GAINESVILLE REGIONAL UTILITIES

2024 TEN-YEAR SITE PLAN

(revised 4/30/2024)

Submitted to:

The Florida Public Service Commission

April 30, 2024

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INTRODUCTION

The 2024 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 2024 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 103,865 customers during 2023. 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 672.9 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.

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 44% of the electric energy supplied by the System in 2023. 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 40% of the electric energy supplied by the System in 2023. 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 16% of the electric energy supplied by the System in 2023.

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 2% of the electric energy supplied by the System in 2023. 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 1.4. 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 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; and an SCR to reduce NO_x. 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.

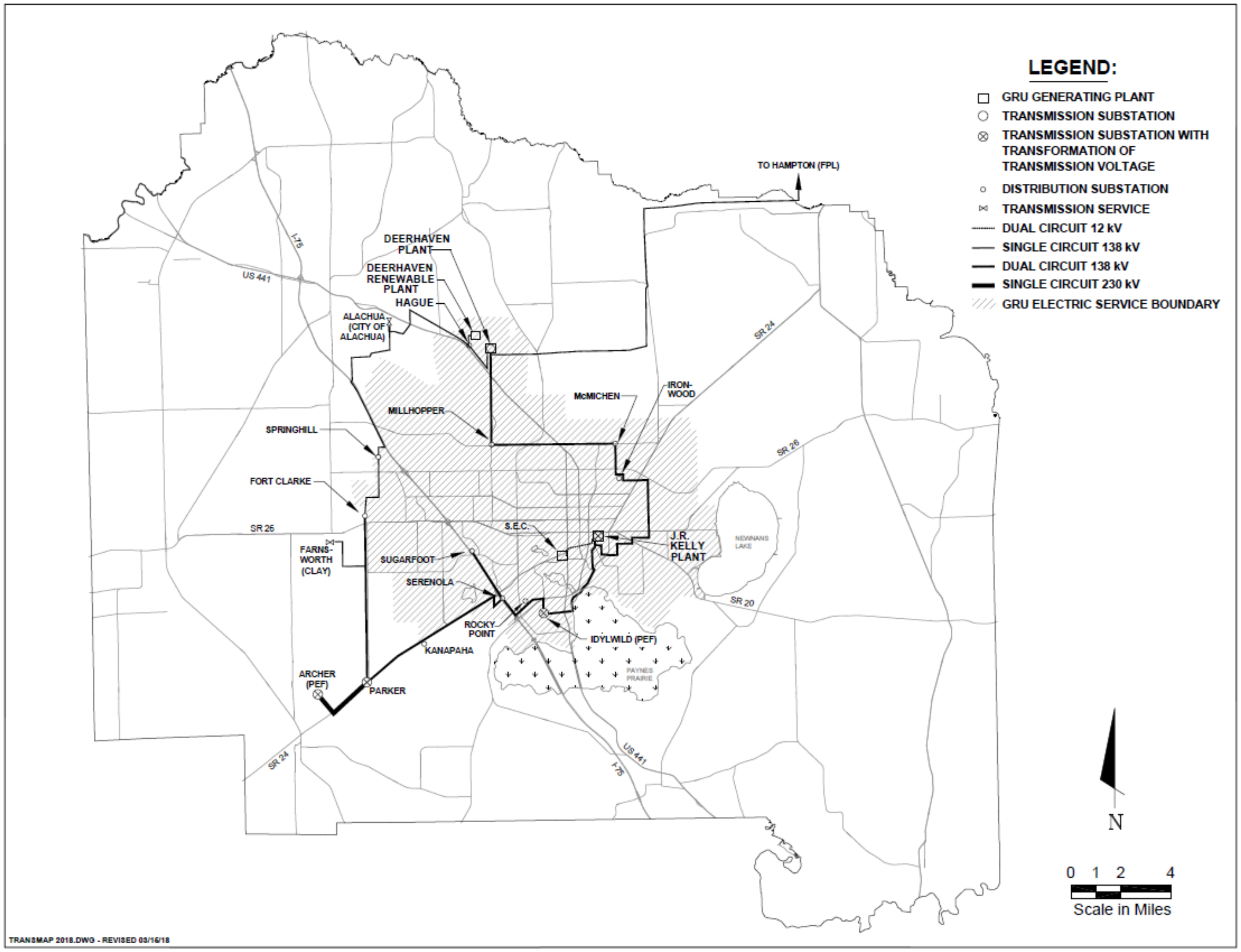
The seven loop-fed distribution substations are connected to the 138 kV bulk power transmission network with feeds that prevent the outage of a single transmission line from causing any outages in the distribution system. Ironwood, Kanapaha, Rocky Point, and Springhill are served by a single tap to the 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 two 33.6 MVA transformers and one 44MVA transformer. Sugarfoot Substation has three 44 MVA transformers. Serenola has two 44MVA transformers. Finally, the McMichen Substation has two transformers at 44MVA and 33MVA respectively. 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 3.8 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, 2024)

(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									**114.0**	**127.4**	**112.0**	**125.4**	
	FS08.2	Sec. 4, T10S, R20E	CA	WH	PL	DFO	TK		[5/01; 5/21]	12/2051	41.5	41.5	41.0	41.0	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	12/2051	72.5	85.9	71.0	84.4	OP
Deerhaven		Alachua County									**439.5**	**459.0**	**414.0**	**433.0**	
	FS02	Secs. 26,27,35	ST	NG	PL	BIT	RR		10/81	12/2036	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	12/2031	18.0	23.0	17.5	22.0	OP
	GT01		GT	NG	PL	DFO	TK		7/76	12/2031	18.0	23.0	17.5	22.0	OP
South Energy Center		Alachua County									**11.2**	**11.5**	**11.2**	**11.5**	
	GT01 (*)	Sec. 10, T10S, R20E	GT	NG	PL				5/09	12/2039	3.8	4.1	3.8	4.1	OP
	IC02 (*)	(GRU)	IC	NG	PL				12/17	12/2047	7.4	7.4	7.4	7.4	OP
Deerhaven Renewable		Alachua County													
	DHR	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**	**672.9**	

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 2014-2033. 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 2023. 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 2023. Population projections used in this forecast were based on projections included in BEBR Bulletins 192, 195 and 198.

(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 1984-2023. The median values from 2014-2023 were used in this forecast.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2017, 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 Woods & Poole Economics, Inc.

(6) Historical estimates of household size were obtained from BEBR Bulletin 197 (December 2023), and projections were held constant at the 2023 level through the forecast horizon.

(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 Woods & Poole Economics, Inc.

(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 1980-2023. 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 2023, 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 2024 through 2033. 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 = -9170 – *23.08 (RESPR17) + 0.99 (HDD) + 22316 (COOL_INDX)*

Where:

RESAVUSE	=	Average Annual Residential Energy Use per Customer
RESPR17	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
COOL_INDX	=	Building Shell Cooling Efficiency Index

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

Adjusted R^2 = 0.8522
DF (error) = 23 (period of study, 1997-2023)
t - statistics:
Intercept = -1.52
RESPR17 = -3.50
HDD = 3.09
COOL_INDX = 3.89

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 residential customer model specifications are:

RESCUS = 28817 + 213.9 (POP)

Where:
RESCUS = Number of Residential Customers
POP = Alachua County Population (thousands)

Adjusted R^2 = 0.9784
DF (error) = 18 (period of study, 2004-2023)
t - statistics:
Intercept = 15.26
POP = 29.32

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= 32.76 – 0.0078 (OPTDCUS) – 0.0859 (GSNPR17) + 0.0009 (CDD)

Where:

GSNAVUSE	=	Average Annual Energy Usage per GSN Customer
OPTDCUS	=	Optional GSD Customers
GSNPR17	=	Delivered Electricity Price
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.9200
DF (error)	=	23 (period of study, 1997-2023)

t - statistics:

Intercept	=	10.69
OPTDCUS	=	-5.97
GSNPR17	=	-7.58
CDD	=	0.91

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 in 2008. The specifications of the general service non-demand customer model are as follows:

GSNCUS = *2030.5 + 27.1 (POP) + 1.15 (COXTRAN)*

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
COXTRAN	=	Cable TV Meters
Adjusted R^2	=	0.9702
DF (error)	=	17 (period of study, 2004-2023)

t - statistics:

Intercept	=	4.79
POP	=	15.14
COXTRAN	=	5.77

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 beginning in 2013. Average energy use projections for general service demand customers result from the following model:

GSDAVUSE= *637.7 - 0.067 (OPTDCUS) – 1.29 (GSNPR17) + 0.015 (CDD) + 44.6 (POLICY)*

Where:

GSDAVUSE	=	Average Annual Energy Use by GSD Customers
OPTDCUS	=	Optional GSD Customers
GSNPR17	=	Delivered Electricity Price
CDD	=	Cooling Degree Days
POLICY	=	Eligibility Indicator Variable
Adjusted R^2	=	0.6802
DF (error)	=	24 (period of study, 1995-2023)
t - statistics:		
Intercept	=	12.40
OPTDCUS	=	-1.89
GSNPR17	=	-6.59
CDD	=	0.91
POLICY	=	2.91

The annual average number of customers was projected using a linear trend analysis of historical data from 2004 – 2023. The forecast adds approximately 3.8 new GSD customers per year.

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 General Service Large Demand Sector

The general service large demand 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 was 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 less than 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, general service large demand, and outdoor lighting. 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 was 0.97. Historical delivered efficiencies from 1999 through 2023 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. A second methodology for projecting peak demands was utilized in the forecasts for this TYSP. Regression equations were developed for summer and winter peak demand, where retail net energy for load and minimum temperature (winter) and maximum temperature (summer) were the explanatory variables. The results from this methodology were combined in a manner such that summer demand was weighted equally between the load factor methodology and the reqression methodology. Winter peak demand forecast was weighted two-thirds load factor and one-third regression equation. GRU is monitoring whether the relationship between energy and demand is changing in recent years as behind the meter solar distributed generation and electric vehicle charging become more commonplace.

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 26.8 MW (35.8% of nameplate) of capacity during GRU's summer peak and 0.0 MW (0% 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 2023.

The effectiveness of historical measures is reflected in usage data. Over the past 10 years, residential usage per customer has declined 0.17% per year and non-residential usage per customer has declined 0.54% 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 2023, GRU estimates that utility-sponsored DSM programs reduced energy sales by 221 GW-h and lowered summer peak demand by 45 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.

GRU's history of utility sponsored conservation programs began in 1980. Subsequent formal conservation plans were developed in 1990, 1995, and 2007. Cumulative energy savings from the 2007 DSM plan alone are estimated to be 104 GWh as of 2023. Cumulative summer demand reductions from the 2007 DSM plan alone are estimated to be 20 MW as of 2023.

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 2023, GRU added three 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 fuel commodity 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 1.1% of the energy produced by the system in calendar year 2023. 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 whenever it enters the market. GRU does not anticipate any near-term coal purchases due to the system only using coal for emergencies, the system having a relatively high coal inventory, and natural gas having lower forecasted prices than coal for the foreseeable future.

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 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 2023, GRU purchased approximately 19 million MMBTU for use by both systems. GRU power plants used 88% of the total purchased for GRU during 2023, while the LDC used the remaining 12%. Natural gas was used to produce approximately 85.2% of the energy produced by GRU's electric generating units during calendar year 2023.

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. Fuel commodity 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 15.5% of the total energy produced by the system in calendar year 2023.

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 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
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	214,155	2.32	844	92,308	9,143	782	11,546	67,729
2024	215,735	2.32	859	92,989	9,238	782	11,630	67,240
2025	217,274	2.32	864	93,653	9,226	784	11,713	66,934
2026	218,771	2.32	869	94,298	9,215	785	11,793	66,565
2027	220,226	2.32	874	94,925	9,207	787	11,871	66,296
2028	221,640	2.32	879	95,535	9,201	789	11,947	66,042
2029	223,012	2.32	885	96,126	9,207	791	12,021	65,802
2030	224,342	2.32	890	96,699	9,204	793	12,092	65,581
2031	225,631	2.32	895	97,255	9,203	795	12,162	65,368
2032	226,878	2.32	900	97,792	9,203	797	12,229	65,173
2033	228,083	2.32	906	98,312	9,216	799	12,294	64,991

* Commercial includes General Service Non-Demand and General Service Demand Rate Classes

Schedule 2.2
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL **				Street and	Other Sales	Total Sales
		Average	Average	Railroads	Highway	to Public	to Ultimate
		Number of	MWh per	and Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Customer	GWh	GWh	GWh	GWh
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	169	11	15,364	0	16	0	1,811
2024	176	11	16,000	0	16	0	1,833
2025	178	11	16,182	0	16	0	1,842
2026	180	11	16,364	0	16	0	1,850
2027	181	11	16,455	0	16	0	1,858
2028	183	11	16,636	0	16	0	1,867
2029	185	12	15,417	0	16	0	1,877
2030	186	12	15,500	0	16	0	1,885
2031	188	12	15,667	0	15	0	1,893
2032	190	12	15,833	0	15	0	1,902
2033	191	12	15,917	0	15	0	1,911

** Industrial includes General Service Large Demand 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
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	36	1,847	0	103,865
2024	0	58	1,891	0	104,630
2025	0	57	1,899	0	105,377
2026	0	58	1,908	0	106,102
2027	0	59	1,917	0	106,807
2028	0	58	1,925	0	107,493
2029	0	57	1,934	0	108,159
2030	0	58	1,943	0	108,803
2031	0	59	1,952	0	109,429
2032	0	60	1,962	0	110,033
2033	0	60	1,971	0	110,618

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
2014	428	26	383	0	0	12	0	7	409
2015	430	37	374	0	0	12	0	7	411
2016	447	38	390	0	0	12	0	7	428
2017	437	38	380	0	0	12	0	7	418
2018	427	37	371	0	0	12	0	7	408
2019	449	28	401	0	0	13	0	7	429
2020	445	28	397	0	0	13	0	7	425
2021	442	29	393	0	0	13	0	7	422
2022	428	0	408	0	0	13	0	7	408
2023	429	0	409	0	0	13	0	7	409
2024	427	0	407	0	0	13	0	7	407
2025	429	0	409	0	0	13	0	7	409
2026	430	0	410	0	0	13	0	7	410
2027	432	0	412	0	0	13	0	7	412
2028	434	0	414	0	0	13	0	7	414
2029	436	0	416	0	0	13	0	7	416
2030	438	0	418	0	0	13	0	7	418
2031	440	0	420	0	0	13	0	7	420
2032	442	0	422	0	0	13	0	7	422
2033	444	0	424	0	0	13	0	7	424

Schedule 3.2
History and Forecast of Winter Peak Demand - MW

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Winter	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2014 / 2015	375	36	324	0	0	9	0	6	360
2015 / 2016	363	35	313	0	0	9	0	6	348
2016 / 2017	348	33	300	0	0	9	0	6	333
2017 / 2018	426	38	372	0	0	10	0	6	410
2018 / 2019	349	24	309	0	0	10	0	6	333
2019 / 2020	354	23	315	0	0	10	0	6	338
2020 / 2021	364	25	323	0	0	10	0	6	348
2021 / 2022	371	25	330	0	0	10	0	6	355
2022 / 2023	326	0	309	0	0	11	0	6	309
2023 / 2024	313	0	296	0	0	11	0	6	296
2024 / 2025	356	0	339	0	0	11	0	6	339
2025 / 2026	357	0	340	0	0	11	0	6	340
2026 / 2027	359	0	342	0	0	11	0	6	342
2027 / 2028	361	0	344	0	0	11	0	6	344
2028 / 2029	362	0	345	0	0	11	0	6	345
2029 / 2030	365	0	347	0	0	12	0	6	347
2030 / 2031	367	0	349	0	0	12	0	6	349
2031 / 2032	368	0	350	0	0	12	0	6	350
2032 / 2033	370	0	352	0	0	12	0	6	352
2033 / 2034	372	0	354	0	0	12	0	6	354

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 %
2014	1,974	56	43	1,708	121	46	1,875	52%
2015	2,123	56	43	1,765	214	45	2,024	55%
2016	2,154	57	43	1,796	221	37	2,054	55%
2017	2,131	57	43	1,773	220	38	2,031	55%
2018	2,180	58	43	1,829	222	28	2,079	58%
2019	2,102	59	43	1,831	134	35	2,000	53%
2020	2,079	59	43	1,790	134	53	1,977	53%
2021	2,055	60	43	1,790	135	27	1,952	53%
2022	1,998	60	43	1,797	31	67	1,895	53%
2023	1,951	61	43	1,812	0	35	1,847	52%
2024	1,996	62	43	1,834	0	57	1,891	53%
2025	2,004	62	43	1,842	0	57	1,899	53%
2026	2,013	62	43	1,851	0	57	1,908	53%
2027	2,023	63	43	1,859	0	58	1,917	53%
2028	2,031	63	43	1,868	0	57	1,925	53%
2029	2,040	63	43	1,876	0	58	1,934	53%
2030	2,050	64	43	1,885	0	58	1,943	53%
2031	2,059	64	43	1,894	0	58	1,952	53%
2032	2,069	64	43	1,903	0	59	1,962	53%
2033	2,079	65	43	1,912	0	59	1,971	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			
	2023		2024		2025	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	292	135	338	147	339	147
FEB	264	120	295	127	295	128
MAR	292	135	278	135	279	135
APR	340	141	311	138	312	139
MAY	331	156	363	166	365	167
JUN	382	171	398	180	400	180
JUL	402	198	402	194	404	195
AUG	409	207	407	197	409	199
SEP	379	175	382	180	384	181
OCT	311	149	332	155	334	155
NOV	255	127	272	132	274	133
DEC	254	132	294	141	296	142

Schedule 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5) ACTUAL 2023	(6) 2024	(7) 2025	(8) 2026	(9) 2027	(10) 2028	(11) 2029	(12) 2030	(13) 2031	(14) 2032	(15) 2033
FUEL REQUIREMENTS			UNITS											
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	9	0	0	0	0	0	0	0	0	0	0
	RESIDUAL													
(3)		STEAM	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
	DISTILLATE													
(7)		STEAM	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(11)		STEAM	1000 MCF	9,708	8,853	6,435	7,602	6,110	5,804	6,471	5,289	5,394	6,144	6,207
(12)		CC	1000 MCF	5,925	7,060	6,830	4,939	6,430	6,816	5,651	6,430	6,545	6,453	5,859
(13)		CT	1000 MCF	382	569	537	533	537	594	539	544	535	533	573
(14)		TOTAL:	1000 MCF	16,015	16,482	13,802	13,074	13,077	13,214	12,661	12,263	12,474	13,130	12,639
(15)	OTHER (specify)		1000 Tons Biomass	372	72	403	498	466	400	527	556	525	526	602

Schedule 6.1
ENERGY SOURCES (GWH)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(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	20	0	0	0	0	0	0	0	0	0	0
	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	812	732	513	591	479	457	512	422	427	482	494
(13)		CC	GWh	731	874	841	607	789	835	692	786	800	789	717
(14)		CT	GWh	31	54	53	53	53	53	53	55	53	55	55
(15)		TOTAL:	GWh	1574	1660	1407	1251	1321	1345	1257	1263	1280	1326	1266
(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	287	55	294	382	347	295	401	420	395	402	462
(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	9	0	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	84	178	178	179	178	178	178	179	178
(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	296	55	378	560	525	474	579	598	573	581	640
(27)	Market Purchases (Sales)		GWh	-43	176	114	97	71	106	98	82	99	55	65
(28)	NET ENERGY FOR LOAD		GWh	1847	1891	1899	1908	1917	1925	1934	1943	1952	1962	1971

Schedule 6.2
ENERGY SOURCES (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(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	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RESIDUAL													
(4)		STEAM	GWh	0.0%	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	44.0%	38.7%	27.0%	31.0%	25.0%	23.7%	26.5%	21.7%	21.9%	24.6%	25.1%
(13)		CC	GWh	39.6%	46.2%	44.3%	31.8%	41.2%	43.4%	35.8%	40.5%	41.0%	40.2%	36.4%
(14)		CT	GWh	1.7%	2.9%	2.8%	2.8%	2.8%	2.8%	2.7%	2.8%	2.7%	2.8%	2.8%
(15)		TOTAL:	GWh	85.2%	87.8%	74.1%	65.6%	68.9%	69.9%	65.0%	65.0%	65.6%	67.6%	64.2%
(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	15.5%	2.9%	15.5%	20.0%	18.1%	15.3%	20.7%	21.6%	20.2%	20.5%	23.4%
(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	0.5%	0.0%	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%	4.4%	9.3%	9.3%	9.3%	9.2%	9.2%	9.1%	9.1%	9.0%
(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	16.0%	2.9%	19.9%	29.4%	27.4%	24.6%	29.9%	30.8%	29.4%	29.6%	32.5%
(27)	Market Purchases (Sales)		GWh	-2.3%	9.3%	6.0%	5.1%	3.7%	5.5%	5.1%	4.2%	5.1%	2.8%	3.3%
(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, combustion turbines #1 and #2, and fossil steam unit #2 and are scheduled for retirement in 2027, 2031, and 2036, respectively. 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. Combustion turbines #1 and #2 will be partially refurbished, and some critical spare parts will be placed in inventory. Fossil steam unit #2 will undergo further assessment to determine its remaining serviceable life. These 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 (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 ten years.

3.3 GENERATION ADDITIONS

In 2024, GRU will finalize an Integrated Resource Plan (IRP) which has evaluated various generating and energy supply options for the System over a 25-year horizon. Based on the preliminary modeling results of the IRP, GRU is currently developing recommendations for various paths forward. Preliminary modeling results from the IRP indicate that CT1, CT2, and DH2 are economical to remain in service through their current retirement dates. These five year retirement date extensions are reflected in Schedules 1, 6.1, 6.2, 7.1, 7.2, and 8.

GRU is anticipating adding 74.9 MW of photovoltaic power to its generation mix in July 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 35.8% (26.8 MW) contribution to the System's summer peak and a 0% (0.0 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
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	409	235	57.4%	0	235	57.4%
2024	640	0	0	0	640	407	233	57.3%	0	233	57.3%
2025	640	27	0	0	667	409	258	63.1%	0	258	63.1%
2026	640	27	0	0	667	410	257	62.7%	0	257	62.7%
2027	640	27	0	0	667	412	255	61.9%	0	255	61.9%
2028	564	27	0	0	591	414	177	42.8%	0	177	42.8%
2029	564	27	0	0	591	416	175	42.1%	0	175	42.1%
2030	564	27	0	0	591	418	173	41.4%	0	173	41.4%
2031	564	27	0	0	591	420	171	40.7%	0	171	40.7%
2032	529	27	0	0	556	422	134	31.8%	0	134	31.8%
2033	529	27	0	0	556	424	132	31.1%	0	132	31.1%

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
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	673	0	0	0	673	337	336	99.7%	0	336	99.7%
2024/25	673	0	0	0	673	339	334	98.5%	0	334	98.5%
2025/26	673	0	0	0	673	340	333	97.9%	0	333	97.9%
2026/27	673	0	0	0	673	342	331	96.8%	0	331	96.8%
2027/28	597	0	0	0	597	344	253	73.5%	0	253	73.5%
2028/29	597	0	0	0	597	345	252	73.0%	0	252	73.0%
2029/30	597	0	0	0	597	347	250	72.0%	0	250	72.0%
2030/31	597	0	0	0	597	349	248	71.0%	0	248	71.0%
2031/32	553	0	0	0	553	350	203	58.0%	0	203	58.0%
2032/33	553	0	0	0	553	352	201	57.1%	0	201	57.1%
2033/34	553	0	0	0	553	354	199	56.2%	0	199	56.2%

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	12/2036	-251.0	-251.0	-232.0	-232.0	RT
	GT01	T8S, R19E	GT	NG	PL	DFO	TK		7/1976	12/2031	-18.0	-23.0	-17.5	-22.0	RT
	GT02	(GRU)	GT	NG	PL	DFO	TK		8/1976	12/2031	-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