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April 14, 2005

Blanca S. Bayo, Director
Florida Public Service Commission
Division of the Commission Clerk and Administrative Services
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Ms. Bayo:

In accordance with Section 186.801, Florida Statutes and Rule 25-22.071, Florida Administrative Code, Gainesville Regional Utilities hereby submits 15 copies of its 2005 Ten Year Site Plan for your review. Should you have any questions regarding this Ten Year Site Plan, please contact me at (352) 393-1272 or:

Roger Westphal (Generation Planning)	(352) 393-1289
Todd Kamhoot (Forecasting)	(352) 393-1280

Sincerely,

Ed Regan, P.E.
Assistant General Manager
Strategic Utility Planning

Enclosures

File: PSC - Ten Year Site Plan

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GAINESVILLE REGIONAL UTILITIES

2005 TEN-YEAR SITE PLAN

Submitted to

The Florida Public Service Commission

April 2005

TABLE OF CONTENTS

1. INTRODUCTION

The 2005 Ten-Year Site Plan for Gainesville Regional Utilities (GRU) is submitted to the Florida Public Service Commission pursuant to Section 186.801, Florida Statutes. The contents of this report conform to information requirements listed in Form PSC/EAG 43, as specified by Rule 25-22.072, Florida Administrative Code. The five sections of the 2005 Ten-Year Site Plan are:

Introduction
Description of Existing Facilities
Forecast of Electric Energy and Demand Requirements
Forecast of Facilities Requirements
Environmental and Land Use Information

Gainesville Regional Utilities is a municipal electric, natural gas, water, wastewater, and telecommunications utility system, owned and operated by the City of Gainesville, Florida. The GRU retail electric system service area includes the City of Gainesville and the surrounding urban area. The highest net integrated peak demand recorded to date on GRU's electrical system was 433 megawatts on July 17, 2002.

2. DESCRIPTION OF EXISTING FACILITIES

The City of Gainesville owns a fully vertically integrated electric power production, transmission, and distribution system (herein referred to as "the System"). GRU is the City of Gainesville enterprise arm that has the responsibility to operate and maintain the System. In addition to retail electric service, GRU also provides wholesale electric service to the City of Alachua (Alachua); Clay Electric Cooperative (Clay); and the City of Starke (Starke). GRU's distribution system serves approximately 127 square miles and 86,264 customers (2004 average). The general locations of GRU electric facilities and the electric system service area are shown in Figure 2.1.

2.1 GENERATION

The existing generating facilities operated by GRU are tabulated in Schedule 1, found at the end of this chapter. The present summer net capability is 611 MW and the winter net capability is 630 MW[1]. Currently, the System's energy is produced by three fossil fuel steam turbines, six simple-cycle combustion turbines, one combined-cycle unit, a 1.4% ownership share of the Crystal River 3 nuclear unit operated by Progress Energy Florida (PEF), and two internal combustion engines that run on landfill gas.

The System has two generating plant sites, Deerhaven and John R. Kelly (JRK). Each site utilizes both steam turbine and gas turbine generating units. The JRK station also utilizes a combined cycle unit. Additionally, two internal combustion engines located at the Alachua County Southwest Landfill provide 1.3 MW of generating capacity.

2.1.1 Generating Units

2.1.1.1 Steam Turbines. The System's three operational simple-cycle steam turbines are powered by fossil fuels and Crystal River 3 is nuclear powered. The fossil

1 Net capability is that specified by the "SERC Guideline Number Two for Uniform Generator Ratings for Reporting." The winter rating will normally exceed the summer rating because generating plant efficiencies are increased by lower ambient air temperatures and lower cooling water temperatures.

fueled steam turbines comprise 54.7% of the System's net summer capability and produced 74.2% of the electric energy supplied by the System in 2004. These units range in size from 23.2 MW to 228.4 MW. The recently installed combined-cycle unit, which includes a heat recovery steam generator/turbine set, comprises 18.3% of the System's net summer capability and produced 18.9% of the electric energy supplied by the System in 2004. The System's 11.0 MW share of Crystal River 3 nuclear unit comprises 1.8% of the System's net summer capability and produced 5.6% of total electric energy in 2004. Deerhaven 2, and Crystal River 3 are used for base load purposes; while Kelly 7, Kelly CC1, and Deerhaven 1 are used for intermediate loading.

2.1.1.2 Gas Turbines. The System's seven industrial gas turbines make up 25.0% of the System's summer generating capability and produced 1.1% of the electric energy supplied by the System in 2004. Except for the turbine associated with the System's combined cycle unit, these units are utilized for peaking purposes only because their energy conversion efficiencies are considerably lower than steam units. As a result, they yield higher operating costs and are consequently unsuitable for base load operation. Gas turbines are advantageous in that they can be started and placed on line in thirty minutes or less. The System's gas turbines are most economically used as peaking units during high demand periods when base and intermediate units cannot serve all of the System loads.

2.1.1.3 Internal Combustion (Piston/Diesel). The System operates two internal combustion engines at the Southwest Landfill. Fueled by gas produced by the landfill, these units represent 0.2% of the System's summer capability and produced 0.2% of total energy in 2004. They are operated as continuously as possible.

2.1.1.4 Environmental Considerations. All of the System's steam turbines, except for Crystal River 3, utilize recirculating cooling towers with a mechanical draft for the cooling of condensed steam. Crystal River 3 uses a once-through cooling system aided by helper towers. Only Deerhaven 2 has flue gas cleaning equipment.

2.1.2 Generating Plant Sites

The locations of the System's generating plant sites are shown on Figure 2.1.

2.1.2.1 John R. Kelly Plant. The Kelly Station is located in southeast Gainesville near the downtown business district and consists of one combined cycle, one steam turbine, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment.

2.1.2.2 Deerhaven Plant. The Deerhaven Station is located six miles northwest of Gainesville. The original site, which was certified pursuant to the Power Plant Siting Act, included an 1146 acre parcel of partially forested land. The facility consists of two steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment and transmission equipment. As amended to include the addition of Deerhaven 2 in 1981, the certified site now includes coal unloading and storage facilities and a zero discharge water treatment plant, which treats water effluent from both steam units. A buffer and potential expansion area, owned by the System and adjacent to the certified Deerhaven plant site, was subsequently acquired, consisting of an additional 2318 acres, for a total of 3464 acres.

2.1.2.3 Southwest Landfill. The Southwest Landfill is located west of the town of Archer on SR 24 near the Alachua county / Levy county line. The landfill is owned by Alachua County. An inter-local agreement between the City of Gainesville and Alachua County approved the concept of using landfill gas to power two internal combustion engine generators. The County granted a special use permit and an easement for GRU to operate and access the generators. The landfill gas to energy project (LFGTE) at the Alachua County Southwest Landfill was commissioned in December of 2003 and is wheeling power over the Progress Energy Florida's (PEF) distribution network to GRU's 230 kV transmission intertie with PEF. The LFGTE facility presently operates two internal combustion generating sets with a combined capacity of 1.3 MW of renewable energy. The generation capacity of the LFGTE system will diminish through time as the landfill gas production rate slows, and generating sets are taken off-line.

2.2 TRANSMISSION

2.2.1 The Transmission Network

GRU's bulk power transmission network consists of a 138 kV loop connecting the following:

1) GRU's two generating stations,
2) GRU's nine distribution substations,
3) Three interties with Progress Energy Florida,
4) An intertie with Florida Power and Light Company,
5) An interconnection with Clay at Farnsworth Substation, and
6) An interconnection with the City of Alachua at Alachua No. 1 Substation

Refer to Figure 2.1 for line geographical locations and Figure 2.2 for electrical connectivity and line numbers.

2.2.2 Transmission Lines

The ratings for all of GRU's transmission lines are given in Table 2.1. The load ratings for GRU's transmission lines were developed in Appendix 6.1 of GRU's Long-Range Transmission Planning Study, March 1991. Refer to Figure 2.2 for a one-line diagram of GRU's electric system. The criteria for normal and emergency loading are taken to be:

Normal loading: conductor temperature not to exceed 100° C (212° F).

Emergency 8 hour loading: conductor temperature not to exceed 125° C (257° F).

The present transmission network consists of the following:

Line	Circuit Miles	Conductor
138 KV double circuit	100.20	795 MCM ACSR
138 KV single circuit	16.47	1192 MCM ACSR
138 KV single circuit	20.74	795 MCM ACSR
230 KV single circuit	2.60	795 MCM ACSR
Total	140.01	

As part of a study in September and October of 2002 the transmission system was subjected to scenario analysis. Each scenario represents a system configuration with different contingencies modeled. A contingency is an occurrence that depends on chance or uncertain conditions and, as used here, represents various equipment failures that may occur. The following conclusions were drawn from this analysis:

Reliability contingencies:

(a) Single contingency transmission line and generator outages (the failure of any one generator or any one transmission line) -- No identifiable problems.

(b) All right-of-way double contingency outages (two lines - common pole) -- No problems with GRU's 138 kV/24 MVAR capacitor on line.

(c) Meeting future load and interchange requirements -- No identifiable problems through 2014, including the proposed capacity addition described in Section 4.

2.2.3 State Interconnections

The System is currently interconnected with PEF and Florida Power and Light (FPL) at a total of four separate points. The System interconnects with PEF's Archer Substation via a 230 kV transmission line to the System's Parker Substation with 224 MVA of transformation capacity from 230 kV to 138 kV. The System also interconnects with PEF's Idylwild Substation with two separate circuits via a 168 MVA 138/69 kV transformer at the Idylwild Substation. The System interconnects with FPL via a 138 kV tie between FPL's Bradford Substation and the System's Deerhaven Substation. This interconnection has a thermal capacity of 224 MVA.

2.3 DISTRIBUTION

The System has six major and three minor distribution substations connected to the transmission network: Ft. Clarke, Kelly, McMichen, Millhopper, Serenola, Sugarfoot, Ironwood, Kanapaha, and Rocky Point substations, respectively. In addition, GRU has two transmission level voltage substations, Parker and Depot. The locations of these substations are shown on Figure 2.1.

Six of GRU's distribution substations are connected to the 138 kV bulk power transmission network with dual feeds, while Ironwood, Kanapaha, and Rocky Point are served by a single tap to the 138 kV network. This prevents the outage of a single transmission line from causing major outages in the distribution system. GRU serves its retail customers through a 12.47 kV distribution network. The distribution substations, their present rated transformer capabilities and present number of circuits are listed in Table 2.2.

The last substation added by GRU, Ironwood, was brought on-line in 2003 to serve the growing load in the area of State Road 24 and NE 31^{st} Avenue and to provide backup support for the Kelly and McMichen substations. Ft. Clarke, Kelly, McMichen, and Serenola substations currently consist of two transformers of equal size allowing these stations to be loaded under normal conditions to 80 percent of the capabilities shown in Table 2.2. Millhopper and Sugarfoot Substations currently consist of three transformers of equal size allowing both of these substations to be loaded under normal conditions to 100 percent of the capability shown in Table 2.2.

2.4 WHOLESALE ENERGY

The System provides full requirements wholesale electric service to Clay Electric Cooperative (Clay) through a contract between GRU and Seminole Electric Cooperative

(Seminole), of which Clay is a member. The System began the 138 kV service at Clay's Farnsworth Substation in February 1975. This substation is supplied through a 2.4 mile radial line connected to the System's transmission facilities.

The System also provides full requirements wholesale electric service to the City of Alachua at two points of service. The Alachua No. 1 Substation is supplied with GRU's looped 138 kV transmission system. Two small residential neighborhoods and a few commercial customers within Alachua's city limits are served by a 12.47 kV distribution circuit, known as the Hague point of service. The System provides approximately 92% of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from the Crystal River 3 and St. Lucie 2 nuclear units. Energy supplied to Alachua by these nuclear units is wheeled over GRU's transmission network, with GRU providing generation backup in the event of outages of these nuclear units.

GRU has a partial requirements firm interchange service commitment with the City of Starke (Starke). The agreement with Starke is non-unit specific and provides for the sale of System capacity (including reserves). This agreement was renewed January 1, 1994 and continues through 2006, with optional three year extensions available indefinitely and allows Starke the option to expand the capacity commitment. This agreement was assigned to the FMPA in 1998 when Starke became an "All Requirements" member of FMPA.

Wholesale sales to Clay and Alachua are included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins. Schedules 7.1 and 7.2 at the end of Section 4 summarize GRU's reserve margins.

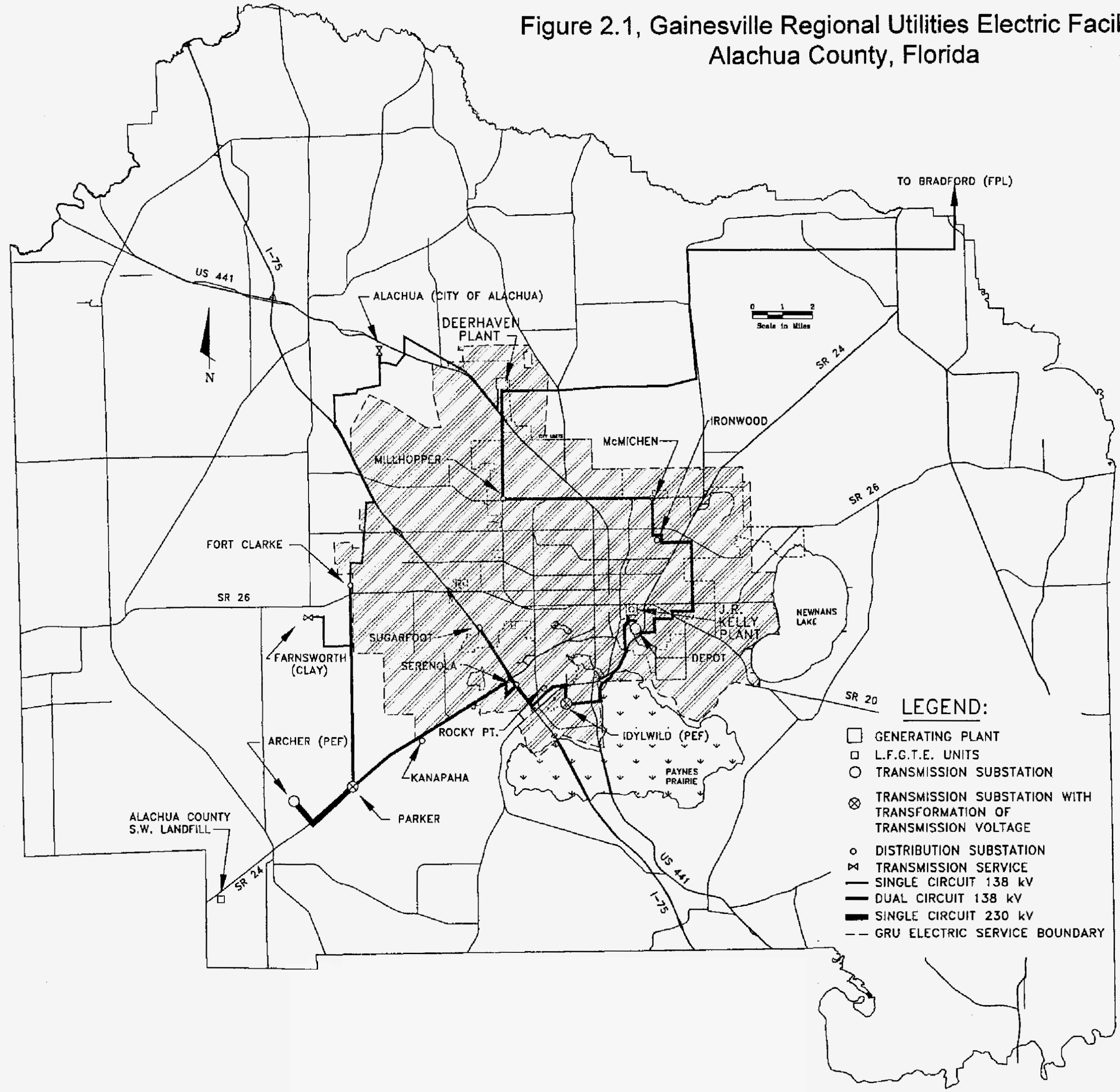
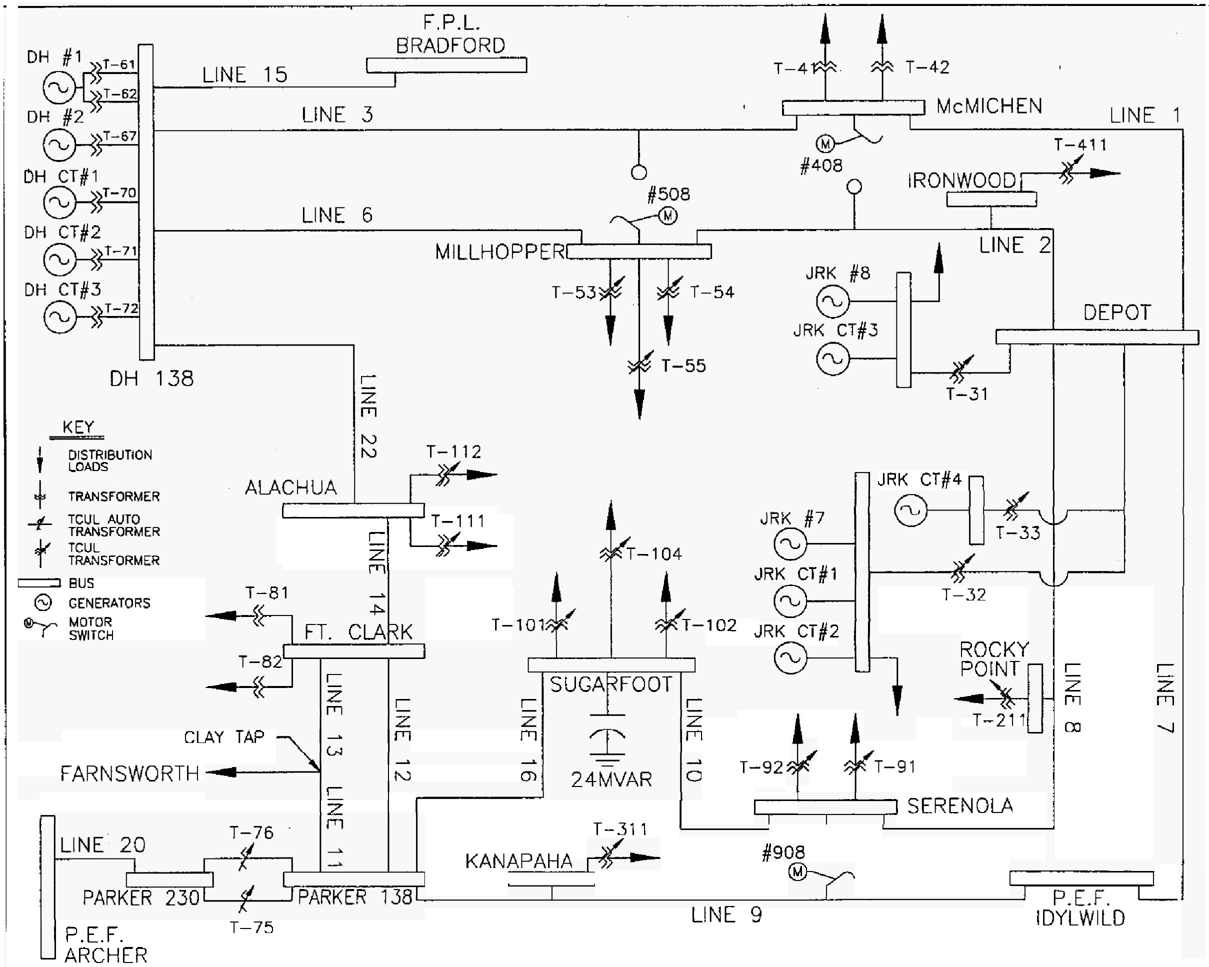


Figure 2.1, Gainesville Regional Utilities Electric Facilities
Alachua County, Florida

FIGURE 2.2 Gainesville Regional Utilities Electric System One-Line Diagram.



Schedule 1
EXISTING GENERATING FACILITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Primary Fuel		Alternate Fuel		Alt. Fuel	Commercial	Expected	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Type	Trans.	Type	Trans.	Storage (Days)	In-Service Month/Year	Retirement Month/Year	Summer MW	Winter MW	Summer MW	Winter MW	Status
J. R. Kelly		Alachua County									180	189	177	186	
		Section 4													
	FS08	Township 10 S	CA	WH	PL				[4/65 ; 5/01]	2051	38	38	37	37	OP
	FS07	Range 20 E	ST	NG	PL	RFO	TK		8/61	8/11	24	24	23	23	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	2051	76	82	75	81	OP
	GT03		GT	NG	PL	DFO	TK		5/69	2019	14	15	14	15	OP
	GT02		GT	NG	PL	DFO	TK		9/68	2018	14	15	14	15	OP
	GT01		GT	NG	PL	DFO	TK		2/68	2018	14	15	14	15	OP
Deerhaven		Alachua County									451	461	422	432	
		Sections 26,27,35													
	FS02	Township 8 S	ST	BIT	RR				10/81	2031	249	249	228	228	OP
	FS01	Range 19 E	ST	NG	PL	RFO	TK		8/72	2023	88	88	83	83	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	76	82	75	81	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	19	21	18	20	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	19	21	18	20	OP
Crystal River (818/815)	3	Citrus County Section 33 Township 17 S Range 16 E (FPC)	ST	NUC	TK				3/77	2037	11	11	11	11	OP
SW Landfill		Alachua County									1.64	1.64 0	1.3	1.3	
		Section 19													
	SW-1	Township 11 S	IC	LFG	PL				12/03	12/09	0.82	0.82	0.65	0.65	OP
	SW-2	Range 18 E	IC	LFG	PL				12/03	12/15	0.82	0.82	0.65	0.65	OP
System Total													611	630	

<u>Unit Type</u>
CA = Combined Cycle Steam Part
CT = Combined Cycle Combustion Turbine Part
GT = Gas Turbine
ST = Steam Turbine
IC = Internal Combustion (diesel, piston) Engine

<u>Fuel Type</u>
NG = Natural Gas
BIT = Bituminous Coal
NUC = Uranium
RFO = Residual Fuel Oil
DFO = Distillate Fuel Oil
WH = Waste Heat
LFG = Landfill Gas

<u>Transportation Method</u>
PL = Pipe Line
RR = Railroad
TK = Truck

<u>Status</u>
OP = Operational

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TABLE 2.1

SUMMER POWER FLOW LIMITS

Transmission Line Number	Description	Normal 100° C (MVA)	Limiting Device	8-Hour Emergency 125° C (MVA)	Limiting Device
1	McMichen - Depot East	236.2	Conductor	282.0	Conductor
2	Millhopper - Depot West	236.2	Conductor	282.0	Conductor
3	Deerhaven - McMichen	236.2	Conductor	282.0	Conductor
6	Deerhaven - Millhopper	236.2	Conductor	282.0	Conductor
7	Depot East - Idylwild	191.2 [1]	Line Trap	191.2 [1]	Line Trap
8	Depot West - Serenola	236.2	Conductor	282.0	Conductor
9	Idylwild - Parker	191.2 [1]	Line Trap	191.2 [1]	Line Trap
10	Serenola - Sugarfoot	236.2	Conductor	282.0	Conductor
11	Parker - Clay Tap	236.2	Conductor	282.0	Conductor
12	Parker - Ft. Clarke	236.2	Conductor	282.0	Conductor
13	Clay Tap - Ft. Clarke	236.2	Conductor	282.0	Conductor
14	Ft. Clarke - Alachua	299.7	Conductor	356.0	Conductor
15	Deerhaven - Bradford	224.0	Transformer	224.0	Transformer
16	Sugarfoot - Parker	236.2	Conductor	282.0	Conductor
20	Parker - Archer	224.0	Transformer	224.0	Transformer
22	Alachua - Deerhaven	299.7	Conductor	356.0	Conductor
xx	Clay Tap - Farnsworth	236.2	Conductor	282.0	Conductor
xx	Idylwild - FPC	168.0	Transformer	168.0	Transformer

[1] –Rating effective through Spring, 2005 (estimate). At this point in time, the 800 ampere wave traps on the Depot E – Idylwild 138 KV and Parker – Idylwild 138 KV circuit at Idylwild will be removed. Thereafter, the normal and emergency rating will be 236.2 MVA and 282.0 MVA, respectively.

Assumptions:

- 100 °C for normal conductor operation
- 125 °C for emergency 8 hour conductor operation
- 40 °C ambient air temperature
- 2 ft/sec wind speed
- T-75 & T-76 are based on a 65 °C oil temperature rise

TABLE 2.2

SUBSTATION TRANSFORMATION AND CIRCUITS

DISTRIBUTION SUBSTATION	TRANSFORMER RATED CAPABILITY	NUMBER OF CIRCUITS
Ft. Clarke	44.8 MVA	4
J. R. Kelly[2]	112.0 MVA	18 (3 de-energized)
McMichen	44.8 MVA	6 (1 de-energized)
Millhopper	100.8 MVA	10
Serenola	67.2 MVA	8
Sugarfoot	100.8 MVA	9
Ironwood	33.6 MVA	3
Kanapaha	33.6 MVA	2
Rocky Point	33.6 MVA	3

TRANSMISSION SUBSTATION	TRANSFORMER RATED CAPABILITY	NUMBER OF CIRCUITS
Parker	224 MVA	5
Depot	0 MVA	6

2 J. R. Kelly is a generating station as well as a distribution substation. The CT portion (75 MW) of JRK CC 1 is connected directly to the 138 kV transmission line from Depot Transmission Substation to J. R. Kelly Distribution Substation/Generation Station and the steam portion is connected to the 12.47 kV substation bus along with the remaining generation capacity at J. R. Kelly Station (102 MW).

3. FORECAST OF ELECTRIC ENERGY AND DEMAND REQUIREMENTS

Section 3 includes documentation of GRU's forecast of number of customers, energy sales and seasonal peak demands; a forecast of energy sources and fuel requirements; and an overview of GRU's involvement in demand-side management programs.

The accompanying tables provide historical and forecast information for calendar years 1995-2014. Energy sales and number of customers are tabulated in Schedules 2.1, 2.2 and 2.3. Schedule 3.1 gives summer peak demand for the base case forecast by reporting category. Schedule 3.2 presents winter peak demand for the base case forecast by reporting category. Schedule 3.3 similarly presents net energy for load for the base case forecast by reporting category. Short-term monthly load data is presented in Schedule 4. Projected net energy requirements for the System, by method of generation, are shown in Schedule 6.1. The percentage breakdowns of energy shown in Schedule 6.1 are given in Schedule 6.2. The quantities of fuel expected to be used to generate the energy requirements shown in Schedule 6.1 are given by fuel type in Schedule 5.

3.1 FORECAST ASSUMPTIONS AND DATA SOURCES

(1) All regression analyses were based on annual data. Historical data was compiled for calendar years 1970 through 2004. System data, such as net energy for load, seasonal peak demands, customer counts and energy sales, was obtained from GRU records and sources.

(2) Estimates and projections of Alachua County population were obtained from the Florida Population Studies, February 2005 (Bulletin No. 141), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

(3) Historical weather data was used to fit regression models. Forecast values of heating degree days and cooling degree days equal the mean (rounded to the nearest hundred) of data reported to NOAA by the

Gainesville Municipal Airport station from 1984-2004, representing "normal" weather conditions.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2004, using the U.S. Consumer Price Index for All Urban Consumers from the U.S. Department of Labor, Bureau of Labor Statistics. Inflation is assumed to average approximately 2.7% per year for each year of the forecast.

(5) The U. S. Department of Commerce provided historical estimates of total income and per capita income for Alachua County. Forecast values of total personal income for Alachua County were obtained from Economy.com.

(6) Historical estimates of household size were obtained from BEBR, and projected levels were derived from a forecast provided by Global Insight.

(7) The Florida Agency for Workforce Innovation and the U.S. Department of Labor provided historical estimates of non-agricultural employment in Alachua County. A forecast of non-agricultural employment was developed by Global Insight.

(8) GRU's corporate model was the basis for projections of the average price of 1,000 kWh of electricity for all customer classes. GRU's corporate model evaluates projected revenue and revenue requirements for the forecast horizon and determines revenue sufficiency under prevailing prices. If revenue from present pricing is insufficient, pricing changes are programmed in and become GRU's official pricing program plan. Programmed price increases from the model for all retail customer classes are projected to be less than the rate of inflation, yielding declining real prices of electricity over the forecast horizon.

(9) Estimates of energy and demand reductions resulting from planned demand-side management programs were subtracted from all retail forecasts. Energy and demand reductions are removed from the forecast of DSM impacts as each conservation measure installed reaches the end of its useful life. GRU's involvement with DSM is described in more detail later in this section.

(10) The City of Alachua will generate (via generation entitlement shares of Progress Energy and Florida Power and Light nuclear units) approximately 8,077 MWh (8%) of its annual energy requirements.

3.2 FORECASTS OF NUMBER OF CUSTOMERS, ENERGY SALES AND SEASONAL PEAK DEMANDS

Number of customers, energy sales and seasonal peak demands were forecast from 2005 through 2014. Separate energy sales forecasts were developed for each of the following customer segments: residential, general service non-demand, general service demand, large power, outdoor lighting, sales to Clay, and sales to Alachua. Separate forecasts of number of customers were developed for residential, general service non-demand, general service demand and large power retail rate classifications. The basis for these independent forecasts originated with the development of least-squares regression models. All modeling was performed in-house using the Statistical Analysis System (SAS)[3]. The following text describes the regression equations utilized to forecast energy sales and number of customers.

3.2.1 Residential Sector

The equation of the model developed to project residential average annual energy use (kilowatt-hours per year) specifies average use as a function of household income in Alachua County, residential price of electricity and weather variation, measured by heating degree days and cooling degree days. The form of this equation is as follows:

$$RESAVUSE = 4202.2 + 0.078\,(HHY04) - 11.44\,(RESPR04) + 0.73\,(HDD) + 0.89\,(CDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use Per Customer
HHY04	=	Average Household Income
RESPR04	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
CDD	=	Annual Cooling Degree Days

---

3 SAS is the registered trademark of SAS Institute, Inc., Cary, NC.

Adjusted R^2	=	0.9047
DF (error)	=	28 (period of study, 1971-2004)
t - statistics:		
Intercept	=	3.09
HHY04	=	5.74
RESPR04	=	-3.09
HDD	=	4.28
CDD	=	4.62

Projections of the average annual number of residential customers were developed from a linear regression model stating the number of customers as a function of Alachua County population. The model was fit to an historical time series that accounted for the history of Clay customer transfers. The residential customer model specifications are:

$$RESCUS = -25822 + 424.24\ (POP)$$

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.9941
DF (error)	=	24 (period of study, 1978-2004)
t - statistics:		
Intercept	=	-20.88
POP	=	64.77

The product of forecasted values of average use and number of customers yielded the projected energy sales for the residential sector.

3.2.2 General Service Non-Demand Sector

The general service non-demand (GSN) customer class includes non-residential customers with maximum annual demands less than 50 kilowatts (kW). In 1990, GRU began offering GSN customers the option to elect the General Service Demand (GSD) rate classification. This option offers potential benefit to GSN customers that use high amounts of energy and have good load factors. Since 1990, 273 customers have elected to transfer to the GSD rate class. The forecast assumes that additional GSN customers will voluntarily elect the GSD classification at a rate comparable to the historical annual median. A regression model was developed to project average annual energy use by GSN customers. The model includes as independent variables, the cumulative number of optional demand customers and cooling degree days. The specifications of this model are as follows:

GSNAVUSE = *23.9 – 0.01(OPTDCUST) + 0.001(CDD)*

Where:

GSNAVUSE	=	Average annual energy usage by GSN customers
OPTDCUST	=	Cumulative number of Optional Demand Customers
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.7325
DF (error)	=	22 (period of study, 1979-2004)
t - statistics:		
Intercept	=	11.97
OPTDCUST	=	-7.95
CDD	=	2.02

The number of general service non-demand customers was projected using an equation specifying customers as a function of Alachua County population. The specifications of the general service non-demand customer model are as follows:

GSNCUS = *-4559.5 + 55.7 (POP)*

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.9851
DF (error)	=	24 (period of study, 1978-2004)
t - statistics:		
Intercept	=	-17.6
POP	=	40.6

Forecasted energy sales to general service non-demand customers were derived from the product of projected number of customers and the projected average annual use per customer.

3.2.3 General Service Demand Sector

The general service demand customer class includes non-residential customers with established annual maximum demands generally of at least 50 kW but less than 1,000 kW. Average annual energy use per customer was projected using an equation specifying average use as a function of per capita income (Alachua County) and the number of optional demand customers. A significant portion of the energy load in this sector is from large retailers such as department stores and grocery stores, whose business activity is related to income levels of area residents. Average energy use projections for general service demand customers result from the following model:

$$GSDAVUSE = 332.7 + 0.0088\,(PCY04) - 0.15\,(OPTDCUST)$$

Where:

GSDAVUSE	=	Average annual energy use by GSD Customers
PCY04	=	Per Capita Income in Alachua County
OPTDCUST	=	Cumulative number of Optional Demand Customers
Adjusted R^2	=	0.7458
DF (error)	=	22 (period of study, 1979-2004)

t - statistics:

Intercept	=	14.3
PCY04	=	8.4
OPTDCUST	=	-4.4

The annual average number of customers was projected based on the results of a regression model in which Alachua County population was the independent variable. The specifications of the general service demand customer model are as follows:

$$GSDCUS = -376.2 + 5.06\,(POP)$$

Where:

GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.9614
DF (error)	=	24 (period of study, 1978-2004)

t - statistics:

Intercept	=	-9.8
POP	=	25.0

The forecast of energy sales to general service demand customers was the resultant product of projected number of customers and projected average annual use per customer.

3.2.4 Large Power Sector

The large power customer class currently includes approximately 18 customers with billing demands of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1976 through 2004. The model developed to project average use by large power customers includes Alachua County nonagricultural employment and large power price of electricity as independent variables. Energy use per customer has been observed to increase over time, presumably due to the periodic expansion or increased utilization of existing facilities. This growth is measured in the model by local employment levels. The specifications of the large power average use model are as follows:

LPAVUSE	=	*11376 + 10.1 (NONAG) - 38.5 (LPPR04)*
Where:		
LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
NONAG	=	Alachua County Nonagricultural Employment (000's)
LPPR04	=	Average Price for 1,000 kWh in the Large Power Sector
Adjusted R^2	=	0.9141
DF (error)	=	26 (period of study, 1976-2004)
t - statistics:		
INTERCEPT	=	7.28
NONAG	=	1.19
LPPR04	=	-4.01

The forecast of energy sales to the large power sector was derived from the product of projected average use per customer and the projected number of large power customers, which are projected to remain constant at eighteen.

3.2.5 Outdoor Lighting Sector

The outdoor lighting sector consists of streetlight, traffic light, and rental light accounts. Outdoor lighting energy sales account for approximately 1.25% of total energy sales. Outdoor lighting energy sales were forecast using a model which specified lighting energy as a function of the number of residential customers. The specifications of this model are as follows:

LGTMWH	=	*-9060 + 0.47 (RESCUS)*
Where:		
LGTMWH	=	Outdoor Lighting Energy Sales
RESCUS	=	Number of Residential Customers

Adjusted R^2	=	0.9803
DF (error)	=	10 (period of study, 1993-2004)
t - statistics:		
Intercept	=	-6.99
RESCUS	=	23.39

3.2.6 Wholesale Energy Sales

As previously described, the System provides control area services to two wholesale customers: Clay Electric Cooperative (Clay) at the Farnsworth Substation; and the City of Alachua (Alachua) at the Alachua No. 1 Substation, and at the Hague Point of Service. Approximately 8% of Alachua's 2004 energy requirements were met through generation entitlements of nuclear generating units operated by PEF and FPL. These wholesale delivery points serve an urban area that is either included in, or adjacent to the Gainesville urban area. These loads are considered part of the System's native load for facilities planning through the forecast horizon. GRU provides other utilities services in the same geographic areas served by Clay and Alachua, and continued electrical service will avoid duplicating facilities. Furthermore, the populations served by Clay and Alachua benefit from services provided by the City of Gainesville, which are in part supported by transfers from the System.

Clay-Farnsworth net energy requirements were modeled with an equation in which Alachua County population was the independent variable. Output from this model was adjusted to account for the history of load that has been transferred between GRU and Clay-Farnsworth, yielding energy sales to Clay. Historical boundary adjustments between Clay and GRU have reduced the duplication of facilities in both companies' service areas. The form of the Clay-Farnsworth net energy requirements equation is as follows:

$$CLYNEL = -29719 + 457.7\,(POP)$$

Where:

CLYNEL	=	Farnsworth Substation Net Energy (MWh)
POP	=	Alachua County Population (000's)
Adjusted R^2	=	0.9573
DF (error)	=	13 (period of study, 1990-2004)
t - statistics:		
Intercept	=	-5.57
POP	=	17.74

Net energy requirements for Alachua were estimated using a model in which City of Alachua population was the independent variable. BEBR provided historical estimates of City of Alachua Population. This variable was projected from a trend analysis of the component populations within Alachua County. The model used to develop projections of sales to the City of Alachua is of the following form:

$$ALANEL = -66321 + 23683\,(ALAPOP)$$

Where:

ALANEL	=	City of Alachua Net Energy (MWh)
ALAPOP	=	City of Alachua Population (000's)
Adjusted R^2	=	0.9788
DF (error)	=	21 (period of study, 1982-2004)
t - statistics:		
Intercept	=	-17.0
ALAPOP	=	31.9

To obtain a final forecast of the System's sales to Alachua, projected net energy requirements were reduced by 8,077 MWh reflecting the City of Alachua's nuclear generation entitlements.

3.2.7 Total System Sales, Net Energy for Load, Seasonal Peak Demands and DSM Impacts

The forecast of total system energy sales was derived by summing energy sales projections for each customer class; residential, general service non-demand, general service demand, large power, outdoor lighting, sales to Clay, and sales to Alachua. Net energy for load was then forecast by applying a delivered efficiency factor for the System to total energy sales. The projected delivered efficiency factor (0.95088) is the median of observed historical values from 1984 through 2004. The impact of energy savings from conservation programs was accounted for in energy sales to each customer class, prior to calculating net energy for load.

The forecasts of seasonal peak demands were derived from forecasts of annual net energy for load. Winter peak demands are projected to occur in January of each year, and summer peak demands are projected to occur in July of each year, although historical data suggests the summer peak is nearly as likely to occur in August. The average ratio of the most recent 21 years' monthly net energy for load for January and July, as a portion of annual net energy for load, was applied to projected annual net energy for load to obtain estimates of January and July net energy for load over the forecast horizon. The medians of the past 21 years' load factors for January and July were applied to January and July net energy for load projections, yielding seasonal peak demand projections. Forecast seasonal peak demands include the net impacts from planned demand-side management programs.

3.3 ENERGY SOURCES AND FUEL REQUIREMENTS

3.3.1 Fuels Used by System

Presently, the system is capable of using coal, residual oil, distillate oil, natural gas, and a small percentage of nuclear fuel to satisfy its fuel requirements. Since the completion of the Deerhaven 2 coal-fired unit, the System has relied upon coal to fulfill much of its fuel requirements. To the extent that the System participates in interchange sales and purchases, actual consumption of these fuels will likely differ from the base case requirements indicated in Schedule 5. These projections are based on a fuel price forecast prepared in May 2004.

3.3.2 Methodology for Projecting Fuel Use

The fuel use projections were produced using the Electric Generation Expansion Analysis System (EGEAS) developed under Electric Power Research Institute guidance and maintained by EPRI Solutions. This is the same software the System uses to perform long-range integrated resource planning. EGEAS has the ability to model each of the System's generating units as well as optimize the selection of new capacity and technologies (see Section 4), and include the effects of environmental limits, dual fuel units, reliability constraints, and maintenance schedules. The production modeling process uses a load-duration curve convolution and conjoint probability model to simulate optimal hourly dispatch of the System's generating resources.

The input data to this model includes:

(1) Long-term forecast of System electric energy and power demand needs;

(2) Projected fuel prices, outage parameters, nuclear refueling cycle (as needed), and maintenance schedules for each generating unit in the System;

(3) Similar data for the new plants that will be added to the system to maintain system reliability.

The output of this model includes:

(1) Monthly and yearly operating fuel expenses by fuel type and unit; and

(2) Monthly and yearly capacity factors, energy production, hours of operation, fuel utilization, and heat rates for each unit in the system.

3.4 DEMAND-SIDE MANAGEMENT

3.4.1 Demand-Side Management Program History and Current Status

Demand and energy forecasts and generation expansion plans outlined in this Ten Year Site Plan include impacts from GRU's planned Demand-Side Management (DSM) programs. The System forecast reflects the residual cumulative effects of program implementations recorded from 1980 through 2004, as well as projected program implementations scheduled through 2014. Included in the total annual effects of DSM measures on energy and demand, is the life cycle of each measure's impact. As each implementation of each measure reaches the end of its useful life, the demand and energy reductions associated with that implementation are removed from the estimated total annual effects. GRU's DSM programs were designed for the purpose of conserving the resources utilized by the System in a manner most cost effective to the customers of GRU. DSM programs are available for all retail customers, including commercial and industrial customers, and are designed to effectively reduce and control the growth rates of electric consumption and weather sensitive peak demands.

GRU is currently active in the following residential conservation efforts: conservation surveys; energy efficient (green) building consultations; programs for low income households including weatherization and natural gas service; rebates for natural gas in residential construction; rebates for natural gas for displacement of electric water heating, space heating and space cooling in existing structures; rebates for solar water heating; rebates for heat recovery water heating; high-efficiency central and room air conditioning rebates; rebates for duct repairs; heat pipe rebates; reflective roof coating rebates; a/c maintenance rebates; promotion of customer-owned photovoltaic systems through a standardized interconnection and buyback agreement; and an increasing block rate structure. GRU offers the following conservation services to its non-residential customers: conservation surveys; lighting efficiency and maintenance services; rebates for natural gas water heating, space cooling and dehumidification; rebates for heat recovery water heating; and promotion of customer-owned photovoltaic systems through a standardized interconnection and buyback agreement.

GRU secured grant funding through the Department of Community Affairs' PV for Schools Educational Enhancement Program for PV systems that were installed at two middle schools in 2003. GRU began offering green energy (i.e., GRUGreen^{sm}) to its customers when the LFGTE project became operational in 2003. The majority of the energy available under this program comes from landfill gas, but also includes some solar and wind energy credits. GRUGreen^{sm} is available to all GRU customers at a cost equivalent to two cents per kWh. A combination of customer contributions and State and Federal grants allowed GRU to add its 10 kW photovoltaic array at the Electric System Control Center in 1996.

GRU has also produced numerous *factsheets,* publications and videos which are available at no charge to customers to assist them in making informed decisions effecting their energy utilization patterns. Examples include: Passive Solar Design-Factors for North Central Florida, a booklet which provides detailed solar and environmental data for passive solar designs in this area; Solar Guidebook, a brochure which explains common applications of solar energy in Gainesville; and The Energy Book, a guide to saving home energy dollars.

3.4.2 Future Demand-Side Management Programs

In addition to the new programs that GRU added in 2005, a new commercial program providing incentives for innovative energy designs is planned for implementation in 2006. GRU has budgeted funds to proceed with installing a new 10 kW PV system at the Gainesville Regional Airport. This project will be supported by voluntary customer contributions and avoided utility costs.

GRU has recently evaluated Requests for Proposals for Innovative Demand-Side Management programs in an effort to identify and capture all the cost-effective energy conservation and power demand reduction potential in the community. The RFP was issued to private companies, individuals and public sector agencies to provide an opportunity to service providers and interested parties to encourage additional energy conservation and power demand reductions in the community. Two entities have begun developing business plans for implementing new programs as a result of this process.

3.4.3 Demand-Side Management Methodology and Results

The expected effect of DSM program participation was derived from a comparative analysis of historical energy usage of DSM program participants and non-participants. The methodology upon which existing DSM programs is based includes consideration of what would happen anyway, the fact that the conservation induced by utility involvement tends to "buy" conservation at the margin, adjustment for behavioral rebound and price elasticity effects and effects of abnormal weather. Known interactions between measures and programs were accounted for when possible. At the end of each measure's useful life, the energy and demand savings assumed to have been induced by GRU are removed to represent the retirement of the given measure. Projected penetration rates were based on historical levels of program implementations and tied to escalation rates paralleling service area population growth.

The implementation of DSM programs planned for 2005-2014 is expected to provide an incremental impact of 5 MW of summer peak reduction, 7 MW of winter peak reduction, and 28 GWh of annual energy savings by the year 2014, as shown in Table 3.1. Total DSM program achievements are shown in Table 3.2.1. DSM impacts that have been retired from total program achievements are shown in Table 3.2.2, and the net DSM reductions included in the System's energy and demand forecasts are shown in Table 3.2.3. These tables are located at the end of Section 3.

3.4.4 Gainesville Energy Advisory Committee

The Gainesville Energy Advisory Committee (GEAC) is a nine-member citizen group that is charged with formulating recommendations concerning national, state and local energy-related issues. The GEAC offers advice and guidance on energy management studies and consumer awareness programs. The GEAC's efforts have resulted in numerous contributions, accomplishments, and achievements for the City of Gainesville. Specifically, the GEAC helped establish a residential energy audit program in 1979. The GEAC was initially involved in the ratemaking process in 1980 which ultimately lead to the approval of an inverted block residential rate and a voluntary residential time-of-use rate. The GEAC promoted *Solar Month* in October of 1991 by sponsoring a seminar to foster the viability of solar energy as an alternative to conventional means of energy supply. Representatives from Sandia National Laboratories, the Florida Solar Energy Center, PEF, and GRU gave presentations on various solar projects and technologies. A recommendation from GEAC followed the Solar Day Seminars for GRU to investigate offering its citizen-ratepayers the option of contributing to photovoltaic power production through monthly donations on their utility bills. The interest generated by the seminars along with grant money from the State of Florida Department of Community Affairs and the Utility PhotoVoltaic Group and donations from GRU customers and friends of solar energy resulted in the 10 kilowatt PV system at the System Control Center. GRU solicited public input on its solar water heater rebate program through the GEAC, and the committee in turn formally supported the program. The GEAC sponsored a Biomass Seminar for a joint meeting of the Gainesville City Commission and the Alachua County Commission. The GEAC has strongly supported the EPA's Energy Star program, and helped GRU earn EPA's 1998 Utility Ally of the Year award. GEAC contributed to the development of a Green Builder program for existing multi-family dwellings as a long-range load reduction strategy. Multi-family dwellings represent approximately 35% of GRU's total residential load. GEAC has also supported GRU's current IRP through their sponsorship of community workshops and review of the IRP.

3.4.5 Supply Side Programs

Deerhaven 2 is also contributing to reduced oil use by other utilities through the Florida energy market. Prior to the addition of Deerhaven Unit 2 in 1982, the System was relying on oil and natural gas for over 90% of native load energy requirements. In 2004, oil-fired generation comprised 5.5% of total net generation, natural gas-fired generation contributed 27.6%, nuclear fuel contributed 5.6%, and coal-fired generation provided 61.3% of total net generation. The PV system at the System Control Center provides slightly more than 10 kilowatts of capacity at solar noon on clear days. The landfill gas to energy (LFGTE) project is capable of providing 1.3 MW of capacity on a continuous basis.

The System has several programs to improve the adequacy and reliability of the transmission and distribution systems, which will also result in decreased energy losses. Periodically, the major distribution feeders are evaluated to determine whether the costs of reconductoring will produce an internal rate of return sufficient to justify expenses when compared to the savings realized from reduced distribution losses, and if so, reconductoring is recommended. Generating units are continually evaluated to ensure that they are maintaining design efficiencies. Transmission facilities are also studied to determine the potential savings from loss reductions achieved by the installation of capacitor banks. System losses have stabilized near 5% of net generation as reflected in the forecasted relationship of total energy sales to net energy for load.

3.5 FUEL PRICE FORECAST ASSUMPTIONS

The sources for projected oil and natural gas prices were the Annual Energy Outlook 2005 (AEO2005), published in February 2005 by the U.S. Department of Energy's Energy Information Administration (EIA), and EIA's Short-Term Energy Outlook (STEO), March 2005. The source for projected coal prices was Hill & Associates, Inc., 2005 Outlook for U.S. Steam Coal Long-Term Forecast to 2024. Projected prices for nuclear fuel were provided by PEF. Typically, these forecasts are provided in constant-year (real) dollars, and GRU translates these prices to nominal dollars using the projected Gross Domestic Product – Implicit Price Deflator from

AEO2005. Fuel prices are analyzed in two parts: the cost of the fuel (commodity), and the cost of transporting the fuel to GRU's generating stations. A summary of historical and projected fuel prices is provided in Table 3.3.

3.5.1 Oil

GRU relies on No. 6 Oil (residual) and No. 2 Oil (distillate or diesel) as back-up fuels for natural gas fired generation. These fuels are delivered to GRU generating stations by truck. Forecast prices for these two types of oil are derived directly from AEO2005.

During calendar year 2004, distillate fuel oil was used to produce 0.06% of GRU's total net generation. The price of distillate fuel oil delivered to GRU is expected to decrease through 2009, and then begin a gradual increase through the long-term forecast horizon. Distillate fuel oil is expected to be the most expensive fuel available to GRU. During calendar year 2004, Residual fuel oil was used to produce 5.4% of GRU's total net generation. The price of residual fuel oil delivered to GRU is also expected to decrease through 2009 and then increase through the long-term forecast horizon. AEO2005 projects prices for residual fuel oil to be slightly lower than prices for natural gas. The quantity of fuel oils used by GRU is expected to remain low.

3.5.2 Coal

Coal is the primary fuel used by GRU to generate electricity, comprising 61.3% of total net generation during calendar year 2004. GRU purchases low-sulfur (0.7%) , high Btu eastern coal for use in Deerhaven Unit 2. Coal markets are experiencing increased prices for 2005 and 2006, but are expected to stabilize beginning 2007. Consequently, prices for coal are expected to be higher in the future than in previous forecasts. In addition to low sulfur compliance coal, GRU projects prices for 1.7% sulfur coal and 3.0% sulfur coal for evaluation in the proposed circulating fluidized bed unit.

Prices for compliance coal for 2005 and 2006 were based on GRU's contractual options with its coal suppliers. Projected prices for compliance coal for 2007 and beyond are based on Hill & Associates, Inc. forecast for a low sulfur coal from the central Appalachian region. GRU has a contract with CSXT for delivery of coal to the Deerhaven plant site through 2019. The rate of change in coal transportation rates from AEO2005 was applied to GRU's current freight rates to develop delivered prices of coal through 2025. Prices for the alternate grades of coal were also derived from Hill & Associates, Inc. forecast.

The long-term growth rate of delivered compliance coal prices is expected to average approximately 3.6% per year, while the alternate grades of coal are expected to see price increases of approximately 3.0% per year through 2025.

3.5.3 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2004, GRU purchased approximately 7.5 million MMBtu for use by both systems. GRU power plants used 69% of the total purchased for GRU during 2004, while the LDC used the remaining 31%.

GRU purchases natural gas via arrangements with producers and marketers connected with the Florida Gas Transmission (FGT) interstate pipeline. GRU's delivered cost of natural gas includes the commodity component, Florida Gas Transmission's (FGT) fuel charge, FGT's usage (transportation) charge, and FGT's reservation (capacity) charge.

Prices for the remainder of 2005 were projected in-house based on current market conditions. Prices for 2006 were derived from EIA's Short-Term Energy Outlook, March 2005. Prices from 2007 through 2025 follow the pattern of price changes outlined in AEO2005, converging to the absolute prices specified in AEO2005 by 2025 GRU's forecast of delivered gas prices are presented in Table 3.3.

GRU's delivered natural gas prices are projected to decrease from about \$7.18/MMBtu in 2005 to a low of \$5.57/MMBtu in 2010, and then increase at a rate of approximately 3.5% per year through 2025.

3.5.4 Nuclear Fuel

GRU's nuclear fuel price forecast includes a component for fuel and a component for fuel disposal. The projection for the price of the fuel component is based on Progress Energy Florida's (PEF) forecast of nuclear fuel prices. The projection for the cost of fuel disposal is based on a trend analysis of actual costs to GRU. Overall nuclear fuel price is projected to increase at a rate of approximately 0.5% per year through the forecast horizon.

3.5.5 Petroleum Coke

Petroleum coke, or "pet coke", is a by-product of the process of refining crude oil into higher value light products. GRU is evaluating pet coke as a fuel that can be blended with coal and wood biomass for use in the proposed CFB unit. To develop a forecast of pet coke prices, GRU determined the average price paid by Florida utilities during 2004, added a transportation component for a short haul by rail, and escalated this price annually at the same rate of change as coal delivered to electric utilities in AEO2005. This forecast results in prices that range from \$1.14/MMBtu in 2005 to \$1.33/MMBtu in 2014.

Schedule 2.1
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			RESIDENTIAL			COMMERCIAL *		
Year	Service Area Population	Persons per Household	GWh	Average Number of Customers	Average kWh per Customer	GWh	Average Number of Customers	Average kWh per Customer
1995	147,248	2.37	704	62,130	11,329	590	7,305	80,767
1996	150,322	2.37	718	63,427	11,313	594	7,539	78,813
1997	153,759	2.36	705	65,152	10,817	598	7,750	77,193
1998	156,797	2.35	777	66,722	11,649	640	7,868	81,363
1999	161,076	2.35	763	68,543	11,137	648	8,095	80,036
2000	164,584	2.34	788	70,335	11,202	674	8,368	80,490
2001	169,395	2.34	803	72,391	11,092	697	8,603	80,986
2002	172,755	2.34	851	73,827	11,527	721	8,778	82,112
2003	174,227	2.34	854	74,456	11,467	726	8,959	81,090
2004	179,459	2.33	878	77,021	11,398	739	9,225	80,143
2005	183,126	2.33	884	78,676	11,236	762	9,462	80,534
2006	186,685	2.33	907	80,288	11,297	784	9,693	80,887
2007	190,237	2.32	931	81,900	11,368	808	9,923	81,424
2008	193,683	2.32	956	83,470	11,453	831	10,148	81,888
2009	197,122	2.32	982	85,039	11,548	854	10,373	82,331
2010	200,455	2.32	1,007	86,567	11,633	877	10,591	82,803
2011	203,781	2.31	1,030	88,094	11,692	899	10,810	83,164
2012	207,002	2.31	1,053	89,579	11,755	921	11,023	83,556
2013	210,216	2.31	1,077	91,064	11,827	943	11,235	83,934
2014	213,325	2.31	1,102	92,506	11,913	966	11,442	84,429

* Commercial includes General Service Non-Demand and General Service Demand Rate Classes

SCH2.xls

Schedule 2.2
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL **						
Year	GWh	Average Number of Customers	Average MWh per Customer	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1995	137	13	10,521	0	18	0	1,449
1996	148	15	9,893	0	19	0	1,479
1997	151	15	10,059	0	21	0	1,475
1998	157	15	10,443	0	21	0	1,595
1999	173	17	10,188	0	22	0	1,606
2000	172	17	10,114	0	22	0	1,656
2001	173	17	10,162	0	23	0	1,696
2002	178	18	10,178	0	24	0	1,774
2003	181	19	9,591	0	24	0	1,786
2004	188	18	10,444	0	25	0	1,830
2005	191	18	10,437	0	26	0	1,863
2006	191	18	10,437	0	26	0	1,909
2007	192	18	10,492	0	27	0	1,958
2008	192	18	10,492	0	28	0	2,008
2009	193	18	10,546	0	29	0	2,057
2010	193	18	10,546	0	29	0	2,107
2011	194	18	10,601	0	30	0	2,152
2012	195	18	10,656	0	31	0	2,198
2013	195	18	10,656	0	31	0	2,247
2014	196	18	10,710	0	32	0	2,296

** Industrial includes Large Power Rate Class

SCH2.xls

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1) Year	(2) Sales For Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers	(6) Total Number of Customers
1995	101	97	1,648	0	69,448
1996	105	75	1,659	0	70,981
1997	104	82	1,661	0	72,917
1998	108	76	1,779	0	74,605
1999	109	83	1,798	0	76,655
2000	120	93	1,868	0	78,720
2001	125	62	1,882	0	81,011
2002	142	92	2,008	0	82,623
2003	146	83	2,015	0	83,434
2004	149	70	2,049	0	86,264
2005	155	104	2,122	0	88,156
2006	160	107	2,177	0	89,999
2007	166	110	2,233	0	91,842
2008	171	113	2,291	0	93,636
2009	176	115	2,349	0	95,430
2010	182	118	2,407	0	97,176
2011	187	121	2,460	0	98,922
2012	192	123	2,514	0	100,620
2013	197	126	2,570	0	102,317
2014	202	129	2,627	0	103,966

SCH2.xls

Schedule 3.1
History and Forecast of Summer Peak Demand - MW
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	423	28	381	0	0	7	0	7	409
2002	446	32	401	0	0	7	0	7	433
2003	429	33	384	0	0	6	0	6	417
2004	444	33	399	0	0	6	0	6	432
2005	469	35	423	0	0	6	0	5	458
2006	481	36	434	0	0	6	0	5	470
2007	493	38	445	0	0	6	0	4	483
2008	504	39	456	0	0	6	0	3	495
2009	517	40	468	0	0	6	0	3	508
2010	528	41	479	0	0	6	0	2	520
2011	540	42	490	0	0	6	0	2	532
2012	552	44	500	0	0	6	0	2	544
2013	566	45	511	0	0	7	0	3	556
2014	579	46	523	0	0	7	0	3	569

SCH3_1.xls

Schedule 3.2
History and Forecast of Winter Peak Demand - MW
Base Case

(1) Winter	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1995 / 1996	381	28	317	0	0	29	0	7	345
1996 / 1997	343	26	280	0	0	30	0	7	306
1997 / 1998	319	23	259	0	0	30	0	7	282
1998 / 1999	389	28	323	0	0	31	0	7	351
1999 / 2000	373	27	310	0	0	29	0	7	337
2000 / 2001	398	33	331	0	0	28	0	6	364
2001 / 2002	402	33	336	0	0	27	0	6	369
2002 / 2003	425	37	357	0	0	26	0	5	394
2003 / 2004	380	31	319	0	0	25	0	5	350
2004 / 2005	404	36	341	0	0	24	0	4	377
2005 / 2006	415	37	353	0	0	22	0	3	390
2006 / 2007	424	39	363	0	0	20	0	2	402
2007 / 2008	434	40	374	0	0	18	0	2	414
2008 / 2009	444	41	386	0	0	16	0	1	427
2009 / 2010	454	42	397	0	0	14	0	1	439
2010 / 2011	464	44	405	0	0	14	0	1	449
2011 / 2012	474	45	413	0	0	15	0	1	458
2012 / 2013	484	46	422	0	0	15	0	1	468
2013 / 2014	494	47	430	0	0	16	0	1	477
2014 / 2015	505	48	439	0	0	17	0	1	487

Schedule 3.3
History and Forecast of Net Energy for Load - GWH
Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1995	1,711	43	20	1,449	101	97	1,648	52.10%
1996	1,721	42	21	1,479	105	75	1,659	51.89%
1997	1,726	44	21	1,475	104	82	1,661	50.84%
1998	1,847	47	21	1,595	108	76	1,779	51.28%
1999	1,869	50	21	1,606	109	83	1,798	48.97%
2000	1,939	50	21	1,656	120	93	1,868	50.19%
2001	1,953	50	20	1,696	125	62	1,882	52.54%
2002	2,079	52	19	1,774	142	92	2,008	52.95%
2003	2,085	53	18	1,786	146	83	2,015	55.15%
2004	2,118	53	16	1,830	149	70	2,049	54.14%
2005	2,190	53	15	1,863	155	104	2,122	52.89%
2006	2,243	52	14	1,910	160	107	2,177	52.88%
2007	2,296	51	12	1,957	166	110	2,233	52.78%
2008	2,350	49	10	2,007	171	113	2,291	52.83%
2009	2,406	48	9	2,058	176	115	2,349	52.79%
2010	2,462	47	8	2,107	182	118	2,407	52.84%
2011	2,518	50	8	2,152	187	121	2,460	52.79%
2012	2,574	52	8	2,199	192	123	2,514	52.75%
2013	2,632	54	8	2,247	197	126	2,570	52.77%
2014	2,691	56	8	2,296	202	129	2,627	52.70%

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST			
	2004		2005		2006	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	350	158	378	165	390	169
FEB	316	143	348	142	357	146
MAR	259	141	311	149	319	153
APR	304	144	339	152	348	156
MAY	420	188	405	184	416	189
JUN	432	201	440	201	452	206
JUL	427	209	458	218	470	223
AUG	427	205	457	221	469	227
SEP	422	185	434	203	446	208
OCT	375	174	373	173	382	177
NOV	329	143	329	151	338	155
DEC	340	158	354	163	363	168

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
FUEL REQUIREMENTS			UNITS	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	NUCLEAR		TRILLION Btu	1.000	0.909	1.004	0.909	1.004	0.791	1.004	0.909	1.004	0.909	1.004
(2)	COAL		1000 tons	479.000	501.410	601.077	623.710	630.609	651.200	665.315	637.456	646.099	658.443	667.380
	RESIDUAL													
(3)		STEAM	1000 bbl	194.969	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(4)		CC	1000 bbl	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(5)		CT	1000 bbl	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(6)		TOTAL:	1000 bbl	194.969	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	DISTILLATE													
(7)		STEAM	1000 bbl	0.678	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(8)		CC	1000 bbl	1.820	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(9)		CT	1000 bbl	0.925	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(10)		TOTAL:	1000 bbl	3.423	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	NATURAL GAS													
(11)		STEAM	1000 Mcf	1,644.662	1,010.739	548.315	626.305	606.446	855.126	1,233.198	71.557	60.328	117.937	104.728
(12)		CC	1000 Mcf	2,933.156	4,463.475	3,982.392	3,723.715	4,108.410	4,184.180	4,467.390	763.719	935.081	925.675	1,185.842
(13)		CT	1000 Mcf	299.169	2,843.298	1,811.373	1,995.209	1,838.585	1,720.285	2,379.315	376.366	289.777	474.311	331.494
(14)		TOTAL:	1000 Mcf	4,876.987	8,317.512	6,342.080	6,345.229	6,553.441	6,759.591	8,079.903	1,211.642	1,285.186	1,517.923	1,622.064
(15)	Landfill Gas		TRILLION Btu	0.057	0.127	0.127	0.127	0.127	0.127	0.063	0.063	0.063	0.063	0.063
(16)	Petroleum Coke		1000 tons	0.000	0.000	0.000	0.000	0.000	0.000	0.000	234.189	237.565	241.519	243.639
(17)	Woody Biomass		1000 tons	0.000	0.000	0.000	0.000	0.000	0.000	0.000	172.748	175.238	178.155	179.719

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Schedule 6.1
ENERGY SOURCES (GWH)
As of January 1, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
ENERGY SOURCES			UNITS	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(2)	NUCLEAR		GWH	102.823	86.538	95.658	86.538	95.658	75.369	95.658	86.538	95.658	86.538	95.658
(3)	COAL		GWH	1,130.125	1,232.524	1,476.656	1,534.934	1,553.758	1,613.417	1,517.565	1,401.086	1,423.309	1,454.935	1,477.802
	RESIDUAL													
(4)		STEAM	GWH	99.932	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(5)		CC	GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(6)		CT	GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(7)		TOTAL:	GWH	99.932	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	DISTILLATE													
(8)		STEAM	GWH	0.220	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(9)		CC	GWH	0.722	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(10)		CT	GWH	0.227	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(11)		TOTAL:	GWH	1.169	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	NATURAL GAS													
(12)		STEAM	GWH	137.172	84.708	45.897	52.443	50.773	72.220	103.787	5.871	5.036	9.865	8.837
(13)		CC	GWH	347.276	504.932	432.385	410.160	446.349	445.035	500.111	75.710	91.333	91.147	115.018
(14)		CT	GWH	19.961	208.494	126.181	135.342	131.048	129.039	178.823	26.585	19.845	31.285	24.125
(15)		TOTAL:	GWH	504.409	798.134	604.463	597.945	628.170	646.294	782.721	108.166	116.214	132.297	147.980
(16)	NUG		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(17)	HYDRO		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(18)	Landfill Gas		GWH	4.214	10.582	10.582	10.582	10.582	10.582	5.291	5.291	5.291	5.291	5.291
(19)	Petroleum Coke		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	674.832	686.083	699.264	706.417
(20)	Woody Biomass		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	184.040	187.108	190.703	192.654
(21)	Starke Contract		GWH	43.446	13.110	13.110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(22)	Purchased Energy		GWH	261.627	6.867	2.414	3.012	3.064	3.660	5.321	0.051	0.174	0.767	1.205
(23)	Energy Sales		GWH	12.299	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(24)	NET ENERGY FOR LOAD		GWH	2,048.554	2,121.535	2,176.663	2,233.011	2,291.232	2,349.322	2,406.556	2,460.004	2,513.837	2,569.795	2,627.006

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Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
ENERGY SOURCES			UNITS	ACTUAL 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(2)	NUCLEAR		%	5.02%	4.08%	4.39%	3.88%	4.17%	3.21%	3.97%	3.52%	3.81%	3.37%	3.64%
(3)	COAL		%	55.17%	58.10%	67.84%	68.74%	67.81%	68.68%	63.06%	56.95%	56.62%	56.62%	56.25%
	RESIDUAL													
(4)		STEAM	%	4.88%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	%	4.88%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	%	0.06%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NATURAL GAS													
(12)		STEAM	%	6.70%	3.99%	2.11%	2.35%	2.22%	3.07%	4.31%	0.24%	0.20%	0.38%	0.34%
(13)		CC	%	16.95%	23.80%	19.86%	18.37%	19.48%	18.94%	20.78%	3.08%	3.63%	3.55%	4.38%
(14)		CT	%	0.97%	9.83%	5.80%	6.06%	5.72%	5.49%	7.43%	1.08%	0.79%	1.22%	0.92%
(15)		TOTAL:	%	24.62%	37.62%	27.77%	26.78%	27.42%	27.51%	32.52%	4.40%	4.62%	5.15%	5.63%
(16)	NUG		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(17)	HYDRO		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(18)	Landfill Gas		%	0.21%	0.50%	0.49%	0.47%	0.46%	0.45%	0.22%	0.22%	0.21%	0.21%	0.20%
(19)	Petroleum Coke		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	27.43%	27.29%	27.21%	26.89%
(20)	Woody Biomass		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.48%	7.44%	7.42%	7.33%
(21)	Starke Contract		%	2.12%	0.62%	0.60%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(22)	Purchased Energy		%	12.77%	0.32%	0.11%	0.13%	0.13%	0.16%	0.22%	0.00%	0.01%	0.03%	0.05%
(23)	Energy Sales		%	0.60%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(24)	NET ENERGY FOR LOAD		%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

TABLE 3.1

DEMAND-SIDE MANAGEMENT IMPACTS
INCREMENTAL EFFECT OF PLANNED PROGRAMS

Year	MWh	Winter kW	Summer kW
2005	2,938	705	550
2006	5,946	1,415	1,120
2007	8,973	2,128	1,704
2008	12,020	2,848	2,294
2009	15,103	3,577	2,895
2010	18,149	4,301	3,490
2011	20,493	4,914	3,818
2012	23,120	5,545	4,246
2013	25,408	6,162	4,515
2014	27,696	6,783	4,790

Notes: Projected impacts from programs planned for 2005-2014.
Net of 2004 estimated cumulative historical program results.

TABLE 3.2.1

DEMAND-SIDE MANAGEMENT IMPACTS
Total Program Achievements

Year	MWh	Winter kW	Summer kW
1980	254	168	168
1981	575	370	370
1982	1,054	687	674
1983	2,356	1,339	1,212
1984	8,024	3,074	2,801
1985	16,315	6,719	4,619
1986	25,416	10,470	7,018
1987	30,279	13,287	8,318
1988	34,922	15,918	9,539
1989	38,824	18,251	10,554
1990	43,661	21,033	11,753
1991	48,997	24,204	12,936
1992	54,898	27,574	14,317
1993	61,356	31,434	15,752
1994	66,725	34,803	16,871
1995	72,057	38,117	18,022
1996	75,894	39,121	18,577
1997	79,998	40,256	19,066
1998	84,017	41,351	19,541
1999	88,631	42,599	20,055
2000	93,132	43,742	20,654
2001	97,312	44,852	21,163
2002	101,941	46,080	21,679
2003	105,942	47,150	22,159
2004	108,982	47,939	22,590
2005	111,920	48,644	23,140
2006	114,924	49,354	23,707
2007	117,943	50,067	24,286
2008	120,989	50,786	24,877
2009	124,072	51,516	25,477
2010	127,227	52,261	26,094
2011	130,286	52,992	26,696
2012	133,345	53,723	27,297
2013	136,114	54,439	27,744
2014	138,884	55,155	28,191

Note: Total cumulative impacts from 1990 Conservation Plan and 1995 DSM Plan.

TABLE 3.2.2

DEMAND-SIDE MANAGEMENT IMPACTS
Program Retirements

Year	MWh	Winter kW	Summer kW
1980	0	0	0
1981	0	0	0
1982	0	0	0
1983	0	0	0
1984	0	0	0
1985	0	0	0
1986	0	0	0
1987	0	0	0
1988	0	0	0
1989	0	0	0
1990	0	0	0
1991	0	0	0
1992	0	0	0
1993	(422)	(75)	(75)
1994	(4,769)	(957)	(957)
1995	(8,891)	(1,778)	(1,786)
1996	(13,746)	(2,795)	(2,815)
1997	(14,813)	(3,276)	(3,271)
1998	(15,952)	(3,945)	(3,815)
1999	(17,460)	(4,838)	(4,563)
2000	(22,160)	(7,899)	(5,787)
2001	(26,886)	(10,871)	(7,395)
2002	(31,335)	(13,564)	(8,586)
2003	(35,834)	(16,129)	(9,750)
2004	(39,588)	(18,433)	(10,730)
2005	(44,156)	(21,149)	(11,864)
2006	(49,330)	(24,285)	(13,008)
2007	(55,047)	(27,612)	(14,342)
2008	(61,391)	(31,446)	(15,752)
2009	(66,739)	(34,811)	(16,867)
2010	(72,171)	(38,145)	(18,036)
2011	(72,886)	(38,263)	(18,310)
2012	(73,318)	(38,363)	(18,484)
2013	(73,799)	(38,461)	(18,662)
2014	(74,282)	(38,556)	(18,834)

Note: Conservation savings that have been retired from total program achievements corresponding to individual program life cycles.

TABLE 3.2.3

DEMAND-SIDE MANAGEMENT IMPACTS
Total Annual Net Effects

Year	MWh	Winter kW	Summer kW
1980	254	168	168
1981	575	370	370
1982	1,054	687	674
1983	2,356	1,339	1,212
1984	8,024	3,074	2,801
1985	16,315	6,719	4,619
1986	25,416	10,470	7,018
1987	30,279	13,287	8,318
1988	34,922	15,918	9,539
1989	38,824	18,251	10,554
1990	43,661	21,033	11,753
1991	48,997	24,204	12,936
1992	54,898	27,574	14,317
1993	60,934	31,358	15,677
1994	61,955	33,845	15,913
1995	63,167	36,339	16,235
1996	62,148	36,325	15,761
1997	65,185	36,979	15,795
1998	68,065	37,406	15,726
1999	71,172	37,761	15,492
2000	70,972	35,843	14,867
2001	70,426	33,981	13,768
2002	70,606	32,516	13,093
2003	70,108	31,021	12,409
2004	69,394	29,506	11,860
2005	67,763	27,496	11,276
2006	65,594	25,069	10,699
2007	62,896	22,455	9,944
2008	59,599	19,340	9,125
2009	57,333	16,705	8,610
2010	55,055	14,116	8,058
2011	57,400	14,729	8,386
2012	60,026	15,360	8,814
2013	62,315	15,977	9,082
2014	64,603	16,599	9,357

Note: Cumulative impacts from 1990 Conservation Plan and 1995 DSM Plan, net of program retirements.

TABLE 3.3

DELIVERED FUEL PRICES
$/MMBtu

Year	Residual Fuel Oil	Distillate Fuel Oil	Natural Gas	0.7% Sulfur Coal (1)	1.7% Sulfur Coal (2)	3.0% Sulfur Coal (3)	Petroleum Coke (4)	Nuclear
1995	3.79	4.60	2.33	1.73				0.45
1996	2.75	4.89	3.37	1.66				0.42
1997	3.26	4.46	3.30	1.66				0.41
1998	2.73	3.97	2.87	1.66				0.41
1999	2.79	3.47	2.86	1.66				0.44
2000	4.52	5.99	4.53	1.62				0.38
2001	4.15	6.53	4.91	1.88				0.38
2002	4.58	5.69	3.82	2.06				0.38
2003	4.87	6.59	5.80	2.04				0.43
2004	5.06	7.24	6.15	2.03				0.41
2005	5.61	7.17	7.18	2.27	2.79	2.59	1.14	0.43
2006	5.29	6.64	6.50	2.95	3.00	2.79	1.16	0.42
2007	4.94	6.33	6.08	2.58	2.23	2.34	1.17	0.42
2008	4.82	6.21	5.70	2.62	2.46	2.46	1.19	0.44
2009	4.76	6.13	5.64	2.67	2.50	2.51	1.20	0.42
2010	4.81	6.16	5.57	2.61	2.64	2.54	1.22	0.47
2011	4.99	6.27	5.70	2.68	2.69	2.62	1.24	0.46
2012	5.17	6.48	5.94	2.77	2.77	2.68	1.27	0.45
2013	5.36	6.69	6.20	2.88	2.86	2.77	1.30	0.44
2014	5.54	6.93	6.53	2.96	2.90	2.81	1.33	0.45

(1) Approximate heat content of 0.7% sulfur coal is 12,200 Btu/lb.
(2) Approximate heat content of 1.7% sulfur coal is 11,550 Btu/lb.
(3) Approximate heat content of 3.0% sulfur coal is 11,150 Btu/lb.
(4) Approximate heat content of pet coke is 14,200 Btu/lb.

4. FORECAST OF FACILITIES REQUIREMENTS

4.1 GENERATION RETIREMENTS

The System plans to retire two of its currently operating generating units prior to 2012 (see Schedule 8). In December of 2003 GRU commissioned its newest units at the Southwest Landfill. Engines installed at the landfill gas to electric energy project will be retired as the gas production decreases through time. The first engine is expected to be removed in 2009. The John R. Kelly steam unit #7 (23 MW) will be 50 years old in 2011 and is tentatively scheduled for retirement in August 2011.

4.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

GRU uses a planning criteria of 15% capacity reserve margin (suggested for emergency power pricing purposes by Florida Public Service Commission Rule 25-6.035). Available generating capacities are compared with System summer peak demands in Schedule 7.1 (and Figure 4.1) and System winter peak demands in Schedule 7.2 (and Figure 4.2). Higher peak demands in summer and lower unit operating capacities in summer result in lower reserve margins during the summer season than in winter. Summer reserve margins without capacity additions are forecast to fall below 15% in 2011. The Gainesville community is discussing the ramifications of adding additional resources by summer 2011 to address its reserve margin requirements.

4.3 GENERATION ADDITIONS

GRU is in the midst of an integrated resource planning process to determine the best plan for our customers' long-term electrical energy needs. The process has proceeded to the point where the alternatives have been screened down to a conceptual plan for public discussion. The facility portion of the proposed plan has not been finalized or approved. A key aspect of the aforementioned integrated resource plan involves hiring an engineering firm to perform a detailed design of the proposed self-build unit to provide a target for the purpose of issuing a Request For Proposals to Provide Capacity and Energy to offset the need for the proposed unit. Without a proper target there will be no competitive bidding. Schedule 9, included at the end of this section, identifies key parameters for the additional generating capacity currently under discussion.

The lead alternative currently under discussion is a 220 net MW coal/petroleum coke/biomass unit at the Deerhaven plant site. This circulating fluidized bed combustion unit would include selective non-catalytic NOx reduction, flue gas or flash dryer absorber for desulphurization, and a fabric filter for particulate control. Due to new regulations, Deerhaven Unit 2 is expected to be retrofitted with selective catalytic NOx reduction, flue-gas desulphurization, and fabric filter bag house for particulate control. The retrofit of Deerhaven Unit 2 is expected to be effective by 2010. The combination of new capacity and retrofitting of existing coal capacity would result in substantially lower total emissions from combined solid fuel combustion than the existing coal unit. The tentative schedule for construction is yet to be determined. A nominal in-service date of June 2011 has been used for this report. This date is the basis of the reserve margin forecast in Schedule 7.1 and Schedule 7.2. Characteristics of the proposed solid fuel facility are summarized in Schedule 9 at the end of this section.

4.4 DISTRIBUTION SYSTEM ADDITIONS

Up to five new, identical, mini-power delivery substations (PDS) were planned for the GRU system in 1999. The first, Rocky Point, located near the intersection of SW Williston Road and SW 23rd Terrace, was installed in 2000. The second, Kanapaha, located at 8500 SW Archer Road, was installed in 2002. The third, Ironwood, located at 1800 NE 31st Avenue, was most recently connected in 2003. A fourth PDS is planned for 2007. The location for PDS #4 will be a parcel owned by GRU in the Springhill area west of Interstate 75 and north of 39th Avenue. A fifth PDS is being considered for addition to the System no earlier than 2010. The location of this proposed fifth PDS would be near NW 43rd Street and U.S. Highway 441. These new mini-power delivery substations have been planned to redistribute the load from the existing substations as new load centers grow and develop within the System.

Each PDS will consist of one (or more) 138-12.47 KV, 33.6 MVA, wye-wye substation transformer with a maximum of eight distribution circuits. The proximity of these new PDSs to other, existing adjacent area substations will allow for backup in the event of a substation transformer failure.

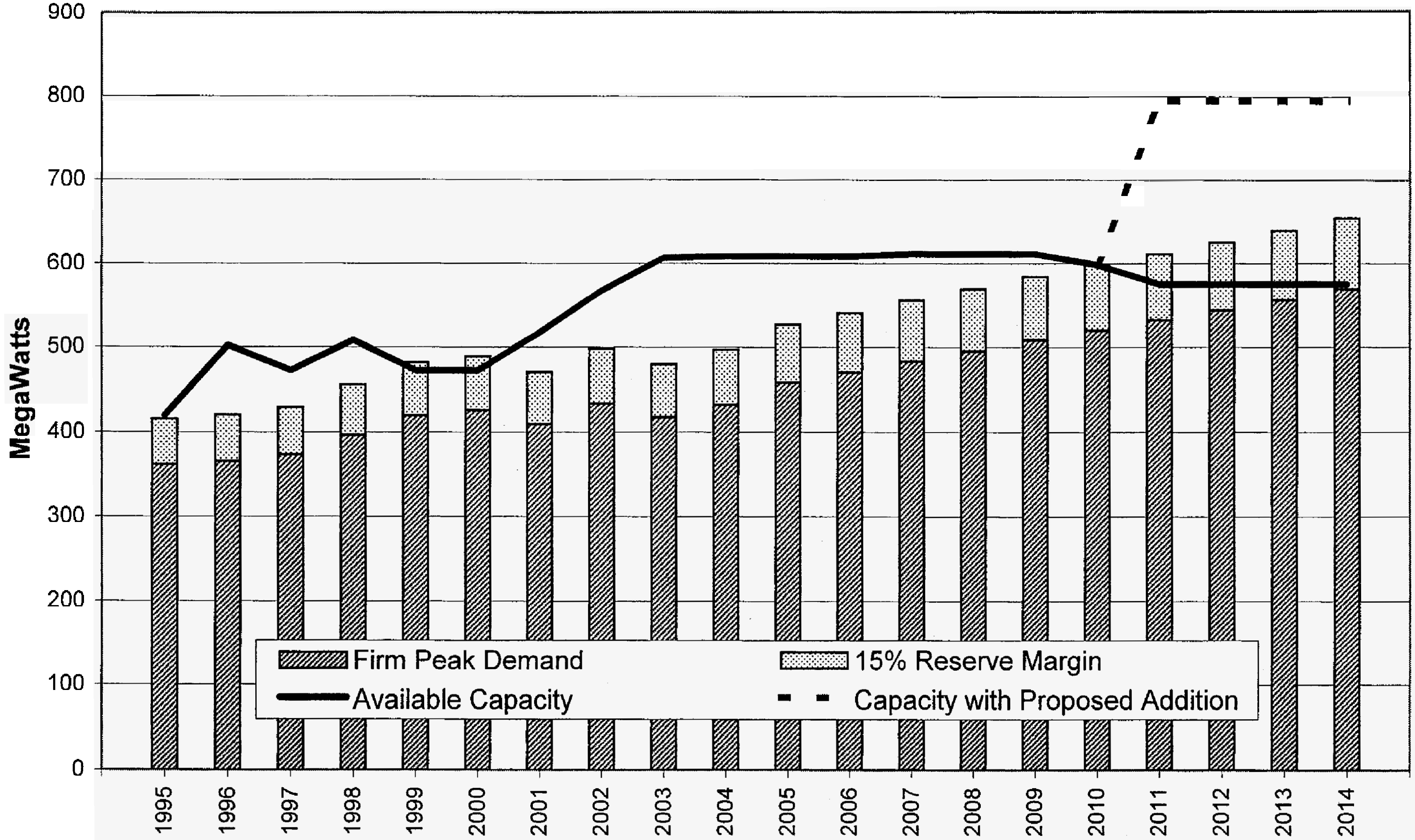
GRU is also planning to add a substation transformer to its Depot transmission substation in 2006. This expansion of the Depot substation to a distribution and transmission substation will enhance reliability by relocating some distribution circuits currently connected to the Kelly substation, while allowing for load growth in Gainesville's downtown area.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1) Year	(2) Total Installed Capacity MW	(3) Firm Capacity Import MW	(4) Firm Capacity Export MW	(5) QF MW	(6) Total Capacity Available MW	(7) System Firm Summer Peak Demand MW	(8) Reserve Margin (1) before Maintenance MW	(9) Reserve Margin (1) before Maintenance % of Peak	(10) Scheduled Maintenance MW	(11) Reserve Margin (1) after Maintenance MW	(12) Reserve Margin (1) after Maintenance % of Peak
1995	452	0	33	0	419	361	58	16.1%	0	58	16.1%
1996	527	18	43	0	502	365	137	37.5%	0	137	37.5%
1997	527	30	85	0	472	373	99	26.5%	0	99	26.5%
1998	550	31	73	0	508	396	112	28.3%	0	112	28.3%
1999	550	32	110	0	472	419	53	12.6%	14	39	9.3%
2000	550	0	78	0	472	425	47	11.1%	0	47	11.1%
2001	610	0	93	0	517	409	108	26.4%	0	108	26.4%
2002	610	0	43	0	567	433	134	30.9%	0	134	30.9%
2003	610	0	3	0	607	417	190	45.6%	0	190	45.6%
2004	611	0	3	0	608	432	176	40.7%	0	176	40.7%
2005	611	0	3	0	608	458	150	32.8%	0	150	32.8%
2006	611	0	3	0	608	470	138	29.4%	0	138	29.4%
2007	611	0	0	0	611	483	128	26.6%	0	128	26.6%
2008	611	0	0	0	611	495	116	23.5%	0	116	23.5%
2009	611	0	0	0	611	508	103	20.3%	0	103	20.3%
2010	598	0	0	0	598	520	78	15.0%	0	78	15.0%
2011	795	0	0	0	795	532	263	49.4%	0	263	49.4%
2012	795	0	0	0	795	544	251	46.1%	0	251	46.1%
2013	795	0	0	0	795	556	239	43.0%	0	239	43.0%
2014	795	0	0	0	795	569	226	39.7%	0	226	39.7%

(1) GRU provides reserve margin backup for 3 MW Schedule D contract with the City of Starke.

Figure 4.1
Summer Peak Demand and Generation Capacity



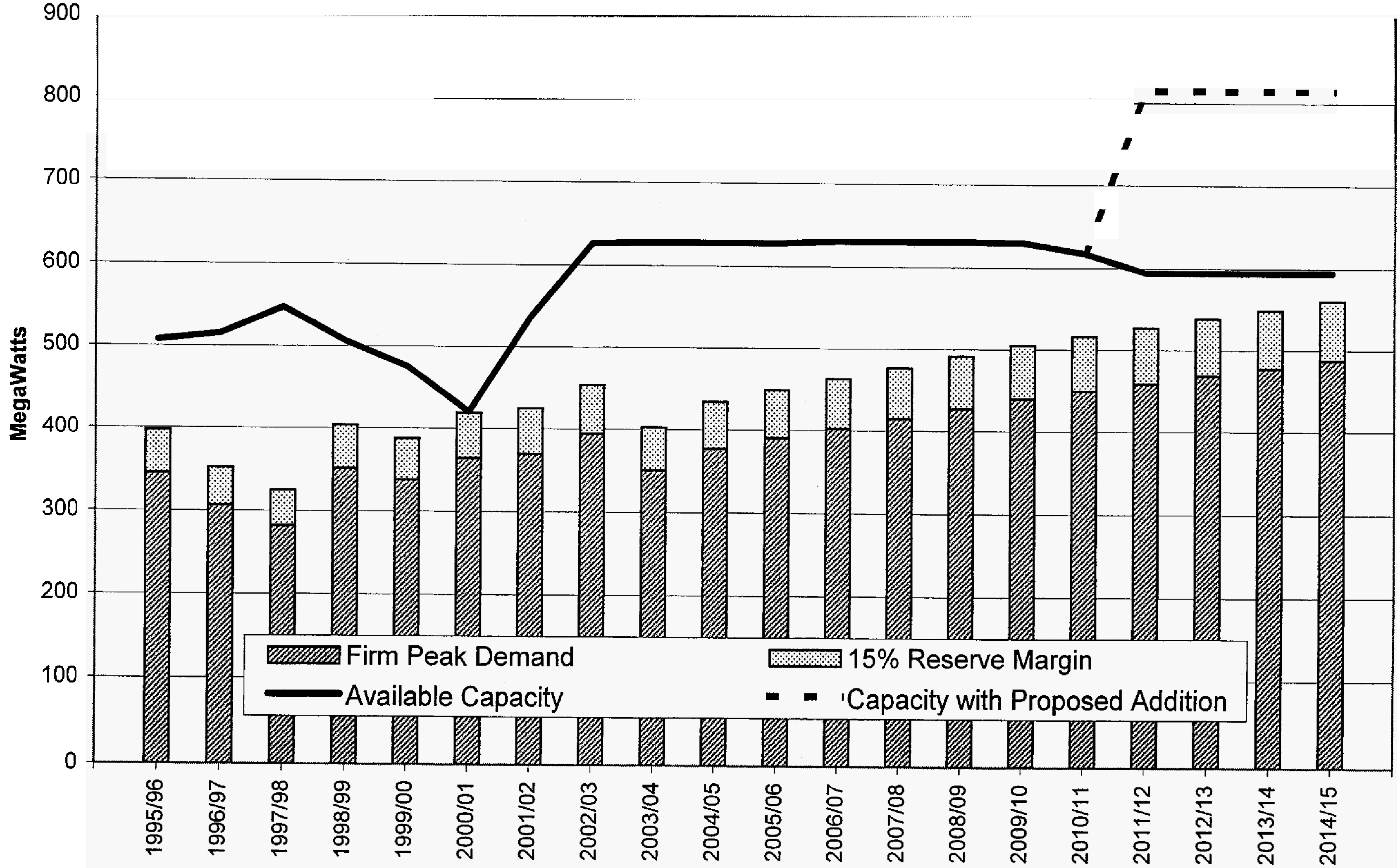
Schedule 7.1, 7.2.xls

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin (1) before Maintenance		Scheduled Maintenance	Reserve Margin (1) after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1995/96	540	0	33	0	507	345	162	47.0%	0	162	47.0%
1996/97	540	18	43	0	515	306	209	68.3%	0	209	68.3%
1997/98	540	30	23	0	547	282	265	94.0%	0	265	94.0%
1998/99	563	31	88	0	506	351	155	44.2%	0	155	44.2%
1999/00	563	0	88	0	475	337	138	40.9%	15	123	36.5%
2000/01	513	0	93	0	420	364	56	15.4%	0	56	15.4%
2001/02	629	0	93	0	536	369	167	45.3%	0	167	45.3%
2002/03	629	0	3	0	626	394	232	58.9%	0	232	58.9%
2003/04	630	0	3	0	627	350	277	79.1%	0	277	79.1%
2004/05	630	0	3	0	627	377	250	66.3%	0	250	66.3%
2005/06	630	0	3	0	627	390	237	60.8%	0	237	60.8%
2006/07	630	0	0	0	630	402	228	56.8%	0	228	56.8%
2007/08	630	0	0	0	630	414	216	52.2%	0	216	52.2%
2008/09	630	0	0	0	630	427	203	47.6%	0	203	47.6%
2009/10	630	0	0	0	630	439	191	43.4%	0	191	43.4%
2010/11	617	0	0	0	617	449	168	37.4%	0	168	37.4%
2011/12	814	0	0	0	814	458	356	77.7%	0	356	77.7%
2012/13	814	0	0	0	814	468	346	73.9%	0	346	73.9%
2013/14	814	0	0	0	814	477	337	70.7%	0	337	70.7%
2014/15	814	0	0	0	814	487	327	67.2%	0	327	67.2%

(1) GRU provides reserve margin backup for 3 MW Schedule D contract with the City of Starke.

Figure 4.2
Winter Peak Demand and Generation Capacity



Schedule 7.1, 7.2.xls

Schedule 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								Const.	Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	(MW)	(MW)	(MW)	(MW)	Status
Deerhaven	2	12-001 (Alachua Co., Sections 26,27,35, Township 8 S, Range 19 E) (GRU)	ST	BIT	-	RR	-	-	10/1981	4/2010	(249)	(249)	(228)	(228)	P
Deerhaven	2	12-001 (Alachua Co., Sections 26,27,35, Township 8 S, Range 19 E) (GRU)	ST	BIT		RR		1/2010	6/2010	Unknown	249	249	215	215	P
Deerhaven	3	12-001 (Alachua Co., Sections 26,27,35, Township 8 S, Range 19 E) (GRU)	ST	BIT/PC/WDS	BIT	RR/TK	RR	6/2006	6/2011	Unknown	244	244	220	220	P
J. R. Kelly	7	Alachua County Section 4 Township 10 S Range 20 E (GRU)	ST	NG	RFO	PL	TK	-	8/1961	8/2011	(24)	(24)	(23)	(23)	P
SW Landfill	1	Alachua County Section 19 Township 11 S Range 18 E (GRU)	IC	LFG		PL			12/2003	12/2009	(0.82)	(0.82)	(0.65)	(0.65)	P

Unit Type
ST = Steam Turbine
IC = Internal Combustion Engine (diesel, piston)

Transportation Method
RR = Railroad
TK = Truck
PL = Pipeline

Fuel Type
BIT = Bituminus Coal
PC = Petroleum Coke
WDS = Wood/Wood Waste Solids (Wood Trimming, Logging Residue, Forest Restoration)
NG = Natural Gas
DFO = Distillate Fuel Oil

Status
P = Proposed for Installation but not City Commission authorized. Not under construction.

Schedule 9
Description of Proposed Facility Under Discussion

(1)	Plant Name and Unit Number:	Deerhaven 3
(2)	Net Capacity	
	a. Summer	220 MW
	b. Winter	220 MW
(3)	Technology Type:	Circulating-Fluidized Bed
(4)	Anticipated Construction Timing	
	a. Field construction start-date:	6/1/2006
	b. Commercial in-service date:	6/1/2011
(5)	Fuel	
	a. Primary Fuel (by Heat Input)	36.36% Coal / 50% Pet Coke / 13.64% Wood Biomass
	b. Alternate Fuel	Bituminous Coal
(6)	Air Pollution Control Strategy:	Circulating Fluidized Bed Flue Gas Desulphurization or Flash Dryer Absorber SNCR if needed Fabric Filter Retrofit of Deerhaven 2 with FGD, SCR and Fabric Filter
(7)	Cooling Method:	Forced Draft Cooling Tower
(8)	Total Site Area (ft^2)	To be determined. (Deerhaven)
(9)	Construction Status:	Proposed, Not Approved by City Commission
(10)	Certification Status:	Proposed, Application Not Filed.
(11)	Status with Federal Agencies:	Not Applicable
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF):	1.0%
	Forced Outage Factor (FOF):	4.0%
	Equivalent Availability Factor (EAF):	95.0%
	Resulting Capacity Factor (CF)	85.0%
	Average Net Operating Heat Rate (ANOHR):	9,910
(13)	Projected Unit Financial Data (1)	
	Book Life (Years)	35
	Direct Construction Cost ($2003/kW):	1831.91
	Escalation:	3.00%
	Fixed O&M ($2003/kW-Yr):	27.68
	Variable O&M ($2003/MWh):	3.51

Notes: (1) Proposal Includes capital cost of upgrading Deerhaven Unit 2 with selective catalytic reduction, flue-gas desulfurization, and fabric filter bag house.

5. ENVIRONMENTAL AND LAND USE INFORMATION

5.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

Not applicable.

5.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

GRU's current preferred alternative is a 244/220 MW (gross/net) circulating fluidized bed (CFB) unit to be located at the Deerhaven plant site, shown in Figure 2.1 and Figure 5.1, located north of Gainesville off U.S. Highway 441. The proposed CFB will be fired with biomass, coal, and petroleum coke (pet coke). The Deerhaven site is preferred for the proposed project for several major reasons as follows. It is an existing power generation site, thereby allowing future development while minimizing impacts to the greenfield (undeveloped) areas. It also has established: 1) access to fuel supply and power delivery; 2) fuel, water and combustion product management facilities; and 3) access to reclaimed water.

5.2.1 Land Use and Environmental Features

The location of the Deerhaven Generating Station ("Site") is indicated on Figure 2.1 and Figure 5.1, overlain on USGS maps that were originally at a scale of 1 inch : 24,000 feet. Figure 5.2 provides a photographic depiction of the land use and cover of the existing site and adjacent areas. The existing land use of the certified portion of the site is industrial (i.e., electric power generation and transmission and ancillary uses such as fuel storage and conveyance; water, combustion product, and forest management). The recently acquired portion of the site is zoned agricultural (silviculture). Surrounding land uses are primarily rural or agricultural with some low-density residential development. The Deerhaven site encompasses approximately 3464 acres, much of which is a natural buffer.

The Site is located in the Suwanee River Water Management District. A small increase in water quantities for potable uses is projected. It is estimated that industrial water usage associated with the new unit will be approximately 3 million gallons per day (MGD). This amount includes a water allocation for a flue gas desulfurization system(s) at the Site. The groundwater allocation in the existing Site Certification may be sufficient to accommodate the requirements of the Site in the future with the proposed new unit, if reclaimed water is used. Water for potable use will be supplied via the City's potable water system. Groundwater will continue to be extracted from the Floridan aquifer. A significant amount of reclaimed water from GRU's Main St. and/or Kanapaha wastewater treatment plants is expected to be made available to the Site to supply industrial process and cooling water needs. Process wastewater is currently collected, treated and reused on-site. The Site has zero discharge of process wastewater to surface waters, with a brine concentrator and on-site storage of water treatment and solid by-products. It is expected that this practice will continue with the addition of the new unit. Other water conservation measures may be identified during the design of the project.

Coal is currently delivered to the Site via rail. It is expected that fuel for the new unit will also be supplied by rail and that the existing coal storage area will be used for storage of fuels (biomass, coal, and pet coke). This area is lined with natural clay and is equipped with a stormwater runoff collection trench and pond.

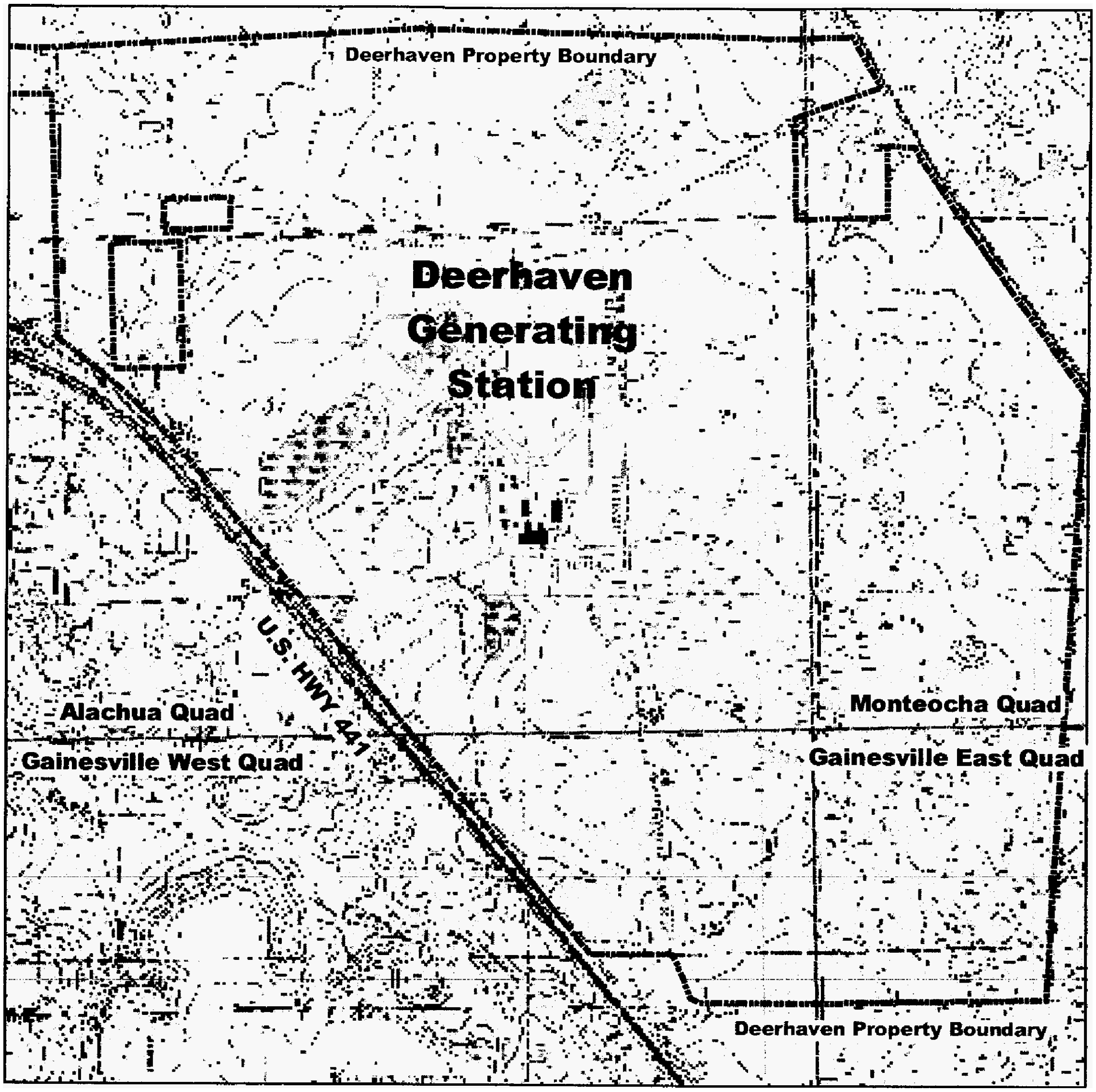
5.2.2 Air Emissions

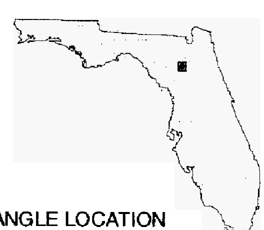
The CFB technology itself minimizes the formation of nitrogen oxides (i.e., NOx) through lower combustion temperatures, and controls SO2 emissions via limestone injection. CFB technology also results in substantial metals removal. A polishing scrubber or a flash dryer absorber may be utilized, if needed, to further reduce SO2 and trace metal emissions. NOx emissions may be further reduced, if needed, using a selective non-catalytic reduction system. Particulate matter emissions will be controlled utilizing a fabric filter.

5.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Not applicable.

Figure 5.1



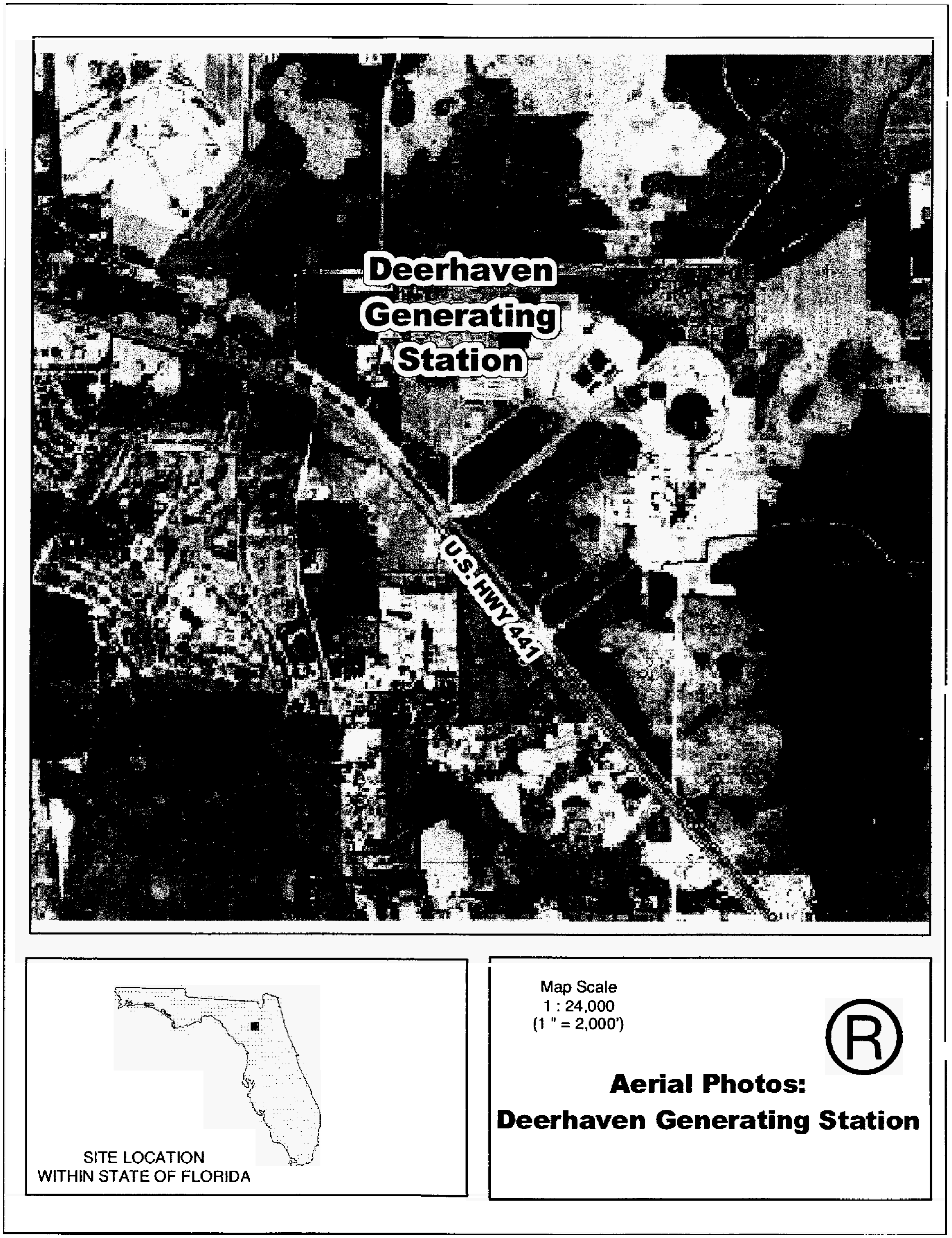


Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')

Location Map:
Deerhaven Generating Station

Data Source: USGS 7.5 Minute Quadrangle Maps : Quad names-Alachua, Gainesville West, Monteocha, Gainesville East

Figure 5.2


Deerhaven
Generating
Station
U.S. HWY 441
SITE LOCATION
WITHIN STATE OF FLORIDA
Map Scale
1 : 24,000
(1 " = 2,000')
Aerial Photos:
Deerhaven Generating Station