GAINESVILLE REGIONAL UTILITIES

2017 TEN-YEAR SITE PLAN

Submitted to:

The Florida Public Service Commission

April 1, 2017

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INTRODUCTION

The 2017 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 2017 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 (Alachua) and Winter Park, 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 95,161 customers during 2016. 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 520.5 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[3]

1.1.1.1 Simple Cycle Steam and Combined Cycle Units. The System's two simple cycle steam turbines and one combined cycle steam turbine are powered by fossil fuels[4]. The two simple cycle fossil-fueled steam turbines comprise 58.2% of the System's Net Summer Continuous Capacity and produced 48.2% of the electric energy supplied by the System in 2016. The combined cycle unit, which includes a heat recovery steam generator (HRSG), steam turbine/generator, and combustion turbine/generator, comprise 20.7% of the System's Net Summer Continuous Capacity and produced 50.0% of the electric energy supplied by the System in 2016. DH 2 (228 MW) and JRK CC1 (108 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 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 2% of the electric energy supplied by the System in 2016. 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 online quickly. The fourth combustion turbine operates to serve base load as

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

4 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.

part of a combined heating and power facility at the South Energy Center, further described in Section 1.5. The combustion turbine mentioned in 1.1.1.1 that is used majority of the time in combined cycle can be operated in simple cycle to provide for peaking power.

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. 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 acid gases, 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 102.5 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 PPA, GREC is dispatchable by GRU, and GRU 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 Duke Energy Florida (DEF),
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:

- 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	

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.

1.2.3 State Interconnections

The System is currently interconnected with DEF and FPL at four separate points. The System interconnects with DEF'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 addition of a third 112 MVA transformer at the Parker Substation is planned, and is expected to be in service by December 2018. The System also interconnects with DEF'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 that 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 experienced 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 the 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 nearly 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 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 City of Alachua by this nuclear unit is wheeled over GRU's transmission network, with GRU providing generation backup in the event of an outages of this nuclear unit. The System began serving the City of Alachua in July 1985 and has provided full-requirements wholesale electric service since January 1988. An agreement was made in 2016 to extend GRU’s service to the City of Alachua until March 2022. 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.

The System also provides wholesale power to the City of Winter Park. Through this agreement, GRU provides up to 10 MW of energy around-the-clock to the City of Winter Park through 2018. This energy is delivered through via Duke Energy’s transmission system.

1.5 DISTRIBUTED GENERATION

The South Energy Center (SEC), a combined heating and power plant (CHP), began providing services to the UF Health Shands Cancer Hospital in February 2009. The SEC houses a 3.5 MW natural gas-fired turbine capable of supplying

100% of the hospital's electric and thermal needs. The SEC 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 construction of a new cardiovascular/neuro-surgical hospital. The SEC is currently being expanded (SEC Phase II) to serve this new facility with the addition of a 7.4 MW reciprocating internal combustion engine.

Figure 1.1

Gainesville Regional Utilities Electric Facilities

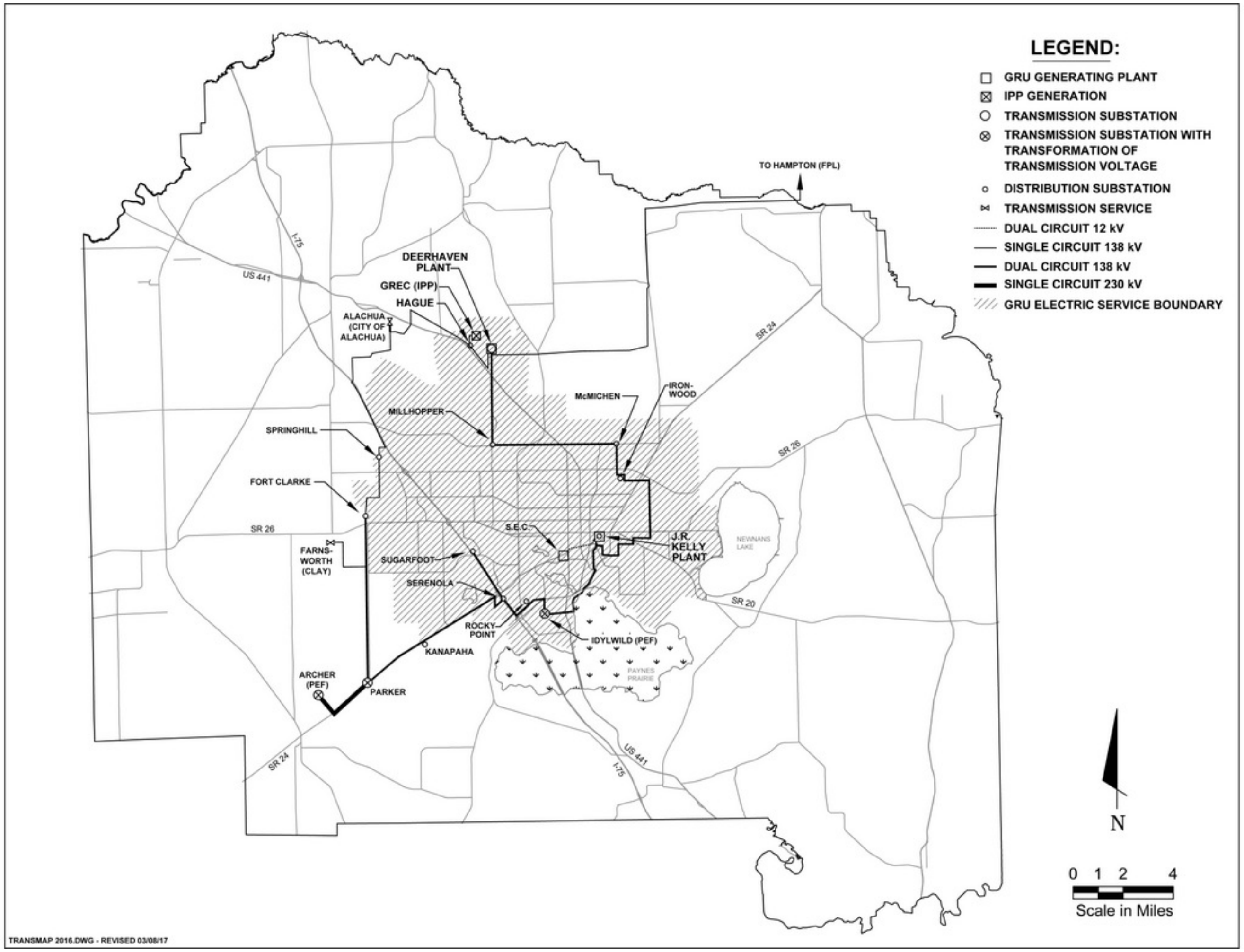
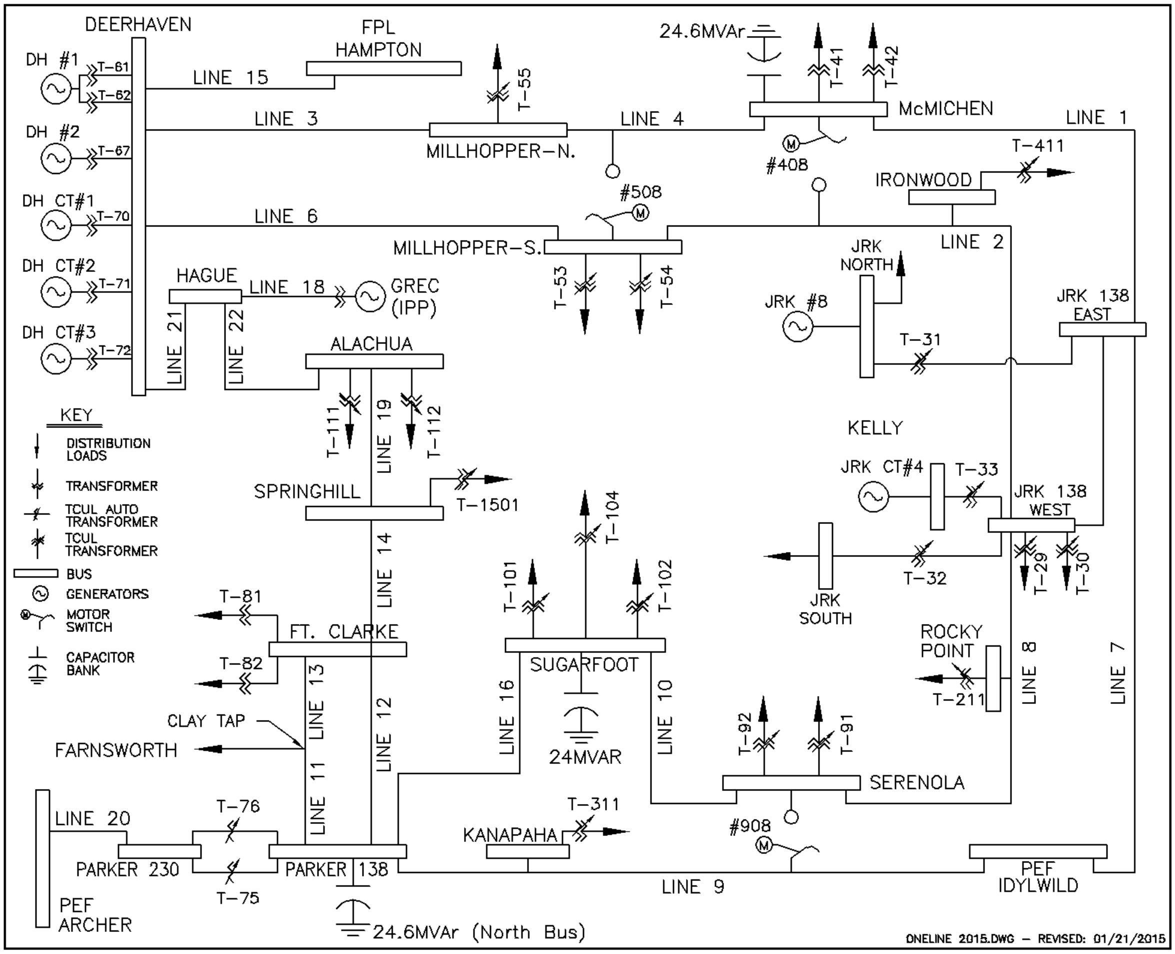


Figure 1.2

Gainesville Regional Utilities Electric System One-Line Diagram



Schedule 1
EXISTING GENERATING FACILITIES (as of January 1, 2017)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								Alt.							
								Fuel	Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Primary Fuel		Alternate Fuel		Storage	In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Type	Trans.	Type	Trans.	(Days)	Month/Year	Month/Year	MW	MW	MW	MW	Status
J. R. Kelly		Alachua County									**110.0**	**120.0**	**108.0**	**118.0**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL	DFO	TK		[4/65 ; 5/01]	2035	37.5	38.0	36.0	37.0	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	2051	72.5	82.0	72.0	81.0	OP
Deerhaven		Alachua County									**438.5**	**459.0**	**409.0**	**428.0**	
	FS02	Secs. 26,27,35	ST	BIT	RR				10/81	2031	251.0	251.0	228.0	228.0	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	71.5	82.0	71.0	81.0	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	18.0	23.0	17.5	22.0	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	18.0	23.0	17.5	22.0	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													**520.5**	**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	22
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 8 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 2007-2026. 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 2016. 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 174 (January 2016), and Estimates of Population by County and City in Florida: April 1, 2016 (December 2016).

(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 1984-2016.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2016, 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 2.25% 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 176 (December 2016), 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 1980-2016. 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 March 2022. Alachua’s ownership of FPL nuclear capacity supplied approximately 2.4% of its annual energy requirements in 2016.

(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 2017 through 2026. 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)[3]. 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:

$$RESAVUSE = 15142 - 43.31\,(RESPR16) + 0.884\,(HDD) - 881.9\,(EE)$$

Where:

RESAVUSE = Average Annual Residential Energy Use per Customer

RESPR16 = Residential Price, Dollars per 1000 kWh

HDD = Annual Heating Degree Days

EE = Energy Efficiency Indicator Variable

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

Adjusted R^2	=	0.9346
DF (error)	=	20 (period of study, 1993-2016)
t - statistics:		
Intercept	=	33.7
RESPR14	=	-13.1
HDD	=	4.37
EE	=	-6.24

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 = *170609 + 303.9 (POP) – 73044 (HHSIZE) + 1.39 (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	=	0.9962
DF (error)	=	20 (period of study, 1993-2016)
t - statistics:		
Intercept	=	5.59
POP	=	20.29
HHSIZE	=	-6.03
CLYRCUS	=	3.33

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. As a result, a significant proportion of current 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= *13.85 – 0.021 (OPTDCUS) + 0.0003 (MSAPCY15)*
+ 0.0018 (CDD)

Where:

GSNAVUSE	=	Average Annual Energy Usage per GSN Customer
OPTDCUS	=	Optional GSD Customers
MSAPCY16	=	Per Capita Income
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.9689
DF (error)	=	20 (period of study, 1993-2016)

t - statistics:		
Intercept	=	3.87
OPTDCUS	=	-14.5
MSAPCY16	=	3.29
CDD	=	2.72

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	=	*-3635 + 52.2 (POP) – 1.04 (OPTDCUS)*
		+ 1.08 (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	=	0.9943
DF (error)	=	20 (period of study, 1993-2016)
t - statistics:		
Intercept	=	-5.51
POP	=	15.4
OPTDCUS	=	-2.11
COXTRAN	=	5.10

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:

$$GSDAVUSE = 390.5 - 0.23\,(OPTDCUS) + 0.79\,(MSA\_NF) + 0.031\,(CDD) + 38.4\,(POLICY)$$

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	=	0.9270
DF (error)	=	19 (period of study, 1993-2016)

t - statistics:

Intercept	=	7.91
OPTDCUS	=	-11.8
MSA_NF	=	2.29
CDD	=	3.18
POLICY	=	5.93

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

GSDCUS	=	*-1182.8 + 9.67 (POP)*
Where:		
GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.9652
DF (error)	=	22 (period of study, 1993-2016)
t - statistics:		
Intercept	=	-13.5
POP	=	25.3

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 2016. 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	=	*8782.4 + 0.044 (MSAPCY16) + 2917.6 (Policy)*
Where:		
LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
MSAPCY16	=	Gainesville MSA Per Capita Income

POLICY	=	Eligibility Indicator Variable
Adjusted R^2	=	0.8999
DF (error)	=	21 (period of study, 1993-2016)
t - statistics:		
INTERCEPT	=	5.90
MSAPCY16	=	1.03
Policy	=	11.0

The number of customers in the large power sector is expected to increase from 13 to 14 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 approximately 1.3% of total energy sales. Outdoor lighting energy sales were held constant at current levels in this forecast.

2.2.6 Wholesale Energy Sales

The System provides full requirements wholesale electric service to the City of Alachua. Approximately 2.4% of Alachua's 2016 energy requirements were met through generation entitlements of nuclear generating units operated by FPL. The agreement to provide wholesale power to Alachua is in effect through March 2022. 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	=	*-262905 + 1385 (POP) + 12.0 (HDD) + 8.7 (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	=	0.9786
DF (error)	=	19 (period of study, 1994-2016)
t - statistics:		
Intercept	=	-15.5
POP	=	30.0
HDD	=	2.8
CDD	=	1.8

GRU is also selling base load energy to the City of Winter Park from 2016 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 0.9750. 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, natural gas, residual oil, and distillate oil 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. Because the System participates in interchange sales and purchases, and because fuel prices constantly change, 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 were constructed under the Solar FIT program. The program was originally scheduled to add capacity through 2016, although no additions were allocated after 2013.

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 2016.

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 1.2% per year and non-residential usage per customer has declined 1.3% per year.

DSM direct services currently available to the System's residential customers include energy and water surveys, allowances for whole house energy efficiency improvements under the Low-income Energy Efficiency Program Plus ($\text{LEEP}^{\text{plus}}$), and natural gas rebates for new construction and conversions in existing homes for water heating, central heating, clothes drying and cooking appliances. An on-line energy survey is available that allows customers to perform a self-survey 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 also produced numerous factsheets, publications, and videos which are available at no charge to customers and which assist them in making informed decisions affecting their consumption.

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 2016, 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 and future years' 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 improved 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. Starting in 2012 to present day, GRU has conducted a Cable

Restoration Project, where direct-buried underground primary cables installed prior to 1980 are injected with a solution that restores the insulation of the cable and extends the cable's useful life. Efforts have been made to increase segmentation of feeders by adding more fusing stages, which reduces the number of customers behind any one device. This reduces the number of customers affected by any one outaged device. Efforts in distribution automation have included adding 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, although in practice they are seldom used. Since the operation of CR3 was 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, Platts Gas 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.

2.5.1 Coal

Coal was used to generate approximately 46.2% of the energy produced by the system in calendar year 2016. 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 2.9% sulfur content. Given the impact of impending environmental regulations on coal generating units, reduced demand, and depressed prompt prices for Central Appalachian (CAPP) 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 CAPP coal. GRU's forecast of coal pricing assumes that 2017 and 2018 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 (NAPP) coal supply. Pricing of these coals was sourced from Argus Coal Daily and CoalDesk 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 by its Local Distribution Company (LDC). In 2016, GRU purchased approximately 13.4 million MMBtu for use by both systems. GRU power plants used 84% of the total purchased for GRU during 2016, while the LDC used the remaining 16%. Natural gas was used to produce approximately 53.7% of the energy produced by GRU's electric generating units during calendar year 2016.

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
2007	188,704	2.33	878	81,128	10,822	778	9,793	79,445
2008	191,198	2.32	820	82,271	9,967	773	10,508	73,563
2009	191,809	2.32	808	82,605	9,781	778	10,428	74,607
2010	190,177	2.32	851	81,973	10,381	780	10,355	75,326
2011	189,964	2.32	805	81,881	9,831	772	10,373	74,424
2012	190,537	2.32	757	82,128	9,217	750	10,415	72,012
2013	191,720	2.32	753	82,638	9,112	757	10,484	72,205
2014	193,889	2.33	773	83,214	9,289	760	10,629	71,502
2015	196,450	2.34	799	83,953	9,517	784	10,663	73,525
2016	197,398	2.34	822	84,358	9,744	784	10,790	72,660
2017	199,230	0.00	822	85,141	9,655	794	10,930	72,644
2018	201,036	0.00	827	85,913	9,626	802	11,069	72,455
2019	202,816	0.00	831	86,673	9,588	811	11,205	72,378
2020	204,569	0.00	836	87,423	9,563	819	11,340	72,222
2021	206,296	0.00	840	88,161	9,528	826	11,472	72,001
2022	207,997	0.00	844	88,887	9,495	834	11,603	71,878
2023	209,671	0.00	848	89,603	9,464	842	11,732	71,770
2024	211,318	0.00	852	90,307	9,434	849	11,859	71,591
2025	212,940	0.00	856	91,000	9,407	856	11,984	71,429
2026	214,535	0.00	860	91,682	9,380	863	12,108	71,275

* 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
2007	196	18	10,889	0	26	0	1,878
2008	184	16	11,500	0	26	0	1,803
2009	168	12	14,000	0	26	0	1,780
2010	168	12	14,000	0	25	0	1,824
2011	164	11	14,909	0	29	0	1,770
2012	168	13	12,923	0	25	0	1,700
2013	159	12	13,250	0	25	0	1,694
2014	151	12	12,583	0	25	0	1,709
2015	157	12	13,083	0	25	0	1,765
2016	165	13	12,692	0	25	0	1,796
2017	166	13	12,769	0	25	0	1,807
2018	179	14	12,786	0	25	0	1,833
2019	180	14	12,857	0	25	0	1,847
2020	180	14	12,857	0	25	0	1,860
2021	181	14	12,929	0	25	0	1,872
2022	182	14	13,000	0	25	0	1,885
2023	182	14	13,000	0	25	0	1,897
2024	183	14	13,071	0	25	0	1,909
2025	183	14	13,071	0	25	0	1,920
2026	184	14	13,143	0	25	0	1,932

** 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
2007	186	58	2,122	0	90,939
2008	196	80	2,079	0	92,795
2009	203	99	2,082	0	93,045
2010	217	98	2,139	0	92,340
2011	201	45	2,016	0	92,265
2012	195	57	1,952	0	92,556
2013	113	46	1,853	0	93,134
2014	121	45	1,875	0	93,855
2015	214	45	2,024	0	94,628
2016	221	37	2,054	0	95,161
2017	223	50	2,080	0	96,084
2018	227	51	2,111	0	96,996
2019	143	51	2,041	0	97,892
2020	146	51	2,057	0	98,777
2021	149	53	2,074	0	99,647
2022	153	52	2,090	0	100,504
2023	156	53	2,106	0	101,349
2024	159	53	2,121	0	102,180
2025	162	54	2,136	0	102,998
2026	165	53	2,150	0	103,804

Schedule 3.1
History and Forecast of Summer Peak Demand - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
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	464	37	384	0	0	27	0	16	421
2016	471	38	390	0	0	27	0	16	428
2017	480	39	398	0	0	27	0	16	437
2018	488	40	404	0	0	28	0	16	444
2019	482	31	407	0	0	28	0	16	438
2020	485	32	409	0	0	28	0	16	441
2021	489	32	413	0	0	28	0	16	445
2022	492	33	415	0	0	28	0	16	448
2023	496	34	418	0	0	28	0	16	452
2024	499	35	420	0	0	28	0	16	455
2025	502	35	423	0	0	28	0	16	458
2026	505	36	425	0	0	28	0	16	461

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
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	424	36	324	0	0	51	0	13	360
2015 / 2016	412	35	313	0	0	51	0	13	348
2016 / 2017	428	38	326	0	0	51	0	13	364
2017 / 2018	435	39	331	0	0	52	0	13	370
2018 / 2019	428	29	334	0	0	52	0	13	363
2019 / 2020	430	30	335	0	0	52	0	13	365
2020 / 2021	433	31	337	0	0	52	0	13	368
2021 / 2022	436	32	339	0	0	52	0	13	371
2022 / 2023	439	32	342	0	0	52	0	13	374
2023 / 2024	442	33	344	0	0	52	0	13	377
2024 / 2025	444	33	346	0	0	52	0	13	379
2025 / 2026	448	34	348	0	0	53	0	13	382
2026 / 2027	450	35	349	0	0	53	0	13	384

Schedule 3.3
History and Forecast of Net Energy for Load - GWH

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2007	2,253	99	32	1,878	186	58	2,122	50%
2008	2,230	110	41	1,803	196	80	2,079	52%
2009	2,248	117	49	1,780	203	99	2,082	51%
2010	2,319	124	56	1,824	217	98	2,139	52%
2011	2,212	133	63	1,770	201	45	2,016	52%
2012	2,162	142	68	1,700	195	57	1,952	54%
2013	2,068	145	70	1,694	113	46	1,853	51%
2014	2,091	146	70	1,709	121	45	1,875	52%
2015	2,241	147	70	1,765	214	45	2,024	55%
2016	2,271	147	70	1,796	221	37	2,054	55%
2017	2,298	148	70	1,807	223	50	2,080	54%
2018	2,329	148	70	1,833	227	51	2,111	54%
2019	2,259	148	70	1,847	143	51	2,041	53%
2020	2,276	149	70	1,860	146	51	2,057	53%
2021	2,293	149	70	1,872	149	53	2,074	53%
2022	2,310	150	70	1,885	153	52	2,090	53%
2023	2,326	150	70	1,897	156	53	2,106	53%
2024	2,341	150	70	1,909	159	53	2,121	53%
2025	2,357	151	70	1,920	162	54	2,136	53%
2026	2,371	151	70	1,932	165	53	2,150	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			
	2016		2017		2018	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	348	159	364	162	370	164
FEB	340	142	335	141	340	144
MAR	302	146	297	149	301	151
APR	338	149	328	152	333	155
MAY	377	177	389	182	395	184
JUN	419	202	426	197	432	200
JUL	421	221	432	213	439	216
AUG	428	213	437	215	444	218
SEP	380	195	408	196	414	200
OCT	336	166	356	169	361	171
NOV	279	140	297	147	302	149
DEC	269	144	313	157	318	159

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
FUEL REQUIREMENTS			UNITS	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	209	439	414	464	427	320	405	400	368	430	375
	RESIDUAL													
(3)		STEAM	1000 BBL	1	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	1	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	209	1409	1197	859	1081	1194	772	0	0	0	0
(12)		CC	1000 MCF	6465	4317	6327	5805	5416	7148	6578	6469	7249	6668	7164
(13)		CT	1000 MCF	473	537	1028	1011	1011	1030	1055	1232	1274	1138	1236
(14)		TOTAL:	1000 MCF	7147	6263	8552	7675	7508	9372	8405	7701	8523	7806	8400
(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, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(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	565	850	770	856	786	579	736	742	666	790	684
	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	184	109	90	63	81	92	60	0	0	0	0
(13)		CC	GWh	778	535	788	725	677	894	823	810	907	835	896
(14)		CT	GWh	30	45	101	100	100	101	103	114	118	108	115
(15)		TOTAL:	GWh	992	689	979	888	858	1087	986	924	1025	943	1011
(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	36	58	34	33	41	40	36	79	97	73	116
(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	23	35	35	35	35	35	35	3	0	0	0
(22)	MSW		GWh	0	0	0	0	0	0	0	0	0	0	0
(23)	SOLAR	FIT & Net	GWh	0	0	0	0	0	0	0	0	0	0	0
(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	59	93	69	68	76	75	71	82	97	73	116
(27)	Purchased Energy		GWh	438	448	293	229	337	333	297	358	333	330	339
(28)	NET ENERGY FOR LOAD		GWh	2054	2080	2111	2041	2057	2074	2090	2106	2121	2136	2150

Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		GWh	27.5%	40.9%	36.5%	41.9%	38.2%	27.9%	35.2%	35.2%	31.4%	37.0%	31.8%
	RESIDUAL													
(4)		STEAM	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		CC	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL:	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	DISTILLATE													
(8)		STEAM	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		CC	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CT	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		TOTAL:	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	NATURAL GAS													
(12)		STEAM	GWh	9.0%	5.2%	4.3%	3.1%	3.9%	4.4%	2.9%	0.0%	0.0%	0.0%	0.0%
(13)		CC	GWh	37.9%	25.7%	37.3%	35.5%	32.9%	43.1%	39.4%	38.5%	42.8%	39.1%	41.7%
(14)		CT	GWh	1.5%	2.2%	4.8%	4.9%	4.9%	4.9%	4.9%	5.4%	5.6%	5.1%	5.3%
(15)		TOTAL:	GWh	48.3%	33.1%	46.4%	43.5%	41.7%	52.4%	47.2%	43.9%	48.3%	44.1%	47.0%
(16)	NUG		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(17)	BIOFUELS		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(18)	BIOMASS	PPA	GWh	1.8%	2.8%	1.6%	1.6%	2.0%	1.9%	1.7%	3.8%	4.6%	3.4%	5.4%
(19)	GEOTHERMAL		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(20)	HYDRO		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(21)	LANDFILL GAS	PPA	GWh	1.1%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	0.1%	0.0%	0.0%	0.0%
(22)	MSW		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(23)	SOLAR	FIT	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(24)	WIND		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(25)	OTHER RENEWABLE		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(26)	Total Renewable		GWh	2.9%	4.5%	3.3%	3.3%	3.7%	3.6%	3.4%	3.9%	4.6%	3.4%	5.4%
(27)	Purchased Energy		GWh	21.3%	21.5%	13.9%	11.2%	16.4%	16.1%	14.2%	17.0%	15.7%	15.4%	15.8%
(28)	NET ENERGY FOR LOAD		GWh	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

3. FORECAST OF FACILITIES REQUIREMENTS

3.1 GENERATION RETIREMENTS

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

GRU is planning for the addition of a 7.4 MW Reciprocating Engine for distributive generation at the South Energy Center. In addition, 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 four - Rocky Point, Kanapaha, and Ironwood - were installed by 2003. A fourth PDS, Springhill, was brought on-line in January

2011; a second transformer is scheduled to be installed here in 2020. The fifth PDS, known at this time as the Northwest Sub, is planned for addition to the System in 2021. 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 consists 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 existing 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
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	708	465	243	52.4%	0	243	52.4%
2010	608	101	0	0	709	470	239	50.7%	0	239	50.7%
2011	608	52	0	0	660	445	215	48.3%	0	215	48.3%
2012	609	52	0	0	662	415	247	59.5%	0	247	59.5%
2013	598	53	0	0	650	416	234	56.3%	0	234	56.3%
2014	533	106	0	0	639	409	230	56.2%	0	230	56.2%
2015	533	106	0	0	639	421	218	51.7%	0	218	51.7%
2016	525	106	0	0	631	430	201	46.7%	0	201	46.7%
2017	521	106	0	0	627	434	193	44.5%	0	193	44.5%
2018	521	106	0	0	627	440	187	42.4%	0	187	42.4%
2019	521	106	0	0	627	434	193	44.5%	0	193	44.5%
2020	521	106	0	0	627	437	189	43.3%	0	189	43.3%
2021	521	106	0	0	627	441	186	42.1%	0	186	42.1%
2022	521	106	0	0	627	444	182	41.0%	0	182	41.0%
2023	446	106	0	0	552	448	104	23.1%	0	104	23.1%
2024	446	103	0	0	548	451	97	21.4%	0	97	21.4%
2025	446	103	0	0	548	455	93	20.5%	0	93	20.5%
2026	446	103	0	0	548	458	90	19.6%	0	90	19.6%

(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 2017-2026 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
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	680	409	271	66.4%	0	271	66.4%
2011/12	630	52	0	0	682	371	311	83.8%	0	311	83.8%
2012/13	618	52	0	0	670	348	322	92.5%	0	322	92.5%
2013/14	550	106	0	0	656	348	308	88.4%	0	308	88.4%
2014/15	550	106	0	0	656	360	296	82.1%	0	296	82.1%
2015/16	550	106	0	0	656	348	308	88.4%	0	308	88.4%
2016/17	554	106	0	0	660	360	299	83.1%	0	299	83.1%
2017/18	550	106	0	0	656	366	290	79.3%	0	290	79.3%
2018/19	550	106	0	0	656	359	297	82.8%	0	297	82.8%
2019/20	550	106	0	0	656	362	294	81.3%	0	294	81.3%
2020/21	550	106	0	0	656	365	291	79.9%	0	291	79.9%
2021/22	550	106	0	0	656	367	288	78.5%	0	288	78.5%
2022/23	475	106	0	0	581	370	210	56.8%	0	210	56.8%
2023/24	475	103	0	0	577	373	204	54.6%	0	204	54.6%
2024/25	475	103	0	0	577	376	201	53.5%	0	201	53.5%
2025/26	475	103	0	0	577	379	198	52.4%	0	198	52.4%
2026/27	453	103	0	0	555	381	174	45.6%	0	174	45.6%

(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 2017-2026 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
South Energy Center	TBD	Alachua County	IC	NG	NA	PL	NA	7/2016	11/2017	11/2047	7.8	7.8	7.4	7.4	V

Unit Type
ST = Steam Turbine
GT = Gas Turbine
IC = Internal Combustion Engine

Fuel Type
NG = Natural Gas
NUC = Uranium
RFO = Residual Fuel Oil
DFO = Distillate Fuel Oil
NA = Not Applicable

Transportation Method
PL = Pipeline
RR = Railroad
TK = Truck
NA = Not Applicable

Status
A = Generating unit capability increased
RT = Generating unit retired or scheduled for retirement
OS = Out of Service
V = Under construction, more than 50% complete

Schedule 9
Description of Proposed Facility Under Discussion

(1)	Plant Name and Unit Number:	GRU Energy Center (Distributed Generation)	
(2a)	Net Capacity		
	a. Summer	7.4	MW
	b. Winter	7.4	MW
(2a)	Gross Capacity		
	a. Summer	7.8	MW
	b. Winter	7.8	MW
(3)	Technology Type:	Reciprocating Internal Combustion	
(4)	Anticipated Construction Timing		
	a. Field construction start-date:	7/1/2016	
	b. Commercial in-service date:	11/1/2017	
(5)	Fuel		
	a. Primary Fuel (by Heat Input)	Natural Gas	
	b. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy:	selective catalytic reduction	
(7)	Cooling Method:	air and water cooled	
(8)	Total Site Area (ft^2):	50,000 (existing)	
(9)	Construction Status:	more than 50% complete	
(10)	Certification Status:	certified	
(11)	Status with Federal Agencies:	approved	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):	3.0%	
	Forced Outage Factor (FOF):	6.0%	
	Equivalent Availability Factor (EAF):	95.0%	
	Resulting Capacity Factor (CF)	90.0%	
	Average Net Operating Heat Rate (ANOHR):	8,341	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (2017$/kW)	1208	
	Direct Construction Cost ($2017/kW):	1113	
	Capitalized Interest ($/kW)	N/A	
	Escalation ($2017/kW)	N/A	
	Escalation:	0%	
	Fixed O&M ($2017/kW-Yr):	0	
	Variable O&M ($2017/MWh):	9.67	

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. The System plans to install 7.4 MW of combined heat and power at the existing South Energy Center generation site. GRU has also been issued a construction permit for up to approximately 50 MW of generation at the existing Deerhaven generation site, but GRU has not yet evaluated what type of generation, if any, will be added to the Deerhaven generating facility.

4.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

Any additional system generation is expected to be sited at the existing Deerhaven and South Energy Center sites. Evaluation of the need for future generation is in progress.

4.2.1 Land Use and Environmental Features

The location of the sites is indicated on Figures 1.1 (see Section 1), 4.1, and 4.2. The existing land use of the certified portion of the Deerhaven 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. Approximately 400,000 gallons per day of the water required for the biomass unit on-site is met using reclaimed water from the City of Alachua. Water for potable use is 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. Both the biomass and the GRU portion of the site have zero discharge of process wastewater to surface and ground waters. GRU uses a brine concentrator/spray dryer and on-site storage and off-site disposal of solid wastewater treatment by-products.

The South Energy Center site is owned by UF Health. GRU has a long-term lease on the South Energy Center property and a long-term contract to supply power, steam, chilled water, and other utilities to UF Health from the South Energy Center. The South Energy Center is surrounded by medical facilities associated with the UF Health south campus. Reclaimed water is supplied to the South Energy Center from GRU's Main Street Water Reclamation facility, and is used as make-up water for the facility's cooling towers.

4.2.2 Air Emissions

The natural gas-fired unit to be added to the South Energy Center will feature Selective Catalytic Reduction (SCR) for NO_X control and an oxidation catalyst for CO control. The generation technology for the South Energy Center unit will meet all applicable standards for all pollutants regulated for this category of emissions unit. The combined heat and power system at the South Energy Center will be more than twice as efficient as traditional power and steam production equipment.

Figure 4.1

Deerhaven Generating Site

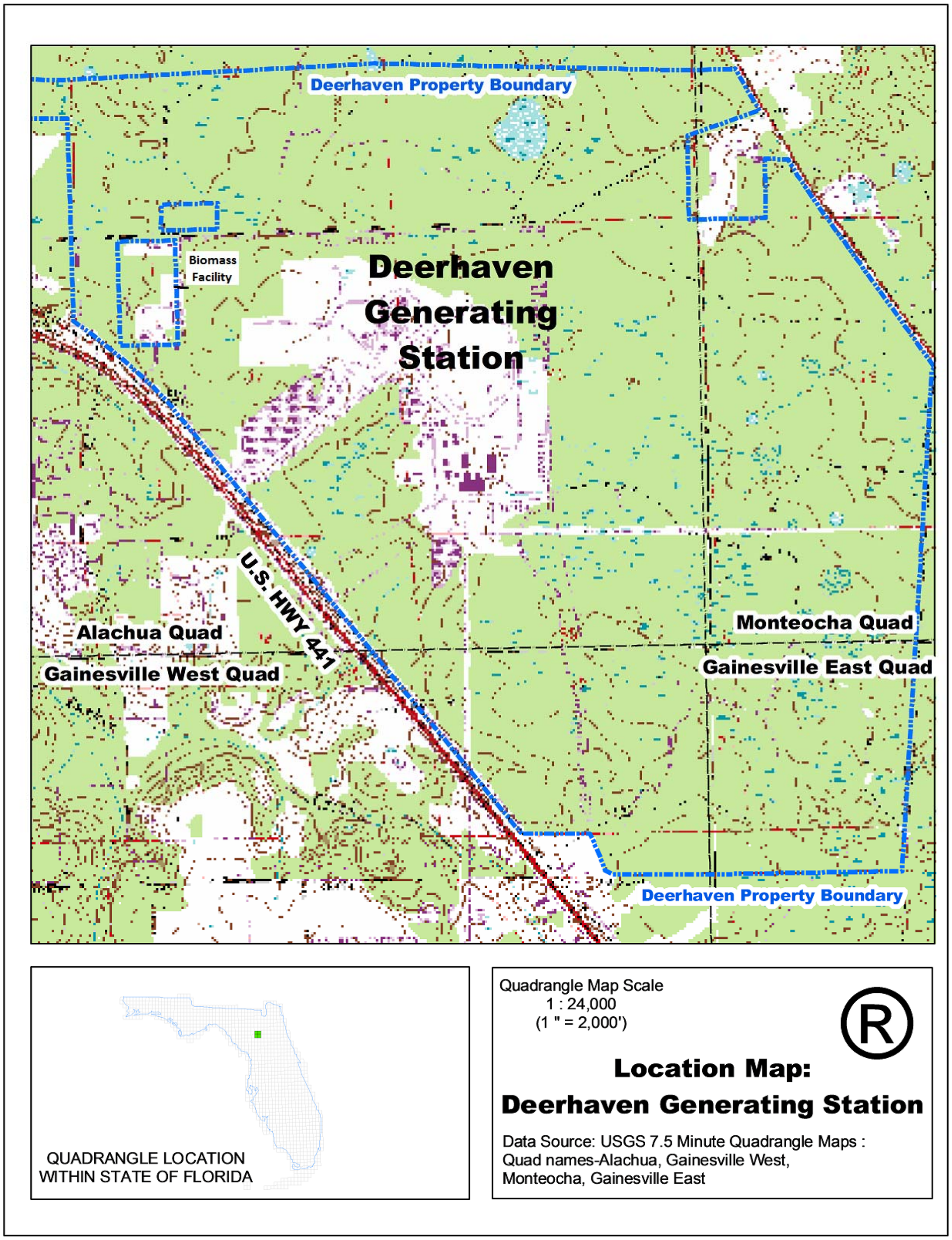


Figure 4.2
South Energy Center Generating Site