
1990	$144,399,075	$17,830,107	12.3	NA	NA
1991	$152,871,496	$18,070,164	11.8	NA	NA
1992	$163,059,584	$18,758,617	11.5	NA	NA
1993	$172,318,529	$19,837,959	11.5	NA	NA
1994	$176,760,227	$22,119,016	12.5	NA	NA
1995	$187,600,727	$20,363,881	10.9	NA	NA
1996	$196,823,727	$19,407,404	9.9	NA	NA
1997	$211,942,795	$16,717,273	7.9	$235,542,775	7.1
1998	$210,294,416	$19,766,356	9.4	$274,735,524	7.2
1999	$221,893,569	$23,441,954	10.6	$261,333,923	9.0
2000	$222,310,596	$22,325,643	10.0	$238,302,922	9.4

NOTES:

a. Ref. 2.7-1.

b. Ref. 2.7-2.

NA = Not Available

2.8 LAND USE PLANNING

This subsection focuses on St. Lucie and Martin counties because approximately 83 percent of the permanent St. Lucie Units 1 & 2 workforce lives in the St. Lucie and Martin combined-county area (see Section 3.4 for workforce description), and FPL pays property taxes in St. Lucie County.

The Florida Statutes require counties and cities to develop and implement comprehensive planning and land development regulations. In order to accommodate and regulate growth and development, St. Lucie and Martin counties have developed comprehensive growth management plans characterizing current conditions and setting standards, regulations, and goals for land development and appropriate uses for land, water, and resources. Martin County's plan was adopted February 20, 1990, and was last amended September 28, 1999 (Ref. 2.8-1). St. Lucie County's plan is currently being updated.

Both Martin and St. Lucie counties have experienced significant growth over the past decade and utilize land use planning tools, such as zoning, to manage future growth and development. Planning agencies in St. Lucie and Martin counties require that urban development be confined within urban service districts and encourage growth in existing urban areas where public facilities and services are either currently available or are planned to be made available. Each county planning agency supports the goal of protecting environmentally sensitive lands, natural resources, rural and agricultural land uses, historic and archaeological resources, and habitats for threatened and endangered species. There are no growth control measures in place to restrict development on the mainland in either county. Growth is encouraged in existing urban areas where public facilities and services are either currently available or are planned to be made available (Ref. 2.8-1). Much of St. Lucie County's coastal area has already been developed, and much of the current development is concentrated in areas surrounding Interstate 95. Commercial development is allowed in certain areas of Hutchinson Island, a barrier island that extends along the coast of St. Lucie County and a portion of Martin County. Development of unvested (vacant or uncommitted) parcels in the Martin County portion of Hutchinson Island is limited to single-family residences. St. Lucie County does not restrict residential development of the Island (Ref. 2.8-2). Much of Hutchinson Island near Fort Pierce has been developed, as have portions south of St. Lucie Units 1 & 2.

Agriculture accounts for approximately 50 percent of all land use in St. Lucie County. Urban uses, such as residential, industrial, and institutional, account for approximately 19 percent of the land area. Wetlands, parks, and other protected areas account for the rest of the current land use. The City of Port St. Lucie is the fastest growing municipality in St. Lucie County, covering approximately one-sixth of St. Lucie County's land area. Approximately 82 percent of Port St. Lucie's land area has been classified as residential, and only 36 percent of this area has been developed (Ref. 2.8-3).

Martin County has approximately 348,792 acres of unincorporated land area, 70 percent of which is classified as agricultural. Residential, institutional, parks, recreational, and agricultural uses are the predominant land uses in Martin County (Ref. 2.8-1).

Development has been particularly strong in the northern region of Martin County. Much of the current development is occurring between the coast and the Florida Turnpike, and growth is particularly strong in the area surrounding the City of Stuart. Lands west of the

Florida Turnpike are largely agricultural or rural, with a small urban center in Indiantown (Ref. 2.8-1).

Agriculture remains a dominant land use component in both Martin and St. Lucie counties, occupying 278,000 and 294,158 acres, respectively, in 1990. Between 1981 and 1990, farmland acreage decreased by approximately 22,000 acres in Martin County and 30,842 in St. Lucie County. This represents losses of 7.3 percent and 9.5 percent for the period. As residential and commercial development expands westward from the coastal regions, agricultural uses move further west. Although wetland draining is no longer permitted, the migration of agricultural land use has stressed the wetland habitats dominating much of western Martin and St. Lucie counties (Ref. 2.8-4).

2.8.1 HOUSING

In 1990, the Martin and St. Lucie combined-county area had housing stocks of 154,199 and 73,843 units, respectively, with vacancy rates of 26 percent and 27 percent, respectively (Ref. 2.8-5). As the area's population has grown, so have housing stocks. U.S. Census Bureau year 2000 estimates for housing units have increased to 65,471 in Martin County and 91,262 in St. Lucie County with vacancy rates of 15.6 percent and 15.7 percent, respectively (Ref. 2.8-6, Chapter 6).

Neither St. Lucie nor Martin County has growth control measures in place that restrict the development of new housing. Both counties have in place policies and programs to promote the development of affordable housing.

2.9 SOCIAL SERVICES AND PUBLIC FACILITIES

2.9.1 PUBLIC WATER SUPPLY

St. Lucie Units 1 & 2 acquire potable water from the City of Fort Pierce through the Fort Pierce Utilities Authority. Current plant usage averages 4 million gallons per month (an average of approximately 131,500 gallons per day) for St. Lucie Units 1 & 2, with no restrictions on supply. Discussion of public water systems focuses on St. Lucie and Martin counties because approximately 83 percent of St. Lucie Units 1 & 2's permanent employees resides in these counties (see Section 3.4 for workforce description). Potable water service is provided by local municipalities and private water companies to residents who do not have individual onsite wells. These providers are subject to regulation under the Federal Safe Drinking Water Act as implemented by Florida's Department of Environmental Regulation.

Groundwater—drawn from the shallow, unconfined Surficial Aquifer is—the primary source of potable water supplies in St. Lucie and Martin counties (Ref. 2.9-1). Currently, small amounts of groundwater are also drawn from the Floridan Aquifer. This deeper aquifer is of lower quality and requires desalination (Ref. 2.9-2). As the demand for potable water increases, the Floridan Aquifer is seen as a promising source of potable water for urban areas (Ref. 2.9-1).

The South Florida Water Management District (SFWMD) estimates that in 1990, approximately 42.2 percent of St. Lucie County residents and 45.6 percent of Martin County residents obtained potable water from private wells. The SFWMD estimates that by 2010, these percentages will decrease to 23.7 percent and 34.1 percent for St. Lucie and Martin counties, respectively (Ref. 2.9-3).

There are approximately 107 permitted water treatment plants in St. Lucie County, 104 of which are privately owned. Only five of the privately owned water treatment plants have permitted capacities greater than 0.1 million gallons per day, and St. Lucie West Utilities is the only privately owned water treatment plant with a permitted capacity of 1.0 million gallons per day or above (Ref. 2.9-4). In 1990, the SFWMD estimates that 23.43 million gallons per day were withdrawn from the Surficial and Floridan aquifers to satisfy water demand in St. Lucie County. Public utilities in St. Lucie County were allocated an average flow of approximately 24.93 million gallons per day. The SFWMD estimates that by 2010, water supply systems in St. Lucie County will service a population of 221,320 people and will have an average daily demand of 40.06 million gallons per day (Ref. 2.9-3).

The City of Port St. Lucie and the City of Fort Pierce, which supplies St. Lucie Units 1 & 2, are the primary public potable water service providers in St. Lucie County. The Fort Pierce Utilities Authority has approximately 40,000 connections in the City of Fort Pierce and in various areas in St. Lucie County. The water treatment plant has a permitted capacity of 20 million gallons per day. SFWMD allocations for the plant include an average flow of 17.2 million gallons per day from the Surficial Aquifer. For the 12 months ending December 1999, actual daily demand averaged 8.5 million gallons per day with a peak demand of approximately 11 million gallons per day. The water treatment plant is not near its capacity and there are no plans to expand the plant's service capabilities, although construction has begun on an adjacent reverse osmosis water plant with a capacity of 5.0 million gallons per

day. The SFWMD estimates that by 2010, the Fort Pierce Utilities Authority will service a population of 81,105 people and will have an average daily demand of 14.03 million gallons per day (Ref. 2.9-3).

Prior to 1991, General Development Utilities, Inc., had a franchise agreement with the City of Port St. Lucie to provide potable water services. Water main connections were not keeping pace with the level of development in the area and only 55 percent of Port St. Lucie's population was connected to a public water supply system. St. Lucie County condemned the utility in 1991, and in 1994, the City of Port St. Lucie bought the utility and agreed to provide service to portions of St. Lucie County (Ref. 2.9-5).

Port St. Lucie Utilities is currently expanding its service capabilities. Port St. Lucie Utilities operates a water service plant withdrawing raw water from the Surficial Aquifer with a permitted capacity of 6.85 million gallons per day, and a reverse osmosis plant withdrawing water from the Floridan Aquifer with a permitted capacity of 4.0 million gallons per day. The capacity of the reverse osmosis plant can be expanded to withdraw 10.0 million gallons of water per day. SFWMD allocations for the plant include a maximum permitted raw water withdrawal of 7.27 million gallons per day from the Surficial Aquifer and 7.34 million gallons per day from the Floridan Aquifer. The plant has approximately 26,542 connections and is adding between 200 and 300 connections each month. For the 12 months ending December 1999, actual daily demand averaged 5.847 million gallons per day with a peak demand of approximately 8.246 million gallons per day. The SFWMD estimates that by 2010, Port St. Lucie Utilities will service a population of 103,378 people and will have an average daily demand of 12.40 million gallons per day (Ref. 2.9-3).

St. Lucie West Utilities is the largest privately owned utility in St. Lucie County and services a seven square mile service area in the City of Port St. Lucie. Its one plant has a permitted capacity of 1.0 million gallons per day and an average daily flow of 0.6 million gallons per day (Ref. 2.9-5). SFWMD allocations for the plant include a maximum permitted raw water withdrawal of 4.03 million gallons per day and an average flow of 2.68 million gallons per day. The plant can easily be expanded to treat 10 million gallons of water per day. The SFWMD estimates that by 2010, St. Lucie West will service a population of 20,399 people and will have an average daily demand of 7.51 million gallons per day (Ref. 2.9-3).

St. Lucie County Utilities operates the Holiday Pines and Lakewood Park Subdivision water treatment plants, for which the combined permitted capacity is less than 0.3 million gallons per day. St. Lucie County Utilities also operates the North Hutchinson Island Water Distribution system, which purchases water from Fort Pierce Utilities (Ref. 2.9-4).

There are 139 water supply systems in Martin County (Ref. 2.9-2). Water plants in North Martin County, the City of Stuart, Port Salerno, and Hobe Sound all have a permitted capacity of at least 3.0 million gallons per day. Three other plants and one proposed plant have permitted capacities between 1.0 and 2.0 million gallons per day (Ref. 2.9-3). In 1990, SFWMD estimates that 21.30 million gallons per day were withdrawn from the Surficial and Floridan aquifers to satisfy water demand in Martin County. Public utilities in Martin County were allocated an average flow of approximately 20.73 million gallons per day. The SFWMD estimates that by 2010, water supply systems in Martin County will service a population of 101,520 people and will have an average daily demand of 24.36 million gallons per day (Ref. 2.9-3).

The City of Stuart's municipal water treatment plant is the largest in Martin County, with a permitted capacity of 6.0 million gallons per day. SFWMD allocations for the plant include a maximum permitted raw water withdrawal of 6.56 million gallons per day and an average flow of 3.86 million gallons per day. In 1999, average plant production was 3.2 million gallons per day, with a peak demand of 5.4 million gallons per day. The SFWMD estimates that by 2010, the City of Stuart will service a population of 16,296 people and will have an average daily demand of 3.96 million gallons per day (Ref. 2.9-3).

2.9.2 TRANSPORTATION

The U.S. Transportation Research Board has developed a commonly used indicator, called "level of service (LOS)," for measuring roadway traffic volume. "Level of service" is a qualitative assessment of traffic flow and how much delay the average vehicle might encounter during peak hours. Table 2.9-1 presents the "level of service" definitions used by local and state agencies, as well as by the NRC in the GEIS (Ref. 2.5-1, Section 3.7.4.2).

Road access to St. Lucie Units 1 & 2 is via State Road A1A, a two-lane highway on Hutchinson Island. In the vicinity of the site, State Road A1A carries an LOS designation of 'A' (Ref. 2.9-6). In Martin County, mainland access to Hutchison Island is available from the Jensen Beach Bridge approximately seven miles south of the site, and the Stuart Causeway approximately 10 miles south of the site. In St. Lucie County, mainland access to Hutchison Island is available from the South Bridge approximately nine miles north of the plant. North of St. Lucie Units 1 & 2, in the areas east of the intersection with U.S. Highway 1 on the mainland and south of Seaway Drive, State Road A1A carries an LOS of 'B.' The South Bridge area has an LOS designation of 'C' (Ref. 2.9-6). South of the site, State Road A1A from the Jensen Beach Causeway to where the State Road leaves Hutchinson Island carries an LOS designation of 'B.' The Stuart Causeway carries an LOS of 'A' (Ref. 2.9-7). A fourth bridge, connecting Hutchinson Island to the mainland, has been proposed to be built in St. Lucie County. However, there are no current plans to build such a bridge and it is currently uncertain when or where the bridge will be constructed (Ref. 2.1-1, Section 2.1.3.1.5). FPL is responsible for the maintenance of the bridges on State Road A1A that cross the site's Intake and Discharge canals (Ref. 2.9-8).

TABLE 2.9-1
LEVEL OF SERVICE DEFINITIONS

Level of Service	Conditions
A	Free flow of the traffic stream; users are unaffected by the presence of others.
B	Stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished.
C	Stable flow that marks the beginning of the range of flow in which the operation of individual users is significantly affected by interactions with the traffic stream.
D	High-density, stable flow in which speed and freedom to maneuver are severely restricted; small increases in traffic will generally cause operational problems.
E	Operating conditions at or near capacity level causing low but uniform speeds and extremely difficult maneuvering that is accomplished by forcing another vehicle to give way; small increases in flow or minor perturbations will cause breakdowns.
F	Defines forced or breakdown flow that occurs wherever the amount of traffic approaching a point exceeds the amount that can traverse the point. This situation causes the formation of queues characterized by stop-and-go waves and extreme instability.

NOTES:

Source: Ref. 2.5-1, Section 3.7.4.2.

2.10 HISTORIC AND ARCHAEOLOGICAL RESOURCES

The construction of St. Lucie Units 1 & 2 in the 1970s did not threaten any known historic or archaeological resources of significance. The north end of the site, which has been left in its natural state, was noted as having some unexplored Indian mounds and middens (Ref. 2.1-2, Section 2.3). An archaeological and historical resources survey of St. Lucie Units 1 & 2's transmission line corridor, performed in 1973 by the Florida Bureau of Historic Sites and Properties, did not reveal any impacts to known historic or archaeological resources of significance (Ref. 2.10-1).

The National Register of Historic Places lists no historic places on or near the St. Lucie Units 1 & 2 site, associated transmission lines, or Hutchinson Island. The nearest site listed is the Captain Hammond House, a residential home built in 1902 in White City, Florida, approximately five and a half miles west of the plant (Ref. 2.10-2). Approximately seven and a half miles northeast of the site lies the Fort Pierce Site, a wooded park that encompasses the ruins of an Ais Indian culture, which was listed with the National Register of Historic Places in 1974.

Florida's Bureau of Archaeological Research of the Division of Historical Resources has listed in the *Florida Master Site File* some 22 archaeological sites and 47 standing structures within approximately 5 miles of St. Lucie Units 1 & 2. Of these, eight archaeological sites are in close proximity to the plant (within 1-2 miles). Four of these sites are shipwrecks of various ages. The other four sites include middens, mounds, and burial middens ranging in age from unspecified, to prehistoric, to the St. John's Period (500 B.C. to 1300 A.D.). The two sites from the St. John's Period are associated with the Malabar Indian culture (Ref. 2.10-3).

2.11 REFERENCES

2.1-1 Florida Power & Light Company. *St. Lucie Unit 1 Updated Final Safety Analysis Report, Amendment No. 17*. Juno Beach, Florida. October 1999.

2.1-2 Florida Power & Light Company *St. Lucie Plant Unit 2 Environmental Report* (as amended). Juno Beach, Florida. 1973.

2.1-3 U.S. Atomic Energy Commission. *Final Environmental Statement Related to the St. Lucie Plant Unit No. 1*; *Florida Power & Light Company*. Docket No. 50-335. Directorate of Licensing. Washington, D.C. June 1973.

2.1-4 Absolutely Florida. *Florida State Parks - Fort Pierce Inlet State Recreation Area*. www.abfla.com/park/FortPierceInlet/fortpierce.html. Accessed January 16, 2001.

2.1-5 St. Lucie County. *Savannas Recreation Area/Camping*. www.stlucieco.gov/liesure/savanna.htm. Accessed January 16, 2001.

2.2-1 U.S. Nuclear Regulatory Commission. *Final Environmental Statement Related to the Operation of St. Lucie Plant, Unit No. 2; Florida Power & Light Company, Orlando Utilities Commission of the City of Orlando, Florida*. Docket No. 50-389. NUREG-0842. Office of Nuclear Reactor Regulation. Washington, D.C. April 1982.

2.2-2 Applied Biology, Inc. "Florida Power & Light Company St. Lucie Plant Annual Non-Radiological Environmental Monitoring Report 1984." Atlanta, Georgia. (L-85-174) April 30, 1985.

2.4-1 National Geographic Society. *Field Guide to the Birds of North America*. Second Edition. Washington, D.C. 1987.

2.4-2 Ecological Associates, Inc. *Physical and Ecological Factors Influencing Sea Turtle Entrainment Levels at the St. Lucie Nuclear Plant: 1976-1998*. Jensen Beach, Florida. (L-2000-78) March 22, 2000.

2.4-3 Florida Power & Light Company. *Annual Environmental Operating Report 2000*. Juno Beach, Florida. (L-2001-90) April 2001.

2.4-4 Florida Fish and Wildlife Conservation Commission. *Florida's Endangered Species, Threatened Species, and Species of Special Concern, Official List*. August 1, 1997. http://floridaconservation.org/pubs/endanger.html. Accessed April 16, 2001.

2.4-5 Florida Department of Agricultural and Consumer Services. "Preservation of Native Flora of Florida." Chapter 5B-40.0055. Division of Plant Industry. Tallahassee, Florida. Amended October 5, 1998.

2.5-1 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

2.5-2 U.S. Census Bureau. Table DP-1. *Profile of General Demographic Characteristics: 2000 for Florida and Selected Counties and Cities*. http://factfinder.census.gov. Accessed July 25, 2001.

2.5-3 Treasure Coast Regional Planning Council. *Treasure Coast Strategic Regional Policy Plan, Introduction to the Region*. June 29, 2000. www.tcrpc.org/srpphtm/intro. Accessed November 30, 2000.

2.5-4 Florida Office of Economic & Demographic Research. *Total Counts Population: April 1, 1970,1975,1980,1985,1990,1995-2010, 2015*. www.state.fl.us/edr/population.htm. Accessed November 30, 2000.

2.5-5 Smith, S. K. and J. Nagle. "Projections of Florida Population by County," *Florida Population Studies*. Vol. 33, No. 2. Bulletin 126. Population Program, Bureau of Economic and Business Research, University of Florida. Tallahassee, Florida. February 2000.

2.5-6 U.S. Census Bureau. *Resident Population Estimates of the United States by Age and Sex*. www.census.gov/population/estimates/nation.html. Accessed July 25, 2001.

2.5-7 U.S. Nuclear Regulatory Commission. "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues." Office Letter No. 906. Office of Nuclear Reactor Regulation. Washington, D.C. September 21, 1999.

2.5-8 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Calvert Cliffs Nuclear Power Plant*. NUREG-1437, Supplement 1. Office of Nuclear Reactor Regulation. Washington, D.C. October 1999.

2.5-9 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Oconee Nuclear Station*. NUREG-1437, Supplement 2, Draft. Office of Nuclear Reactor Regulation. Washington, D.C. May 1999.

2.5-10 U.S. Census Bureau. *1990 Census of Population and Housing, Public Law 94-171 Data (Official), Age by Race and Hispanic Origin*. Linked to All Census Tracts for St. Lucie, Indian River, Brevard, Okeechobee, Martin, and Palm Beach Counties, Florida. Database Applications on the Web: Public Law 94-171 (1990 Census). http://tier2.census.gov/CGI-WIN/pL94-171/PL94DATA.EXE. Accessed December 20, 2000.

2.5-11 *U.S. Census Bureau. 1990 Census Summary Tape File 3 (STF3), Sample Count—All Socioeconomic and Demographic Variables*. 1990 Census Data Lookup Server at http://homer.ssd.census.gov/cdrom/lookup. Accessed August 28, 2001.

2.5-12 U.S. Department of Agriculture, National Agricultural Statistics Service. *1997 Census of Agriculture, Volume 1: Geographic Area Series*. Florida-9, Table 5, "Hired Farm Labor-Workers and Payroll: 1997." www.nass.usda.gov/census/census97/volume1/fl-9/fl2_05.pdf. Accessed December 27, 2000.

2.5-13 U.S. Department of Agriculture, National Agricultural Statistics Service. *1997 Census of Agriculture, Volume 1: Geographic Area Series*. Florida-9, Table 1, "County Summary Highlights: 1997." www.nass.usda.gov/census/census97/volume1/fl-9/fl2_01.pdf. Accessed December 27, 2000.

2.6-1 Treasure Coast Regional Planning Council. *Treasure Coast Strategic Regional Policy Plan, Economic Development Mission Statement*. www.tcrpc.org/srpp.htm. Accessed December 5, 2000.

2.6-2 St. Lucie County Chamber of Commerce. *St. Lucie County, Florida Business Opportunities*. www.stluciechamber.org/business.html. Accessed November 10, 2000.

2.6-3 Stuart Martin Chamber of Commerce. *Stuart Martin Chamber of Commerce: Business & Industry*. www.goodnature.org/business/index.html. Accessed December 5, 2000.

2.6-4 Enterprise Florida, Inc. *St. Lucie and Martin County Profiles*. www.eflorida.com/all_facts.html. Accessed July 25, 2001.

2.6-5 Treasure Coast Economic Development Coalition. *Treasure Coast Infrastructure*. www.floridaatc.com/infrastructure.html. Accessed November 10, 2000.

2.6-6 U.S. Census Bureau. *Metropolitan Area Ranked by Percent Population Change: 2000*. www.census.gov/population/www/cen2000/phc-t3.html. Accessed July 25, 2001.

2.6-7 Bureau of Labor Statistics. *Unemployment Rates for States. Local Area Unemployment Statistics.* http://stats.bls.gov/laus/lastrk00.htm. Accessed July 25, 2001.

2.7-1 Conrad, D. J. (St. Lucie County Tax Collector). "Tax Collector's Recapitulation of the Tax Roll for St. Lucie County, Florida, 1990 through 1999." Fort Pierce, Florida. November 13, 2000.

2.7-2 St. Lucie Board Office of Management and Budget. "St. Lucie County Commissioners Budget by Fund, Fiscal Year 2000-01." Fort Pierce, Florida. February 2, 2001.

2.8-1 Martin County, Florida, Board of County Commissioners. *Martin County, Florida Comprehensive Growth Management Plan, Future Land Use Element*. Stuart, Florida. February 20, 1990. Amended September 28, 1999.

2.8-2 Martin County, Florida, Board of County Commissioners. *Martin County, Florida Comprehensive Growth Management Plan, Coastal Management Element*. Stuart, Florida. February 20, 1990. Amended December 15, 1998.

2.8-3 City of Port St. Lucie. *City of Port St. Lucie Comprehensive Growth Management Plan, Future Land Use Element*. Port St. Lucie, Florida. February 9, 1998.

2.8-4 Treasure Coast Regional Planning Council. *Treasure Coast Strategic Regional Policy Plan*. June 29, 2000. www.tcrpc.org/srpp.htm. Accessed December 1, 2000.

2.8-5 U.S. Census Bureau. *1990 Census of Populational Housing. Housing Units; Totals, Occupied, and Vacant for Martin and St. Lucie County Florida*. factfinder.census.gov/servlet/DTTable. Accessed May 3, 2001.

2.8-6 U.S. Census Bureau. *Housing Units, 2000 on State and County Quick Facts*. Linked to *Quick Facts for Martin and St. Lucie Counties, Florida*. http://quickfacts.census.gov/qfd/states/12/12085.html. Accessed July 9, 2001.

2.9-1 South Florida Water Management District. *UEC Water Supply Plan - Planning Document*. Stuart, Florida. February 1998.

2.9-2 Martin County Board of County Commissioners. *Martin County, Florida Comprehensive Growth Management Plan, Potable Water Services Element*. Stuart, Florida. February 20, 1990.

2.9-3 South Florida Water Management District. *UEC Water Supply Plan – Appendices*. Stuart, Florida. February 1998.

2.9-4 St. Lucie County Utilities. *St. Lucie County Water & Wastewater Plan*. Fort Pierce, Florida. August 2000.

2.9-5 City of Port St. Lucie. *City of Port St. Lucie Comprehensive Growth Management Plan, Potable Water Sub-Element*. Port St. Lucie, Florida. 1997.

2.9-6 St. Lucie County, Florida, Metropolitan Planning Organization, St. Lucie County Community Development, "Geographic Information Systems Traffic Capacity – Spring 2000." Fort Pierce, Florida. April 12, 2001.

2.9-7 Martin County Board of County Commissioners. *Level of Service Inventory Report*. Appendix I-11, "St. Lucie Unit 2." Stuart, Florida. December 1998.

2.9-8 State of Florida and Florida Power & Light Company. *State Road A1A Agreement for Plant St. Lucie*. Stuart, Florida. July 9, 1973.

2.10-1 Morrell, L. R. (State of Florida, Bureau of Historic Sites and Properties) Letter to W. J. Barrow (FPL). "Archaeological and Historical Survey Results of the St. Lucie Plant Transmission Line Right-of-Way." May 31, 1973 [See Appendix 6 to the Unit 1 Final Environmental Statement dated June 1973].

2.10-2 National Register Information System. *National Register of Historic Places*. www.nr.nps.gov/nrloc1.htm. Accessed November 8, 2000.

2.10-3 Florida Division of Historical Resources, Bureau of Archaeological Research. *Florida Master Site File*. St. Lucie County, Florida. 2000.

3.0 PROPOSED ACTION

NRC

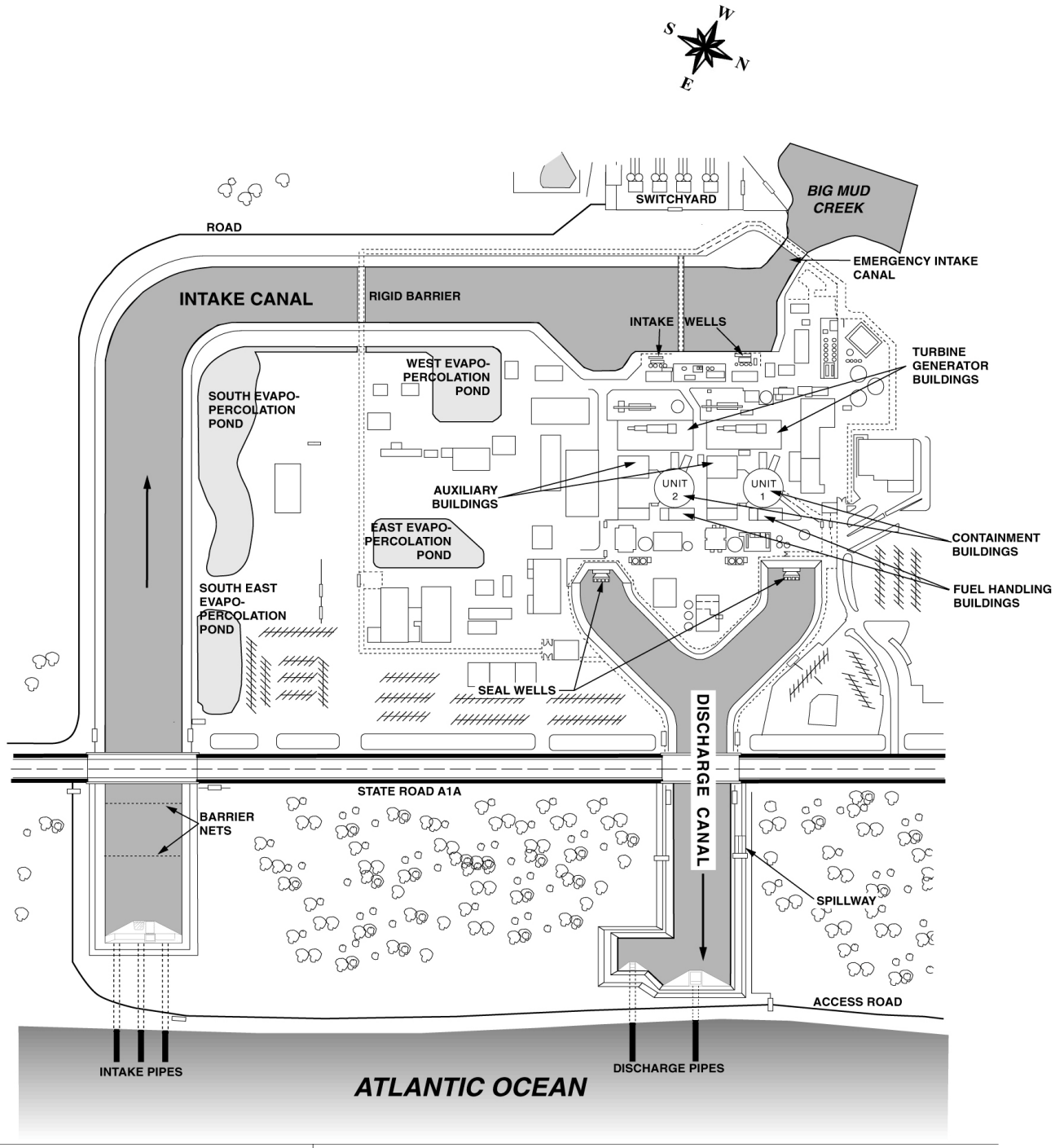
"The report must contain a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures…This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

Florida Power & Light Company (FPL) proposes that the U.S. Nuclear Regulatory Commission (NRC) renew the St. Lucie Units 1 & 2 operating licenses for an additional 20 years. Renewal would give FPL and the State of Florida the option of relying on St. Lucie Units 1 & 2 to meet Florida's future needs for electric generation. Section 3.1 provides a general description of selected plant design and operating features. Sections 3.2 through 3.4 address potential changes that could be required to support renewed operating licenses.

3.1 GENERAL PLANT INFORMATION

General information about design and operational features of St. Lucie Units 1 & 2 of interest from an environmental impact standpoint is available in several documents. Among the most comprehensive sources are the Final Environmental Statements prepared by the NRC or its predecessor agency, the U.S. Atomic Energy Commission (AEC), and Updated Final Safety Analysis Reports (UFSARs), prepared and maintained by FPL. The AEC issued a Final Environmental Statement (FES) in 1973 that addressed continued construction and operation of Unit 1 (Ref. 3.1-1), and issued an FES in 1974 that addressed construction of Unit 2 (Ref. 3.1-2). The NRC issued the FES for Unit 2 operation in 1982 (Ref. 3.1-3). FPL maintains separate Unit 1 and Unit 2 UFSARs, which provide current design information (Ref. 3.1-4; Ref. 3.1-5). The NRC's *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) describes some St. Lucie Units 1 & 2 plant features of interest to license renewal (Ref. 3.1-6). FPL used these documents and other sources as a basis for the plant descriptive information presented in the remainder of Section 3.1.

The arrangement of St. Lucie Units 1 & 2 major structures and equipment in the power block and nearby areas is shown in Figure 3.1-1. The prominent structures and housed facilities and equipment associated with each of the Units include: the Containment Building, which houses the nuclear steam supply system, including the reactor, steam generators, reactor coolant pumps, and related equipment; the Turbine Generator Building, where the turbine generator and associated main condensers are located; the Auxiliary Building, which houses waste management facilities, engineered safety features components, and other facilities; and the Fuel Handling Building, where the spent fuel storage pool and storage facilities for new fuel are located. Prominent features beyond the power block area include the Intake Canal, Discharge Canal, Intake Wells, Evaporation/Percolation (i.e., Evapo-percolation) Ponds, Switchyard, technical and administrative support facilities, and public education facilities (Energy Encounter Exhibit, Marine Education Facility). The taller buildings on the site, particularly the Containment Buildings (approximately 200 feet high) are visible from the mainland.



LEGEND:
= COOLING WATER
= EVAPO-PERCOLATION PONDS
= MANGROVE IMPOUNDMENTS
= PARKING

FIGURE 3.1-1
ST. LUCIE UNITS 1 & 2 POWER BLOCK AREA
LICENSE RENEWAL APPLICATION
ST. LUCIE UNITS 1 & 2

3.1.1 REACTOR AND CONTAINMENT SYSTEMS

The nuclear power units for St. Lucie Units 1 & 2 are of comparable design, each consisting of a pressurized light-water reactor with two steam generators that produce steam that turns a turbine to generate electricity. Each Unit is currently licensed to operate at an output of 2,700 megawatts (thermal) [MW(t)], with a corresponding gross electrical output of approximately 890 megawatts (electric) [MW(e)]. Discounting onsite electrical power usage, each reactor unit has a current net capability of 839 MW(e), for a combined plant capability of 1,678 MW(e) (net summer rating) (Ref. 3.1-4; Ref. 3.1-5, Section1.1; Ref. 3.1-7, Schedule 1).

Each reactor is housed in a containment comprising a steel containment vessel surrounded by a reinforced concrete shield building. The dry containment structures are designed to withstand environmental effects and the internal pressure and temperature accompanying a postulated loss-of-coolant accident (LOCA). Together with its engineered safety features, each containment structure is designed to adequately retain fission products that could escape from the reactor coolant system in the event of a LOCA.

3.1.2 NUCLEAR FUEL

St. Lucie Units 1 & 2 are licensed for uranium-dioxide fuel that is slightly enriched up to 4.5 percent by weight uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Each reactor core includes 217 fuel assemblies.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at an interval of approximately 18 months. FPL operates the reactors such that the average burnup for fuel discharged from the reactors is approximately 47,000 megawatt-days per metric ton uranium.

3.1.3 COOLING AND AUXILIARY WATER SYSTEMS

3.1.3.1 WATER USE OVERVIEW

Water use associated with operation of St. Lucie Units 1 & 2 consists of saltwater withdrawn from the Atlantic Ocean for non-contact cooling purposes and freshwater from a municipal water source for potable and service water use, discussed in more detail below. Minor amounts of ocean water are also withdrawn by St. Lucie County from the Intake Canal for seasonal flushing of the mangrove impoundment between the Intake and Discharge canals (see Figure 3.1-1) to enhance growth of mangroves and assist in mosquito control (Ref. 3.1-8). FPL also withdraws small amounts of water from the canals for mariculture and related projects.

As described in Section 2.9-1, FPL acquires potable and service water from the City of Fort Pierce through the Fort Pierce Utilities Authority. Although the municipal water supply for St. Lucie Units 1 & 2 draws on groundwater sources, plant operation does not involve any direct withdrawals of groundwater. Onsite groundwater withdrawals are limited to those needed to contain and treat groundwater that was contaminated by a diesel fuel spill in 1992. The total design flow rate for recovery wells associated with this remediation activity is 7.5 gallons per minute (gpm); actual withdrawals have averaged substantially less (Ref. 3.1-9). FPL

expects the remediation to be completed within the next few years, prior to the period of extended operation.

An onsite package plant was originally used to treat the site's sanitary wastewater, which was then discharged into the Discharge Canal. However, since September 1997, upon completion of St. Lucie County's South Hutchinson Island Water Reclamation Facility, site sanitary wastewater has been discharged to the St. Lucie County system for treatment.

3.1.3.2 COOLING WATER SYSTEMS

St. Lucie Units 1 & 2 use once-through cooling water from the Atlantic Ocean to remove heat from the main (turbine) condensers via the Circulating Water System, and to remove heat from other auxiliary equipment via the Intake Cooling Water System (i.e., Auxiliary Cooling Water System). The great majority of this cooling water is used for the Circulating Water System.

As with other pressurized water reactors, heat generated in the reactors is transferred in loops in a way that useful energy can be safely extracted to produce electricity. St. Lucie Units 1 & 2 have a two-loop, three-stage heat-transfer design. The primary system circulates reactor coolant (demineralized water that has been treated to control chemistry and corrosion) under high pressure through the reactor and two steam generators. The steam generators, steam turbine, and main turbine condensers are similarly connected in a secondary closed loop containing treated, demineralized water. Secondary-system water flashes to steam in the steam generators and the steam turns the turbine to generate electricity. After exiting the turbine, the steam in the secondary system passes through the main condensers, where it is cooled to liquid water before returning to the steam generator to complete the secondary loop.

The Circulating Water System is the final (tertiary) stage in this heat transfer system. Unlike the primary and secondary loops, the tertiary stage is unconfined. Ocean water is drawn through three offshore intake structures into the Intake Canal. This water is then pumped from the Intake Canal at the Intake Wells through the main condensers to the Discharge Canal. The heated water is finally discharged back to the Atlantic Ocean through offshore diffusers (see Figures 2.1-3 and 3.1-1). Circulation of water in the system is provided by a total of eight circulating water pumps (four per Unit) located at the Intake Wells. Nominal total capacity of the pumps is 968,000 gpm, though capacity may range from 800,000 gpm to 1,120,000 gpm, depending on condenser cleanliness (Ref. 3.1-8). When all pumps are operating and both Units are operating at 100 percent capacity, temperature rise across the condensers is approximately 24°F.

The three cooling water intake structures for St. Lucie Units 1 & 2 are located approximately 1,200 feet offshore where the water is approximately 23 feet deep. Two of the structures were installed prior to startup of Unit 1 in 1976. The third intake structure, which is larger than the initial two, was installed in 1983. The designs of the structures are essentially identical, featuring a large concrete base with a vertical cylindrical opening in the center and a concrete velocity cap supported by columns extending approximately 6 feet from the base (Ref. 3.1-3; Ref. 3.1-10). The velocity cap configuration was designed to reduce potential entrainment of marine organisms by eliminating vertical flows and limiting horizontal flow velocities. Water withdrawn from the structures is conveyed through separate buried pipes, beneath the beach and dune system, to the Intake Canal. Inside diameters of the pipes,

which correspond to those of the vertical cylindrical openings in the concrete bases of the structures, are 16 feet for the large intake and 12 feet for the small intakes. Calculated flow velocities at various points of the Intake System with both Units operating are as follows (Ref. 3.1-10):

Location	Velocity (feet per second)	
	12-foot Diameter Intakes	16-foot Diameter Intake
Velocity Cap Intake	0.37 – 0.41	0.9 – 1.0
Vertical Section	1.2 – 1.3	6.2 – 6.8
Intake Pipe	4.2 – 4.7	5.9 – 6.8
Intake Canal	1.0[a]	

NOTES:

a. Flow rate represents the combined flow from all intake pipes once merged in the Intake Canal.

The Intake Canal, a 4,920-foot long trapezoidal channel approximately 180 feet wide and 30 feet deep at normal water levels (Ref. 3.1-11), conveys cooling water to the Intake Wells during normal operation. FPL has installed and maintains three barriers in the channel to reduce potential for losses of marine life, particularly sea turtles, and to facilitate return of turtles to the ocean. These include deployment of a 5-inch mesh barrier net across the channel approximately midway between State Road A1A and the Canal headwall and an 8-inch mesh barrier net immediately east of State Road A1A, and installation of a rigid barrier across the north-south arm of the Intake Canal (see Figure 3.1-1) (Ref. 3.1-10). FPL dredged accumulated sediments from the Intake Canal on one occasion (in the mid-1990s) in accordance with a U.S. Army Corps of Engineers permit (Ref. 3.1-11), and sold the dewatered sediments for clean fill. The permit includes provisions for periodic dredging in the future, if needed (Ref 3.1-11).

Under emergency conditions (e.g., failure of the intake canal headwall as a result of a design-basis earthquake), water can be withdrawn from Big Mud Creek via the Emergency Intake Canal (see Figure 3.1-1) through two 54-inch pipe assemblies in the barrier wall that separates the Creek from the Canal. FPL does not use this intake during normal operations, but does test this system semi-annually by exercising the valves in the two pipe inlets.

Water is withdrawn from the Intake Canal at eight separate Intake Wells (4 per Unit). Water enters the Wells through a series of trash racks (vertical bars spaced 3 inches apart), then through traveling screens (3/8-inch mesh), which are periodically backwashed. The water is then pumped from the Wells through the main turbine condensers. Heated water is discharged to the Discharge Canal. Biofouling of the condenser tubes and other system components is controlled exclusively through the use of plastic foam balls (Taprogge® system) and injection of sodium hypochlorite. The foam balls are injected upstream from the condenser, scrub the condenser tubes as they pass through the tubes, and are collected in ball strainers downstream from the condensers (Ref. 3.1-8). FPL uses best management practices to minimize ball loss to the environment. Sodium hypochlorite injections are controlled to ensure that free available oxidant is at or below 0.5 milligrams per liter (mg/l) at the condenser outlet and total residual oxidant concentration at the eastern end of the

Discharge Canal is at or below 0.10 mg/l, as required by the Industrial Wastewater Facility Permit for St. Lucie Units 1 & 2 (Ref. 3.1-12).

The Discharge Canal, 2,200 feet long with transverse dimensions similar to those described for the Intake Canal, transports the heated cooling water to two discharge pipes at its eastern terminus. The pipes transport water beneath the beach and dune system back to the Atlantic Ocean. One of the pipes, completed in 1975 to serve St. Lucie Unit 1, is 12 feet in diameter, extends approximately 1,500 feet offshore, and terminates in a two-port "Y" diffuser. The other pipe, installed in 1981 for two-unit operation, is 16 feet in diameter, extends approximately 3,400 feet offshore, and features a multiport diffuser. This diffuser consists of fifty-eight 16-inch diameter ports located 24 feet apart on the easternmost 1,400 feet of the pipe. The discharge of heated water through the Y-port and multiport diffusers ensure distribution over a wide area and rapid and efficient mixing with ambient waters (Ref. 3.1-8; Ref. 3.1-9). Modeling studies presented by the AEC and NRC in the operating stage FESs indicate that the areas of the thermal plumes to the 2°F isotherm from the St. Lucie Units 1 & 2 diffusers under typical conditions would be approximately 180 acres and 175 acres, respectively (Ref. 3.1-1; Ref. 3.1-3).

Temperature of the discharged cooling water is limited by the Industrial Wastewater Facility Permit for St. Lucie Units 1 & 2 (Ref. 3.1-12). These limits require that heated water from the diffusers, as measured near the exit from the Discharge Canal, not exceed 113°F or 30°F above ambient during normal operations; a maximum temperature of 117°F or 32°F above ambient is permitted during certain maintenance operations, when throttling circulating water pumps to minimize use of chlorine, and when biofouling of the Circulating Water System occurs.

The Intake Cooling Water System for St. Lucie Units 1 & 2 is also a once-through cooling system, but uses much less water than the Circulating Water Systems. Up to 58,000 gpm of ocean cooling water is pumped from the Intake Canal using intake cooling water pumps. This non-contact cooling water is pumped through heat exchangers to provide cooling for a wide variety of plant equipment, and is discharged to the Discharge Canal. Low-level chlorination is used to control biofouling of this system (Ref. 3.1-8).

3.1.3.3 MUNICIPAL WATER SUPPLY

St. Lucie Units 1 & 2 use a combined total of approximately 4 million gallons per month (0.13 million gallons per day) of fresh water from the Fort Pierce Municipal Water Supply System. This water supply provides the raw water source for the plant water treatment facility, which provides demineralized water for makeup to various plant systems including the primary and secondary reactor cooling loops and the spent fuel pool. The municipal water also is the source of supply to potable, sanitary, and fire protection systems.

3.1.4 POWER TRANSMISSION SYSTEMS

FPL constructed three 230 kilovolt (kV) transmission lines for the purpose of connecting St. Lucie Units 1 & 2 to the transmission system. Beginning at the St. Lucie Units 1 & 2 Switchyard, these three lines run west across the Indian River and overland for approximately 11 miles in one corridor, with the lines terminating at the Midway Substation (see Figure 3.1-2). "Corridor" is a general term used to identify land over which utilities construct and operate transmission lines. A utility can own the land, in which case it holds

the corridor as a property owner, or others can own the land and the utility holds the right of use, called an easement, to install and maintain the transmission line on the land. FPL holds the preponderance of the Midway Corridor as a property owner. The 1.5-mile segment that goes north into the Midway Substation is held in easement.

The Midway Corridor varies in width between 660 feet and 813 feet. For much of this route, only the three 230 kV lines from the St. Lucie Units 1 & 2 Switchyard occupy this Corridor with additional space within the right-of-way available for future transmission line expansion. However, approximately 4 miles of the Corridor from St. Lucie Units 1 & 2 to the Midway Substation also include other 230 kV and 500 kV lines that connect to the Midway Substation but are not associated with St. Lucie Units 1 & 2. Figure 3.1-2 provides an overall arrangement of the transmission lines in the Midway Corridor.

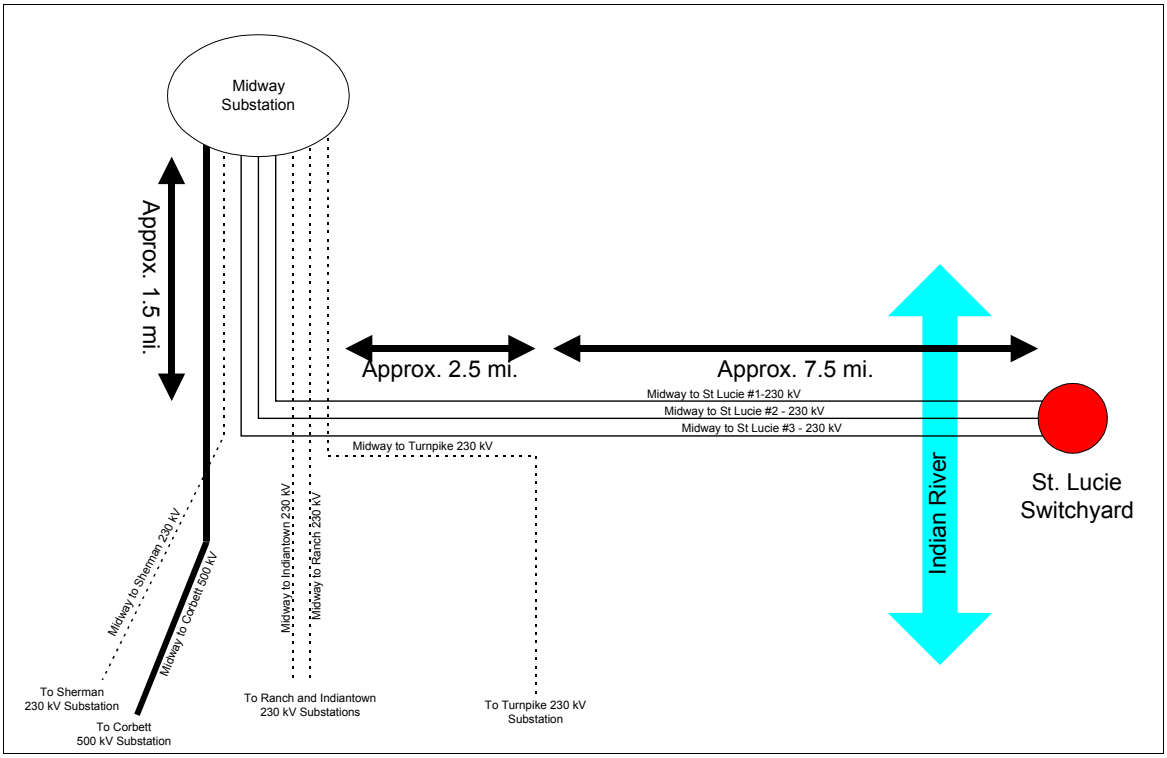


FIGURE 3.1-2 FPL ST. LUCIE UNITS 1 & 2 TO MIDWAY TRANSMISSION CORRIDOR

The 230 kV transmission lines from St. Lucie Units 1 & 2 are each spaced 100 feet apart in the sections over land, and this spacing increases to 200 feet over the Indian River. The crossing over the Intra-Coastal Waterway (Indian River) provides 90 feet of clearance between the 230 kV conductors and mean sea level, and 60 feet of clearance elsewhere in the River. The 230 kV lines to St. Lucie Units 1 & 2 were originally built to operate at 230 kV, and continue to do so today without any increase in operating voltage.

Land use on this Corridor has not significantly changed since the lines were originally constructed. The agricultural lands have since been abandoned and have reverted to shrubby species. Pasture land is still in use. Other habitats along the Corridor include sand

pine scrub, dry prairie, pine flatwoods, wet prairie, isolated marshes, and ruderal or disturbed sites. The corridor passes through the Savannas State Preserve.

FPL maintains the Midway Corridor using a combination of trimming, mowing, and herbicide application. Where required, FPL trims trees at the 14-foot level to maintain clearances. Typically, FPL only needs to do this at mid-span. In open, undeveloped areas, FPL mows approximately every five years. FPL uses spot and broadcast treatment with herbicides primarily to control tall exotic grasses and spot treatment for individual trees that may grow over 14 feet tall. These herbicides are applied under supervision by persons licensed by the State for herbicide application. These are the most common management practices for the Midway Corridor.

3.2 REFURBISHMENT ACTIVITIES

NRC

"The report must contain a description of...the applicant's plans to modify the facility or its administrative control procedures.... This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item…." (Ref. 3.1-6, Section 2.6.3.1, page 2-41.) ["SMITTR" defined at GEIS Section 2.4, page 2-30, as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping]

In the GEIS (Ref. 3.1-6, Section 3.1 and Table B.2, Appendix B), the NRC identifies refurbishment activities that utilities might perform for license renewal. Performing such major refurbishment activities would necessitate changing administrative control procedures and modifying the facility. The GEIS analysis assumed that an applicant would begin any major refurbishment work shortly after the NRC granted a renewed license and would complete the activities during five outages, including one major outage at the end of the 40th year of operation. The GEIS refers to this as the refurbishment period.

GEIS Table B.2 lists license renewal refurbishment activities that the NRC anticipated utilities might undertake. In identifying these activities, the GEIS intended to encompass actions that typically take place only once in the life of a nuclear power plant, if at all. The GEIS analysis assumed that a utility would undertake these activities solely for the purpose of extending plant operations beyond 40 years and would undertake them during the refurbishment period. The GEIS indicates that many plants will have undertaken various major refurbishment activities to support the current license period but that some plants might undertake such tasks only to support extended plant operations.

FPL has performed some major construction activities at St. Lucie Units 1 & 2 (e.g., Unit 1 steam generator replacement, and velocity cap repair). However, the St. Lucie Units 1 & 2 Integrated Plant Assessment that FPL has conducted under 10 CFR Part 54 and included as part of this Application has not identified the need to undertake any refurbishment or replacement actions to maintain the functionality of important systems, structures, and components during the St. Lucie Units 1 & 2 license renewal period or any other modifications related to license renewal. Therefore, no refurbishments or modifications have been identified that would directly affect the environment or plant effluents.

3.3 PROGRAMS AND ACTIVITIES FOR MANAGING THE EFFECTS OF AGING

NRC

"The report must contain a description of...the applicant's plans to modify the facility or its administrative control procedures....This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item…." (Ref. 3.1-6, Section 2.6.3.1, page 2-41.) ["SMITTR" defined at GEIS Section 2.4, page 2-30, as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping]

Appendix A of the St. Lucie Units 1 & 2 License Renewal Application contains a separate supplement for each Unit's Updated Final Safety Analysis Report. In accordance with NRC requirements [10 CFR 54.21(d)], the supplements contain a description of the programs and activities for managing the effects of St. Lucie Units 1 & 2 aging. In addition to describing existing programs, the supplements describe proposed modifications (enhancements) to existing programs and proposed programs and activities.

3.4 EMPLOYMENT

3.4.1 CURRENT WORKFORCE

FPL employs a permanent workforce of approximately 791 employees and 138 contractors at St. Lucie Units 1 & 2, a number that is less than the range of 600 to 800 personnel per reactor unit that the NRC cited in GEIS Section 2.3.8.1. Of the total number of employees, approximately 46 percent lives in St. Lucie County, 37 percent in Martin County, 8 percent in Indian River County, 6 percent in Palm Beach County, with the rest living in various other locations.

FPL refuels each St. Lucie Unit on an 18-month schedule, which typically means at least 1 refueling every year and 2 refuelings every third year. During refueling outages, site employment increases by as many as 575 to 870 workers for temporary (30 to 40 days) duty. These numbers are within the GEIS range of 200 to 900 additional workers per reactor outage.

3.4.2 LICENSE RENEWAL INCREMENT

Performing the license renewal surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping (SMITTR) activities discussed in Section 3.3 would necessitate increasing St. Lucie Units 1 & 2 staff workload by some increment. The size of this increment would be a function of the schedule within which FPL must accomplish the work and the amount of work involved.

In the GEIS, the NRC assumes that each nuclear power plant license renewal would be for a 20-year period plus the remaining duration of the current license and that the NRC would issue the renewal approximately 10 years prior to current license expiration. In other words, the renewed license would be effective for 30 years. The NRC determined that the utility would initiate SMITTR activities at the time of issuance and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant, sometimes during full-power operation (Ref. 3.1-6, Section B.3.1.3) but mostly during normal refueling, and during 5-year and 10-year in-service inspections during refueling outages (Ref. 3.1-6, Table B.4).

FPL has determined that the NRC's scheduling assumptions in the GEIS are reasonably representative of St. Lucie Units 1 & 2 incremental license renewal workload scheduling. Many SMITTR activities that Section 3.3 encompasses would have to be performed during outages. Although some St. Lucie Units 1 & 2 license renewal SMITTR activities would be one-time efforts, others would be recurring, periodic activities that would continue for the lives of the Units.

The NRC estimates in the GEIS that no more than 60 additional personnel would be needed to perform license renewal SMITTR activities during the 3-month duration of a 10-year in-service inspection refueling outage. Having established this upper value for what would be a single event in 20 years, the NRC uses this number as the expected number of additional permanent workers needed per unit attributable to license renewal. In GEIS (Ref. 3.1-6) Section C.3.1.2, the NRC uses this approach in order to, "...provide a realistic upper bound to potential population-driven impacts…."

FPL expects that existing “surge” capabilities for routine activities such as outages will enable plant staff to perform the increased SMITTR workload without adding St. Lucie Units 1 & 2 personnel. For the purpose of performing its own analyses in this Environmental Report, FPL is adopting the NRC’s GEIS approach with one alteration. FPL license renewal plant modifications would be SMITTR activities that would be performed mostly during outages, and FPL would generally stagger St. Lucie Units 1 & 2 outage schedules so that both Units are not shut down at the same time. Therefore, FPL believes that it is unreasonable to assume that each Unit would need an additional 60 workers. Instead, as a reasonably conservative high estimate, FPL is assuming that St. Lucie Units 1 & 2 would require no more than a total of 60 additional permanent workers to perform license renewal SMITTR activities.

Adding full-time employees to the plant workforce for continued operation during the license renewal period would have the indirect effect of creating additional jobs and related population growth in the community. Using 1997 data, University of Florida researchers calculated a regional employment multiplier appropriate for the electric services sector in the combined-county area of Martin and St. Lucie counties. FPL has used this value, 2.3044, to estimate the number of direct and indirect jobs supported by additional St. Lucie Units 1 & 2 employees that might be needed during the license renewal period (Ref. 3.4-1). Applying the multiplier, a total of 138 (60 × 2.3044) new jobs would be created in the Martin and St. Lucie combined-county area, where total employment in 2000 was slightly over 128,000 persons. These 138 new direct and indirect jobs represent 0.1 percent of current total employment in the two counties (Ref. 3.4-2). In summary, FPL is assuming that 60 additional permanent direct workers during the license renewal period would create an additional 78 indirect jobs in the community.

These 138 new jobs (60 direct and 78 indirect) could result in a population increase of 339 in the area [138 jobs multiplied by 2.46 average number of persons per household in the State of Florida (Ref. 3.4-3)]. This increase represents approximately 0.1 percent of the population in 2000 (319,426 persons) for the combined-county area.

3.5 REFERENCES

3.1-1 U.S. Atomic Energy Commission. *Final Environmental Statement Related to the St. Lucie Plant Unit No. 1; Florida Power & Light Company*. Docket No. 50-335. Directorate of Licensing. Washington, D.C. June 1973.

3.1-2 U.S. Atomic Energy Commission. Final Environmental Statement Related to the Construction of St. Lucie Plant, Unit No. 2; Florida Power & Light Company. Docket No. 50-389. Directorate of Licensing. Washington, D.C. May 1974.

3.1-3 U.S. Nuclear Regulatory Commission. Final Environmental Statement Related to the Operation of St. Lucie Plant, Unit No. 2; Florida Power & Light Company, Orlando Utilities Commission of the City of Orlando, Florida. Docket No. 50-389. NUREG-0842. Office of Nuclear Reactor Regulation. Washington, D.C. April 1982.

3.1-4 Florida Power & Light Company. St. Lucie Unit 1 Updated Final Safety Analysis Report. Amendment 17. Juno Beach, Florida. October 1999.

3.1-5 Florida Power & Light Company. St. Lucie Unit 2 Updated Final Safety Analysis Report. Amendment 13. Juno Beach, Florida. May 16, 2000.

3.1-6 U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. NUREG-1437. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

3.1-7 Florida Power & Light Company. Ten Year Power Plant Site Plan; 2001-2010. Miami, Florida. April 2001.

3.1-8 Florida Power & Light Company. St. Lucie Plant Wastewater Permit Application. Jensen Beach, Florida. April 1996.

3.1-9 Foster-Wheeler Environmental Corporation. Annual Operation & Maintenance Status Report (1999-2000) for FPL St. Lucie Power Plant Unit 1 & Unit 2 Remedial Action. Stuart, Florida. August 3, 2000.

3.1-10 Ecological Associates, Inc. Physical and Ecological Factors Influencing Sea Turtle Entrainment Levels at the St. Lucie Nuclear Plant: 1976-1998. Jensen Beach, Florida. (L-2000-78) March 22, 2000.

3.1-11 U.S. Army Corps of Engineers. Department of the Army Permit No. 199301803. U.S. Army Engineer District. Jacksonville, Florida. December 27, 1993.

3.1-12 Florida Department of Environmental Protection. State of Florida Wastewater Facility Permit. Permit No. FL0002208-Major. Issued to Florida Power & Light Company for St. Lucie Power Plant Units 1 & 2. Tallahassee, Florida. January 10, 2000.

3.4-1 University of Florida. Employment Multipliers for the Combined-County Region of St. Lucie and Martin Counties. Food and Resource Economic Department. Tallahassee, Florida. December 12, 2000.

3.4-2 State of Florida. St. Lucie and Martin County Profiles. www.eflorida.com/all_facts.html. Accessed July 25, 2001.

3.4-3 U.S. Census Bureau. Table DP-1. Profile of General Demographic Characteristics: 2000 for Florida and Selected Counties and Cities. http://factfinder.census.gov. Accessed July 25, 2001.

4.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS

NRC

The environmental report shall discuss the "…impact of the proposed action on the environment. Impacts shall be discussed in proportion to their significance[.]" 10 CFR 51.45(b)(1) as adopted by 51.53(c)(2)

4.1 INTRODUCTION

Chapter 4 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of the St. Lucie Units 1 & 2 operating licenses. The U.S. Nuclear Regulatory Commission (NRC) has identified and analyzed 92 environmental issues that it considers associated with nuclear power plant license renewal and has designated the issues as Category 1, Category 2, or Not Applicable (NA). The NRC has designated the issues as "Category 1" if, after analysis, the following criteria were met:

- The environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic; and
- A single significance level (i.e., small, moderate, or large) has been assigned to the impacts (except for collective offsite radiological impacts from the fuel cycle and from high-level-radioactive waste and spent-fuel disposal); and
- Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, the NRC designated the issue as Category 2. The NRC requires plant-specific analyses for Category 2 issues. The NRC designated two issues as "NA," signifying that the categorization and impact definitions do not apply to these issues. NRC rules do not require analyses of Category 1 issues that the NRC has resolved using generic findings (10 CFR 51, Subpart A, Appendix B, Table B-1) based on its *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS). An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

Appendix A of the St. Lucie Units1 & 2 Environmental Report lists the 92 issues with their NRC-assigned categorizations, and identifies the Environmental Report and GEIS sections that address each issue. For those issues not applicable to St. Lucie Units 1 & 2, a notation gives the basis for that designation. The issues are numbered in the same order in which they are listed in Table B-1 of Appendix B to Subpart A of 10 CFR 51, for ease of reference.

4.1.1 CATEGORY 1 LICENSE RENEWAL ISSUES

NRC

"The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(i)

"…[A]bsent new and significant information, the analysis for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal…." (61 *Federal Register*, page 28483).

Florida Power & Light Company (FPL) has determined that of the 69 Category 1 issues, 15 do not apply to St. Lucie Units 1 & 2 because they apply to design, operational, or location features that do not exist at the facility. These features are intake and discharge from a small river, lake, or canal; cooling towers; and groundwater withdrawal. In addition, because FPL does not plan to conduct any refurbishment activities, the NRC findings for the seven Category 1 issues that apply only to refurbishment clearly overestimate St. Lucie Units 1 & 2 refurbishment impacts and do not apply. FPL has reviewed the NRC findings and has identified no new and significant information, or become aware of any such information that would make the NRC findings inapplicable to St. Lucie Units 1 & 2. Therefore, FPL adopts by reference the NRC findings for the 47 Category 1 issues that FPL determined to be applicable to St. Lucie Units 1 & 2.

4.1.2 CATEGORY 2 LICENSE RENEWAL ISSUES

NRC

"The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for those issues identified as Category 2 issues in Appendix B to subpart A of this part…." 10 CFR 51.53(c)(3)(ii)

"The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues…." 10 CFR 51.53(c)(3)(iii)

The NRC designated 21 issues as Category 2. As in the case of Category 1 issues, some Category 2 issues (six) do not apply to design, operational, or location features that exist at St. Lucie Units 1 & 2. These issues and their bases for exclusion are listed below:

Issue	Basis for Exclusion
13. Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	Not applicable because St. Lucie Units 1 & 2 are not equipped with cooling ponds or cooling towers.
33. Groundwater use conflicts (potable, service, and dewatering; plants that use>100 gpm)	Not applicable because St. Lucie Units 1 & 2 are not direct users of groundwater (no dewatering; potable and service water are from municipal supply).
34. Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	Not applicable because St. Lucie Units 1 & 2 are not equipped with cooling towers.
35. Groundwater use conflicts (Ranney wells)	Not applicable because St. Lucie Units 1 & 2 do not use Ranney wells.
39. Groundwater quality degradation (cooling ponds at inland sites)	Not applicable because St. Lucie Units 1 & 2 are not equipped with cooling ponds.
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	Not applicable because St. Lucie Units 1 & 2 do not use lakes or canals, or cooling towers or cooling ponds that discharge to a small river.

Sections 4.2 through 4.15 of this Environmental Report address the Category 2 issues applicable to St. Lucie Units 1 & 2 and the issues that apply to refurbishment activities. Each section begins with a statement of the issue, and explains why the NRC was not able to generically resolve the issue. If the issue does not warrant detailed analysis, the section explains the basis for inapplicability.

If the subject Category 2 issue has been determined by FPL to be applicable to St. Lucie Units 1 & 2, the section provides both details on the issue and the required detailed analysis. These analyses include conclusions regarding the significance of the impacts relative to renewal of the operating licenses for St. Lucie Units 1 & 2 and discuss potential mitigative alternatives when applicable and to the extent required. FPL has determined that

11 Category 2 issues warrant this detailed discussion. For each, FPL has identified the significance of the impacts associated with the issue as either small, moderate, or large, consistent with the criteria that the NRC established at 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3, as follows:

Small – Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the NRC has concluded that those impacts that do not exceed permissible levels in the NRC's regulations are considered small.

Moderate – Environmental effects are sufficient to alter noticeably but not to destabilize any important attribute of the resource.

Large – Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

In accordance with National Environmental Policy Act practice, FPL considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than do impacts that are large).

4.1.3 "NA" LICENSE RENEWAL ISSUES

The NRC determined that its categorization and impact finding definitions did not apply to two issues. FPL included these issues in Appendix A. The NRC noted that applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 5). For the other NA issue, environmental justice, the NRC does not require information from applicants but noted that it will be addressed in individual license renewal reviews (10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 6). FPL has included an environmental justice analysis in Section 4.16, along with supporting demographic information in Section 2.5.2.

4.2 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant can not provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…entrainment." 10 CFR 51.53(c)(3)(ii)(B)

"The impacts of entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 25

The NRC made impacts on fish and shellfish resources resulting from entrainment a Category 2 issue because it could not assign a single significance level (small, moderate, or large) to the issue; the impacts of entrainment are small at many plants, but they may be moderate or large impacts at some plants. Also, ongoing restoration efforts may increase the number of fish susceptible to intake effects during the license renewal period (Ref. 4.2-1, Section 4.2.2.1.2). Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond); and (2) current Clean Water Act Section 316(b) determination or equivalent state documentation.

As indicated in Section 3.1.3, St. Lucie Units 1 & 2 have a once-through heat dissipation system. Entrainment at St. Lucie Units 1 & 2 was evaluated based on densities of entrainable forms in the ocean during pre-operational and early operational monitoring for Unit 1. The NRC summarized early Unit 1 operational data from ocean ichthyoplankton surveys. The most common larval fishes in the area of the intakes were herrings and anchovies (Ref. 4.2-2, Section 4.3.8.2.5). Based on five years of ichthyoplankton sampling, an estimate was made of the conditional mortality of fish larvae due to entrainment. Under normal conditions, it was estimated that 0.4 percent of the fish eggs and larvae passing the site could be entrained. Using the most conservative assumptions, the loss was estimated at less than 4 percent. Based on this assessment, the NRC concluded that entrainment losses would not represent a significant impact to the local fisheries (Ref. 4.2-2, Section 5.6.3).

As indicated in the current Industrial Wastewater Facility Permit No. FL0002208 for St. Lucie Units 1 & 2 (see Appendix B), St. Lucie Units 1 & 2 have documentation of Clean Water Act 316(b) compliance indicating that the existing Intake Structure reflects the best technology available for minimizing environmental impacts at St. Lucie Units 1 & 2. Given this determination, FPL concludes that St. Lucie Units 1 & 2 entrainment impacts (Issue 25; see Appendix A, Table A-1) are SMALL, and that further mitigation would be unwarranted.

4.3 IMPINGEMENT OF FISH AND SHELLFISH

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant can not provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…impingement…" 10 CFR 51.53(c)(3)(ii)(B)

"The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 26

The NRC made impacts on fish and shellfish resources resulting from impingement a Category 2 issue because it could not assign a single significance level to the issue; impingement impacts are small at many plants, but might be moderate or large at a few plants. Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond); and (2) current Clean Water Act 316(b) determination or equivalent state documentation.

As indicated in Section 3.1.3, St. Lucie Units 1 & 2 have a once-through heat dissipation system. The NRC summarized impingement sampling carried out at St. Lucie Unit 1 during 1976-1978, as directed by the Unit 1 operating license (Ref. 4.2-2, Section 5.6.2). During this period, 226 twenty-four-hour (24-hr) collections were made of fish and shellfish trapped on the traveling intake screens. Assuming continuous operation, annual impingement rates were estimated at 34,000 (1978) to 131,000 (1976) finfish, and 26,000 (1976) to 37,000 (1978) shellfish. Over the entire study, mean numbers of finfish and shellfish impinged per 24-hr period were 222 and 82 individuals, respectively. Corresponding mean weights were 1.7 kilograms (kg) and 0.5 kg. The most commonly impinged species groups were anchovy, grunt, jack, croaker, mojarro, shrimp, and blue crab (*Callinectes sapidus*). The length of over 80 percent of the impinged fish was 8 centimeters (cm) or less, and virtually all of the impinged shrimp were 4 cm or less in length. In January 1979, the NRC issued an amendment to the Unit 1 operating license deleting the requirement for impingement monitoring. It was concluded that impingement losses at Unit 1 were insignificant when compared to the fish populations in the site vicinity and (for shrimp) the number caught commercially off of Florida's east coast (Ref. 4.2-2, Section 5.6.2).

The NRC acknowledged that startup of St. Lucie Unit 2 would double the intake flow volume and increase impingement rates over those measured during only Unit 1 operation (Ref. 4.2-2, Section 5.6.2). It was projected that a doubling of the weight of organisms impinged would be equivalent to less than one-half of one percent of the commercial catch of fish and shellfish in either St. Lucie or Martin County. Based on this, the NRC concluded that even the combined estimates of Unit 1 and Unit 2 impingement would be insignificant when compared to local commercial landings. Additional impingement monitoring for St. Lucie Unit 2 was not required.

Applied Biology reported on Intake Canal gill-net sampling carried out annually from 1976 to 1984 (Ref. 4.3-1, Section B). The purpose of this program was to determine the extent of entrapment and accumulation of fish and shellfish in the Intake Canal, and whether this

could represent an adverse impact to the communities in the site vicinity. It was concluded that fish and shellfish were not accumulating in the Intake Canal, based on an average catch rate for the study period of 3.5 to 12.5 fish per 30 meters (m) of gill net per day. There were peaks in some years due to influxes of blue runners (*Caranx crysos*), crevalle jacks (*Caranx hippos*), and smooth dogfish (*Mustelus canis*) in 1977, 1978, and 1984, respectively. The highest mean catch rate for the period occurred in 1980, and resulted from an influx of spot (*Leiostomus xanthurus*) into the Intake Canal. In spite of these sporadic influxes of some species into the Canal, there was no accumulation documented. It is possible that factors such as predation within the Canal operate to keep the numbers low. Some of the fish entrapped in the Intake Canal were commercial species, but losses were negligible relative to the weight of commercial landings. Of particular note is that of three of the most important commercial species, only five Spanish mackerel, 10 king mackerel, and 37 bluefish were found in the Intake Canal over the nine-year study period. The low rate of entrapment was attributed to the velocity caps at the ocean intakes, which create horizontal currents that are more easily avoided by fish relative to vertical currents.

Pursuant to a special condition of the St. Lucie Unit 2 Site Certification issued by the Florida Department of Environmental Protection in compliance with Florida Law (Ref. 4.3-2, Section XI), a mitigation program was implemented whereby FPL periodically traps fish from the Intake Canal, tags them, and releases them in the ocean. This program is carried out at the behest of the Florida Fish and Wildlife Conservation Commission (FWCC). Although the special condition specified that this mitigation take place during construction of St. Lucie Unit 2, FPL has continued the program beyond the construction period. Collections are made on a quarterly to a monthly basis, with a goal of tagging and releasing 1,000 fish per year.

Additional mitigation is provided via FPL's cooperation with various institutions to provide specimens for display and research. Upon request, FPL makes the Intake Canal available to these institutions for the collection of fish. Such in-state institutions as the Florida Aquarium (Tampa), the Marinelife Center of Juno Beach, the Living Seas at Disney Epcot Center, and the Florida Oceanographic Society Keys Marine Laboratory avail themselves of the unique collection opportunity afforded by the St. Lucie Units 1 & 2 Intake Canal. Out-of-state institutions also take advantage of the opportunity, with regular collections made by the South Carolina Aquarium and the National Aquarium (Baltimore, Maryland). The collection of specimens from the Intake Canal rather than the open ocean is much more economical for the institutions involved. Consequently, by making the Intake Canal available to these institutions, FPL provides valuable support to public education and research on marine resources.

As indicated in the current Industrial Wastewater Facility Permit No. FL0002208 for St. Lucie Units 1 & 2 (see Appendix B), St. Lucie Units 1 & 2 have documentation of Clean Water Act 316(b) compliance indicating that the existing Intake Structure reflects the best technology available for minimizing environmental impacts at St. Lucie Units 1 & 2. Given this determination, FPL concludes that St. Lucie Units 1 & 2 impingement impacts (Issue 26; Appendix A, Table A-1)) are SMALL, and that further mitigation would not be warranted.

4.4 HEAT SHOCK

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act… 316(a) variance in accordance with 40 CFR part 125, or equivalent State permits and supporting documentation. If the applicant can not provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock …" 10 CFR 51.53(c)(3)(ii)(B)

"Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants...."10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

The NRC made impacts on fish and shellfish resources resulting from heat shock a Category 2 issue because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions. Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond); and (2) evidence of a Clean Water Act 316(a) variance or equivalent state documentation.

As indicated in Section 3.1.3, St. Lucie Units 1 & 2 have a once-through heat dissipation system. Prior to startup of both Units 1 and 2, extensive thermal plume modeling studies were conducted, as summarized by the NRC and its predecessor agency, the U.S. Atomic Energy Commission (AEC) (Ref. 4.2-2, Section 5.6.4; Ref. 4.4-1, Section V-B). These studies described rapidly rising, buoyant thermal plumes from the diffuser discharges with resulting surface temperatures less than the 97° Fahrenheit (36.1° Celsius) surface water limitation in the Water Quality Standards [Ref. 4.4-2, Section 62-302.520(4)(c)]. Potential interaction of the thermal plume with benthic, planktonic, and nektonic (fish and sea turtles) communities was evaluated and projected to be minimal. No detectable impact was predicted due to scouring of the benthic community, plume entrainment of plankton (including fish eggs and larvae), or heat shock to adult fish or turtle hatchlings.

As indicated in Section 3(C)(1) of the Fact Sheet associated with the current Industrial Wastewater Facility Permit No. FL0002208 for St. Lucie Units 1 & 2 (see Appendix B), the thermal discharge from the plant complies with Florida Water Quality Standards without recourse to a Clean Water Act Section 316(a) variance. Consequently, FPL concludes that St. Lucie Units 1 & 2 heat shock impacts (Issue 27; Appendix A, Table A-1) would be SMALL and, because the standard-setting process provides for minimizing environmental impact, further mitigation would not be warranted.

4.5 IMPACTS OF REFURBISHMENT ON TERRESTRIAL RESOURCES

NRC

The environmental report must contain an assessment of "…the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats…." 10 CFR 51.53(c)(3)(ii)(E)

"Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 40

"If no important resources would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant…." (Ref. 4.2-1, Section 3.6, page 3-6)

The NRC made impacts of refurbishment on terrestrial resources a Category 2 issue because the significance of ecological impacts cannot be determined without considering site-specific and project-specific details (Ref. 4.2-1, Section 3.6). Aspects of the site and the project to be ascertained are: (1) the identification of important ecological resources; (2) the nature of refurbishment activities; and (3) the extent of impacts to plant and animal habitat.

Detailed analyses are not required for this issue because, as discussed in Section 3.2, FPL has no plans for major refurbishment or other license-renewal-related construction activities at St. Lucie Units 1 & 2.

4.6 THREATENED OR ENDANGERED SPECIES

NRC

"All license renewal applicants shall assess the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)

"Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 49

The NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed, and site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate Federal agency (Ref. 4.2-1, Sections 3.9 and 4.1).

Sections 2.2 and 2.3 discuss ecological habitats at St. Lucie Units 1 & 2 and along associated transmission lines. Section 2.4 presents a list of federally threatened and endangered species and state species of special concern (SSC) that may occur at St. Lucie Units 1 & 2 and along transmission lines. In this section, the environmental consequences to these species of future plant refurbishment activities and continued operation of the plant are assessed.

As discussed in Section 3.2, FPL has no plans for major refurbishment or construction at St. Lucie Units 1 & 2 in association with license renewal. Therefore, there would be no refurbishment-related impacts to special-status species, and no further analysis of refurbishment-related impacts is required. During the almost 20 years of St. Lucie Unit 2 commercial operation, the only notable effect of the two-unit facility's operation on protected species has related to sea turtles that have entered the Intake Canal. There have been isolated incidents involving Florida manatees and Least Terns. A notable positive impact on protected species would be realized by the continuation of the educational programs and marine environmental protection programs that would be supported by the continued operation of St. Lucie Units 1 & 2.

There have been five occasions when manatees have entered in the Intake Canal. During the first event, in 1991, FPL coordinated the capture with the U.S. Fish and Wildlife Service (FWS) and Florida Department of Environmental Protection (predecessor to the FWCC). Due to techniques employed, capture took 32 days. The animal underwent evaluation and rehabilitation and was released to the wild. During the four subsequent events, improved capture techniques were employed and the animals were removed from the Canal within a day of each first sighting. Two of these animals were taken to rehabilitation facilities prior to their release. One was treated for deep propeller wounds that it incurred prior to entering the Canal and one appeared to be a small calf separated from its mother. None of the manatees appeared to have been harmed or to have died as a result of entering the Intake

Canal. FPL procedures require coordination with the FWCC on the capture and evaluation of entrapped manatees. FPL assists the FWCC, as needed, in transporting ill or injured animals to approved rehabilitation facilities, and in releasing animals that have entered the Intake Canal back to the wild.

There have been two incidents, one in 1991 and one in 1998, in which juvenile Least Terns were washed by stormwater from nests built on the roof of the St. Lucie Units 1 & 2 Training Center. The loss of a total 17 Terns occurred because of the failure of a protective netting system covering the stormwater system. The FWS was notified of the incident under the requirements of the Migratory Bird Treaty Act. The stormwater system has since been modified to prevent such incidents.

Soon after startup of St. Lucie Unit 1, in 1976, sea turtles were discovered in the Intake Canal (Ref. 4.6-1; Ref. 4.6-2). These turtles had entered the offshore velocity cap intake and were swept through the intake pipe into the Canal. A program was initiated to capture the turtles from the Intake Canal and return them to the ocean. In 1978, a large-mesh (eight inch) barrier net was deployed in the Canal to capture turtles before they transited the entire Intake Canal, entered the Intake Wells, and became impinged on the traveling intake screens. A Biological Assessment and Endangered Species Act Section 7 Consultation were completed in 1982 (Ref. 4.6-2) to address turtle entrapment in light of the pending construction and operation of St. Lucie Unit 2. At this time, the turtle entrapment history at St. Lucie Unit 1 was approximately 150 turtles per year from 1976 to 1981. Mortality rates for loggerhead and green sea turtles for this period were 14.6 percent and 8.9 percent, respectively. Projecting mortality losses to include operation of St. Lucie Unit 2, the Biological Assessment indicated that turtle losses at St. Lucie Units 1 & 2 would represent 0.1 percent (loggerhead) to 0.03 percent (green) of the respective adult Caribbean populations. It was concluded that no impact to the population of either species would be expected. The assessment made several recommendations for enhancement of the ongoing capture-release and beach-nest monitoring programs.

In 1995 in response to an increase in the number of sea turtles that had entered the Intake Canal, particularly green sea turtles, the NRC reinitiated the Endangered Species Act Section 7 Consultation process with the National Marine Fisheries Service (NMFS). Early in this consultation process, construction of a new, smaller mesh barrier east of the large mesh barrier was identified as appropriate, and construction of this small-mesh (five inch) barrier net was completed January 1996. The size of the mesh was selected to be smaller than any of the green sea turtles that had entered the Intake Canal during the first half of 1995. The new net was located halfway between the old eight-inch mesh barrier net and the intake headwall, confining sea turtles that enter the Intake Canal to a smaller area, thus facilitating their safe capture and release. The new net is anchored along the bottom of the Canal and held up by an aerial wire that is strung between tensioning towers on the sides of the Canal. The net is inspected and maintained regularly.

As a result of this consultation, the NMFS issued a Biological Opinion on the matter (Ref. 4.6-3). In the Biological Opinion, the NMFS concluded that the continued operation of St. Lucie Units 1 & 2 is not likely to jeopardize the existence of the sea turtle species. To increase protective measures for the turtles, NMFS included in the Biological Opinion an Incidental Take Statement. This Incidental Take Statement specifies the permissible annual mortality level of sea turtles that enter the Intake Canal. The requirements of the Incidental

Take Statement were incorporated as part of the St. Lucie Units 1 & 2 operating licenses. If the annual mortality level criteria are exceeded, reinitiation of Section 7 Consultation is required.

In November 1999, the NRC formally requested reinitiation of the Section 7 process after St. Lucie Units 1 & 2 exceeded the NMFS's anticipated incidental take of green turtles per year established in the Incidental Take Statement of the 1997 Opinion. In March 2000, FPL submitted to the NMFS a report analyzing the physical and ecological facts influencing sea turtle entrainment levels during the period 1976 through 1998 (Ref. 4.6-1). In May 2001, the NMFS released their Biological Opinion and revised Incidental Take Statement. The Opinion reiterates the previous conclusions and states, "…it is NMFS' biological opinion that the continued use of St. Lucie Nuclear Power Plant's circulating seawater cooling system is not likely to jeopardize the continued existence of the endangered green, leatherback, hawksbill, and Kemp's ridley sea turtles or the threatened loggerhead sea turtle." (Ref. 4.6-5, page 42) The requirement of the revised Incidental Take Statement will be appended to the St. Lucie Units 1 & 2 operating licenses. The NMFS specified that the annual incidental capture could be up to 1,000 turtles with that number being in any combination of the five species found in the area. The permissible annual mortality of entrapped green and loggerhead sea turtles for the next 10 years is one percent of the total combined number of green and loggerhead sea turtles captured. The permissible mortality levels for the other three species of sea turtle found in the area are two Kemp's ridley turtles per year and one hawksbill or leatherback turtle every two years for the next 10 years. Some of the terms and conditions of the previous Opinion were also revised. Specifically, there are additional requirements for the Intake Canal capture and release program. Citing the loss rate on flipper tags and the scarring that can result, the NMFS now requires all turtles captured in the Intake Canal be tagged with a passive integrated transponder (PIT). Those turtles not exhibiting flipper scarring and damage shall also be flipper tagged so that data can continue to be collected on the loss rates. Additionally, FPL biologists must notify the Florida Sea Turtle Stranding and Salvage Network staff of any sick or injured turtles within 30 minutes of discovery so that the turtles can receive proper attention. The NMFS again stipulated that if the Incidental Take Statement requirements are exceeded, reinitiation of Section 7 Consultation is required.

An extensive program is in place at St. Lucie Units 1 & 2 to mitigate the effects on sea turtles that enter the Intake Canal. This program includes recovery of turtles from the Intake Canal and release to the ocean, beach-nest monitoring, beach-stranding monitoring, and compliance with facility lighting restrictions to protect turtles. The Canal-monitoring program has evolved over the years, and currently is based on the protection afforded by barrier nets upstream (east) of the State Road A1A bridge, at the State Road A1A bridge, and downstream of the State Road A1A bridge (see Figure 2.1-3). This system of barriers restricts turtles to the eastern end of the Canal where capture efficiency is greatest and residency time is reduced. The Canal and barrier nets are monitored seven days a week, 8 to 12 hours per day, by onsite biologists. In addition to entanglement nets, which are used only in daylight hours and under continual surveillance, turtles are removed by dip nets and hand capture by snorkel and skin divers. Hand captures have had a significant impact in reducing residence time for turtles in the Canal. FPL has constantly evaluated and continuously improved its netting program to minimize trauma to turtles and to maximize capture efficiency. Any captured turtles are identified, measured, weighed, tagged, and

examined for health condition (Ref. 4.6-1, page 5). Healthy turtles are released to the ocean the day of capture. Sick or injured turtles are sent to rehabilitation facilities determined by the FWCC. Any dead turtles are processed similarly and, if in fresh condition, necropsied. Additional mitigation carried out by FPL includes performance of sea turtle nesting surveys, participation in the Sea Turtle Stranding and Salvage Network, and sponsorship of educational public sea turtle walks. FPL has also created a vegetative light screen, and uses shielded security lighting to prevent direct lighting of the beach. This was done to avoid disorientation of turtle hatchlings, or discouragement of females from nesting near the St. Lucie Units 1 & 2 site. FPL also participates in a 24-hour on-call (beach) stranding monitoring program (Ref. 4.6-4, Sections 6.2, 6.3, 6.4, and 7.2.3).

In summarizing the sea turtle issue at St. Lucie Units 1 & 2, the NMFS (Ref. 4.6-3) concluded that the increase in the number of turtles entering the Intake Canal over the operating history of the plant was most likely due to an increase in turtle abundance in the area. The agency acknowledged that protective measures have been refined and enhanced over the years. Improvements to the Canal capture program have included improvements to the barrier net and capture techniques, and leaving the nets in the water for longer time intervals. The new turtle barrier net, installed in 1996, greatly restricts the movement of turtles within the Intake Canal and so facilitates their capture and removal. Since 1996, mortality rates have been less than 1 percent for loggerhead and green sea turtles (Ref. 4.6-6).

FPL has initiated contacts with the FWS, the NMFS, and the FWCC regarding St. Lucie Units 1 & 2 license renewal. Copies of the contact letters are provided in Appendix C. Based on the FPL analysis, license renewal impacts to threatened, endangered, or other special-status species (Issue 49) would be SMALL, and further mitigation would not be warranted.

4.7 AIR QUALITY DURING REFURBISHMENT (NON-ATTAINMENT OR MAINTENANCE AREAS)

NRC

"If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended." 10 CFR 51.53(c)(3)(ii)(F)

"Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 50

The NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern, and a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status of each site and the number of workers expected to be employed during the outage (Ref. 4.2-1, Section 3.3). Information needed would include: (1) the attainment status of the plant-site area; and (2) number of additional vehicles as a result of refurbishment activities.

St. Lucie Units 1 & 2 are not located in or near a non-attainment or maintenance area. Additionally, detailed analysis is not required for this issue because, as discussed in Section 3.2, FPL has no plans for major refurbishment at St. Lucie Units 1 & 2 in association with license renewal.

4.8 ELECTRIC SHOCK FROM TRANSMISSION-LINE-INDUCED CURRENTS

NRC

"If the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electrical Safety Code for preventing electric shock from induced currents, an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines must be provided." 10 CFR 51.53 (c)(3)(ii)(H)

"Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site." 10 CFR Part 51, Subpart A, Appendix B, and Table B-1, Issue 59

The NRC made the impact of electric shock from transmission lines a Category 2 issue because without a review of each plant's transmission line conformance with the National Electrical Safety Code® (NESC®) criteria, the NRC could not determine the significance of the electrical shock potential. The regulation at 10 CFR 51.53(c)(3)(ii)(H) does not define the phrase "transmission line," but in the GEIS, the NRC indicates that transmission lines use voltages of about 115/138 kilovolts (kV) and higher, and that, in contrast, distribution lines use voltages below the 115/138 kV level (Ref. 4.2-1, Sections 2.2.7 and 4.5.1). The GEIS also specifies that the transmission line of concern is located between the plant switchyard and the intertie to the transmission system. Information to be ascertained includes: (1) change in line use and voltage since last analysis; (2) conformance with NESC® (1981) standards; and the potential change in land use along the transmission lines since the initial National Environmental Policy Act (NEPA) review.

The NESC® specifies minimum vertical clearances to the ground for electric lines. For electric lines operating at voltages exceeding 98 kV alternating current (AC) to ground (Ref. 4.8-1), the clearance provided must limit the steady-state current[1] due to electrostatic effects to 5 milliamperes (mA) if the largest anticipated vehicle were short-circuited to ground. For this determination, the lines should be evaluated assuming final unloaded conductor sag at 120°F. The Electric Power Research Institute (EPRI) has published a guide (Ref. 4.8-2) and has developed a computer program named ENVIRO (Ref. 4.8-3), which together are used to calculate the steady-state short-circuit current that may exist beneath transmission lines. The calculation is a two-step process in which the analyst first calculates the electric field strength profile under the transmission line at the location(s) of minimum wire clearance. The second step is to utilize the calculated electric field strength profile to calculate the steady-state short-circuit current value.

The St. Lucie to Midway Substation 230 kV transmission lines #1, #2, and #3 were installed in 1973, before the NESC® established a steady-state current limit. For this reason, an analysis was performed to evaluate the lines' adherence to the NESC® present steady-state limit. The largest vehicle that is anticipated under the St. Lucie lines is a 65-foot long

[1] The NESC® and the GEIS use the phrase "steady-state current," whereas 10 CFR 51.53(c)(3)(ii)(H) uses the phrase "induced current." The phrases have the same meaning here.

tractor-trailer parked along a public roadway. The minimum design clearance above any public roadway along the transmission line corridor occurs at I-95 where the conductor is 28 feet above ground at the NESC®-specified temperature of 120°F. The wire clearances at this location, together with line characteristics such as voltage, current, and conductor position, were entered into the EPRI ENVIRO computer program. The results yielded by this program include the electric field strengths at 1m above ground and at 10-foot intervals under the lines. The maximum calculated electric field strength at this roadway crossing is 2.79 kV/m. Centering a 65-foot object under the line at the location of the maximum electric field and perpendicular to the alignment of the transmission lines would result in the object being located in fields between 2.79 kV/m and 1.40 kV/m. The maximum average electric field strength along the 65-foot long object is 2.09 kV/m.

Using the maximum average electric field strength and the EPRI reference book methodology (Ref. 4.8-2, Section 8.8), calculations were made to determine the steady-state current for a tractor trailer 65 feet long, 8 feet wide, and 13.5 feet high (which is the largest regularly allowed vehicle on Florida roads). The resultant value, 1.9 mA, is less than the 5-mA limit imposed by the NESC®.

An additional analysis was performed to evaluate the electric shock concern if a vehicle were parked anywhere under the lines at a point where the transmission conductor was as low as allowable under the NESC® (Ref. 4.8-4). For this analysis, FPL used a clearance to ground of 22 feet for the 230 kV lines. Using the same methods as detailed above, FPL calculated a maximum electric field of 3.3 kV/m. The associated average electric field for a 65-foot object centered under the line at the location of the maximum electric field and perpendicular to the alignment of the lines at this location is 2.51 kV/m. Using this maximum average electric field strength, the EPRI calculation method for steady-state current results in a value of 2.3 mA, which is again less than the 5-mA limit imposed by the NESC®.

A final supplemental analysis was performed for a section of the transmission line corridor where the St. Lucie 230 kV transmission lines run parallel to a 500 kV circuit. These two lines share the corridor for about 1.5 miles prior to the transmission lines terminating at the Midway Substation. For this analysis, FPL calculated the maximum electric field strength to be 6.15 kV/m under the 500 kV line. While these field strengths are clearly associated with the 500 kV line and not the St. Lucie 230 kV lines located 188 feet away, the corridor contains both sets of lines. While it is, therefore, not needed, FPL included an analysis of this section for completeness. The maximum electric field strength under the 500 kV line was calculated to be 6.15 kV/m, with an average over a 65-foot span located perpendicular to the line of 4.95 kV/m. Using this maximum average electric field strength, the EPRI calculation method for steady-state currents results in a value of 4.5 mA, which is again less than the 5-mA limit imposed by the NESC®.

As described previously, the St. Lucie to Midway Substation 230 kV transmission lines #1, #2, and #3 adhere to the NESC®'s present steady-state current limit. Therefore, FPL concludes that the St. Lucie 230 kV transmission lines #1, #2, and #3 meet the NESC® recommendations for preventing electric shock from induced currents and further assessment of the impact of the proposed action on the potential shock hazard is not required. FPL adopts, by reference, the NRC's conclusion in the GEIS that the impact of electric shock (Issue 59) is of SMALL significance for such lines. Due to the small

significance of the issue, mitigation measures, such as the installation of warning signs at roadway crossings or increasing wire clearances, are not warranted.

4.9 HOUSING IMPACTS

NRC

The environmental report must contain " …An assessment of the impact of the proposed action on housing availability…" 10 CFR 51.53(c)(3)(ii)(I)

"Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 63

"…[S]mall impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs." (Ref. 4.2-1, Section 4.7.1.1)

The NRC made housing impacts a Category 2 issue because impact magnitude depends on local conditions that the NRC could not predict for all plants at the time of GEIS publication (Ref. 4.2-1, Section 3.7.2). Local conditions to be ascertained are: (1) population categorization as small, medium, or high; and (2) applicability of growth control measures.

Refurbishment activities and continued operations could result in housing impacts due to increased staffing. As described in Section 3.2, FPL does not plan to perform major refurbishment activities in association with license renewal. FPL concludes that there would be no refurbishment-related impacts to area housing and, therefore, no analysis is required. Accordingly, the following discussion focuses on impacts of continued operations on local housing availability.

As described in Section 2.5, the St. Lucie Units 1 & 2 site is located in a medium population area. Martin and St. Lucie counties, as noted in Section 2.8, are not subject to growth control measures that limit housing development. At 10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 63), the NRC concludes that impacts to housing are expected to be of small significance at plants located in "medium" population areas where growth control measures are not in effect. Therefore, FPL expects housing impacts to be small.

This conclusion is supported by the following site-specific housing analysis. The maximum impact to area housing is calculated using the following assumptions: (1) all direct and indirect jobs would be filled by in-migrating residents; (2) the residential distribution of new residents would be similar to current worker distribution; and (3) each new job created (direct and indirect) represents one housing unit. As described in Section 3.4, approximately 83 percent of the total number of St. Lucie Units 1 & 2 employees resides in Martin and St. Lucie counties. Therefore, the focus of the housing impact analysis is on these two counties. As described in Section 3.4, FPL's conservative estimate of 60 license renewal employees could generate the demand for 138 housing units (60 direct and 78 indirect jobs). If it is assumed that 83 percent of the 138 new workers would locate in the Martin- and St. Lucie-County areas, consistent with current employee trends, a need for 115 new housing units would be created. In an area with a population of over 319,000 and vacancy rates in excess of 15 percent, this would not create a discernible change in housing availability, change rental rates and housing values, or spur housing construction or

conversion. Given the magnitude of impact, which is SMALL, mitigative measures are not necessary.

4.10 PUBLIC UTILITIES: PUBLIC WATER SUPPLY AVAILABILITY

NRC

The environmental report must contain "…an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(l)

"An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 65

"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (Ref. 4.2-1, Section 3.7.4.5)

The NRC made public utility impacts a Category 2 issue because an increased problem with water availability may occur in conjunction with plant demand and plant-related population growth as a result of current water shortages in some areas (Ref. 4.2-1, Section 4.7.3.5). Local information needed would include: (1) a description of water shortages experienced in the area; and (2) an assessment of the public water supply system's available capacity.

The NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. As discussed in Section 3.2, FPL plans no major refurbishment in association with license renewal, so plant demand would not be affected by major refurbishment activities.

The impact to the local water supply systems resulting from plant-related population growth can be determined by calculating the amount of water that would be required by these individuals. The average American uses between 50 and 80 gallons per day for personal use (Ref. 4.10-1, page 2). As described in Section 3.4, FPL's conservative estimate of 60 license renewal employees could generate a total of 138 new jobs. This could result in a population increase of 339 in the area [138 jobs multiplied by 2.46 average number of persons per household in the State of Florida (Ref. 4.10-2)]. Using this consumption rate, the plant-related population increase would require approximately 17,000 to 27,000 additional gallons per day. This amount represents less than one percent of the current South Florida Water Management District allocation for either Martin or St. Lucie County. Therefore, the impacts resulting from plant-related population growth to the public water supply would be SMALL, requiring no increase in allocations and not warranting mitigation.

4.11 EDUCATION IMPACTS FROM REFURBISHMENT

NRC

The environmental report must contain, "An assessment of the impact of the proposed action on…public schools (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(I)

"Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 66

"…[S]mall impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts generally are associated with 4 to 8 percent increases in enrollment…and… if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service…. Large impacts are associated with project-related enrollment increases above 8 percent…." (Ref. 4.2-1, Section 3.7.4.1)

The NRC made impacts to education a Category 2 issue because site-specific and project-specific factors determine the significance of impacts (Ref. 4.2-1, Section 3.7.4.1). Local factors to be ascertained include: (1) project-related enrollment increases; and (2) status of the student/teacher ratio.

As described in Section 3.2, FPL does not plan to perform major refurbishment activities at St. Lucie Units 1 & 2 in association with license renewal. FPL concludes that there would be no refurbishment-related impacts to education and, therefore, no analysis is required.

4.12 OFFSITE LAND USE

4.12.1 REFURBISHMENT

NRC

The environmental report must contain, "An assessment of the impact of the proposed action on…land-use… (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(l)

"Impacts may be of moderate significance at plants in low population areas." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 68

"…if plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile…and at least one urban area with a population of 100,000 or more within…50 miles…." (Ref. 4.2-1, Section 3.7.5)

The NRC made impacts to offsite land use as a result of refurbishment activities a Category 2 issue because land-use changes could be considered beneficial by some community members and adverse by others. Local conditions to be ascertained include: (1) plant-related population growth; (2) patterns of residential and commercial development; and (3) proximity to an urban area of at least 100,000.

As described in Section 3.2, FPL does not plan to perform major refurbishment activities at St. Lucie Units 1 & 2 in association with license renewal. FPL concludes that there would be no refurbishment-related impacts to offsite land use and, therefore, no analysis is required.

4.12.2 OFFSITE LAND USE: LICENSE RENEWAL TERM

NRC

The environmental report must contain, "An assessment of the impact of the proposed action on …land-use…within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(l)

"Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 69

"…if plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…" (Ref. 4.2-1, Section 3.7.5)

"If the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development." (Ref. 4.2-1, Section 4.7.4.1)

The NRC made impacts to offsite land use during the license renewal term a Category 2 issue because land-use changes may be perceived to be beneficial by some community members and adverse by others. Therefore, the NRC could not assess the potential significance of site-specific offsite land-use impacts (Ref. 4.2-1, Section 4.7.4.1). Site-specific factors to consider in an assessment of new tax-driven land-use impacts include: (1) the size of plant-related population growth compared to the area's total population; (2) the size of the plant's tax payments relative to the community's total revenue; (3) the nature of the community's existing land-use pattern; and (4) the extent to which the community already has public services in place to support and guide development.

In the GEIS, the NRC presents an analysis of offsite land use for the renewal term that is characterized by two components, population-driven and tax-driven impacts (Ref. 4.2-1, Section 4.7.4.1). Based on the GEIS case study analysis, the NRC concludes that all new population-driven land-use changes during the license renewal term at all nuclear power plants would be small. [Population growth caused by license renewal would represent a much smaller "percentage of the local area's" total population than the percentage represented by operations-related growth (Ref. 4.2-1, Section 4.7.4.2)].

As described in Section 3.2, no major refurbishment or construction activities will be associated with St. Lucie Units 1 & 2 license renewal. FPL, therefore, does not anticipate any new tax payments that would influence offsite land use. As shown in Table 2.7-1 of Section 2.7, FPL annual property tax payments to St. Lucie County for St. Lucie Units 1 & 2 represented approximately 10.8 percent of the county's total annual property tax revenues from 1990 through 2000, and for the years 1997-2000 approximately 8.2 percent of St. Lucie County's annual total revenues. The NRC has determined that the significance of tax payments is small if payments are less than 10 percent of a taxing jurisdiction's total revenues (Ref. 4.2-1, Section 4.7.2.1). The NRC has further determined that if a plant's tax payments are projected to be small, license renewal tax-driven land-use changes would most likely be small with very little new development and minimal changes to the area's land-use patterns (Ref. 4.2-1, Section 4.7.4.1). FPL concurs with the NRC determination and concludes that tax-driven land-use impacts would be SMALL and mitigative measures would not be warranted.

4.13 TRANSPORTATION

NRC

The environmental report must contain an assessment of "…the impact of the proposed project on local transportation during periods of license renewal refurbishment activities…." 10 CFR 51.53(c)(3)(ii)(J)

"Transportation impacts are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 70

Level of Service (LOS) "A and B are associated with small impacts because the operation of individual users is not substantially affected by the presence of other users." LOS A is characterized by "free flow at the traffic stream; users are unaffected by the presence of others." LOS B is characterized by "stable flow in which the freedom to maneuver is slightly diminished." (Ref. 4.2-1, Section 3.7.4.2)

The NRC made impacts to transportation a Category 2 issue because impact significance is determined primarily by road conditions existing at the time of the project, which the NRC could not forecast for all plants (Ref. 4.2-1, Section 3.7.4.2). Local road conditions to be ascertained are: (1) level of service conditions; and (2) incremental increase in traffic associated with refurbishment activities and license renewal staff.

As described in Section 3.2, FPL does not plan to perform major refurbishment activities at St. Lucie Units 1 & 2 in association with license renewal. FPL concludes that there would be no refurbishment-related impacts to local transportation and, therefore, no analysis is required.

As noted in Section 2.9.2, access to St. Lucie Units 1 & 2 is via State Road A1A, which carries a level-of-service (LOS) designation of 'A' in the vicinity of the site. North and south of the site, State Road A1A carries an LOS designation of 'B.' In GEIS Section 3.7.4.2 (Ref. 4.2-1), the NRC concluded that impacts to roads with LOS designations of 'A' or 'B' are small.

The current workforce associated with St. Lucie Units 1 & 2 is approximately 930 employees (FPL and contractors). Each refueling outage, which lasts about 30 days, adds 575-870 workers. Each Unit has a refueling outage once every 18 months. The FPL conservative projection of 60 additional employees associated with "operating over the license renewal term" for St. Lucie Units 1 & 2 represents approximately a 6 percent increase in the current number of employees and an even smaller percentage of the employees present on site during periodic refueling. Given these employment projections and LOS designations of 'A' and 'B' for the access road to St. Lucie Units 1 & 2, it is consistent with the GEIS to conclude that impacts to transportation would be SMALL and mitigative measures would not be necessary.

4.14 HISTORIC AND ARCHAEOLOGICAL RESOURCES

NRC

The environmental report must contain an assessment of "…whether any historic or archaeological properties will be affected by the proposed project." 10 CFR 51.53(c)(3)(ii)(K)

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71

"Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Office (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about the character; and (3) if the conditions associated with moderate impacts do not occur." (Ref. 4.2-1, Section 3.7.7)

The NRC made impacts to historic and archaeological resources a Category 2 issue because determinations of impacts to historic and archaeological resources are site-specific in nature, and the National Historic Preservation Act mandates that determination of impacts must be made through consultation with the State Historic Preservation Officer (SHPO) (Ref. 4.2-1, Section 4.7.7.3).

As described in Section 3.2, FPL does not plan to perform land-disturbing refurbishment activities at St. Lucie Units 1 & 2 in association with license renewal. Therefore, FPL concludes that there would be no refurbishment-related impacts to historic and archaeological resources and, therefore, no analysis is required.

As described in Section 2.10, no known archaeological or historic sites of significance were threatened during construction of St. Lucie Units 1 & 2 in the 1970s and 1980s. The records of the SHPO depict, on the north end of the site in the vicinity of the property boundary, two archaeological sites consisting of Malibar Indian middens, mounds, and burial mounds. On the south end of the site, in the vicinity of the property boundary, is a swamp wreck dating from the 19th or 20th century. These areas are wetlands and mangroves and, therefore, would not be likely candidates for land-disturbing activities during the license renewal term.

Transmission line rights-of-way have been categorized and inventoried. No known archaeological or historic sites of significance have been identified on the rights-of-way. Therefore, continued use of transmission lines and rights-of-way are projected to cause little or no impact.

FPL has initiated discussions with the SHPO regarding St. Lucie Units 1 & 2 license renewal, and the SHPO has determined that it is unlikely that historical properties would be affected by this undertaking. Copies of the correspondence with the SHPO are provided in Appendix D.

Appropriate care will be taken to protect archaeological and historic resources should any land-clearing or ground-disturbing activities be undertaken in previously undisturbed areas during the period of continued operations. FPL concludes that continued operation would

have no adverse impacts to historic resources; hence, there would be no impacts to mitigate. Because the definition of “small” includes impacts that are not detectable, the appropriate characterization of the impact on historic and archaeological resources is SMALL.

4.15 SEVERE ACCIDENT MITIGATION ALTERNATIVES

NRC

The environmental report must contain a consideration of alternatives to mitigating severe accidents "[i]f the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environmental assessment…" 10 CFR 51.53(c)(3)(ii)(L)

"The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 76

The term "accident" refers to any unintentional event (i.e., outside the normal or expected plant operational envelope) that results in the release or a potential for release of radioactive material to the environment. Generally, the NRC categorizes accidents as "design basis" or "severe." Design basis accidents are those for which the risk is great enough that an applicant is required to design and construct a plant to prevent unacceptable accident consequences. Severe accidents are those considered too unlikely to warrant design controls.

Historically, the NRC has not included in its Environmental Impact Statements (EISs) or environmental assessments any analysis of alternative ways to mitigate the environmental impacts of severe accidents. A 1989 court decision ruled that, in the absence of an NRC finding that severe accidents are remote and speculative, severe accident mitigation alternatives (SAMAs) should be considered in the NEPA analysis [*Limerick Ecology Action v. NRC*, 869 F.d 719 (3rd Cir. 1989)]. For most plants, including St. Lucie Units 1 & 2, license renewal is the first licensing action that would necessitate consideration of SAMAs.

The NRC concludes in its generic license renewal rulemaking that the unmitigated environmental impacts from severe accidents meet the Category 1 criteria, but the NRC has made consideration of mitigation alternatives a Category 2 issue because ongoing regulatory programs related to mitigation [i.e., Individual Plant Examination (IPE) and Accident Management] are not complete for all plants. Since these programs have identified plant programmatic and procedural improvements (and, in a few cases, minor modifications) as cost-effective in reducing severe accident and risk consequences, the NRC thought it premature to draw a generic conclusion as to whether severe accident mitigation would be required for license renewal. Site-specific information to be presented in the environmental report includes: (1) potential SAMAs; (2) benefits and costs of implementing potential SAMAs; and (3) sensitivity of the analysis to changes to key underlying assumptions.

4.15.1 METHODOLOGY OVERVIEW

The methodology to perform the SAMA cost-benefit analysis is based primarily on the handbook used by the NRC to analyze benefits and costs of its regulatory activities, NUREG/BR-0184 (Ref. 4.15-1), subject to consideration of plant-specific SAMAs identified by FPL.

EISs and environmental reports are prepared using a sliding scale in which impacts of greater concern and mitigating measures of greater potential value receive more detailed analysis than do impacts of less concern and mitigating measures of less potential value. Accordingly, FPL uses less detailed feasibility investigative and cost estimation techniques for SAMAs having disproportionately high costs and low benefits and more detailed evaluations for the most viable candidates. The reduction in the total potential costs of severe accidents resulting from the implementation of a SAMA constitutes the benefit associated with that SAMA. This benefit is compared with the estimated cost of the implementation of the SAMA to determine if it is cost beneficial to implement that SAMA.

The following is a brief outline of the approach taken in the SAMA analysis:

- Establish the Base Case – The current Probabilistic Risk Assessment (PRA) at the time of the evaluation was considered the base case for comparison. The methodology of NUREG/BR-0184 was followed to evaluate severe accident impacts:
  - Offsite exposure – Monetary value of consequences (dose) to offsite population:

    Use the St. Lucie Units 1 & 2 Probabilistic Safety Assessment (PSA) model, which uses PRA techniques, to determine total accident frequency (core damage frequency and containment release frequency); the Melcor Accident Consequence Code System (MACCS) to convert release input to public dose; and the NUREG/BR-0184 methodology to convert dose to present-worth dollars (based on valuation of $2,000 per person-rem and a present-worth discount factor of 7 percent).
  - Offsite economic costs – Monetary value of damage to offsite property:

    Use the PSA model to determine total accident frequency (core damage frequency and containment release frequency); the MACCS to convert release input to offsite property damage; and the NUREG/BR-0184 methodology to convert offsite property damage estimate to present-worth dollars.
  - Onsite exposure costs – Monetary value of dose to workers:

    Use NUREG/BR-0184 best estimate occupational dose values for immediate and long-term dose, then apply the NUREG/BR-0184 methodology to convert dose to present worth dollars (based on valuation of $2,000 per person-rem and a present-worth discount factor of 7 percent).
  - Onsite economic costs – Monetary value of damage to onsite property:

    Use NUREG/BR-0184 best estimate cleanup and decontamination costs, including replacement power costs; then apply the NUREG/BR-0184 methodology to convert onsite property damage estimate to present-worth dollars.
- SAMA Identification – Identify potential SAMAs from the following sources:
  - Severe Accident Mitigation Design Alternative (SAMDA) analyses submitted in support of original licensing activities for other operating nuclear power plants and advanced light water reactor plants; SAMA analyses submitted in support of license renewal activities for other nuclear power plants; NRC and industry documentation discussing potential plant improvements; and documented insights provided by plant staff.

- Preliminary Screening – Eliminate obviously non-viable candidates, based upon:
  - SAMA improvements that modify features not applicable to St. Lucie Units 1 & 2; or
  - SAMA improvements already implemented at the plant.
- Final Disposition of Remaining SAMAs – Eliminate candidates based on cost-benefit:
  - Screening based on excessive cost – Eliminate candidates based upon whether the cost of implementing the SAMA would greatly exceed the maximum benefit for base case evaluation.
  - Benefit/cost evaluation – Evaluate benefits and costs of implementing the SAMA:
    - Benefit calculation – Estimate benefits of implementing each SAMA individually; use updated Level 2 model to determine revised core damage frequency (CDF) and release fractions.
    - SAMA impacts – Calculate impacts (i.e., onsite/offsite dose and damages) by manipulating the plant model to simulate revised plant risk following implementation of each individual SAMA.
    - SAMA benefits – Calculate benefits for each SAMA in terms of averted consequences. Averted consequences are the arithmetic differences between the calculated impact for the base case and the revised impact following implementation of each individual SAMA.
    - Cost estimate – Estimate cost of implementing each evaluated SAMA. The detail of the cost estimate must be commensurate with the benefit; if a benefit is very low, it is not necessary to perform a detailed cost estimate to determine that the SAMA is not cost beneficial—engineering judgment can be applied.
- Sensitivity Analysis – Determine the effect that changing the discount rate would have on the cost-benefit calculation.
- Conclusions – Identify SAMAs that are cost beneficial, if any, and describe implementation plans or the basis for not implementing.

The FPL SAMA analysis for St. Lucie Units 1 & 2 is presented in the following sections. These sections provide a detailed discussion of the process presented above.

4.15.2 ESTABLISHING THE BASE CASE

The purpose of establishing the base case is to provide the baseline for determining the risk reductions (benefits) that would be attributable to the implementation of potential SAMAs. The primary source of data relating to the base case is the PSA model. Severe accident risk is calculated through use of the St. Lucie Units 1 & 2 PSA model and the MACCS2 Level 3 model. The model is the latest version of the St. Lucie Units 1 & 2 risk model and uses PRA techniques to:

- Develop an understanding of severe accident behavior;
- Understand the most likely severe accident consequences;

- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and
- Evaluate hardware and procedure changes to assess the overall probabilities of core damage and fission product releases.

The PSA model includes internal events (e.g., loss of feedwater event, loss-of-coolant accident) and is far more advanced than the IPE submitted by FPL to the NRC December 1993 (Ref. 4.15-2). Due to periodic refinement, the PSA model is considered a "living" plant risk model. The PSA model is periodically updated as a result of:

- Equipment Performance – As data collection progresses, estimated failure rates and system unavailability change.
- Plant Configuration Changes – A time lag exists between changes to the plant and incorporation of those changes into the PSA model.
- Modeling Changes – The PSA model is continually refined to incorporate the latest state of knowledge. For example, if a new design calculation indicates that the heat-up rate of various plant areas is not as significant as initially estimated, then this information is incorporated into the model.

The PSA model describes the results of the first two levels of the PSA for the plant. These levels are defined as follows: Level 1 – determines core damage frequencies based on system analyses and human-factor evaluations; and Level 2 – determines the physical and chemical phenomena that affect the performance of the containment and other radiological release mitigation features to quantify accident behavior and release of fission products to the environment. The scope of plant challenges considered in the PSA model includes only internal events (e.g., turbine trips, loss of main feedwater, internal floods). Appendix E.1 provides information regarding the St. Lucie Units 1 & 2 PSA models and the modeling approaches used in this SAMA analysis.

Using the results of these analyses, the next step is to perform a Level 3 PRA analysis, which calculates the hypothetical impacts of severe accidents on the surrounding environment and members of the public. The MACCS2 computer code is used for determining the offsite impacts for the Level 3 analysis, whereas the magnitude of the onsite impacts (in terms of cleanup and decontamination costs and occupational dose) are based on information provided in NUREG/BR-0184 (Ref. 4.15-1). The principal phenomena analyzed are atmospheric transport of radionuclides; mitigating actions (i.e., evacuation, condemnation of contaminated crops and milk) based on dose projection; dose accumulation by a number of pathways, including food and water ingestion; and economic costs. Input for the Level 3 analysis includes the reactor core radionuclide inventory, source terms from the IPE (as applied to the PSA model), site meteorological data, projected population distribution (within a 50-mile radius) for the year 2025, emergency response evacuation modeling, and economic data. Appendix E.2 describes the MACCS input data, assumptions, and results.

4.15.2.1 OFFSITE EXPOSURE COSTS

The Level 3 base case analysis shows an annual offsite exposure risk of 15.31 person-rem. This calculated value is converted to a monetary equivalent (dollars) via application of the

NRC's conversion factor of $2,000 per person-rem. This monetary equivalent is then discounted to present value using the NRC standard formula (Ref. 4.15-1):

$W_{pha} = C \times Z_{pha}$

where:

W_{pha} = monetary value of public health risk after discounting ($)

C = $[1 - \exp(-rt_f)]/r$

where:

t_f = years remaining until end of facility life = 20 years

r = real discount rate (as fraction) = 0.07

Z_{pha} = monetary value of public health (accident) risk per year before discounting ($/year)

Using a 20-year period for remaining plant life and a 7 percent discount rate results in a value of approximately 10.76 for C. Therefore, calculating the discounted monetary equivalent of public health risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value, approximately 10.76. The resulting monetary equivalent is $329,505.

4.15.2.2 OFFSITE ECONOMIC COSTS

The Level 3 analysis shows that the offsite property loss factor multiplied by accident frequency yields an annual offsite economic risk of $42,542. Calculated values of offsite economic costs caused by severe accidents are also discounted to present value. Discounting is performed in the same manner as for the public health risk discussed above. The resulting monetary equivalent is $457,875.

4.15.2.3 ONSITE EXPOSURE COSTS

Values for occupational exposure associated with severe accidents are not derived from the PSA model, but, instead, are obtained from information published by the NRC (Ref. 4.15-1). Occupational exposure consists of "immediate dose" and "long-term dose." The best estimate value provided by the NRC for immediate occupational dose is 3,300 person-rem and for long-term occupational dose is 20,000 person-rem (over a ten-year cleanup period). The following equations are applied to these values to calculate monetary equivalents.

4.15.2.3.1 IMMEDIATE DOSE

For a currently operating facility, the NRC, in NUREG/BR-0184, recommends calculating the immediate dose present value with the following equation:

Equation (1):

$$W_{IO} = \left(F_S D_{IO_S} - F_A D_{IO_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting ($)
R = monetary equivalent of unit dose ($/person-rem)
F = accident frequency (events/yr)
D_{IO} = immediate occupational dose (person-rem/event)
s = subscript denoting status quo (current conditions)
A = subscript denoting after implementation of proposed action
r = real discount rate
t_f = years remaining until end of facility life

The values used in the analysis are:

R = $2,000/person-rem
r = 0.07
D_{IO} = 3,300 person-rem/accident (best estimate)
t_f = 20 years

Assuming F_A is zero for the base case, the monetary value of the immediate dose associated with the plant accident risk is:

$$W_{IO} = \left(F_S D_{IO_S}\right) R \frac{1 - e^{-rt_f}}{r}$$

$$= 3300 * F * \$2000 * \frac{1 - e^{-.07*20}}{.07}$$

The CDF for the base case is 2.99 X 10^{-5}/year; therefore,

$$W_{IO} = \$2,125$$

4.15.2.3.2 LONG-TERM DOSE

For a currently operating facility, the NRC, in NUREG/BR-0184, recommends calculating the long-term dose present value with the following equation:

Equation (2):

$$W_{LTO} = \left(F_S D_{LTO_S} - F_A D_{LTO_A}\right) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm} \qquad (2)$$

where:

W_{LTO} = monetary value of accident risk-avoided long-term doses, after discounting, ($)
R = monetary equivalent of unit dose ($/person-rem)
F = accident frequency (events/yr)
D_{LTO} = long-term occupational dose (person-rem/event)
m = years over which long-term doses accrue
s = subscript denoting status quo (current conditions)
A = subscript denoting after implementation of proposed action
r = real discount rate
t_f = years remaining until end of facility life

The values used in the analysis are:

R = \$2,000/person-rem
r = 0.07
D_{LTO} = 20,000 person-rem/accident (best estimate)
m = "as long as 10 years"
t_f = 20 years

Assuming F_A is zero for the base case, the monetary value of the long-term dose associated with the plant accident risk is:

$$W_{LTO} = \left(F_S D_{LTO_S}\right) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm}$$

$$= \left(F_S \times 20000\right) \$2000 * \frac{1 - e^{-.07*20}}{.07} * \frac{1 - e^{-.07*10}}{.07*10}$$

The CDF for the base case is 2.99 X 10^{-5}/year; therefore,

$$W_{LTO} = \$9,262$$

4.15.2.3.3 TOTAL OCCUPATIONAL EXPOSURES

Combining equations (1) and (2) above and using the above numerical values, the long-term accident related onsite (occupational) bounding dose (W_O) is equivalent to:

$$W_O = W_{IO} + W_{LTO} = \$2,125 + \$9,262 = \$11,387$$

4.15.2.4 ONSITE ECONOMIC COSTS[2]

Onsite economic costs are considered to include costs associated with cleanup/ decontamination, replacement power, and repair/refurbishment. Each of these factors is discussed in the following sections.

4.15.2.4.1 CLEANUP/DECONTAMINATION

The total cost of cleanup/decontamination of a power reactor facility subsequent to a severe accident is estimated by the NRC, in NUREG/BR-0184, at \$1.5x10^9; this same value is adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1 - e^{-rm}}{r}\right)$$

where:

[2] Calculated values presented in this and subsequent subsections were calculated using a spreadsheet and may differ slightly from values calculated from the numbers provided; this is due to rounding performed on the numbers presented in this document.

PV_{CD} = present value of the cost of cleanup/decontamination ($)
C_{CD} = total cost of the cleanup/decontamination effort, $1.5 x 10^9
m = cleanup period (10 years)
r = discount rate (7 percent)

Therefore:

$$PV_{CD} = \left(\frac{\$1.5E+9}{10}\right)\left(\frac{1-e^{-.07*10}}{.07}\right)$$

$$PV_{CD} = \$1.079E+9$$

This cost is integrated over the license renewal period as follows:

$$U_{CD} = PV_{CD}\frac{1-e^{-rt_f}}{r}$$

where:

U_{CD} = net present value of cleanup/decontamination over the life of the plant ($)
t_f = years remaining until end of facility life (20 years)

Based upon the values previously assumed:

$$U_{CD} = \$1.161E+10$$

4.15.2.4.2 REPLACEMENT POWER COSTS

Replacement power costs, U_{RP}, are an additional contributor to onsite costs. These are calculated in accordance with NUREG/BR-0184, Section 5.6.7.2.[3] Since replacement power will be needed for that time period following a severe accident and for the remainder of the expected generating plant life, long-term power replacement calculations have been used. The calculations are based on the 910 megawatts (electric) [MW(e)] reference plant, and for conservatism, the values are not scaled down for the 800 MW(e) output of St. Lucie Units 1 & 2. The present value of replacement power is calculated as follows:

$$PV_{RP} = \left(\frac{\$1.2E+8}{r}\right)\left(1-e^{-rt_f}\right)^2$$

where:

PV_{RP} = present value of the cost of replacement power for a single event ($)
t_f = years remaining until end of facility life
r = discount rate (as fraction)

[3]The section number for Section 5.6.7.2 apparently contains a typographical error. This section is a subsection of 5.7.6 and follows 5.7.6.1. However, the section number as it appears in the NUREG is cited in this document.

The $\$1.2 \times 10^8$ value has no intrinsic meaning but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event (Ref. 4.15-1). This equation was developed per NUREG/BR-0184 for discount rates between 5 percent and 10 percent only.

For discount rates between 1 percent and 5 percent, NUREG/BR-0184 indicates that a linear interpolation is appropriate between present values of $\$1.2 \times 10^9$ at 5 percent and $\$1.6 \times 10^9$ at 1 percent (Ref. 4.15-1). So for discount rates in this range, the following equation was used to perform this linear interpolation:

$$PV_{RP} = (\$1.6E+9) - \left(\frac{[(\$1.6E+9) - (\$1.2E+9)]}{[5\% - 1\%]} * [\, r_s - 1\%] \right)$$

where:

r_s = discount rate (small), between 1 percent and 5 percent

To account for the entire lifetime of the facility, U_{RP} was then calculated from PV_{RP}, as follows:

$$U_{RP} = \frac{PV_{RP}}{r}\left(1 - e^{-rt_f}\right)^2$$

where:

U_{RP} = present value of the cost of replacement power over the life of the facility ($)

As noted for PV_{RP}, the equation for U_{RP} is only applicable in the range of discount rates from 5 percent to 10 percent. NUREG/BR-0184 states that for lower discount rates, linear interpolations for U_{RP} are recommended between $\$1.9 \times 10^{10}$ at 1 percent and $\$1.2 \times 10^{10}$ at 5 percent. Therefore, for the sensitivity analysis, which considers a 3 percent discount rate, the following equation was used to perform this linear interpolation:

$$U_{RP} = (\$1.9E+10) - \left(\frac{[(\$1.9E+10) - (\$1.2E+10)]}{[5\% - 1\%]} * [\, r_s - 1\%] \right)$$

where:

r_s = Discount rate (small), between 1 percent and 5 percent

Based upon the values previously assumed,

$$U_{RP} = \$7.89E+9$$

4.15.2.4.3 REPAIR AND REFURBISHMENT

FPL has no plans for major repair/refurbishment following a severe accident; therefore, there is no contribution to onsite economic costs from this source.

4.15.2.4.4 TOTAL ONSITE ECONOMIC COSTS

The total onsite economic cost is the sum of the cleanup/decontamination cost (U_{CD}) and the replacement power cost (U_{RP}) multiplied by the CDF (2.99 x 10^{-5}/year). Therefore the total onsite economic cost is $583,332.

4.15.2.5 MAXIMUM ATTAINABLE BENEFIT

The present dollar value equivalent for severe accidents at St. Lucie Units 1 & 2 is the sum of the offsite exposure costs, offsite economic costs, onsite exposure costs, and onsite economic costs. Table 4.15-1 lists each of these values for the base case as calculated in the previous sections. As shown, the monetized value of severe accident risk is approximately $1,382,099.

The maximum theoretical benefit is based upon the elimination of all plant risk and equates to the base case severe accident risk described above. Therefore, the maximum attainable benefit (MAB) is $1,382,099.

TABLE 4.15-1
ESTIMATED PRESENT DOLLAR VALUE EQUIVALENT FOR SEVERE ACCIDENT RISK AT ST. LUCIE UNITS 1 & 2

Parameter	Present Dollar Value
Offsite population dose	$329,505
Offsite economic costs	$457,875
Onsite dose	$11,387
Onsite economic costs	$583,332
Total	$1,382,099

4.15.3 SAMA IDENTIFICATION AND SCREENING

The NRC and the nuclear power industry have documented analyses of methods to mitigate severe accident impacts for existing and new plant designs and for in-system evaluations. Appendix E.3 lists documents from which FPL has gathered descriptions of candidate SAMAs. In addition, FPL considered insights into possible plant-specific improvements gained through the preparation of the IPE and Individual Plant Examination of External Events (IPEEE) (Ref. 4.15-2; Ref. 4.15-3). Finally, the top 100 cutsets of the Level 1 PSA update were examined to identify the important contributors to plant risk (both plant equipment and operator actions) and to ensure that the important contributors were addressed by one or more SAMAs. Since the IPEEE was based on a screening type of approach, no cutsets were available for a similar type of assessment. Shutdown related improvements are not addressed explicitly. However, SAMAs that affect structures, systems, and components that may enhance mitigation functions during both at-power and shutdown conditions are addressed.

Table E.3-1, in Appendix E.3, lists 169 candidate SAMAs that FPL identified for analysis and identifies the sources of the information. The first step in the analysis is to eliminate non-viable SAMAs through preliminary screening.

4.15.3.1 PRELIMINARY SCREENING

The purpose of the preliminary SAMA screening is to eliminate from further consideration enhancements that are obviously not viable for implementation at St. Lucie Units 1 & 2. Screening criteria include:

- Not applicable to the plant, and
- Met the intent or already implemented at the plant.

Table E.3-1 of Appendix E.3 provides a brief discussion of each candidate SAMA and its disposition, whether eliminated from further consideration as not applicable or as already implemented, or designated for further analysis. Based on this preliminary screening, 119 candidate SAMAs were eliminated, and 50 of the original SAMAs were designated for further analysis.

4.15.3.2 FINAL SCREENING/COST-BENEFIT ANALYSIS

FPL estimates the costs of implementing each SAMA through the application of engineering judgment, estimates from other licensee submittals, and site-specific cost estimates (if necessary). The evaluation is on a single-unit implementation basis. The cost estimates do not include the cost of replacement power during extended outages required to implement the modifications, nor do they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past are presented in terms of dollar values at the time of implementation (or estimation) and are not adjusted to present-day dollars.

In the performance of the cost-benefit analyses two basic values were assumed, the minimum cost of a procedure change and the minimum cost of a hardware change. The minimum cost associated with implementation of a procedure change was assumed to be $30,000, and the minimum cost associated with development and implementation of an integrated hardware modification package (including post-implementation costs, e.g., training) was assumed to be $70,000.

The benefits resulting from the bounding estimates presented in the benefit analysis are, in general, rather low. In most cases the benefits are so low that it is obvious that the implementation costs would exceed the benefit, even without a detailed cost estimate. In many cases, plant staff judgment is applied in assessing whether the benefit approaches the expected implementation costs. A detailed cost estimate is only applied to those situations in which the benefit is significant and application of judgment might be questioned.

Screening based on level of benefit achieved is carried out in two steps. The first step involves using the maximum benefit that could possibly be provided by any one SAMA or combination of SAMAs. As shown in Table 4.15-1, the monetized value of this risk is approximately $1,382,099. Therefore, any SAMA having an estimated single-unit cost of implementation exceeding this value is not considered cost beneficial and is screened from further consideration.

The next step involves performing a benefits analysis on the remaining SAMAs. Section 4.15.2 discusses maximum benefit calculations in more detail. The methodology for determining if a SAMA is beneficial consists of determining whether the benefit provided by implementation of the SAMA exceeds the expected cost of implementation. Where the benefits of the SAMAs are small, engineering judgment is used as the basis for costs. The benefit is defined as the sum of the reductions in the dollar equivalents for each severe accident impact (offsite exposure, offsite economic costs, occupational exposure, and onsite economic costs) resulting from the implementation of a SAMA. In general, if the expected cost exceeds twice the calculated benefit, the SAMA is considered not to be cost beneficial. Comparison of the expected cost with twice the benefit calculated from consideration of only internal events is undertaken to recognize and account for the potential contribution to risk from external events.

The result of implementation of each SAMA would be a change in the plant's severe accident risk (i.e., a change in frequency or consequence of severe accidents). The methodology for calculating the magnitude of these changes is straightforward. First, the severe accident risk after implementation of each SAMA is calculated using the same methodology as for the base case. A spreadsheet is then used to combine the results of the Level 2 model with the Level 3 model to calculate these post-SAMA risks. The results of the benefit analysis for each of the SAMAs are presented in Section 4.15.4.

Each SAMA evaluation is performed in a bounding fashion. Bounding evaluations are performed to address the generic nature of the initial SAMA concepts. Such bounding calculations overestimate the benefit and thus are conservative calculations. For example, one SAMA deals with a digital feedwater upgrade (SAMA #101); the bounding calculation to estimate the benefit of this improvement assumes total elimination of feedwater trips and failures not involving steam generator check valves or feed line breaks. Such a calculation obviously overestimates the benefit. However, if the inflated benefit indicates that the SAMA is not cost-beneficial, then the purpose of the analysis is satisfied.

Two types of evaluations are used in determining the benefit of the SAMAs, model requantification and importance measure analysis. Some of the SAMAs involve modification of system models; these SAMAs are evaluated by making relatively simple bounding changes to one or more system models and requantifying the full model. This results in a new set of plant damage-state frequencies that are analyzed to determine the impact on public risk. An example of such an evaluation is the estimation of the benefit of less dependence on Reactor Auxiliaries Building (RAB) ventilation. This SAMA is evaluated in a bounding manner by modifying the fault trees such that the Emergency Core Cooling System (ECCS) pumps are not dependent on any RAB ventilation; this results in an upper limit on the improvement that is possible through more reliable ventilation.

Other SAMAs are more quickly evaluated simply by examining (through importance measures) the contribution of specific components or human actions to the CDF. For example, the SAMA associated with replacing ECCS pump motors with air-cooled motors (SAMA #13); this failure was found to contribute essentially nothing (approximately 0 percent) to CDF. Thus, the benefit from replacing the ECCS pump motors with air-cooled motors is estimated to be negligibly small. For the cases in which the impact on risk is estimated through use of component or human action contribution to CDF, it is assumed

that the benefit is approximately proportional to the reduction in CDF. Appendix E.4 describes the modeling approaches used to evaluate the SAMAs.

As described above for the base case, values for avoided public and occupational health risks (benefits) are converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem (Ref. 4.15-1) and discounted to present value. Values for avoided offsite economic costs (benefits) are also discounted to present value. The formula for calculating net value for each SAMA is as follows:

Net value = ($APE + $AOC + $AOE + $AOSC) – COE

where:

$APE = monetized value of averted public exposure ($)
$AOC = monetized value of averted offsite costs ($)
$AOE = monetized value of averted occupational exposure ($)
$AOSC = monetized value of averted onsite costs ($)
COE = cost of enhancement ($)

If the net value of a SAMA is negative, the cost of the enhancement is greater than the benefit and the SAMA is not cost beneficial. The expected cost of each SAMA (COE) was determined by either utilizing applicable cost estimates published in NRC submittals from other licensees or by expert judgment by knowledgeable plant staff. If these previous licensee submittals contain costs for a specific mitigation alternative, the description is reviewed to determine if the cost estimate can reasonably be applied at St. Lucie Units 1 & 2, based on the plant design and licensing bases and knowledge of implementing plant modifications. If the previous licensee submittals do not contain cost estimates or if these cost estimates cannot be applied, an expert panel reviews the benefit to determine whether the SAMA can be implemented for a cost equivalent to twice the benefit.

4.15.4 RESULTS

FPL analyzed 169 conceptual alternatives for mitigating severe accident impacts. Preliminary screening eliminated 119 SAMAs from further consideration, based on inapplicability to the plant design or features already incorporated into the current design and/or procedures and programs. During the final disposition, 50 remaining SAMA candidates were eliminated because the cost is expected to exceed twice their benefit or because of disproportionately high implementation costs (see Table 4.15-2).

In NUREG/BR-0184, the NRC recommends using a 7 percent real (i.e., inflation-adjusted) discount rate for value-impact analyses and notes that a 3 percent discount rate should be used for sensitivity analyses to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. Analyses presented in Section 4.15.3 use the 7 percent discount rate in calculating potential SAMA benefits. FPL performed a sensitivity analysis by substituting the lower discount rate and recalculating the benefits of the candidate SAMAs. Reducing the discount rate increases the benefits of potential SAMAs but does not change any decision concerning whether they are cost beneficial. Table 4.15-2 presents the results of the cost-benefit analysis for each of the SAMAs evaluated for St. Lucie Units 1 & 2.

In summary, based on the results of this SAMA analysis, FPL found no SAMAs that were cost-beneficial associated with license renewal.

TABLE 4.15-2
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
8	Eliminate RCP thermal barrier dependence on CCW, such that loss of CCW does not result directly in core damage.	Case 4, eliminating U2 seal LOCAs for causes other than operator failures has a benefit of $50K for U2, less for U1.	Cost of modifying 4 seals, plus spares, per Unit and revising multiple procedures would be >>2xbenefit.	Negative net value. Current U1 and U2 seals are not designed for seal injection. Improved seals have been installed at St. Lucie. The new RCP seal design is such that failure is very unlikely if RCPs are stopped and bleedoff isolated within one hour of loss of CCW. Procedures require this and operators are trained to do so (see SAMAs 2 & 3 in Appendix E.4). If operators do not stop RCPs and isolate bleedoff, it would not be prudent to assume they would initiate seal injection, thus incremental improvements related to seal injection and improved charging pumps would be low or non-existent while costs of new cooling system would be high.
10	Create an independent RCP seal injection system, with dedicated diesel.	Case 4, eliminating U2 seal LOCAs for causes other than operator failures has a benefit of $50K.	>>2x benefit.	Negative net value. This SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of CCW or service water, or from SBO. Site procedure [1(2)-EOP-02] is specific about stopping RCPs on loss of CCW. The cost of modifying seals and spares, installing independent system with diesel, revising multiple procedures, and training operators would far exceed the benefits.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
11	Create an independent RCP seal injection system, without dedicated diesel.	Case 4, eliminating U2 seal LOCAs for causes other than operator failures has a benefit of $50K.	>>2x benefit.	Negative net value. This SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of CCW or service water, or from SBO. The present U1 and U2 seals do not have provisions for seal injection. Site procedure [1(2)-EOP-02] is specific about stopping RCPs on loss of CCW. The cost of modifying seals and spares, installing independent system with diesel, revising multiple procedures, and training operators would far exceed the benefits.
12	Use existing hydro test pump for RCP seal injection.	Case 4, eliminating U2 seal LOCAs for causes other than operator failures has a benefit of $50K.	>>2x benefit.	Negative net value. This SAMA would provide an independent seal injection source, without cost of a new system. The present U1 and U2 seals do not have provisions for seal injection. The cost of modifying seals and spares, revising multiple procedures, and training operators would far exceed the benefits.
13	Replace ECCS pump motors with air-cooled motors.	The maximum benefit for eliminating all HPSI failures is $279K. Since only a small fraction is actually CCW related, this provides margin to also bound the low-pressure safety injection and containment spray pumps.	>>2x benefit.	Negative net value. Many procedures relate to the three affected systems and the cost of the required procedure revisions would exceed the benefit, without even considering design change and hardware replacement costs.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
16	Prevent charging pump flow diversion from the relief valves.	Case 4, eliminating U2 seal LOCAs for causes other than operator failures has a benefit of $50K.	>>2x benefit.	Negative net value. If relief valve opening causes a flow diversion large enough to prevent RCP seal injection, then modification can reduce frequency of loss of RCP seal cooling. However, the present U1 and U2 seals do not have provisions for seal injection. The cost of modifying seals and spares, modifying the charging system relief valves, revising multiple procedures, and training operators would significantly exceed the benefits.
34	Install a filtered containment vent to remove decay heat.	NA	TVA estimate $20M (Ref. 4.15-4); expected to well exceed MAB ($1.38M).	Negative net value. This SAMA assumes injection is available (non-ATWS sequences) and it would provide alternate decay heat removal with the released fission products being scrubbed.
35	Install an unfiltered, hardened containment vent.	NA	TVA estimate $20M (Ref. 4.15-4); expected to well exceed MAB ($1.38M).	Negative net value. This SAMA would provide an alternate decay heat removal method (non-ATWS), which is not filtered. To harden the St. Lucie Units 1 & 2 purge system would be quite costly and impacts of the modification on the environment would be high, reducing the benefits.
38	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris.	NA	CE SYS 80 estimate $108M (Ref. 4.15-5); expected to well exceed MAB ($1.38M).	Negative net value. A molten core escaping from the vessel would be contained within the crucible. The water-cooling mechanism would cool the molten core, preventing a melt through.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
39	Create a water-cooled rubble bed on the pedestal.	NA	CE SYS 80 estimate $18M (Ref. 4.15-5); expected to well exceed MAB ($1.38M).	Negative net value. This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled. The wet cavity design also meets part of the intent.
46	Provide containment inerting capability.	NA	TVA estimate $10.9M (Ref. 4.15-4); expected to well exceed MAB ($1.38M).	Negative net value. This SAMA would prevent combustion of hydrogen and carbon monoxide gases. Also, St. Lucie Units 1 & 2 have hydrogen recombiners that meet part of the intent.
48	Install a passive Containment Spray System.	Case 1 calculated $200K (U1) and $112K (U2), if Containment Spray System impact on Level 2/3 results was eliminated.	TVA estimated $20M (Ref. 4.15-4).	Negative net value. Containment spray functions at a very high reliability, and without support systems. Function to limit post-accident pressure in containment is also supported/provided by containment fan coolers, reducing benefits.
50	Increase containment design pressure.	NA	>>MAB ($1.38M).	Negative net value. This SAMA would reduce chance of containment overpressure.
53	Create another building, maintained at a vacuum, to be connected to the containment.	NA	CE SYS 80 estimate of >$10M (Ref. 4.15-5) far exceeds MAB ($1.38M).	Negative net value. In an accident, connecting the new building to the containment would depressurize the containment and reduce any fission product release.
59	Use fuel cells instead of lead-acid batteries.	Elimination of battery failures zzbat1a[b]dep and R#dc-ab = F give CDF reduction of 10.6%, giving estimated benefit of $147K.	Cost of replacing one battery in kind is estimated to be $120K.	Negative net value. This SAMA would extend DC power availability in a SBO. Replacing both trains with new technology requires extensive engineering and construction; therefore the cost to replace all batteries would far exceed the benefit.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
71	Install gas turbine generators.	The CDF contribution of loss of grid is 16.2% giving an estimated benefit of $224K for U1.	CCNPP estimate $10M (Ref. 4.15-6); this is expected to well exceed MAB ($1.38M).	Negative net value. This SAMA would improve onsite AC power reliability.
75	Provide a connection to alternate offsite power source.	The CDF contribution of loss of grid is 16.2%, giving an estimated benefit of $224K for U1.	In 1994, at BGE, a 500kV line was installed at a cost of $1M/mile (Ref. 4.15-6); this is expected to well exceed MAB ($1.38M).	Negative net value. This SAMA would increase offsite power redundancy. Given the geography and distance (miles) required, this would far exceed the MAB.
76	Implement underground offsite power lines.	The CDF contribution of loss of grid is 16.2%, giving an estimated benefit of $224K for U1.	>>MAB ($1.38M).	Negative net value. This SAMA could improve offsite power reliability, particularly during severe weather. However, this would require several miles of buried cable, given that the severe weather to which the plant is susceptible (primarily hurricanes) typically affects a broad area. Also, FPL grid sources are not supplied by buried cable.
80	Improve SGTR coping abilities.	Case NOSGTR calculates benefit for eliminating U1 SGTRs as <$111K (U2 much less).	CCNPP estimate $9.5M for scrubbing releases (Ref. 4.15-6); this well exceeds MAB ($1.38M).	Negative net value. This SAMA would improve instrumentation to detect SGTR, or add systems to scrub fission product releases. St. Lucie Units 1 & 2 procedures already provide direction regarding proper diagnosis to verify (and isolate) SGTR. Therefore, intent is met for detection, and the “fission product scrubber” aspect is not cost beneficial.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
81	Add other SGTR coping features.	Case NOSGTR calculates benefit for eliminating U1 SGTRs as <$111K (U2 much less).	>>2xbenefit.	Negative net value. This SAMA could be considered three ways: (a) A highly reliable (closed loop) SG shell-side heat removal system that relies on natural circulation and stored water sources; (b) a system that returns the discharge from the SG relief valve back to the primary containment; (c) an increased pressure capability on the SG shell side with corresponding increases in the safety valve setpoints. However, CCNPP determined that increasing the secondary-side pressure at an existing plant would not be feasible. Additionally, per System 80+, relief valve return to containment requires major redesign.
82	Increase secondary-side pressure capacity such that an SGTR would not cause the relief valves to lift.	Case NOSGTR calculates benefit for eliminating U1 SGTRs as <$111K (U2 much less).	>>2xbenefit.	Negative net value. SGTR sequences would not have a direct release pathway. CCNPP determined that increasing the secondary-side pressure at an existing plant would not be feasible.
83	Replace SGs with new design.	Case NOSGTR calculates benefit for eliminating U1 SGTRs as <$111K (U2 much less).	Industry (and U1) cost estimates approach $100M; which well exceeds MAB ($1.38M).	Negative net value. This SAMA would lower the frequency of SGTRs. U1 has replaced SGs with new design and U2 has had relatively few problems with its SGs.
85	Establish a maintenance practice that inspects 100% of the tubes in an SG.	Case NOSGTR calculates benefit for eliminating U1 SGTRs as <$111K (U2 much less).	Additional inspection costs of $500K-$750K per inspection >>2xbenefit.	Negative net value. This SAMA would reduce chances of tube rupture. Unit 2 performs 100% tube inspections. Unit 1 has replaced SGs with new design and inspections do not indicate any need for 100% inspections. If problems are found, FPL is required to expand the inspection, meeting at least part of the intent.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
87	Locate RHR inside of containment.	NA	>>MAB ($1.38M).	Negative net value. This SAMA would prevent ISLOCA occurrences via the RHR pathway. For an existing plant such as St. Lucie Units 1 & 2, relocating the RHR inside the containment is not feasible, as it would require an entirely new RHR system.
88	Install self-actuating containment isolation valves.	Although early containment failures are calculated at 1% of CDF, if 10% is assumed the CDF impact of 10% gives estimated benefits of $138K (U1).	>>2xbenefit.	Negative net value. This SAMA would reduce the frequency of isolation failure. St. Lucie penetrations that are required to close for accidents have at least one fail closed valve either on loss of air or electric power or are check valves and thus meet the intent. Also, it must be noted that NRC regulations do not allow only check valves for isolation—there must be at least one valve that is not a check valve (and with positive position indication).
89	Install additional instrumentation for ISLOCA sequences.	Case NOISLOCA calculated benefits of $251K for U1 and $487K for U2.	TVA estimate $2.3M (Ref. 4.15-4); >>2xbenefit.	Negative net value. This SAMA would decrease ISLOCA frequency by installing pressure or leak monitoring instruments between the first two pressure isolation valves on low-pressure injection lines, RHR suction lines, and high-pressure injection lines.
90	Increase frequency of valve leak testing.	Case NOISLOCA calculated benefits of $251K for U1 and $487K for U2.	>>2xbenefit.	Negative net value. This SAMA would decrease ISLOCA frequency. Testing at power would require installation of instruments to allow proper and safe testing. Cost of extra shut downs for testing would exceed benefits in a relatively short time.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
95	Ensure all ISLOCA releases are scrubbed.	Case NOISLOCA calculated benefits of $251K for U1 and $487K for U2.	>>2xbenefit.	Negative net value. This SAMA would scrub ISLOCA releases. This would require extensive effort to isolate/scrub all paths from the RAB. One suggestion was to plug drains in the break area so the break point would cover with water. However, critical piping areas already have filtered ventilation, further reducing the available benefits.
96	Add redundant and diverse limit switch to each containment isolation valve.	Case NOISLOCA calculated benefits of $251K for U1 and $487K for U2.	>>2xbenefit.	Negative net value. This SAMA would enhanced isolation valve position indication, which would reduce frequency of containment isolation failures and ISLOCAs.
101	Install digital feedwater upgrade.	CDF reduction is 11%, giving an estimated benefit of $158K, if all feedwater trips and failures not involving SG check valves or feedline breaks are eliminated.	>>2xbenefit.	Negative net value. This SAMA would reduce the chance of loss of the Main Feedwater System following a plant trip.
113	Install an independent diesel for the Condensate Storage Tank makeup pumps.	Estimated auxiliary feedwater suction CDF impact by falsing CST rupture, CST check valves, motor pump suction valves, and suction line failures is a 2.9% reduction, which would provide an estimated benefit of <$41K.	>>2xbenefit.	Negative net value. This SAMA would allow continued inventory in CST during a SBO.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
115	Create passive secondary-side coolers.	NA	>>MAB ($1.38M).	Negative net value. This SAMA would provide a passive heat removal loop with a condenser and heat sink, and would reduce CDF from the loss of feedwater. CCNPP determined that this would require major changes to plant structures.
117	Provide an additional HPSI pump with independent diesel.	Common-cause failures of HPSI pumps contribute 6.7% to CDF. This gives a total estimated benefit of $80K for elimination of HPSI pump common-cause failures.	>>2xbenefit.	Negative net value. This SAMA would reduce frequency of core melt from small LOCA sequences and from SBO sequences. In order to implement this alternative, significant plant hardware and building additions and modifications to existing piping and controls would be needed.
118	Install independent AC HPSI system.	Failures of HPSI contribute 18% to CDF. This gives a total estimated benefit of $249K for elimination of ALL HPSI failures. Addition of another AC train would not eliminate the pump common-cause failures, leaving 6.71% from the pump CDF, reducing benefits by >$80K to $169K.	>>2xbenefit.	Negative net value. This SAMA would allow makeup and feed-and-bleed capabilities during a SBO. In order to implement this alternative, significant plant hardware additions and modifications would be needed.
123	Upgrade CVCS to mitigate small–small LOCAs.	Case 3 calculates that elimination of ALL S1 LOCAs reduces CDF by 23.3%, giving a benefit of $225K for U1, less for U2.	>>2xbenefit.	Negative net value. For a plant like the AP600 where CVCS cannot mitigate a small-small LOCA, an upgrade would decrease CDF from small-small LOCAs. In order to implement this alternative, significant plant hardware modifications would be needed.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
126	Replace two of the four safety injection pumps with diesel pumps.	NA	>>2xbenefit (determined in SAMA #117).	Negative net value. Intended for System 80+, which has four trains of SI. This SAMA would reduce common-cause failure probability. U1 and U2 each have only two trains of HPSI to the plant so this would be adding one or two trains. In order to implement this alternative, significant plant hardware and building additions and modifications to existing piping and controls would be needed (similar to SAMA #117).
140	Install a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS.	CDF reduction from ATWS elimination is about 2.6%, giving an estimated benefit of $35K.	>>2xbenefit.	Negative net value. This SAMA would improve equipment availability after an ATWS.
145	Make procedural changes only for the RCS depressurization option.	RTOP1RLTC CDF reduction is ~0.0% giving an estimated benefit of ~$0.	>>2xbenefit.	Negative net value. This SAMA would reduce RCS pressure without the cost of a new system.
146	Defeat 100% load rejection capability. (Interpreted as "Provide 100%…")	Contribution of T2 to U1 CDF is 0.3%; contribution of a stuck open PORV is another 0.7%. Estimated benefit of $4K if T2 is eliminated and another $6K ($10K total) if PORV sticking open were eliminated.	>>2xbenefit.	Negative net value. This SAMA eliminates the possibility of a stuck open PORV after a loss of power, since PORV opening wouldn't be needed.

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
148	Install secondary-side guard pipes up to the MSIVs.	Eliminating main steam line breaks gives a CDF reduction of 0.2%, giving an estimated benefit of <$2K.	>>2xbenefit.	Negative net value. This SAMA would prevent secondary-side depressurization should a steam line break occur upstream of the MSIVs. It would also guard against or prevent consequential multiple SGTRs following a main steam line break event.
149	Provide digital large break LOCA protection.	CDF reduction for elimination of large break LOCA is 4.7%, giving an estimated benefit of <$65K.	>>2xbenefit.	Negative net value. This SAMA would upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).
151	Provide self-cooled ECCS seals.	No benefit is expected.	NA	Negative net value. ECCS pump seals are CCW cooled. Need CCW to motor. Elimination of seal cooling would not prevent pump failure.
152	Separate non-vital buses from vital buses.	Eliminating a 480V breaker fault gives a CDF reduction of 2.2%, giving an estimated benefit of $26K.	>>2xbenefit.	Negative net value. Some non-vital loads mixed with vital loads on load centers causing load shedding difficulties.
155	Provide a centrifugal charging pump.	Eliminating ALL charging system failures reduces CDF by 0.7%, giving an estimated benefit of $10K.	>>2xbenefit.	Negative net value. Currently charging pumps are positive displacement pumps. Hardware modifications to add or replace a pump are expected to well exceed benefit.
158	Improve RHR sump reliability.	$6K benefit for U1. Essentially $0 benefit estimated for U2.	>>2xbenefit.	Negative net value. Common-mode failure of RHR due to debris in sump. Recently, U1 and U2 sumps have had extensive inspection to ensure no gaps in screens (which should reduce failure probability).

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
159	Provide AB vent/seal structure.	Case NOISLOCA calculated benefits of $251K for U1 and $487K for U2.	>>2xbenefit.	Negative net value. This SAMA would enhance ventilation in the AB. The intent is to reduce leakage from the AB after an ISLOCA.
160	Add charcoal filters on the AB exhaust.	Case NOISLOCA calculated benefits of $251K for U1 and $487K for U2.	>>2xbenefit.	Negative net value. This SAMA would enhance fission product removal after an ISLOCA.
161	Add penetration valve leakage control system.	Although early containment failures are calculated at 1% of CDF, if 10% is assumed the CDF impact of 10% gives estimated benefits of $138K.	>>2xbenefit.	Negative net value. This SAMA would enhance capability to detect/control leakage from penetration valves. Detection is generally available, either by radiation monitors or level detectors. Later leakage less important and resources to aid in detection will be available.
165	Man Safe Shutdown Facility continuously to align Coolant Makeup System for RCP seal cooling.	Eliminating failure of RTOP1S1RCP and the operator failure portion (~50%) of ZZXCROSST would reduce CDF by 18.7%, giving an estimated benefit of <$258K.	Oconee estimated $5M, which >>2xbenefit.	Negative net value. The specific actions are not applicable to St. Lucie Units 1 & 2. Of the top 2 operator actions, the second one is done from the Control Room (RTOP1S1RCP), which is already continuously manned so that adding a dedicated operator would not fully eliminate failure. The other is done primarily in the Control Room as well (ZZXCROSST).

TABLE 4.15-2 (continued)
DISPOSITION OF SAMAs RELATED TO ST. LUCIE UNITS 1 & 2

SAMA Number	Potential Improvement	Benefit Evaluation[a]	Cost of Implementation	Screening Results and Discussion
167	Replace reactor vessel with stronger vessel.	NA	>>MAB ($1.38M).	Negative net value. This SAMA would reduce core damage contribution due to vessel failure. New vessel would greatly exceed the MAB.

NOTES:

a. SAMA evaluation case results are provided in Appendix E.4, Table E.4-3 and Table E.4-4 for Unit 1 and Unit 2, respectively.

AB = Auxiliary Building
AC = alternating current
ATWS = Anticipated Transient Without Scram
BGE = Baltimore Gas and Electric Company
CCNPP = Calvert Cliffs Nuclear Power Plant
CCW = component cooling water
CDF = core damage frequency
CE = Combustion Engineering, Inc.
CST = Condensate Storage Tank
CVCS = Chemical Volume Control System
DC = direct current
ECCS = Emergency Core Cooling System
FPL = Florida Power & Light Company
HPSI = high-pressure safety injection
ISLOCA = interfacing system loss-of-coolant accident
K = thousand
kV = kilovolt
LOCA = loss-of-coolant accident
MAB = maximum attainable benefit
M = million
MSIV = main steam isolation valve
NA = not applicable
NRC = U.S. Nuclear Regulatory Commission
PORV = power-operated relief valve
RAB = Reactor Auxiliaries Building
RCP = reactor coolant pump
RCS = Reactor Coolant System
RHR = residual heat removal
SAMA = severe accident mitigation alternative
SBO = Station Blackout
SG = steam generator
SGTR = steam generator tube rupture
SI = safety injection
T2 = reactor trip with PORV challenge
TVA = Tennessee Valley Authority
U1 = St. Lucie Unit 1
U2 = St. Lucie Unit 2
V = volt

4.16 ENVIRONMENTAL JUSTICE

NRC

"The need for and the content of an analysis of environmental justice will be addressed in plant-specific reviews." 10 CFR Part 51, Subpart A, Appendix B, Table B-1, Issue 92

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations" (Ref. 4.16-1), requires Executive agencies to identify and address, as appropriate, "disproportionately high and adverse human health or environmental effects" from their programs, policies, and activities on minority and low-income populations. The Presidential Memorandum that accompanied Executive Order 12898 emphasized the importance of using existing laws, including the NEPA, to identify and address environmental justice concerns, "including human health, economic, and social effects, of Federal actions."

Although the NRC is not subject to Executive Order 12898, it has voluntarily committed to conducting environmental justice reviews of actions under its jurisdiction and has issued procedural guidance (Ref. 4.16-2, Attachment 4). The guidance does not provide a standard approach or formula for identifying and addressing environmental justice issues. Instead, it offers general principles for conducting an environmental justice analysis under NEPA. The NRC guidance makes clear that if no significant impacts are anticipated from the proposed action, then "…no member of the public will be substantially affected" and, as a consequence, "…there can be no disproportionate high and adverse effects or impacts on any member of the public including minority or low income populations."

FPL has reviewed and adopted by reference NRC findings for Category 1 issues that FPL determined are applicable to St. Lucie Units 1 & 2 (see Section 4.1.1). The NRC had concluded that environmental impacts for each of these issues would be SMALL. FPL has addressed each Category 2 issue and has performed required analyses for those that FPL determined are applicable to St. Lucie Units 1 & 2 (see Sections 4.1 through 4.15 and Appendix A).

For each applicable Category 2 issue requiring analysis, FPL has concluded that the environmental impacts would be SMALL. These include:

- Entrainment, impingement, and heat shock;
- Threatened or endangered species;
- Electric shock from transmission-line-induced currents;
- Housing, public water supply, offsite land use, and transportation;
- Historic and archaeological resources; and
- Severe accident mitigation alternatives.

Based on the FPL review, St. Lucie Units 1 & 2 license renewal and continued operations would result in no significant impact. No member of the public would be substantially affected and, as a consequence, there would be no disproportionately high and adverse impacts on any member of the public, including minority and low-income populations. In

such instances, a qualitative review of potential environmental justice impacts is adequate and no mitigation measures need be described.

4.17 REFERENCES

4.2-1 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

4.2-2 U.S. Nuclear Regulatory Commission. Final Environmental Statement Related to the Operation of St. Lucie Plant, Unit No. 2; Florida Power & Light Company, Orlando Utilities Commission of the City of Orlando, Florida. Docket No. 50-389. NUREG-0842. Office of Nuclear Reactor Regulation. Washington, D.C. April 1982.

4.3-1 Applied Biology, Inc. "Florida Power & Light Company St. Lucie Plant Annual Non-Radiological Environmental Monitoring Report 1984." Atlanta, Georgia. (L-85-174) April 30, 1985.

4.3-2 Florida Department of Environmental Protection. "Site Certification, St. Lucie Power Plant Unit 2, Florida Power & Light Co." Certification No. PA 74-02C, OGC Case No. 94-1053. 1976 (and subsequent modifications).

4.4-1 U.S. Atomic Energy Commission. Final Environmental Statement Related to the St. Lucie Plant Unit No. 1; Florida Power & Light Company. Docket No. 50-335. Directorate of Licensing. Washington, D.C. June 1973.

4.4-2 Florida Department of Environmental Protection. "Surface Water Quality Standards." Rule G2-302.520(4)(c). December 26, 1996.

4.6-1 Ecological Associates, Inc. Physical and Ecological Factors Influencing Sea Turtle Entrainment Levels at the St. Lucie Nuclear Plant: 1976-1998. Jensen Beach, Florida. (L-2000-78) March 22, 2000.

4.6-2 U.S. Nuclear Regulatory Commission. Assessment of the Impacts of the St. Lucie Nuclear Plant on Threatened and Endangered Species. Docket No. 50-398. Office of Nuclear Reactor Regulation. Washington, D.C. March 1982.

4.6-3 National Marine Fisheries Service. Endangered Species Act Section 7 Consultation Biological Opinion. St. Petersburg, Florida. February 7, 1997.

4.6-4 Florida Power & Light Company. Assessment of the Impacts of the St. Lucie Nuclear Generating Plant on Sea Turtle Species Found in the Nearshore Waters of Florida. Juno Beach, Florida. (L-95-309) November 20, 1995.

4.6-5 Letter from J.E. Powers (NMFS) to K.N. Jabbour (NRC), "National Marine Fisheries Service Biological Opinion." St. Petersburg, Florida. May 4, 2001.

4.6-6 Florida Power & Light Company. Annual Environmental Operating Report 2000. Juno Beach, Florida. (L-2001-90) April 2001.

4.8-1 National Electrical Safety Code®. Part 2, Rules 232Cic and 232D3c. 1997 Edition. C2-1997.

4.8-2 Electric Power Research Institute. Transmission Line Reference Book. 345 kV and Above. Second Edition, Revised. Palo Alto, California. 1987.

4.8-3 Electromagnetic Workstation: ENVIRO Code. Electric Power Research Institute, Version 3.1, Baltimore Gas & Electric. October 18, 1994.

4.8-4 National Electrical Safety Code®. Part 2, Rules 232A1 and 232B1. 1997 Edition. C2-1997.

4.10-1 Fetter, Jr., C. W. Applied Hydrogeology. Charles E. Merrill Publishing Co./Bell & Howell Co. Columbus, Ohio. 1980.

4.10-2 U.S. Census Bureau. DP-1. Profile of General Demographic Characteristics: 2000 for Florida and Selected Counties and Cities. http://factfinder.census.gov. Accessed July 25, 2001.

4.15-1 U.S. Nuclear Regulatory Commission. Regulatory Analysis Technical Evaluation Handbook. NUREG/BR-0184. Office of Nuclear Regulatory Research. Washington, D.C. January 1997.

4.15-2 Letter from D.A. Sager (FPL) to Document Control Desk (NRC), "St. Lucie Units 1 & 2 Summary Report of Individual Plant Examination for Severe Accident Vulnerabilities – Generic Letter 88-20." (L-93-301) December 9, 1993.

4.15-3 Letter from D.A. Sager (FPL) to Document Control Desk (NRC), "St. Lucie Units 1 & 2 – NRC Generic Letter 88-20, Supplement 4, Individual Plant Examination for Severe Accident Vulnerabilities Report." (L-94-318, with Enclosure) December 15, 1994.

4.15-4 Letter from Mr. W. J. Museler (TVA) to Document Control Desk (NRC), "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Severe Accident Mitigation Design Alternatives (SAMDA) - (TAC Nos. M77222 and M77223)." June 5, 1993.

4.15-5 U.S. Nuclear Regulatory Commission. Final Safety Evaluation Report Related to the Certification of the System 80+ Design. NUREG-1462. Associate Director for Advanced Reactors & License Renewal. Washington, D.C. August 1994.

4.15-6 Baltimore Gas & Electric Company. Calvert Cliffs Nuclear Power Plant, Units 1 and 2, License Renewal Application. Attachment 3, "Applicant's Environmental Report – Operating License Renewal Stage." Lusby, Maryland. April 1998.

4.16-1 "Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations." Federal Register. Vol. 59, No. 32. (February 16, 1994). www.access.gpo/su_docs/aces/aaces002.html. Accessed February 27, 2001.

4.16-2 U.S. Nuclear Regulatory Commission. "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues." NRR Office Letter No. 906, Rev. 2. Office of Nuclear Reactor Regulation. Washington, D.C. September 21, 1999.

5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

NRC

"…The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to Subpart A of this part." 10 CFR 51.53(c)(3)(i)

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants and provides for license renewal, requiring a license renewal application that includes an environmental report (10 CFR 54.23). NRC regulations at 10 CFR 51 prescribe the environmental report content and identify the specific analyses the applicant must perform. In an effort to perform the environmental review efficiently and effectively, the NRC has resolved most of the environmental issues generically, but requires an applicant's analysis of all the remaining issues.

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert the NRC to such information so that the staff can determine whether to seek the Commissioners' approval to waive or suspend application of the Rule with respect to the affected generic analysis. The NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of the NRC's *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) conclusions (Ref. 5.1-1, page C9-13, Concern Number NEP.015).

Florida Power & Light Company (FPL) assumes new and significant information would be the following:

- Information that identifies a significant environmental issue not covered in the GEIS and codified in the regulation, or
- Information that was not covered in the GEIS analyses and that leads to an impact finding different from that codified in the regulation.

The NRC does not define the term "significant." For the purpose of its review, FPL used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act (NEPA) authorizes the CEQ to establish implementing regulations for federal agency use. The NRC requires license renewal applicants to provide the NRC with input, in the form of an environmental report, that the NRC will use to meet NEPA requirements as they apply to license renewal (10 CFR 51.10). CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), to focus on significant environmental issues (40 CFR 1502.1) and to eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action, and the intensity or severity of the impact(s) (40 CFR 1508.27). FPL assumed that moderate or large impacts, as defined by the NRC, would be significant. Section 4.1.2 presents the NRC definitions of "moderate" and "large" impacts.

FPL is aware of no new and significant information regarding the environmental impacts of St. Lucie Units 1 & 2 license renewal.

5.1 REFERENCES

5.1-1 U.S. Nuclear Regulatory Commission. Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response. NUREG-1529. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

Florida Power & Light Company (FPL) has reviewed the environmental impacts associated with renewing the St. Lucie Units 1 & 2 operating licenses and has concluded that all of the impacts would be small and would not require mitigation. This environmental report documents FPL's bases for its conclusion. Section 4.1.1 incorporates by reference U.S. Nuclear Regulatory Commission (NRC) findings for the 47 Category 1 issues that apply to St. Lucie Units 1 & 2, all of which have impacts that are SMALL (see Appendix A). Subsections 4.2 through 4.15 of Chapter 4 analyze the 15 Category 2 issues that apply to St. Lucie Units 1 & 2, all of which have impacts that would be SMALL or non-existent, due to the lack of refurbishment activities associated with St. Lucie Units 1 & 2 license renewal. Section 4.16 discusses the basis for inclusion and appropriate depth of an environmental justice analysis summarizing that there are no disproportionately high and adverse human health or environmental effects since impacts from all Category 1 and Category 2 issues applicable to St. Lucie Units 1 & 2 are SMALL. Table 6.1-1 identifies the impacts that St. Lucie Units 1 & 2 license renewal would have on resources associated with Category 2 issues and environmental justice.

TABLE 6.1-1
ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT ST. LUCIE UNITS 1 & 2

No.	Issue[a]	Environmental Impact
Surface Water Quality, Hydrology, and Use (for all plants)		
13	Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	NONE. The issue is not applicable because St. Lucie Units 1 & 2 are not equipped with cooling ponds or cooling towers.
Aquatic Ecology (for all plants with once-through and cooling pond heat dissipation systems)		
25	Entrainment of fish and shellfish in early life stages	SMALL. FPL has a current NPDES permit that constitutes compliance with CWA Section 316 (b) requirements to provide best available technology to minimize entrainment.
26	Impingement of fish and shellfish	SMALL. FPL has a current NPDES permit that constitutes compliance with CWA Section 316 (b) requirements to provide best available technology to minimize impingement.
27	Heat shock	SMALL. Thermal discharge from St. Lucie Units 1 & 2 complies with Florida Water Quality Standards without recourse to a CWA Section 316(a) variance.
Groundwater Use and Quality		
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use more than 100 gpm)	NONE. The issue is not applicable because St. Lucie Units 1 & 2 are not direct users of groundwater (no dewatering; potable and service water are from municipal supply).
34	Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	NONE. The issue is not applicable because St. Lucie Units 1 & 2 are not equipped with cooling towers.
35	Groundwater use conflicts (Ranney wells)	NONE. The issue is not applicable because St. Lucie Units 1 & 2 do not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites)	NONE. The issue is not applicable because St. Lucie Units 1 & 2 are not equipped with cooling ponds.
Terrestrial Resources		
40	Refurbishment impacts	NONE. FPL has no plans for major refurbishment at St. Lucie Units 1 & 2.

NOTES:

a. Source: 10 CFR 51, Subpart A, Appendix B, Table B-1.

CWA = Clean Water Act

FPL = Florida Power & Light Company

gpm = gallons per minute

LOS = level of service

NPDES = National Pollutant Discharge Elimination System

SFWMD = South Florida Water Management District

TABLE 6.1-1 (continued)
ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT ST. LUCIE UNITS 1 & 2

No.	Issue[a]	Environmental Impact
	Threatened or Endangered Species	
49	Threatened or endangered species	SMALL. Protective measures to return sea turtles that have entered the Intake Canal have been refined and enhanced. The canal monitoring program ensures minimization of impacts and compliance to the commitments of the operating license. No other impacts to threatened or endangered species were identified.
	Air Quality	
50	Air quality during refurbishment (non-attainment and maintenance areas)	NONE. FPL has no plans for major refurbishment at St. Lucie Units 1 & 2.
	Human Health	
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	NONE. The issue is not applicable because St. Lucie Units 1 & 2 do not use lakes or canals or use cooling ponds or cooling towers that discharge to a small river.
59	Electromagnetic fields, acute effects (electric shock)	SMALL. All circuits meet National Electrical Safety Code® requirements for limiting induced shock.
	Socioeconomics	
63	Housing impacts	SMALL. No impacts are anticipated because no additional employees are expected. Analyzed impact from adding as many as 60 employees during the license renewal term; 115 housing units would be required in an area with a population greater than 319,000. This impact would be small.

NOTES:

a. Source: 10 CFR 51, Subpart A, Appendix B, Table B-1.

CWA = Clean Water Act

FPL = Florida Power & Light Company

gpm = gallons per minute

LOS = level of service

NPDES = National Pollutant Discharge Elimination System

SFWMD = South Florida Water Management District

TABLE 6.1-1 (continued)
ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT ST. LUCIE UNITS 1 & 2

No.	Issue[a]	Environmental Impact
65	Public services: public utilities	SMALL. No impacts are anticipated because no additional employees are expected. Analyzed impact from adding as many as 60 employees during the license renewal term; this could result in as many as 339 new residents in Martin and St. Lucie counties and approximately 27,000 additional gallons of water per day demand on water systems in the two counties. This would be less than one percent of SFWMD daily allocations for either county. This impact would be small.
66	Public services: education (refurbishment)	NONE. FPL has no plans for major refurbishment at St. Lucie Units 1 & 2.
68	Offsite land use (refurbishment)	NONE. FPL has no plans for major refurbishment at St. Lucie Units 1 & 2.
69	Offsite land use (license renewal term)	SMALL. FPL annual property tax payments for St. Lucie Units 1 & 2 averaged approximately 10.8 percent of the County's total annual property tax revenues and approximately 8.2 percent of its total annual revenues. License renewal tax-driven land-use changes would generate very little new development and minimal changes in the area's land-use patterns.
70	Public services: transportation	SMALL. No impacts are anticipated because no additional employees are expected and the LOS designations for the access road to St. Lucie Units 1 & 2 are 'A' and 'B.' Analyzed impact from adding as many as 60 employees during the license renewal period would be small.
71	Historic and archaeological resources	SMALL. No impacts to historic or archaeological resources were identified.
76	Severe accidents	SMALL. FPL identified no cost-effective severe accident mitigation measures.
	Environmental Justice	
92	Environmental justice	SMALL. No disproportionately high or adverse impacts to minority or low-income populations.

NOTES:

a. Source: 10 CFR 51, Subpart A, Appendix B, Table B-1.

CWA = Clean Water Act

FPL = Florida Power & Light Company

gpm = gallons per minute

LOS = level of service

NPDES = National Pollutant Discharge Elimination System

SFWMD = South Florida Water Management District

6.2 MITIGATION

NRC

"The report must contain a consideration of alternatives for reducing adverse impacts...for all Category 2 license renewal issues..." 10 CFR 51.53(c)(3)(iii)

"The environmental report shall include an analysis that considers and balances...alternatives available for reducing or avoiding adverse environmental effects...." 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2)

All impacts of St. Lucie Units 1 & 2 license renewal are beneficial or small, and would not require additional mitigation. St. Lucie Units 1 & 2's once-through cooling system was designed and constructed so as to minimize impacts to aquatic life. Baseline studies were done characterizing the environs of the Indian River Lagoon and the Atlantic Ocean along Hutchinson Island. Data indicated that the Lagoon supports a diverse and abundant assemblage of marine life. The marine life of the Atlantic, particularly within the offshore, mid-island region inside Pierce Shoal, is less so. Indications of this include less variability in hydrographic condition, absence of attached macrophytes and hard-bottom substrate, and isolation from major spawning grounds of most species of finfish and shellfish.

Additionally, the St. Lucie Units 1 & 2 intake pipes were sited seaward of the nearshore worm rocks in an area devoid of hard bottom and the intake structures were fitted with velocity caps. The caps on the vertical intake shafts prevent the formation of a vortex and allow cooling water to be drawn from mid-depth rather than from the surface or the bottom of the water column. These two design features reduce the potential for entrainment of marine life since fish eggs and larvae are buoyant and drift near the surface, and most invertebrates and many fish species live on the bottom.

An effective program to return sea turtles that have entered the Intake Canal was developed with the permitting of St. Lucie Unit 1, and has evolved over time. FPL has performed studies of techniques to deter the turtles from entering the intake structures. Techniques such as static light and bubble screens, weak electric impulses, seismic profiling/pneumatic air guns, and strobe lights have been tested. The practicality of using physical barriers at the intake structures was also assessed. It was also determined that the series of barrier nets coupled with visual monitoring proved to be the most effective and practical approach.

Current operations include mitigation activities that would continue during the term of the St. Lucie Units 1 & 2 license renewals. FPL would continue to utilize protective measures, including mesh barriers and capture and release, to prevent sea turtles from entering the Intake Canal. FPL makes additional contributions to promote awareness of species protection through additional mitigative activities including sea turtle surveys, Sea Turtle Stranding and Salvage Network participation, and sea turtle nesting public awareness walks (Ref. 6.2-1).

Since initial operations began, FPL has evaluated and implemented many mitigative measures as summarized above. As discussed in Chapter 4, the impacts associated with continued operations during the license renewal term would be either beneficial or small, and further mitigation would not be warranted.

6.3 UNAVOIDABLE ADVERSE IMPACTS

NRC

The environmental report shall discuss any "...adverse environmental effects which cannot be avoided should the proposal be implemented..." 10 CFR 51.45(b)(2) as adopted by 51.53(c)(2)

FPL adopts by reference for this environmental report the NRC findings stated in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (*GEIS)* for applicable Category 1 issues (see Appendix A), including discussions of any unavoidable adverse impacts. In Chapter 4.0, FPL examined the 21 Category 2 issues identified by the NRC in the GEIS and the environmental justice issue, and identified the following unavoidable adverse impacts of renewing the operating licenses for St. Lucie Units 1 & 2:

- Some early life stages of fish and shellfish are entrained by the cooling water system during plant operation. The NRC has estimated that, under normal conditions, 0.4 percent of the fish eggs and larvae passing the site could be entrained, and concluded that entrainment losses would not represent a significant impact to local fisheries (see Section 4.2).
- Some fish and shellfish are impinged on the traveling screens at the St. Lucie Units 1 & 2 Intake Wells. The NRC concluded that the combined estimates of Unit 1 and Unit 2 impingement would be insignificant when compared to local commercial landings (see Section 4.3).
- Some fish and shellfish are entrained in the St. Lucie Units 1 & 2 intake structures and become entrapped in the Intake Canal. Monitoring studies conducted during early years of plant operation did not document accumulation of these organisms in the Canal, possibly because factors such as predation within the Canal operate to keep numbers low. Some of the fish entrapped in the Intake Canal were commercial species, but these losses were negligible relative to the weight of commercial landings (see Section 4.3).
- Some protected sea turtles enter the St. Lucie Units 1 & 2 Intake Canal. FPL implements a highly effective program to capture turtles that have entered the Intake Canal and to return them to the ocean; however, some losses do occur. Mortalities are closely monitored, and the National Marine Fisheries Service (NMFS) has established permissible annual mortalities in an Incidental Take Statement (see Section 4.6). FPL has modified plant design and procedures over the years to minimize impacts to sea turtles entrained in the Intake Canal. FPL further mitigates potential adverse impacts to sea turtles by conducting sea turtle surveys and sea turtle nesting public awareness walks, and by participating in the Sea Turtle Stranding and Salvage Network (see Sections 4.6 and 6.2).
- FPL does not expect to add additional staff for the license renewal period. However, for purposes of analysis, FPL assumed that license renewal could necessitate adding as many as 60 additional staff. The assumed addition of 60 direct workers to Martin and St. Lucie counties, where approximately 83 percent of the St. Lucie Units 1 & 2 employees resides, could result in small impacts to housing availability, public water supplies, offsite land use, or transportation infrastructure (see Sections 4.9,

4.10, 4.12.2, and 4.13). All of these impacts are small, and do not warrant further mitigation.

6.4 IRREVERSIBLE OR IRRETRIEVABLE RESOURCE COMMITMENTS

NRC

The environmental report shall discuss any "...irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented..." 10 CFR 51.45(b)(5) as adopted by 51.53(c)(2)

The continued operation of St. Lucie Units 1 & 2 for the license renewal term will result in irreversible and irretrievable resource commitments including:

- Nuclear fuel, which is utilized in the reactor and converted to radioactive waste;
- Land required to permanently store, or dispose of this spent nuclear fuel and the low-level radioactive wastes generated as a result of plant operations;
- Elemental materials that will become radioactive; and
- Materials used for the normal industrial operations of the plant that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

6.5 SHORT-TERM USE VERSUS LONG-TERM PRODUCTIVITY OF THE ENVIRONMENT

NRC

The environmental report shall discuss the "...relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity..." 10 CFR 51.45(b)(4) as adopted by 51.53(c)(2)

The current balance between short-term use and long-term productivity of the environment at the St. Lucie Units 1 & 2 site was basically set once the Units began operating in 1976 and 1983, respectively. The U.S. Atomic Energy Commission (AEC) documented its evaluations of this balance in its Final Environmental Statement (FES) for St. Lucie Unit 1 (Ref. 6.5-1) and in its construction-phase FES for Unit 2 (Ref. 6.5-2). The latter evaluation was subsequently reaffirmed by the NRC in its FES for the operation phase of Unit 2 (Ref. 6.5-3). Of particular note in these evaluations was the conversion of approximately 300 acres of land, mostly mangrove swamps that had been previously modified for mosquito control, to facilities for electrical power generation. The AEC noted that upon decommissioning, much of the facility could be dismantled and restored to its original condition for the long term. The AEC also acknowledged in its Unit 1 evaluation that some adverse impacts on the marine environment from plant operation could occur, but would be appropriately monitored and mitigated, and thus were expected to be temporary and represent a potential short-term cost for production of electric power (Ref. 6.5-1).

FPL notes that the current balance is now well established, and can be expected to remain essentially unchanged by renewal of the operating licenses and extended operation of St. Lucie Units 1 & 2. Extended operation of the Units would postpone restoration of the site and its potential availability for uses other than electrical power generation. It would also result in other short-term impacts on the environment, all of which have been determined on the basis of the NRC's evaluation in the GEIS and FPL's evaluation in this environmental report to be small. In addition, extended operation would enable FPL to continue its efforts to monitor sea turtle populations in the vicinity of the site, and carry out related mitigation activities noted in Section 6.2.

6.6 REFERENCES

6.2-1 Gleaves, W.C. (NRC) Letter to T.F. Plunkett (FPL). "St. Lucie Plant, Units 1 and 2 – Issuance of Amendments Regarding the Environmental Protection Plans (TAC Nos. M99396, M99397, MA4605, and MA4606)." July 2, 1999.

6.5-1 U.S. Atomic Energy Commission. Final Environmental Statement Related to the St. Lucie Plant Unit No. 1; Florida Power & Light Company. Docket No. 50-335. Directorate of Licensing. Washington, D.C. June 1973.

6.5-2 U.S. Atomic Energy Commission. Final Environmental Statement Related to the Construction of St. Lucie Plant, Unit No. 2; Florida Power & Light Company. Docket No. 50-389. Directorate of Licensing. Washington, D.C. May 1974.

6.5-3 U.S. Nuclear Regulatory Commission. Final Environmental Statement Related to the Operation of St. Lucie Plant, Unit No. 2; Florida Power & Light Company, Orlando Utilities Commission of the City of Orlando, Florida. Docket No. 50-389. NUREG-0842. Office of Nuclear Reactor Regulation. Washington, D.C. April 1982.

7.0 ALTERNATIVES TO THE PROPOSED ACTION

NRC

The environmental report shall discuss "Alternatives to the proposed action…." 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2)

"...The report is not required to include discussion of need for power or the economic costs and economic benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation...." 10 CFR 51.53(c)(2)

"While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable…" (Ref. 7.0-1, Section 8.1)

"…The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area…." (Ref. 7.0-2, Section II.H, page 66541)

Florida Power & Light Company's (FPL's) evaluation of alternatives to St. Lucie Units 1 & 2 license renewal is described in this Chapter. The evaluation includes an examination of actions that FPL might take, and associated environmental impacts, if the U.S. Nuclear Regulatory Commission (NRC) does not renew the plant operating licenses. It also includes a description of alternative actions that FPL has evaluated but determined to be unreasonable and presents the information upon which FPL bases that determination.

FPL divided its alternatives discussion into two categories: "no action" and "alternatives that meet system generating needs." In determining the level of detail and analysis necessary for each category, FPL relied on the NRC decision-making standard for license renewal:

> "…the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision makers would be unreasonable." [10 CFR 51.95(c)(4)]

FPL determined that as long as the environmental report provides information sufficient to clearly indicate whether an alternative would have a smaller, comparable, or greater environmental impact than the proposed action, the document would support NRC decision making. Providing additional detail or analysis would serve no function if it would only bring to light more adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which provide that the consideration of alternatives (including the proposed action) devote substantial enough treatment that reviewers may evaluate their comparative merits [40 CFR 1502.14(b)]. Therefore, FPL has generally limited its evaluation of alternatives to the level of detail sufficient to establish the basis for comparisons with impacts of the proposed action, which are described in Chapter 4.

In characterizing environmental impacts from alternatives, FPL has used the same definitions of "SMALL," "MODERATE," and "LARGE" that are provided in the Chapter 4 Introduction (see Section 4.1.2).

7.1 NO-ACTION ALTERNATIVE

FPL is using the phrase “no-action alternative” to refer to a scenario in which the NRC does not renew the St. Lucie Units 1 & 2 operating licenses. Components of this alternative include replacing the generating capacity of St. Lucie Units 1 & 2, or otherwise meeting FPL’s generating needs, and decommissioning the facility as described below.

St. Lucie Units 1 & 2 supply approximately 1,678 megawatts (MW) of capacity to the FPL system and annually provide approximately 13.7 terawatt-hours of electricity to the grid that supplies electricity to Florida customers, including approximately ½-million households. FPL believes that any alternative would be unreasonable if it did not include replacing an equivalent amount of capacity in a way that would enable the FPL system to “make up” this amount of annual energy. Replacement could be accomplished by (1) building new generating capacity, (2) purchasing power from outside the FPL system, or (3) reducing power requirements through demand reduction. FPL provides a detailed description of each of these possibilities in Section 7.2.1; Section 7.2.2 describes the environmental impacts that would result from implementation of alternatives determined to be feasible.

The NRC, in its *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), i.e., NUREG-1437, defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. The decommissioning options that the NRC evaluated in the GEIS include immediate decontamination and dismantlement (DECON) and safe storage of the stabilized and defueled facility (SAFSTOR) for a period of time, followed by decontamination and dismantlement. Regardless of the option chosen, decommissioning must be completed within a 60-year period (Ref. 7.0-1, Chapter 7). Under the no-action alternative, FPL would continue operating St. Lucie Units 1 & 2 until the current licenses expire, then initiate decommissioning activities for both Units at the time of expiration of the Unit 2 license in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of a reactor larger than St. Lucie Units 1 & 2 (the “reference” pressurized-water reactor is the 1,175-MW Trojan Nuclear Plant). This description bounds decommissioning activities that FPL would conduct for St. Lucie Units 1 & 2.

As indicated in the GEIS, the NRC has evaluated environmental impacts from decommissioning. The impacts the NRC evaluated include occupational and public dose; impacts of waste management; and impacts to air, water, ecological, and socioeconomic resources. The NRC has indicated that the decommissioning environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations (Ref. 7.1-1, page 4-15). FPL adopts by reference the GEIS conclusions regarding environmental impacts of decommissioning.

FPL notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. FPL will have to decommission St. Lucie Units 1 & 2 regardless of the NRC decision on license renewal; license renewal would only postpone decommissioning for another 20 years. The NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. FPL adopts by reference the NRC findings to the effect that delaying decommissioning until after the renewal term would have small

environmental impacts (10 CFR 51, Subpart A, Appendix B, Table B-1, “Decommissioning”). The discriminators between the proposed action and the no-action alternative lie within the choice of generation replacement options that compose the no-action alternative. FPL’s analysis of the impacts from these options is provided in Section 7.2.2.

FPL concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those that would occur following license renewal as identified in the GEIS. These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

Decisions regarding reasonable alternatives for meeting electric reliability needs in Florida are made primarily by two entities, utility companies and the Florida Public Service Commission (FPSC). The current mix of generation in Florida is one indicator of what these entities believe have been and continue to be feasible alternatives within the State. Data available at the time of this study show that Florida's electric utility industry had a total generating capability of 36.5 gigawatts-electric fueled by gas or oil dual fired (35 percent), coal (29 percent), oil (17 percent), nuclear (11 percent), gas (8 percent), and other, which includes hydroelectric, geothermal, biomass, wind, solar thermal, and photovoltaic (0.1 percent) (Ref. 7.2-1). Based on 1998 generation, utilization of this capability was dominated by coal (39 percent), followed by oil (24 percent), gas (19 percent), nuclear (18 percent), and other (0.1 percent) (Ref. 7.2-1).

The differences between capability and utilization are reflections of preferential usage influenced primarily by the economics of dispatching the various types of units. For example, nuclear energy represented 11 percent of installed capability but produced 18 percent of the electricity generated. This reflects the state's preferential reliance on nuclear energy as a baseload generating source. Figure 7.2-1 illustrates Florida utilities' 1998 generating capabilities and utilization.

Florida has experienced a drop in oil-fired generation that is at least partially attributable to FPSC Order 9552 and Rule 25-17.016, which the FPSC issued during the 1980s to reduce reliance on oil as a generation fuel. The FPSC has since repealed the Rule and Order.

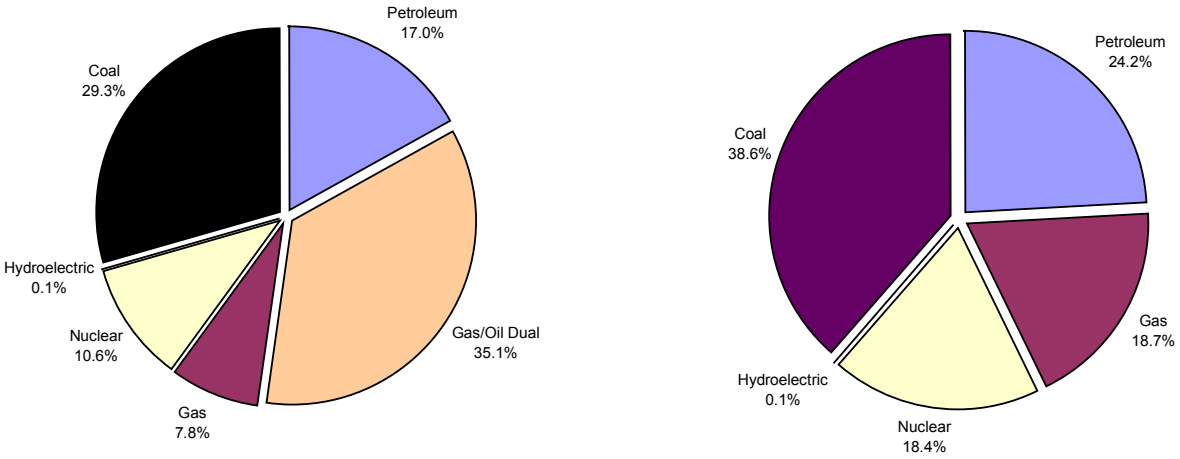
FPL's generation utilization is slightly different than the State composite, reflecting a higher reliance on nuclear energy and a lower reliance on coal, as illustrated in Figure 7.2-2 for the years 1998 and 2000. FPL's *Ten-Year Power Plant Site Plan: 2001-2010* provides detailed fuel and energy source forecasts through 2010 (Ref. 7.2-2).

7.2.1 ALTERNATIVES CONSIDERED

7.2.1.1 BUILD NEW GENERATING CAPACITY

The NRC indicated in the GEIS that while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy given the purposes of the alternatives analysis. Therefore, the NRC determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation technologies that are technically reasonable and commercially viable (Ref. 7.0-1, page 8-1). Consistent with the NRC determination, FPL has not evaluated mixes of generating sources.

FPL periodically performs a rigorous evaluation of a wide variety of generating technologies and annually evaluates what it considers to be the most viable options. FPL's last evaluation of a wide variety of generating technologies took place in 1991. The evaluation considered not only commercially existing supply technologies, but also emerging technologies that might prove to be feasible later on. The 38 generation options FPL evaluated and the evaluation results are summarized in Table 7.2-1.

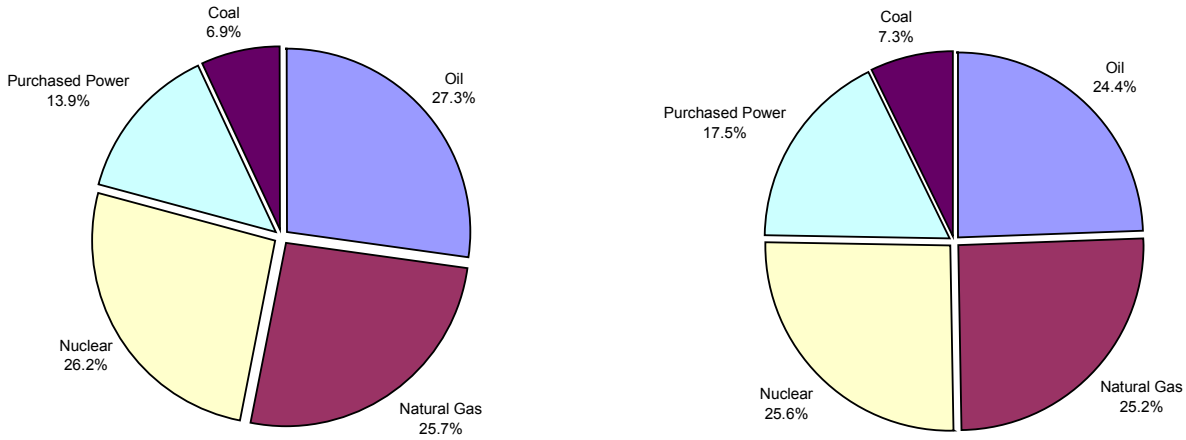


Capability **Utilization**

FIGURE 7.2-1 FLORIDA UTILITY GENERATION CAPABILITY AND UTILIZATION (1998)

NOTES:

Source: Ref. 7.2-1.



1998 **2000**

FIGURE 7.2-2 FPL GENERATION UTILIZATION (1998 AND 2000)

NOTES:

Source: Ref. 7.2-2, Schedule 6.2; Ref. 7.2-3, Schedule 6.2.

TABLE 7.2-1
1991 TECHNICAL FEASIBILITY EVALUATION OF FPL GENERATION OPTIONS

Technology	Economic Candidate	Technical Maturity	Technical Feasibility
Coal			
Steam, wet limestone, FGD, 400 MW	No	Existing	Feasible
Steam, wet limestone, FGD, 800 MW	Yes	Existing	Feasible
Steam, dry FGD, subcritical	No	Existing	Limited fuel range
Atmospheric fluidized bed, circulating	No	Existing	Scale-up limitations
Atmospheric fluidized bed, bubbling	No	Demonstration	Feasible
Pressurized fluidized bed, bubbling combined cycle	No	Demonstration	Feasible
Coal gasification, combined cycle	Yes	Demonstration	Feasible
Oil/Gas			
Oil, steam, wet limestone FGD, 400 MW	No	Existing	Feasible, but undesirable primary fuel
Conventional combustion turbine	No	Existing	Feasible, but not as good as advanced CT
Advanced combustion turbine	Yes	Existing	Feasible
Intercooled injected gas turbine	No	Demonstration	Feasible
Conventional combined cycle	No	Existing	Feasible, but not as good as advanced CT
Advanced combined cycle	Yes	Existing	Feasible
Advanced combustion turbine repowering	No	Existing	Feasible
Fuel Cell			
Phosphoric acid	No	Demonstration	Feasible
Molten carbonate	No	Demonstration	Feasible
Solid oxide	No	Prototype	Feasible
Orimulsion			
Orimulsion, steam, wet limestone, FGD, subcritical, 800 MW	Yes	Existing	Feasible
Nuclear			
Pressurized water reactor	No	Existing	Feasible
Liquid metal fast-breeder reactor	No	Prototype	Feasible
Advanced passive reactor	No	Design	Feasible
Hydro			
Conventional 400 MW	No	Existing	Insufficient resources

NOTES:

CT = combustion turbine

FGD = flue-gas desulfurization

FPL = Florida Power & Light Company

MW = megawatts

TABLE 7.2-1 (continued)
1991 TECHNICAL FEASIBILITY EVALUATION OF FPL GENERATION OPTIONS

Technology	Economic Candidate	Technical Maturity	Technical Feasibility
Renewables			
Geothermal	No	Existing	Insufficient resources
Wind turbines	No	Existing	Insufficient resources
Hybrid solar central receiver	No	Existing	Concern over Florida solar resources
Solar photovoltaic	No	Existing	Concern over production capabilities
Ocean thermal	No	No major sponsor	Feasible
Ocean current	No	No major sponsor	Feasible
Ocean wave	No	No major sponsor	Insufficient resources
Ocean tidal	No	Existing	Insufficient resources
Wood-fired steam	No	Existing	Insufficient resources
Municipal refuse steam	No	Existing	Insufficient resources
Storage			
Lead acid battery	No	Existing, with supply limitations	Feasible
Advanced battery	No	Developmental	Feasible
Pumped hydro	No	Existing	Inappropriate geography
Compressed air – rock, salt, aquifer	No	Existing	Inappropriate geology
Compressed air – vessel	No	Existing	Feasible, but limited application
Superconducting magnetic energy	No	No major sponsor	Feasible

NOTES:

CT = combustion turbine

FGD = flue-gas desulfurization

FPL = Florida Power & Light Company

MW = megawatts

Of the nine alternative generation options that the NRC evaluated in the GEIS (wind, solar photovoltaic, solar thermal power, hydroelectric, geothermal, wood waste, municipal solid waste, energy crops, and advanced light-water reactor), the FPL study addressed all but energy crops. The NRC analyzed these latter two technologies for the Calvert Cliffs, Oconee, Arkansas Nuclear One, and Plant Hatch license renewals (Ref. 7.2-4, Section 8.2.4; Ref. 7.2-5, Section 8.2.4; Ref. 7.2-6, Section 8.2.4; Ref. 7.2-7, Section 8.2.4). The NRC indicated that energy crop technology is not currently competitive or reliable enough for large baseload applications. FPL is unaware of any new information that would change this assessment and also concludes that this technology is not a reasonable alternative to St. Lucie Units 1 & 2 license renewal.

Similarly, the NRC cited relatively high costs and political uncertainties as reasons why new nuclear power plants were not forecasted to be built in the U.S. in the foreseeable future. Although both industry and government have recently expressed positive interest in the development of new nuclear power plants, new reactor designs have not yet been demonstrated to be capable of being built at a sufficiently attractive capital cost. Therefore, FPL does not consider nuclear power to be a reasonable alternative to St. Lucie Units 1 & 2 license renewal.

Table 7.2-2 presents the types of generating units examined by FPL in its annual review of alternative generation options. That analysis resulted in the preferred generation expansion plan presented in FPL's *Ten Year Power Plant Site Plan: 2001-2010* (Ref. 7.2-2, pages 5-8). As shown, the FPL review has focused on constructing coal- and gas-fired units and repowering existing units. Consistent with Table 7.2-2, FPL has evaluated one coal-fired technology, pulverized coal, and one gas-fired technology, combined cycle, as potential alternatives to St. Lucie Units 1 & 2 license renewal. In addition, FPL has evaluated oil-fired steam technology. Although FPL believes this presently to be an economically infeasible alternative (see Table 7.2-1), FPL has evaluated this option because of the unpredictability in the future price of oil relative to other fuel options, and because use of oil-fired generation may be advisable to provide the diversity of generation/fuel sources needed to ensure needed reliability in the future. FPL describes these alternatives in more detail in the following sections.

FPL has implemented a program of repowering existing units in order to meet its current predictions of load growth. "Repowering" means converting existing generating technology to combined-cycle technology. FPL has evaluated combined-cycle technology as one alternative to St. Lucie Units 1 & 2 license renewal, and believes that it appropriately represents repowering as an alternative. Therefore, FPL has not separately evaluated repowering as an alternative to St. Lucie Units 1 & 2 license renewal.

Generation capacity changes in the FPL system planned for 2001 through 2010 are projected to add 6,392 MW (summer) to 6,299 MW (winter) (Ref. 7.2-2, Section III.B). These changes reflect changes to existing units, scheduled changes in the delivered amounts of purchased power, repowering of existing units, new unit construction, and conversion of combustion turbine units to combined-cycle units. Since these generation capacity changes have been credited in FPL's *Ten-Year Power Plant Site Plan: 2001-2010* as necessary to meet projected customer demand and reserve margins (Ref. 7.2-2, Schedule 7.1), the capacity gains are not available to replace St. Lucie Units 1 & 2 capacity.

TABLE 7.2-2
2000 TECHNICAL FEASIBILITY EVALUATION OF FPL GENERATION OPTIONS

Technology	Economic Candidate	Technical Maturity	Technical Feasibility
Coal			
Circulating fluidized bed, 400 MW	Yes	Existing	Feasible
Pulverized coal, 400 MW	Yes	Existing	Feasible
Oil/Gas			
Combined cycle, H Machine, 400 MW	Yes	Design	Feasible
Combined cycle, G Machine, 300 MW	Yes	Existing	Feasible
Combined cycle, H Machine, 800 MW	Yes	Design	Feasible
Combustion turbine, 150 MW	Yes	Existing	Feasible
Combined cycle, F Machine, 500 MW	Yes	Existing	Feasible
Repowering of existing steam units	Yes	Existing	Feasible

NOTES:
FPL = Florida Power & Light Company
MW = megawatt

A discussion of fossil-fuel-fired generation and imported power as reasonable alternatives to license renewal follows. Due to the need to have "replacement" fossil-fuel generating facilities in operation on the date the St. Lucie Units 1 & 2 facility would cease operation and the small amount of potentially usable space at the St. Lucie site, FPL made the assumption that all of the replacement units would be constructed at presently unknown "greenfield" sites in central Florida, generally in the area south of Orlando and north of Miami.

FPL owns 100 percent of the St. Lucie Unit 1 capacity, but 15 percent of the capacity of St. Lucie Unit 2 is contractually obligated to entities in Florida other than FPL. A denial of the St. Lucie Units 1 & 2 license renewal request would nonetheless result in the need to replace 100 percent of the capacity of both Units. Therefore, FPL has assumed for this evaluation that the entire capacity of St. Lucie Units 1 & 2 would be replaced.

7.2.1.1.1 COAL-FIRED GENERATION

A scenario of, for example, four 420-MW coal-fired units could be assumed to replace the 1,678-MW St. Lucie Units 1 & 2 capacity. However, FPL's experience indicates that although customized unit sizes can be built, using standardized sizes is more economical. As Table 7.2-2 shows, FPL has recently evaluated a 400-MW coal-fired unit. Assuming four 400-MW units, for a total of 1,600 MW, would result in slightly less generating capacity than a one-for-one replacement of St. Lucie Units 1 & 2. Assuming five 400-MW units, for a total of 2,000 MW, would result in excess capacity. In order to avoid overestimating environmental impacts from the coal-fired generation alternative, FPL evaluated an alternative that consists of four 400-MW coal-fired units.

Table 7.2-3 presents the basic coal-fired generation alternative and associated emission control characteristics. FPL based its emission control technology and percentage control

TABLE 7.2-3
COAL-FIRED GENERATION ALTERNATIVE

Characteristic	Basis
Unit size = 400-MW ISO rating net[a]	Standard size (FPL experience)
Unit size = 424-MW ISO rating gross[a]	Calculated based on 6 percent onsite power usage (FPL experience): 400 MW x 1.06
Number of units = 4	Calculated to be < St. Lucie Units 1 & 2 net capacity of 1,678 MW
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (Ref. 7.2-8, Table 1.1-3)
Fuel type = bituminous, pulverized coal	Typical for coal used in Florida (FPL experience)
Fuel heating value = 12,116 Btu/lb	Typical for coal used in Florida - 1999 (Ref. 7.2-9)
Fuel ash content by weight = 8.0 percent	Typical for coal used in Florida - 1999 (Ref. 7.2-9)
Fuel sulfur content by weight = 1.63 percent	Typical for coal used in Florida - 1999 (Ref. 7.2-9)
Heat rate = 9,800 Btu/kWh	Typical for coal-fired steam turbine generators (FPL experience)
Capacity factor = 0.9	Typical for large coal-fired units (FPL experience)
NO_x control = low NO_x burners, overfire air, selective catalytic reduction (95 percent reduction)	Best available for minimizing NO_x emissions (Ref. 7.2-8, Section 1.1.4.3 and Table 1.1-2).
Particulate control = fabric filters or electrostatic precipitators (99.9 percent removal efficiency)	Best available for minimizing particulate emissions (Ref. 7.2-8, Section 1.1.4.1)
SO_x control = Wet limestone flue-gas desulfurization (90 percent removal efficiency)	Best available for minimizing SO_x emissions (Ref. 7.2-8, Section 1.1.4.2 and Table 1.1-1)

NOTES:

a. The difference between “net” and “gross” is electricity consumed on site.

Btu = British thermal unit

FPL = Florida Power & Light Company

ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch

kWh = kilowatt hour

lb = pound(s)

MW = megawatts

NOx = nitrogen oxides

Ref. = Reference

SOx = sulfur oxides

assumptions on alternatives that the U.S. Environmental Protection Agency (EPA) has identified as being available for minimizing emissions (Ref. 7.2-8). A pulverized coal-fired design for this alternative would likely utilize precipitators and, at inland sites with an adequate freshwater supply, wet scrubbers. Coal and limestone (or lime) would be delivered by rail, or possibly barge at coastal locations, to the greenfield site. Additional offsite facilities that could be required for this alternative include transmission lines to connect the plant to the grid and cooling water intake and discharge pipelines (see Section 7.2.2).

7.2.1.1.2 OIL-FIRED GENERATION

Use of oil as an energy source for power generation in Florida has declined since the late-1980s (Ref. 7.2-1), due in part to past FPSC policies that encouraged alternatives that minimized use of oil as a generation fuel, and in part by economic considerations. In order to make the oil-fired generation alternative most directly comparable to the coal- and gas-fired generation alternatives, FPL assumed four 400-MW units. The basic oil-fired generation alternative characteristics are presented in Table 7.2-4. As is the case for the coal-fired generation alternative, FPL assumed construction at a greenfield site in central Florida, but assumed fuel would be delivered by barge and, for inland sites, pipelines.

Additional offsite facilities that could be required for this alternative include transmission lines to connect the plant to the grid and cooling water intake and discharge pipelines (see Section 7.2.2).

FPL has assumed a capacity factor for the oil-fired generation alternative, 90 percent, that is the same as that for the coal- and gas-fired generation alternatives. This assumption makes the three alternatives most directly comparable. However, FPL notes that, from a practical standpoint, the oil-fired utilization would probably be closer to 50 percent. This reduced utilization would be a reflection of the high cost of fuel oil rather than any limitation inherent in the technology. The utility might choose to operate other technologies or purchase power before using the oil-fired generation alternative. However, FPL has addressed the impacts of other technologies (i.e., gas- and coal-fired generation) and power purchase in its alternatives analysis.

7.2.1.1.3 GAS-FIRED GENERATION

As previously discussed for coal-fired generation, FPL experience indicates that standardized gas-fired unit sizes are available and are more economical than customized unit sizes. FPL has analyzed three 596-MW gas-fired combined-cycle units located at a greenfield site in central Florida. These units correspond to the 500-MW “F-Machine” listed in Table 7.2-2, but are configured for duct-firing to more readily accommodate changes in demand.

The total net capability of the units (1,788 MW), more fully described in Table 7.2-5, would be slightly higher than the combined capability of St. Lucie Units 1 & 2 (1,680 MW) when all three units are duct-fired. It is unclear what pollution control equipment would be required for these units in 2016, when St. Lucie Unit 1 would be replaced. However, for purposes of this analysis, dry-low nitrogen oxides (NO_x) combustors or water-steam injection and selective catalytic reduction for NO_x control are assumed.

TABLE 7.2-4
OIL-FIRED GENERATION ALTERNATIVE

Characteristic	Basis
Unit size = 400-MW ISO rating net[a]	Standard size (FPL experience)
Unit size = 416-MW ISO rating gross[a]	Calculated based on 4 percent onsite power usage (FPL experience): 400 MW x 1.04
Number of units = 4	Calculated to be < St. Lucie Units 1 & 2 net capacity of 1,678 MW
Fuel type = No. 6 fuel oil	Typical for oil-fired units in Florida (FPL experience)
Fuel heating value = 151,705 Btu/gal	Typical for No. 6 fuel oil used in Florida - 1999 (Ref. 7.2-9)
Fuel ash content by weight = 0.21 percent	Typical for No. 6 fuel oil (calculated from uncontrolled emission factor for particulates from Ref. 7.2-10, Table 1.3-4; density of residual oil from Ref. 7.2-11, page A-6)[b]
Fuel sulfur content by weight = 1.45 percent	Typical for No. 6 fuel oil used in Florida - 1999 (Ref. 7.2-9)
Heat rate = 9,800 Btu/kWh	Typical for fuel-oil-fired steam turbine generators (FPL experience)
Capacity factor = 0.9	Typical for large oil-fired units (FPL experience)
NO_x control = low NO_x burners; selective catalytic reduction (85 percent reduction)	Best available for minimizing NO_x emissions (Ref. 7.2-10, Section 1.3.4.3)
Particulate control = fabric filters (99 percent removal efficiency)	Best available for minimizing particulate emissions (Ref. 7.2-10, Section 1.3.4.1)
SO_x control = Wet limestone flue-gas desulfurization (90 percent removal efficiency)	Best available for minimizing SO_x emissions (Ref. 7.2-10, Section 1.3.4.2)

NOTES:

a. The difference between “net” and “gross” is electricity consumed on site.

b. Percent Ash (assumed approx. = percent particulates) = 8.3A lb/1000 gal x 1gal/7.88 lb x 100, where A = 1.12 x percent sulfur by weight + 0.37. Therefore: Percent Ash = 8.3 x [1.12 x 1.45 + 0.37] x 1/7.88 x 100 = 0.21.

Btu = British thermal unit

FPL = Florida Power & Light Company

gal = gallon

ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch

kWh = kilowatt hour

lb = pound

MW = megawatt

NOx = nitrogen oxides

Ref. = Reference

SOx = sulfur oxides

TABLE 7.2-5
GAS-FIRED GENERATION ALTERNATIVE

Characteristic	Basis
Unit size = 596-MW ISO rating net:[a] 2 ea. 170-MW combustion turbines 1 ea. 256-MW heat recovery boiler	Standard size (FPL experience)
Unit size = 609 MW ISO rating gross:[a] 2 ea. 174-MW combustion turbines 1 ea. 261-MW heat recovery boiler	Standard size (FPL experience)
Number of units = 3	Approximates St. Lucie Units 1 & 2 net capacity of 1,678 MW
Fuel type = natural gas	Assumed
Fuel heating value = 1,019 Btu/ft^3	Typical for natural gas used in Florida - 1999 (Ref. 7.2-9)
Fuel sulfur content = 1 grain/100 ft^3 (= 0.0034 wt %)	Typical for FPL estimates
Heat rate = 7,150 Btu/kWh	Typical for gas-fired combined-cycle units with duct firing (FPL experience)
Capacity factor = 0.9	Typical for large gas-fired units (FPL experience)
NO_x control = dry-low NO_x combustors or water-steam injection; selective catalytic reduction (90% reduction)	Best available for minimizing NO_x emissions (Ref. 7.2-14, Section 1.4.4; Ref. 7.2-15, Section 3.1.4)

NOTES:

a. The difference between "net" and "gross" is electricity consumed on site.

Btu = British thermal unit

ea. = each

FPL = Florida Power & Light Company

ft^3 = cubic foot

ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch. Ratings are for units with duct firing.

kWh = kilowatt hour

MW = megawatts

NOx = nitrogen oxides

Ref. = Reference

wt = weight

It is currently unclear whether adequate supplies of natural gas would be available in central Florida for a large consumptive facility such as the St. Lucie Units 1 & 2 gas-fired generation alternative. Demand is expected to exceed current capacity in the near future; however, the current main supplier to Florida's utilities, Florida Gas Transmission (FGT), has indicated it would expand its natural gas pipeline system, which has a current capacity of 1.5 billion cubic feet per day (bcf/day), to meet all forecasted electric demand (Ref. 7.2-12, page 15). In addition, a major new supply pipeline is being constructed to meet demand in this area of Florida, the Williams-Duke Gulfstream Natural Gas System "Gulfstream" project. This project, recently approved, is projected to provide an additional 1.1 bcf/day in Phase I capacity to Florida through pipelines from Pascagoula, Mississippi, and Mobile, Alabama, across the Gulf of Mexico some 400 miles to near Tampa, Florida, then to interior Florida (Ref. 7.2-13). This project is expected to be completed by June 2002, and would meet demands for many years. However, FPL assumes that if sufficient capacity is not available, demand posed by the gas-fired generation alternative could contribute to a decision to construct an additional pipeline similar to the Gulfstream project or development of any alternate means of ensuring adequate supply.

In any event, FPL assumes that a natural gas pipeline from a main supply line would have to be constructed to implement this alternative. Additional offsite facilities that could be required include transmission lines to connect the plant to the grid and cooling water intake and discharge pipelines (see Section 7.2.2).

7.2.1.2 PURCHASE POWER

FPL currently has contracts (some extending through 2026) with a number of cogeneration, small power-production facilities, and other utilities to purchase firm capacity and energy (Ref. 7.2-2, Sections 1.B and 1.D). A cogeneration facility simultaneously produces electrical and thermal energy, with the thermal energy being used for industrial, commercial, or cooling and heating purposes. A small power-production facility does not (without exemption) exceed 80-MW capacity and uses renewable resources as its primary energy source. Because these contracts are part of FPL's current and future capacity and no substantial new capacity additions from cogeneration facilities are foreseen in the non-utility generation sector, FPL does not consider such power purchases a feasible option for the purchase-power alternative.

Florida is a net importer of power (Ref. 7.2-1) and, as Figure 7.2-2 shows, power purchase is a substantial portion of the FPL energy mix. FPL plans to contract the purchase of approximately 1,300-2,400 megawatts of capacity annually, much of which is coal-fired, to meet projected customer demand through mid-year 2010 (Ref. 7.2-2, Section 1.0). FPL presumes that this capacity might be available for purchase after the year 2010, and could be imported to the region to meet demand. However, because FPL is using it to meet currently projected demand, FPL could not rely on this power purchase as an alternative to St. Lucie Units 1 & 2 license renewal. Therefore, FPL assumes that the capacity for the purchase-power alternative would come from other sources. FPL also assumes that the generating technology for the purchase-power alternative would be one of those that the NRC analyzed in the GEIS. For this reason, FPL is adopting by reference, as representative of the purchase-power alternative, the GEIS description of the alternative generating technologies.

Florida's peninsula limits interconnection alternatives for obtaining imported power, and the location of the St. Lucie Units 1 & 2 load center (i.e., central Florida) would require FPL to construct additional transmission facilities from the Florida State line to central Florida, a distance of approximately 200-300 miles. In addition, depending on the source of the imported power, additional transmission facilities may have to be built in other states to the Florida State line.

7.2.1.3 REDUCE DEMAND

FPL has an aggressive demand-side management (DSM) program that reduces generation needs through a combination of energy conservation and load management programs. FPL's Ten Year Power Plant Site Plan: 2001-2010 describes these programs and details annual DSM goals, including a DSM cumulative summer reduction goal of 795 MW between 2000 and 2009 (Ref. 7.2-2, Section III.C). DSM program reductions from 1981 through 2000 have totaled approximately 3,036 MW, of which 1,678 MW are attributed to energy conservation and 1,358 MW are from load management. Progress for the period 1993 through 2000 is illustrated in Figure 7.2-3. Historical and projected DSM reductions have been credited in FPL's Ten-Year Site Plan: 2001-2010 as necessary to meet part of FPL's projected customer demand.

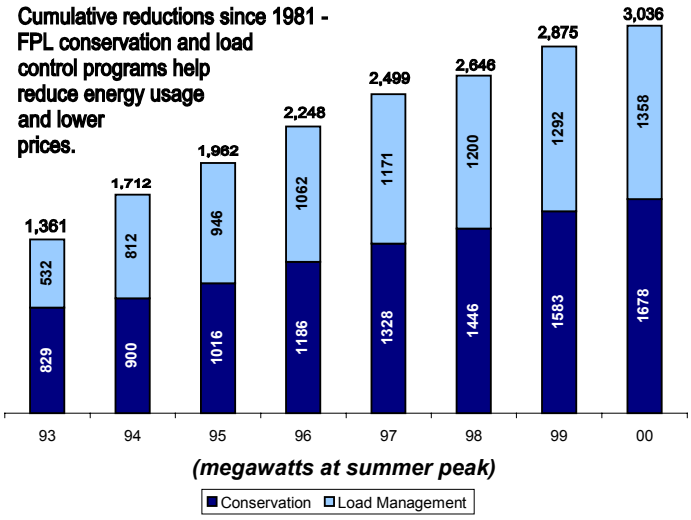


FIGURE 7.2-3 FPL DEMAND-SIDE MANAGEMENT (1993-2000)

NOTES:

Source: Ref. 7.2-16.

In theory, additional DSM could be found in FPL's service territory, which would, in total or in part, replace the resources lost if the St. Lucie Units 1 & 2 licenses were not renewed. FPL can only ascertain the actual feasibility of additional DSM with a detailed economic-based study, which would determine how much money would be cost-effective to spend on DSM versus other options such as license renewal or acquiring replacement generation capacity. Once this amount of money was established, FPL could determine the market potential of DSM that could reasonably be achieved with these expenditures. FPL has not performed such an economic analysis of this specific issue.

However, FPL has performed relevant environmental analyses of DSM versus new generating units that provide valuable insight into how DSM would compare with license renewal of a nuclear power unit from an environmental perspective. These analyses, which focused on total air emissions from the FPL system, looked at whether total system emissions would be greater with the addition of new units or with the addition of DSM to meet FPL's new resource needs. The results of these analyses have consistently shown that FPL's total system emissions would be higher if DSM were chosen instead of new baseload units, particularly so if the new baseload units were gas-fired. This result is driven by two primary factors: the relatively low “capacity factor” of DSM compared to that of baseload units, and the significantly lower emission rates of new baseload units compared to those of FPL's existing units. Based on these results, it is expected that a similar analysis that focused on additional DSM versus the continued operation of a baseload nuclear power unit (which has even lower emissions than a new gas-fired unit) would show that DSM as a replacement for this nuclear power capacity would be an even worse choice from an air-emissions perspective. Consequently, from an environmental perspective, additional DSM is not considered to be a viable alternative to the license renewal and continued operation of St. Lucie Units 1 & 2.

7.2.2 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

In this section, FPL evaluates the feasible alternatives to St. Lucie Units 1 & 2 license renewal that were presented in Section 7.2.1.1 (i.e., development of new coal-, oil-, or gas-fired generating capacity at hypothetical greenfield sites in central Florida, and purchase of power from other suppliers). FPL has made the following common assumptions to facilitate its evaluation of new generation alternatives presented in Sections 7.2.2.1 through 7.2.2.3, and to establish development scenarios that are reasonable and do not overstate potential adverse impacts of these alternatives relative to the proposed action:

- The new generating capacity would be developed as a single multi-unit site rather than multiple sites. Location of multiple units at a single site is standard utility practice that offers economies through the use of shared facilities and resources, and minimizes the amount of land required.
- The new generating capacity would be developed with closed-cycle cooling using mechanical draft cooling towers. This cooling scheme is commonly used for new power plants and broadens the potential availability of potentially acceptable greenfield sites for purposes of the evaluation.
- The new generating capacity would be phased as needed to replace the capacity of St. Lucie Unit 1 in 2016, and Unit 2 in 2023.

- The new generating capacity would operate for 25-40 years. Design lives of 25 years for gas-fired units and 40 years for coal-fired units are commonly assumed by the utility industry. Based on economic considerations, FPL would not commit to build and operate new baseload units for only 20 years, the period of extended operation of St. Lucie Units 1 & 2.
- The hypothetical greenfield site would be located on the basis of a siting analysis that would ensure it is within reasonable distance to an acceptable source of cooling water and the transmission grid, and would avoid areas of obviously conflicting land use or resource value (e.g., residential areas, formally designated natural and cultural resource areas). It is specifically assumed for these analyses that the site would be located:
  - in central Florida in the area generally north of Miami and south of Orlando,
  - close enough to a coastal or inland water body suitable as a cooling water source, precluding the necessity to construct a cooling pond,
  - within approximately 20 miles from suitable interconnection to the grid [a 330-foot transmission line right-of-way (ROW) is assumed, based on that currently used for transmission lines from St. Lucie Units 1 & 2], and
  - on land where development can be essentially restricted to areas that have been previously disturbed (e.g., through agriculture, logging, industrial development).

7.2.2.1 COAL-FIRED GENERATION

As discussed in Section 7.2.1.1, FPL's reference coal-fired generation alternative for this evaluation consists of a four-unit pulverized coal-fired plant. Basic specifications for the generating units, fuel, and air emissions controls are provided in Table 7.2-3. In addition to the general assumptions stated above, FPL assumes for purposes of this evaluation that limestone used for scrubber operation and coal would be delivered by rail or possibly barge at coastal sites or by rail at inland sites. FPL's evaluation is based, in part, on information provided by the NRC in the GEIS (Ref. 7.0-1, Chapter 8) and GEIS supplements (Ref. 7.2-4, Section 8.2.1; Ref. 7.2-5, Section 8.2.1), which reference utility plans for modern pulverized coal-fired plants comparable to FPL's representative plant.

7.2.2.1.1 LAND USE

The amount of land required to accommodate the representative coal-fired power plant alternative can vary widely from site to site, depending on such factors as facility configuration, and the need for onsite disposal of site clearing debris or buffer areas as may be appropriate for isolation from adjacent land uses (e.g., visual screening) or protection of natural resources (e.g., wetlands). Based on estimates for power generating and support facilities cited by the NRC for a comparable three-unit, 1,800-MW new facility (Ref. 7.2-4) and calculated area requirements for onsite waste disposal, FPL estimates that approximately 1,155 acres would be required for the plant site. Estimated onsite land requirements and possible land requirements for offsite facilities are as follows:

Component	Area (Acres)
Plant Site	
Power Generation Facilities (power block, coal storage/handling, rail or barge facilities, cooling towers, storage tanks, etc.)	325
Infrastructure and Support Facilities (switchyard, roads, parking, office buildings, water supply, sewage treatment, etc.)	150
Waste Disposal (ash and sludge disposal)	680
Plant Site Total	1,155
Offsite	
Transmission Line (assumed 20 miles, 330-foot ROW)	800
Rail Spur (assumed 20 miles, 50-foot ROW)	120
Cooling Water Intake/Discharge Pipelines (assumed 2 miles, 100-foot ROW)	20
Offsite Total	940
Total	2,095

Specific needs to conform the site to minimize environmental impacts on site and in adjacent areas could increase land area requirements. For example, the NRC cites an estimate of 1,700 acres for a 1,000-MW plant in the GEIS (Ref. 7.0-1, Table 8.1). Specific land requirements to accommodate such needs would be determined on the basis of an appropriate site planning analysis. Depending on the location of the greenfield site, additional land could be required off site for new transmission lines to connect the plant to the electric grid and a new rail line to transport coal and limestone to the plant. Offsite cooling water intake and discharge pipelines also may be used in view of continued development bordering the coast and inland water bodies in central Florida. FPL assumes that approximately 940 acres could be required for these offsite facilities, as listed above, and that these linear features would be routed, designed, and constructed to ensure conflicts with existing land use are at acceptable levels.

Under the assumptions of this evaluation, the coal-fired plant site may be located in an industrial area resulting in little immediate change in land use. However, considering the large area requirements for the plant, it would more likely be located on land that is predominantly current or former agricultural cropland or otherwise characterized by disturbed natural vegetation, land-use resources that are common in central Florida. Approximately 1,155 acres would be dedicated to industrial use for the life of the plant, and land uses that could compromise the integrity of the landfill area would be precluded on approximately 680 acres for the long term. These changes would be clearly noticeable, even in an industrial area, but would not be expected to destabilize land use in the surrounding area. Associated land-use impact is, therefore, considered to be MODERATE.

Land use would be similarly affected by offsite linear facilities that may be required. FPL assumes that the required transmission lines and rail line would be routed primarily across rural lands characterized by a predominance of active and former agricultural lands and previously disturbed natural vegetation. Existing land use for the area occupied by the rail line (120 acres assumed) would be converted exclusively to transportation use. Installation

of these facilities would be noticeable but would not be expected to change the basic land-use characteristics of the area, and some current land uses (e.g., agriculture) could continue within the transmission line ROW. Resultant impacts are, therefore, considered to be SMALL to MODERATE.

Overall, impact on land use associated with the coal-fired generation alternative is considered to be MODERATE.

7.2.2.1.2 ECOLOGICAL RESOURCES

Under the conditions assumed for this evaluation and considerations discussed below, potential impact to ecological resources resulting from development of the coal-fired generation alternative at a hypothetical greenfield site is considered to be MODERATE. FPL assumes that all onsite and offsite facilities would be located and configured to ensure appropriate protection of highly valued species and habitats on the basis of an appropriate siting analysis and pre-construction baseline surveys. In addition, FPL notes that actual site configuration could result in increased protection of onsite habitats that are not occupied by plant facilities.

Construction of site facilities is assumed to result in the loss of 1,155 acres of relatively marginal terrestrial habitat (e.g., vacant industrial land, active or former agricultural land, disturbed natural vegetation) that is common in central Florida. A loss of 120 acres of mostly marginal terrestrial habitat could result from construction of rail access, if needed. Permanent alteration of habitat for construction of transmission lines would be limited primarily to conversion of forested areas to scrubland. Construction would also result in alteration of some aquatic habitat from construction of cooling water intake and discharge structures and, for coastal sites, possibly the construction of a barge channel and associated dockage and unloading facilities. Any construction in aquatic habitats and wetlands would be conducted in accordance with applicable U.S. Army Corps of Engineers and state permit conditions. Considering these controls and previously stated assumptions, construction impacts would noticeably alter habitats on the plant site and areas occupied by offsite facilities, but would not be expected to destabilize any species or other attribute of these ecological resources, a characteristic of MODERATE impact.

Operation of the coal-fired plant and associated transmission facilities would not be expected to result in noticeable adverse impact to terrestrial ecological resources, and positive impacts could be realized from management practices with respect to habitat maintenance in unoccupied areas of the site and along pipelines and transmission lines such as is practiced by FPL at the St. Lucie Units 1 & 2 site and associated transmission line rights-of-way. Potential impacts on aquatic ecological resources from plant operation include potential cooling water system impacts, particularly impingement and entrainment of aquatic organisms and potential impacts of thermal and biocide discharges. However, required compliance with provisions of the Clean Water Act (CWA), most notably Section 316(b) related to cooling water intake impacts and Section 402 [National Pollutant Discharge Elimination System (NPDES) permit for discharges to surface water], should ensure that associated adverse impacts on aquatic resources, while potentially noticeable, would not destabilize any important attribute of the resource. A similar conclusion applies to maintenance and operation of facilities associated with barge delivery of coal and limestone, which would be closely regulated by the U.S. Army Corps of Engineers and U.S. Coast

Guard. Operational impacts on ecological resources are, therefore, considered to be SMALL to MODERATE.

7.2.2.1.3 WATER QUALITY

Potential impacts on surface water quality from construction of onsite and offsite facilities for the coal-fired generation alternative may include minor, localized, and temporary introduction of sediments from such activities as land clearing, installation of cooling water intake and discharge structures, and possibly a barge channel and associated shore-based facilities. These impacts would be limited by appropriate best management practices and associated permit restrictions during both construction and operation. Considering the temporary and localized nature of these impacts and the regulatory controls that would be in place, associated impacts are considered to be SMALL.

Discharge of cooling water and other wastewater to surface water during operation represents a potential source of impact to water quality during operation. The proposed coal-fired generation alternative features closed-cycle cooling with mechanical draft cooling towers. Wastewater discharges from the plant would consist mostly of cooling tower blowdown, characterized primarily by an increased temperature and concentration of dissolved solids relative to the receiving water body (assuming it also serves as the makeup water source), and intermittent low concentrations of biocides (e.g., chlorine). Appropriately treated low-volume process waste streams and sanitary wastewater may also be discharged. However, all of these discharges would be subject to the strict limitations of an NPDES permit and, outside of an allowable mixing zone, changes in water quality characteristics generally should not be noticeable.

Overall impact to water quality is, therefore, considered to be SMALL.

7.2.2.1.4 AIR QUALITY

Air quality impacts of coal-fired generation differ substantially from those of nuclear power. A coal-fired plant would emit sulfur oxides, nitrogen oxides, particulate matter, and carbon monoxide, all of which are regulated pollutants. As indicated in Section 7.2.1.1, FPL has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. FPL estimates the coal-fired generation alternative emissions to be as follows:

Sulfur oxides(SOx) = 16,748 tons per year

Nitrogen oxides (NOx) = 2,028 tons per year

Carbon monoxide (CO) = 1,352 tons per year

Particulates:

Total suspended particulates = 216 tons per year

PM_{10} (particulates having diameter of less than 10 microns) = 50 tons per year

Table 7.2-6 shows the FPL calculations for these emissions.

All counties in Florida are in attainment for all criteria air pollutants. However, Orange, Duval, Hillsborough, Pinellas, Miami-Dade, Broward, and Palm Beach counties are

TABLE 7.2-6
AIR EMISSIONS FROM COAL-FIRED GENERATION ALTERNATIVE

Parameter	Calculation	Result
Annual coal consumption	$4\,\text{units} \times \frac{424\,\text{MW}}{\text{unit}} \times \frac{9{,}800\,\text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\,\text{kW}}{\text{MW}} \times \frac{\text{lb}}{12{,}116\,\text{Btu}} \times \frac{\text{ton}}{2000\,\text{lb}} \times 0.9 \times \frac{24\,\text{hr}}{\text{day}} \times \frac{365\,\text{day}}{\text{yr}}$	5,407,659 tons coal per year
SO_x[a,c]	$\frac{38 \times 1.63\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2000\ \text{lb}} \times (1 - 90/100) \times \frac{5{,}407{,}659\ \text{tons}}{\text{yr}}$	16,748 tons SO_x per year
NO_x[b,c]	$\frac{15\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2000\ \text{lb}} \times (1 - 95/100) \times \frac{5{,}407{,}659\ \text{tons}}{\text{yr}}$	2,028 tons NO_x per year
CO[c]	$\frac{0.5\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2000\ \text{lb}} \times \frac{5{,}407{,}659\ \text{tons}}{\text{yr}}$	1,352 tons CO per year
TSP[d]	$\frac{10 \times 8.0\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2000\ \text{lb}} \times (1 - 99.9/100) \times \frac{5{,}407{,}659\ \text{tons}}{\text{yr}}$	216 tons TSP per year
PM_{10}[d]	$\frac{2.3 \times 8.0\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2000\ \text{lb}} \times (1 - 99.9/100) \times \frac{5{,}407{,}659\ \text{tons}}{\text{yr}}$	50 tons PM_{10} per year

NOTES:

a. Based on data in Table 7.2-3 and Ref. 7.2-8, Table 1.1-1

b. Based on data in Table 7.2-3 and Ref. 7.2-8, Table 1.1-2

c. Based on data in Table 7.2-3 and Ref. 7.2-8, Table 1.1-3

d. Based on data in Table 7.2-3 and Ref. 7.2-8, Table 1.1-4

Btu = British thermal unit
CO = carbon monoxide
hr = hour
kW = kilowatt
lb = pound
MW = megawatt
NOx = nitrogen oxides
PM10 = particulates having diameter less than 10 microns
SOx = sulfur oxides
TSP = total suspended particulates (filterable)
yr = year

maintenance areas for ozone (Ref. 7.2-17). While there are numerous areas in central Florida where a plant could be located, proximity to maintenance areas would make it important to conduct modeling of NO_x emissions in view of the role they play in the formation of ground-level ozone.

The Clean Air Act (CAA) Amendments of 1990 specified a number of utility-owned/operated power plants to begin compliance with stricter emissions standards for SO_x and NO_x in 1995. Emissions of SO_x from Florida electric power generation declined from 1994 to 1995, but increased from 1995 to 1998. Emissions of both CO and NO_x, which had increased in years prior to 1995, leveled off in the period 1995-1997, then increased in 1998 (Ref. 7.2-1).

Although Florida participated in the Ozone Transport Assessment Group process, Florida generators are not subject to the recently announced proposal from the EPA requiring submission of state implementation plans to address the regional transport of ground-level ozone. However, Florida fossil-fuel-fired units are subject to the emissions reductions requirements of Phase II of the EPA's Acid Rain Program, which took effect January 1, 2000.

The CAA Amendments capped the nation's sulfur dioxide (SO_2) emissions from power plants, and each utility was allocated SO_2 allowances. To be in compliance with the Act, FPL must hold enough allowances to cover its SO_2 emissions annually. FPL would have to purchase additional allowances from the open market if it did not have enough surplus allowances to operate an additional fossil-burning plant at the greenfield site. The NRC did not quantify coal-fired emissions in the GEIS, but implied that air impacts would be substantial. In particular, the NRC noted that adverse human health effects from coal combustion have led to important federal legislation in recent years, and that public health risks, such as cancer and emphysema, have been associated with coal combustion. The NRC also mentioned global warming and acid rain as potential impacts. FPL concludes that federal legislation and large-scale issues, such as acid rain and global warming, are indications of concerns about destabilizing important attributes of air resources, and that sulfur dioxide emissions allowances, nitrogen oxide emissions offsets, low NO_x burners, overfire air, selective catalytic reduction, fabric filters or electrostatic precipitators, and scrubbers are essentially mitigation measures imposed through regulation. As such, FPL concludes that the coal-fired generation alternative impacts on air quality would be MODERATE; the impacts would be clearly noticeable but would not destabilize air quality in the area.

7.2.2.1.5 WASTE MANAGEMENT

FPL concurs with the NRC's assessment in the GEIS that the coal-fired generation alternative would generate a substantial amount of solid waste. Depending on land characteristics, large quantities of debris could be generated from construction clearing and grubbing operations on approximately 1,155 acres of the site. FPL assumes that this debris could be disposed of on site, possibly requiring additional acreage, or at an offsite facility. FPL assumes that municipal solid waste generated during construction and operation would be disposed of at a permitted offsite facility.

The coal-fired generation alternative would annually consume approximately 5,400,000 tons of coal having an ash content of 8.0 percent (see Tables 7.2-6 and 7.2-3). Nearly all of the ash (99.9 percent), approximately 430,000 tons per year (dry weight), would be collected.

FPL assumes that approximately 10 percent of the ash is bottom ash that would be used beneficially, and that the remaining (90 percent) would be fly-ash and disposed of on site. In addition, approximately 270,000 tons of limestone would be used annually for flue-gas desulfurization, generating approximately 586,000 tons (wet) of scrubber sludge that would be disposed of on site each year. Assuming a landfill depth of 30 feet, FPL estimates that ash and scrubber waste disposal over the 40-year plant life would impact approximately 680 acres. While only half of this waste volume and land use would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

FPL notes that some or all scrubber sludge from the assumed flue-gas desulfurization process (gypsum) and fly ash potentially represent useable products. However, considering the large volume of these wastes and uncertainties in future demand, FPL has ignored this potential in the evaluation of impacts for both the coal-fired and oil-fired generation alternatives.

FPL believes that with proper facility siting, design, operation, and closure in accordance with regulatory requirements, waste disposal would not destabilize any resources. After closure and revegetation of the ash-sludge waste disposal facility, the land could be made available for other noninvasive uses (e.g, recreation). For these reasons, FPL believes that waste disposal impacts for the coal-fired generation alternative would be MODERATE; the impacts would be clearly noticeable but would not destabilize any important resource.

7.2.2.1.6 HUMAN HEALTH

In the GEIS, the NRC cites risk of accidents to workers and public risks (e.g., cancer, emphysema) from inhalation of toxics and particulates associated with air emissions as potential risks to human health associated with the coal-fired generation alternative. FPL assumes that regulatory requirements imposed on facility design and operations under authority of the Occupational Safety and Health Act (OSHA), CAA, and related statutes are designed to provide an appropriate level of protection to workers and the public with respect to these risks, and that compliance with those requirements should, therefore, result in SMALL, if any, impacts on human health.

7.2.2.1.7 SOCIOECONOMICS

Major sources of potential impact of the coal-fired generation alternative from a socioeconomic perspective include the following:

- temporary increases in jobs, general economic activity, and demand for housing and public services in communities surrounding the greenfield site during the construction period, and
- changes in permanent jobs, economic activity, and tax revenues for the period of plant operation, considering also corresponding losses resulting from shutdown of St. Lucie Units 1 & 2.

FPL assumes that construction of the alternative coal-fired plant would be staged to complete two units in time to replace St. Lucie Unit 1 in 2016, and two units in time to replace St. Lucie Unit 2 in 2023. Estimates cited by the NRC (Ref. 7.2-4; Ref. 7.2-7) indicate that three 600-MW pulverized coal units could be constructed in approximately five years with an average and peak construction workforce of 1,500 and 2,000 workers,

respectively. Scaling from these estimates, FPL expects that the first two coal-fired units could be constructed in approximately four to five years with an average and peak workforce of approximately 1,000 and 2,000 workers, respectively. On the same basis, and assuming that the first stage of construction includes basic site work and other appropriate accommodations for full site development, FPL estimates that the second two units would be constructed in approximately four years with a similar workforce. The NRC estimates in the GEIS that an operating workforce of 250 would be required for a 1,000-MW coal-fired plant; similar estimates (220-250) are cited for plants consisting of 600-MW units (Ref. 7.2-4; Ref. 7.2-7). On this basis, FPL has assumed permanent operating workforces of 250 and 300 for the first two units and the fully developed plant, respectively.

Potential impacts related to increased demand for housing and public services from a 1,000- to 2,000-person construction workforce and a 250- to 300-person operating workforce would depend to a large extent on the nearness of the greenfield site to high population areas that provide a relatively large source of available labor and have greater ability to absorb these increased demands. FPL notes that the vast majority of central Florida is within approximately 40 miles (commuting distance) of growing metropolitan areas with current populations greater than 250,000 (Ref. 7.2-18), and that, with few exceptions, the projected 2010 populations for all counties in south-central Florida are greater than 30,000 (Ref. 7.2-19).

In view of these data, FPL considers it reasonable to expect that a greenfield site in central Florida could be located within 40 miles of one or more metropolitan areas with populations greater than 250,000, and in a county with a population greater than 30,000. Under this scenario, it is expected that relatively few construction workers would relocate to smaller communities in the site vicinity. Permanent in-migration to these communities during operation, represented by some plant workers and their families and some secondary jobs created in these communities, would be limited by these same factors, and by the moderate operating workforce requirement (250 initially and 50 more when all four units operate). It is expected that the increased demand for housing and public services would be clearly noticeable in communities near the site, but that these communities could accommodate these demands without a destabilizing effect. Depending on the nearness of the site to large population centers, resultant impacts may range from SMALL to MODERATE. Communities in the site vicinity would realize some temporary socioeconomic benefits during construction, including some increase in jobs and plant expenditures. These communities would similarly realize the benefits of additional permanent jobs, plant expenditures, and substantial tax revenues during the operational phase.

Implementation of the coal-fired generation alternative at a greenfield site has specific socioeconomic implications for the St. Lucie Units 1 & 2 area. FPL employs approximately 930 workers at St. Lucie Units 1 & 2, mostly residents of St. Lucie and Martin counties, and property taxes from the plant amount to approximately 8 percent of St. Lucie County's total annual revenues (see Sections 2.7 and 3.4). Implementation of the coal-fired generation alternative at a greenfield site remote from the St. Lucie and Martin combined-county area would result in the eventual loss of virtually all of these direct jobs and loss of tax revenues following shutdown and decommissioning of St. Lucie Units 1 & 2. St. Lucie and Martin counties are experiencing rapid growth, projected to reach approximately 379,300 by 2010 (Ref. 7.2-19). Therefore, it is expected that these job losses and the resultant slowdown in economic activity would have a SMALL impact. Similarly, assuming the proportion of tax

revenues to St. Lucie County attributable to operation of St. Lucie Units 1 & 2 remains below 10 percent, associated impacts are considered to be SMALL. Location of the greenfield site in the St. Lucie and Martin combined-county area would reduce net loss of direct jobs in the area by 300, and would similarly help to offset impacts resulting from indirect job losses, plant expenditures, and tax revenues.

7.2.2.1.8 AESTHETICS

Based on design characteristics cited for comparable pulverized coal plants, the boiler buildings for the proposed coal-fired generation alternative would be approximately 200 feet high, and mechanical draft cooling towers may be 50 to 100 feet tall (Ref. 7.2-4; Ref. 7.2-7, Section 8.2.1.2). Using the EPA's criteria for good engineering practice stack height (40 CFR 51.100) and assuming the height of the boiler building is the governing parameter, exhaust stacks would be approximately 500 feet high. The boiler buildings, stacks, and vapor plumes from the plant may be visible for several miles, and some noise from the mechanical draft towers and coal handling equipment could be noticeable off site. The aesthetic impact of the facility would vary substantially with topography and land use in the general area of the plant. Location in an industrialized area would likely result in SMALL to MODERATE impact. However, the plant could markedly change the perceived aesthetic character of a relatively large area at other sites (e.g., relatively flat rural agricultural lands), and impact could be considered LARGE.

7.2.2.1.9 CULTURAL RESOURCES

The greenfield site for the coal-fired generating plant and associated offsite facilities would be located on previously disturbed areas on the basis of siting studies that would consider the potential existence of cultural resources, including archaeological and historical structures and sites. Site-specific cultural resource studies and resource preservation, as appropriate, would be conducted in the pre-construction and construction phases of the project. In view of these measures, development of the plant should result in little or no detectable impact, and could result in benefits (e.g., through study or preservation) in the event resources are present. FPL concludes that impacts to cultural resources would be SMALL, if any.

7.2.2.2 OIL-FIRED GENERATION

As discussed in Section 7.2.1.2, FPL's reference oil-fired generation alternative for this evaluation is a 1,600-MW (net) plant consisting of four 400-MW units, located at a greenfield site in central Florida. Basic specifications for the generating units, fuel, and air emission controls are provided in Table 7.2-4. In addition to the general assumptions stated in the introductory text to Section 7.2.2, FPL assumes for purposes of this evaluation that limestone used for scrubber operation would be delivered by truck or possibly barge (at coastal sites), and that oil would be delivered by barge and then by pipeline to inland sites.

FPL's evaluation is based, in part, on information provided by the NRC in the GEIS for oil-fired power production (Ref. 7.0-1), and the layout and selected design features of FPL's oil-fired Turkey Point Units 1 & 2. Turkey Point Units 1 & 2 are co-located with two nuclear power units (Units 3 & 4) at a coastal site about 25 miles south of Miami, Florida. Each of the two oil-fired units has a net continuous rating of 404 MW, and fuel is delivered by barge to the site. The switchyard, administrative and some technical support facilities, and

transmission lines that emanate from the four-unit site are shared. These characteristics are similar to those of FPL's representative four-unit oil-fired plant, and thus provide a useful basis for impact analysis.

FPL's impact evaluation of the oil-fired generation alternative is presented below. On the basis of this evaluation, FPL concurs with the NRC's conclusion that constructing and operating an oil-fired generating station would have environmental impacts similar to those for a comparable coal-fired generating station. In view of the close similarities of this evaluation and its conclusions with those for the coal-fired plant, the following impact discussion is abbreviated, with frequent reference to corresponding topics addressed for the coal-fired generation alternative.

7.2.2.2.1 LAND USE

FPL used the same basic assumptions as discussed for the coal-fired generation alternative to determine land-use requirements for onsite and offsite facilities, as follows:

Component	Area (Acres)
Plant Site	
Power Generation Facilities (power block, oil storage/handling, barge facilities, switchyard, cooling towers, storage tanks, etc.)	100
Infrastructure and Support Facilities (roads, parking, administration building, water supply, sewage treatment, etc.)	20
Waste Disposal (ash and sludge disposal)	190
Plant Site Total	310
Offsite	
Transmission Line (assumed 20 miles, 330-foot ROW)	800
Oil Pipeline (assumed 20 miles, 80-foot ROW)	190
Cooling Water Intake/Discharge Pipelines (assumed 2 miles, 100-foot ROW)	20
Offsite Total	1,010
Total	1,320

Discounting the potential for such needs as onsite debris disposal and buffers, FPL estimates that a minimum of approximately 310 acres would be required for the plant site. This area is substantially larger than the estimate of 120 acres provided by the NRC in the GEIS, and is attributed to the substantial land area (approximately 190 acres) required for ash and scrubber sludge disposal. Offsite facilities that could be required for the plant (transmission lines, an oil pipeline, and cooling water intake and discharge lines) and assumed acreage requirements are similar to those assumed for the coal-fired generation alternative.

Associated land-use impacts for this alternative would be the same in kind and magnitude to those discussed for the coal-fired generation alternative, and for the same reasons. Approximately 310 acres of the plant site would be dedicated to industrial use, of which 190 acres, dedicated to ash and sludge disposal, would be subject to permanent land-use restrictions. As discussed for the coal-fired alternative, these alterations are likely to influence land use, even if the plant is located in an industrial area. However, under the

assumptions of this evaluation, it is not expected that land use in the area would be destabilized, and impact is considered to be MODERATE. Similarly, assuming offsite facilities are located on the basis of an appropriate siting analysis, associated impacts to land use are expected to be MODERATE.

7.2.2.2.2 ECOLOGICAL RESOURCES

As discussed above, construction of the oil-fired generation alternative is expected to require less land for the plant site than a comparable coal-fired facility, while estimated land requirements for offsite facilities are approximately the same. FPL assumes that the potential for adverse effects on ecological resources would be similarly reduced but would otherwise be as previously described for the coal-fired generation alternative. That is, approximately 310 acres of relatively marginal terrestrial habitat (e.g., active or former agricultural land, disturbed natural vegetation) common in central Florida would be eliminated on site. Similar offsite habitats would be altered from construction of pipelines (e.g., 190 acres) and transmission lines (e.g., 800 acres). Any construction in or affecting aquatic habitats and wetlands would be conducted in accordance with applicable permit conditions. Overall, predicted construction impacts are similar to those expected for a coal-fired plant and, therefore, are considered to be MODERATE, for the same reasons.

Operation of an oil-fired plant and associated transmission facilities poses a potential for adverse impact on ecological resources comparable to that discussed for the coal-fired generation alternative. Maintenance practices along transmission line rights-of-way could result in improved habitat. Cooling water requirements are expected to be similar to those for the coal-fired facility (Ref. 7.0-1) and, as for the coal-fired facility, potential intake and discharge effects would be subject to protective regulation. Impacts related to operation are, therefore, considered to be SMALL to MODERATE.

Based on the above considerations and general assumptions of this evaluation, overall impact to ecological resources from development of the oil-fired generation alternative is considered to be MODERATE.

7.2.2.2.3 WATER QUALITY

Potential sources of impact on surface water quality from construction of the oil-fired generation alternative would be the same as for the coal-fired facility, though impacts may be smaller due to the relatively smaller land area disturbed and associated potential for erosion and sedimentation. Potential sources of impact during operation would be comparable to those from the coal-fired generation alternative, with the notable exception of potential releases of fuel oil. However, fuel oil transport, unloading, storage, and handling would be undertaken with appropriate measures for spill prevention and control in place and in accordance with applicable regulatory requirements (e.g., U.S. Coast Guard, U.S. Department of Transportation, EPA), which should provide a high level of protection. Discharges of cooling water and other smaller volume waste streams also would be similar to those expected for a coal-fired plant, and would be subject to strict regulation. Potential adverse impacts related to water quality are, therefore, considered to be SMALL.

7.2.2.2.4 AIR QUALITY

Predicted air emissions from oil-fired generation are lower than those for coal-fired generation for most parameters. An oil-fired plant would emit sulfur oxides, nitrogen oxides, particulate matter, and carbon monoxide. The plant design would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. FPL estimates the oil-fired generation alternative emissions to be as follows:

SO_x = 9,646 tons per year

NO_x = 1,653 tons per year

CO = 2,119 tons per year

Particulates:

Total suspended particulates = 70 tons per year

PM_{10} = 44 tons per year

Table 7.2-7 shows the FPL calculations for these emissions.

The discussion of regional air quality and CAA requirements in Section 7.2.2.1 is also applicable to the oil-fired generation alternative. The effect of NO_x emissions on ozone levels, SO_2 allowances, and nitrogen oxide emissions offsets could all be issues of concern for oil-fired combustion at a greenfield site in the area of central Florida considered under assumptions of this evaluation.

The NRC did not quantify oil-fired emissions but noted that they would be typical of coal plants. FPL concurs and believes that, for the same reasons as for coal-fired generation, impacts from oil-fired generation on air quality would be MODERATE assuming the application of mitigation measures imposed by air emissions regulations.

7.2.2.2.5 WASTE MANAGEMENT

Construction of the oil-fired generation alternative would generate the same types of waste as discussed previously for the coal-fired generation alternative. However, the smaller land area requirements could result in less debris from land clearing and grubbing operations. As is the case for coal, oil combustion and removal of pollutants by air pollution control equipment would generate solid waste in the form of ash and scrubber sludge, but amounts for the oil-fired units would be less. FPL estimates that the oil-fired generation alternative would result in annual combustion of 847,473,480 gallons of fuel having an ash content of approximately 0.21 percent (see Table 7.2-4). FPL assumes nearly all of this ash (99 percent, approximately 7,000 tons per year, dry) would be collected and disposed of on site. In addition, approximately 150,000 tons of limestone would be used annually for flue-gas desulfurization, generating approximately 320,000 tons of wet scrubber sludge that would be disposed of on site each year. Assuming a landfill depth of 30 feet, FPL estimates that ash and scrubber waste disposal over the 40-year plant life would impact approximately 190 acres. For the same reasons cited previously for the coal-fired generation alternative, FPL concludes that the oil-fired generation alternative impacts from waste management would be MODERATE.

TABLE 7.2-7
AIR EMISSIONS FROM OIL-FIRED GENERATION ALTERNATIVE

Parameter	Calculation	Result
Annual oil consumption	$4\ \text{units} \times \frac{416\ \text{MW}}{\text{unit}} \times \frac{9{,}800\ \text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times 0.9 \times \frac{\text{gal}}{151{,}705\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}}$	847,473,480 gal oil per year
SO_x[a]	$157 \times \frac{1.45\ \text{lb}}{1{,}000\ \text{gal}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1 - 90/100) \times \frac{847{,}473{,}480\ \text{gal}}{\text{yr}}$	9,646 tons SO_x per year
NO_x[a]	$\frac{26\ \text{lb}}{1{,}000\ \text{gal}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1 - 85/100) \times \frac{847{,}473{,}480\ \text{gal}}{\text{yr}}$	1,653 tons NO_x per year
CO[a]	$\frac{5\ \text{lb}}{1{,}000\,\text{gal}} \times \frac{\text{ton}}{2000\ \text{lb}} \times \frac{847{,}473{,}480\ \text{gal}}{\text{yr}}$	2,119 tons CO per year
TSP[a]	$\frac{9.19 \times 1.45 + 3.22\ \text{lb}}{1{,}000\ \text{gal}} \times \frac{\text{ton}}{2000\ \text{lb}} \times (1 - 99/100) \times \frac{847{,}473{,}480\ \text{gal}}{\text{yr}}$	70 tons TSP per year
PM_{10}[b]	$\frac{0.63 \times 70\ \text{tons}}{\text{yr}}$	44 tons PM_{10} per year

NOTES:

a. Based on data in Table 7.2-4 and Ref. 7.2-10, Table 1.3-1

b. Based on data in Table 7.2-4 and Ref. 7.2-10, Table 1.3-4

Btu = British thermal unit
CO = carbon monoxide
gal = gallon(s)
hr = hour
kW = kilowatt
lb = pound
MW = megawatt
NOx = nitrogen oxides
PM10 = particulates having diameter less than 10 microns
SOx = sulfur oxides
TSP = total suspended particulates (filterable)
yr = year

7.2.2.2.6 HUMAN HEALTH

As discussed for the coal-fired generation alternative, FPL assumes that regulatory requirements imposed on facility design and operations under authority of the OSHA, CAA, and related statutes are designed to provide an appropriate level of protection to workers and the public with respect to risks to worker safety and to the public from air emissions cited by the NRC for this alternative, and that compliance with those requirements would result in SMALL, if any, impacts on human health from the oil-fired generation alternative.

7.2.2.2.7 SOCIOECONOMICS

FPL notes that the sources and types of socioeconomic impacts from development of the oil-fired generation alternative would be essentially the same as those examined previously for the coal-fired generation alternative. At a given greenfield site, the magnitude of impacts can be attributed primarily to the size of construction and operating workforces.

FPL assumes that construction of the alternative oil-fired plant would be staged to complete two units in time to replace St. Lucie Unit 1 in 2016, and two units in time to replace St. Lucie Unit 2 in 2023. These units would be similar in general configuration, but somewhat smaller and less complex to construct and operate than the alternative coal-fired units. Similarly, the amount of land to be developed for the overall site would be less than for the coal-fired generation alternative. Estimates provided by the NRC in the GEIS (Ref. 7.0-1, Tables 8.1 and 8.2) indicate that construction and operating workforces for a 1,000-MW oil-fired facility could be approximately 32 percent and 20 percent less, respectively, than would be required for a comparable coal-fired plant. On this basis, and using the same assumptions as for the coal-fired generation alternative, FPL estimates that the first two oil-fired units would be constructed in approximately four to five years with an average and peak workforce of approximately 700 and 1,400 workers, respectively, and that the second two units would be constructed in approximately four years with a similar or somewhat smaller workforce. On this basis, estimates for permanent operating workforce are 200 and 240 for the first two units and the fully developed plant, respectively.

FPL concludes that potential impacts related to increased demand for housing and public services during construction and operation of the oil-fired generation alternative would be similar but somewhat less than those determined for the coal-fired generation alternative. The actual impact on socioeconomics would depend on the proximity of the site to large population centers, and could range from SMALL to MODERATE in surrounding communities.

The socioeconomic impact of the oil-fired generation alternative on the St. Lucie Units 1 & 2 area would differ little from that previously discussed for the coal-fired plant. Locating the oil-fired plant in the St. Lucie-Martin combined-county vicinity would provide fewer jobs than the coal-fired generation alternative to offset those lost as a result of shutdown of St. Lucie Units 1 & 2; however, these losses are expected to result in only SMALL impacts regardless of the alternative plant location. Similarly, locating the oil-fired generation alternative in the St. Lucie-Martin combined-county area would reduce losses of tax revenues to St. Lucie County resulting from shutdown of St. Lucie Units 1 & 2, and better ensure that local impacts resulting from this revenue loss would be SMALL.

7.2.2.2.8 AESTHETICS

Although the plant site and facilities for the oil-fired units may be somewhat smaller than for a coal-fired plant, these differences would not be appreciable from an aesthetic standpoint. The site would constitute a large industrial complex, and the boiler buildings, stacks (estimated to be 400 feet high based on the Turkey Point Units 1 & 2 facility), and cooling tower plumes could be visible for several miles. As such, the facility could be viewed as aesthetically disruptive outside of an industrial setting. For the same reasons cited previously for the coal-fired generation alternative, FPL considers that aesthetic impacts from the oil-fired generation alternative could range from SMALL to LARGE, depending on location-specific factors.

7.2.2.2.9 CULTURAL RESOURCES

The greenfield site for the oil-fired generating plant and associated offsite facilities would be located on previously disturbed areas, and appropriate efforts would be made to ensure that resources are appropriately protected. For the same reasons cited for the coal-fired generation alternative, FPL concludes that impacts to cultural resources from the oil-fired generation alternative would be SMALL.

7.2.2.3 GAS-FIRED GENERATION

As discussed in Section 7.2.1.1, FPL's reference gas-fired generation alternative for this evaluation is a 1,788-MW (net) plant consisting of three 596-MW units, located at a greenfield site in south Florida. Basic specifications for the generating units, fuel, and air emission controls are provided in Table 7.2-5. As for the coal- and oil-fired generation alternatives, FPL used the general assumptions stated in the introductory text to Section 7.2.2 for its evaluation of this alternative. However, unlike the previous alternatives, no rail or barge facilities would be required because fuel (natural gas) would be delivered to the site by pipeline, and no scrubber would be required.

The NRC has evaluated the environmental impacts of constructing and operating a 1,000-MW gas-fired power plant in the GEIS (Ref. 7.0-1), and has specifically evaluated the impacts of a 1,760-MW, four-unit combined-cycle gas-fired plant as an alternative to nuclear power plant license renewal (Ref. 7.2-4, Section 8.2.2). Although FPL's gas-fired generation alternative consists of only three units, the facility is comparable in design and capacity to the plant evaluated by the NRC, so FPL used information from this plant as a partial basis for impact estimates. Similarly, FPL also used the U.S. Department of Energy's (DOE's) evaluation of the proposed Griffith Energy Project (Ref. 7.2-20, Section 2.1.1) to estimate some impact parameters. The Griffith Energy Project design is for a modern two-unit combined-cycle plant with baseload and peaking capacities of 520 MW and 650 MW, respectively, and features closed-cycle cooling using mechanical draft cooling towers. The previously evaluated plants thus provide a reasonable basis for evaluating the impacts of FPL's alternative.

FPL's impact evaluation of the gas-fired generation alternative is presented below. In view of the similarities of this evaluation to those presented previously, the following impact discussion is abbreviated, with frequent reference to corresponding topics addressed for the coal- and oil-fired generation alternatives.

7.2.2.3.1 LAND USE

FPL used land-use estimates cited by the DOE and the NRC, and basic assumptions as discussed for the coal- and oil-fired generation alternatives, to determine land-use requirements for onsite and offsite facilities, as follows:

Component	Area (Acres)
Plant Site	
Power Generation Facilities (power block, switchyard, cooling towers, etc.)	65
Infrastructure and Support Facilities (roads, parking, administration building, water supply, sewage treatment, etc.)	10
Plant Site Total	75
Offsite	
Transmission Line (assumed 20 miles, 330-foot ROW)	800
Natural Gas Supply Pipeline (assumed 20 miles, 95-foot ROW)	230
Cooling Water Intake/Discharge Pipelines (assumed 2 miles, 100-foot ROW)	20
Offsite Total	1,050
Total	1,125

Discounting the potential for such needs as onsite debris disposal and buffers, FPL estimates that a minimum of approximately 75 acres would be required for the plant site. Depending on site-specific needs, additional land could be required. For example, the NRC indicated in the GEIS that 110 acres could be required for a 1,000-MW gas-fired plant.

Offsite facilities required for the plant may reasonably include transmission lines, cooling water intake and discharge lines, and a natural gas supply pipeline. The amount of land required for these linear features depends on the location of the site. Assuming a need for 20 miles each of transmission line and natural gas pipeline and 2 miles of cooling water piping, a total of 1,050 acres of land would be required for these offsite facilities.

As noted in Section 7.2.1, the demand represented by the gas-fired generation alternative could contribute to a decision to develop a new major supply pipeline into Florida. It is assumed that this pipeline, if needed, would be routed from Mobile, Alabama, across the Gulf of Mexico some 400 miles to Florida's west coast, then into central Florida for 100 miles or more, as is the case for the recently approved Gulfstream Project (see Section 7.2.1.1). Assuming 100 miles of pipeline and a 110-foot ROW, approximately 1,300 acres of land in central Florida would be required.

Under the assumptions of this evaluation, which include location of the greenfield site on the basis of an appropriate siting analysis that seeks to minimize land-use conflicts, FPL assumes that the plant would be located on previously disturbed land, possibly in an industrial area, but more likely in a rural area (e.g., on active or former agricultural land). Conversion to industrial use would be limited to approximately 75 acres, and onsite ash and sludge disposal and associated long-term land-use restrictions would not occur. Based on these considerations, land-use changes would be noticeable, but would be expected to have

minor or, at most, moderate effect on land-use patterns in the general area. Similarly, FPL assumes that appropriate routing studies would ensure that natural gas pipelines, transmission lines, and cooling water intake/discharge pipelines required for the plant could be routed such that land-use impacts in the area would be, at most, moderate. Potential direct impacts to land use from this alternative are therefore considered to be SMALL to MODERATE.

Development of a new natural gas supply pipeline into Florida as a partial result of demand created by the gas-fired generation alternative represents a potential source of indirect impact on land use. FPL assumes that such a pipeline would be located on the basis of an appropriate routing analysis that would minimize potential impacts, e.g., by maximizing use of existing ROW. Resultant impacts could be noticeable in some areas, but in any case would not be expected to destabilize land use. On that basis, resultant impacts would be SMALL to MODERATE.

7.2.2.3.2 ECOLOGICAL RESOURCES

Under the assumptions of this evaluation, construction of onsite facilities for the gas-fired generation alternative would result in the loss of approximately 75 acres of relatively marginal terrestrial habitat (e.g., active or former agricultural land, disturbed natural vegetation) common in central Florida. Similar offsite habitats could be disrupted from construction of pipelines (e.g., 230 acres) and transmission lines (e.g., 800 acres). However, as previously discussed for the coal- and gas-fired generation alternatives, appropriate site configuration and maintenance practices (e.g., along transmission line rights-of-way) could preserve and enhance habitat values. Any construction in, or affecting aquatic habitats and wetlands, would be conducted in accordance with applicable permit conditions. Similarly, potential intake and discharge effects on aquatic organisms (e.g., impingement, entrainment, thermal effects) would be subject to protective regulations. Based on the above considerations and general assumptions of this evaluation, FPL expects that construction and operation of the gas-fired generation alternative and associated offsite facilities would result in little or no noticeable change in available habitat and that populations of important species in the area would not be noticeably affected. Therefore, direct impacts on ecological resources would be appropriately considered to be SMALL to MODERATE.

Indirect impacts that could result from construction of a new natural gas pipeline into central Florida would similarly depend on pipeline routing. Assuming that routing is established on the basis of an appropriate pipeline routing study, impacts on ecological resources should be SMALL to MODERATE.

7.2.2.3.3 WATER QUALITY

The potential sources of adverse impact on water quality from the gas-fired generation alternative are essentially the same as discussed for the coal- and oil-fired generation alternatives. However, FPL would expect that potential impacts would be relatively smaller because less land would be disturbed, potentially less construction in aquatic habitat would be required (e.g., no barge channel construction), and a smaller quantity of water would be required for cooling (Ref. 7.0-1, Table 8.2). On the basis of rationale provided for previous alternatives (e.g., adherence to regulatory requirements), potential adverse impacts on water quality from this alternative would be SMALL.

7.2.2.3.4 AIR QUALITY

Natural gas is a relatively clean-burning fuel, and the gas-fired generation alternative would release similar types of emissions but in much smaller quantities than the coal- and oil-fired generation alternatives, excluding particulates emissions. Control technology for gas-fired turbines focuses on nitrogen oxide emissions. FPL estimates the gas-fired generation alternative emissions to be as follows:

SO_x = 165 tons per year

NO_x = 669 tons per year

CO = 1,545 tons per year

Particulates (filterable) = 98 tons per year (all particulates are PM_{10})

Table 7.2-8 shows the FPL calculations for these emissions.

The discussion in Section 7.2.2.1 of regional air quality and CAA requirements is also applicable to the gas-fired generation alternative. The effect of NO_x emissions on ozone levels, SO_2 allowances, and nitrogen oxide emissions offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal- and oil-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. However, site-specific modeling would be necessary to determine whether the emissions would noticeably alter local air quality. In the absence of modeling, and in order to avoid overstating the impacts, FPL concludes that the impacts of the gas-fired generation alternative on air quality would be SMALL.

7.2.2.3.5 WASTE MANAGEMENT

Gas-fired generation would result in little waste generation, producing minor, if any, impacts. FPL concludes that gas-fired generation waste management impacts would be SMALL.

7.2.2.3.6 HUMAN HEALTH

The GEIS mentions potential gas-fired generation alternative risks that are associated with air emissions. Regulatory requirements imposed on air emissions are designed to protect human health. Compliance with those requirements should keep any impacts on human health SMALL.

7.2.2.3.7 SOCIOECONOMICS

FPL notes that the substantially smaller construction and operating workforces needed for a gas-fired combined-cycle plant would result in smaller socioeconomic impacts than for a comparably sized coal- or oil-fired plant at the same site, although the types of impacts observed would be essentially the same.

The DOE's evaluation of the Griffith Energy Project indicates that a 520- to 650-MW two-unit combined-cycle plant could be constructed in 18-22 months with a peak workforce of 350 workers, and could be operated by 22 full-time staff, assuming remote monitoring and dispatching and outsourcing of such functions as major turbine and generator maintenance (Ref. 7.2-20, Sections 2.1.1.3, 2.1.1.4). The NRC has indicated that a 1,760-MW four-unit

TABLE 7.2-8
AIR EMISSIONS FROM GAS-FIRED GENERATION ALTERNATIVE[a]

Parameter	Calculation	Result
Annual gas consumption	$3\ \text{units} \times \frac{609\ \text{MW}}{\text{unit}} \times \frac{7{,}150\ \text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times 0.9 \times \frac{\text{ft}^3}{1{,}019\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}}$	101,068,800,000 ft^3 gas per year
Annual Btu input	$3\ \text{units} \times \frac{609\ \text{MW}}{\text{unit}} \times \frac{7{,}150\ \text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times 0.9 \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}} \times \frac{\text{MBtu}}{10^6 \times \text{Btu}}$	102,989,100 MBtu per year
SO_x[b]	$\frac{0.94 \times 0.0034}{\text{MBtu}} \times \frac{\text{ton}}{2000\ \text{lb}} \times \frac{102{,}989{,}100\ \text{MBtu}}{\text{yr}}$	165 tons SO_x per year
NO_x[c]	$\frac{0.13\ \text{lb}}{\text{MBtu}} \times \frac{\text{ton}}{2000\ \text{lb}} \times (1 - 90/100) \times \frac{102{,}989{,}100\ \text{MBtu}}{\text{yr}}$	669 tons NO_x per year
CO[c]	$\frac{0.030\ \text{lb}}{\text{MBtu}} \times \frac{\text{ton}}{2000\ \text{lb}} \times \frac{102{,}989{,}100\ \text{MBtu}}{\text{yr}}$	1,545 tons CO per year
TSP[b]	$\frac{0.0019\ \text{lb}}{\text{MBtu}} \times \frac{\text{ton}}{2000\ \text{lb}} \times \frac{102{,}989{,}100\ \text{MBtu}}{\text{yr}}$	98 tons TSP per year
PM_{10}[b]	$\frac{98\ \text{tons TSP}}{\text{yr}} \times 1.00$	98 tons PM_{10} per year

NOTES:

a. Emission factors for duct-firing (Ref. 7.2-14, Tables 1.4-1, 1.4-2) are comparable to or higher than those for combustion turbines (Ref. 7.2-15, Tables 3.1-1, 3.1-2a), and duct-firing comprises a relatively small fraction of total unit output. Therefore, calculations are based on emission factors for combustion turbines.

b. Based on data from Table 7.2-5 and Ref. 7.2-15, Table 3.1-2a

c. Based on data from Table 7.2-5 and Ref. 7.2-15, Table 3.1-1

Btu = British thermal unit
CO = carbon monoxide
ft3 = cubic feet
hr = hour
kW = kilowatt
lb = pound
M = million
MW = megawatt
NOx = nitrogen oxides
PM10 = particulates having diameter less than 10 microns
SOx = sulfur oxides
TSP = total suspended particulates
yr = year

combined-cycle plant could be constructed in three years with average and peak workforces of 500 and 750 workers, respectively, and operated with 125 workers (Ref. 7.2-4, Section 8.2.2.1). Considering these estimates and assuming that construction of the alternative gas-fired plant would be staged to facilitate replacement of St. Lucie Unit 1 in 2016 and St. Lucie Unit 2 in 2023, FPL estimates that the first two units could be constructed as a single project in two to three years with a peak workforce of less than 700, and that the operating workforce for the fully developed plant would be below the 125-worker estimate cited by the NRC for a comparable facility.

These workforce requirements are modest. Considering also the proximity of a greenfield site to population centers, as discussed for the coal-fired generation alternative, FPL concludes that increased demand for housing and public services during construction and operation would not result in appreciable adverse effects even for communities in the site vicinity. Therefore, these impacts are considered to be SMALL.

Locating the gas-fired plant in the St. Lucie-Martin combined-county vicinity would provide few jobs to offset those lost as a result of shutdown of St. Lucie Units 1 & 2; however, these losses are expected to result in only SMALL impacts regardless of the alternative plant location. Similarly, locating the gas-fired generation alternative in the St. Lucie-Martin combined-county area would provide partial replacement of tax revenue losses to St. Lucie County resulting from shutdown of St. Lucie Units 1 & 2, and better ensure that resultant local impacts resulting from this revenue loss would be SMALL.

7.2.2.3.8 AESTHETICS

The combustion turbines and heat recovery steam generators would be relatively low structures that could be visible at a moderate offsite distance depending on the area chosen. Taller structures, most notably the exhaust stacks (130-230 feet, based on NRC and DOE descriptions of comparable facilities), and cooling tower vapor plumes would be visible for greater distances off site. Aesthetic resource impacts would be noticeable, but would not exert a destabilizing effect. FPL concludes that the gas-fired generation alternative aesthetics impacts would be SMALL to MODERATE.

7.2.2.3.9 CULTURAL RESOURCES

The greenfield site for the gas-fired generating plant and associated offsite facilities would be located on previously disturbed areas, and appropriate efforts would be made to ensure that resources are appropriately protected. For the same reasons cited for the coal- and oil-fired generation alternatives, FPL concludes that impacts of the gas-fired generation alternative to cultural resources would be SMALL, if any.

7.2.2.4 PURCHASE POWER

As discussed in Section 7.2.1.2, FPL assumes that the generating technology employed under the purchase power alternative would be one of those that the NRC analyzed in the GEIS. FPL is adopting by reference the NRC analysis of the environmental impacts from those technologies. Therefore, under the purchase power alternative, environmental impacts would still occur, but would be located elsewhere, probably within the southeastern United States.

The purchase power alternative would include adding as much as 200-300 miles of transmission lines to transmit power (perhaps from the State line) to meet the demand in central Florida that is satisfied by St. Lucie Units 1 & 2. Assuming a 350-foot ROW, this could affect 8,500-12,700 acres of land with associated impact on land use and related ecological resources (e.g., aesthetics). FPL assumes that the transmission line construction mostly would be on previously disturbed land along existing transmission line rights-of-way, and concludes that the impact on land use and related resources in these segments would be small to moderate. Generally, changes would be so minor that they would neither destabilize nor noticeably alter any important attributes of these resources. However, given the length of the transmission lines, it is reasonable to assume changes to land use and related resources would be clearly noticeable in some transmission line segments, a characteristic of MODERATE impact.

7.3 REFERENCES

7.0-1 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

7.0-2 U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register. Vol. 61, No. 244. (December 18, 1996): 66537-54.

7.1-1 U.S. Nuclear Regulatory Commission. Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities. NUREG-0586. Office of Nuclear Regulatory Research. Washington, D.C. August 1988.

7.2-1 Energy Information Administration. State Electricity Profiles - Florida. November 25, 2000 (data through 1998). www.eia.doe.gov/cneaf/electricity/st_profiles/florida.pdf. Accessed February 4, 2001.

7.2-2 Florida Power & Light Company. FPL Ten Year Power Plant Site Plan; 2001-2010. Miami, Florida. April 2001.

7.2-3 Florida Power & Light Company. FPL Ten Year Power Plant Site Plan; 2000-2009. Miami, Florida. April 2000.

7.2-4 U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Calvert Cliffs Nuclear Power Plant. NUREG-1437, Supplement 1. Office of Nuclear Reactor Regulation. Washington, D.C. October 1999.

7.2-5 U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Oconee Nuclear Station. NUREG-1437, Supplement 2. Office of Nuclear Reactor Regulation. Washington, D.C. December 1999.

7.2-6 U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Arkansas Nuclear One, Unit 1. NUREG-1437, Supplement 3. Office of Nuclear Reactor Regulation. Washington, D.C. April 2001.

7.2-7 U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Edwin I. Hatch Nuclear Plant, Units 1 & 2. NUREG-1437, Supplement 4. Office of Nuclear Reactor Regulation. Washington, D.C. May 2001.

7.2-8 U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. Vol. 1, Stationary Point and Area Sources. Chapter 1, External Combustion Sources, Section 1.1, "Bituminous and Subbituminous Coal Combustion." AP-42. September 1998. www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf. Accessed February 5, 2001.

7.2-9 Energy Information Administration. Electric Power Annual 1999. Volume 2, Table 28, "Average Quality of Fossil Fuels Burned at U.S. Electric Utilities by Census Division and State, 1998 and 1999." DOE/EPA-0348(99/2. October 2000. Available at www.eia.doe.gov/cneaf/electricity/epav2/epav2.pdf.

7.2-10 U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. Vol. 1, Stationary Point and Area Sources. Chapter 1, External Combustion Sources, Section 1.3, "Fuel Oil Combustion." AP-42. September 1998, and Errata to Section 1.3, April 28, 2000. www.epa.gov/ttn/chief/ap42/ch01/final/c01s03.pdf. Accessed February 5, 2001.

7.2-11 U.S. Environmental Protection Agency. Air Pollution Emission Factors. Vol. 1, Stationary Point and Area Sources. Appendix A, "Miscellaneous Data & Conversion Factors." AP-42. September 1985. www.epa.gov/ttn/chief/ap42/appendix/appol.pdf. Accessed May 2, 2001.

7.2-12 Florida Public Service Commission. Review of Electric Utility 2000 Ten-Year Site Plans. Tallahassee, Florida. December 2000.

7.2-13 GULFSTREAM: Project Description. www.gulfstream gas.com/project.html. Accessed July 30, 2001.

7.2-14 U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. Vol. 1, Stationary Point Sources and Area Sources. Chapter 1, External Combustion Sources, Section 1.4, "Natural Gas Combustion." AP-42. July 1998. www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf. Accessed February 21, 2001.

7.2-15 U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. Vol. 1, Stationary Point and Area Sources. Chapter 3, Stationary Internal Combustion Sources, Section 3.1, "Stationary Gas Turbines for Electricity Generation." AP-42. October 1996. www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf. Accessed February 5, 2001.

7.2-16 Florida Power & Light Company. FPL Conservation and Load Control Programs. www.fpl.com/about/profile/contents/reducing_demand/shtml. Accessed April 30, 2001.

7.2-17 Florida Department of Environmental Protection. Air Monitoring Report. Division of Air Resources Management. Tallahassee, Florida. 2000.

7.2-18 U.S. Census Bureau. American FactFinder. Detailed Tables, P001. Persons. Data Set: 1990 Summary Tape File 3. http://factfinder.census.gov. Accessed January 29, 2001.

7.2-19 Smith, S. K. and J. Nagle. "Projections of Florida Population by County," Florida Population Studies. Vol. 33, No. 2. Bulletin 126. Population Program, Bureau of Economic and Business Research, University of Florida. Tallahassee, Florida. February 2000.

7.2-20 U.S. Department of Energy. Griffith Energy Project Draft Environmental Impact Statement. DOE/EIS-0297. Western Area Power Administration. Kingman, Arizona. October 1998.

8.0 COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

NRC

"To the extent practicable, the environmental impacts of the proposal and the alternatives should be presented in comparative form..." 10 CFR 51.45(b)(3) as adopted by 51.53(c)(2)

Florida Power & Light Company (FPL) has presented its evaluation of environmental impacts associated with renewal of the operating licenses for St. Lucie Units 1 & 2 in Chapter 4.0, and impacts associated with alternatives to license renewal in Chapter 7.0. Table 8.0-1 summarizes the environmental impacts of the proposed action (license renewal) and the alternatives in a comparative format. The environmental impacts summarized in Table 8.0-1 consist of Category 2 issues associated with the proposed action and issues that the U.S. Nuclear Regulatory Commission (NRC) identified in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Ref 8.0-1, Section 8.1) as major considerations in an alternatives analysis. For example, the NRC concluded in the GEIS that air quality and resultant human health impacts from the proposed action would be small (Category 1), but noted the potential for major human health concerns associated with air emissions from fossil-fuel generation alternatives (see Section 7.2.2.1). Therefore, Table 8.0-1 compares the air quality impacts among the proposed action and the evaluated alternatives. Table 8.0-2 provides a more detailed impacts comparison.

TABLE 8.0-1
IMPACTS COMPARISON SUMMARY

Impact	Proposed Action (License Renewal)	No-Action Alternatives				
		Base (Decommis-sioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power
Land Use	SMALL	SMALL	MODERATE	MODERATE	SMALL to MODERATE	MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Air Quality	SMALL	SMALL	MODERATE	MODERATE	SMALL	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	MODERATE	MODERATE	SMALL to MODERATE	MODERATE
Human Health	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Socioeconomics	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE	SMALL	SMALL to MODERATE
Waste Management	SMALL	SMALL	MODERATE	MODERATE	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	SMALL to LARGE	SMALL to LARGE	SMALL to MODERATE	SMALL to LARGE
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL

NOTES:

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.

MODERATE - Environmental effects are sufficient to alter noticeably but not to destabilize any important attribute of the resource.

LARGE – For the issue, environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource. (10 CFR 51, Subpart A, Appendix B, Table B-1, footnote 3)

TABLE 8.0-2
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Description					
St. Lucie Units 1 & 2 license renewals for 20 years each, followed by decommissioning (see Chapter 3)	Decommissioning following expiration of current St. Lucie Units 1 & 2 licenses; adopting by reference, as bounding St. Lucie Units 1 & 2 decommissioning, GEIS description (see Section 7.1)	New construction at a 1,155-acre greenfield site in central Florida, with assumed offsite facilities as follows: 20-mile transmission line, 20-mile rail spur, 2-mile cooling water pipelines	New construction at a 310-acre greenfield site in central Florida, with assumed offsite facilities as follows: 20-mile transmission line, 20-mile oil pipeline, 2-mile cooling water pipelines	New construction at a 75-acre greenfield site in central Florida, with assumed offsite facilities as follows: 20-mile transmission line, 20-mile gas pipeline, 2-mile cooling water pipeline	Construct 200-300 miles of transmission lines Could involve construction of new generation capacity out of state; adopting by reference GEIS description of alternate technologies (see Section 7.2.1.2)
		Four 400-MW tangentially fired, dry-bottom units; capacity factor 0.9	Four 400-MW units; capacity factor 0.9	Three 596-MW units; each consisting of two 170-MW combustion turbines and a 256-MW heat recovery boiler with duct-firing; capacity factor 0.9	
		Closed-cycle cooling; mechanical draft cooling towers	Closed-cycle cooling; mechanical draft cooling towers	Closed-cycle cooling; mechanical draft cooling towers	

TABLE 8.0-2 (continued)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Description (Continued)					
		Pulverized bituminous coal, 12,116 Btu/lb; 9,800 Btu/kWh; 8.0% ash; 1.63% sulfur; 5,407,659 tons coal/yr	No. 6 fuel oil; 151,705 Btu/gal; 9,800 Btu/kWh; 0.21% ash; 1.45% sulfur; 847,473,480 gallons oil/yr	Natural gas, 1,019 Btu/ft^3; 7,150 Btu/kWh; 101,068,800,000 ft^3 gas/yr	
		Low NO_x burners, overfire air, selective catalytic reduction (95% NO_x removal efficiency)	Low NO_x burners; selective catalytic reduction (85% NO_x removal efficiency)	Dry-low NO_x combustor or water-steam injection; selective catalytic reduction (90% NO_x removal efficiency) (see Sections 7.2.1.1, 7.2.2.3)	
		Wet limestone flue-gas desulfurization (90% SO_x removal efficiency); 270,000 tons limestone/yr	Wet limestone flue-gas desulfurization (90% SO_x removal efficiency); 150,000 tons limestone/yr		
		Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency) (see Sections 7.2.1.1, 7.2.2.1)	Fabric filters (99% particulate removal efficiency) (see Sections 7.2.1.1, 7.2.2.2)		

TABLE 8.0-2 (continued)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Description (Continued)					
		Construction workforce: 1,000 average, 2,000 peak; operating workforce: 300 (see Section 7.2.2.1)	Construction workforce: 700 average, 1,400 peak; operating workforce: 240 (see Section 7.2.2.2)	Construction workforce: <700; operating workforce: <125 (see Section 7.2.2.3)	
Land Use Impacts					
SMALL – Adopting by reference Category 1 issue findings (see Appendix A, Table A-1, Issues 52, 53)	SMALL – Not an impact evaluated by the NRC (Ref. 8.0-1, Section 7.3)	MODERATE – 1,155 acres potentially converted to industrial use, including 680 acres for waste disposal; potential land use alterations off site: 800 acres for transmission lines, 120 acres for rail spur, 20 acres for cooling water pipelines (see Section 7.2.2.1)	MODERATE – 310 acres potentially converted to industrial use, including 190 acres for waste disposal; potential land use alterations off site: 800 acres for transmission lines, 190 acres for oil pipeline, 20 acres for cooling water pipelines (see Section 7.2.2.2)	SMALL to MODERATE - 75 acres potentially converted to industrial use; potential land use alterations off site: 800 acres for transmission lines, 230 acres for gas pipeline, 20 acres for cooling water pipeline; potential indirect impact from construction of new gas pipeline into central Florida (see Section 7.2.2.3)	MODERATE – Adopting by reference GEIS description of land use impacts from alternate technologies (Ref. 8.0-1, Section 8.2); 8,500 to 12,700 acres for transmission facilities (see Section 7.2.2.4)

TABLE 8.0-2 (continued)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Water Quality Impacts					
SMALL – Adopting by reference Category 1 issue findings (see Appendix A, Table A-1, Issues 1-3, 6-7, 9-12, 31); Category 2 water-use conflicts and groundwater issues not applicable (see Section 4.1.2, Issues 13, 33-35, 39)	SMALL – Adopting by reference Category 1 issue finding (see Appendix A, Table A-1, Issue 89)	SMALL – Construction impacts minimized by use of best management practices; operation impacts minimized by using closed-cycle cooling and regulatory controls (see Section 7.2.2.1)	SMALL – Same as for coal-fired generation; some potential for fuel oil releases (see Section 7.2.2.2)	SMALL – Same as for coal-fired generation though relatively smaller due to less land disturbance and associated potential for erosion and sedimentation (see Section 7.2.2.3)	SMALL – Adopting by reference GEIS description of water quality impacts from alternate technologies (Ref. 8.0-1, Section 8.2)
Air Quality Impacts					
SMALL – Adopting by reference Category 1 issue finding (see Appendix A, Table A-1, Issue 51); Category 2 issue not applicable (see Section 4.7, Issue 50)	SMALL – Adopting by reference Category 1 issue finding (see Appendix A, Table A-1, Issue 88)	MODERATE – • 16,748 tons SO_x/yr • 2,028 tons NO_x/yr • 1,352 tons CO/yr • 216 tons TSP/yr • 50 tons PM_{10}/yr (see Section 7.2.2.1)	MODERATE – • 9,646 tons SO_x/yr • 1,653 tons NO_x/yr • 2,119 tons CO/yr • 70 tons TSP/yr • 44 tons PM_{10}/yr (see Section 7.2.2.2)	SMALL – • 165 tons SO_x/yr • 669 tons NO_x/yr • 1,545 tons CO/yr • 98 tons TSP/yr (all PM_{10}) (see Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (Ref. 8.0-1, Section 8.2)

TABLE 8.0-2 (continued)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Ecological Resources Impacts					
SMALL – Adopting by reference Category 1 issue findings (see Appendix A, Table A-1, Issues 14-24, 45-48) Impacts to threatened and endangered species expected to be small due to protective measures to prevent sea turtles from entering the Intake Canal (see Section 4.6, Issue 49)	SMALL – Adopting by reference Category 1 issue finding (see Appendix A, Table A-1, Issue 90)	MODERATE – Potential loss of 1,275 acres of previously disturbed terrestrial habitat for plant and rail line, alteration of 800 acres of similar habitat for transmission lines, loss or alteration of 20 acres of similar habitat for cooling water pipelines; potential cooling water system impacts on aquatic resources subject to regulatory control (see Section 7.2.2.1)	MODERATE – Potential loss of 310 acres of previously disturbed terrestrial habitat for plant, alteration of 800 acres of similar habitat for transmission lines, loss or alteration of 210 acres of similar habitat for pipelines; potential cooling water system impacts on aquatic resources subject to regulatory control (see Section 7.2.2.2)	SMALL to MODERATE –Loss of 75 acres of previously disturbed terrestrial habitat for plant, alteration of 800 acres of similar habitat for transmission lines, loss or alteration of 250 acres of similar habitat for pipelines; potential cooling water system impacts on aquatic resources subject to regulatory control; potential indirect impacts from construction of new gas pipeline into central Florida (see Section 7.2.2.3)	MODERATE – Potential alteration of 8,500 – 12,700 acres of terrestrial habitat for new transmission line (see Section 7.2.2.4); adopting by reference GEIS description of ecological resources impacts from alternate technologies (Ref. 8.0-1, Section 8.2)

TABLE 8.0-2 (continued)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Human Health Impacts					
SMALL – Category 1 issues (see Appendix A, Table A-1, Issues 56, 58, 61, 62); Category 2 human health issues not applicable (see Section 4.1, Issue 57); risk due to transmission-line-induced currents minimal due to conformance with National Electric Safety Code® criteria (see Section 4.8, Issue 59); risk from microbiological organisms minimal; discharges to Atlantic Ocean via short canal that does not support species of concern (see Section 4.1, Issue 57)	SMALL – Adopting by reference Category 1 issue finding (see Appendix A, Table A-1, Issue 86)	SMALL– Some risk of cancer and emphysema from air emissions and risk of accidents to workers; as noted in GEIS, regulatory controls assumed to reduce risk to acceptable levels (Ref. 8.0-1, Section 8.3.9)	SMALL – Same as for coal-fired alternative (Ref. 8.0-1, Section 8.3.9)	SMALL – Same as for coal-fired alternative (Ref. 8.0-1, Table 8.2)	SMALL – Adopting by reference GEIS description of human health impacts from alternate technologies (Ref. 8.0-1, Section 8.2)

TABLE 8.0-2 (continued)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Socioeconomic Impacts					
SMALL – Adopting by reference Category 1 issue findings (see Appendix A, Table A.0-1, Issues 64, 67); two Category 2 issues not applicable (see Section 4.11, Issue 66; Section 4.12.1, Issue 68); location in area of medium population minimizes potential for housing impact (see Section 4.9, Issue 63); plant contribution is small proportion of county tax base, minimizing potential for land use impacts (see Section 4.12.2, Issue 69); capacity of public water supply and transportation services minimizes potential for related impacts (see Section 4.10, Issue 65; Section 4.13, Issue 70)	SMALL – Adopting by reference Category 1 issue finding (see Appendix A, Table A-1, Issue 91)	SMALL to MODERATE– Potential socioeconomic impacts limited by relatively large population in central Florida, but would vary depending on nearness of the site to large population centers (see Section 7.2.2.1)	SMALL to MODERATE – Impacts similar to coal-fired alternative, but impacts further limited by smaller workforce (see Section 7.2.2.2)	SMALL – Impacts similar to coal-fired alternative, but much smaller workforce would minimize socioeconomic impacts (see Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies (Ref. 8.0-1, Section 8.2)

TABLE 8.0-2 (continued)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Waste Management Impacts					
SMALL – Adopting by reference Category 1 issue findings (see Appendix A, Table A-1, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (see Appendix A, Table A-1, Issue 87)	MODERATE - 430,000 tons ash and 586,000 tons wet scrubber sludge generated annually (see Section 7.2.2.1)	MODERATE – 7,000 tons of ash and 320,000 tons of wet scrubber sludge generated annually (see Section 7.2.2.2)	SMALL –Relatively small waste generation (see Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (Ref. 8.0-1, Section 8.2)
Aesthetic Impacts					
SMALL – Adopting by reference Category 1 issue findings (see Appendix A, Table A-1, Issues 72-74)	SMALL – Not an impact evaluated by the NRC (Ref. 8.0-1, Section 7.3)	SMALL to LARGE – Large industrial complex; site structures, occasional cooling tower plumes, transmission lines highly visible off site; rail or barge traffic (see Section 7.2.2.1)	SMALL to LARGE – Relatively large industrial complex; site structures, occasional cooling tower plumes, transmission lines highly visible off site; barge traffic (see Section 7.2.2.2)	SMALL to MODERATE – Relatively modest industrial complex; site structures, occasional cooling tower plumes, transmission lines highly visible off site (see Section 7.2.2.3)	SMALL to LARGE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (Ref. 8.0-1, Section 8.2)

TABLE 8.0-2 (continued)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	No-Action Alternatives				
	Base (Decommissioning)	With Coal-Fired Generation	With Oil-Fired Generation	With Gas-Fired Generation	With Purchased Power[a]
Cultural Resources Impacts					
SMALL – Lack of resources and SHPO consultation minimize potential for impact (see Section 4.14, Issue 71)	SMALL – Not an impact evaluated by the NRC (Ref. 8.0-1, Section 7.3)	SMALL – Preservation measures, if necessary, would minimize impact (see Section 7.2.2.1)	SMALL – Preservation measures, if necessary, would minimize impact (see Section 7.2.2.2)	SMALL – Preservation measures, if necessary, would minimize impact (see Section 7.2.2.3)	SMALL – Adopting by reference GEIS description of cultural resources impacts from alternate technologies (Ref. 8.0-1, Section 8.2)

NOTES:

[a] Impact significance levels (SMALL, MODERATE, LARGE) shown for Purchased Power alternative are FPL estimates. The estimates are based on the assumption that impacts would fall within the range determined in Chapter 4.0 for the coal-, oil-, and gas-fired alternatives, modified by the consideration that impacts on land use and related resources would likely be MODERATE due to the 200-300 miles of transmission line required to import power (see Section 7.2.2.4).

SMALL – Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.

MODERATE – Environmental effects are sufficient to alter noticeably but not to destabilize any important attribute of the resource.

LARGE – For the issue, environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

(10 CFR 51, Subpart A, Appendix B, Table B-1, footnote 3)

Btu = British thermal unit

ft^3 = cubic foot

FPL = Florida Power & Light Company

gal = gallon

GEIS = *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (Ref. 8.0-1)

kWh = kilowatt hour

lb = pound

MW = megawatt

NO_X = nitrogen oxides

NRC = U.S. Nuclear Regulatory Commission

PM_{10} = particulates having diameter less than 10 microns

SHPO = State Historic Preservation Officer

SO_x = sulfur dioxides

TSP = total suspended particulates

yr = year

8.1 REFERENCES

8.0-1 U.S. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437. Office of Nuclear Regulatory Research. Washington, D.C. May 1996.

9.0 STATUS OF COMPLIANCE

9.1 PROPOSED ACTION

NRC

"The environmental report shall list all Federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with these requirements. The environmental report shall also include a discussion of the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection." 10 CFR 51.45(d), as required by 10 CFR 51.53(c)(2)

9.1.1 GENERAL

Table 9.1-1 lists environmental authorizations that Florida Power & Light Company (FPL) has obtained for current St. Lucie Units 1 & 2 operations. In this context, FPL uses "authorizations" to include any permits, licenses, approvals, or other entitlements. FPL expects to continue renewing these authorizations during the current license period and through the license renewal period. FPL operates St. Lucie Units 1 & 2 in compliance with applicable environmental standards and requirements.

Table 9.1-2 lists additional environmental authorizations and consultations that would be conditions precedent to U.S. Nuclear Regulatory Commission (NRC) renewal of the St. Lucie Units 1 & 2 licenses to operate. As indicated, FPL anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.5 discuss some of these items in more detail.

No permits from, or consultations with, states others than Florida are necessary because St. Lucie Units 1 & 2 are located on the peninsula of Florida. Given this location, the quality of the water and air in neighboring states would not be affected by the proposed action of license renewal.

9.1.2 THREATENED AND ENDANGERED SPECIES CONSULTATION

Section 7 of the Endangered Species Act (16 USC 1531 et seq.) requires Federal agencies to ensure that agency action is not likely to jeopardize any species that is listed or threatened. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (FWS) regarding effects on non-marine species, or the National Marine Fisheries Service (NMFS), for marine species, or both. FWS and NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, which address consultation, and FWS maintains the joint list of threatened and endangered species at 50 CFR 17.

As discussed in Section 2.4, several Federal threatened and endangered species and state species of special concern are found on the St. Lucie Units 1 & 2 site, along the St. Lucie Units 1 & 2 transmission line corridor, and in the vicinity of St. Lucie Units 1 & 2. These include marine and non-marine species. In preparation for the Federal consultation

TABLE 9.1-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT ST. LUCIE UNITS 1 & 2 OPERATIONS

Agency	Authority	Requirement	Number	Expiration Date	Activity Covered
U.S. Nuclear Regulatory Commission	Atomic Energy Act [42 USC 2011, et seq.], 10 CFR 50.10	License to operate	DPR-67 (Unit 1) NPF-16 (Unit 2)	3/1/2016 (Unit 1) 4/6/2023 (Unit 2)	Operation of St. Lucie Units 1 & 2.
U.S. Fish and Wildlife Service	Migratory Bird Treaty Act [16 USC 703 – 712]	Special Purpose Salvage	MB-697722-0	12/31/2003	Carcass salvage and injured bird transport. This is an FPL system-wide permit that may be applied as necessary and appropriate at St. Lucie Units 1 & 2.
U.S. Army Corps of Engineers	Rivers and Harbors Act (33 USC 403) and Clean Water Act (33 USC 1344)	Dredge Permit	199301803	12/21/2003	Maintenance dredging of Intake Canal.
Florida Department of Environmental Protection (DEP)	Florida Statutes Chapter 403	Industrial Wastewater Facility Permit	FL0002208	1/9/2005	Wastewater treatment and effluent disposal. State implementation of National Pollutant Discharge Elimination System.

NOTES:

a. Effective July 1, 1999, the Florida Fish and Wildlife Conservation Commission replaced the Florida Game and Fresh Water Fish Commission.

CFR = Code of Federal Regulations

DEP = (Florida) Department of Environmental Protection

FPL = Florida Power & Light Company

FWCC = (Florida) Fish and Wildlife Conservation Commission

SFWMD = South Florida Water Management District

USC = United State Code

TABLE 9.1-1 (continued)
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT ST. LUCIE UNITS 1 & 2 OPERATIONS

Agency	Authority	Requirement	Number	Expiration Date	Activity Covered
DEP	Florida Statutes Chapter 376	Annual storage tank registration	Facility ID: 8630677 Placard No: 135878	6/30/2002	Operation of above-ground storage tanks. Five tanks for petroleum products (Tank ID Nos. 9, 10, 11, 12, and 13).
DEP (Siting Coordination Office) and Siting Board (Governor and Cabinet)	Florida Statutes § 403.501-518	Power Plant Siting Act Certification	Case No: PA74-02	Life of plant	Siting, construction, and operation of St. Lucie Unit 2 (Unit 1 permitted prior to 1973 enactment of the Power Plant Siting Act).
DEP	Florida Statutes Chapter 403	Air Permit	1110071-003-AO	6/26/2005	Emissions from six emergency diesel generators, miscellaneous diesel-driven equipment, and facility-wide fugitive emission from storage tanks, roadways, and paint/sandblasting.

NOTES:

a. Effective July 1, 1999, the Florida Fish and Wildlife Conservation Commission replaced the Florida Game and Fresh Water Fish Commission.

CFR = Code of Federal Regulations

DEP = (Florida) Department of Environmental Protection

FPL = Florida Power & Light Company

FWCC = (Florida) Fish and Wildlife Conservation Commission

SFWMD = South Florida Water Management District

USC = United State Code

TABLE 9.1-1 (continued)
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT ST. LUCIE UNITS 1 & 2 OPERATIONS

Agency	Authority	Requirement	Number	Expiration Date	Activity Covered
Florida Fish and Wildlife Conservation Commission (FWCC)[a]	Florida Administrative Code Chapter 39	Special Purpose Permit	01S-018	1/26/2002	Collection and possession of marine organisms for experimental purposes.
FWCC	Florida Administrative Code Chapter 39	Marine Turtle Permit	TP#026	1/31/2002	Conduct turtle watches and maintain and display preserved specimens.
FWCC	Florida Administrative Code Chapter 39	Marine Turtle Permit	TP#125	1/31/2002	Conduct turtle activities including net capture, tagging, nesting surveys, hand-capture, nest relocation, rescue and release of hatchlings, stranding and salvage activities.

NOTES:

a. Effective July 1, 1999, the Florida Fish and Wildlife Conservation Commission replaced the Florida Game and Fresh Water Fish Commission.

CFR = Code of Federal Regulations

DEP = (Florida) Department of Environmental Protection

FPL = Florida Power & Light Company

FWCC = (Florida) Fish and Wildlife Conservation Commission

SFWMD = South Florida Water Management District

USC = United State Code

TABLE 9.1-1 (continued)
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT ST. LUCIE UNITS 1 & 2 OPERATIONS

Agency	Authority	Requirement	Number	Expiration Date	Activity Covered
FWCC	Florida Administrative Code Chapter 39	Scientific Collecting Permit	WS01374	6/25/2004	Carcass or wildlife salvaged and possessed for scientific or educational purposes. This is an FPL system-wide permit that may be applied as necessary and appropriate at St. Lucie Units 1 & 2.
FWCC	Florida Administrative Code Chapter 39	Migratory Bird Nest Permit	WN01373	6/25/2003	Authorization to destroy inactive nests of migratory birds other than ospreys (*Pandion haliaetus*) for routine facility maintenance. This is an FPL system-wide permit that may be applied as necessary and appropriate at St. Lucie Units 1 & 2.

NOTES:

a. Effective July 1, 1999, the Florida Fish and Wildlife Conservation Commission replaced the Florida Game and Fresh Water Fish Commission.

CFR = Code of Federal Regulations

DEP = (Florida) Department of Environmental Protection

FPL = Florida Power & Light Company

FWCC = (Florida) Fish and Wildlife Conservation Commission

SFWMD = South Florida Water Management District

USC = United State Code

TABLE 9.1-1 (continued)
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT ST. LUCIE UNITS 1 & 2 OPERATIONS

Agency	Authority	Requirement	Number	Expiration Date	Activity Covered
South Florida Water Management District (SFWMD)	Florida Administrative Code §40E-20.042	General Water Use Permit	56-01238-W	7/13/2002	Aquifer remediation of surficial aquifer.
SFWMD	Florida Administrative Code §65-25	Stormwater Discharge Permit	56-00848-S	Perpetual	Stormwater discharge from overflow parking lot.
SFWMD	Florida Administrative Code §62-25	Stormwater Discharge Permit	85-142	Perpetual	Stormwater discharge from the Simulator Building.

NOTES:

a. Effective July 1, 1999, the Florida Fish and Wildlife Conservation Commission replaced the Florida Game and Fresh Water Fish Commission.

CFR = Code of Federal Regulations

DEP = (Florida) Department of Environmental Protection

FPL = Florida Power & Light Company

FWCC = (Florida) Fish and Wildlife Conservation Commission

SFWMD = South Florida Water Management District

USC = United State Code

TABLE 9.1-2
ENVIRONMENTAL AUTHORIZATIONS FOR ST. LUCIE UNITS 1 & 2 LICENSE RENEWAL[a]

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License renewal	Environmental report submitted in support of license renewal application.
FWS and NMFS	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires Federal agency issuing a license to consult with FWS and NMFS.
Florida Department of Environmental Protection	Clean Water Act Section 401 (33 USC 1341) Florida Statutes Chapter 62-4.160(13)(c)	Certification	St. Lucie Units 1 & 2 Industrial Wastewater Permit constitutes State Certification (see Appendix B).
Florida Division of Historic Resources	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires Federal agency issuing a license to consider cultural impacts and consult with SHPO. SHPO has concurred that license renewal will not affect any sites currently listed or eligible for listing (see Appendix D).
Florida Department of Community Affairs	Federal Coastal Zone Management Act (16 USC 1451 et seq.)	Certification	Requires an applicant to provide certification to the Federal agency issuing the license that license renewal would be consistent with the federally approved state coastal zone management program. Based on its review of the proposed activity, the State must concur with or object to the applicant's certification (see Appendix F).

NOTES:

a. No renewal-related requirements identified for local or other agencies.

FPL = Florida Power & Light Company

FWS = U.S. Fish and Wildlife Service

NMFS = National Marine Fisheries Service

SHPO = State Historic Preservation Officer

USC = United States Code

process, FPL invited comment from Federal and State of Florida agencies regarding potential effects that St. Lucie Units 1 & 2 license renewal might have on threatened and endangered species. Appendix C includes copies of FPL correspondence with the FWS and NMFS. In addition, FPL has corresponded with the Florida Fish and Wildlife Conservation Commission regarding potential effects on state-listed species; Appendix C also includes copies of this correspondence. License renewal effects on threatened and endangered species could be beneficial due to continued stewardship of species habitat.

9.1.3 COASTAL ZONE MANAGEMENT PROGRAM COMPLIANCE

The Federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a Federal license to conduct an activity that could affect a state's coastal zone. The Act requires the applicant to certify to the licensing agency that the proposed activity would be consistent with the state's federally approved coastal zone management plan [16 USC 1456(c)(3)(A)]. The National Oceanic and Atmospheric Administration (NOAA) has promulgated implementing regulations that indicate that the requirement is applicable to renewal of Federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. The regulations require that the license applicant provide its certification to the Federal licensing agency and a copy to the applicable state agency [15 CFR 930.57(a)].

The NRC Office of Nuclear Reactor Regulation has issued guidance to its staff regarding compliance with the Act. This guidance acknowledges that Florida has an approved coastal zone management program (Ref. 9.1-1, Attachment 5). St. Lucie Units 1 & 2 are located within the Florida coastal zone, and Appendix F contains a copy of the FPL coastal zone management program certification for St. Lucie Units 1 & 2 license renewal. FPL submitted project descriptive material and a certification to the State. Concurrent with submitting the *Applicant's Environmental Report - Operating License Renewal Stage* to the NRC, FPL will submit a copy of this report to the State of Florida in fulfillment of the regulatory requirement.

9.1.4 HISTORIC PRESERVATION CONSULTATION

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires Federal agencies having the authority to license any undertaking, prior to issuing the license, to take into account the effect of the undertaking on historic properties and to afford the Advisory Committee on Historic Preservation an opportunity to comment on the undertaking. Committee regulations provide for establishing an agreement with any State Historic Preservation Officer (SHPO) to substitute state review for Council review (35 CFR 800.7). Although not required by Federal law or NRC regulation, FPL has chosen to invite comment by the Florida SHPO. Appendix D includes copies of FPL correspondence with the SHPO. Based on the FPL submittal and meeting discussions, the SHPO concurred with the FPL conclusion that St. Lucie Units 1 & 2 license renewal would not affect known historic or archaeological properties.

9.1.5 WATER QUALITY (401) CERTIFICATION

Federal Clean Water Act Section 401 requires that applicants for a Federal license to conduct an activity that might result in a discharge into navigable waters provide the licensing agency a certification from the state that the discharge will comply with applicable

Clean Water Act requirements (33 USC 1341). FPL is applying to the NRC for a license (i.e., license renewal) to continue St. Lucie Units 1 & 2 operations.

The State of Florida has U.S. Environmental Protection Agency (EPA) authorization to implement the National Pollutant Discharge Elimination System (NPDES) within the State for facilities such as St. Lucie Units 1 & 2. Pursuant to State authority and the EPA authorization, the Florida Department of Environmental Protection has issued an Industrial Wastewater Facility permit for St. Lucie Units 1 & 2. Chapter 62-4.160 of the Florida Administrative Code addresses conditions of permits issued by the Florida Department of Environmental Protection and specifies, at 62-4.160(13)(c), that the "permit also constitutes . . . certification of compliance with State Water Quality Standards (Section 401, PL92-500)." Appendix B contains a copy of the permit.

9.2 FEASIBLE ALTERNATIVES

NRC

"The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements." 10 CFR 45(d) as required by 10 CFR 51.53(c)(2)

The coal-, gas-, and oil-fired generation and purchase power alternatives that Section 7.2.1 discusses probably could be constructed and operated so as to comply with all applicable environmental quality standards and requirements. FPL notes that increasingly stringent air quality protection requirements could make construction of a large fossil-fuel-fired power plant infeasible in many locations.

Although construction and operation details for the purchase power alternative (see Section 7.2.1.2) are not known, it is reasonable to assume that any facility offering power for purchase would be in compliance.

9.3 REFERENCES

9.1-1 U.S. Nuclear Regulatory Commission. "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues." NRR Office Letter No. 906, Rev. 2. Office of Nuclear Reactor Regulation. Washington, D.C. September 21, 1999.