GAINESVILLE REGIONAL UTILITIES

2023 TEN-YEAR SITE PLAN

Submitted to:

The Florida Public Service Commission

April 1, 2023

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Table of Contents

INTRODUCTION

The 2023 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 2023 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 transmission service to the City of Alachua (Alachua) and Seminole Electric Cooperative (Seminole). GRU's distribution system served its retail territory of approximately 124 square miles and an average of 101,051 customers during 2022. 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 640.2 MW and the Winter Net Continuous Capacity is 669.5 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; a biomass steam turbine; 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; and an internal combustion engine which also provides distributed generation.

The System has three primary generating plant sites: Deerhaven (DH), Deerhaven Renewable (DHR), and John R. Kelly (JRK). These sites are shown on Figure 1.1.

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1 One steam turbine, JRK steam turbine (ST) 8.2, 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 into which it exhausts when in combined cycle mode is produced by fossil fuel. Therefore ST8.2 is indirectly driven by fossil fuel. No capability exists to directly burn fossil fuel to produce steam for ST8.2.

1.1.1 Generating Units[2]

1.1.1.1 Simple Cycle Steam and Combined Cycle Units. The System has two simple cycle steam turbines and one combined cycle steam turbine powered by fossil fuels[3]. The System also consists of a biomass-fueled simple cycle steam turbine. The two simple cycle fossil-fueled steam turbines comprise 49% of the System's Net Summer Continuous Capacity and produced 33% of the electric energy supplied by the System in 2022. The combined cycle unit, which includes a heat recovery steam generator (HRSG), a steam turbine/generator, and combustion turbine/generator, comprises 18% of the System's Net Summer Continuous Capacity and produced 36% of the electric energy supplied by the System in 2022. DH2 (232 MW), JRK CC1 (112 MW), and DHR (103 MW) are used for base load purposes, while DH1 (76 MW) has more commonly been used for intermediate loading. DHR comprises 16% of the System’s Net Summer Continuous Capacity and produced 32% of the electric energy supplied by the System in 2022.

1.1.1.2 Simple Cycle Combustion Gas Turbines. The System's four industrial combustion turbines that operate only in simple cycle comprise 18% of the System's Summer Net generating capacity and produced less than 1% of the electric energy supplied by the System in 2022. 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. However, simple cycle combustion turbines are advantageous in that they can be started and placed online quickly. The fourth combustion turbine operates to serve load as part of a combined heat 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 the majority of the time in combined cycle can also be operated in simple cycle to provide for peaking power.

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2 All MW ratings are Summer Net continuous capacity unless otherwise stated.

3 One steam turbine, JRK steam turbine (ST) 8.2, 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 into which it exhausts when in combined cycle mode is produced by fossil fuel. Therefore ST8.2 is indirectly driven by fossil fuel. No capability exists to directly burn fossil fuel to produce steam for ST8.2.

1.1.1.3 Reciprocating Internal Combustion Engine. The System operates a 7.4 MW natural gas-fired internal combustion engine at the South Energy Center. The engine is used in a combined heat and power application, where the engine's waste heat is captured to make steam and hot water for an academic medical campus.

1.1.1.4 Environmental Considerations. DH2 has an Air Quality Control System, consisting of a selective catalytic reduction system (currently not in service); low NO_x burners to reduce NO_x; a dry recirculating flue gas desulfurization unit to reduce acid gases, sulfur dioxide (SO_2) and mercury; and a fabric filter baghouse to reduce particulates. The Deerhaven Renewable (biomass) unit uses a fabric filter baghouse to reduce particulates; an SCR to reduce NO_x; and wood fly ash augmented with a dry sorbent injection system (used when necessary) to reduce SO_2, acid gases, and mercury. Both the Deerhaven and Deerhaven Renewable Plant Sites operate with zero liquid discharge to surface waters.

1.1.2 Generating Plant Sites

The locations of the System's primary 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 combustion turbines, associated cooling facilities, fuel storage, pumping equipment, transmission equipment, coal unloading facilities, and coal storage facilities.

1.1.2.3 Deerhaven Renewable Plant. The Deerhaven Renewable biomass-fueled generation facility is located northwest of the Deerhaven Generating Station. GRU purchased this 103 MW generating unit in November 2017. The facility consists of one steam turbine, the associated cooling facilities, and biomass unloading and storage facilities.

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 three primary generating stations,
2) GRU's eleven distribution substations,
3) One 230 kV and one 69 kV intertie 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 geographical locations of the System's transmission lines.

1.2.2 Transmission Lines

The present transmission network consists of the following:

Line	Circuit Miles	Conductor
138 kV double circuit	80.08	795 MCM ACSR 26/7
138 kV single circuit	16.86	1192 MCM ACSR 45/7
138 kV single circuit	20.61	795 MCM ACSR 26/7
230 kV single circuit	2.53	795 MCM ACSR 26/7
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 or fault conditions 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 System also interconnects with DEF's Idylwild Substation 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 also evaluating increasing transmission capacity with DEF and/or FPL. The timing, cost, and feasibility of this transmission upgrade is currently being assessed.

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

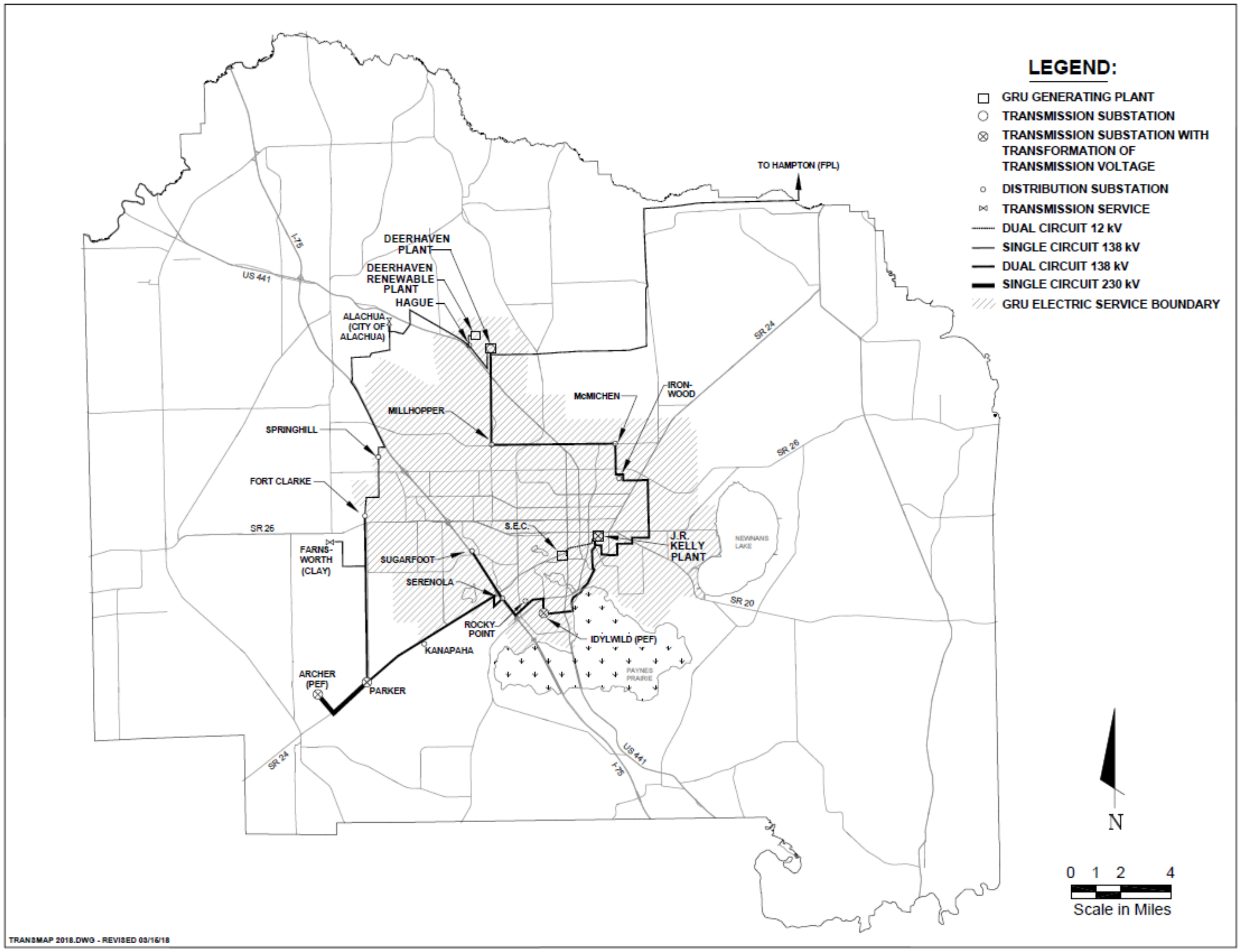
The seven loop-fed distribution substations are connected to the 138 kV bulk power transmission network with feeds that prevent the outage of a single transmission line from causing any outages in the distribution system. Ironwood, Kanapaha, Rocky Point, and Springhill are served by a single tap to the 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 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 substation has a 22.4 MVA and a 28 MVA transformer. Kelly West Substation has a 56 MVA and a 33.6 MVA transformer. Millhopper Substation has three 33.6 MVA transformers, and Sugarfoot Substations has two 44 MVA and one 33.6 MVA transformers, Serenola has a 44MVA and a 33.6MVA transformer. Under normal peak conditions, the system’s substation transformers are loaded in the range of 50% to 75% of their capacity.

1.4 DISTRIBUTED GENERATION

The South Energy Center (SEC), a combined heat and power plant, has served the UF Health South Campus since February 2009. The SEC houses a 3.5 MW natural gas-fired turbine and a 7.4 MW natural gas-fired reciprocating internal combustion engine which are capable of supplying 100% of the UF Health Cancer, Heart and Vascular, and Neuromedicine hospitals' electric and thermal needs. The SEC provides electricity, chilled water, steam, heating hot water, and the storage and delivery of medical gases to the hospitals. The unique design is at least 65% 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 energy output is not totally utilized by the UF Health South Campus.

Figure 1.1

Gainesville Regional Utilities Electric Facilities



Schedule 1

EXISTING GENERATING FACILITIES (as of January 1, 2023)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Primary Fuel		Alternate Fuel		Alt. Fuel Storage	Commercial	Expected	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Type	Trans.	Type	Trans.	(Days)	In-Service Month/Year	Retirement Month/Year	Summer MW	Winter MW	Summer MW	Winter MW	Status
J. R. Kelly		Alachua County									**114.0**	**124.0**	**112.0**	**122.0**	
	FS08.2	Sec. 4, T10S, R20E	CA	WH	PL	DFO	TK		[5/01; 5/21]	12/2051	41.5	40.5	41.0	40.0	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	12/2051	72.5	83.5	71.0	82.0	OP
Deerhaven		Alachua County									**439.5**	**459.0**	**414.0**	**433.0**	
	FS02	Secs. 26,27,35	ST	NG	PL	BIT	RR		10/81	12/2031	251.0	251.0	232.0	232.0	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	12/2027	81.0	81.0	76.0	76.0	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	12/2046	71.5	81.0	71.0	81.0	OP
	GT02		GT	NG	PL	DFO	TK		8/76	12/2026	18.0	23.0	17.5	22.0	OP
	GT01		GT	NG	PL	DFO	TK		7/76	12/2026	18.0	23.0	17.5	22.0	OP
South Energy Center		Alachua County									**12.3**	**12.3**	**11.2**	**11.5**	
	GT01 (*)	Sec. 10, T10S, R20E	GT	NG	PL				5/09	12/2039	4.5	4.5	3.8	4.1	OP
	IC02 (*)	(GRU)	IC	NG	PL				12/17	12/2047	7.8	7.8	7.4	7.4	OP
Deerhaven Renewable		Alachua County													
	FS01	Sec. 26, T08, R19	ST	WDS	TK				12/13	12/2043	**114.0**	**114.0**	**103.0**	**103.0**	OP
		(GRU)													
System Total													**640.2**	**669.5**	

Unit Type
- CA = Combined Cycle - Steam Part
- CT = Combined Cycle - CT Part
- GT = Gas Turbine
- ST = Steam Turbine
- IC = Internal Combustion Engine

Fuel Type
- BIT = Bituminous Coal
- DFO = Distillate Fuel Oil
- NG = Natural Gas
- RFO = Residual Fuel Oil
- WH = Waste Heat
- WDS = Wood Waste Solids

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

Status
- OP = Operational

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 2013-2032. Energy sales and number of customers are tabulated in Schedules 2.1, 2.2, and 2.3. Schedule 3.1 gives the summer peak demand forecast by reporting category. Schedule 3.2 presents the winter peak demand forecast by reporting category. Schedule 3.3 presents net energy for load 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 2022. 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. Historical estimates used in this forecast were taken from Florida Estimates of Population 2022. Population projections used in this forecast were based on BEBR Bulletin 192.

(3) Historical weather data was used to fit regression models. The forecast assumes normal weather conditions. Heating degree days and cooling degree days as reported to NOAA by the Gainesville Municipal Airport

station were compiled from 1984-2022. The median values from 2013-2022 were used in this forecast.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2012, using the Personal Consumption Expenditures Price Index, published by the U.S. Bureau of Economic Analysis. 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 S&P Global (formerly IHS Markit).

(6) Historical estimates of household size were obtained from BEBR Bulletin 194 (December 2022), 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 S&P Global.

(8) Retail electric prices for each billing rate category were assumed to increase at a nominal rate of approximately 2.5% 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 1980-2022. GRU's involvement with DSM is described in more detail later in this section.

(10) Separate forecasts of solar net metering impacts and electric vehicle charging impacts were incorporated into this forecast for each customer rate classification. The overall impacts of these uses, net of impacts through 2022, results in progressively increasing energy usage in the later years of the forecast.

11) GRU does not have any firm wholesale agreements with other utilities. All customer, sales and load projections included in this forecast represent retail activity only.

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 2023 through 2032. Separate energy sales forecasts were developed for each of the following customer segments: residential, general service non-demand, general service demand, large power, and outdoor lighting. 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)[4]. 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 and heating degree days. The form of this equation is as follows:

RESAVUSE = -9713 – *24.30 (RESPR12)* + *1.023 (HDD)* + *22819 (COOL_INDX)*

Where:

RESAVUSE = Average Annual Residential Energy Use per Customer

RESPR12 = Residential Price, Dollars per 1000 kWh

HDD = Annual Heating Degree Days

COOL_INDX = Building Shell Cooling Efficiency Index

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

Adjusted R^2	=	0.8427
DF (error)	=	22 (period of study, 1997-2022)
t - statistics:		
Intercept	=	-1.59
RESPR12	=	-3.43
HDD	=	3.05
COOL_INDX	=	3.92

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 and number of customers transferred from Clay Electric Cooperative to GRU. The residential customer model specifications are:

RESCUS = *9662 + 216.5 (POP) + 3.90 (CLYRCUS)*

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
CLYRCUS	=	Customers Transferred to GRU from CEC

Adjusted R^2	=	0.9830
DF (error)	=	22 (period of study, 1998-2022)
t - statistics:		
Intercept	=	5.06
POP	=	19.07
CLYRCUS	=	7.35

The product of forecasted values of average usage per customer 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, electric price, and cooling degree days. The specifications of this model are as follows:

GSNAVUSE= 26.64 – 0.0122 (OPTDCUS) – 0.0440 (GSNPR12) + 0.0017 (CDD)

Where:

GSNAVUSE	=	Average Annual Energy Usage per GSN Customer
OPTDCUS	=	Optional GSD Customers
GSNPR12	=	Delivered Electricity Price
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.9605
DF (error)	=	22 (period of study, 1997-2022)

t - statistics:

Intercept	=	10.85
OPTDCUS	=	-9.72
GSNPR12	=	-3.87
CDD	=	2.41

The number of general service non-demand customers was projected using an equation specifying customers as a function of Alachua County population 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 = *500.5 + 32.8 (POP) + 1.23 (COXTRAN)*

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
COXTRAN	=	Cable TV Meters
Adjusted R^2	=	0.9737
DF (error)	=	22 (period of study, 1998-2022)

t - statistics:

Intercept	=	0.89
POP	=	13.23
COXTRAN	=	4.47

Forecasted energy sales to general service non-demand customers were derived from the product of projected number of customers and the projected average annual usage 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, electric price, 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= 560.4 - 0.136 (OPTDCUS) - 0.800 (GSNPR12) + 0.025 (CDD) + 51.250.3 (POLICY)

Where:

GSDAVUSE	=	Average Annual Energy Use by GSD Customers
OPTDCUS	=	Optional GSD Customers
GSNPR12	=	Delivered Electricity Price
CDD	=	Cooling Degree Days
POLICY	=	Eligibility Indicator Variable
Adjusted R^2	=	0.7768
DF (error)	=	23 (period of study, 1995-2022)

t - statistics:

Intercept	=	11.19
OPTDCUS	=	-3.91
GSNPR12	=	-3.41
CDD	=	1.80
POLICY	=	4.56

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

GSDCUS = *-62.77 + 4.81 (POP)*

Where:

GSDCUS = Number of General Service Demand Customers

POP = Alachua County Population (thousands)

Adjusted R^2 = 0.5699

DF (error) = 23 (period of study, 1998-2022)

t - statistics:

Intercept = -0.30

POP = 5.73

The forecast of energy sales to general service demand customers was the resultant product of projected number of customers and projected average annual usage per customer.

2.2.4 Large Power Sector

The large power customer class currently includes eleven customers that maintain an average monthly billing demand of at least 1,000 kW. Because of this requirement to maintain a minimum average billing demand, there is occasional rate migration between the large power and general service demand classes. The forecast of large power energy sales was developed via analysis of each individual account. Recent historical energy sales were examined for the presence of any trends in usage patterns. This methodology has been described as an heuristic approach. The forecast of usage per customer is held constant through the forecast horizon.

The number of customers in the large power sector is expected to increase by approximately one customer every ten years. Since the timing of any prospective customer addition is not known, fractional increases were included each year providing for a smooth transition of modest load growth. Future forecasts will incorporate known, specific changes within this sector when and if they are identified.

2.2.5 Outdoor Lighting Sector

The outdoor lighting sector consists of public streetlights and rental lighting accounts. Outdoor lighting energy sales account for approximately one percent of retail energy sales. Outdoor lighting energy sales were forecast to decline slightly as more energy efficient lighting sources replace older technologies.

2.2.6 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 0.97533. Historical delivered efficiencies from 2008 through 2022 were examined to make this determination. The impact of energy savings from conservation programs, solar net metering, and electric vehicle charging 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 the System

Presently, the System is capable of using coal, woody biomass, natural gas, residual oil, and distillate oil to satisfy its fuel requirements. The System has historically relied upon coal to fulfill much of its fuel requirements. However, with lower natural gas prices, and subsequent fuel switching, natural gas has become the largest portion of generation fuel. 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 requirements indicated in Schedule 5.

2.3.2 Purchased Power Agreements

2.3.2.1 G2 Energy Baseline Landfill Gas. GRU entered into 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.

2.3.2.2 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 is purchasing solar energy from approximately 250 privately-owned systems distributed throughout GRU's service territory. Each FIT system has an individual contract with a 20-year term. Approximately 18.6 MW of solar generation were constructed under the Solar FIT program.

2.3.2.3 Sand Bluff Solar. GRU is working with Origis Energy on a potential 74.9 MW solar PPA. This project is currently moving through approvals and is expected to deliver power to GRU in 2025. For planning purposes, this facility is expected to contribute 41.2 MW (55% of nameplate) of capacity during GRU's summer peak and 6.7 MW (9% of nameplate) of capacity during GRU's winter peak.

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 2022.

The effectiveness of historical measures is reflected in usage data. Over the past 10 years, residential usage per customer has increased 0.29% per year and non-residential usage per customer has declined 0.63% 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 (LEEP^{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. GRU also has a streetlight replacement program to replace high pressure sodium streetlights with more energy efficient LED streetlights throughout its service territory.

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 regarding 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 2022, GRU estimates that utility-sponsored DSM programs reduced energy sales by 221 GW-h and lowered summer peak demand by 44 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, feeders have been installed underground using 1000 MCM underground cable and most if not all new distribution feeder installations must be underground. GRU adds capacitors on its distribution feeders where necessary to support a high system-wide power factor. GRU conducted a Cable Restoration Project, where direct-buried underground primary cables installed prior to 1985 were injected with a solution that restored 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. Efforts in distribution automation have included adding reclosers and automated switches, which decrease outage times by enabling GRU's system operators to remotely switch customers to adjacent feeders when outages occur. In 2022, GRU added ten reclosers to its distribution network.

GRU has a vegetation management program targeting feeders on a three to four year rotational basis as well as a wood pole inspection program that follows an eight year inspection cycle.

2.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU relies on natural gas and biomass as primary fuels used to meet its generation needs. Both heavy and light fuel oils as well as coal are used as backup for natural gas-fired generation, although in practice they are rarely used. GRU consults a number of reputable sources such as EIA, S&P Global Platts, 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 CSX rail, and natural gas is transported over the Florida Gas Transmission (FGT) Company pipeline system.

2.5.1 Coal

Coal was used to generate approximately 1.7% of the energy produced by the system in calendar year 2022. Thus far, GRU has purchased low sulfur and medium sulfur, high BTU eastern coal for use in DH2. In 2009, DH2 was retrofitted with an air quality control system, which was added as a means of complying with new environmental regulations. Following this retrofit, DH2 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. GRU's forecast of coal pricing assumes that 2023 coal procurement will primarily consist of high quality CAPP coals. Pricing of these coals was sourced from S&P Global Platts, EIA, and Coaldesk publications.

In addition to the commodity price of coal and rail transport expense, GRU's all-in price of coal also incorporates the cost of environmental commodities (pebble lime) used during the combustion of coal to comply with environmental regulations as well as expenses associated with railcar maintenance, disposal of combustion by-products, and diesel for pile maintenance.

In 2021, the System completed a dual-fuel upgrade on Deerhaven Unit 2 to allow the boiler to be able to operate both on natural gas and coal. As natural gas prices are forecasted to remain relatively low over the 10-year horizon, coal consumption is forecasted to be minimal. However, if natural gas prices increase beyond coal prices, the unit may switch its fuel source back to coal if coal supply is readily available. Coal will be the back-up/emergency fuel for the unit if natural gas is unavailable.

2.5.2 Natural Gas

GRU procures natural gas for power generation and for distribution by its Local Distribution Company (LDC). In 2022, GRU purchased approximately 16.7 million MMBTU for use by both systems. GRU power plants used 87% of the total purchased for GRU during 2022, while the LDC used the remaining 13%. Natural gas was used to produce approximately 70.6% of the energy produced by GRU's electric generating units during calendar year 2022.

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, 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.

2.5.3 Biomass

GRU procures woody biomass consisting mainly of forest residue from logging operations and urban wood waste from within a 75-100-mile radius of the plant. The major portion of biomass fuel is secured by contracts of varying lengths with the remainder purchased on a spot basis to take advantage of opportunity fuel. The forecast of biomass prices is based on contract prices escalated by forecasts of the Producer Price Index for diesel and the Consumer Price Index. Biomass was used to generate approximately 32.2% of the total energy produced by the system in calendar year 2022.

In addition to the delivered commodity price of woody biomass, GRU's all-in price of biomass fuel also incorporates the cost of environmental commodities (ammonia) required for combustion of biomass to comply with environmental regulations as well as expenses associated with disposal of combustion by-products and diesel for pile maintenance.

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
2013	190,894	2.31	753	82,638	9,112	757	10,484	72,205
2014	192,224	2.31	773	83,214	9,289	760	10,629	71,502
2015	193,931	2.31	799	83,953	9,517	784	10,663	73,525
2016	194,867	2.31	822	84,358	9,744	784	10,790	72,660
2017	198,030	2.30	806	86,100	9,361	775	11,132	69,619
2018	198,968	2.30	834	86,508	9,641	796	11,161	71,320
2019	200,215	2.30	837	87,050	9,615	800	11,264	71,023
2020	203,299	2.30	850	88,391	9,616	752	11,313	66,472
2021	208,252	2.32	839	89,764	9,347	759	11,342	66,919
2022	208,222	2.32	840	89,751	9,359	762	11,289	67,499
2023	209,722	2.31	844	90,789	9,296	774	11,530	67,129
2024	210,153	2.30	847	91,371	9,270	778	11,626	66,919
2025	211,459	2.30	851	91,939	9,256	782	11,720	66,724
2026	212,733	2.30	854	92,493	9,233	785	11,812	66,458
2027	213,974	2.30	858	93,032	9,223	789	11,901	66,297
2028	215,182	2.30	863	93,557	9,224	792	11,988	66,066
2029	216,357	2.30	869	94,068	9,238	796	12,072	65,938
2030	217,500	2.30	876	94,565	9,263	800	12,154	65,822
2031	218,610	2.30	883	95,048	9,290	804	12,234	65,718
2032	219,687	2.30	892	95,516	9,339	808	12,312	65,627

* 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
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	168	13	12,923	0	25	0	1,774
2018	175	12	14,583	0	25	0	1,830
2019	170	10	17,000	0	23	0	1,830
2020	168	10	16,800	0	20	0	1,790
2021	175	11	15,909	0	18	0	1,791
2022	179	11	16,273	0	16	0	1,797
2023	175	11	15,909	0	16	0	1,809
2024	177	11	16,091	0	16	0	1,818
2025	178	11	16,182	0	16	0	1,827
2026	180	11	16,364	0	16	0	1,835
2027	181	11	16,455	0	16	0	1,844
2028	183	12	15,250	0	15	0	1,853
2029	185	12	15,417	0	15	0	1,865
2030	186	12	15,500	0	15	0	1,877
2031	188	12	15,667	0	15	0	1,890
2032	190	12	15,833	0	15	0	1,905

** 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
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	220	37	2,031	0	97,245
2018	222	27	2,079	0	97,681
2019	134	36	2,000	0	98,324
2020	134	53	1,977	0	99,714
2021	135	26	1,952	0	101,117
2022	31	67	1,895	0	101,051
2023	0	46	1,855	0	102,330
2024	0	46	1,864	0	103,008
2025	0	46	1,873	0	103,670
2026	0	46	1,881	0	104,316
2027	0	46	1,890	0	104,944
2028	0	48	1,901	0	105,557
2029	0	47	1,912	0	106,152
2030	0	48	1,925	0	106,731
2031	0	48	1,938	0	107,294
2032	0	47	1,952	0	107,840

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
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	461	38	380	0	0	27	0	16	418
2018	452	37	371	0	0	28	0	16	408
2019	473	28	401	0	0	28	0	16	429
2020	469	28	397	0	0	28	0	16	425
2021	466	29	393	0	0	28	0	16	422
2022	452	0	408	0	0	28	0	16	408
2023	439	0	395	0	0	28	0	16	395
2024	440	0	396	0	0	28	0	16	396
2025	442	0	398	0	0	28	0	16	398
2026	444	0	400	0	0	28	0	16	400
2027	446	0	402	0	0	28	0	16	402
2028	448	0	404	0	0	28	0	16	404
2029	451	0	407	0	0	28	0	16	407
2030	454	0	410	0	0	28	0	16	410
2031	456	0	412	0	0	28	0	16	412
2032	459	0	415	0	0	28	0	16	415

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
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	397	33	300	0	0	51	0	13	333
2017 / 2018	475	38	372	0	0	52	0	13	410
2018 / 2019	398	24	309	0	0	52	0	13	333
2019 / 2020	403	23	315	0	0	52	0	13	338
2020 / 2021	413	25	323	0	0	52	0	13	348
2021 / 2022	420	25	330	0	0	52	0	13	355
2022 / 2023	375	0	309	0	0	53	0	13	309
2023 / 2024	394	0	328	0	0	53	0	13	328
2024 / 2025	396	0	330	0	0	53	0	13	330
2025 / 2026	397	0	331	0	0	53	0	13	331
2026 / 2027	399	0	333	0	0	53	0	13	333
2027 / 2028	401	0	335	0	0	53	0	13	335
2028 / 2029	403	0	337	0	0	53	0	13	337
2029 / 2030	405	0	339	0	0	53	0	13	339
2030 / 2031	407	0	341	0	0	53	0	13	341
2031 / 2032	411	0	344	0	0	54	0	13	344
2032 / 2033	413	0	346	0	0	54	0	13	346

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 %
2013	2,068	145	70	1,695	113	45	1,853	51%
2014	2,091	146	70	1,708	121	46	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	2,249	148	70	1,773	220	38	2,031	55%
2018	2,297	148	70	1,829	222	28	2,079	58%
2019	2,219	149	70	1,831	134	35	2,000	53%
2020	2,197	150	70	1,790	134	53	1,977	53%
2021	2,172	150	70	1,790	135	27	1,952	53%
2022	2,116	151	70	1,797	31	67	1,895	53%
2023	2,076	151	70	1,809	0	46	1,855	54%
2024	2,086	152	70	1,818	0	46	1,864	54%
2025	2,095	152	70	1,826	0	47	1,873	54%
2026	2,103	152	70	1,835	0	46	1,881	54%
2027	2,113	153	70	1,844	0	46	1,890	54%
2028	2,124	153	70	1,854	0	47	1,901	54%
2029	2,135	153	70	1,865	0	47	1,912	54%
2030	2,149	154	70	1,877	0	48	1,925	54%
2031	2,162	154	70	1,890	0	48	1,938	54%
2032	2,176	154	70	1,904	0	48	1,952	54%

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			
	2022		2023		2024	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	355	157	327	144	328	145
FEB	292	136	295	125	286	126
MAR	278	143	268	132	269	133
APR	297	139	299	135	300	136
MAY	355	169	354	163	355	164
JUN	408	187	385	176	386	177
JUL	390	191	389	190	391	191
AUG	398	193	395	193	396	194
SEP	392	170	369	177	371	177
OCT	293	141	324	152	325	152
NOV	283	131	265	130	266	130
DEC	309	138	285	138	286	139

Schedule 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
FUEL REQUIREMENTS			UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	17	0	0	0	0	0	0	0	0	0	0
	RESIDUAL													
(3)		STEAM	1000 BBL	3	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	3	0	0	0	0	0	0	0	0	0	0
	DISTILLATE													
(7)		STEAM	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	1	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	1	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(11)		STEAM	1000 MCF	7,720	6,993	7,615	5,745	5,540	6,432	5,642	5,019	6,376	5,621	0
(12)		CC	1000 MCF	5,532	6,641	6,969	6,318	5,698	6,453	5,501	6,332	7,051	5,633	6,902
(13)		CT	1000 MCF	439	546	529	530	532	527	526	528	552	527	537
(14)		TOTAL:	1000 MCF	13,691	14,180	15,113	12,593	11,770	13,412	11,669	11,879	13,979	11,781	7,439
(15)	OTHER (specify)		1000 Tons Biomass	735	766	665	800	749	774	755	743	780	759	758

Schedule 6.1
ENERGY SOURCES (GWH)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
(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	32	0	0	0	0	0	0	0	0	0	0
	RESIDUAL													
(4)		STEAM	GWh	2	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	2	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	618	536	579	430	416	474	417	371	470	415	0
(13)		CC	GWh	685	290	319	243	326	269	380	458	309	411	414
(14)		CT	GWh	35	53	53	53	53	53	53	55	53	55	55
(15)		TOTAL:	GWh	1338	879	951	726	795	796	850	884	832	881	469
(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		GWh	610	712	621	736	695	721	698	686	727	704	702
(19)	GEOTHERMAL		GWh	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
(21)	LANDFILL GAS	PPA	GWh	12	10	0	0	0	0	0	0	0	0	0
(22)	MSW		GWh	0	0	0	0	0	0	0	0	0	0	0
(23)	SOLAR		GWh	0	0	0	178	178	178	179	178	178	178	179
(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	622	722	621	914	873	899	877	864	905	882	881
(27)	Market Purchases		GWh	-99	254	292	233	213	195	174	164	188	175	602*
(28)	NET ENERGY FOR LOAD		GWh	1895	1855	1864	1873	1881	1890	1901	1912	1925	1938	1952

*In 2032, the forecast for Market Purchases reflects an anticipated power purchase agreement(s) to cover the retirement of DH2 at the end of 2031

Schedule 6.2
ENERGY SOURCES (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
(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	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RESIDUAL													
(4)		STEAM	GWh	0.1%	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	0.1%	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	32.6%	28.9%	31.1%	23.0%	22.1%	25.1%	21.9%	19.4%	24.4%	21.4%	0.0%
(13)		CC	GWh	36.1%	15.6%	17.1%	13.0%	17.3%	14.2%	20.0%	24.0%	16.1%	21.2%	21.2%
(14)		CT	GWh	1.8%	2.9%	2.8%	2.8%	2.8%	2.8%	2.8%	2.9%	2.8%	2.8%	2.8%
(15)		TOTAL:	GWh	70.6%	47.4%	51.0%	38.8%	42.3%	42.1%	44.7%	46.2%	43.2%	45.5%	24.0%
(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		GWh	32.2%	38.4%	33.3%	39.3%	36.9%	38.1%	36.7%	35.9%	37.8%	36.3%	36.0%
(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	0.6%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	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		GWh	0.0%	0.0%	0.0%	9.5%	9.5%	9.4%	9.4%	9.3%	9.2%	9.2%	9.2%
(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	32.8%	38.9%	33.3%	48.8%	46.4%	47.6%	46.1%	45.2%	47.0%	45.5%	45.1%
(27)	Market Purchases & Sales		GWh	-5.2%	13.7%	15.7%	12.4%	11.3%	10.3%	9.2%	8.6%	9.8%	9.0%	30.8%*
(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%

*In 2032, the forecast for Market Purchases reflects an anticipated power purchase agreement(s) to cover the retirement of DH2 at the end of 2031

3. FORECAST OF FACILITIES REQUIREMENTS

3.1 GENERATION RETIREMENTS

Deerhaven combustion turbines #1 and #2, fossil steam unit #1, and fossil steam unit #2 and are scheduled for retirement in 2026, 2027, and 2031, respectively. These planned changes to the System's generation mix are tabulated in Schedule 8. Deerhaven fossil steam unit #1 had an engineering lifetime assessment completed in late 2022 to determine the unit's remaining operational life based upon equipment condition.

3.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

GRU uses a planning criterion of 15% capacity reserve margin (required for emergency power 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 in excess of 15% over the next nine years. As shown in Schedules 7.1 and 7.2, GRU will have a reserve margin of less than 15% if DH2 retires in December 2031 as currently scheduled. Currently, GRU is undergoing an Integrated Resource Plan (IRP) to evaluate generation options that would replace generating capacity that is set to retire within the next ten years. For 2023 reporting period, Schedules 6.1 and 6.2 reflect that GRU would make-up for the lost capacity via an off-system power purchase agreement(s), beginning in 2032.

3.3 GENERATION ADDITIONS

In 2023, the System will begin an Integrated Resource Plan (IRP) which will evaluate various generating and energy supply options for the System over a 25-year horizon. The System will evaluate the recommendations of this IRP for integration into its future energy supply plans.

The System is anticipating adding 74.9 MW of photovoltaic power to its generation mix in January 2025. This energy will be procured through a power purchase agreement with a private solar developer. GRU assumes that this photovoltaic system will have a 55% (41.2 MW) contribution to the System's summer peak and a 9% (6.7 MW) contribution to the System's winter peak.

3.4 DISTRIBUTION SYSTEM ADDITIONS

The Rocky Point, Kanapaha, and Ironwood compact power delivery systems (PDS) utilize single 33 MVA class transformers that are radial-tapped to the System's looped 138 kV system. These three radial-tapped substations all have remote controlled motor-operated tie reclosers to remotely switch distribution load in a matter of minutes. 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	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
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	428	203	47.4%	0	203	47.4%
2017	521	106	0	0	627	418	209	49.9%	0	209	49.9%
2018	631	4	0	0	635	408	227	55.6%	0	227	55.6%
2019	631	4	0	0	635	429	206	48.0%	0	206	48.0%
2020	631	4	0	0	635	425	210	49.4%	0	210	49.4%
2021	631	4	0	0	635	422	213	50.4%	0	213	50.4%
2022	634	4	0	0	638	408	230	56.3%	0	230	56.3%
2023	640	4	0	0	644	395	249	63.0%	0	249	63.0%
2024	640	0	0	0	640	396	244	61.7%	0	244	61.7%
2025	640	41	0	0	681	398	283	71.2%	0	283	71.2%
2026	640	41	0	0	681	400	281	70.3%	0	281	70.3%
2027	605	41	0	0	646	402	244	60.8%	0	244	60.8%
2028	529	41	0	0	570	404	166	41.2%	0	166	41.2%
2029	529	41	0	0	570	407	163	40.1%	0	163	40.1%
2030	529	41	0	0	570	410	160	39.1%	0	160	39.1%
2031	529	41	0	0	570	412	158	38.4%	0	158	38.4%
2032	297	41	0	0	338	415	-77	-18.5%	0	-77	-18.5%

(1) Details of planned changes to installed capacity from 2023-2032 are reflected in Schedule 8.

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	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
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	333	327	98.1%	0	327	98.1%
2017/18	659	4	0	0	663	410	253	61.7%	0	253	61.7%
2018/19	659	4	0	0	663	333	330	99.1%	0	330	99.1%
2019/20	661	4	0	0	664	338	326	96.5%	0	326	96.5%
2020/21	661	4	0	0	664	348	316	90.9%	0	316	90.9%
2021/22	666	4	0	0	669	355	314	88.5%	0	314	88.5%
2022/23	666	4	0	0	669	309	360	116.6%	0	360	116.6%
2023/24	669	0	0	0	669	328	341	104.0%	0	341	104.0%
2024/25	669	7	0	0	676	330	346	104.8%	0	346	104.8%
2025/26	669	7	0	0	676	331	345	104.2%	0	345	104.2%
2026/27	625	7	0	0	632	333	299	89.7%	0	299	89.7%
2027/28	549	7	0	0	556	335	221	65.9%	0	221	65.9%
2028/29	549	7	0	0	556	337	219	64.9%	0	219	64.9%
2029/30	549	7	0	0	556	339	217	63.9%	0	217	63.9%
2030/31	549	7	0	0	556	341	215	63.0%	0	215	63.0%
2031/32	317	7	0	0	324	344	-20	-5.9%	0	-20	-5.9%
2032/33	317	7	0	0	324	346	-22	-6.4%	0	-22	-6.4%

(1) Details of planned changes to installed capacity from 2023-2032 are reflected in Schedule 8.

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	ST	NG	RFO	PL	TK		8/1972	12/2027	-81.0	-81.0	-76.0	-76.0	RT
	FS02	Secs. 26, 27, 35,	ST	NG	BIT	PL	RR		10/1981	12/2031	-251.0	-251.0	-232.0	-232.0	RT
	GT01	T8S, R19E	GT	NG	PL	DFO	TK		7/1976	12/2026	-18.0	-23.0	-17.5	-22.0	RT
	GT02	(GRU)	GT	NG	PL	DFO	TK		8/1976	12/2026	-18.0	-23.0	-17.5	-22.0	RT

Unit Type
ST = Steam Turbine

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

Transportation Method
PL = Pipeline
TK = Truck

Status
RT = Generating unit retired or scheduled for retirement

4. ENVIRONMENTAL AND LAND USE INFORMATION

4.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

Currently, there are no new potential generation sites planned.

GRU anticipates purchasing up to 74.9 MW of solar energy through a power purchase agreement beginning in 2025. It is anticipated that this facility will be located on privately-owned agricultural land near GRU's Parker Road Substation.

4.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

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

4.2.1 Land Use and Environmental Features

The location of Deerhaven Generating Station is indicated on Figures 1.1 (see Section 1) and 4.1. 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 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. Water for potable use is supplied via the City's potable water system. Groundwater is extracted from the Floridian aquifer. Process wastewater is currently collected, treated and reused on-site. The site has zero discharge of process wastewater to surface or ground waters. GRU uses a brine concentrator/spray dryer and off-site disposal of solid wastewater treatment by-products.

4.2.2 Air Emissions

Any generation technology installed at the Deerhaven site will meet all applicable standards for all pollutants regulated for the category of emissions unit.

Figure 4.1

Deerhaven Generating Site