GAINESVILLE REGIONAL UTILITIES

2015 TEN-YEAR SITE PLAN

Submitted to:

The Florida Public Service Commission

April 1, 2015

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INTRODUCTION

The 2015 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 2015 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 cities of Alachua (COA) and Winter Park (WP), and transmission service to Seminole Electric Cooperative (SECI). GRU's distribution system served its territory of approximately 124 square miles and an average of 93,855 customers during 2014. 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 section. The present Summer Net Continuous Capacity is 532.5 MW and the Winter Net Continuous Capacity is 549.5 MW. Currently, the System's energy is produced by three fossil fuel steam turbines[1], one of which is part of a combined cycle unit; and five combustion turbines, three of which are simple cycle, one which can generate in either simple or combined cycle mode; and one which provides distributed generation.

The System has two primary generating plant sites – Deerhaven (DH) and John R. Kelly (JRK). Each site is comprised of both steam turbine and combustion turbine generating units. The JRK station is the site of the steam turbine and combustion turbine that normally operate in combined cycle.[1,2]

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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.

2 CT4 may be operated in simple cycle.

1.1.1 Generating Units[4]

1.1.1.1 Simple Cycle Steam and Combined Cycle Units. The System's two operational simple cycle steam turbines and one combined cycle steam turbine are powered by fossil fuels[3]. The two simple cycle fossil fueled steam turbines comprise 58.1% of the System's Net Summer Continuous Capacity and produced 50.2% of the electric energy supplied by the System in 2014. The combined cycle unit, which includes a heat recovery steam generator (HRSG), steam turbine/generator, and combustion turbine/generator, comprises 20.9% of the System's Net Summer Continuous Capacity and produced 14.3% of the electric energy supplied by the System in 2014. 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 100 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 Combustion Gas Turbines. The System's four industrial combustion turbines that operate only in simple cycle comprise 21.0% of the System's Summer Net generating capacity and produced less than 1% of the electric energy supplied by the System in 2014. Three of these simple cycle combustion turbines are utilized for peaking purposes only as their energy conversion efficiencies are considerably lower than steam or combined cycle units. Simple cycle combustion turbines are advantageous in that they can be started and placed on line quickly. The fourth combustion 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.

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3 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.

4 From this point forward in the document, all MW ratings are Summer Net continuous capacity unless otherwise stated.

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.

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

1.1.3 Other Generation Entitlements

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 approximately 100 MW generating unit became commercially operational December 17, 2013.

The site and location of the biomass facility is northwest of Gainesville, off of U.S. Highway 441 as shown in Figure 1.1 and Figure 4.1 (see Section 4). Under a 30-year Power

Purchase Agreement (PPA), GREC is dispatchable by GRU which has 100% entitlement to all Available Energy, Delivered Energy and Environmental Energy attributes.

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 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 (COA). The Alachua No. 1 Substation is supplied by GRU's looped 138 kV transmission system. The System provides approximately 98% of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from FPL’s St. Lucie 2 nuclear unit. Energy supplied to the COA by this nuclear unit is wheeled over GRU's transmission network, with GRU providing generation backup in the event of outages of this nuclear unit. The System began serving the COA 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 COA have been included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins through this planning horizon.

In January 2015, the system began delivering 10 MW of must-take power to the city of Winter Park (WP) for a term of four years. WP may restrict delivered energy to 5 MW for up to 500 hours per year. The point of delivery is GRU's connection with Duke.

1.5 DISTRIBUTED GENERATION

The South Energy Center (SEC), a combined heating and power plant (CHP), began providing services to the UF Health South Campus hospital in February 2009. In November 2009, UF Health South Campus hospital went into full hospital operation. SEC 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.

UF Health has begun the construction of a new cardio-vascular/neuro-surgical hospital. The SEC is being expanded (SEC Phase II) to serve this new facility.

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

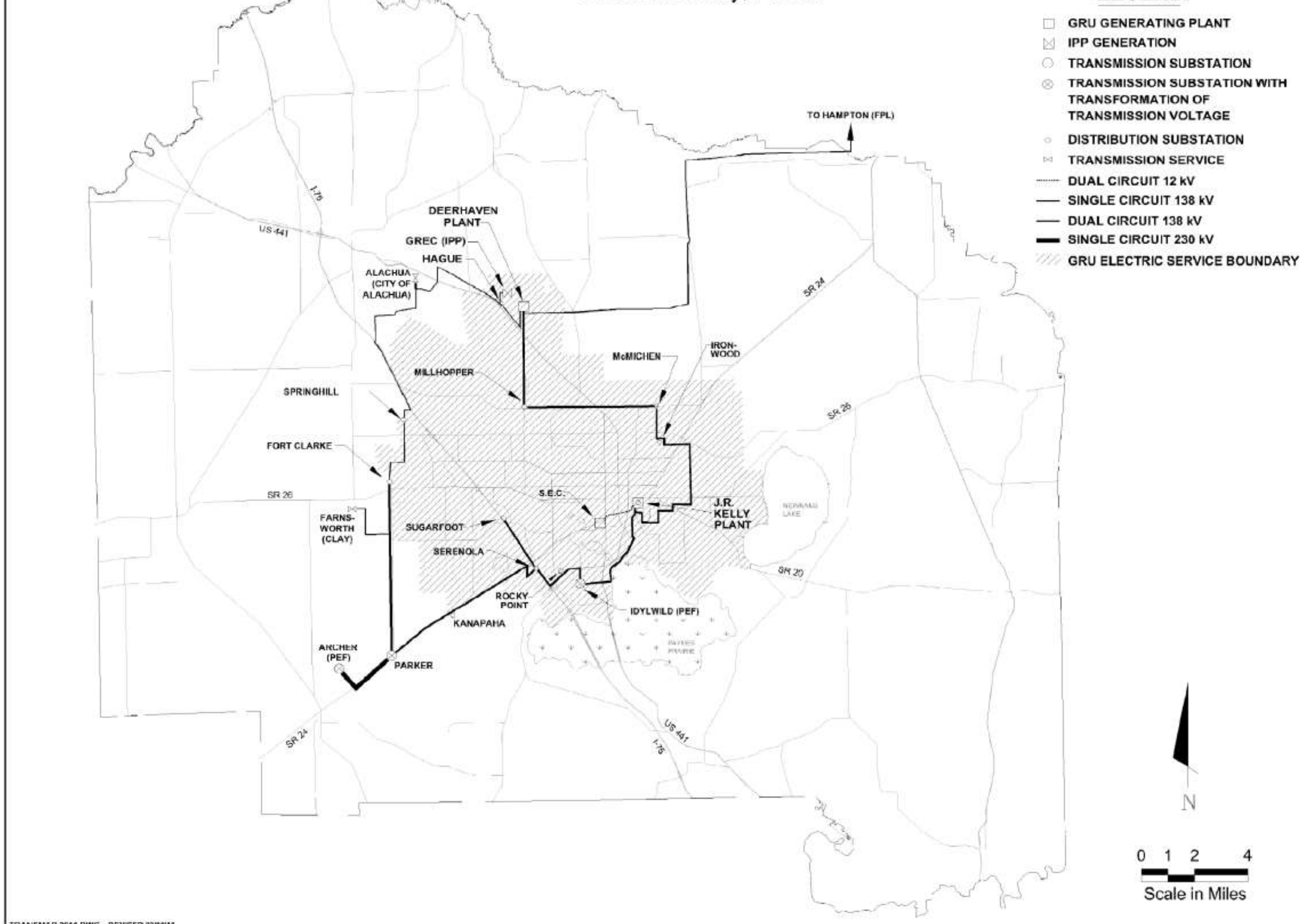
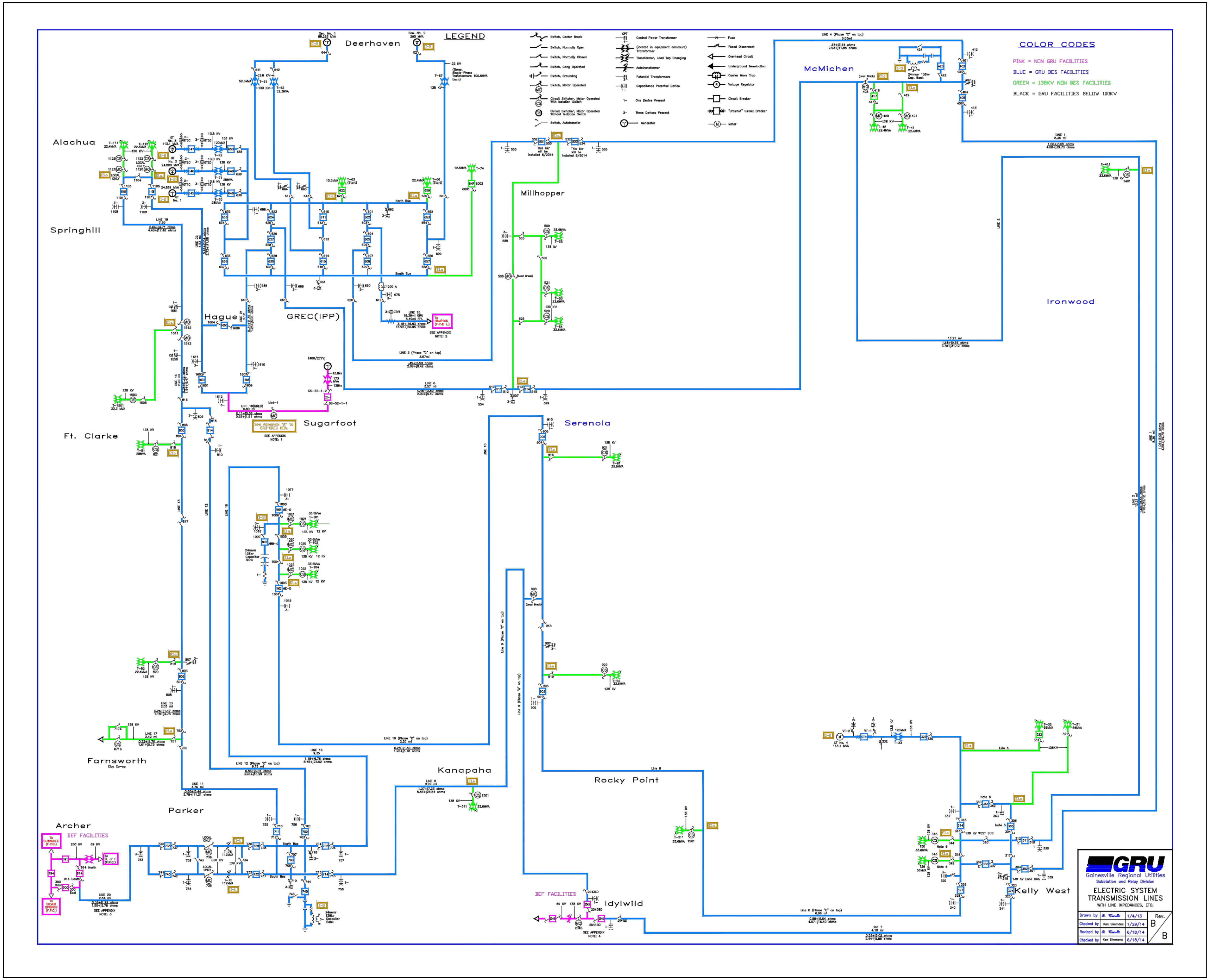


FIGURE 1.2

Gainesville Regional Utilities Electric System One-Line Diagram



Schedule 1

EXISTING GENERATING FACILITIES (as of January 1, 2015)

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Primary Fuel Type	(6) Primary Fuel Trans.	(7) Alternate Fuel Type	(8) Alternate Fuel Trans.	(9) Alt. Fuel Storage (Days)	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gross Capability Summer MW	(13) Gross Capability Winter MW	(14) Net Capability Summer MW	(15) Net Capability Winter MW	(16) Status
J. R. Kelly		Alachua County									**112.0**	**125.0**	**110.0**	**123.0**	
	FS08	Sec. 4, T10S, R20E	CA	WH					[4/65 ; 5/01]	2051	38.0	38.0	37.0	37.0	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	2051	74.0	87.0	73.0	86.0	OP
Deerhaven		Alachua County									**444.0**	**464.0**	**413.0**	**433.0**	
	FS02	Secs. 26,27,35	ST	BIT	RR				10/81	2031	254.0	254.0	231.0	231.0	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	2022	80.0	80.0	75.0	75.0	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	74.0	84.0	73.0	83.0	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	18.0	23.0	17.0	22.0	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	18.0	23.0	17.0	22.0	OP
South Energy Center Distributed Generation	GT1	Alachua County SEC. 10, T10S, R20E	GT	NG		PL			5/09		**4.5**	**4.5**	**3.5**	**3.5**	OP
System Total													**526.5**	**559.5**	

<u>Unit Type</u>
- CA = Combined Cycle - Steam Part
- CT = Combined Cycle - CT Part
- GT = Gas Turbine
- ST = Steam Turbine

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

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

<u>Status</u>
- 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 – Duke	168.0[2]	Transformer	168.0[2]	Transformer

1) These two transformers are located at the FPL Hampton 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 Duke.

3) Transformers T75 & T76 normal limits are based on a 65° C temperature rise rating, and the emergency rating is 133%% loading for two hours.

<u>Assumptions</u>:

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[1]	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

1 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 7 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 2005-2024. 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 2014. 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 168 (April 2014), and Estimates of Population by County and City in Florida: April 1, 2014 (10/17/2014).

(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 1984-2014.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2014, 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 170 (December 2014), 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 1980-2014. 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 of FPL nuclear capacity supplied approximately 2.3% of its annual energy requirements in 2014.

(11) GRU will supply 10 MW of base load energy to the City of Winter Park from 2015 through 2018.

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 2015 through 2024. 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 the City of Alachua, and sales to the City of Winter Park. 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:

$$RESAVUSE = 15017 - 41.56\,(RESPR14) + 0.766\,(HDD) - 956.9\,(EE)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use per Customer
RESPR14	=	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	=	0.9372
DF (error)	=	18 (period of study, 1993-2014)
t - statistics:		
Intercept	=	34.07
RESPR14	=	-11.30
HDD	=	3.58
EE	=	-6.59

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 = *208850 + 285.6 (POP) – 87892 (HHSIZE) + 1.53 (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	=	0.9958
DF (error)	=	18 (period of study, 1993-2014)
t - statistics:		
Intercept	=	3.31
POP	=	9.38
HHSIZE	=	-3.57
CLYRCUS	=	3.18

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 40% 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:

$$GSNAVUSE = 15.15 - 0.019\,(OPTDCUS) + 0.0003\,(MSAPCY14) + 0.0016\,(CDD)$$

Where:

GSNAVUSE	=	Average Annual Energy Usage per GSN Customer
OPTDCUS	=	Optional GSD Customers
MSAPCY14	=	Per Capita Income
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.9668
DF (error)	=	18 (period of study, 1993-2014)

t - statistics:		
Intercept	=	4.35
OPTDCUS	=	-14.20
MSAPCY14	=	3.31
CDD	=	2.16

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, the addition of a group of individually metered cable amplifiers that were previously bulk metered, and the number of recent additions to this class that were previously billed in the traffic signal rate category. The specifications of the general service non-demand customer model are as follows:

$$GSNCUS = -3717 + 52.6\,(POP) - 0.97\,(OPTDCUS) + 1.07\,(COXTRAN) + 1.44\,(TRFTRAN)$$

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
OPTDCUS	=	Optional GSD Customers
COXTRAN	=	Cable TV Meters
TRFTRAN	=	Traffic Signal GSN Customers
Adjusted R^2	=	0.9936
DF (error)	=	17 (period of study, 1993-2014)

t - statistics:

Intercept	=	-4.75
POP	=	12.91
OPTDCUS	=	-1.74
COXTRAN	=	4.60
TRFTRAN	=	1.18

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, cooling degree days, and an indicator variable representing a change in eligibility criteria for the large power rate category. Average energy use projections for general service demand customers result from the following model:

$$GSDAVUSE = 422.1 - 0.21\,(OPTDCUS) + 0.67\,(MSA\_NF) + 0.024\,(CDD) + 32.6\,(POLICY)$$

Where:

GSDAVUSE	=	Average Annual Energy Use by GSD Customers
OPTDCUS	=	Optional GSD Customers
MSA_NF	=	Non-Farm Employment
CDD	=	Cooling Degree Days
POLICY	=	Eligibility Indicator Variable

Adjusted R^2	=	0.9359
DF (error)	=	17 (period of study, 1993-2014)
t - statistics:		
Intercept	=	8.03
OPTDCUS	=	-11.82
MSA_NF	=	1.98
CDD	=	2.21
POLICY	=	4.25

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	=	*--948.8 + 8.42 (POP) + 0.19 (OPTDCUS)*
Where:		
GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
OPTDCUS	=	Optional GSD Customers
Adjusted R^2	=	0.9792
DF (error)	=	19 (period of study, 1993-2014)
t - statistics:		
Intercept	=	-4.33
POP	=	7.58
OPTDCUS	=	1.65

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 2014. The model developed to project average use by large power customers includes per capita income, cooling degree days, 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	=	*5694 + 0.062 (MSAPCY14) + 0.90 (CDD) + 3248 (Policy)*
Where:		
LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
MSAPCY14	=	Gainesville MSA Per Capita Income
CDD	=	Cooling Degree Days
POLICY	=	Eligibility Indicator Variable
Adjusted R^2	=	0.9187
DF (error)	=	18 (period of study, 1993-2014)
t - statistics:		
INTERCEPT	=	2.74
MSAPCY14	=	1.71
CDD	=	1.54
Policy	=	11.08

The number of customers in the large power sector is expected to increase from 12 to 13 in 2018 with the addition of a new hospital. 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.

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 2.3% of Alachua's 2014 energy requirements were met through generation entitlements of a nuclear generating unit operated by 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 Alachua County population, heating degree days, and cooling degree days as the independent variables. The model used to develop projections of sales to the City of Alachua is of the following form:

$$ALAMWh = -266969 + 1390\,(POP) + 11.7\,(HDD) + 9.9\,(CDD)$$

Where:

ALAMWh	=	Energy Sales to the City of Alachua (MWh)
POP	=	Alachua County Population (000's)
HDD	=	Heating Degree Days
CDD	=	Cooling Degree Days
Adjusted R^2	=	0.9746
DF (error)	=	17 (period of study, 1994-2014)

t - statistics:

Intercept	=	-12.86
POP	=	27.14
HDD	=	2.61
CDD	=	1.69

GRU is also selling base load energy to the City of Winter Park from 2015 through 2018. The agreement calls for Winter Park to purchase 10 MW for all but 500 hours each year, when they may purchase as little as 5 MW.

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 for resale. 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 0.9600. 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. March 2009 GRU became the first utility in the United States to offer a European-style Solar Feed-in Tariff (FIT) Program. The program was scheduled to add capacity through 2016, limiting total capacity of 4 (additional) MW per year. Subsequently GRU agreed to purchase 100% of solar power produced by any qualified private generator, at a fixed rate, for a contract term of 20 years. The cost would be recovered through fuel adjustment charges.

Approximately 18.6 MW were constructed under the Solar FIT Program through 2013. There were no additions allocated for 2014 or 2015 due to the program being suspended indefinitely. GRU is no longer accepting new projects or adding capacity.

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 2014.

During 2014 budget deliberations, GRU management and the Gainesville City Commission agreed to eliminate the majority of programs offering financial incentives in an effort to cut costs and keep prices down for customers. The effectiveness of historical measures is reflected in usage data. Over the past 10 years, residential usage per customer has declined 2.2% per year and non-residential usage per customer has declined 1.7% per year.

DSM direct services currently available to the System's residential customers include allowances for whole house energy efficiency improvements under the Low-income Energy Efficiency Program (LEEP), natural gas rebates for new construction and conversions in existing homes for water heating, central heating, clothes drying and cooking appliances, and energy and water surveys. A new on-line energy survey will be available mid-2015. This service will allow customers to perform their own analysis using their actual usage data.

Energy and water surveys are available at no cost to the System's non-residential customers. 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 2014, GRU estimates that utility sponsored DSM programs reduced energy sales by 218 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 and future year's budgets.

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 1980 were injected with a solution restoring the insulation of the cable and extending 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.

2.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU relies on coal and natural gas as primary fuels used to meet its generation needs. Both heavy and light fuel oils are used as backup for natural gas fired generation.. 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, Coaldesk, 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 69.3% of the energy produced by the system in calendar year 2014. 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. Given the impact of impending environmental regulations on coal generating units, reduced demand, and depressed prompt prices for Central Appalachian coal, GRU has continued to purchase relatively high quality Eastern coals. Rates available under GRU's rail transport contract also provide an incentive for GRU to purchase and transport its coal supplies on the East Coast. The forecast of coal prices is based on a blend of low sulfur and medium sulfur central Appalachian coal. GRU's forecast of coal pricing assumes that 2015 and 2016 coal procurement will primarily consist of high quality CAPP coals.. GRU does not expect the favorable economics of rail transported CAPP coal to be diminished in the near term. Although not included in its forecast pricing, GRU continues to evaluate the economics of Illinois Basin and Northern Appalachian coal supply. Pricing of these coals was sourced from Argus Coal Daily publications. GRU has a contract with CSXT for delivery of coal to the Deerhaven plant site through 2019. Rates for coal transportation are based on the terms of GRU's existing rail contract and historical rates of escalation under the contract. A step increase in the delivered coal price is expected in 2020 resulting from higher transportation costs.

In addition to the commodity price of coal and rail transport expense, GRU's delivered price of coal also incorporates the cost of environmental commodities (pebble lime and urea) required for combustion of coal in compliance with environmental regulations.

2.5.2 Natural Gas

GRU procures natural gas for power generation and for distribution as a Local Distribution Company (LDC). In 2014, GRU purchased approximately 6.6 million MMBtu for use by both systems. GRU power plants used 69% of the total purchased for GRU during 2014, while the LDC used the remaining 31%. Natural gas was used to produce approximately 30.6% 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. Commodity fuel cost projections were based on closing NYMEX natural gas futures prices for the Henry Hub.

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
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	189,964	2.32	805	81,881	9,829	772	10,373	74,401
2012	190,537	2.32	757	82,128	9,219	750	10,415	72,025
2013	191,720	2.32	753	82,638	9,118	757	10,484	72,240
2014	193,889	2.33	773	83,214	9,287	760	10,629	71,479
2015	195,023	2.32	769	84,061	9,143	769	10,790	71,272
2016	196,949	2.32	775	84,892	9,124	778	10,948	71,090
2017	198,835	2.32	780	85,705	9,105	788	11,103	70,961
2018	200,682	2.32	786	86,501	9,088	796	11,255	70,717
2019	202,489	2.32	792	87,280	9,071	804	11,405	70,530
2020	204,256	2.32	797	88,041	9,056	813	11,552	70,411
2021	205,983	2.32	803	88,786	9,041	822	11,696	70,273
2022	207,670	2.32	808	89,513	9,026	830	11,837	70,149
2023	209,317	2.32	813	90,223	9,013	839	11,976	70,037
2024	210,925	2.32	818	90,916	9,001	847	12,111	69,918

* 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 **						
Year	GWh	Average Number of Customers	Average MWh per Customer	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
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	151	12	12,614	0	25	0	1,709
2015	158	12	13,148	0	24	0	1,720
2016	158	12	13,190	0	24	0	1,735
2017	159	12	13,249	0	24	0	1,751
2018	173	13	13,288	0	24	0	1,779
2019	173	13	13,331	0	24	0	1,793
2020	174	13	13,380	0	24	0	1,808
2021	175	13	13,424	0	24	0	1,824
2022	175	13	13,465	0	24	0	1,837
2023	176	13	13,508	0	24	0	1,852
2024	176	13	13,552	0	24	0	1,865

** Industrial includes Large Power Rate Class

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

(1) Year	(2) Sales For Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers	(6) Total Number of Customers
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	121	46	1,875	0	93,855
2015	209	76	2,005	0	94,863
2016	212	78	2,025	0	95,851
2017	216	79	2,046	0	96,820
2018	220	79	2,078	0	97,769
2019	138	81	2,012	0	98,697
2020	142	82	2,032	0	99,606
2021	146	81	2,051	0	100,494
2022	149	83	2,069	0	101,363
2023	153	83	2,088	0	102,212
2024	156	84	2,105	0	103,040

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
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	25	391	0	0	27	0	16	416
2014	452	26	383	0	0	27	0	16	409
2015	466	37	386	0	0	27	0	16	423
2016	470	38	389	0	0	27	0	16	427
2017	476	39	393	0	0	28	0	16	432
2018	483	39	400	0	0	28	0	16	439
2019	477	30	403	0	0	28	0	16	433
2020	481	31	406	0	0	28	0	16	437
2021	485	32	409	0	0	28	0	16	441
2022	489	33	412	0	0	28	0	16	445
2023	493	33	416	0	0	28	0	16	449
2024	497	34	419	0	0	28	0	16	453

Schedule 3.2
History and Forecast of Winter Peak Demand - MW

(1) Winter	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2005 / 2006	436	40	346	0	0	42	0	8	386
2006 / 2007	413	38	324	0	0	43	0	8	362
2007 / 2008	416	40	321	0	0	45	0	10	361
2008 / 2009	478	50	371	0	0	46	0	11	421
2009 / 2010	522	55	409	0	0	47	0	11	464
2010 / 2011	470	51	358	0	0	49	0	12	409
2011 / 2012	434	47	324	0	0	50	0	13	371
2012 / 2013	412	22	326	0	0	51	0	13	348
2013 / 2014	412	23	325	0	0	51	0	13	348
2014 / 2015	384	36	284	0	0	51	0	13	320
2015 / 2016	417	37	316	0	0	51	0	13	353
2016 / 2017	422	38	319	0	0	52	0	13	357
2017 / 2018	428	39	324	0	0	52	0	13	363
2018 / 2019	421	29	327	0	0	52	0	13	356
2019 / 2020	424	30	329	0	0	52	0	13	359
2020 / 2021	428	31	332	0	0	52	0	13	363
2021 / 2022	431	32	334	0	0	52	0	13	366
2022 / 2023	434	32	337	0	0	52	0	13	369
2023 / 2024	437	33	339	0	0	52	0	13	372
2024 / 2025	440	34	341	0	0	52	0	13	375

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 %
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	2,248	117	49	1,781	203	98	2,082	51%
2010	2,319	124	56	1,825	217	97	2,139	52%
2011	2,213	134	63	1,770	201	45	2,016	52%
2012	2,163	143	68	1,700	195	57	1,952	54%
2013	2,070	147	70	1,695	113	45	1,853	51%
2014	2,093	148	70	1,709	121	45	1,875	52%
2015	2,223	148	70	1,719	209	77	2,005	54%
2016	2,244	149	70	1,736	212	77	2,025	54%
2017	2,265	149	70	1,751	216	79	2,046	54%
2018	2,298	150	70	1,779	220	79	2,078	54%
2019	2,232	150	70	1,794	138	80	2,012	53%
2020	2,253	151	70	1,808	142	82	2,032	53%
2021	2,272	151	70	1,823	146	82	2,051	53%
2022	2,290	151	70	1,837	149	83	2,069	53%
2023	2,310	152	70	1,851	153	84	2,088	53%
2024	2,327	152	70	1,865	156	84	2,105	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			
	2014		2015		2016	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	348	161	*330*	155	353	156
FEB	313	126	*370*	135	317	136
MAR	249	132	287	142	290	143
APR	327	138	322	146	325	147
MAY	346	161	383	176	387	178
JUN	387	177	418	191	422	193
JUL	392	191	423	206	427	208
AUG	409	194	423	209	427	212
SEP	381	173	406	191	410	193
OCT	325	150	349	163	353	164
NOV	263	134	291	140	294	142
DEC	279	138	317	151	320	153

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
FUEL REQUIREMENTS			UNITS	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	395	440	563	447	448	437	422	433	416	433	439
	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	0	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(11)		STEAM	1000 MCF	65	566	442	181	194	271	224	196	126	0	0
(12)		CC	1000 MCF	1523	2480	2196	1737	1872	1280	1712	1707	2332	2039	2274
(13)		CT	1000 MCF	0	8	16	4	15	36	27	7	2	220	164
(14)		TOTAL:	1000 MCF	1588	3055	2653	1922	2081	1588	1963	1910	2460	2259	2438
(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, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR Replacement Power		GWh	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	820	853	848	838	840	815	781	804	766	807	820
	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	56	61	33	13	13	19	16	14	8	0	0
(13)		CC	GWh	250	303	269	210	226	154	206	206	281	245	273
(14)		CT	GWh	9	1	1	0	1	2	2	0	0	15	11
(15)		TOTAL:	GWh	315	365	302	223	240	175	224	220	289	260	284
(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	576	586	764	797	799	798	803	800	793	798	804
(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	0
(22)	MSW		GWh	0	0	0	0	0	0	0	0	0	0	0
(23)	SOLAR	FIT & Net	GWh	31	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	635	645	823	856	858	857	861	859	852	857	835
(27)	Purchased Energy		GWh	105	142	52	129	140	165	166	168	162	165	166
(28)	Energy Sales		GWh	0	0	0	0	0	0	0	0	0	0	0
(29)	NET ENERGY FOR LOAD		GWh	1875	2005	2025	2046	2078	2012	2032	2051	2069	2088	2105

Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(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	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(3)	COAL		GWh	43.74%	42.57%	41.87%	40.97%	40.44%	40.50%	38.42%	39.22%	37.02%	38.62%	38.97%
	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	2.99%	3.04%	1.62%	0.61%	0.62%	0.95%	0.78%	0.66%	0.40%	0.00%	0.00%
(13)		CC	GWh	13.34%	15.13%	13.26%	10.28%	10.87%	7.66%	10.15%	10.02%	13.56%	11.72%	12.96%
(14)		CT	GWh	0.48%	0.03%	0.05%	0.01%	0.04%	0.12%	0.09%	0.02%	0.00%	0.73%	0.53%
(15)		TOTAL:	GWh	16.81%	18.20%	14.93%	10.90%	11.53%	8.72%	11.02%	10.71%	13.97%	12.46%	13.49%
(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	30.69%	29.23%	37.73%	38.95%	38.47%	39.66%	39.50%	39.02%	38.34%	38.22%	38.19%
(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	1.49%	1.40%	1.38%	1.37%	1.35%	1.39%	1.38%	1.37%	1.35%	1.34%	0.00%
(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	1.65%	1.53%	1.51%	1.50%	1.48%	1.52%	1.51%	1.50%	1.48%	1.47%	1.46%
(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	33.84%	32.15%	40.62%	41.82%	41.30%	42.58%	42.39%	41.88%	41.18%	41.02%	39.65%
(27)	Purchased Energy		GWh	5.60%	7.08%	2.57%	6.30%	6.74%	8.20%	8.17%	8.19%	7.83%	7.90%	7.89%
(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, compact power delivery systems (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 at this time as the 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 compact-power delivery systems 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 MVA class transformers that are radial-tapped to our looped 138 kV system. The Springhill Substation consists of one 33 MVA class transformer served by a loop fed pole mounted switch. Each PDS will consist of one (or more) 138/12.47 kV, 33 MVA class, wye-wye substation transformer with a maximum of eight distribution circuits. 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)
Year	Total Installed Capacity (2) MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available (3) MW	System Firm Summer Peak Demand (1) MW	Reserve Margin before Maintenance MW	Reserve Margin before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance (1) MW	Reserve Margin after Maintenance (1) % of Peak
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	57.9%	0	241	57.9%
2014	523	113	0	0	635	409	226	55.3%	0	226	55.3%
2015	523	113	0	0	635	423	212	50.2%	0	212	50.2%
2016	523	113	0	0	635	427	208	48.6%	0	208	48.6%
2017	523	113	0	0	635	432	203	47.1%	0	203	47.1%
2018	523	113	0	0	635	439	196	44.7%	0	196	44.7%
2019	523	113	0	0	635	433	202	46.7%	0	202	46.7%
2020	523	113	0	0	635	437	198	45.3%	0	198	45.3%
2021	523	113	0	0	635	441	194	43.9%	0	194	43.9%
2022	448	113	0	0	560	445	115	25.8%	0	115	25.8%
2023	448	113	0	0	560	449	111	24.6%	0	111	24.6%
2024	448	109	0	0	557	453	103	22.8%	0	103	22.8%

(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 2015-2024 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
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	348	309	88.9%	0	309	88.9%
2014/15	560.5	107.9	0	0	668.4	340	329	96.8%	0	329	96.8%
2015/16	560.5	107.9	0	0	668.4	353	315	89.2%	0	315	89.2%
2016/17	560.5	107.9	0	0	668.4	357	312	87.3%	0	312	87.3%
2017/18	560.5	107.9	0	0	668.4	363	306	84.4%	0	306	84.4%
2018/19	560.5	107.9	0	0	668.4	356	313	87.8%	0	313	87.8%
2019/20	560.5	107.9	0	0	668.4	359	309	86.0%	0	309	86.0%
2020/21	560.5	107.9	0	0	668.4	363	306	84.3%	0	306	84.3%
2021/22	560.5	107.9	0	0	668.4	366	303	82.7%	0	303	82.7%
2022/23	485.5	107.9	0	0	593.4	369	224	60.8%	0	224	60.8%
2023/24	485.5	104.2	0	0	589.7	372	217	58.4%	0	217	58.4%
2024/25	486	104	0	0	590	375	214	57.1%	0	214	57.1%

(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 2015-2024 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
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

Any additional system generation is expected to be sited at the existing Deerhaven plant. Evaluation of the need for future generation is in progress.

4.2.1 Land Use and Environmental Features

The location of the site is indicated on Figure 1.1 (see Section 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 has been reduced by 1.4 MGD to accommodate the

GREC biomass 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 GRU portion of the site has zero discharge of process wastewater to surface and ground waters, with a brine concentrator/spray dryer and on-site storage and off-site disposal of solid wastewater 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

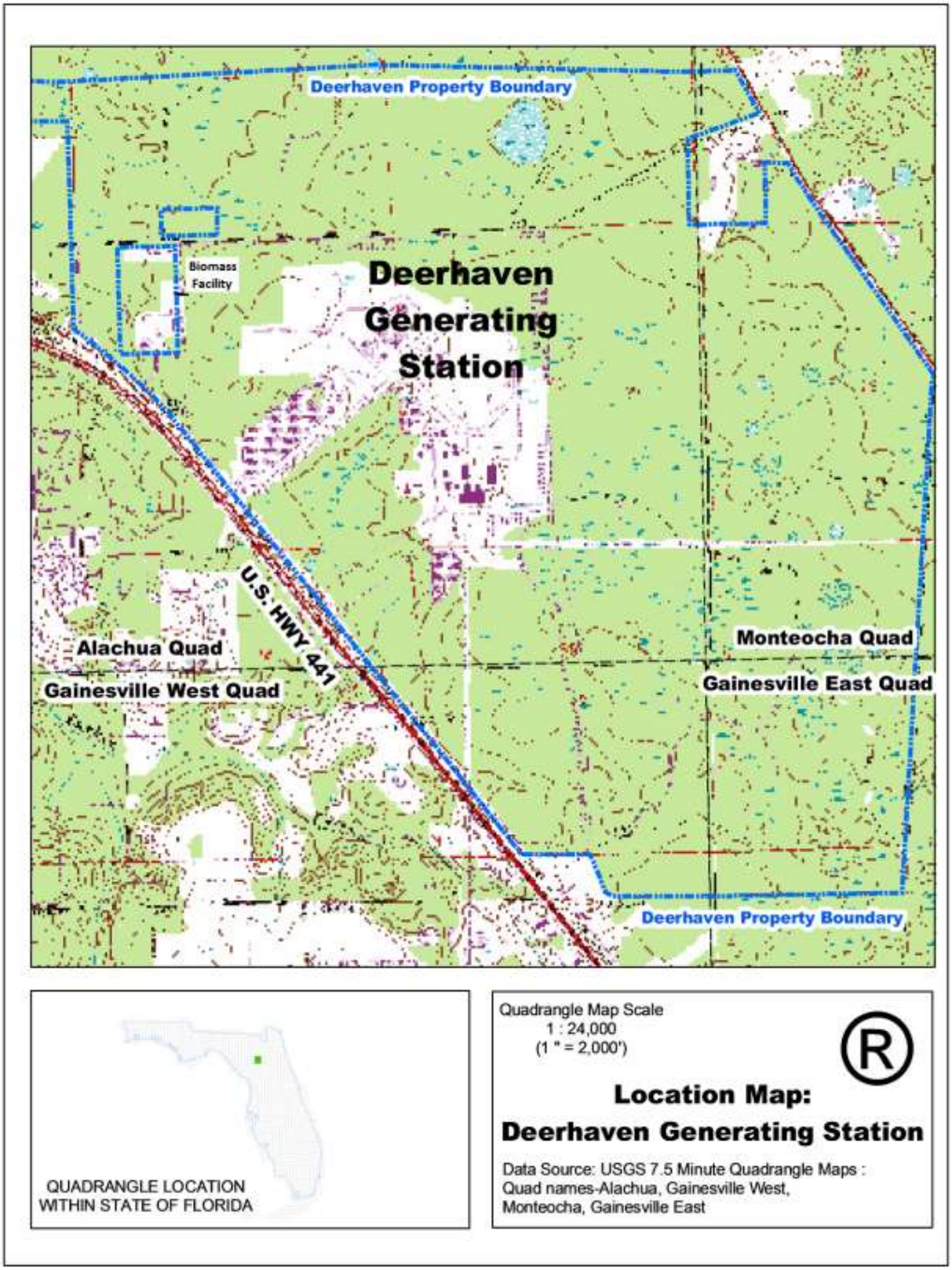

Deerhaven Property Boundary
Biomass Facility
Deerhaven Generating Station
U.S. HWY 441
Alachua Quad
Gainesville West Quad
Monteocha Quad
Gainesville East Quad
Deerhaven Property Boundary
QUADRANGLE LOCATION WITHIN STATE OF FLORIDA
Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')
Location Map:
Deerhaven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

Figure 4.2


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