ORIGINAL

GRU More than Energy

GAINESVILLE REGIONAL UTILITIES

STRATEGIC PLANNING

April 1, 2006

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 20 copies of its 2006 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

2006 TEN-YEAR SITE PLAN

GRU[SM]

More than Energy[TM]

Submitted to:

The Florida Public Service Commission

April 2006

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1. INTRODUCTION

The 2006 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 2006 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 465 megawatts on August 18, 2005.

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 124 square miles and 87,560 customers (2005 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 632 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 87.4% of the electric energy supplied by the System in 2005. These units range in size from 23.2 MW to 228.4 MW. The combined-cycle unit, which includes a heat recovery steam generator/turbine and combustion turbine set, comprises 18.3% of the System's net summer capability and produced 6.1% of the electric energy supplied by the System in 2005. The System's 11.43 MW share of Crystal River 3 nuclear unit comprises 1.9% of the System's net summer capability and produced 4.5% of total electric energy in 2005. Deerhaven Unit 2, and Crystal River 3 are used for base load purposes; while JRK Unit 7, JRK CC1, and Deerhaven Unit 1 are used for intermediate loading.

2.1.1.2 Gas Turbines. The System's six industrial gas turbines make up 24.9% of the System's summer generating capability and produced 1.7% of the electric energy supplied by the System in 2005. These simple-cycle combustion turbines 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 0.3% of total energy in 2005. 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 Unit 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 2328 acres, for a total of 3474 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	80.01	795 MCM ACSR
138 KV single circuit	16.30	1192 MCM ACSR
138 KV single circuit	20.91	795 MCM ACSR
230 KV single circuit	2.53	795 MCM ACSR
Total	119.75	

Annually, GRU participates in Florida Reliability Coordinating Council (FRCC) studies to analyze multi-level contingencies. Contingencies are occurrences that depend on changes or uncertain conditions and, as used here, represent various equipment failures that may occur. All single and two circuits-common pole contingencies have no identifiable problems.

A scenario at peak summer load with Deerhaven Unit 2 and Archer 230 kV tie out of service was studied and identified GRU bus voltages that would fall below acceptable levels. A 138kV 48 MVAr capacitor bank located at our Parker Substation is the preferred solution being considered.

The state system security coordinator is responsible for the integrity and stability of the entire Florida transmission grid. In reviewing our system import capability, it has been indicated that GRU could plan to import about 150-170 MW. This limit is based on not exceeding the bus voltage standard for reliability with the given import. The proposed capacitor bank above would benefit GRU by allowing additional import capacity.

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 150 MVA 138/69 kV transformer at the Idylwild Substation. The System interconnects with FPL via a 138 kV tie between FPL's Hampton Substation and the System's Deerhaven Substation. This interconnection has a thermal capacity of 224 MVA. All listed capacities are based on normal (Rating A) capacities.

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. Parker is GRU's only transmission level voltage substation. The locations of these substations are shown on Figure 2.1.

The six major distribution substations are connected to the 138 kV bulk power transmission network with looped feeds which prevent the outage of a single transmission line from causing major outages in the distribution system. Ironwood, Kanapaha and Rocky Point are served by a single tap to the 138 kV network which would require distribution switching to restore customer power if the single transmission line tapped is outaged. GRU serves its retail customers through a 12.47 kV distribution network. The distribution substations, their present and future rated transformer capabilities and 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 31st 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. One of the two 22.4 MVA transformers at Ft. Clarke is being repaired and rewound to a 28.0 MVA rating.

This will make the normal rating for the substation 50.4 MVA.

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 2.32 mile radial line connected to the System's transmission facilities at Parker Road near NW 24th Avenue.

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 by GRU's looped 138 kV transmission system. Two small residential neighborhoods and a few commercial customers within Alachua's city limits are served from a GRU 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 ends December 31, 2006. 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

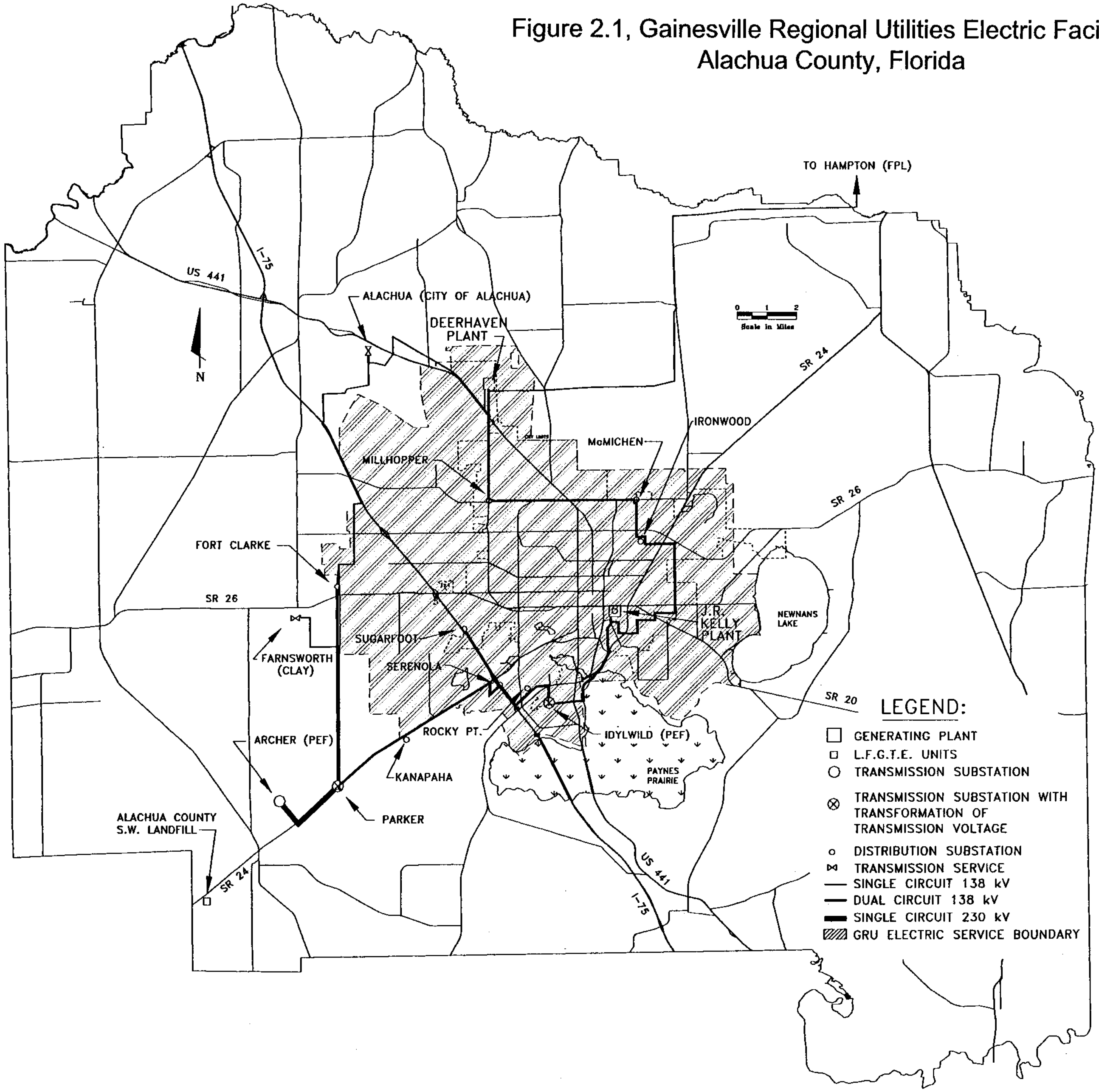
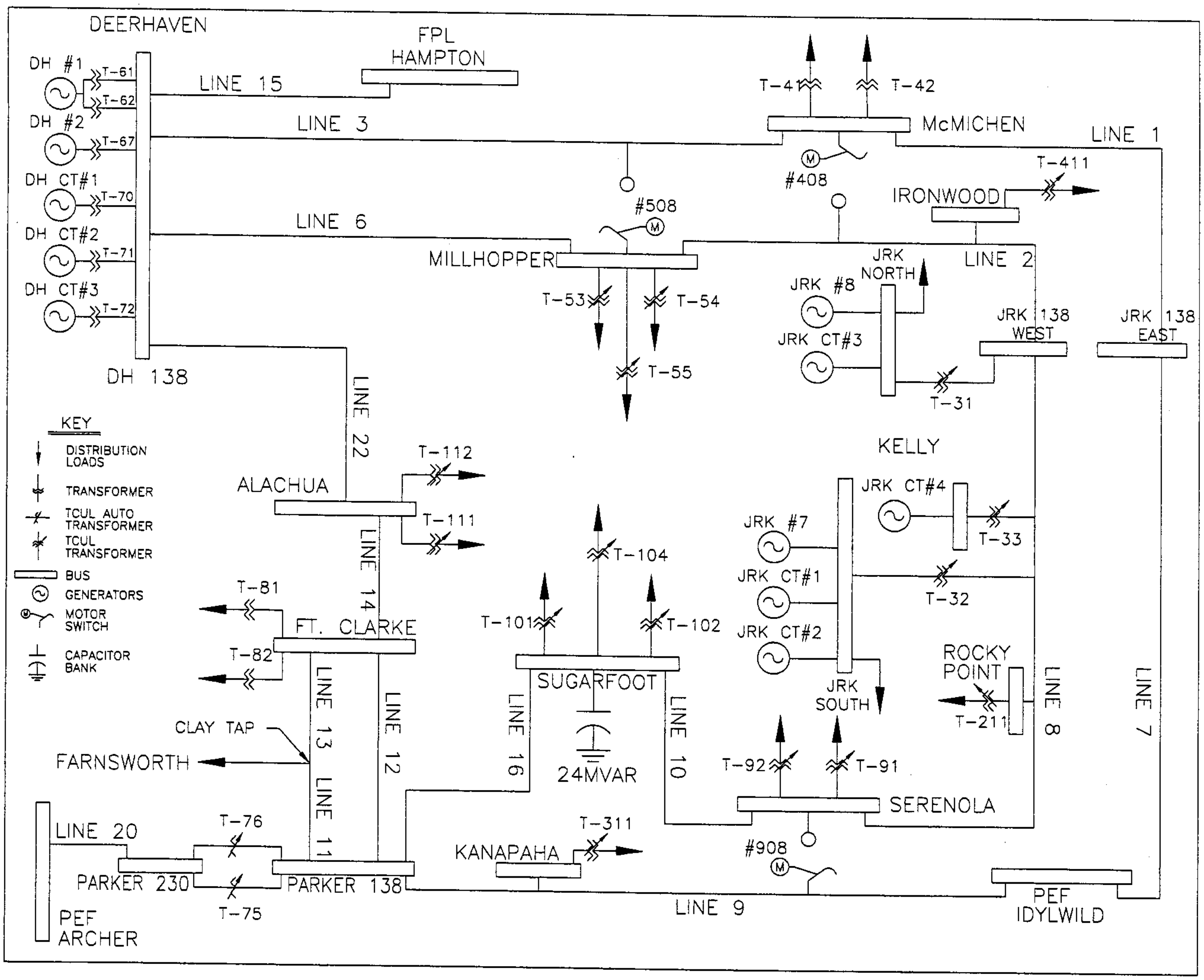


FIGURE 2.2 Gainesville Regional Utilities Electric System One-Line Diagram.



Schedule 1
EXISTING GENERATING FACILITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								Alt.							
								Fuel	Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Primary Fuel		Alternate Fuel		Storage	In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Type	Trans.	Type	Trans.	(Days)	Month/Year	Month/Year	MW	MW	MW	MW	Status
J. R. Kelly		Alachua County									**180.00**	**189.00**	**177.20**	**186.20**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL				[4/65 ; 5/01]	2051	38.00	38.00	37.00	37.00	OP
	FS07	(GRU)	ST	NG	PL	RFO	TK		8/61	8/11	24.00	24.00	23.20	23.20	OP
	GT04		CT	NG	PL	DFO	TK		5/01	2051	76.00	82.00	75.00	81.00	OP
	GT03		GT	NG	PL	DFO	TK		5/69	05/19	14.00	15.00	14.00	15.00	OP
	GT02		GT	NG	PL	DFO	TK		9/68	09/18	14.00	15.00	14.00	15.00	OP
	GT01		GT	NG	PL	DFO	TK		2/68	02/18	14.00	15.00	14.00	15.00	OP
Deerhaven		Alachua County									**451.00**	**461.00**	**421.40**	**432.40**	
	FS02	Secs. 26,27,35	ST	BIT	RR				10/81	2031	249.00	249.00	228.40	228.40	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	08/22	88.00	88.00	83.00	83.00	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	76.00	82.00	75.00	81.00	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	19.00	21.00	17.50	20.00	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	19.00	21.00	17.50	20.00	OP
Crystal River (818/815)	3	Citrus County Sec. 33, T17S, R16E (FPC)	ST	NUC	TK				3/77	2037	**12.07**	**12.24**	**11.43**	**11.71**	OP
SW Landfill		Alachua County									**1.64**	**1.64**	**1.30**	**1.30**	
	SW-1	Sec. 19, T11S, R18E	IC	LFG	PL				12/03	12/09	0.82	0.82	0.65	0.65	OP
	SW-2		IC	LFG	PL				12/03	12/15	0.82	0.82	0.65	0.65	OP
System Total													**611.33**	**631.61**	

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

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

Transportation Method
PL = Pipe Line
RR = Railroad
TK = Truck

Status
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 - Hampton	224.0[2]	Transformers	291.2[2]	Transformers
16	Sugarfoot - Parker	236.2	Conductor	282.0	Conductor
20	Parker - Archer (T75, T76)	224.0	Transformers	300.0	Transformers
22	Alachua - Deerhaven	299.7	Conductor	356.0	Conductor
xx	Clay Tap - Farnsworth	236.2	Conductor	282.0	Conductor
xx	Idylwild - FPC	150.0	Transformer	168.0	Transformer

[1] –Rating effective through Spring, 2007 (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.

[2] –These two transformers are located at the FPL Bradford Substation and are the limiting elements in this intertie.

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
Transformers T75 & T76 normal limits are based on a 65 °C oil temperature rise

TABLE 2.2

SUBSTATION TRANSFORMATION AND CIRCUITS

Distribution Substation	Normal Transformer Rated Capability	Current Number of Circuits
Ft. Clarke	50.4 MVA	4
J.R. Kelly[2]	112.0 MVA	15
McMichen	44.8 MVA	5
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	Normal Transformer Rated Capability	Number of Circuits
Parker	224 MVA	5

2 J.R. Kelly is a generating station as well as a distribution substation. The CT portion (75 MW) of JRK CC1 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 1996-2015. 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 2005. 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 2006 (Bulletin No. 144), 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. The forecast assumes normal weather conditions. Normal heating degree days and cooling degree days equal the mean of data reported to NOAA by the Gainesville Municipal Airport station from 1984-2005.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2005, 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 per capita income for Alachua County were obtained from Global Insight.

(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 and become GRU's official pricing program plan. The price of electricity is expected to slightly outpace inflation 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 2006 through 2015. 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 as measured by heating degree days and cooling degree days. The form of this equation is as follows:

$$\begin{aligned} RESAVUSE = {} & 5140.7 + 0.065\,(HHY05) - 12.08\,(RESPR05) \\ & + 0.67\,(HDD) + 0.82\,(CDD) \end{aligned}$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use Per Customer
HHY05	=	Average Household Income
RESPR05	=	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	=	0.9024
DF (error)	=	29 (period of study, 1971-2005)
t - statistics:		
Intercept	=	4.07
HHY05	=	5.55
RESPR05	=	-3.38
HDD	=	3.84
CDD	=	4.20

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 number of persons per household, the historical series of Clay customer transfers, and an indicator variable for customer counts recorded under the previous billing system. The residential customer model specifications are:

$$RESCUS = 44207 + 336.8\,(POP) - 21387\,(HHSize) + 0.71\,(CLYRCus) - 1716\,(OldSys)$$

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
HHSize	=	Number of Persons per Household
CLYRCus	=	Clay Customer Transfers
OldSys	=	Previous Billing System (1978-1991)
Adjusted R^2	=	0.9992
DF (error)	=	22 (period of study, 1978-2005)
t - statistics:		
Intercept	=	7.65
POP	=	42.81
HHSize	=	-11.06
CLYRCus	=	4.13

OldSys = -4.22

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, 331 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 = *23.89 – 0.012 (OPTDCus) + 0.0014 (CDD)*

Where:

GSNAVUSE = Average annual energy usage by GSN customers

OPTDCus = Cumulative number of Optional Demand Customers

CDD = Annual Cooling Degree Days

Adjusted R^2 = 0.7743

DF (error) = 23 (period of study, 1979-2005)

t - statistics:

Intercept = 12.19

OPTDCus = -9.07

CDD = 2.03

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

GSNCUS	=	*-6094.9 + 64.7(POP) + 2.27(CLYNCus) - 4.63(OptDCus)*
Where:		
GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
CLYNCus	=	Clay Non-Demand Transfer Customers
OptDCus	=	Optional Demand Customers
Adjusted R^2	=	0.9966
DF (error)	=	23 (period of study, 1978-2005)
t - statistics:		
Intercept	=	-12.6
POP	=	21.3
CLYNCus	=	2.49
OptDCus	=	-8.04

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	=	*327.5 + 0.0088 (PCY05) – 0.21 (OPTDCust)*
Where:		
GSDAVUSE	=	Average annual energy use by GSD Customers
PCY05	=	Per Capita Income in Alachua County
OPTDCust	=	Cumulative number of Optional Demand Customers
Adjusted R^2	=	0.6980
DF (error)	=	23 (period of study, 1979-2005)
t - statistics:		
Intercept	=	12.6
PCY05	=	7.72
OPTDCust	=	-5.57

The annual average number of customers was projected using a regression model that includes Alachua County population, Clay demand customer transfers, and the number of optional demand customers as independent variables. The specifications of the general service demand customer model are as follows:

GSDCUS	=	*-421.7 + 5.27(POP) + 18.27(CLYDCus) + 0.56(OptDCus)*
Where:		
GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
CLYDCus	=	Clay Demand Transfer Customers
OptDCus	=	Optional Demand Customers
Adjusted R^2	=	0.9947
DF (error)	=	23 (period of study, 1978-2005)

t - statistics:

Intercept	=	-5.46
POP	=	11.1
CLYDCus	=	4.06
OptDCus	=	6.19

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 2005. 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:

$$LPAVUSE = 10319 + 16.2\,(NONAG) - 31.2\,(LPPR05)$$

Where:

LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
NONAG	=	Alachua County Nonagricultural Employment (000's)
LPPR05	=	Average Price for 1,000 kWh in the Large Power Sector
Adjusted R^2	=	0.9188
DF (error)	=	27 (period of study, 1976-2005)

t - statistics:

INTERCEPT	=	7.32
NONAG	=	2.14
LPPR04	=	-3.65

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 = *-8522 + 0.46 (RESCUS)*

Where:

LGTMWH	=	Outdoor Lighting Energy Sales
RESCUS	=	Number of Residential Customers
Adjusted R^2	=	0.9817
DF (error)	=	11 (period of study, 1993-2005)

t - statistics:

Intercept	=	-7.18
RESCUS	=	25.4

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 2005 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:

$$CLYNEL = -34537 + 482.14\,(POP)$$

Where:

CLYNEL	=	Farnsworth Substation Net Energy (MWh)
POP	=	Alachua County Population (000's)
Adjusted R^2	=	0.9586
DF (error)	=	14 (period of study, 1990-2005)

t - statistics:

Intercept	=	-6.39
POP	=	18.67

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 = *-64924 + 23392 (ALAPOP)*

Where:

ALANEL	=	City of Alachua Net Energy (MWh)
ALAPOP	=	City of Alachua Population (000's)
Adjusted R^2	=	0.9819
DF (error)	=	22 (period of study, 1982-2005)
t - statistics:		
Intercept	=	-18.3
ALAPOP	=	35.3

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 (0.95478) is the median of observed historical values from 1995 through 2005. 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 23 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 23 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 March 2005.

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 2005, as well as projected program implementations scheduled through 2015. 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; 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; HVAC sizing calculations; 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.

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 2006-2015 is expected to provide an incremental impact of 5 MW of summer peak reduction, 7 MW of winter peak reduction, and 29 GWh of annual energy savings by the year 2015, 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 2005, oil-fired generation comprised 4.0% of total net generation, natural gas-fired generation contributed 16.9%, nuclear fuel contributed 4.5%, and coal-fired generation provided 74.6% 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 4.5% 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 2006 (AEO2006), published in February 2006 by the U.S. Department of Energy's Energy Information Administration (EIA), and EIA's Short-Term Energy Outlook (STEO), March 2006. 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 AEO2006. 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 AEO2006.

During calendar year 2005, distillate fuel oil was used to produce 0.02% of GRU's total net generation. The price of distillate fuel oil delivered to GRU is expected to decrease from 2006 to 2010, and then increase through the long-term forecast horizon. Distillate fuel oil is expected to be the most expensive fuel available to GRU. During calendar year 2005, residual fuel oil was used to produce 4.0% of GRU's total net generation. The price of residual fuel oil delivered to GRU is also expected to decrease through 2010 and then increase through the long-term forecast horizon. 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 74.6% of total net generation during calendar year 2005. GRU purchases low-sulfur (0.7%), high Btu eastern coal for use in Deerhaven Unit 2. In addition to low sulfur compliance coal, GRU projects prices for medium (1.7%) sulfur coal and high (3.6%) sulfur coal for evaluation in the proposed circulating fluidized bed unit. In 2010, Deerhaven Unit 2 will begin operating following the retrofit of an air quality control system, which is being added as a means of complying with new environmental regulations. Deerhaven Unit 2 will be designed to operate with medium sulfur coal following the retrofit.

Prices for compliance coal for 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 AEO2006 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 the Hill & Associates, Inc. forecast.

The long-term growth rate of the price of coal delivered to GRU is expected to average approximately 3.5% per year from 2010 through 2025.

3.5.3 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2005, GRU purchased approximately 6.1 million MMBtu for use by both systems. GRU power plants used 62% of the total purchased for GRU during 2005, while the LDC used the remaining 38%.

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 2006 through 2007 were derived from EIA's Short-Term Energy Outlook, March 2006, as reported for the Henry Hub, with a transportation component added. Prices from 2008 through 2025 follow the pattern of price changes outlined in AEO2006, calibrated to reflect prices for the Henry Hub region, which are typically slightly higher than U.S. Wellhead average prices. GRU's forecast of delivered gas prices is presented in Table 3.3.

GRU's delivered natural gas prices are projected to decrease from about \$8.54/MMBtu in 2006 to a low of \$7.71/MMBtu in 2011, and then increase at a rate of approximately 2.7% per year through the end of the forecast horizon.

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. The price of nuclear fuel is projected to increase at a rate of 2.3% from 2006 through 2015.

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, then added a transportation component for a short haul by rail. The short haul transportation cost was escalated based on the rate of change in coal transportation costs from AEO2006, and the cost of the pet coke was escalated based on the rate of change in commodity coal prices from AEO2006. This forecast results in prices that range from $1.28/MMBtu in 2006 to $1.47/MMBtu in 2015.

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
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	182,904	2.34	888	78,164	11,358	752	9,378	80,199
2006	185,929	2.33	913	79,696	11,454	775	9,600	80,743
2007	188,932	2.33	937	81,227	11,540	798	9,822	81,294
2008	191,836	2.32	962	82,723	11,631	821	10,036	81,850
2009	194,641	2.31	985	84,186	11,704	842	10,244	82,214
2010	197,428	2.31	1,007	85,648	11,760	861	10,452	82,426
2011	200,040	2.30	1,029	87,042	11,827	881	10,645	82,734
2012	202,633	2.29	1,048	88,436	11,849	898	10,839	82,891
2013	205,131	2.28	1,066	89,795	11,872	916	11,026	83,034
2014	207,611	2.28	1,086	91,155	11,917	934	11,213	83,311
2015	209,921	2.27	1,107	92,446	11,980	953	11,385	83,733

* 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
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	189	18	10,477	0	25	0	1,854
2006	190	18	10,580	0	26	0	1,904
2007	191	18	10,602	0	27	0	1,953
2008	191	18	10,626	0	27	0	2,002
2009	191	18	10,639	0	28	0	2,047
2010	192	18	10,646	0	29	0	2,089
2011	192	18	10,657	0	29	0	2,131
2012	192	18	10,664	0	30	0	2,168
2013	192	18	10,681	0	30	0	2,204
2014	193	18	10,697	0	31	0	2,244
2015	193	18	10,716	0	32	0	2,285

** 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)	(2)	(3)	(4)	(5)	(6)
Year	Sales For Resale GWh	Utility Use and Losses GWh	Net Energy for Load GWh	Other Customers	Total Number of Customers
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	163	66	2,082	0	87,560
2006	168	98	2,170	0	89,314
2007	173	101	2,227	0	91,066
2008	178	103	2,283	0	92,778
2009	182	106	2,335	0	94,448
2010	187	108	2,384	0	96,117
2011	192	110	2,433	0	97,705
2012	196	112	2,476	0	99,293
2013	200	114	2,518	0	100,839
2014	205	116	2,565	0	102,385
2015	209	118	2,612	0	103,849

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
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	476	37	428	0	0	6	0	5	465
2006	481	38	432	0	0	6	0	5	470
2007	493	40	443	0	0	6	0	4	483
2008	504	41	454	0	0	6	0	3	495
2009	515	42	464	0	0	6	0	3	506
2010	526	43	474	0	0	6	0	3	517
2011	535	44	482	0	0	6	0	3	526
2012	546	45	491	0	0	7	0	3	536
2013	555	46	499	0	0	7	0	3	545
2014	566	47	509	0	0	7	0	3	556
2015	576	48	518	0	0	7	0	3	566

SCH3_1.xls

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Winter	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
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	405	36	341	0	0	24	0	4	377
2005 / 2006	411	40	346	0	0	22	0	3	386
2006 / 2007	425	40	363	0	0	20	0	2	403
2007 / 2008	435	41	374	0	0	18	0	2	415
2008 / 2009	444	42	385	0	0	16	0	1	427
2009 / 2010	451	43	394	0	0	14	0	0	437
2010 / 2011	460	45	400	0	0	15	0	0	445
2011 / 2012	468	46	407	0	0	15	0	0	453
2012 / 2013	476	47	413	0	0	16	0	0	460
2013 / 2014	485	48	420	0	0	17	0	0	468
2014 / 2015	494	49	428	0	0	17	0	0	477
2015 / 2016	503	49	436	0	0	18	0	0	485

SCH3_2.xls

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 %
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	2,151	53	15	1,854	163	66	2,082	51.12%
2006	2,237	53	14	1,904	168	98	2,170	52.71%
2007	2,291	52	12	1,953	173	101	2,227	52.63%
2008	2,344	51	10	2,002	178	103	2,283	52.65%
2009	2,394	50	9	2,047	182	106	2,335	52.68%
2010	2,441	49	8	2,089	187	108	2,384	52.64%
2011	2,493	52	8	2,131	192	110	2,433	52.80%
2012	2,539	54	9	2,168	196	112	2,476	52.73%
2013	2,584	57	9	2,204	200	114	2,518	52.74%
2014	2,633	59	9	2,244	205	116	2,565	52.66%
2015	2,682	61	9	2,285	209	118	2,612	52.68%

Schedule 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2005		FORECAST 2006		FORECAST 2007	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	377	156	340	169	403	173
FEB	286	137	386	146	366	149
MAR	287	149	319	153	327	157
APR	285	140	344	155	352	159
MAY	376	169	412	187	422	192
JUN	405	193	448	204	460	210
JUL	454	225	470	223	482	229
AUG	465	226	470	227	483	233
SEP	425	207	445	207	456	213
OCT	387	176	383	177	393	182
NOV	292	144	336	154	345	158
DEC	321	160	361	168	371	172

SCH4.xls

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
FUEL REQUIREMENTS			UNITS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	NUCLEAR		TRILLION BTU	0.921	1.004404	0.908646	1.004404	0.791370	1.004404	0.908646	1.004404	0.908646	1.004404	0.908646
(2)	0.7% COAL		1000 TON	624.832	617.839	638.037	661.566	638.920						
(2.1)	1.7% COAL		1000 TON						642.574	660.860	680.662	436.443	432.410	432.255
	RESIDUAL													
(3)		STEAM	1000 BBL	156.057	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	156.057	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	0.609	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(8)		CC	1000 BBL	0.311	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(9)		CT	1000 BBL	0.147	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(10)		TOTAL:	1000 BBL	1.068	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	2,030.498	770.175	666.942	724.847	1,108.519	1,225.431	1,119.056	1,057.303	53.226	130.963	130.275
(12)		CC	1000 MCF	1,116.532	3,864.836	3,982.666	3,731.966	4,257.619	4,390.327	4,475.210	4,135.954	784.049	853.899	1,211.973
(13)		CT	1000 MCF	470.682	1,952.352	1,993.695	2,136.053	2,384.968	2,554.911	2,657.813	3,061.505	288.777	488.375	363.890
(14)		TOTAL:	1000 MCF	3,617.712	6,587.363	6,643.303	6,592.866	7,751.106	8,170.669	8,252.079	8,254.762	1,126.052	1,473.237	1,706.138
(15)	Landfill Gas		TRILLION BTU	0.069	0.127	0.127	0.127	0.127	0.063	0.063	0.063	0.063	0.063	0.063
(16)	Solid Fuel (proposed DH3)		1000 TON	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	601.608	608.023	616.969
(17)	2.7% Coal: 32.7858% by wt, 36.3623% by Btu		1000 TON	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	197.242	199.345	202.278
(18)	Petroleum Coke: 38.6793% by wt, 50.0% by Btu		1000 TON	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	232.697	235.179	238.639
(19)	Woody Biomass: 28.535% by wt, 13.6377% by Btu		1000 TON	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	171.669	173.499	176.052

Schedule 6.1
ENERGY SOURCES (GWH)
As of January 1, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
ENERGY SOURCES			UNITS	ACTUAL 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(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	89.415	95.658	86.538	95.658	75.369	95.658	86.538	95.658	86.538	95.658	86.538
(3)	COAL		GWH	1,467.267	1,444.026	1,492.983	1,550.589	1,499.118	1,490.362	1,533.834	1,581.194	954.823	947.908	950.939
	RESIDUAL													
(4)		STEAM	GWH	78.909	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	78.909	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	DISTILLATE													
(8)		STEAM	GWH	0.065	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(9)		CC	GWH	0.236	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(10)		CT	GWH	0.027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(11)		TOTAL:	GWH	0.328	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	172.683	64.775	55.726	60.823	93.303	103.203	94.971	89.642	4.446	11.098	11.077
(13)		CC	GWH	120.166	422.338	436.024	415.341	473.290	493.352	507.159	474.643	77.119	84.648	119.494
(14)		CT	GWH	33.341	142.770	142.111	146.603	178.014	190.116	196.188	220.744	19.515	31.690	26.204
(15)		TOTAL:	GWH	326.189	629.883	633.861	622.767	744.607	786.671	798.318	785.029	101.080	127.436	156.775
(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	5.356	10.582	10.582	10.582	10.582	5.291	5.291	5.291	5.291	5.291	5.291
(19)	Solid Fuel (Proposed DH3)		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1,370.379	1,387.395	1,411.089
(20)	2.7% Coal: 32.7858% by wt, 36.3623% by Btu		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	498.301	504.489	513.104
(21)	Petroleum Coke: 38.6793% by wt, 50.0% by Btu		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	685.190	693.698	705.545
(22)	Woody Biomass: 28.535% by wt, 13.6377% by Btu		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	186.888	189.209	192.440
(23)	Starke Contract		GWH	16.755	13.110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(24)	Purchased Energy		GWH	165.307	3.425	2.879	3.538	5.218	5.809	8.837	8.897	0.945	1.358	1.572
(25)	Energy Sales		GWH	33.614	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.612	0.438	0.050
(26)	NET ENERGY FOR LOAD		GWH	2,082.401	2,170.464	2,226.843	2,283.134	2,334.894	2,383.791	2,432.818	2,476.069	2,518.444	2,564.608	2,612.154

Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
ENERGY SOURCES			UNITS	ACTUAL 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(2)	NUCLEAR		GWH	4.29%	4.41%	3.89%	4.19%	3.23%	4.01%	3.56%	3.86%	3.44%	3.73%	3.31%
(3)	COAL		GWH	70.46%	66.53%	67.04%	67.91%	64.20%	62.52%	63.05%	63.86%	37.91%	36.96%	36.40%
	RESIDUAL													
(4)		STEAM	GWH	3.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	GWH	3.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	GWH	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	GWH	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NATURAL GAS													
(12)		STEAM	GWH	8.29%	2.98%	2.50%	2.66%	4.00%	4.33%	3.90%	3.62%	0.18%	0.43%	0.42%
(13)		CC	GWH	5.77%	19.46%	19.58%	18.19%	20.27%	20.70%	20.85%	19.17%	3.06%	3.30%	4.57%
(14)		CT	GWH	1.60%	6.58%	6.38%	6.42%	7.62%	7.98%	8.06%	8.92%	0.77%	1.24%	1.00%
(15)		TOTAL:	GWH	15.66%	29.02%	28.46%	27.28%	31.89%	33.00%	32.81%	31.70%	4.01%	4.97%	6.00%
(16)	NUG		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(17)	HYDRO		GWH	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		GWH	0.26%	0.49%	0.48%	0.46%	0.45%	0.22%	0.22%	0.21%	0.21%	0.21%	0.20%
(19)	Solid Fuel (Proposed DH3)		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	54.41%	54.10%	54.02%
(20)	2.7% Coal: 32.7858% by wt, 36.3623% by Btu		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	19.79%	19.67%	19.64%
(21)	Petroleum Coke: 38.6793% by wt, 50.0% by Btu		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	27.21%	27.05%	27.01%
(22)	Woody Biomass: 28.535% by wt, 13.6377% by Btu		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.42%	7.38%	7.37%
(23)	Starke Contract		GWH	0.80%	0.60%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(24)	Purchased Energy		GWH	7.94%	0.16%	0.13%	0.15%	0.22%	0.24%	0.36%	0.36%	0.04%	0.05%	0.06%
(25)	Energy Sales		GWH	1.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	0.00%
(26)	NET ENERGY FOR LOAD		GWH	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

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TABLE 3.1

DEMAND-SIDE MANAGEMENT IMPACTS
INCREMENTAL EFFECT OF PLANNED PROGRAMS

Year	MWh	Winter kW	Summer kW
2006	3,428	789	663
2007	6,825	1,572	1,325
2008	10,218	2,350	1,993
2009	13,617	3,127	2,665
2010	16,971	3,893	3,331
2011	19,590	4,535	3,722
2012	22,467	5,188	4,212
2013	24,915	5,817	4,522
2014	27,337	6,442	4,837
2015	29,414	7,035	5,033

Notes: Projected impacts from programs planned for 2006-2015.
Net of 2005 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	97,428	44,873	21,185
2002	102,159	46,121	21,720
2003	106,277	47,213	22,222
2004	109,441	48,028	22,676
2005	113,182	48,893	23,405
2006	116,720	49,702	24,089
2007	120,235	50,506	24,778
2008	123,725	51,302	25,464
2009	127,191	52,091	26,149
2010	130,631	52,874	26,831
2011	134,046	53,649	27,511
2012	137,435	54,418	28,190
2013	140,434	55,160	28,686
2014	143,408	55,895	29,180
2015	146,356	56,624	29,673

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	(22,159)	(7,898)	(5,787)
2001	(27,002)	(10,892)	(7,417)
2002	(31,553)	(13,604)	(8,626)
2003	(36,169)	(16,192)	(9,813)
2004	(40,019)	(18,510)	(10,812)
2005	(44,764)	(21,259)	(11,979)
2006	(50,050)	(24,415)	(13,148)
2007	(55,895)	(27,763)	(14,514)
2008	(62,335)	(31,615)	(15,941)
2009	(67,750)	(34,992)	(17,069)
2010	(73,160)	(38,322)	(18,234)
2011	(73,955)	(38,455)	(18,523)
2012	(74,469)	(38,570)	(18,712)
2013	(75,019)	(38,684)	(18,898)
2014	(75,571)	(38,794)	(19,077)
2015	(76,442)	(38,930)	(19,373)

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	69,422	29,518	11,864
2005	68,419	27,634	11,426
2006	66,669	25,288	10,942
2007	64,340	22,743	10,264
2008	61,390	19,687	9,523
2009	59,441	17,099	9,080
2010	57,471	14,552	8,597
2011	60,090	15,194	8,988
2012	62,967	15,847	9,478
2013	65,415	16,476	9,788
2014	67,837	17,102	10,103
2015	69,914	17,694	10,299

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)	3.6% Sulfur Coal (3)	Petroleum Coke (4)	Nuclear
1996	2.75	4.89	3.37	1.66				0.45
1997	3.26	4.46	3.30	1.66				0.42
1998	2.73	3.97	2.87	1.66				0.41
1999	2.79	3.47	2.86	1.66				0.40
2000	4.52	5.99	4.53	1.62				0.44
2001	4.15	6.53	4.94	1.88				0.38
2002	4.58	5.69	3.95	2.06				0.38
2003	4.87	6.59	5.97	2.04				0.38
2004	5.17	9.23	6.40	2.03				0.43
2005	7.15	9.96	9.15	2.38				0.41
2006	6.85	11.10	8.54	2.95	2.37	2.30	1.28	0.45
2007	6.99	10.71	9.11	2.59	2.36	2.26	1.31	0.42
2008	6.89	10.65	8.76	2.59	2.39	2.31	1.33	0.42
2009	6.64	10.40	8.23	2.61	2.42	2.31	1.34	0.44
2010	6.45	10.23	7.88	2.53	2.45	2.36	1.38	0.43
2011	6.63	10.47	7.71	2.60	2.52	2.49	1.38	0.50
2012	6.79	10.89	7.80	2.68	2.62	2.58	1.40	0.49
2013	6.88	10.79	8.11	2.79	2.73	2.68	1.42	0.49
2014	7.08	11.22	8.13	2.87	2.82	2.72	1.44	0.48
2015	7.32	11.56	7.96	2.92	2.85	2.71	1.47	0.50

(1) Approximate heat content of 0.7% sulfur coal is 12,200 Btu/lb.
(2) Approximate heat content of 1.7% sulfur coal is 12,500 Btu/lb.
(3) Approximate heat content of 3.6% sulfur coal is 12,350 Btu/lb.
(4) Approximate heat content of pet coke is 14,200 Btu/lb.

Table 3.3.xls

4. FORECAST OF FACILITIES REQUIREMENTS

4.1 GENERATION RETIREMENTS

The System plans to retire three of its currently operating generating units prior to the end of 2015 (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 December 2009, and the second in December 2015. 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% starting in 2011. The Gainesville community is discussing the ramifications of adding additional resources by summer 2013 to address its reserve margin requirements. GRU expects to import firm capacity in 2011 and 2012, and/or possibly implement a direct load control program, to maintain adequate reserves.

4.3 GENERATION ADDITIONS

GRU conducted an integrated resource planning process to propose the best plan for our customers' long-term electrical energy needs. GRU's current proposed alternative consists of a 220 megawatt (net) circulating fluidized bed combustion (CFB) unit that would be fired with coal, petroleum coke and biomass. The plan also proposed the installation of an air quality control system (AQCS) on the existing Deerhaven Unit 2.

The plan has been publicly discussed but has not been finalized or approved by the Gainesville City Commission. THE CITY COMMISSION MAY CHOOSE DIFFERENT TECHNOLOGIES, SIZES OF CAPACITY, AND STANDARDS FOR ENERGY CONSERVATION PLANNING THAN ARE ASSUMED IN THIS REPORT. While a nominal in-service date of June 2013 has been used for this report, a tentative construction schedule has not been determined. Once a plan or range of plans for meeting the future needs of the customers is approved, GRU will issue a Request For Proposals to Provide Capacity and Energy to offset the need for any proposed new unit. Schedule 9, included at the end of this section, identifies key parameters for the proposed generating capacity currently under discussion.

Due to new EPA regulations promulgated in March 2005, the retrofit of an AQCS on Unit 2 is proceeding as an independent project as one means of complying with the new regulations. The AQCS will consist of a selective catalytic reduction (SCR) system and a dry flue gas desulfurization system (FGD) which will include a baghouse (BH). It is expected that the SCR and the FGD/BH will be operational by 2009 and 2010, respectively. The tentative schedule for construction of any proposed new unit is yet to be determined. A nominal in-service date of June 2013 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 currently 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 connected in 2003. A fourth PDS is planned for 2007. The location for this PDS, which will be known as Springhill, will be a parcel owned by GRU 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 in the northern part of the service territory near 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.

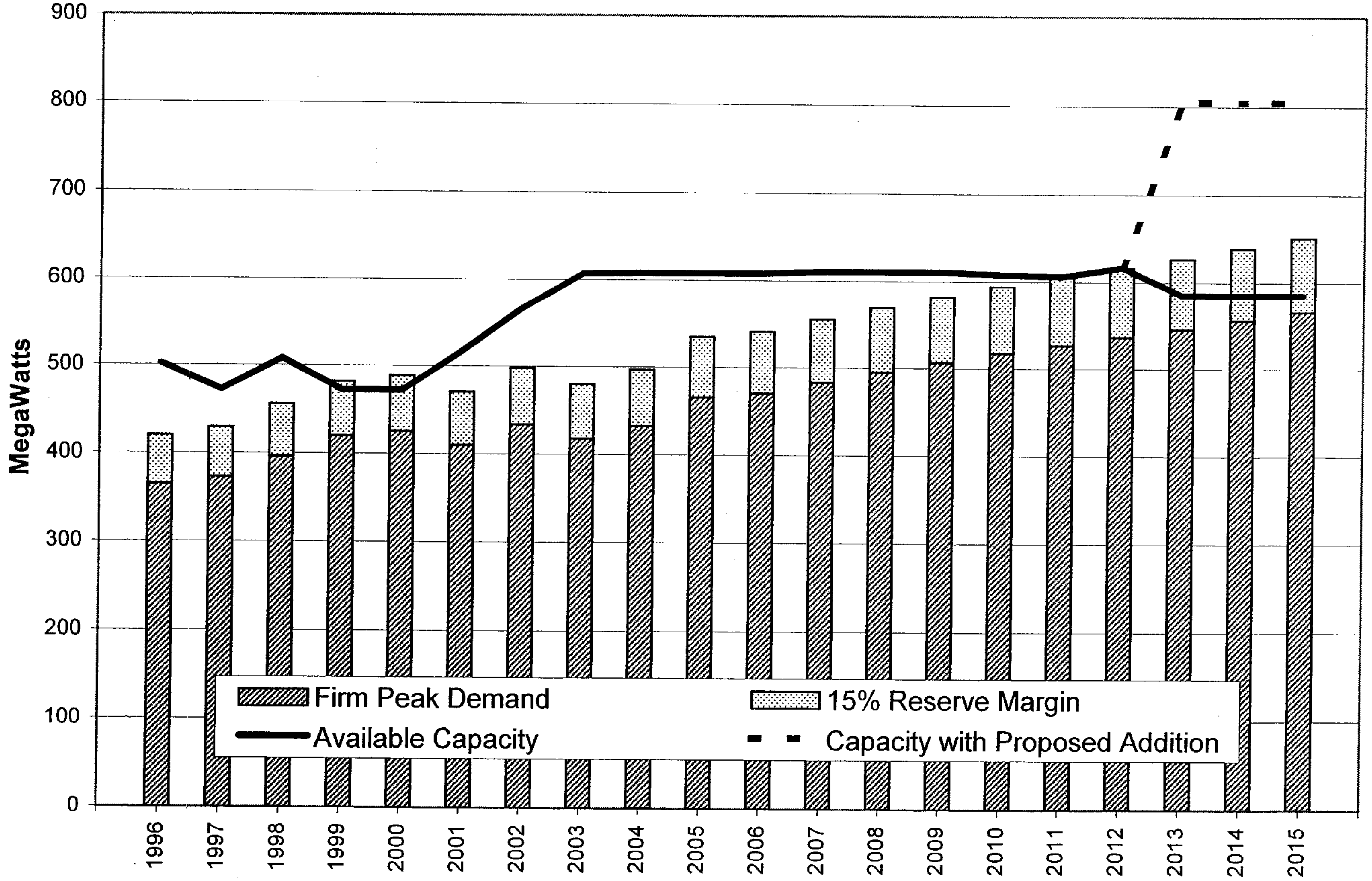
GRU is also planning to expand its John R. Kelly Plant generation-transmission-distribution substation to include a new 56 MVA 138-12.47 kV transformer located on the south side of the plant. This expansion will enhance reliability by reassigning load to a point on the system not directly tied to the generator buses of the plant. The additional transformer capacity will allow for load growth in Gainesville's downtown area.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	DSM, DLC and/or Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer 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
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	465	143	30.8%	0	143	30.8%
2006	611	0	3	0	608	470	138	29.4%	0	138	29.4%
2007	611	0	0	0	611	483	128	26.5%	0	128	26.5%
2008	611	0	0	0	611	495	116	23.4%	0	116	23.4%
2009	611	0	0	0	611	506	105	20.8%	0	105	20.8%
2010	608	0	0	0	608	517	91	17.6%	0	91	17.6%
2011	584	21	0	0	605	526	79	15.0%	0	79	15.0%
2012	584	33	0	0	617	536	81	15.1%	0	81	15.1%
2013	804	0	0	0	804	545	259	47.5%	0	259	47.5%
2014	804	0	0	0	804	556	248	44.6%	0	248	44.6%
2015	804	0	0	0	804	566	238	42.0%	0	238	42.0%

(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



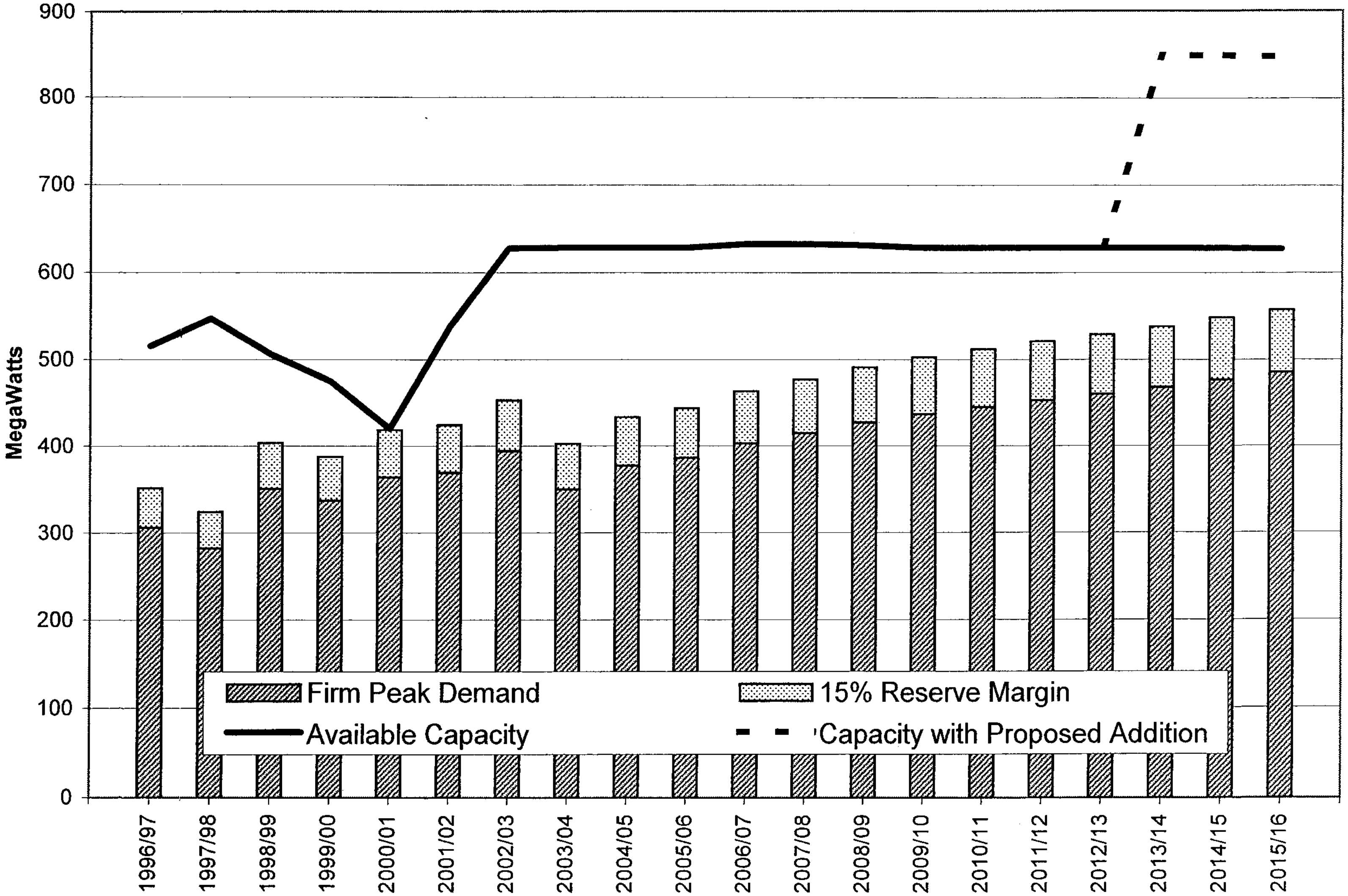
Schedule 7.1, 7.2 rounded capacity.xls

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

(1) Year	(2) Total Installed Capacity MW	(3) DSM, DLC and/or Firm Capacity Import MW	(4) Firm Capacity Export MW	(5) QF MW	(6) Total Capacity Available MW	(7) System Firm Winter 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
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	630	0	93	0	537	369	168	45.5%	0	168	45.5%
2002/03	630	0	3	0	627	394	233	59.1%	0	233	59.1%
2003/04	631	0	3	0	628	350	278	79.4%	0	278	79.4%
2004/05	631	0	3	0	628	377	251	66.6%	0	251	66.6%
2005/06	631	0	3	0	628	386	242	62.7%	0	242	62.7%
2006/07	632	0	0	0	632	403	229	56.8%	0	229	56.8%
2007/08	632	0	0	0	632	415	217	52.3%	0	217	52.3%
2008/09	631	0	0	0	631	427	204	47.8%	0	204	47.8%
2009/10	628	0	0	0	628	437	191	43.7%	0	191	43.7%
2010/11	628	0	0	0	628	445	183	41.1%	0	183	41.1%
2011/12	628	0	0	0	628	453	175	38.6%	0	175	38.6%
2012/13	628	0	0	0	628	460	168	36.5%	0	168	36.5%
2013/14	848	0	0	0	848	468	380	81.2%	0	380	81.2%
2014/15	848	0	0	0	848	477	371	77.8%	0	371	77.8%
2015/16	847	0	0	0	847	485	362	74.6%	0	362	74.6%

(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 rounded capacity.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)
				Fuel		Fuel Transport		Const.	Commercial	Expected	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Status
DEERHAVEN	FS02	Alachua County Secs. 26,27 35 T8S, R19E	ST	BIT		RR		Jan-07	Oct-08		0	0	-0.5	-0.5	D
DEERHAVEN	FS02	Alachua County Secs. 26,27 35 T8S, R19E	ST	BIT		RR		Jan-07	Oct-09		0	0	-2.5	-2.5	D
SOUTHWEST LANDFILL	LFG1	Alachua County Sec. 19, T11S, R18E	IC	LFG		PL				Dec-09	-0.65	-0.65	-0.65	-0.65	RT
J. R. KELLY	FS07	Alachua County Sec. 4, T10S, R20E	ST	NG	RFO	PL	TK			Aug-11	-24	-24	-23.2	-23.2	RT
DEERHAVEN	FSO3	Alachua County Secs. 26,27 35 T8S, R19E	ST	BIT/PC/WDS	BIT	RR/TK	RR	Jun-08	Jun-13		244	244	220	220	P
SOUTHWEST LANDFILL	LFG2	Alachua County Sec. 19, T11S, R18E	IC	LFG		PL				Dec-15	-0.65	-0.65	-0.65	-0.65	RT

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
RFO = Residual Fuel Oil

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

Sch8 RAW 3-28-06.xls

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:	6/1/2008
	b. Commercial in-service date:	6/1/2013
(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
(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):	9,465
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost (2013$/kW)	3091.56
	Direct Construction Cost ($2013/kW):	2651.75
	~~Escalation ($2013/kW)~~	~~75.98~~
	Escalation:	3.00%
	Fixed O&M ($2013/kW-Yr):	28.99
	Variable O&M ($2013/MWh):	6.01

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 proposed 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 would 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 access to fuel supply and power delivery; and fuel, water and combustion product management facilities.

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 3474 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 would continue with the addition of a 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 a new unit would also be supplied by rail and that the existing coal storage area would 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.

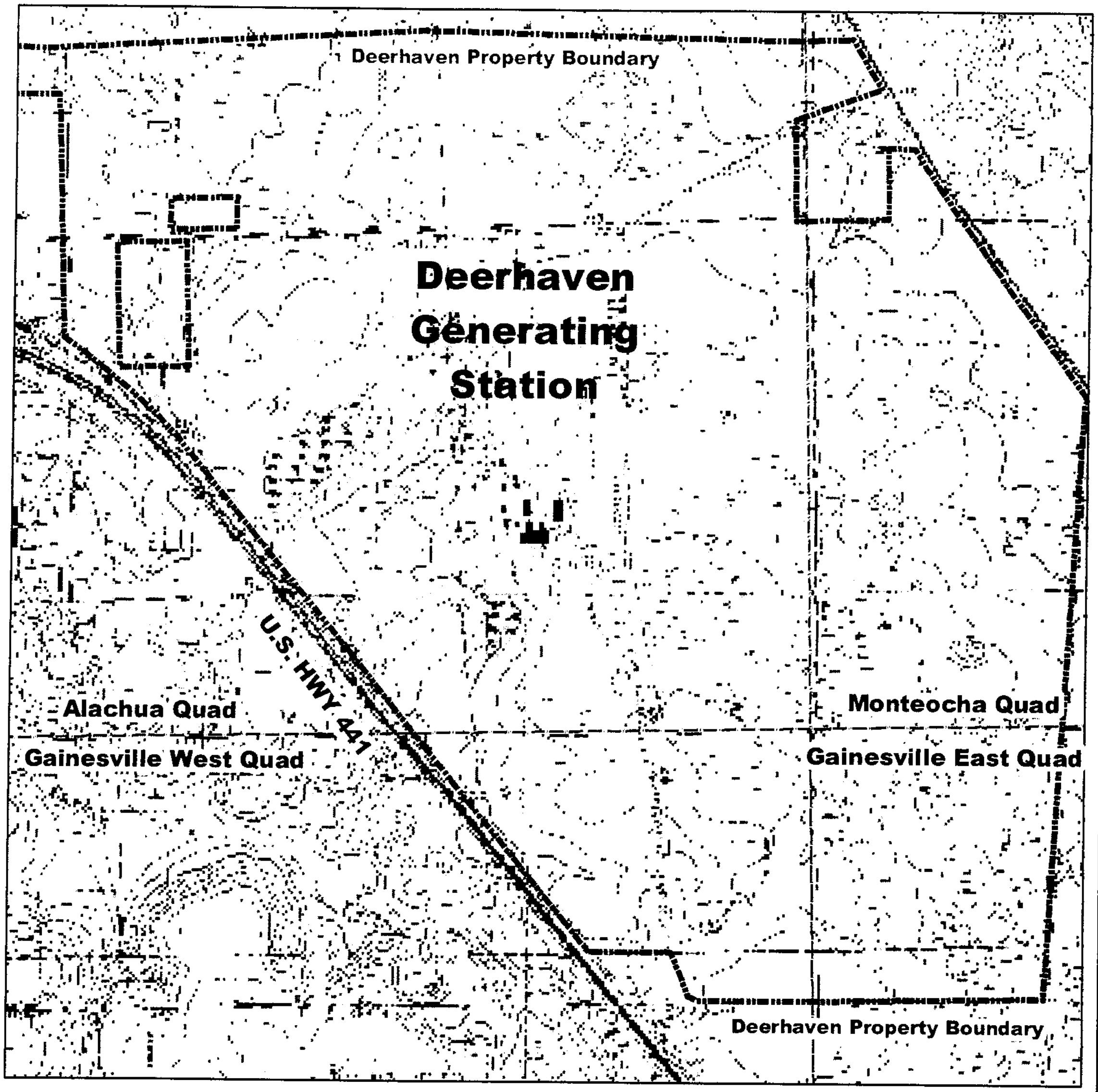
5.2.2 Air Emissions

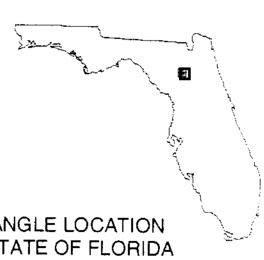
The CFB technology itself minimizes the formation of nitrogen oxides (i.e., NOx) through lower combustion temperatures, and controls SO2 emissions via limestone injection. CFB technology also results in substantial metals removal. A polishing scrubber or a flash dryer absorber may be utilized, if needed, 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 would be controlled utilizing a fabric filter.

5.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Not applicable.

Figure 5.1



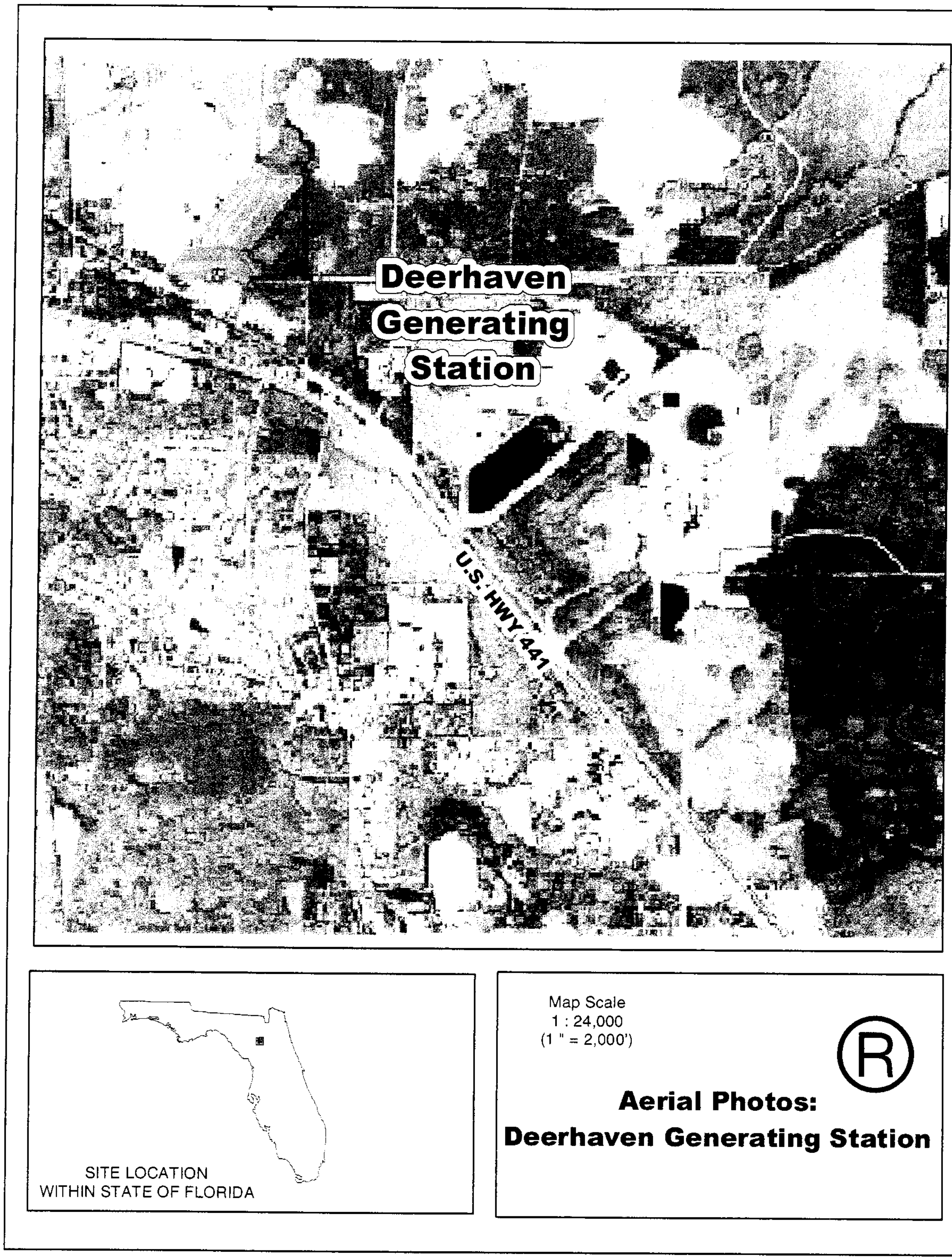


Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')

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