GAINESVILLE REGIONAL UTILITIES

2014 TEN-YEAR SITE PLAN

More than Energy

Submitted to:

The Florida Public Service Commission

April 1, 2014

March 21, 2014

Carlotta Stauffer, Director
Florida Public Service Commission
Office of Commission Clerk
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Ms. Stauffer:

In accordance with Section 186.801, Florida Statutes and Rule 25-22.071(1), Florida Administrative Code, Gainesville Regional Utilities hereby submits five copies of its 2014 Ten Year Site Plan for your review. We are also submitting this document electronically through your web based filing system. Please let me know if you have any questions regarding our Ten Year Site Plan.

Sincerely,

/s/ Todd Kamhoot

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INTRODUCTION

The 2014 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 2014 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 transmission service to Seminole Electric Cooperative (Seminole). GRU's distribution system serves its retail territory of approximately 124 square miles and an average of 93,133 customers during 2013. 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 533 MW and the winter net capability is 550 MW. Currently, the System's energy is produced by (i) three fossil fuel steam turbines[1], one of which is part of a combined cycle unit, (ii) four combustion turbines, three of which are simple cycle and one of which can generate in either simple or combined-cycle unit mode, (iii) and distributed generation consisting of one gas turbine.

The System has two primary generating plant sites – Deerhaven (DH) and John R. Kelly (JRK). Each site is comprised of both steam-turbine and gas-turbine generating units. The JRK station is the site of the steam turbine and combustion turbine that can be operated in combined cycle.

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1 One steam turbine, JRK steam turbine (ST) 8, operates only in combined cycle with JRK combustion turbine (CT) 4. As CT4 is fossil fueled, the steam created by the heat recovery steam generator (HRSG) into which it exhausts when in combined cycle mode is produced by fossil fuel. Therefore ST8 is indirectly driven by fossil fuel. No capability exists to directly burn fossil fuel to produce steam for ST8.

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. The two simple cycle fossil fueled steam turbines comprise 57.7% of the System's net summer capability and produced 61.9% of the electric energy supplied by the System in 2013. The combined-cycle unit, which includes a heat recovery steam generator/turbine and combustion turbine set, comprises 21.0% of the System's net summer capability and produced 35.7% of the electric energy supplied by the System in 2013. DH 2 (232 MW) and JRK CC1 (112 MW) have historically been used for base load purposes, while DH 1 (75 MW) was more commonly used for intermediate loading. The addition of 102.5 MW of biomass power by purchased power agreement (PPA) in 2013 has resulted in seasonal operation and increased load cycling of DH 2. It has also resulted in increased off/on cycling of JRK CC1 and reduced capacity factor of DH 1.

1.1.1.2 Simple Cycle Gas Turbines. The System's four industrial gas turbines that operate only in simple cycle comprise 21.3% of the System's summer generating capability and produced 2.4% of the electric energy supplied by the System in 2013. Three of these simple-cycle combustion turbines are utilized for peaking purposes only. Their energy conversion efficiencies are considerably lower than steam units. Simple cycle combustion 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. The fourth gas turbine operates to serve base load as part of a combined heating and power facility at the South Energy Center, further described in Section 1.5.

1.1.1.3 Environmental Considerations. The System's steam turbines utilize recirculating cooling towers with a mechanical draft for the cooling of condensed steam. Currently, only DH 2 has an Air Quality Control System (AQCS) consisting of a “hot-side” electrostatic precipitator for the removal of fly ash, a selective catalytic reduction system (SCR) to reduce NO_x, a dry recirculating flue gas desulfurization unit to reduce sulfur dioxide (SO_2) and mercury (Hg), and a fabric filter baghouse to reduce particulates. The Deerhaven site operates with zero liquid discharge (ZLD) to surface waters.

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 and the associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment. One conventional steam turbine and three simple-cycle gas turbines were retired from operation in October 2013.

1.1.2.2 Deerhaven Plant. The Deerhaven Station is located six miles northwest of Gainesville. The facility consists of two steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment and transmission equipment. DH 2 is coal fired and the site includes the coal unloading and storage facilities. 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, in the northwest corner of the site, is the location of a 102.5 MW capacity biomass fueled power generating facility that began commercial operation on December 17, 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, and Figure 1.2 shows 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	80.08	795 MCM ACSR
138 kV single circuit	16.86	1192 MCM ACSR
138 kV single circuit	20.61	795 MCM ACSR
230 kV single circuit	2.53	795 MCM ACSR
Total	120.08	

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 168 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 consists 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 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 DEF'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 the City of Alachua have been included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins through this planning horizon.

1.5 DISTRIBUTED GENERATION

The South Energy Center, a combined heating and power plant (CHP) began commercial operation in May 2009. The South Energy Center provides multiple onsite utility services to the UF Health Shands South Campus hospital. This facility houses a 3.5 MW 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

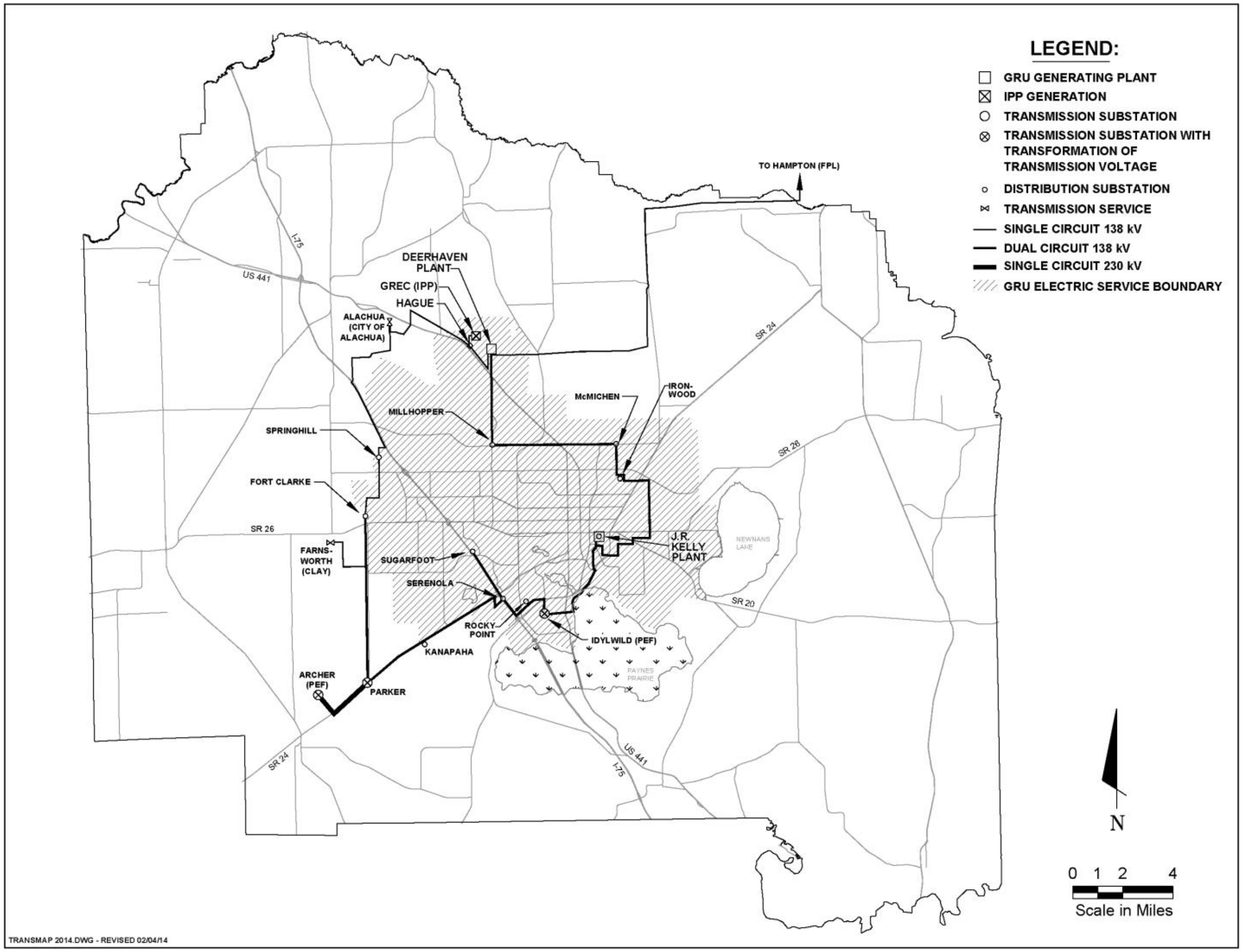
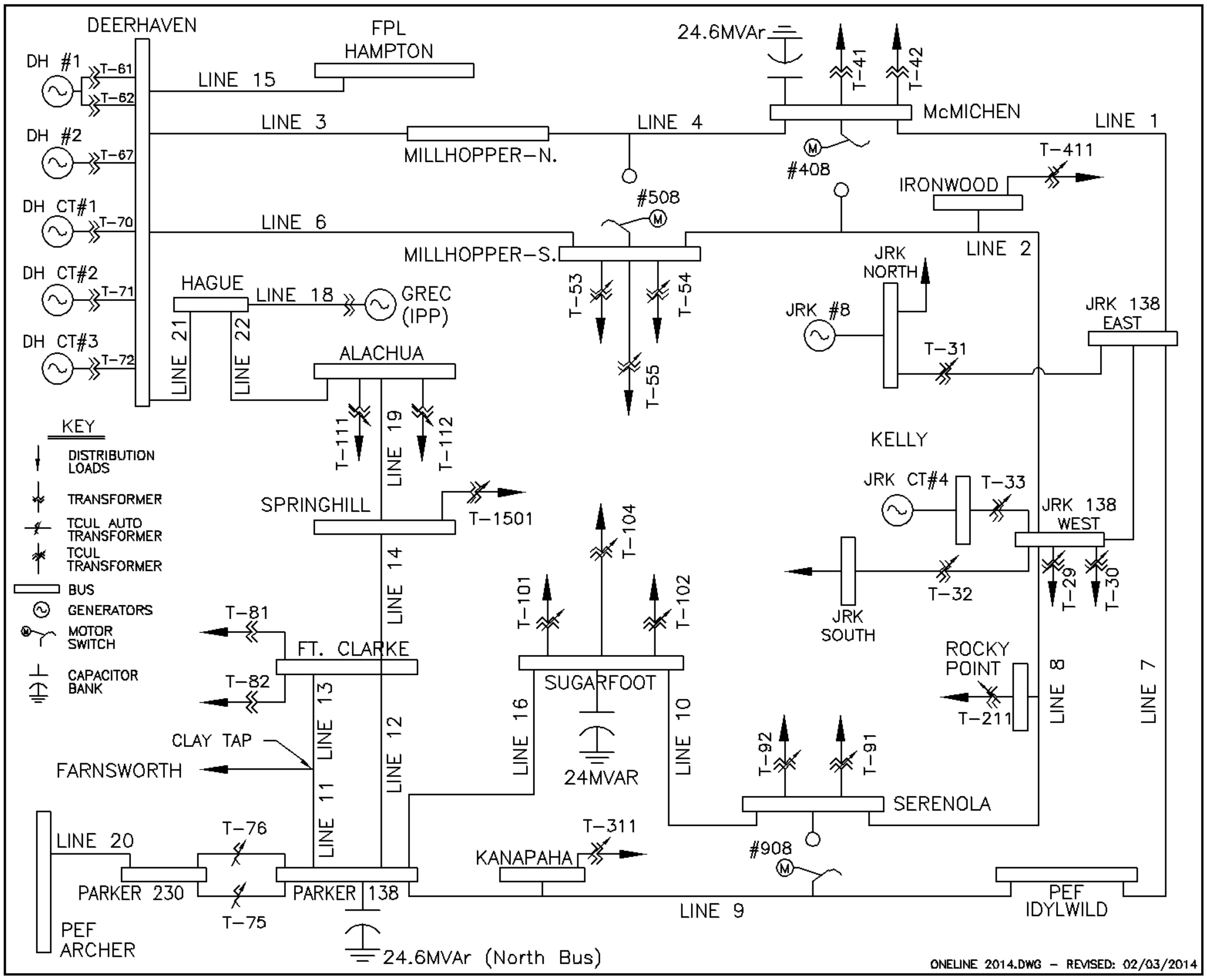


FIGURE 1.2

Gainesville Regional Utilities Electric System One-Line Diagram.



Schedule 1
EXISTING GENERATING FACILITIES (as of January 1, 2014)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Primary Fuel		Alternate Fuel		Alt. Fuel	Commercial	Expected	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Type	Trans.	Type	Trans.	Storage (Days)	In-Service Month/Year	Retirement Month/Year	Summer MW	Winter MW	Summer MW	Winter MW	Status
J. R. Kelly		Alachua County									**114.0**	**120.0**	**112.0**	**118.0**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL				[4/65 ; 5/01]	2051	38.0	38.0	37.0	37.0	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	2051	76.0	82.0	75.0	81.0	OP
Deerhaven		Alachua County									**449.0**	**459.0**	**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	80.0	80.0	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
South Energy Center	GT1	Alachua County	GT	NG		PL			5/09		**4.5**	**4.5**	**3.5**	**3.5**	OP
Distributed Generation		SEC. 10, T10S, R20E													
System Total													**532.5**	**549.5**	

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
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
17	Clay Tap – Farnsworth	236.2	Conductor	282.0	Conductor
19	Springhill - Alachua	300.0	Conductor	356.0	Conductor
20	Parker-Archer(T75,T76)	224.0	Transformers[3]	300.0	Transformers[3]
21	Deerhaven – GREC	287.3	Switch	356.0	Conductor
22	Alachua - Deerhaven	300.0	Conductor	356.0	Conductor
xx	Idylwild – PEF	168.0[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]	201.6 MVA	21
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 10 distribution feeders fed from one 56 MVA transformer and one 33.6 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 2004-2023. 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 2013. 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 based on population data published by The Bureau of Economic and Business Research at the University of Florida. Population projections were based on BEBR Bulletin 165 (March 2013), and Estimates of Population by County and City in Florida: April 1, 2013 (10/15/2013, revised 1/6/2014).

(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 1984-2013.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2013, 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 Bulletin 167 (December 2013), and projections were estimated from a logarithmic trend analysis of historical estimates.

(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 nominal rate of approximately 2.7% per year. 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 1980-2013. GRU's involvement with DSM is described in more detail later in this section.

(10) Sales to The City of Alachua were assumed to continue through the duration of this forecast. The agreement to serve Alachua is in effect through December 2020. Alachua’s ownership in PEF and FPL nuclear units supplied approximately 6% of its annual energy requirements in 2013.

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 2014 through 2023. 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, and sales to the City of 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 an indicator variable representing a recent downturn in usage. The form of this equation is as follows:

$$RESAVUSE = 15165 - 42.57\,(RESPR13) + 0.673\,(HDD) - 1069\,(EE)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use per Customer
RESPR13	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
EE	=	Energy Efficiency Indicator Variable

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

Adjusted R^2	=	0.9317
DF (error)	=	17 (period of study, 1993-2013)
t - statistics:		
Intercept	=	33.69
RESPR13	=	-11.55
HDD	=	3.00
EE	=	-6.20

Projections of the average annual number of residential customers were developed from a linear regression model stating the number of customers as a function of Alachua County population, the number of persons per household, and the historical series of customers transferred from Clay Electric Cooperative, Inc. to GRU. The residential customer model specifications are:

RESCUS = *252943 + 263.0 (POP) – 104871 (HHSIZE) + 1.698 (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	=	0.9954
DF (error)	=	17 (period of study, 1993-2013)
t - statistics:		
Intercept	=	2.67
POP	=	5.68
HHSIZE	=	-2.85
CLYRCUS	=	3.04

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 billing 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. Approximately 38% of all GSD customers have voluntarily elected this rate category. The forecast assumes that additional GSN customers will opt into 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, per capita income, and cooling degree days. The specifications of this model are as follows:

GSNAVUSE= 14.53 – 0.021 (OPTDCUS) + 0.0003 (MSAPCY13) + 0.0019 (CDD)

Where:

GSNAVUSE	=	Average Annual Energy Usage per GSN Customer
OPTDCUS	=	Optional GSD Customers
MSAPCY13	=	Per Capita Income
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.9629
DF (error)	=	17 (period of study, 1993-2013)

t - statistics:

Intercept	=	4.02
OPTDCUS	=	-12.29
MSAPCY13	=	3.43
CDD	=	2.38

The number of general service non-demand customers was projected using an equation specifying customers as a function of Alachua County population, the cumulative 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 = *-3601 + 52.0 (POP) – 0.88 (OPTDCUS) + 1.06 (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	=	0.9931
DF (error)	=	17 (period of study, 1993-2013)

t - statistics:

Intercept	=	-4.66
POP	=	12.94
OPTDCUS	=	-1.60
COXTRAN	=	4.50

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 cumulative number of optional demand customers, non-farm employment, and cooling degree days. Average energy use projections for general service demand customers result from the following model:

$$GSDAVUSE = 420.9 - 0.20\,(OPTDCUS) + 0.58\,(MSA\_NF) + 0.028\,(CDD)$$

Where:

GSDAVUSE	=	Average Annual Energy Use by GSD Customers
OPTDCUS	=	Optional GSD Customers
MSA_NF	=	Non-Farm Employment
CDD	=	Cooling Degree Days
Adjusted R^2	=	0.9177
DF (error)	=	17 (period of study, 1993-2013)
t - statistics:		
Intercept	=	6.94
OPTDCUS	=	-10.17
MSA_NF	=	1.52
CDD	=	2.14

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

$$GSDCUS = -804.3 + 7.65\,(POP) + 0.29\,(OPTDCUS)$$

Where:

GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
OPTDCUS	=	Optional GSD Customers
Adjusted R^2	=	0.9853
DF (error)	=	18 (period of study, 1993-2013)
t - statistics:		
Intercept	=	-4.23
POP	=	7.91
OPTDCUS	=	2.90

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 twelve 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 2013. The model developed to project average use by large power customers includes per capita income, and an indicator variable representing a policy change defining eligibility for this rate category. Energy use per customer has been observed to increase slightly over time, presumably due to the periodic expansion or increased utilization of existing facilities. This growth is measured in the model by per capita income. The specifications of the large power average use model are as follows:

LPAVUSE = 8706 + 0.048 (MSAPCY13) + 3248 (Policy)

Where:		
LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
MSAPCY13	=	Gainesville MSA Per Capita Income
POLICY	=	Indicator Variable for Policy Change in 2009
Adjusted R^2	=	0.9312
DF (error)	=	18 (period of study, 1993-2013)
t - statistics:		
INTERCEPT	=	8.61
MSAPCY13	=	1.59
Policy	=	13.14

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.

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 1.4% of total energy sales. A model to forecast outdoor lighting energy sales was developed that specified lighting energy as a function of the natural log of the number of residential customers. However, energy sales to the lighting sector were held constant at current levels in this forecast, and the model was not used.

2.2.6 Wholesale Energy Sales

The System provides full requirements wholesale electric service to the City of Alachua. Approximately 6% of Alachua's 2013 energy requirements were met through generation entitlements of nuclear generating units operated by DEF and FPL. The agreement to provide wholesale power to Alachua is in effect through December 2020. Energy sales to the City of Alachua are considered part of the System's native load for facilities planning through the forecast horizon.

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 to change in step with Alachua County population. The model used to develop projections of sales to the City of Alachua is of the following form:

ALAMWh	=	*-54067 + 18022 (ALAPOP) + 11.96 (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	=	0.9577
DF (error)	=	17 (period of study, 1994-2013)
t - statistics:		
Intercept	=	-6.07
ALAPOP	=	20.64
HDD	=	2.14

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, 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 0.9548. 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 expected to occur in January of each year, and summer peak demands are expected to occur in August. 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 and natural gas 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 Purchased Power Agreements

2.3.2.1 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. G2 is located within DEF's distribution system, and GRU receives approximately 3.7 MW net of distribution and transmission losses.

2.3.2.2 Gainesville Renewable Energy Center. The Gainesville Renewable Energy Center (GREC) is a 102.5 MW biomass-fired power production facility. GRU entered a 30 year agreement with GREC to purchase all of the output of this unit and anticipates reselling a portion of the output over time. The GREC generating unit began commercial operation on December 17, 2013.

2.3.2.3 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. 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 2013, approximately 18.6 MW has been constructed under the Solar FIT program. The program was originally scheduled to add capacity through 2016, although no additions were allocated for 2014.

2.4 DEMAND-SIDE MANAGEMENT

2.4.1 Demand-Side Management Programs

Demand and energy forecasts 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 2013. DSM programs are available for all residential and non-residential customers, and are designed to effectively reduce and control the growth rates of electric consumption and weather sensitive peak demands.

During 2014 budget deliberations, GRU management and the Gainesville City Commission agreed to eliminate the majority of programs offering financial incentives in an effort cut costs and keep prices down for customers. The effectiveness of historical measures is reflected in usage data. Weather normalized usage per customer was nearly 17% lower in 2013 than 2004, measuring 787 kWh/month compared with 947 kWh/month ten years ago.

DSM direct services currently available to the System's residential customers include energy and water surveys, rebates for whole house energy efficiency improvements under the Low-income Energy Efficiency Program (LEEP), and natural gas rebates for new construction and conversions in existing homes for water heating, space heating, clothes drying and cooking appliances.

Energy and water surveys are available at no cost to the System's non-residential customers. GRU offers free replacement of high-water-use spray nozzles in commercial kitchens, to reduce water use and costs associated with heating water. Rebates for natural gas water heating are also available to GRU's non-residential customers.

The System continues to offer standardized interconnection procedures and net meter billing for both residential and non-residential customers who install photovoltaic solar systems on their homes or businesses.

GRU has 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 that explains common applications of solar energy in Gainesville; and The Energy Book, a guide to conserving energy at home.

2.4.2 Demand-Side Management Methodology and Results

Energy and demand savings resulting from DSM program implementation have been estimated using a combination of techniques, including engineering calculations, pre and post billing analysis, and measurement and verification for specific measures. Known interactions between measures and programs were accounted for where possible. From 1980 through 2013, GRU estimates that utility sponsored DSM programs reduced energy sales by 217 GWh and lowered summer peak demand by 43 MW. In the forecast period, DSM related savings are projected to be very small relative to system load due to the scaling back of programs in this year's budget.

2.4.3 Supply Side Programs

The System has undertaken several initiatives to improve the adequacy and reliability of the transmission and distribution systems. GRU purchases overhead and underground transformers that exceed the efficiency specified by the NEMA TP-1 Standard. GRU has been continuously improving the feeder system by reconductoring feeders from 4/0 Copper to 795 MCM aluminum overhead conductor. In specific areas the feeders have been installed underground using 1000 MCM underground cable. GRU adds capacitors on its distribution feeders where necessary to support a high system-wide power factor. During 2012 and 2013, GRU conducted a Cable Injection Project, where direct-buried underground primary cables installed prior to 1985 were injected with a solution that rejuvenates the insulation of the cable and extends the cable's useful life. Efforts have been made to increase segmentation of feeders, reducing the number of customers behind any one device by adding more fusing stages. This reduces the number of customers affected by any one outaged device. Recent efforts in distribution automation have added reclosers and automated switches, which decreases outage times by enabling GRU's system operators to remotely switch customers to adjacent feeders when outages occur. There is a discernible trend in System data showing a decrease in losses over the past 20 years.

2.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU relies on coal and natural gas as primary fuels used to meet its generation needs. Fuel oils may be used as a backup for natural gas fired generation, although in practice they are seldom used. Since the operation of CR3 has discontinued, nuclear fuel is no longer part of the System's fuel mix. GRU consults a number of reputable sources such as EIA, PIRA, Argus Coal Daily, and the NYMEX futures market, when assessing expected future commodity fuel prices. Costs associated with transporting coal and natural gas to GRU's generating stations are specific to arrangements with transportation entities. Coal is transported to GRU by rail, and natural gas is transported over the Florida Gas Transmission Company (FGT) pipeline system. A summary of historical and projected delivered coal and natural gas prices is provided in Table 2.1.

2.5.1 Coal

Coal was used to generate approximately 47% of the energy produced by the system in 2013. Thus far, GRU has purchased 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. The forecast of coal prices is based on a blend of low sulfur central Appalachian coal and medium sulfur Indiana basin coal that does not exceed this specification. Price projections for these coal types were sourced from the Annual Energy Outlook 2014, Table 140. GRU has a contract with CSXT for delivery of coal to the Deerhaven plant site through 2019. A step increase in the delivered coal price is expected in 2020 resulting from higher transportation costs.

2.5.2 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2013, GRU purchased approximately 9.2 million MMBtu for use by both systems. GRU power plants used 78% of the total purchased for GRU during 2013, while the LDC used the remaining 22%. Natural gas was used to produce approximately 53% of the energy produced by GRU's electric generating units.

GRU purchases natural gas via arrangements with producers and marketers connected with the FGT interstate pipeline. GRU's delivered cost of natural gas includes the commodity component, FGT's fuel charge, FGT's usage (transportation) charge, FGT's reservation (capacity) charge, and basis adjustments. Henry Hub commodity spot price projections were referenced from the Annual Energy Outlook 2014, Table 13.

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
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	189,950	2.32	805	81,881	9,829	772	10,373	74,401
2012	190,428	2.32	757	82,128	9,219	750	10,415	72,025
2013	191,519	2.32	753	82,638	9,118	757	10,484	72,240
2014	194,355	2.32	767	83,900	9,142	762	10,630	71,663
2015	196,398	2.32	774	84,819	9,120	775	10,806	71,704
2016	198,392	2.31	780	85,717	9,100	789	10,979	71,833
2017	200,207	2.31	786	86,536	9,080	801	11,135	71,952
2018	201,862	2.31	791	87,286	9,062	811	11,276	71,961
2019	203,419	2.31	796	87,993	9,044	820	11,408	71,916
2020	204,946	2.31	801	88,686	9,028	829	11,538	71,837
2021	206,497	2.31	806	89,389	9,012	837	11,672	71,737
2022	208,067	2.31	811	90,100	8,998	846	11,808	71,670
2023	209,637	2.31	816	90,810	8,984	855	11,945	71,602

* 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
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	168	13	13,441	0	25	0	1,700
2013	159	12	13,340	0	25	0	1,694
2014	157	12	13,690	0	24	0	1,710
2015	158	12	13,723	0	24	0	1,731
2016	158	12	13,769	0	24	0	1,751
2017	159	12	13,818	0	24	0	1,770
2018	159	12	13,856	0	24	0	1,785
2019	160	12	13,888	0	24	0	1,800
2020	160	12	13,914	0	24	0	1,814
2021	160	12	13,939	0	24	0	1,827
2022	161	12	13,964	0	24	0	1,842
2023	161	12	13,989	0	24	0	1,856

** 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
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	195	74	1,968	0	92,556
2013	113	66	1,873	0	93,134
2014	118	86	1,914	0	94,542
2015	120	87	1,938	0	95,637
2016	122	88	1,961	0	96,707
2017	124	89	1,983	0	97,682
2018	125	92	2,002	0	98,573
2019	127	91	2,018	0	99,412
2020	128	92	2,034	0	100,236
2021	130	93	2,050	0	101,073
2022	132	93	2,067	0	101,919
2023	133	94	2,083	0	102,766

Schedule 3.1

History and Forecast of Summer Peak Demand - MW

(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
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	456	43	372	0	0	26	0	15	415
2013	459	45	371	0	0	27	0	16	416
2014	455	26	386	0	0	27	0	16	412
2015	460	26	391	0	0	27	0	16	417
2016	465	27	395	0	0	27	0	16	422
2017	471	27	400	0	0	28	0	16	427
2018	475	27	404	0	0	28	0	16	431
2019	478	28	406	0	0	28	0	16	434
2020	482	28	410	0	0	28	0	16	438
2021	485	28	413	0	0	28	0	16	441
2022	489	29	416	0	0	28	0	16	445
2023	493	29	420	0	0	28	0	16	449

Schedule 3.2
History and Forecast of Winter Peak Demand - MW

(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
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	413	43	305	0	0	52	0	13	348
2013 / 2014	413	23	325	0	0	52	0	13	348
2014 / 2015	405	25	315	0	0	52	0	13	340
2015 / 2016	409	26	318	0	0	52	0	13	344
2016 / 2017	413	26	321	0	0	53	0	13	347
2017 / 2018	417	27	324	0	0	53	0	13	351
2018 / 2019	420	27	327	0	0	53	0	13	354
2019 / 2020	422	27	329	0	0	53	0	13	356
2020 / 2021	425	28	331	0	0	53	0	13	359
2021 / 2022	428	28	334	0	0	53	0	13	362
2022 / 2023	431	28	337	0	0	53	0	13	365
2023 / 2024	434	29	339	0	0	53	0	13	368

Schedule 3.3

History and Forecast of Net Energy for Load - GWH

(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 %
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	2,179	143	68	1,700	195	73	1,968	54%
2013	2,091	148	70	1,695	113	65	1,873	51%
2014	2,133	149	70	1,710	118	86	1,914	53%
2015	2,157	149	70	1,730	120	88	1,938	53%
2016	2,181	150	70	1,751	122	88	1,961	53%
2017	2,204	151	70	1,769	124	90	1,983	53%
2018	2,223	151	70	1,786	125	91	2,002	53%
2019	2,240	152	70	1,800	127	91	2,018	53%
2020	2,256	152	70	1,814	128	92	2,034	53%
2021	2,273	153	70	1,827	130	93	2,050	53%
2022	2,290	153	70	1,841	132	94	2,067	53%
2023	2,307	154	70	1,856	133	94	2,083	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			
	2013		2014		2015	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	287	137	*348*	146	340	148
FEB	348	128	*313*	128	313	130
MAR	328	137	275	135	278	137
APR	320	142	307	139	311	141
MAY	352	155	367	168	371	170
JUN	411	181	399	182	404	184
JUL	398	186	406	197	411	199
AUG	416	200	412	200	417	203
SEP	384	181	388	183	392	185
OCT	330	156	334	156	338	158
NOV	249	133	277	134	280	136
DEC	265	137	312	146	316	147

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
FUEL REQUIREMENTS			UNITS	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	285	342	311	370	424	381	441	191	339	443	400
	RESIDUAL													
(3)		STEAM	1000 BBL	0	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	0	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	1	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	1	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(11)		STEAM	1000 MCF	2384	2105	2064	1534	1039	1896	816	2864	1519	874	0
(12)		CC	1000 MCF	4171	1484	1757	2039	1974	1358	1589	3627	2589	1602	2243
(13)		CT	1000 MCF	124	1290	1710	821	588	1190	1228	1652	1118	850	2160
(14)		TOTAL:	1000 MCF	6679	4879	5531	4394	3601	4444	3633	8143	5226	3326	4403
(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, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR Replacement Power		GWh	81	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	626	667	611	735	832	766	873	356	643	845	756
	RESIDUAL													
(4)		STEAM	GWh	0	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	0	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	0	0	0	0	0	0	0	0	0	0	0
(11)		TOTAL:	GWh	0	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(12)		STEAM	GWh	192	176	172	125	84	157	67	236	125	72	0
(13)		CC	GWh	472	179	212	247	236	158	190	443	311	191	263
(14)		CT	GWh	31	105	136	70	52	98	97	132	92	73	163
(15)		TOTAL:	GWh	696	459	520	442	372	413	353	811	529	336	426
(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	167	730	748	726	721	764	733	807	819	827	842
(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	28	28	28	28	28	28	28	28	28	28	28
(22)	MSW		GWh	0	0	0	0	0	0	0	0	0	0	0
(23)	SOLAR	FIT & Net	GWh	20	31	31	31	31	31	31	31	31	31	31
(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	215	789	807	784	779	823	791	866	878	886	901
(27)	Purchased Energy		GWh	255	0	0	0	0	0	0	0	0	0	0
(28)	Energy Sales		GWh	0	0	0	0	0	0	0	0	0	0	0
(29)	NET ENERGY FOR LOAD		GWh	1873	1914	1938	1961	1983	2002	2018	2034	2050	2067	2083

Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(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 Replacement Power		GWh	4.34%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(3)	COAL		GWh	33.41%	34.82%	31.53%	37.45%	41.94%	38.26%	43.27%	17.50%	31.37%	40.89%	36.29%
	RESIDUAL													
(4)		STEAM	GWh	0.00%	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	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	GWh	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWh	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	GWh	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NATURAL GAS													
(12)		STEAM	GWh	10.25%	9.17%	8.86%	6.39%	4.23%	7.84%	3.31%	11.63%	6.12%	3.47%	0.00%
(13)		CC	GWh	25.22%	9.33%	10.94%	12.58%	11.92%	7.90%	9.40%	21.77%	15.17%	9.24%	12.64%
(14)		CT	GWh	1.68%	5.46%	7.03%	3.58%	2.62%	4.90%	4.81%	6.51%	4.51%	3.53%	7.82%
(15)		TOTAL:	GWh	37.15%	23.97%	26.82%	22.56%	18.76%	20.64%	17.51%	39.90%	25.80%	16.23%	20.45%
(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	8.91%	38.15%	38.62%	37.00%	36.34%	38.17%	36.30%	39.71%	39.97%	40.04%	40.43%
(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	1.50%	1.46%	1.44%	1.43%	1.41%	1.40%	1.39%	1.38%	1.37%	1.35%	1.34%
(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	1.06%	1.60%	1.58%	1.56%	1.55%	1.53%	1.52%	1.51%	1.50%	1.48%	1.47%
(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	11.47%	41.21%	41.64%	39.99%	39.30%	41.10%	39.21%	42.59%	42.83%	42.88%	43.25%
(27)	Purchased Energy		GWh	13.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(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%

3. FORECAST OF FACILITIES REQUIREMENTS

3.1 GENERATION RETIREMENTS

The System retired four generating units in October 2013. These retirements included JRK steam unit #7 (23.2 MW), and JRK combustion turbines 1, 2, and 3 (14 MW each). Deerhaven fossil steam unit #1 is scheduled for retirement in August 2022. These recent and planned changes to the System's generation mix 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. However, GRU has been issued a construction permit for the installation of a nominal 50 MW of peaking power in 2018, if required. The need, timing and technology of this peaking power addition are under evaluation.

3.4 DISTRIBUTION SYSTEM ADDITIONS

Up to five new, identical, mini-power delivery substations (PDS) were planned for the GRU system 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, known as Northwest Sub, is planned for addition to the System in 2019. 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
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	44.3%	0	202	44.3%
2009	608	101	0	0	709	465	244	52.4%	0	244	52.4%
2010	608	102	0	0	710	470	240	51.0%	0	240	51.0%
2011	608	56	0	0	663	445	218	49.0%	0	218	49.0%
2012	609	57	0	0	667	415	252	60.7%	0	252	60.7%
2013	598	59	0	0	657	416	241	58.0%	0	241	58.0%
2014	533	113	0	0	645	412	233	56.7%	0	233	56.7%
2015	533	113	0	0	645	417	228	54.8%	0	228	54.8%
2016	533	113	0	0	645	422	223	52.9%	0	223	52.9%
2017	533	113	0	0	645	427	218	51.2%	0	218	51.2%
2018	533	113	0	0	645	431	214	49.8%	0	214	49.8%
2019	533	113	0	0	645	434	211	48.5%	0	211	48.5%
2020	533	113	0	0	645	438	207	47.4%	0	207	47.4%
2021	533	113	0	0	645	441	204	46.2%	0	204	46.2%
2022	458	113	0	0	570	445	125	28.1%	0	125	28.1%
2023	458	113	0	0	570	449	122	27.1%	0	122	27.1%

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

(2) Details of planned changes to installed capacity from 2014-2023 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
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	631	0	0	0	631	361	270	74.7%	0	270	74.7%
2008/09	634	76	0	0	711	421	290	68.8%	0	290	68.8%
2009/10	628	76	0	0	704	464	240	51.8%	0	240	51.8%
2010/11	628	53	0	0	681	409	272	66.4%	0	272	66.4%
2011/12	630	53	0	0	683	371	312	84.1%	0	312	84.1%
2012/13	618	54	0	0	671	348	323	92.9%	0	323	92.9%
2013/14	550	108	0	0	657	335	322	96.0%	0	322	96.0%
2014/15	549.5	107.9	0	0	657.4	340	318	93.6%	0	318	93.6%
2015/16	549.5	107.9	0	0	657.4	344	314	91.3%	0	314	91.3%
2016/17	549.5	107.9	0	0	657.4	347	310	89.2%	0	310	89.2%
2017/18	549.5	107.9	0	0	657.4	351	307	87.5%	0	307	87.5%
2018/19	549.5	107.9	0	0	657.4	354	304	85.9%	0	304	85.9%
2019/20	549.5	107.9	0	0	657.4	356	301	84.5%	0	301	84.5%
2020/21	549.5	107.9	0	0	657.4	359	298	83.1%	0	298	83.1%
2021/22	549.5	107.9	0	0	657.4	362	295	81.6%	0	295	81.6%
2022/23	474.5	107.9	0	0	582.4	365	217	59.6%	0	217	59.6%
2023/24	474.5	104.2	0	0	578.7	368	211	57.3%	0	211	57.3%

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

(2) Details of planned changes to installed capacity from 2014-2023 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
Cyrstal River	3	Citrus County Sec. 33, T17S, R16E	ST	NUC		TK			3/1977	1/2013	-13.5	-13.7	-11.8	-12.0	RT
J. R. KELLY	FS07	Alachua County Sec. 4, T10S, R20E	ST	NG	RFO	PL	TK		8/1961	10/2013	-24.0	-24.0	-23.2	-23.2	RT
J. R. KELLY	GT01	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK		2/1968	10/2013	-14.0	-15.0	-14.0	-15.0	RT
J. R. KELLY	GT02	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK		9/1968	10/2013	-14.0	-15.0	-14.0	-15.0	RT
J. R. KELLY	GT03	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK		5/1968	10/2013	-14.0	-15.0	-14.0	-15.0	RT
Deerhaven	FS01	Alachua County Secs. 26, 27,35, T8S, R19E	ST	NG	RFO	PL	TK		8/1972	8/2022	-80.0	-80.0	-75.0	-75.0	RT

Unit Type
ST = Steam Turbine
GT = Gas Turbine

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

Transportation Method
PL = Pipeline
RR = Railroad
TK = Truck

Status
A = Generating unit capability increased
RT = Generating unit retired or scheduled for retirement
OS = Out of Service

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 Gainesville Renewable Energy Center (GREC) biomass-fueled generation facility is located on land leased from GRU on the northwest portion of the existing Deerhaven Generating Station plant (site). This 100 MW generating unit became commercially operational December 17, 2013. The site is shown in Figure 1.1 and Figure 4.1, located north of Gainesville off U.S. Highway 441. 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 GREC biomass unit utilizes a wastewater treatment system to also accomplish zero liquid discharge however the solid waste produced will not be stored onsite.

4.2.2 Air Emissions

The generation technology for the biomass unit meets all applicable standards for all pollutants regulated for this category of emissions unit.

Figure 4.1

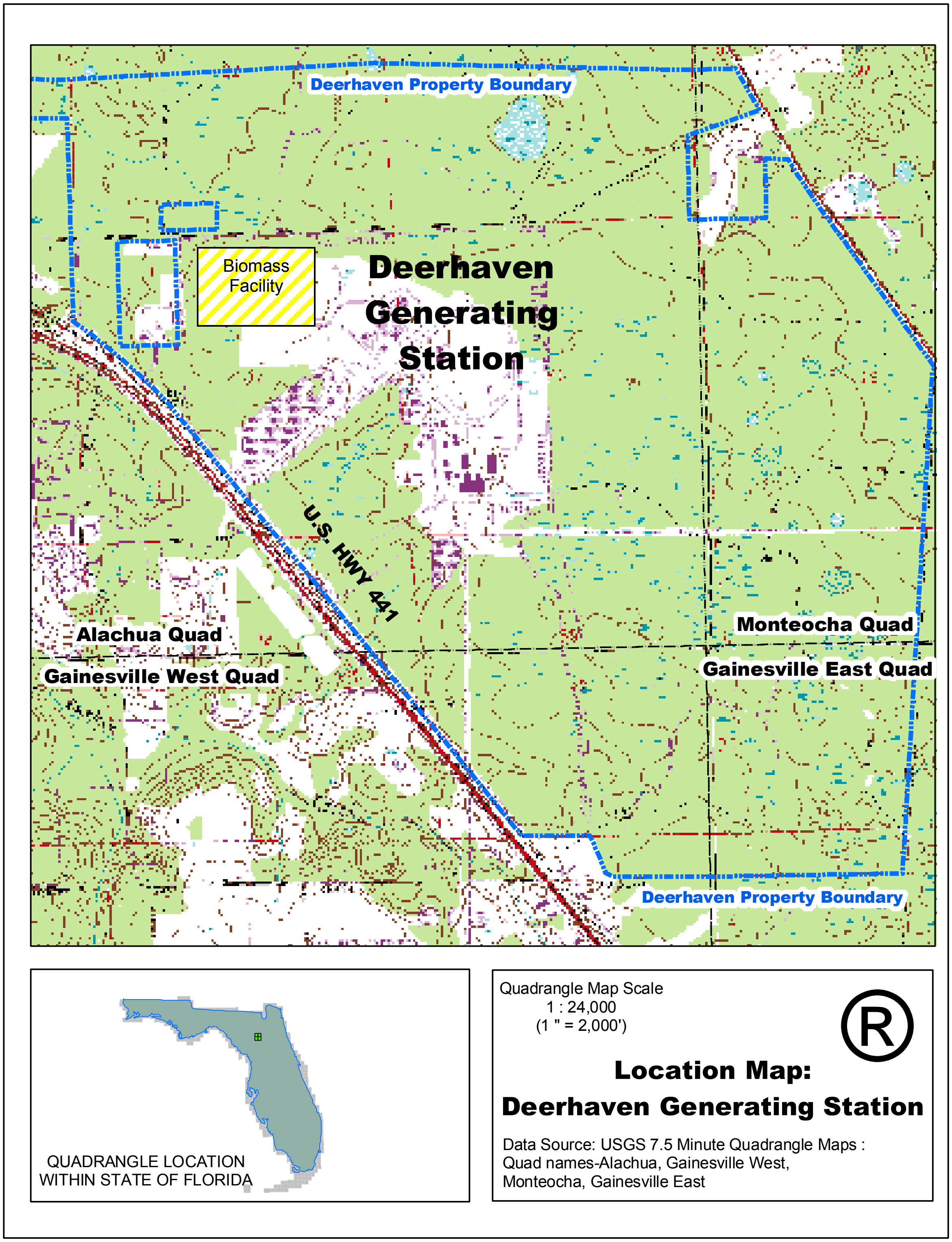
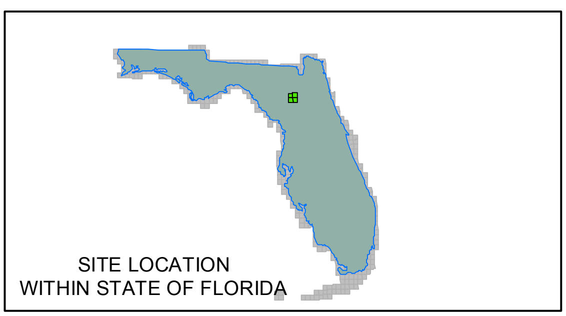

Deerhaven Property Boundary
Biomass Facility
Deerhaven Generating Station
U.S. HWY 441
Alachua Quad
Gainesville West Quad
Monteocha Quad
Gainesville East Quad
Deerhaven Property Boundary
QUADRANGLE LOCATION WITHIN STATE OF FLORIDA
Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')
Location Map:
Deerhaven Generating Station
Data Source: USGS 7.5 Minute Quadrangle Maps :
Quad names-Alachua, Gainesville West,
Monteocha, Gainesville East

Figure 4.2



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

Aerial Photos:
Deerhaven Generating Station