GAINESVILLE REGIONAL UTILITIES

2012 TEN-YEAR SITE PLAN

GRU100

100 YEARS of SERVICE | 1912-2012

Submitted to:

The Florida Public Service Commission

April 1, 2012

Table of Contents

INTRODUCTION

The 2012 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/RAD 043-E, as specified by Rule 25-22.072, Florida Administrative Code. The four sections of the 2012 Ten-Year Site Plan are:

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

Gainesville Regional Utilities (GRU) 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 481 Megawatts on August 8, 2007.

1. DESCRIPTION OF EXISTING FACILITIES

Gainesville Regional Utilities (GRU) operates a fully vertically-integrated electric power production, transmission, and distribution system (herein referred to as "the System"), and is wholly owned by the City of Gainesville. In addition to retail electric service, GRU also provides wholesale electric service to the City of Alachua (Alachua) and Clay Electric Cooperative (Clay). GRU's distribution system serves its retail territory of approximately 124 square miles and an average of 92,265 customers during 2011. The general locations of GRU electric facilities and the electric system service area are shown in Figure 1.1.

1.1 GENERATION

The existing generating facilities operated by GRU are tabulated in Schedule 1 at the end of this chapter. The present summer net capability is 610 MW and the winter net capability is 630 MW[1]. Currently, the System's energy is produced by three fossil fuel steam turbines, seven simple-cycle combustion turbines, one combined-cycle unit, and a 1.4079% ownership share of the Crystal River 3 (CR3) nuclear unit operated by Progress Energy Florida (PEF).

The System has two primary generating plant sites -- Deerhaven and John R. Kelly (JRK). Each site is comprised of both steam-turbine and gas-turbine generating units. The JRK station also utilizes a combined cycle unit.

[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.

1.1.1 Generating Units

1.1.1.1 Simple-Cycle Steam and Combined Cycle Units. The System's three operational simple-cycle steam turbines are powered by fossil fuels. CR3 is nuclear powered. The fossil fueled steam turbines comprise 54.1% of the System's net summer capability and produced 80.7% of the electric energy supplied by the System in 2011. These units range in size from 23 MW to 232 MW. The combined-cycle unit, which includes a heat recovery steam generator/turbine and combustion turbine set, comprises 18.4% of the System's net summer capability and produced 16.8% of the electric energy supplied by the System in 2011. The System's 11.9 MW share of CR3 comprises 1.9% of the System's net summer capability, but due to the outage during all of 2011, no energy was received from CR3. Deerhaven Unit 2 and CR3 have historically been used for base load purposes, while JRK Unit 7, JRK CC1, and Deerhaven Unit 1 have been used for intermediate loading.

1.1.1.2 Gas Turbines. The System's six industrial gas turbines make up 25.6% of the System's summer generating capability and produced 2.5% of the electric energy supplied by the System in 2011. 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 quickly. 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.

1.1.1.3 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 currently has flue gas cleaning equipment consisting of a “hot-side” electrostatic precipitator. Installation of a selective catalytic reduction system to reduce NO_x, and a dry flue gas desulfurization unit with fabric filters to reduce SO_2, mercury, and particulates, was completed in 2009. Operation of this equipment decreases net output for Deerhaven 2 by 6 MW.

1.1.2 Generating Plant Sites

The locations of the System's generating plant sites are shown on Figure 1.1.

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

1.1.2.2 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, includes 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 potential expansion area, owned by the System and adjacent to the certified Deerhaven plant site, was incorporated into the Gainesville City limits February 12, 2007 (ordinance 0-06-130), consists of an additional 2328 acres, for a total of 3474 acres. On September 28, 2009 GRU entered into a 47 year lease of approximately 13 acres of property to the Gainesville Renewable Energy Center, LLC. The property is in the northwest corner of the site and will be the location of a net 100 MW capacity biomass fuel power generating facility due to come on line in 2013.

1.2 TRANSMISSION

1.2.1 The Transmission Network

GRU's bulk electric power transmission network (System) consists of a 230 kV radial and a 138 kV loop connecting the following:

1) GRU's two generating stations,
2) GRU's ten distribution substations,
3) One 230 kV and two 138 kV interties with Progress Energy Florida (PEF),
4) A 138 kV intertie with Florida Power and Light Company (FPL),
5) A radial interconnection with Clay at Farnsworth Substation, and
6) A loop-fed interconnection with the City of Alachua at Alachua No. 1 Substation.

Refer to Figure 1.1 for line geographical locations and Figure 1.2 for electrical connectivity and line numbers.

1.2.2 Transmission Lines

The ratings for all of GRU's transmission lines are given in Table 1.1. 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 1.2 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, Inc. (FRCC) studies that 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.

1.2.3 State Interconnections

The System is currently interconnected with PEF and FPL at four separate points. The System interconnects with PEF's Archer Substation via a 230 kV transmission line to the System's Parker Road 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 their 150 MVA 138/69 kV transformer. 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 transformation capacity at Bradford Substation of 224 MVA. All listed capacities are based on normal (Rating A) capacities.

The System is planned, operated, and maintained to be in compliance with all FERC, NERC, and FRCC requirements to assure the integrity and reliability of Florida's Bulk Electric System (BES).

1.3 DISTRIBUTION

The System has seven loop-fed and three radial distribution substations connected to the transmission network: Ft. Clarke, Kelly, McMichen, Millhopper, Serenola, Springhill, Sugarfoot, Ironwood, Kanapaha, and Rocky Point substations, respectively. Parker Road is GRU's only 230 kV transmission voltage substation. The locations of these substations are shown on Figure 1.1.

The seven loop fed distribution substations are connected to the 138 kV bulk power transmission network with feeds which prevent the outage of a single transmission line from causing any 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 experiences an outage. GRU serves its retail customers through a 12.47 kV distribution network. The distribution substations, their present rated transformer capabilities, and the number of circuits for each are listed in Table 1.2. The System has three Power Delivery Substations (PDS) with single 33.6 MVA transformers that are directly radial-tapped to our looped 138 kV system. The new Springhill Substation consist of one 33.3 MVA transformer served by a loop fed SEECO pole mounted switch. Ft. Clarke, Kelly, McMichen, and Serenola substations currently consist of two transformers of basically equal size allowing these stations to be loaded under normal conditions to 80 percent of the capabilities shown in Table 1.2. 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 1.2. One of the two 22.4 MVA transformers at Ft. Clarke has been repaired with rewinding to a 28.0 MVA rating. This makes the normal rating for this substation 50.4 MVA.

1.4 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 System 2.37 mile radial line connected to the System's transmission facilities on Parker Road near SW 24th Avenue.

The System also provides full requirements wholesale electric service to the City of Alachua. The Alachua No. 1 Substation is supplied by GRU's looped 138 kV transmission system. The System provides approximately 94% of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from the PEF’s Crystal River 3 and FPL’s St. Lucie 2 nuclear units. Energy supplied to the City of 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. The System began serving the City of Alachua in July 1985 and has provided full requirements wholesale electric service since January 1988. A 10-year extension amendment was approved in 2010 and made effective on January 1, 2011.

Wholesale sales to Clay and the City of Alachua have been included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins. This forms a conservative basis for planning purposes in the event these contracts are renewed. Schedules 7.1 and 7.2 at the end of Section 3 summarize GRU’s reserve margins.

1.5 DISTRIBUTED GENERATION

The South Energy Center began commercial operation in May 2009. The South Energy Center provides multiple onsite utility services to the new Shands at UF South Campus hospital. The new facility houses a 4.1 MW (summer rating) natural gas-fired turbine capable of supplying 100% of the hospital's electric and thermal needs. The South Energy Center provides electricity, chilled water, steam, and the storage and delivery of medical gases to the hospital. The unique design is 75% efficient at primary fuel conversion to useful energy and greatly reduces emissions compared to traditional generation. The facility is designed to provide electric power into the GRU distribution system when its capacity is not totally utilized by the hospital.

Figure 1.1, Gainesville Regional Utilities Electric Facilities
Alachua County, Florida

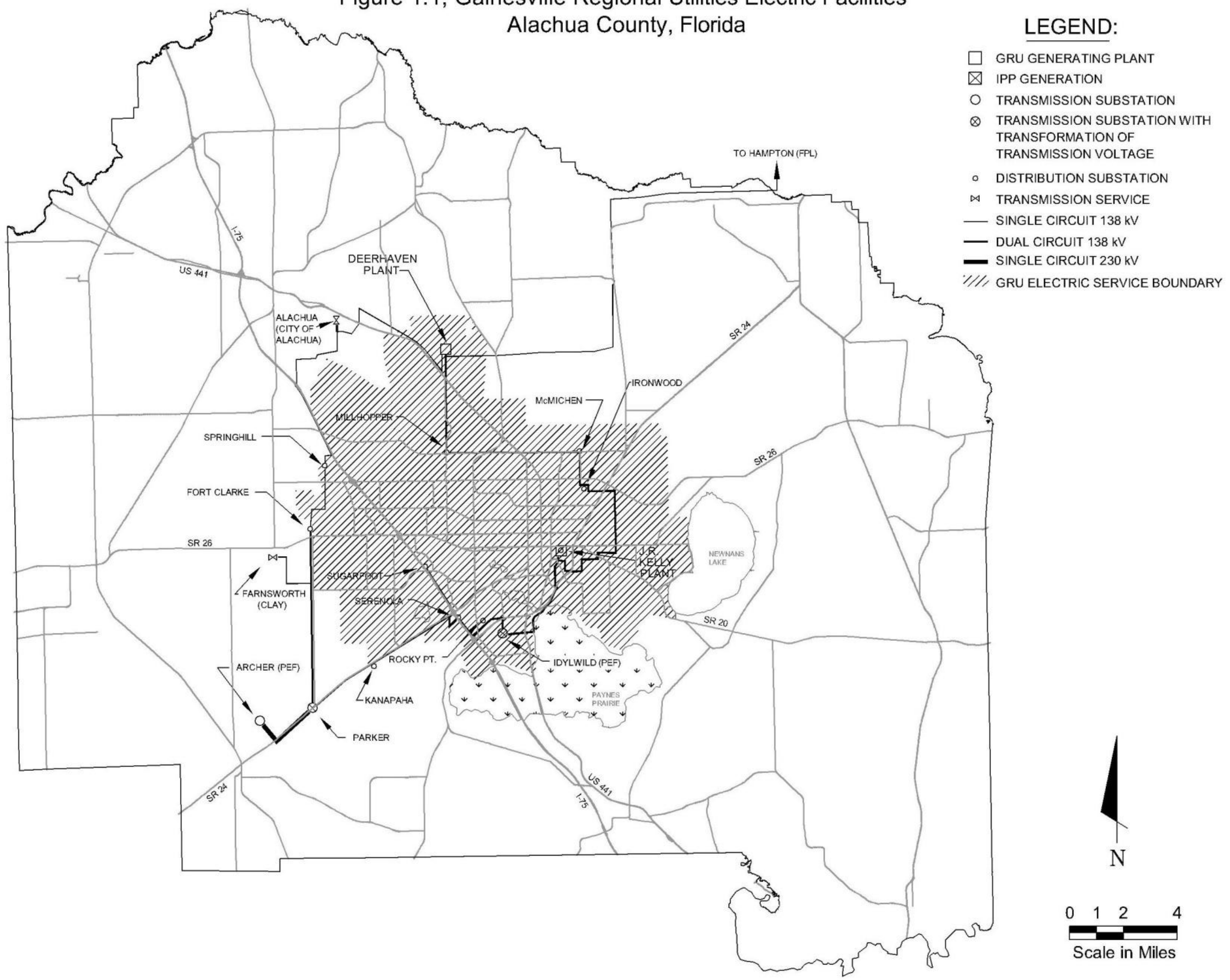
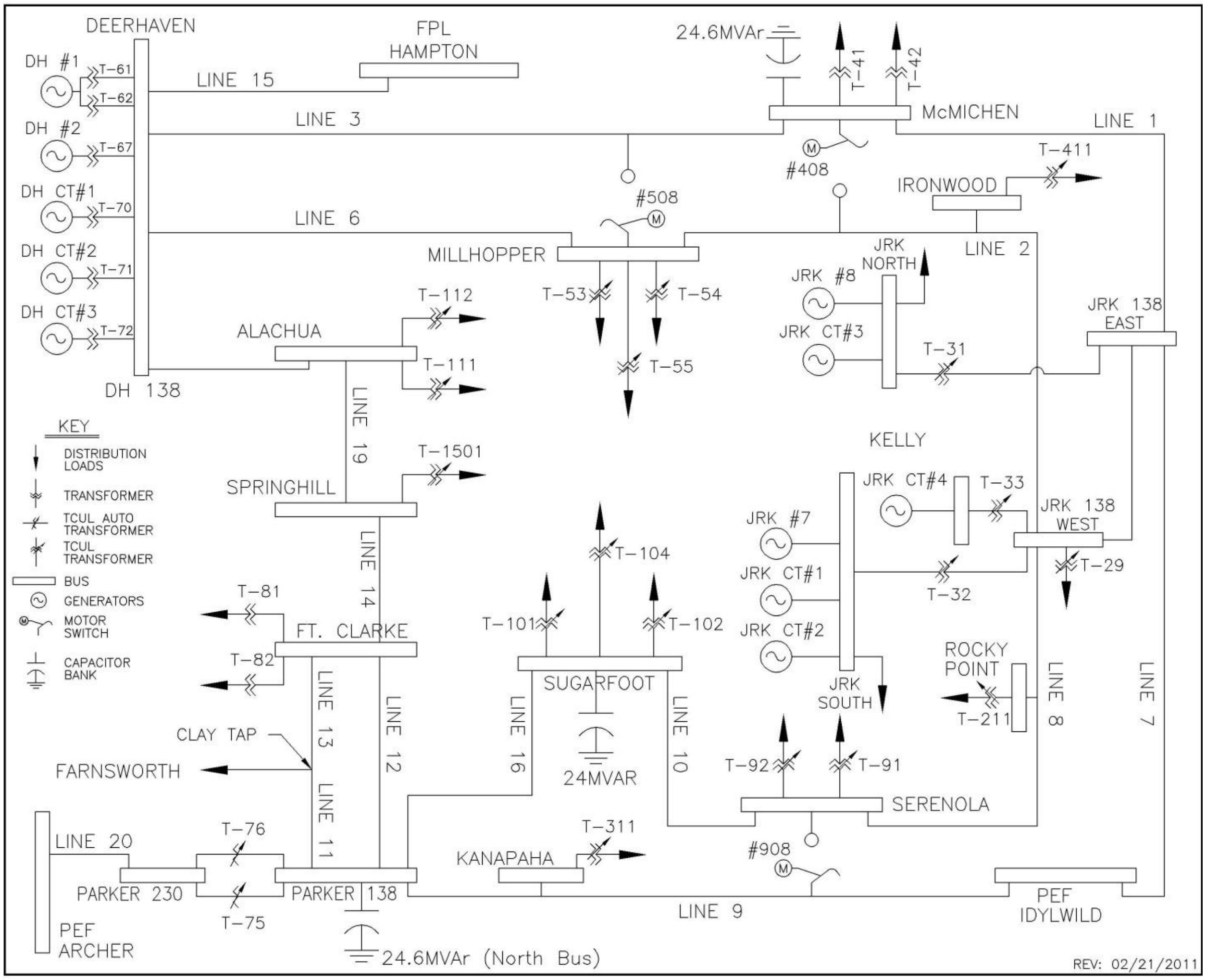


FIGURE 1.2 Gainesville Regional Utilities Electric System One-Line Diagram.



Schedule 1

EXISTING GENERATING FACILITIES (as of January 1, 2012)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Primary Fuel		Alternate Fuel		Alt. Fuel Storage	Commercial In-Service	Expected Retirement	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Type	Trans.	Type	Trans.	(Days)	Month/Year	Month/Year	Summer MW	Winter MW	Summer MW	Winter MW	Status
J. R. Kelly		Alachua County									**180.0**	**189.0**	**177.2**	**186.2**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL				[4/65 ; 5/01]	2051	38.0	38.0	37.0	37.0	OP
	FS07	(GRU)	ST	NG	PL	RFO	TK		8/61	10/15	24.0	24.0	23.2	23.2	OP
	GT04		CT	NG	PL	DFO	TK		5/01	2051	76.0	82.0	75.0	81.0	OP
	GT03		GT	NG	PL	DFO	TK		5/69	05/19	14.0	15.0	14.0	15.0	OP
	GT02		GT	NG	PL	DFO	TK		9/68	09/18	14.0	15.0	14.0	15.0	OP
	GT01		GT	NG	PL	DFO	TK		2/68	02/18	14.0	15.0	14.0	15.0	OP
Deerhaven		Alachua County									**448.0**	**458.0**	**417.0**	**428.0**	
	FS02	Secs. 26,27,35	ST	BIT	RR				10/81	2031	255.0	255.0	232.0	232.0	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	08/22	79.0	79.0	75.0	75.0	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	76.0	82.0	75.0	81.0	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	19.0	21.0	17.5	20.0	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	19.0	21.0	17.5	20.0	OP
Crystal River	3	Citrus County Sec. 33, T17S, R16E	ST	NUC	TK				3/77	2037	**13.5**	**13.7**	**11.9**	**12.1**	OP
South Energy Center Distributed Generation	GT1	Alachua County SEC. 10, T10S, R20E	GT	NG		PL			5/09		**4.5**	**4.5**	**4.1**	**4.1**	OP
System Total													**610.2**	**630.4**	

Unit Type
CA = Combined Cycle - Steam Part
CT = Combined Cycle - CT Part
GT = Gas Turbine
ST = Steam Turbine

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

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

Status
OP = Operational

TABLE 1.1

TRANSMISSION LINE RATINGS
SUMMER POWER FLOW LIMITS

Line Number	Description	Normal 100°C (MVA)	Limiting Device	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	236.2	Conductor	282.0	Conductor
8	Depot West - Serenola	236.2	Conductor	282.0	Conductor
9	Idylwild - Parker	236.2	Conductor	236.2	Conductor
10	Serenola - Sugarfoot	236.2	Conductor	282.0	Conductor
11	Parker - Clay Tap	143.6	Conductor	282.0	Conductor
12	Parker - Ft. Clarke	236.2	Conductor	282.0	Conductor
13	Clay Tap - Ft. Clarke	143.6	Conductor	186.0	Conductor
14	Ft. Clarke - Springhill	287.3	Switch	356.0	Conductor
15	Deerhaven - Hampton	224.0[1]	Transformers	270.0	Transformers
16	Sugarfoot - Parker	236.2	Conductor	282.0	Conductor
19	Springhill - Alachua	287.3	Switch	356.0	Conductor
20	Parker-Archer(T75,T76)	224.0	Transformers[3]	300.0	Transformers[3]
22	Alachua - Deerhaven	287.3	Switch	356.0	Conductor
xx	Clay Tap - Farnsworth	236.2	Conductor	282.0	Conductor
xx	Idylwild – PEF	150.0[2]	Transformer	168.0[2]	Transformer

1) These two transformers are located at the FPL Bradford Substation and are the limiting elements in the Normal and Emergency ratings for this intertie.

2) This transformer, along with the entire Idylwild Substation, is owned and maintained by PEF.

3) Transformers T75 & T76 normal limits are based on a 65° C temperature rise rating, and the emergency rating is 140% loading for two hours.

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

TABLE 1.2

SUBSTATION TRANSFORMATION AND CIRCUITS

Distribution Substation	Normal Transformer Rated Capability	Current Number of Circuits
Ft. Clarke	50.4 MVA	4
J.R. Kelly[2]	168.0 MVA	20
McMichen	44.8 MVA	6
Millhopper	100.8 MVA	10
Serenola	67.2 MVA	8
Springhill	33.3 MVA	2
Sugarfoot	100.8 MVA	9
Ironwood	33.6 MVA	3
Kanapaha	33.6 MVA	3
Rocky Point	33.6 MVA	3

Transmission Substation	Normal Transformer Rated Capability	Number of Circuits
Parker	224 MVA	5
Deerhaven	No transformations- All 138 kV circuits	4

2 J.R. Kelly is a generating station as well as 2 distribution substations. One substation has 14 distribution feeders directly fed from the 2- 12.47 kV generator buses with connection to the 138 kV loop by 2- 56 MVA transformers. The other substation (Kelly West) has 6 distribution feeders fed from a single, loop-fed 56 MVA transformer.

2. FORECAST OF ELECTRIC ENERGY AND DEMAND REQUIREMENTS

Section 2 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 2002-2021. 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 presents net energy for load for the base case forecast by reporting category. Short-term monthly load data is presented in Schedule 4. Projected sources of energy for the System, by method of generation, are shown in Schedule 6.1. The percentage breakdowns of energy sources 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.

2.1 FORECAST ASSUMPTIONS AND DATA SOURCES

(1) All regression analyses were based on annual data. Historical data was compiled for calendar years 1970 through 2011. 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 Bureau of Economic and Business Research at the University of Florida. Population projections were taken from BEBR Bulletin 162, February 2012.

(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 1984-2011.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2011, 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 2.5% per year for each year of the forecast.

(5) The U.S. Department of Commerce, Bureau of Economic Analysis, provided historical estimates of total personal income. Forecast values of total personal income were obtained from Global Insight.

(6) Historical estimates of household size were obtained from BEBR, and projected levels were estimated from a logarithmic trend.

(7) The U.S. Department of Labor, Bureau of Labor Statistics, provided historical estimates of non-farm employment. Forecast values of non-farm employment were obtained from Global Insight.

(8) Retail electric prices for each billing rate category were assumed to increase at a rate of 3% in the first year of this forecast, tapering to 2.8% by 2031. Prices are expressed in dollars per 1,000 kWh.

(9) Estimates of energy and demand reductions resulting from planned demand-side management programs (DSM) were subtracted from all retail forecasts. GRU has been involved in formal conservation efforts since 1980. The forecast reduces energy sales and seasonal demands by the projected conservation impacts, net of cumulative impacts from 1980-2011. GRU's involvement with DSM is described in more detail later in this section.

(10) Sales to Clay (Seminole Electric Cooperative) and Alachua (City of Alachua) were assumed to continue through the duration of this forecast. The agreement to serve Clay currently runs through December 2012 and the agreement to serve Alachua was recently renewed through December 2020. This forecast assumes these agreements will be renewed as they near maturity. Alachua’s ownership in PEF and FPL nuclear units supplied approximately 6% of its annual energy requirements in 2011.

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

Number of customers, energy sales and seasonal peak demands were forecast from 2012 through 2021. 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)[1]. The following text describes the regression equations utilized to forecast energy sales and number of customers.

2.2.1 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 residential price of electricity, heating degree days, and cooling degree days. The form of this equation is as follows:

RESAVUSE = *14314 - 44.33 (RESPR11 + 0.73 (HDD) + 0.30 (CDD)*

Where:

RESAVUSE = Average Annual Residential Energy Use Per Customer

RESPR11 = Residential Price, Dollars per 1000 kWh

HDD = Annual Heating Degree Days

CDD = Annual Cooling Degree Days

[1] SAS is the registered trademark of SAS Institute, Inc., Cary, NC.

Adjusted R^2	=	0.8862
DF (error)	=	15 (period of study, 1993-2011)
t - statistics:		
Intercept	=	16.44
RESPR11	=	-11.92
HDD	=	3.28
CDD	=	1.14

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, and the historical series of Clay customer transfers. The residential customer model specifications are:

$$RESCUS = 134019 + 323.6\,(POP) - 59001\,(HHSize) + 1.23\,(CLYRCus)$$

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
HHSize	=	Number of Persons per Household
CLYRCus	=	Clay Residential Customer Transfers
Adjusted R^2	=	0.9944
DF (error)	=	15 (period of study, 1993-2011)
t - statistics:		
Intercept	=	1.58
POP	=	7.71
HHSize	=	-1.79
CLYRCus	=	2.20

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

2.2.2 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 relative to their billing demands. Since 1990, 562 customers have elected to transfer to the GSD rate class. The forecast assumes that additional GSN customers will voluntarily elect the GSD classification, but at a more modest pace than has been observed historically. 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, GSN electricity price, and cooling degree days. The specifications of this model are as follows:

GSNAVUSE= 28.63 – 0.013 (OPTDCus) – 0.036 (GNDPR11) + 0.0012 (CDD)

Where:

GSNAVUSE	=	Average annual energy usage by GSN customers
OPTDCus	=	Cumulative number of Optional GSD Customers
GNDPR11	=	GSN Price, Dollars per 1000 kWh
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.9357
DF (error)	=	15 (period of study, 1993-2011)

t - statistics:

Intercept	=	9.01
OPTDCus	=	-9.95
GNDPR11	=	-2.22
CDD	=	1.36

The number of general service non-demand customers was projected using an equation specifying customers as a function of Alachua County population, the number of optional demand customers, and the addition of a group of individually metered cable amplifiers that were previously bulk metered. The specifications of the general service non-demand customer model are as follows:

$$GSNCUS = -3995 + 54.1\,(POP) - 1.19\,(OptDCus) + 1.10\,(CoxTran)$$

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
OptDCus	=	Optional GSD Customers
CoxTran	=	Cable TV Meters
Adjusted R^2	=	0.9921
DF (error)	=	15 (period of study, 1993-2011)

t - statistics:

Intercept	=	-4.42
POP	=	11.45
OptDCus	=	-1.81
CoxTran	=	4.46

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.

2.2.3 General Service Demand Sector

The general service demand customer class includes non-residential customers with average billing 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 the price of electricity, the number of optional demand customers, and cooling degree days. Average energy use projections for general service demand customers result from the following model:

$$GSDAVUSE = 520.7 - 0.26\,(DEMPR11) - 0.17\,(OPTDCust) + 0.024\,(CDD)$$

Where:

GSDAVUSE	=	Average annual energy use by GSD Customers
DEMPR11	=	GSD Price, Dollars per 1000 kWh
OPTDCust	=	Cumulative number of Optional GSD Customers
CDD	=	Cooling Degree Days
Adjusted R^2	=	0.9218
DF (error)	=	15 (period of study, 1993-2011)
t - statistics:		
Intercept	=	14.44
DEMPR11	=	-1.61
OPTDCust	=	-11.90
CDD	=	1.99

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

$$GSDCUS = -535.3 + 6.23(POP) + 0.49(OptDCus)$$

Where:		
GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
CLYDCus	=	Clay GSD Transfer Customers
OptDCus	=	Optional GSD Customers
Adjusted R^2	=	0.9917
DF (error)	=	16 (period of study, 1993-2011)
t - statistics:		
Intercept	=	-3.39
POP	=	7.70
OptDCus	=	5.36

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.

2.2.4 Large Power Sector

The large power customer class currently includes eleven customers that maintain an average monthly billing demand of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1993 through 2011. The model developed to project average use by large power customers includes Gainesville MSA non-farm employment and an indicator variable representing a policy change defining eligibility for this rate category. 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 = *8509 + 15.1 (NonFarm) + 3588 (Policy)*

Where:		
LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
NonFarm	=	Gainesville MSA Non-Farm Employment (000's)
Policy	=	Indicator Variable for policy change in 2009
Adjusted R^2	=	0.9333
DF (error)	=	16 (period of study, 1993-2011)
t - statistics:		
INTERCEPT	=	7.31
NonFarm	=	1.58
Policy	=	15.07

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 is projected to remain constant at eleven.

2.2.5 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 natural log of the number of residential customers. The specifications of this model are as follows:

LGTMWH	=	*-299358 + 28961 (LNRESCUS)*
Where:		
LGTMWH	=	Outdoor Lighting Energy Sales
LNRESCUS	=	Number of Residential Customers (natural log)
Adjusted R^2	=	0.9577
DF (error)	=	17 (period of study, 1993-2011)

t - statistics:

Intercept	=	-18.77
RESCUS	=	20.22

2.2.6 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 6% of Alachua's 2011 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. The agreement to provide wholesale power to Alachua was recently renewed, effective from 2011 through 2020. The wholesale agreement with Clay is in effect through December 31, 2012 and renewal of this agreement is assumed in this forecast.

Energy sales to Clay-Farnsworth were modeled using an equation that includes Alachua County population and Heating Degree Days as the independent variables. Historical boundary adjustments between Clay and GRU have reduced the duplication of facilities in both companies’ service areas. The form of the Clay-Farnsworth energy sales equation is as follows:

$$CLYMWh = -207889 + 1137\,(POP) + 7.72\,(HDD)$$

Where:

CLYMWh	=	Energy Sales to Clay (MWh)
POP	=	Alachua County Population (000's)
HDD	=	Heating Degree Days
Adjusted R^2	=	0.9758
DF (error)	=	9 (period of study, 2000-2011)
t - statistics:		
Intercept	=	-15.86
POP	=	20.68
HDD	=	2.82

Energy Sales to Alachua were estimated using a model including City of Alachua population and heating degree days as the independent variables. 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:

ALAMWh = *-55241 + 18883 (ALAPOP) + 6.87 (HDD)*

Where:

ALAMWh	=	Energy Sales to the City of Alachua (MWh)
ALAPOP	=	City of Alachua Population (000's)
HDD	=	Heating Degree Days
Adjusted R^2	=	0.9895
DF (error)	=	15 (period of study, 1994-2011)
t - statistics:		
Intercept	=	-12.44
ALAPOP	=	38.33
HDD	=	2.18

2.2.7 Total System Sales, Net Energy for Load, Seasonal Peak Demands and Conservation 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 (NEL) was then forecast by applying a delivered efficiency factor for the System to total energy sales. The projected delivered efficiency factor used in this forecast is 0.9540. Historical delivered efficiencies were examined from the past 25 years to make this determination. The impact of energy savings from conservation programs was accounted for in energy sales to each customer class, prior to calculating NEL.

The forecasts of seasonal peak demands were derived from forecasts of annual NEL. Winter peak demands are projected to occur in January of each year, and summer peak demands are projected to occur in August of each year, although historical data suggests the summer peak is nearly as likely to occur in July. The average ratio of the most recent 25 years' monthly NEL for January and August, as a portion of annual NEL, was applied to projected annual NEL to obtain estimates of January and August NEL over the forecast horizon. The medians of the past 25 years' load factors for January and August were applied to January and August NEL projections, yielding seasonal peak demand projections. Forecast seasonal peak demands include the net impacts from planned conservation programs.

2.3 ENERGY SOURCES AND FUEL REQUIREMENTS

2.3.1 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.

2.3.2 Methodology for Projecting Fuel Use

The fuel use projections were produced using the GenTrader ® program developed by Power Costs, Inc. (PCI), 3550 West Robinson, Suite 200, Norman, Oklahoma 73072. PCI provides support, maintenance, and training for the GenTrader ® software. GenTrader ® has the ability to model each of the System's generating units, as well as purchase options from the energy market, on an hour-by-hour basis and includes the effects of environmental limits, dual fuel units, reliability constraints, maintenance schedules, startup time & startup fuel, and minimum down time for forced outages.

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, and maintenance schedules for each generating unit in the System;

(3) Purchase power & energy options from the market.

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.

2.3.3 Purchased Power Agreements

2.3.3.1 G2 Energy Baseline Landfill Gas. GRU entered a 15-year contract with G2 Energy Marion, LLC and began receiving 3 MW of landfill gas fueled capacity in January 2009. G2 completed a capacity expansion of 0.8 MW in May 2010, bringing net output to 3.8 MW.

2.3.3.2 Progress Energy 50 MW. GRU negotiated a contract with Progress Energy Florida (PEF) for 50 MW of base load capacity. This contract began January 1, 2009 and continues through December 31, 2013. Extensions of this contract are subject to negotiation.

2.3.3.3 Gainesville Renewable Energy Center. The Gainesville Renewable Energy Center (GREC) is a planned 100 MW biomass unit to be built and owned by American Renewables. GRU will purchase all of the output of this unit and anticipates reselling a portion of the output over time. During 2010, GREC received a Determination of Need from the FPSC; Site Certification from the State Siting Board ; and the air construction permit from the Florida Department of Environmental Protection. Construction has begun, and the unit is expected to be online by December 2013.

2.3.3.4 Solar Feed-In Tariff. In March of 2009 GRU became the first utility in the United States to offer a European-style solar feed-in tariff (FIT). Under this program, GRU agrees to purchase 100% of the solar power produced from any qualified private generator at a fixed rate for a contract term of 20 years. The FIT rate has built-in subsidy to incentivize the installation of solar in the community, and help create a strong solar marketplace. GRU’s FIT costs are recovered through fuel adjustment charges, and have been limited to 4 MW of installed capacity per year. Through the end of 2011, approximately 9.3 MW has been constructed under the Solar FIT program. The amount of capacity available for any given calendar year will be the combination of the 4 MW originally allotted under each year, plus any unassigned and unused capacity from the previous year, unless otherwise noted. The exact capacity available to the public each annual period will be announced before the annual application period, along with currently approved tariff rates for the program.

2.4 DEMAND-SIDE MANAGEMENT

2.4.1 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 Demand-Side Management (DSM) programs. The System forecast reflects the incremental impacts of DSM measures, net of cumulative impacts from 1980 through 2011. 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.

DSM direct services currently available to the System's residential customers, or expected to be implemented during 2012, include energy audits and low income household whole house energy efficiency improvements. GRU also offers rebates and other financial incentives for the promotion of:

- super-efficient central air conditioning
- solar water heating
- solar photovoltaic systems
- natural gas in new construction
- Home Performance with the federal Energy Star program
- Green Building practices
- heating/cooling duct repair
- variable speed pool pumps
- energy efficiency for low-income households
- attic and raised-floor insulation
- removing second refrigerators from homes and recycling the materials
- compact fluorescent light bulbs
- energy efficiency low-interest loans

- natural gas for displacement of electric in water heating, space heating, and space cooling in existing structures
- home energy reports to compare household energy consumption to that of neighbors
- heat pump water heaters
- energy-efficiency windows, window film, and solar shades

Energy audits are available to the System's non-residential customers. In addition GRU offers rebates and other considerations for the promotion of:

- solar water heating
- natural gas for water heating and space heating
- customized business rebates for energy efficiency retrofits

The System continues to offer standardized interconnection procedures and compensation for excess energy production for both residential and non-residential customers who install distributed resources and offers rebates to residential customers for the installation of photovoltaic generation. The solar feed-in tariff has replaced photovoltaic rebates as the incentive for non-residential customers to implement distributed solar generation.

Grants and voluntary customer contributions have made several renewable projects possible within GRU's service area. 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 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. Most recently, GRU utilized an Energy Efficiency and Conservation Block Grant, funded by the American Recovery and Reinvestment Act of 2009, to install 5.77 kW of semitransparent photovoltaic panels in its atrium skylights during early 2011.

GRU has also produced numerous *factsheets,* publications, and videos which are available at no charge to customers to assist them in making informed decisions affecting 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 conserving energy at home.

2.4.2 Future Demand-Side Management Programs

GRU continues to monitor the potential for additional DSM efforts including programs addressing thermal storage, additional energy efficiency in low-income households, and demand response. GRU continues to review the efforts of conservation leaders in the industry, and has conducted fact finding trips to California, Texas, Vermont and New York to maximize these efforts. GRU plans to continue to expand its DSM programs as a way to cost-effectively meet customer needs and hedge against potential future carbon tax and trade programs.

2.4.3 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 under current conditions, 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 where possible. Projected penetration rates were based on historical levels of program implementations and tied to escalation rates paralleling service area population growth. GRU contracted with a consultant to perform a measurement and verification analysis of several of the conservation programs implemented over the past three years. Results from this study aided GRU in both determining which programs are most effective and in quantifying the energy and demand savings achieved by these measures. In 2012, GRU plans to continue third-party evaluation, measurement, and verification.

The implementation of DSM programs planned for 2012-2021 is expected to provide an additional 20 MW of summer peak reduction and 83 GWh of annual energy savings by the year 2021. A history and projection of total DSM program achievements from 1980-2021 is shown in Table 2.1.

2.4.4 Supply Side Programs

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 2011, oil-fired generation comprised 0.3% of total net generation, natural gas-fired generation contributed 27.5%, nuclear fuel contributed 0%, and coal-fired generation provided 72.2% of total net generation.

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. These include the installation of distribution capacitors, purchase of high-efficiency distribution transformers, and the reconductoring of the feeder system.

2.4.4.1 Transformers. GRU has been purchasing overhead and underground transformers with a higher efficiency than the NEMA TP-1 Standard for the past 22 years. Higher efficiency translates to less power lost due to the design of the transformers. GRU has exceeded NEMA standards since 1988.

2.4.4.2 Reconductoring. GRU has been continuously improving the feeder system by reconductoring feeders from 4/0 Copper to 795 MCM aluminum overhead conductor. Also, in specific areas the feeders have been installed underground using 1000 MCM underground cable.

2.4.4.3 Distribution Capacitors. GRU strives to maintain an average power factor of 0.98 by adding capacitors where necessary on each distribution feeder. Without these capacitors the average uncorrected power factor could be less than 0.92.

The percentage of loss reduction can be calculated as shown:

% Loss Reduction=[1-(Uncorrected pf/Corrected pf)^2] x 100

% Loss Reduction=[1-(0.92/0.98)^2] x 100

% Loss Reduction = 11.9

In general, overall system losses have stabilized in the range of 3% to 5% as reflected in the forecasted relationship of total energy sales to net energy for load.

2.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU consults a variety of reputable sources to compile projections of fuel prices for fuels currently used and those that are evaluated for potential future use. Oil prices were obtained from the Annual Energy Outlook 2012 Early Release (AEO2012), published in January 2012 by the U.S. Energy Information Administration (EIA). Short-term natural gas prices were projected internally by GRU staff, while long-term natural gas projections were obtained from AEO2012. Similarly, short-term coal prices were projected by staff based on knowledge of contractual agreements with suppliers. Long-term coal prices were obtained from AEO2011 using data from the full release in late April 2011. Projected prices for nuclear fuel were provided by PEF. Any price forecasts provided in constant-year (real) dollars were translated to nominal dollars using the Gross Domestic Product – Implicit Price Deflator from the Annual Energy Outlook. 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. The external forecasts typically address the commodity prices, and GRU's specific transportation costs are included to derive delivered prices. A summary of historical and projected fuel prices is provided in Table 2.2.

2.5.1 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 were taken directly from Table 3 of AEO2012.

During calendar year 2011 distillate fuel oil was used to produce 0.07% of GRU's total net generation. Distillate fuel oil is expected to be the most expensive fuel available to GRU. During calendar year 2011, residual fuel oil was used to produce 0.19% of GRU's total net generation. The quantity of fuel oils used by GRU is expected to remain low.

2.5.2 Coal

Coal is the primary fuel used by GRU to generate electricity, comprising 72.2% of total net generation during calendar year 2011. GRU purchases low sulfur and medium sulfur, high Btu eastern coal for use in Deerhaven Unit 2. In 2009, Deerhaven Unit 2 was retrofitted with an air quality control system, which was added as a means of complying with new environmental regulations. Following this retrofit, Deerhaven Unit 2 is able to utilize coals with up to approximately 1.7% sulfur content with the new control system.

Projected prices for coal used by Deerhaven Unit 2 for 2012 were based on GRU's contractual options with its coal suppliers. Projected prices for commodity coal beyond 2012 were obtained from AEO2011, table 141, Central Appalachia –

low sulfur coal. GRU has a contract with CSXT for delivery of coal to the Deerhaven plant site through 2019.

2.5.3 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2011, GRU purchased approximately 6.6 million MMBtu for use by both systems. GRU power plants used 69% of the total purchased for GRU during 2011, while the LDC used the remaining 31%.

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

Prices for 2012 were projected in-house using anticipated impacts from risk management activities, commodity costs, and other pricing impacts including transportation costs. Delivered prices from 2013 through 2021 represent the sum of GRU's anticipated transportation costs and spot commodity prices at Henry Hub from Table 13 of AEO2012.

2.5.4 Nuclear Fuel

GRU's nuclear fuel price forecast includes a component for fuel, a component for fuel disposal, and a transmission charge. 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. And the transmission charge is capacity based. Currently, CR3 is expected to be back on line generating power in 2014.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			RESIDENTIAL			COMMERCIAL *		
Year	Service Area Population	Persons per Household	GWh	Average Number of Customers	Average kWh per Customer	GWh	Average Number of Customers	Average kWh per Customer
2002	172,460	2.34	851	73,827	11,527	721	8,778	82,112
2003	173,780	2.33	854	74,456	11,467	726	8,959	81,090
2004	179,613	2.33	878	77,021	11,398	739	9,225	80,143
2005	182,122	2.33	888	78,164	11,358	752	9,378	80,199
2006	184,859	2.33	877	79,407	11,047	746	9,565	78,042
2007	188,704	2.33	878	81,128	10,817	778	9,793	79,398
2008	191,198	2.32	820	82,271	9,969	773	10,508	73,538
2009	191,809	2.32	808	82,605	9,785	778	10,428	74,591
2010	190,177	2.32	851	81,973	10,387	780	10,355	75,304
2011	189,807	2.32	805	81,881	9,829	772	10,373	74,401
2012	191,089	2.32	809	82,500	9,808	762	10,430	73,063
2013	192,733	2.31	819	83,274	9,833	765	10,542	72,528
2014	194,371	2.31	820	84,045	9,752	767	10,656	71,999
2015	196,004	2.31	821	84,813	9,674	770	10,769	71,477
2016	197,986	2.31	823	85,731	9,596	774	10,912	70,937
2017	199,963	2.31	825	86,646	9,524	778	11,054	70,406
2018	201,934	2.31	828	87,559	9,458	783	11,198	69,883
2019	203,901	2.30	831	88,469	9,393	787	11,341	69,370
2020	205,863	2.30	834	89,376	9,328	791	11,485	68,868
2021	207,776	2.30	837	90,262	9,269	795	11,626	68,378

* Commercial includes General Service Non-Demand and General Service 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	Other Sales	Total Sales
		Average	Average	Railroads	Highway	to Public	to Ultimate
		Number of	MWh per	and Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Customer	GWh	GWh	GWh	GWh
2002	178	18	10,178	0	24	0	1,774
2003	181	19	9,591	0	24	0	1,786
2004	188	18	10,396	0	25	0	1,830
2005	189	18	10,526	0	25	0	1,854
2006	200	20	10,093	0	25	0	1,849
2007	196	18	10,742	0	26	0	1,877
2008	184	16	11,438	0	26	0	1,803
2009	168	12	13,842	0	26	0	1,781
2010	168	12	13,625	0	25	0	1,825
2011	164	11	14,575	0	29	0	1,769
2012	157	11	14,232	0	28	0	1,756
2013	156	11	14,207	0	29	0	1,769
2014	156	11	14,191	0	29	0	1,772
2015	156	11	14,180	0	29	0	1,776
2016	156	11	14,171	0	30	0	1,783
2017	156	11	14,156	0	30	0	1,789
2018	155	11	14,133	0	30	0	1,796
2019	155	11	14,109	0	31	0	1,804
2020	155	11	14,089	0	31	0	1,811
2021	155	11	14,067	0	31	0	1,818

** Industrial includes Large Power Rate Class

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
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	174	75	2,099	0	88,992
2007	188	57	2,122	0	90,939
2008	196	79	2,079	0	92,795
2009	203	99	2,083	0	93,045
2010	217	99	2,141	0	92,340
2011	201	53	2,024	0	92,265
2012	207	95	2,058	0	92,941
2013	214	95	2,078	0	93,828
2014	218	96	2,086	0	94,712
2015	222	96	2,094	0	95,593
2016	227	96	2,106	0	96,654
2017	232	98	2,119	0	97,712
2018	237	98	2,131	0	98,767
2019	241	98	2,143	0	99,821
2020	246	99	2,156	0	100,872
2021	251	99	2,168	0	101,899

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2002	454	32	401	0	0	13	0	8	433
2003	439	33	384	0	0	14	0	8	417
2004	455	33	399	0	0	14	0	9	432
2005	489	37	428	0	0	15	0	9	465
2006	488	39	425	0	0	15	0	9	464
2007	508	44	437	0	0	17	0	10	481
2008	487	43	414	0	0	19	0	11	457
2009	498	46	419	0	0	21	0	12	465
2010	505	48	422	0	0	22	0	13	470
2011	484	46	399	0	0	24	0	15	445
2012	488	47	399	0	0	27	0	15	446
2013	494	49	401	0	0	28	0	16	450
2014	497	50	401	0	0	30	0	16	451
2015	501	51	402	0	0	31	0	17	453
2016	505	52	404	0	0	32	0	17	456
2017	510	53	405	0	0	34	0	18	458
2018	513	54	406	0	0	35	0	18	460
2019	518	55	408	0	0	37	0	18	463
2020	522	56	409	0	0	38	0	19	465
2021	525	57	410	0	0	39	0	19	467

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
2002 / 2003	442	37	357	0	0	40	0	8	394
2003 / 2004	398	31	319	0	0	40	0	8	350
2004 / 2005	426	36	341	0	0	41	0	8	377
2005 / 2006	436	40	346	0	0	42	0	8	386
2006 / 2007	414	38	324	0	0	44	0	8	362
2007 / 2008	417	40	321	0	0	46	0	10	361
2008 / 2009	479	50	371	0	0	47	0	11	421
2009 / 2010	523	55	409	0	0	48	0	11	464
2010 / 2011	471	51	358	0	0	50	0	12	409
2011 / 2012	435	47	324	0	0	51	0	13	371
2012 / 2013	434	49	319	0	0	53	0	13	368
2013 / 2014	437	50	320	0	0	54	0	13	370
2014 / 2015	439	51	320	0	0	54	0	14	371
2015 / 2016	443	52	322	0	0	55	0	14	374
2016 / 2017	446	54	322	0	0	56	0	14	376
2017 / 2018	450	55	323	0	0	57	0	15	378
2018 / 2019	453	56	324	0	0	58	0	15	380
2019 / 2020	457	57	326	0	0	59	0	15	383
2020 / 2021	461	58	327	0	0	60	0	16	385
2021 / 2022	463	59	328	0	0	60	0	16	387

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 %
2002	2,110	78	24	1,774	142	92	2,008	53%
2003	2,121	82	24	1,786	146	83	2,015	55%
2004	2,158	84	25	1,830	149	70	2,049	54%
2005	2,196	88	26	1,854	163	65	2,082	51%
2006	2,215	90	26	1,849	174	76	2,099	52%
2007	2,253	99	32	1,877	186	59	2,122	50%
2008	2,230	110	41	1,804	196	79	2,079	52%
2009	2,249	117	49	1,781	203	99	2,083	51%
2010	2,321	124	56	1,825	217	99	2,141	52%
2011	2,221	134	63	1,770	201	53	2,024	52%
2012	2,270	146	66	1,756	207	95	2,058	53%
2013	2,301	154	69	1,768	214	96	2,078	53%
2014	2,316	158	72	1,772	218	96	2,086	53%
2015	2,332	163	75	1,776	222	96	2,094	53%
2016	2,351	167	78	1,782	227	97	2,106	53%
2017	2,372	172	81	1,789	232	98	2,119	53%
2018	2,391	176	84	1,796	237	98	2,131	53%
2019	2,410	180	87	1,804	241	98	2,143	53%
2020	2,429	184	89	1,810	246	100	2,156	53%
2021	2,448	188	92	1,817	251	100	2,168	53%

Schedule 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST			
	2011		2012		2013	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	*409*	*166*	*363*	*140*	367	160
FEB	*329*	*137*	*371*	138	334	139
MAR	*271*	*139*	294	145	296	146
APR	*366*	*157*	325	148	328	150
MAY	*397*	*180*	390	179	394	180
JUN	*445*	*201*	428	195	432	197
JUL	*422*	*208*	436	211	440	213
AUG	*438*	*221*	445	216	449	217
SEP	*391*	*189*	419	197	423	198
OCT	*308*	*149*	357	165	360	167
NOV	*277*	*136*	298	144	300	145
DEC	*270*	*141*	338	157	341	158

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
FUEL REQUIREMENTS			UNITS	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	560	587	628	573	547	570	577	589	595	564	584
	RESIDUAL													
(3)		STEAM	1000 BBL	11	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
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:	1000 BBL	11	0	0	0	0	0	0	0	0	0	0
	DISTILLATE													
(7)		STEAM	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	2	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	2	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(11)		STEAM	1000 MCF	1195	842	726	853	1070	994	937	919	918	983	984
(12)		CC	1000 MCF	2488	2939	2509	2570	2890	2515	2590	2444	2565	2772	2536
(13)		CT	1000 MCF	197	310	211	326	383	367	428	286	282	371	318
(14)		TOTAL:	1000 MCF	3880	4091	3446	3749	4343	3876	3955	3649	3765	4126	3838
(15)	OTHER (specify)		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0

Schedule 6.1
ENERGY SOURCES (GWH)
As of January 1, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR		GWh	105	122	108	122	108	122	108	122	108	122	108
(3)	COAL		GWh	1286	1363	1466	1321	1265	1317	1334	1364	1378	1294	1348
	RESIDUAL													
(4)		STEAM	GWh	4	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWh	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
(7)		TOTAL:	GWh	4	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
(9)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWh	1	0	0	0	0	0	0	0	0	0	0
(11)		TOTAL:	GWh	1	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(12)		STEAM	GWh	98	65	54	65	81	76	72	70	70	76	75
(13)		CC	GWh	273	338	282	283	322	280	285	269	281	313	280
(14)		CT	GWh	14	22	15	22	27	25	31	21	21	27	23
(15)		TOTAL:	GWh	385	425	351	370	430	381	388	360	372	416	378
(16)	NUG		GWh	0	0	0	0	0	0	0	0	0	0	0
(17)	BIOFUELS		GWh	0	0	0	0	0	0	0	0	0	0	0
(18)	BIOMASS	PPA	GWh	0	0	0	394	394	394	394	394	394	394	394
(19)	GEOTHERMAL		GWh	0	0	0	0	0	0	0	0	0	0	0
(20)	HYDRO	PPA	GWh	0	0	0	0	0	0	0	0	0	0	0
(21)	LANDFILL GAS		GWh	24	24	24	24	24	24	24	24	24	24	24
(22)	MSW		GWh	0	0	0	0	0	0	0	0	0	0	0
(23)	SOLAR	FIT-PV	GWh	8	16	24	32	40	46	46	46	46	46	46
(24)	WIND		GWh	0	0	0	0	0	0	0	0	0	0	0
(25)	OTHER RENEWABLE		GWh	0	0	0	0	0	0	0	0	0	0	0
(26)	Total Renewable		GWh	32	40	48	450	458	464	464	464	464	464	464
(27)	Purchased Energy		GWh	211	103	97	-185	-175	-186	-185	-188	-188	-150	-140
(28)	Energy Sales		GWh	0	0	0	0	0	0	0	0	0	0	0
(29)	NET ENERGY FOR LOAD		GWh	2024	2053	2070	2078	2086	2098	2109	2122	2134	2146	2158

Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		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	5.19%	5.94%	5.22%	5.87%	5.18%	5.82%	5.12%	5.75%	5.06%	5.68%	5.00%
(3)	COAL		GWh	63.54%	66.39%	70.82%	63.57%	60.64%	62.77%	63.25%	64.28%	64.57%	60.30%	62.47%
	RESIDUAL													
(4)		STEAM	GWh	0.20%	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	0.20%	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	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWh	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	GWh	0.05%	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	4.84%	3.17%	2.61%	3.13%	3.88%	3.62%	3.41%	3.30%	3.28%	3.54%	3.48%
(13)		CC	GWh	13.49%	16.46%	13.62%	13.62%	15.44%	13.35%	13.51%	12.68%	13.17%	14.59%	12.97%
(14)		CT	GWh	0.69%	1.07%	0.72%	1.06%	1.29%	1.19%	1.47%	0.99%	0.98%	1.26%	1.07%
(15)		TOTAL:	GWh	19.02%	20.70%	16.96%	17.81%	20.61%	18.16%	18.40%	16.97%	17.43%	19.38%	17.52%
(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)	BIOFUELS		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(18)	BIOMASS	PPA	GWh	0.00%	0.00%	0.00%	18.96%	18.89%	18.78%	18.68%	18.57%	18.46%	18.36%	18.26%
(19)	GEOTHERMAL		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(20)	HYDRO		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(21)	LANDFILL GAS	PPA	GWh	1.19%	1.17%	1.16%	1.15%	1.15%	1.14%	1.14%	1.13%	1.12%	1.12%	1.11%
(22)	MSW		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(23)	SOLAR	FIT	GWh	0.40%	0.78%	1.16%	1.54%	1.92%	2.19%	2.18%	2.17%	2.16%	2.14%	2.13%
(24)	WIND		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(25)	OTHER RENEWABLE		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(26)	Total Renewable		GWh	1.58%	1.95%	2.32%	21.66%	21.96%	22.12%	22.00%	21.87%	21.74%	21.62%	21.50%
(27)	Purchased Energy		GWh	10.42%	5.02%	4.69%	-8.90%	-8.39%	-8.87%	-8.77%	-8.86%	-8.81%	-6.99%	-6.49%
(28)	Energy Sales		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(29)	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%

TABLE 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	116,544	49,619	24,078
2007	130,876	52,029	26,510
2008	151,356	55,609	30,139
2009	165,775	57,272	33,059
2010	180,842	59,756	35,827
2011	196,824	62,277	38,958
2012	212,487	64,258	41,935
2013	222,909	65,691	44,089
2014	230,798	67,006	45,980
2015	238,381	68,271	47,780
2016	245,807	69,512	49,557
2017	253,358	70,752	51,470
2018	260,368	71,941	53,251
2019	266,972	73,088	55,024
2020	273,550	74,224	56,833
2021	280,101	75,346	58,677

TABLE 2.2

DELIVERED FUEL PRICES
$/MMBtu

Year	Residual Fuel Oil	Distillate Fuel Oil	Natural Gas	Coal	Nuclear
2002	4.58	5.69	3.95	2.05	0.38
2003	4.87	6.59	5.97	2.04	0.43
2004	5.17	5.17	6.40	2.03	0.41
2005	7.15	18.67	9.15	2.38	0.45
2006	8.07	15.24	8.68	3.00	0.45
2007	7.68	16.35	8.37	2.94	0.40
2008	7.60	13.74	10.60	4.10	0.42
2009	6.39	11.07	6.11	3.96	0.59
2010	10.73	17.10	6.64	3.48	0.76
2011	18.53	23.80	5.67	3.80	0.73
2012	18.02	24.19	5.66	4.14	1.10
2013	21.30	21.39	5.03	3.86	1.11
2014	22.90	22.98	5.16	3.90	1.19
2015	24.35	24.43	5.38	3.96	1.19
2016	25.16	25.32	5.50	4.07	1.22
2017	26.07	26.34	5.74	4.20	1.22
2018	26.79	27.05	6.04	4.27	1.21
2019	27.55	27.84	6.31	4.38	1.21
2020	28.36	28.65	6.52	4.98	1.22
2021	29.09	29.50	6.89	5.10	1.24

3. FORECAST OF FACILITIES REQUIREMENTS

3.1 GENERATION RETIREMENTS

The System plans to retire four generating units within the next 10 years. The John R. Kelly steam unit #7 (JRK #7) (23 MW) is presently scheduled to be retired in October 2015. JRK combustion turbines 1, 2, and 3 (14 MW each) are scheduled to be retired in February 2018, September 2018, and May 2019, respectively. These unit retirements are tabulated in Schedule 8.

3.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

GRU uses a planning criterion 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 System winter peak demands in Schedule 7.2. Higher peak demands in summer and lower unit operating capacities in summer result in lower reserve margins during the summer season than in winter. In consideration of existing resources, expected future purchases, and savings impacts from conservation programs, GRU expects to maintain a summer reserve margin well in excess of 15% over the next 10 years.

3.3 GENERATION ADDITIONS

No additions to GRU owned generating capacity are scheduled within this ten year planning horizon.

GRU has entered into a 30 year power purchase agreement with the Gainesville Renewable Energy Center for 100 MW net capacity, fueled entirely with biomass. Initial synchronization is scheduled for June 26, 2013 with full commercial operation by the end of 2013.

3.4 DISTRIBUTION SYSTEM ADDITIONS

Up to five new, identical, mini-power delivery substations (PDS) were planned for the GRU system back in 1999. Three of the five; Rocky Point, Kanapaha, and Ironwood were installed by 2003. A fourth PDS, Springhill, was brought on-line in January 2011. The fifth PDS is planned for addition to the System in 2014. This PDS will be located in the 2000 block of NW 53rd Avenue. 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.

The Rocky Point, Kanapaha, and Ironwood PDS utilize single 33.6 MVA transformers that are directly radial-tapped to our looped 138 kV system. The new Springhill Substation consists of one 33.3 MVA transformer served by a loop fed SEECO pole mounted switch. The proximity of these new PDS's 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 (2)	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available (3)	System Firm Summer Peak Demand (1)	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance (1)	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2002	610	0	43	0	567	433	133	30.7%	0	133	30.7%
2003	610	0	3	0	607	417	189	45.3%	0	189	45.3%
2004	611	0	3	0	608	432	175	40.5%	0	175	40.5%
2005	611	0	3	0	608	465	143	30.8%	0	143	30.8%
2006	611	0	3	0	608	464	144	31.0%	0	144	31.0%
2007	611	0	0	0	611	481	130	27.1%	0	130	27.1%
2008	610	49	0	0	659	457	202	44.2%	0	202	44.2%
2009	608	101	0	0	709	465	244	52.5%	0	244	52.5%
2010	608	102	0	0	710	470	240	51.1%	0	240	51.1%
2011	608	56	0	0	664	445	219	49.2%	0	219	49.2%
2012	610	58	0	0	668	445	223	50.1%	0	223	50.1%
2013	610	59	0	0	669	449	220	49.1%	0	220	49.1%
2014	610	62	0	0	672	450	222	49.3%	0	222	49.3%
2015	610	63	0	0	673	452	221	49.0%	0	221	49.0%
2016	587	65	0	0	652	454	198	43.5%	0	198	43.5%
2017	587	65	0	0	652	457	195	42.6%	0	195	42.6%
2018	573	65	0	0	638	459	179	39.1%	0	179	39.1%
2019	545	66	0	0	611	462	149	32.2%	0	149	32.2%
2020	545	66	0	0	611	464	147	31.7%	0	147	31.7%
2021	545	66	0	0	611	466	145	31.2%	0	145	31.2%

(1) System Peak demands shown in this table reflect continued service to partial and full requirements wholesale customers.
(2) Details of planned changes to installed capacity from 2012-2021 are reflected in Schedule 8.
(3) The coincidence factor used for Summer photovoltaic capacity is 35%.

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 (2)	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available (3)	System Firm Winter Peak Demand (1)	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance (1)	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2002/03	630	0	3	0	627	394	232	58.9%	0	232	58.9%
2003/04	631	0	3	0	628	350	278	79.4%	0	278	79.4%
2004/05	632	0	3	0	629	377	251	66.6%	0	251	66.6%
2005/06	632	0	3	0	629	386	242	62.7%	0	242	62.7%
2006/07	632	0	0	0	632	362	270	74.5%	0	270	74.5%
2007/08	630	0	0	0	630	361	269	74.6%	0	269	74.6%
2008/09	635	76	0	0	711	421	290	68.9%	0	290	68.9%
2009/10	628	76	0	0	705	464	241	51.9%	0	241	51.9%
2010/11	628	53	0	0	681	409	272	66.6%	0	272	66.6%
2011/12	630	53	0	0	684	371	313	84.3%	0	313	84.3%
2012/13	630	54	0	0	684	367	317	86.5%	0	317	86.5%
2013/14	630	55	0	0	686	369	317	85.9%	0	317	85.9%
2014/15	630	56	0	0	686	371	315	85.0%	0	315	85.0%
2015/16	607	56	0	0	663	373	290	77.9%	0	290	77.9%
2016/17	607	57	0	0	664	375	289	77.0%	0	289	77.0%
2017/18	592	57	0	0	649	377	272	72.1%	0	272	72.1%
2018/19	577	57	0	0	634	380	254	66.8%	0	254	66.8%
2019/20	562	57	0	0	619	382	237	62.1%	0	237	62.1%
2020/21	562	57	0	0	619	384	235	61.2%	0	235	61.2%
2021/22	562	57	0	0	619	386	233	60.4%	0	233	60.4%
2022/23	487	57	0	0	544	388	156	40.3%	0	156	40.3%

(1) System Peak demands shown in this table reflect continued service to partial and full requirements wholesale customers.

(2) Details of planned changes to installed capacity from 2012-2021 are reflected in Schedule 8.

(3) The coincidence factor used for Winter photovoltaic capacity is 9.3%.

Schedule 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								Const.	Comm.	Expected	Gross Capability		Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retire	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	(MW)	(MW)	(MW)	(MW)	Status
J. R. KELLY	FS07	Alachua County Sec. 4, T10S, R20E	ST	NG	RFO	PL	TK			10/2015	-24	-24	-23.2	-23.2	RT
J. R. KELLY	GT01	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK			2/2018	-14	-15	-14	-15	RT
J. R. KELLY	GT02	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK			9/2018	-14	-15	-14	-15	RT
J. R. KELLY	GT03	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK			5/2019	-14	-15	-14	-15	RT

Unit Type
ST = Steam Turbine
GT = Gas Turbine

Fuel Type
NG = Natural Gas
RFO = Residual Fuel Oil
DFO = Distillate Fuel Oil

Transportation Method
PL = Pipeline
RR = Railroad
TK = Truck

Status
A = Generating unit capability increased
RT = Existing generator scheduled for retirement

4. ENVIRONMENTAL AND LAND USE INFORMATION

4.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

Currently, there are no new potential generation sites planned.

4.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

The new Gainesville Renewable Energy Center (GREC) biomass-fueled generation facility is currently under construction on land leased from GRU on the northwest portion of the existing Deerhaven Generating Station plant (site). The site is shown in Figure 1.1 and Figure 4.1, located north of Gainesville off U.S. Highway 441. The site is preferred for this project for several major reasons. Since it is an existing power generation site, future development is possible while minimizing impacts to the greenfield (undeveloped) areas. It also has an established access to fuel supply, power delivery, and potable water facilities. The location of the biomass facility is shown on Figure 4.1.

4.2.1 Land Use and Environmental Features

The location of the site is indicated on Figure 1.1 and Figure 4.1, overlain on USGS maps that were originally at a scale of 1 inch : 24,000 feet. Figure 4.2 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 withdrawal, combustion product handling and disposal, and forest management). The areas acquired since 2002 have been annexed into the City of Gainesville. The site is a PS, Public Services and Operations District, zoned property. Surrounding land uses are primarily rural or agricultural with some low-density residential development. The Deerhaven site encompasses approximately 3,474 acres.

The Deerhaven Generating Station plant site is located in the Suwannee River Water Management District. A small increase in water quantities for potable uses is projected, with the addition of the biomass facility. It is estimated that industrial processes and cooling water needs associated with the new unit will average 1.4 million gallons per day (MGD). Approximately 400,000 gallons per day of these needs will initially be met using reclaimed water from the City of Alachua. The groundwater allocation in the existing Deerhaven Site Certification will be reduced by 1.4 MGD to accommodate the GREC biomasss unit however, the remaining allocation of 5.1 MGD is sufficient to accommodate the requirements of the GRU portion of the site in the future. Water for potable use will be supplied via the City's potable water system. Groundwater will continue to be extracted from the Floridian aquifer. Process wastewater is currently collected, treated and reused on-site. The site has zero discharge of process wastewater to surface and ground waters, with a brine concentrator and on-site storage of solid water treatment by-products. The new GREC biomass unit will use a wastewater treatment system to also accomplish zero liquid discharge however the solid waste produced will not be stored onsite. Other water conservation measures may be identified during the design of the project.

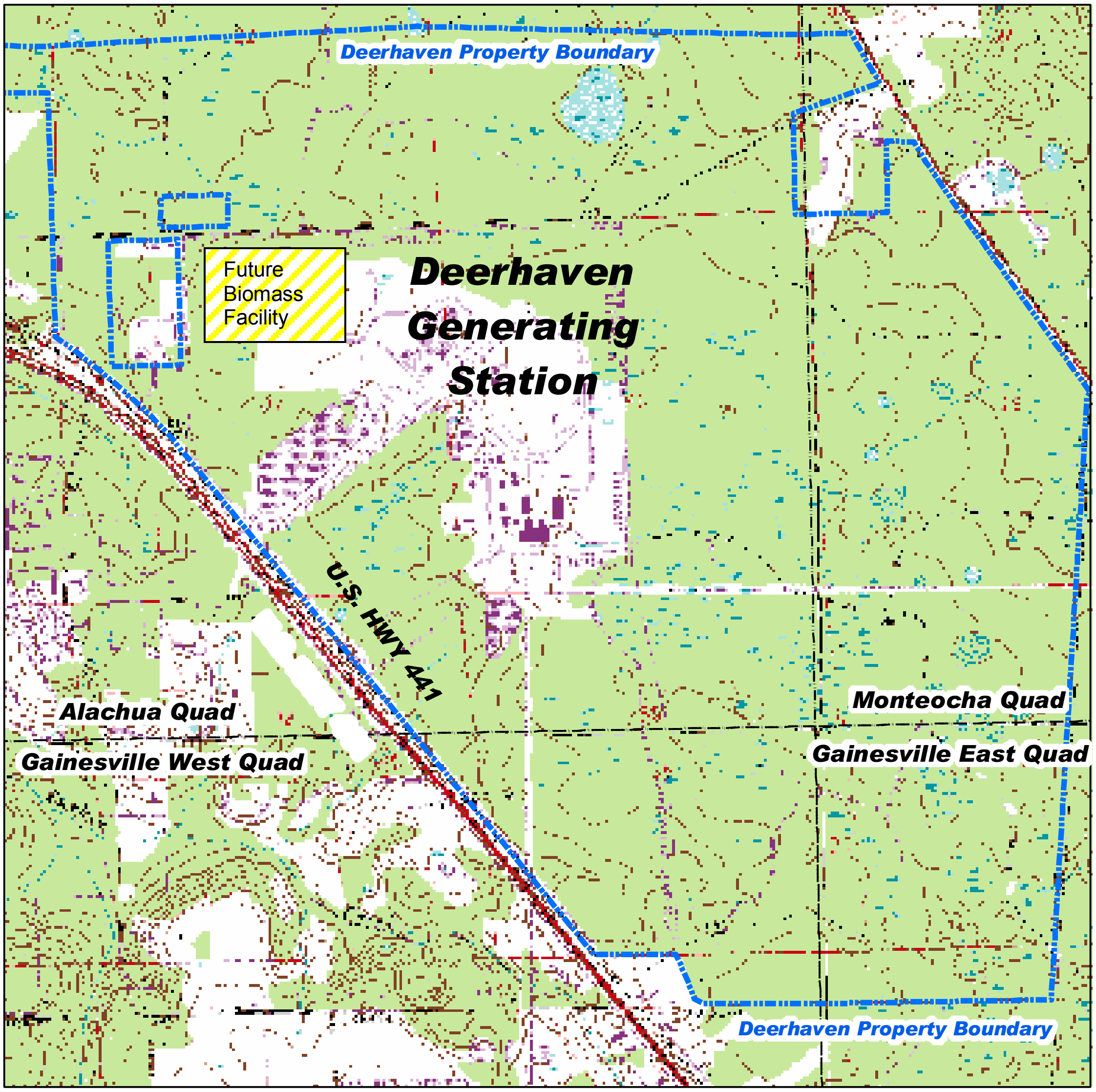
4.2.2 Air Emissions

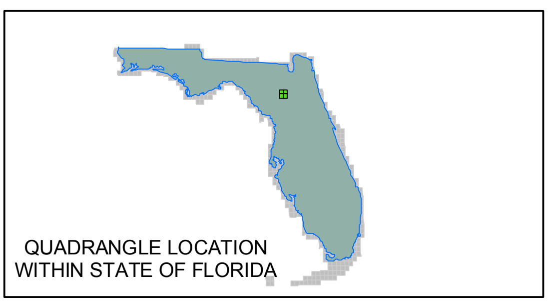
The proposed generation technology for the biomass unit will necessarily meet all applicable standards for all pollutants regulated for this category of emissions unit.

4.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Gainesville Renewable Energy Center LLC received unanimous approval for certification under the Power Plant Siting Act on December 7, 2010. The Florida Department of Environmental Protection approved the air construction permit for GREC on December 29, 2010, fulfilling the final regulatory requirement for the biomass facility.

Figure 4.1



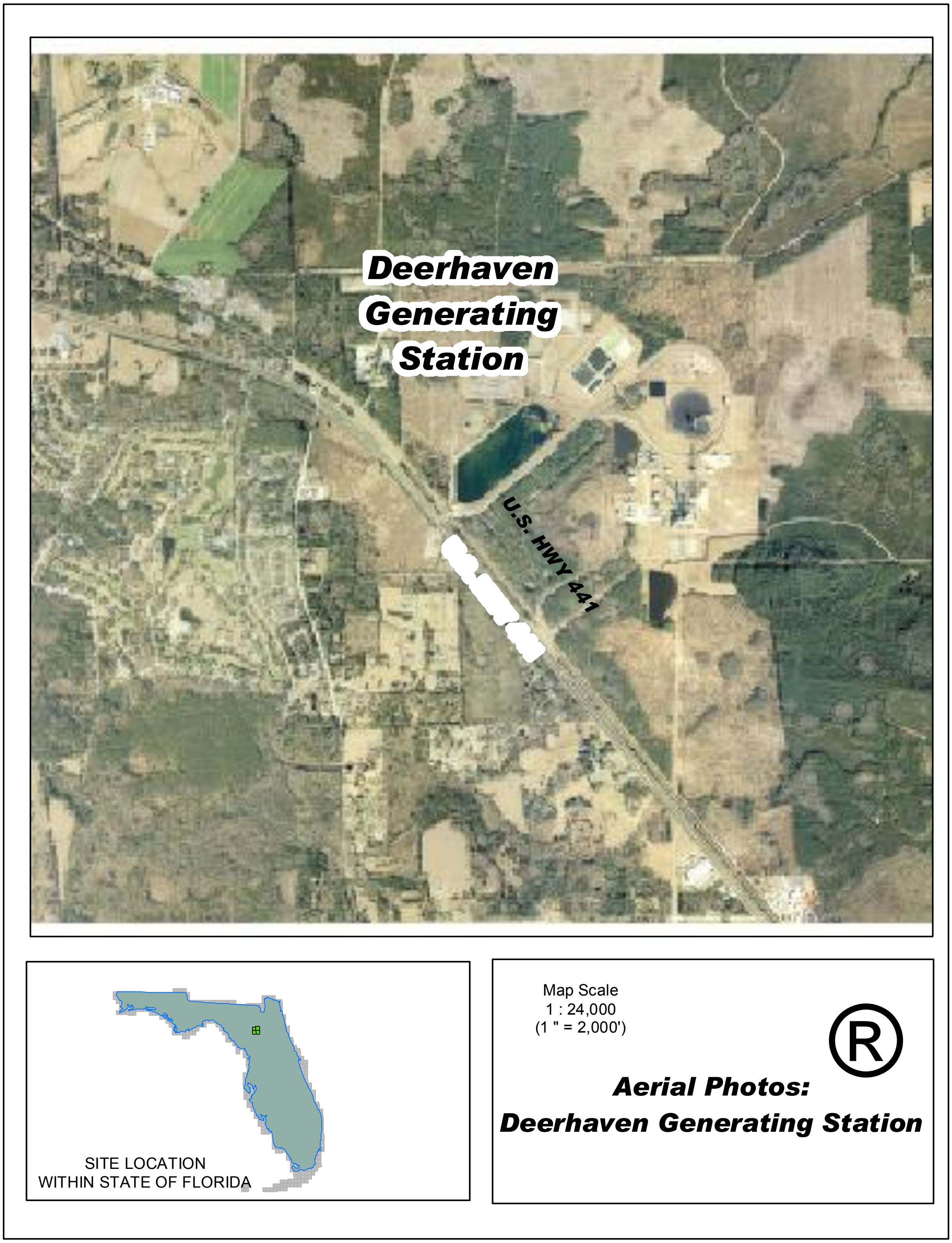


Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')

Location Map:
Deerhaven Generating Station

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

Figure 4.2


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