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GAINESVILLE REGIONAL UTILITIES

STRATEGIC PLANNING

April 23, 2004

Blanca S. Bayo, Director
Florida Public Service Commission
Division of Records & Reporting
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 25 copies of its 2004 Ten Year Site Plan for your review. Thank you for allowing us additional time to prepare our TYSP this year, and I apologize for any inconveniences we may have caused you. 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

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GAINESVILLE REGIONAL UTILITIES

2004 TEN-YEAR SITE PLAN

GRU[SM]

More than Energy[TM]

Submitted to:

The Florida Public Service Commission

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1. INTRODUCTION

The 2004 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 2004 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. 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. The repowering of J. R. Kelly Unit 8 to a 112 megawatt combined-cycle unit increased net summer capability to 610 megawatts in May 2001, and the Landfill Gas to Energy project brought the system total to 612 MW in December 2003. JRK CC1 provides benefit to the system in improved operating efficiency; reduced emission rates; reduced total emissions; and participation in the redevelopment of downtown Gainesville. The Landfill Gas to Energy project avoids the use of fossil fuels and reduces greenhouse gas emissions. Both of these projects increased system capacity at a time when the reserve margin for Peninsular Florida is relatively tight.

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 83,434 customers (2003 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. Two types of generating units are located at the System's two generating plant sites: steam turbines and gas turbines. GRU's single combined cycle unit, which is a combination of a gas turbine, a heat recovery steam generator (to capture the waste heat from the gas turbine and generate steam), and a steam turbine, is located at the John R. Kelly Station. Additionally, three internal combustion engines located at the Alachua County Southwest Landfill provide 2.28 MW of generating capacity.

The present summer net capability is 612 MW and the winter net capability is 631 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 three internal combustion engines that run on landfill gas.

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[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.

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 fueled steam turbines comprise 54.6% of the System's net summer capability and produced 82.9% of the electric energy supplied by the System in 2003. 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 11.0% of the electric energy supplied by the System in 2003. 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 4.9% of total electric energy in 2003. 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 1.2% of the electric energy supplied by the System in 2003. 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's three new internal combustion engines are located at the Southwest Landfill Gas to Energy Project and represent 0.3% of the installed capacity. They are operated as continuously as possible (base load units).

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 facilities 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 three 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 has three internal combustion generating sets with a combined capacity of 2.28

MW of green power. 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.

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 one transmission level voltage substation (Parker). 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 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.

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. Approximately 400 residences 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.

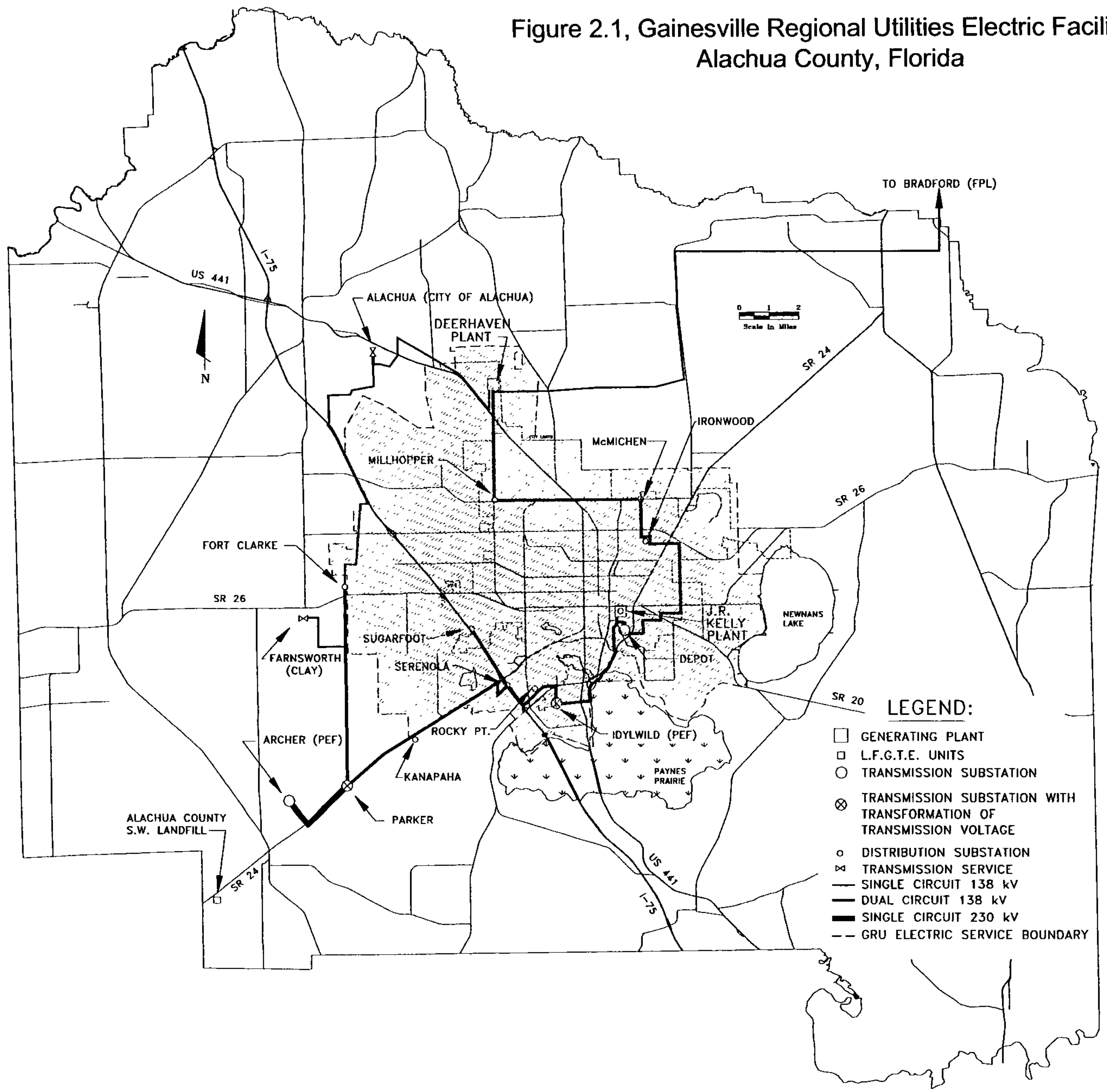
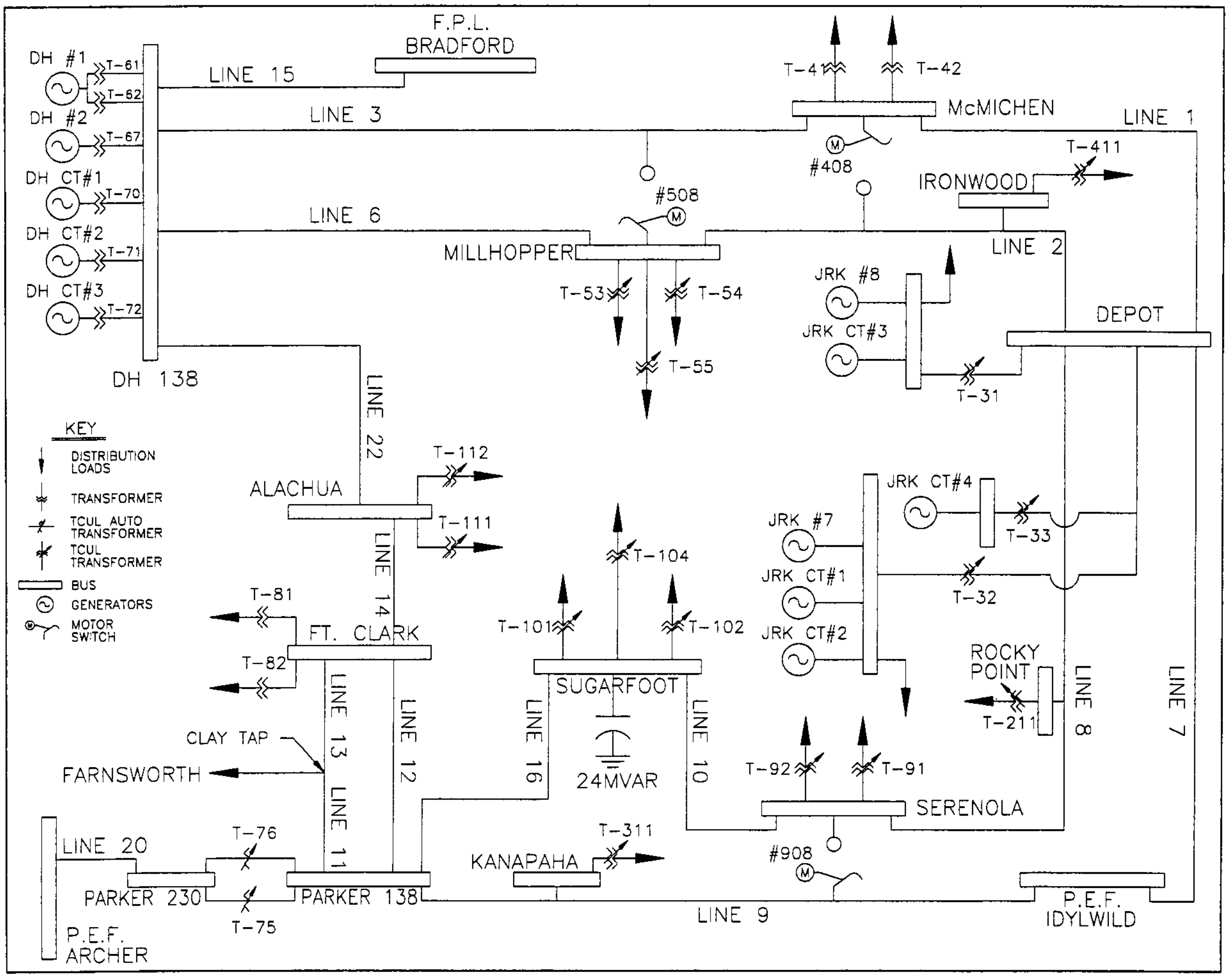


Figure 2.1, Gainesville Regional Utilities Electric Facilities
Alachua County, Florida

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



Schedule 1
EXISTING GENERATING FACILITIES

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Primary Fuel Type	(6) Primary Fuel Trans.	(7) Alternate Fuel Type	(8) Alternate Fuel Trans.	(9) Alt. Fuel Storage (Days)	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gross Capability Summer MW	(13) Gross Capability Winter MW	(14) Net Capability Summer MW	(15) Net Capability Winter MW	(16) 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	3	Citrus County	ST	NUC	TK				3/77	2037	11	11	11	11	OP
(818/815)		Section 33													
		Township 17 S													
		Range 16 E													
		(FPC)													
SW Landfill		Alachua County									2.46	2.46	2.28	2.28	
		Section 19													
	SW-1	Township 11 S	IC	LFG	PL				12/03	12/09	0.82	0.82	0.76	0.76	OP
	SW-2	Range 18 E	IC	LFG	PL				12/03	12/15	0.82	0.82	0.76	0.76	OP
	SW-3	(GRU)	IC	LFG	PL				12/03	12/18	0.82	0.82	0.76	0.76	OP
System Total													612	631	

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

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 trap's 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	17
McMichen	44.8 MVA	6
Millhopper	100.8 MVA	10
Serenola	67.2 MVA	8
Sugarfoot	100.8 MVA	8
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 1994-2013. 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 2003. 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 2004 (Bulletin No. 138), 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 1984-2003, representing "normal" weather conditions.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2003, 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 3% 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. The BEBR projected income levels for Alachua County in The Florida Long-Term Economic Forecast 2002.

(6) The Florida Long-Term Economic Forecast 2002 and Florida Population Studies, Bulletin 137, were used to estimate and project average household size (number of persons per household) in Alachua County.

(7) The Florida Agency for Workforce Innovation and the U.S. Department of Labor provided historical estimates of non-agricultural employment in Alachua County. The Florida Long-Term Economic Forecast 2002 was the source for projections of non-agricultural employment.

(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 Florida Power Corporation 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 2004 through 2013. 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:

$$RESAVUSE = 4104.8 + 0.078\,(HHY03) - 8.59\,(RESPR03) + 0.66\,(HDD) + 0.85\,(CDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use Per Customer
HHY03	=	Average Household Income
RESPR03	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
CDD	=	Annual Cooling Degree Days

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

Adjusted R^2 = 0.9111
DF (error) = 27 (period of study, 1971-2003)
t - statistics:
Intercept = 3.26
HHY03 = 6.33
RESPR03 = -2.18
HDD = 4.01
CDD = 4.61

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 residential customer model specifications are:

RESCUS = *-26975 + 430.92 (POP)*
Where:
RESCUS = Number of Residential Customers
POP = Alachua County Population (thousands)
Adjusted R^2 = 0.9952
DF (error) = 23 (period of study, 1978-2003)
t - statistics:
Intercept = -23.6
POP = 70.3

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 enter the General Service Demand (GSD) class. This option offers potential benefit to GSN customers that use high amounts of energy, and 248 customers have elected to voluntarily transfer to the GSD class since 1990. Many of the existing customers likely to benefit from this rate option have already elected the change, so the forecast assumes that only ten additional GSN customers per year will voluntarily elect the GSD rate. 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	=	0.6901
DF (error)	=	21 (period of study, 1979-2003)
t - statistics:		
Intercept	=	11.63
OPTDCUST	=	-6.89
CDD	=	1.95

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:

$$GSNCUS = -4689.6 + 56.4\ (POP)$$

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.9845
DF (error)	=	23 (period of study, 1978-2003)
t - statistics:		
Intercept	=	-17.4
POP	=	39.1

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:

$$GSDAVUSE = 340.2 + 0.0086\,(PCY03) - 0.18\,(OPTDCUST)$$

Where:

GSDAVUSE	=	Average annual energy use by GSD Customers
PCY03	=	Per Capita Income in Alachua County
OPTDCUST	=	Cumulative number of Optional Demand Customers
Adjusted R^2	=	0.7502
DF (error)	=	21 (period of study, 1979-2003)

t - statistics:

Intercept	=	14.8
PCY03	=	8.1
OPTDCUST	=	-4.2

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 = *-409.9 + 5.26 (POP)*

Where:

GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.9685
DF (error)	=	23 (period of study, 1978-2003)

t - statistics:

Intercept	=	-11.3
POP	=	27.2

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 2003. 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, is expected to increase due to the periodic expansion 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	=	*11454 + 9.59 (NONAG) - 39.9 (LPPR03)*
Where:		
LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
NONAG	=	Alachua County Nonagricultural Employment (000's)
LPPR03	=	Average Price for 1,000 kWh in the Large Power Sector
Adjusted R^2	=	0.9097
DF (error)	=	25 (period of study, 1976-2003)
t - statistics:		
INTERCEPT	=	6.84
NONAG	=	1.04
LPPR98	=	-3.82

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 less than 1.5% 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	=	*-10968 + 0.47 (RESCUS)*
Where:		
LGTMWH	=	Outdoor Lighting Energy Sales

RESCUS	=	Number of Residential Customers
Adjusted R^2	=	0.9789
DF (error)	=	9 (period of study, 1993-2003)
t - statistics:		
Intercept	=	-7.42
RESCUS	=	21.6

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 2003 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 total county income was the independent variable. Adjusting the history of net energy requirements to include the history of customers transferred between GRU and Clay, which over time have reduced the duplication of facilities by smoothing the boundaries of Clay and GRU, yields energy sales to Clay. The form of this equation is as follows:

$$CLYNEL = -6.87 + 12.18\ (COY03)$$

Where:

CLYNEL = Farnsworth Substation Net Energy (MWh)

COY03 = Total Personal Income (Alachua County)

Adjusted R^2 = 0.9200

DF (error) = 12 (period of study, 1990-2003)

t - statistics:

Intercept = -0.001

COY03 = 12.27

Net energy requirements for Alachua were estimated using a model in which City of Alachua population was the independent variable. The model used to develop projections of sales to the City of Alachua is of the following form:

$$ALANEL = -67900 + 24016\,(ALAPOP)$$

Where:

ALANEL = City of Alachua Net Energy (MWh)

ALAPOP = City of Alachua Population (000's)

Adjusted R^2 = 0.9751

DF (error) = 20 (period of study, 1982-2003)

t - statistics:

Intercept = -15.7

ALAPOP = 28.7

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 (0.95055) is the median of observed historical values from 1983 through 2003.

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. Adjustments to forecasted seasonal peak demands were made to reflect 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 2003.

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 2003, as well as projected program implementations scheduled through 2013. 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 and loans for solar water heating; 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; 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

GRU plans to implement additional DSM programs beginning 2005 that will address high-efficiency air conditioning, heat recovery, duct leakage, heat pipes, reflective roof coatings, thermal storage and window shading. 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 issued a Request for Proposals for Innovative Demand-Side Mangement 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.

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 additional DSM programs is expected to provide an incremental impact of 6 MW of summer peak reduction, 7 MW of winter peak reduction, and 30 GWh of annual energy savings by the year 2013. The System's projections of energy sales and peak demands reflect the effects of these DSM programs. Table 3.1 gives total annual effects of GRU's DSM programs from 1980-2013, and Table 3.2 gives the incremental impacts of additional programs added for the period 2004-2013. 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. Most recently, 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.

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 2003, oil-fired generation comprised 4.4% of total net generation, natural gas-fired generation contributed 23.2%, nuclear fuel contributed 4.9%, and coal-fired generation provided 67.5% 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 2.28 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

Forecast prices for each type of fossil fuel analyzed by GRU were generally developed in two parts. Short-term monthly forecasts extending through 2004 were developed in-house by GRU's Fuels Department staff. Long-term fuel price forecasts were developed based upon forecasts of the U.S. Department of Energy's Energy Information Administration (EIA) as published in the Annual Energy Outlook 2003. In essence, the end-point of the GRU short-term forecasts became the starting point for the long-term forecasts, subject to adjustment such that escalation rates within the long-term forecasts were consistent with those in EIA forecasts. EIA's "real price" projections were converted to "nominal dollars" by application of EIA's forecast Implicit Price Deflator. The costs of transporting fossil fuels were forecast separately from fuel commodity costs. Forecast fuel commodity costs and transportation costs were aggregated to develop forecast delivered fuel costs. The following documentation describes GRU's fuel price forecasts by fuel type, which were prepared in May 2003.

3.5.1 Oil

GRU does not have access to waterborne deliveries of oil and there are no pipelines in this area. Consequently, GRU relies on "spot" or as needed purchases from nearby vendors. The cost for purchasing and then trucking relatively insignificant quantities of oil to GRU's generating sites usually makes oil the most expensive and less favored of fuel sources available to GRU. Accordingly, short-term oil price forecasts for No.6 (residual oil) and No.2 (distillate or diesel oil) were based on actual costs to GRU over the past five years and on near term expectations for this limited market. An additional cost component, representing freight charges, was added to yield the final delivered oil price forecasts.

During calendar year 2003, No. 2 oil was used to produce 0.20% of GRU's total net generation. Over the next 10 years, the price of No.2 oil delivered to GRU is expected to increase 2.7% annually while the actual volume of oil used remains small. During calendar year 2003, No. 6 oil was used to produce 4.15% of GRU's total net generation. Over the next 10 years, the price of No.6 oil delivered to GRU is expected to increase 2.1% annually while the actual volume of oil used remains small.

3.5.2 Coal

Coal is the primary fuel used by GRU to generate electricity, comprising 67.5% of total net generation during calendar year 2003. Historically, GRU has purchased a low sulfur, high Btu eastern coal for use at its Deerhaven site. An increased demand for coal by utilities beginning in 2001, combined with a tightened supply, contributed to an increase in the market price for coal. Consequently, prices for coal are expected to be higher in the future than in previous forecasts. Resource planning studies require forecasts of two types of coal; low sulfur compliance coal which is presently used in Deerhaven Unit 2, and a medium-high sulfur coal commonly used in a flue gas desulfurization (FGD) unit or circulating fluidized bed (CFB) unit.

The short-term forecast price of low sulfur compliance coal was based on GRU's contractual options with its coal supplier. The long-term forecast price of low sulfur compliance coal was developed by applying the long term EIA forecast in the same manner as explained previously. Base line prices were determined for medium-high sulfur coal by utilizing a combination of acknowledged transactions and confidential state of the trade discussions with buyers and sellers of coal as reported in Coal Week. The base line prices were then escalated by applying the long term EIA forecast in the same manner as described previously.

GRU's long term contract with CSXT allows for delivery of coal through 2019. The short-term forecast transportation rate for all coals was based on actual rates from the pertinent coal supply districts for aluminum cars and four-hour loading facilities and on known contractual provisions. The long-term forecast of transportation rates was developed by applying projections of the Rail Cost Adjustment Factor (RCAF) indices, adjusted and unadjusted, to the short term forecast. The unadjusted RCAF was allowed to grow at a rate of 3% per year, while the adjusted RCAF was held constant through the forecast horizon.

Based on the above factors, the price for coal delivered to GRU is expected to increase at an average annual rate of 1.3% for low sulfur compliance coal, and 1.4% for medium-high sulfur coal, from 2004 through 2013.

3.5.3 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2003, GRU purchased approximately 7.4 million MMBtu for use by both systems. GRU power plants used 67% of the total purchased for GRU during 2003, while the LDC used the remaining 33%.

GRU purchases natural gas via arrangements with producers and marketers connected with the Florida Gas Transmission (FGT) interstate pipeline. The starting point for GRU's gas cost is the weighted average cost of gas (WACOG). The sum of the following components make up GRU's delivered cost of natural gas: the WACOG; Florida Gas Transmission's (FGT) fuel charge; FGT's transportation charge; and FGT's reservation charge.

Short-term natural gas prices were projected based upon recent trends in historical prices and a forecast published by Cambridge Energy Research Associates in May 2003. The long-term forecast was then developed by applying the long term EIA forecast in the same manner as described previously.

Based on the above factors, the price of natural gas delivered to GRU is expected to increase at an annual rate of 3.1% from 2004 through 2013.

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 2.5% per year through the forecast horizon.

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)
	RURAL AND 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
1994	144,852	2.38	649	60,862	10,670	558	7,059	79,024
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	180,356	2.34	881	77,042	11,434	750	9,188	81,580
2005	183,594	2.34	903	78,593	11,493	771	9,410	81,917
2006	186,818	2.33	927	80,145	11,567	793	9,632	82,301
2007	189,925	2.33	950	81,653	11,635	814	9,847	82,698
2008	193,017	2.32	973	83,161	11,704	836	10,063	83,046
2009	195,995	2.32	997	84,626	11,778	857	10,273	83,387
2010	198,957	2.31	1,021	86,092	11,856	878	10,483	83,750
2011	201,993	2.31	1,045	87,557	11,933	900	10,692	84,203
2012	204,829	2.30	1,065	88,979	11,970	920	10,896	84,429
2013	207,551	2.30	1,085	90,358	12,013	939	11,093	84,686

* Commercial represents GS Non-Demand and GS Demand Rate Classes.

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 **				Street and Highway Lighting	Other Sales to Public Authorities	Total Sales to Ultimate Consumers
Year	GWh	Average Number of Customers	Average MWh per Customer	Railroads and Railways GWh	GWh	GWh	GWh
1994	134	13	10,344	0	18	0	1,359
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	182	18	10,103	0	25	0	1,838
2005	183	18	10,145	0	26	0	1,883
2006	183	18	10,186	0	27	0	1,930
2007	184	18	10,226	0	28	0	1,976
2008	185	18	10,265	0	28	0	2,022
2009	185	18	10,305	0	29	0	2,068
2010	186	18	10,344	0	30	0	2,115
2011	187	18	10,383	0	30	0	2,163
2012	188	18	10,422	0	31	0	2,204
2013	188	18	10,459	0	32	0	2,245

** Industrial represents Large Power Rate Class.

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
1994	91	69	1,519	0	67,934
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	152	103	2,093	0	86,248
2005	157	106	2,146	0	88,021
2006	163	109	2,202	0	89,794
2007	168	112	2,256	0	91,518
2008	174	114	2,310	0	93,243
2009	179	117	2,364	0	94,917
2010	185	120	2,419	0	96,592
2011	191	122	2,476	0	98,267
2012	197	125	2,525	0	99,893
2013	202	127	2,575	0	101,469

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
1994	347	21	310	0	0	9	0	7	331
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	467	35	420	0	0	6	0	6	455
2005	478	36	431	0	0	6	0	5	467
2006	490	37	442	0	0	6	0	5	479
2007	501	38	453	0	0	6	0	4	491
2008	511	40	462	0	0	6	0	3	502
2009	523	41	473	0	0	6	0	3	514
2010	534	42	484	0	0	6	0	2	526
2011	546	44	494	0	0	6	0	2	538
2012	558	45	504	0	0	7	0	2	549
2013	569	46	514	0	0	7	0	2	560

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
1994 / 1995	350	25	289	0	0	29	0	7	314
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	415	37	351	0	0	23	0	4	388
2005 / 2006	425	38	362	0	0	22	0	3	400
2006 / 2007	435	39	373	0	0	20	0	3	412
2007 / 2008	444	41	383	0	0	18	0	2	424
2008 / 2009	453	42	394	0	0	16	0	1	436
2009 / 2010	463	43	405	0	0	14	0	1	448
2010 / 2011	473	45	413	0	0	14	0	1	458
2011 / 2012	483	46	421	0	0	15	0	1	467
2012 / 2013	491	47	428	0	0	15	0	1	475
2013 / 2014	501	49	435	0	0	16	0	1	484

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 %
1994	1,581	44	18	1,359	91	69	1,519	52.39%
1995	1,711	43	20	1,449	101	98	1,648	52.11%
1996	1,721	42	21	1,479	105	75	1,659	51.89%
1997	1,726	44	21	1,475	104	82	1,661	50.83%
1998	1,847	47	21	1,595	108	76	1,779	51.28%
1999	1,869	50	21	1,606	109	83	1,798	48.99%
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	2,163	53	17	1,837	152	104	2,093	52.51%
2005	2,213	52	15	1,883	157	106	2,146	52.46%
2006	2,268	52	14	1,930	163	109	2,202	52.48%
2007	2,319	51	12	1,977	168	111	2,256	52.45%
2008	2,370	50	10	2,022	174	114	2,310	52.53%
2009	2,422	49	9	2,068	179	117	2,364	52.50%
2010	2,475	48	8	2,115	185	119	2,419	52.50%
2011	2,535	51	8	2,163	191	122	2,476	52.54%
2012	2,587	54	8	2,204	197	124	2,525	52.50%
2013	2,639	56	8	2,245	202	128	2,575	52.49%

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Schedule 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2003		FORECAST 2004		FORECAST 2005	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	394	171	376	163	388	167
FEB	280	132	342	140	363	144
MAR	309	144	312	148	320	151
APR	328	149	333	150	342	153
MAY	379	187	397	180	407	185
JUN	393	187	434	197	445	202
JUL	417	200	455	215	467	221
AUG	407	198	453	219	465	225
SEP	377	187	429	200	440	205
OCT	329	160	368	170	377	174
NOV	319	145	325	149	333	153
DEC	320	155	350	162	359	166

Schedule 5
FUEL REQUIREMENTS
As Of JANUARY 1, 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
				ACTUAL	ACTUAL	ACTUAL										
	FUEL REQUIREMENTS		UNITS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	NUCLEAR		TRILLION BTU	1	1	1	1	1	1	1	1	1	1	1	1	1
(2)	COAL		1000 TON	574	580	549	577	598	609	611	601	609	612	943	953	969
	RESIDUAL															
(3)		STEAM	1000 BBL	70	2	146	0	0	0	0	0	0	0	0	0	0
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:	1000 BBL	70	2	146	0	0	0	0	0	0	0	0	0	0
	DISTILLATE															
(7)		STEAM	1000 BBL	0	1	1	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	7	4	5	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	7	3	3	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	14	8	9	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS															
(11)		STEAM	1000 MCF	2,677	2,587	2,464	732	671	834	941	1,218	1,503	1,454	91	92	121
(12)		CC	1000 MCF	1,425	1,911	1,914	3,379	3,552	3,526	3,719	3,839	4,007	4,100	888	1,008	1,057
(13)		CT	1000 MCF	810	862	238	1,800	1,750	1,778	2,011	2,313	2,428	2,648	281	297	366
(14)		TOTAL:	1000 MCF	4,912	5,360	4,617	5,912	5,973	6,139	6,671	7,370	7,938	8,202	1,260	1,397	1,545
(15)	Landfill Gas		TRILLION BTU	0.000	0.000	0.005	0.223	0.223	0.223	0.223	0.223	0.148	0.148	0.148	0.148	0.148

Schedule 6.1
ENERGY SOURCES (GWH)
As Of JANUARY 1, 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
				ACTUAL	ACTUAL	ACTUAL										
	ENERGY SOURCES		UNITS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR		GWH	92	103	94	91	83	91	83	91	72	91	83	91	83
(3)	COAL		GWH	1,384	1,217	1,287	1,415	1,468	1,498	1,504	1,481	1,501	1,511	2,264	2,291	2,334
	RESIDUAL															
(4)		STEAM	GWH	36	50	79	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL:	GWH	36	50	79	0	0	0	0	0	0	0	0	0	0
	DISTILLATE															
(8)		STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWH	3	2	3	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	2	1	1	0	0	0	0	0	0	0	0	0	0
(11)		TOTAL:	GWH	5	3	4	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS															
(12)		STEAM	GWH	223	258	213	63	57	71	81	105	129	125	8	8	11
(13)		CC	GWH	158	296	206	374	392	391	413	434	456	470	87	99	106
(14)		CT	GWH	59	80	22	135	131	136	152	175	186	202	20	22	27
(15)		TOTAL:	GWH	440	634	441	572	580	598	646	714	771	797	115	129	144
(16)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
(17)	HYDRO		GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
(18)	Contract & Market Sales/Purchases & Landfill Gas Proj.		GWH	-75	1	110	15	15	15	23	24	20	20	14	14	14
(19)	NET ENERGY FOR LOAD		GWH	1,882	2,008	2,015	2,093	2,146	2,202	2,256	2,310	2,364	2,419	2,476	2,525	2,575

Schedule 6.2
ENERGY SOURCES (%)
As Of JANUARY 1, 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
				ACTUAL	ACTUAL	ACTUAL										
	ENERGY SOURCES		UNITS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(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%	0.00%	0.00%
(2)	NUCLEAR		%	4.89%	5.13%	4.67%	4.35%	3.87%	4.13%	3.68%	3.94%	3.05%	3.76%	3.35%	3.60%	3.22%
(3)	COAL		%	73.54%	60.61%	63.87%	67.62%	68.42%	68.02%	66.67%	64.11%	63.48%	62.47%	91.45%	90.73%	90.64%
	RESIDUAL															
(4)		STEAM	%	1.91%	2.49%	3.92%	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%	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%	0.00%	0.00%
(7)		TOTAL:	%	1.91%	2.49%	3.92%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE															
(8)		STEAM	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	%	0.16%	0.10%	0.15%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	%	0.11%	0.05%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	%	0.27%	0.15%	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NATURAL GAS															
(12)		STEAM	%	11.85%	12.85%	10.57%	3.01%	2.66%	3.22%	3.59%	4.55%	5.46%	5.17%	0.32%	0.32%	0.43%
(13)		CC	%	8.40%	14.74%	10.22%	17.87%	18.27%	17.75%	18.31%	18.79%	19.29%	19.43%	3.51%	3.92%	4.12%
(14)		CT	%	3.13%	3.98%	1.09%	6.45%	6.11%	6.18%	6.74%	7.58%	7.87%	8.34%	0.81%	0.87%	1.05%
(15)		TOTAL:	%	23.38%	31.57%	21.89%	27.33%	27.03%	27.15%	28.64%	30.91%	32.61%	32.94%	4.65%	5.11%	5.59%
(16)	NUG		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(17)	HYDRO		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(18)	OTHER (SPECIFY)		%	-3.99%	0.05%	5.46%	0.70%	0.68%	0.70%	1.01%	1.04%	0.86%	0.83%	0.55%	0.56%	0.54%
(19)	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%	100.00%	100.00%

TABLE 3.1

DEMAND-SIDE MANAGEMENT IMPACTS
TOTAL ANNUAL 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	70,967	35,842	14,866
2001	70,536	34,002	13,788
2002	70,700	32,534	13,111
2003	70,191	31,037	12,425
2004	69,140	29,424	11,818
2005	67,565	27,423	11,224
2006	65,443	24,990	10,657
2007	62,962	22,387	9,972
2008	59,904	19,289	9,238
2009	57,874	16,679	8,807
2010	55,915	14,123	8,378
2011	58,443	14,706	8,791
2012	61,312	15,307	9,336
2013	64,074	15,890	9,843

Notes: Cumulative net impacts from 1990 Conservation Plan and 1995 DSM Plan, including net residual effects from historical implementations as well as planned program implementations.
Conservation measures vintaged corresponding to their useful life.

TABLE 3.2

DEMAND-SIDE MANAGEMENT IMPACTS
INCREMENTAL EFFECT OF PLANNED PROGRAMS

Year	MWh	Winter kW	Summer kW
2004	2,684	684	371
2005	5,679	1,400	911
2006	8,734	2,102	1,491
2007	11,978	2,828	2,146
2008	15,264	3,563	2,821
2009	18,583	4,318	3,505
2010	21,948	5,075	4,225
2011	24,475	5,658	4,637
2012	27,344	6,258	5,182
2013	30,107	6,842	5,690

Notes: Projected impacts from programs planned for 2004-2013.
Net of 2003 estimated cumulative historical program results.

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 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. Schedule 8, included at the end of this section, identifies key parameters for the additional generating capacity currently under discussion.

In consideration of the load forecast, reserve margin requirements, and system reliability, GRU's Electric System will require additional generating capacity by 2011. The lead alternative currently under discussion is a 220 net MW coal/petroleum coke/wood 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. As part of the conceptual plan, the existing coal unit, Deerhaven Unit 2, would be retrofitted with selective catalytic NOx reduction, flue-gas desulphurization, and fabric filter bag house for particulate control. 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.

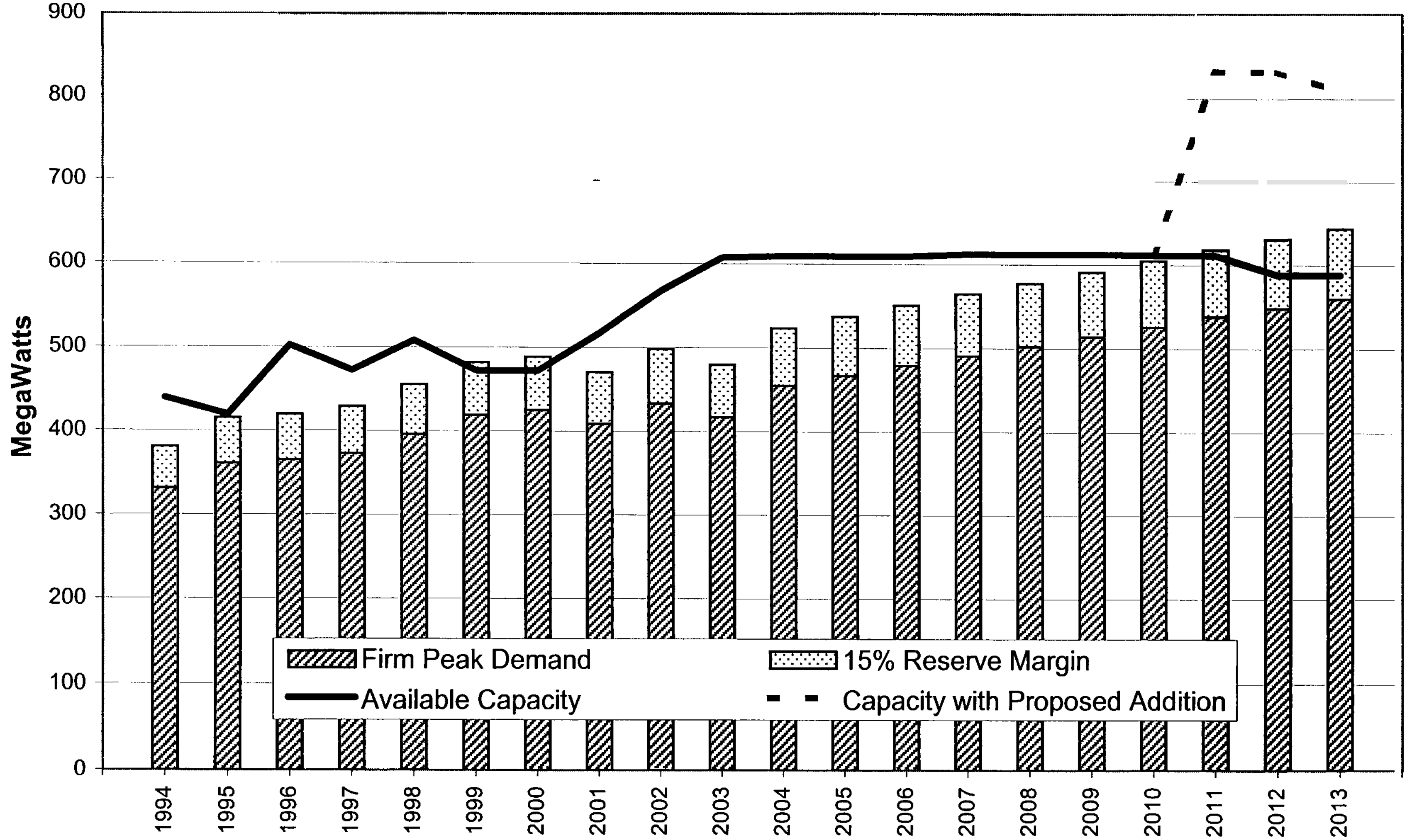
Each PDS will consist of one (or more) 138-12.47 KV, 33.6 MVA, wye-wye substation transformer with a maximum of eight distribution circuits. The proximity of these new PDSs to other, existing adjacent area substations will allow for backup in the event of a substation transformer failure.

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	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin1 before Maintenance		Scheduled Maintenance	Reserve Margin1 after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1994	452	0	13	0	439	331	108	33%	0	108	33%
1995	452	0	33	0	419	361	58	16%	0	58	16%
1996	527	18	43	0	502	365	137	38%	0	137	38%
1997	527	30	85	0	472	373	99	27%	0	99	27%
1998	550	31	73	0	508	396	112	28%	0	112	28%
1999	550	32	110	0	472	419	53	13%	14	39	9%
2000	550	0	78	0	472	425	47	11%	0	47	11%
2001	610	0	93	0	517	409	108	26%	0	108	26%
2002	610	0	43	0	567	433	134	31%	0	134	31%
2003	610	0	3	0	607	417	190	46%	0	190	46%
2004	612	0	3	0	609	455	154	34%	0	154	34%
2005	612	0	3	0	609	467	142	30%	0	142	30%
2006	612	0	3	0	609	479	130	27%	0	130	27%
2007	612	0	0	0	612	491	121	25%	0	121	25%
2008	612	0	0	0	612	502	110	22%	0	110	22%
2009	612	0	0	0	612	514	98	19%	0	98	19%
2010	612	0	0	0	612	526	86	16%	0	86	16%
2011	832	0	0	0	832	538	294	55%	0	294	55%
2012	809	0	0	0	809	549	260	47%	0	260	47%
2013	809	0	0	0	809	560	249	44%	1	248	44%

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

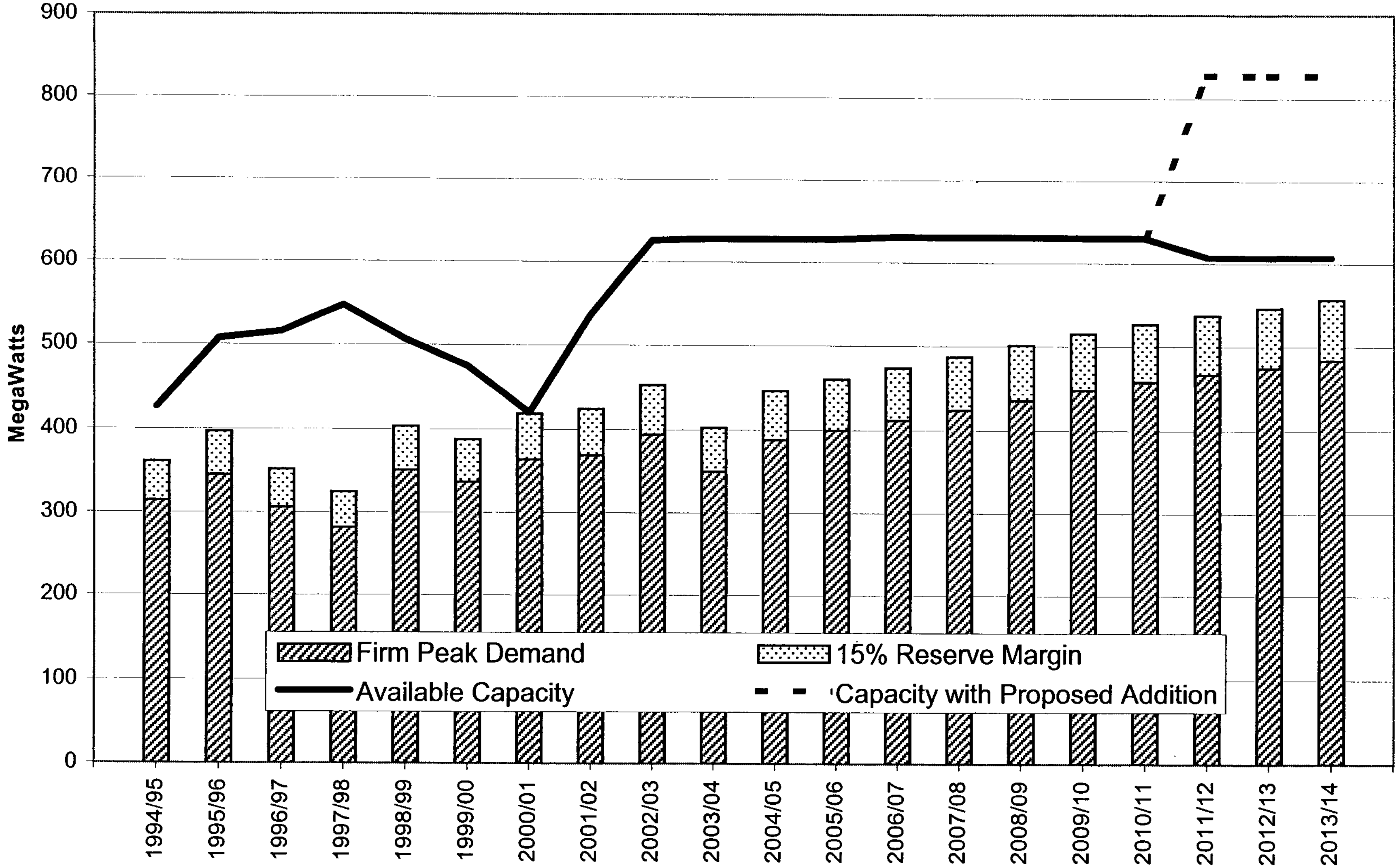
Figure 4.
Summer Peak Demand and eneration Capacity



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 Margin1 before Maintenance		Scheduled Maintenance	Reserve Margin1 after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1994/95	459	0	33	0	426	314	112	36%	0	112	36%
1995/96	540	0	33	0	507	345	162	47%	0	162	47%
1996/97	540	18	43	0	515	306	209	68%	0	209	68%
1997/98	540	30	23	0	547	282	265	94%	0	265	94%
1998/99	563	31	88	0	506	351	155	44%	0	155	44%
1999/00	563	0	88	0	475	337	138	41%	15	123	36%
2000/01	513	0	93	0	420	364	56	15%	0	56	15%
2001/02	629	0	93	0	536	369	167	45%	0	167	45%
2002/03	629	0	3	0	626	394	232	59%	0	232	59%
2003/04	631	0	3	0	628	350	278	79%	0	278	79%
2004/05	631	0	3	0	628	388	240	62%	0	240	62%
2005/06	631	0	3	0	628	400	228	57%	0	228	57%
2006/07	631	0	0	0	631	412	219	53%	0	219	53%
2007/08	631	0	0	0	631	424	207	49%	0	207	49%
2008/09	631	0	0	0	631	436	195	45%	0	195	45%
2009/10	631	0	0	0	631	448	183	41%	0	183	41%
2010/11	631	0	0	0	631	458	173	38%	0	173	38%
2011/12	828	0	0	0	828	467	361	77%	0	361	77%
2012/13	828	0	0	0	828	475	353	74%	0	353	74%
2013/14	828	0	0	0	828	484	344	71%	0	344	71%

Figure 4.2
Winter Peak Demand and Generation Capacity



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	3	12-001 (Alachua Co., Sections 26,27,35, Township 8 S, Range 19 E) (GRU)	ST	BIT/PC/WDS	NG/DFO	RR/TK	PL/TK	5/2006	5/2011	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)	(0.76)	(0.76)	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 (2)	
	a. Field construction start-date:	TBD
	b. Commercial in-service date:	TBD
(5)	Fuel	
	a. Primary Fuel	43% Coal / 43% Petroleum Coke / 14% Wood Biomass
	b. Alternate Fuel	Natural Gas / Distillate Fuel Oil
(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.

(2) TBD - to be determined

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 lead 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, by using reclaimed water. 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, 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 petcoke). This area is lined with natural clay and is equipped with a stormwater runoff collection trench and pond.

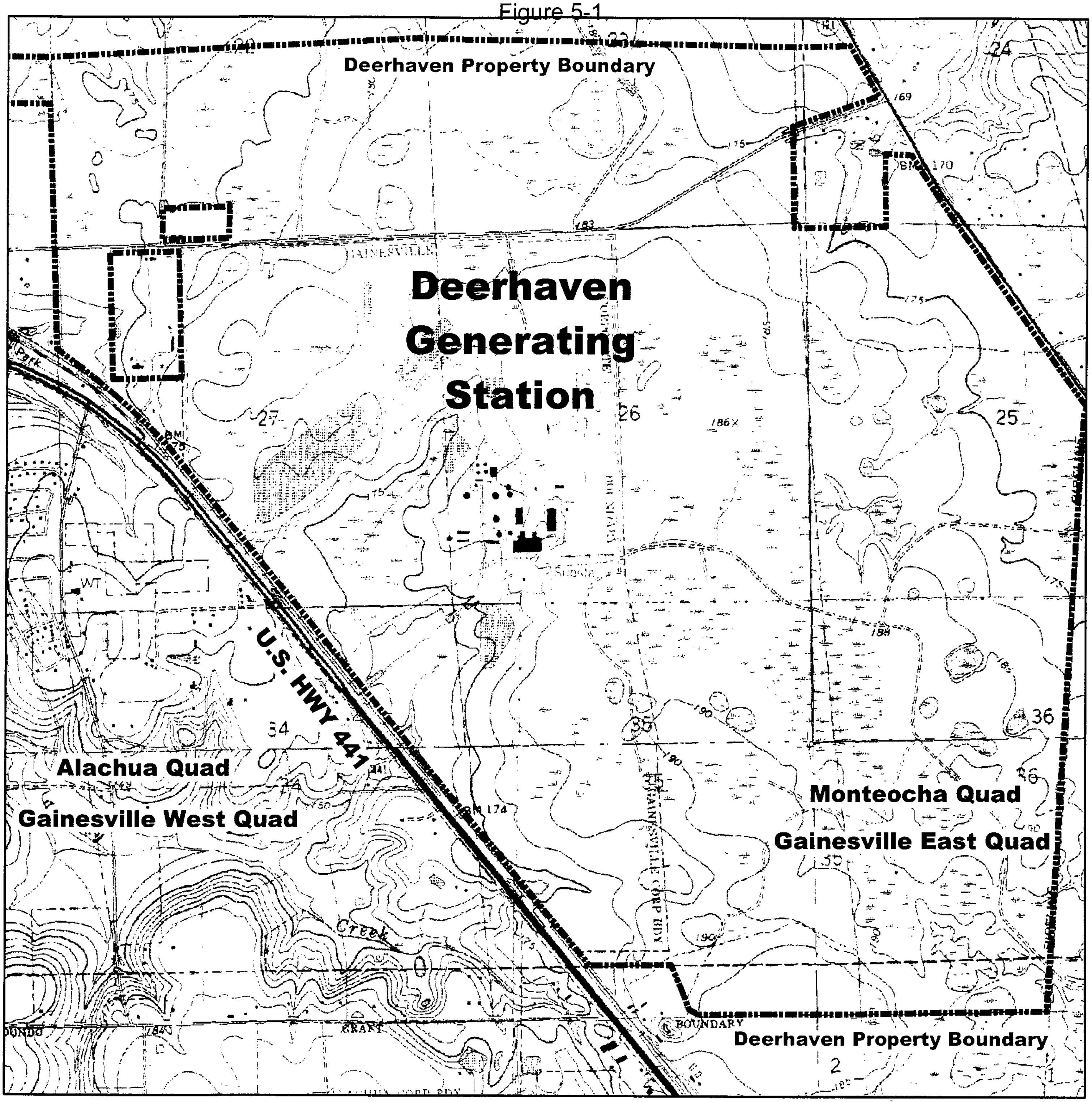
5.2.2 Air Emissions

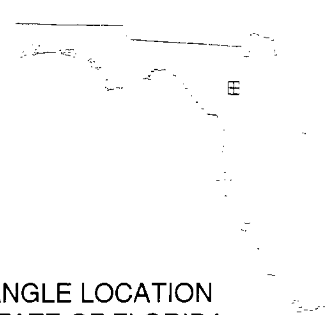
The CFB technology itself minimizes the formation of nitrogen oxides (i.e., NOx) through lower combustion temperatures, and controls SO2 emissions via limestone injection. CFB technology also results in substantial metals removal. A polishing scrubber or a flash dryer absorber may be utilized, if needed,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



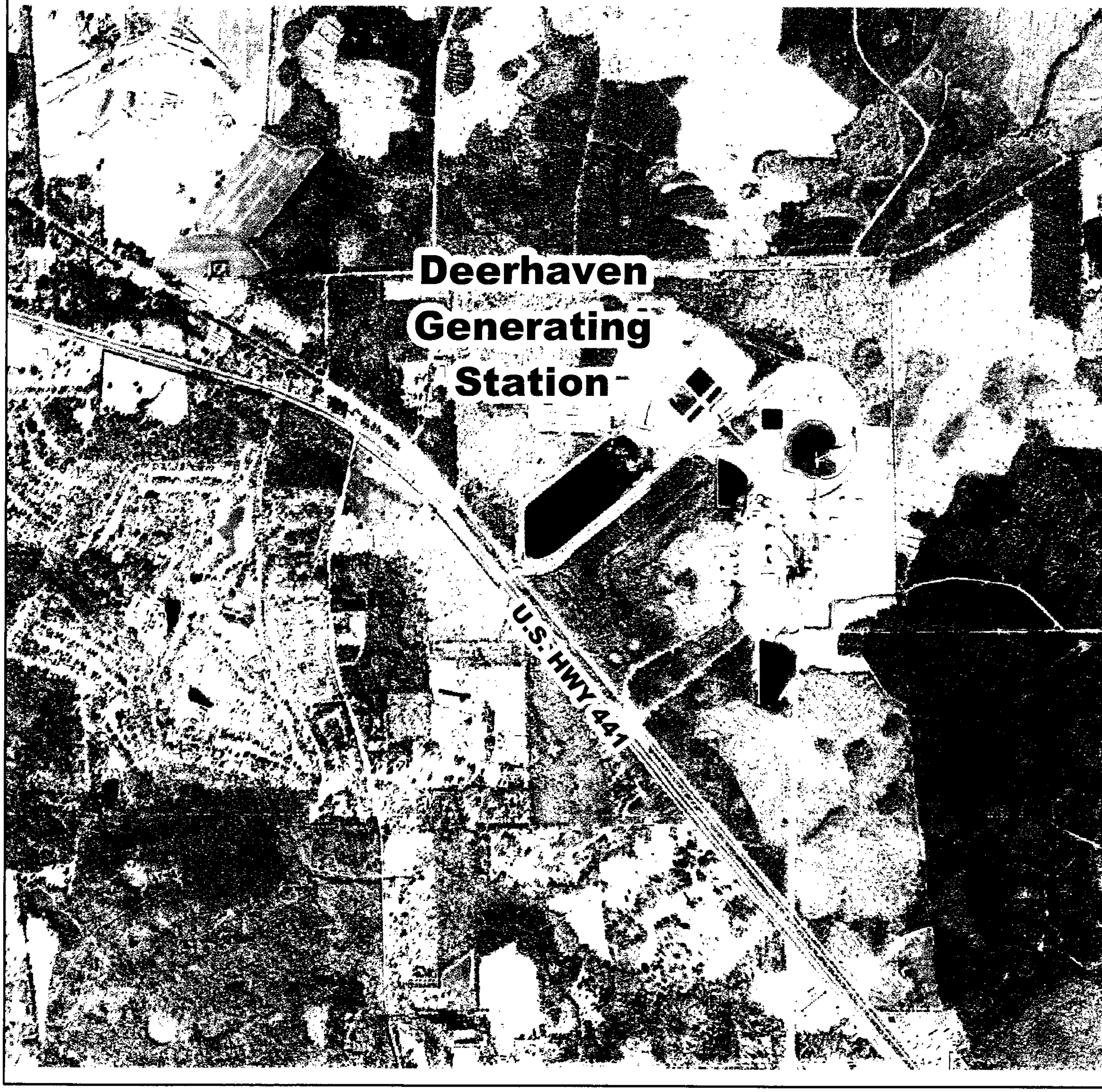


QUADRANGLE LOCATION
WITHIN STATE OF FLORIDA

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

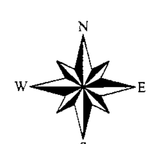
Location Map:
Deerhaven Generating Station

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



SITE LOCATION
WITHIN STATE OF FLORIDA

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



Aerial Photos:
Deerhaven Generating Station