GRU
More than Energy

GAINESVILLE REGIONAL UTILITIES

March 17, 2021

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

Dear Sir/Madam,

In accordance with Section 186.801, Florida Statutes and Rule 25-22.071(1), Florida Administrative Code, Gainesville Regional Utilities hereby submits its electronic version of the 2021 Ten-Year Site Plan through your web-based filing system for your review.

GRU is also submitting five hardcopies of this document via mail to arrive no later than April 1st.

Please let me know if you have any questions regarding our Ten-Year Site Plan.

Sincerely,

/s/Jamie Verschage
Managing Analyst
Gainesville Regional Utilities

GAINESVILLE REGIONAL UTILITIES

2021 TEN-YEAR SITE PLAN

Submitted to:

The Florida Public Service Commission

April 1, 2021

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INTRODUCTION

The 2021 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 2021 Ten-Year Site Plan are:

- Description of Existing Facilities
- Forecast of Electric Energy and Demand Requirements
- Forecast of Facilities Requirements
- Environmental and Land Use Information

Gainesville Regional Utilities (GRU) is a municipal electric, natural gas, water, wastewater, and telecommunications utility system, owned and operated by the City of Gainesville, Florida. The GRU retail electric system service area includes the City of Gainesville and the surrounding urban area. The highest net integrated peak demand recorded to date on GRU's electrical system was 481 Megawatts on August 8, 2007.

1. DESCRIPTION OF EXISTING FACILITIES

Gainesville Regional Utilities (GRU) operates a fully vertically-integrated electric power production, transmission, and distribution system (herein referred to as "the System"), and is wholly owned by the City of Gainesville. In addition to retail electric service, GRU also provides wholesale electric service to the City of Alachua (Alachua) and transmission service to Seminole Electric Cooperative (Seminole). GRU's distribution system served its retail territory of approximately 124 square miles and an average of 99,714 customers during 2020. 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 631.2 MW and the Winter Net Continuous Capacity is 660.5 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, 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 is indirectly driven by fossil fuel. No capability exists to directly burn fossil fuel to produce steam for ST8.

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 48% of the System's Net Summer Continuous Capacity and produced 32% of the electric energy supplied by the System in 2020. The combined cycle unit, which includes a heat recovery steam generator (HRSG), steam turbine/generator, and combustion turbine/generator, comprises 17% of the System's Net Summer Continuous Capacity and produced 41% of the electric energy supplied by the System in 2020. DH 2 (228 MW), JRK CC1 (108 MW), and DHR (103 MW) are used for base load purposes, while DH 1 (75 MW) has more commonly been used for intermediate loading. DHR comprises 16% of the System's Net Summer Continuous Capacity and produced 25% of the electric energy supplied by the System in 2020.

1.1.1.2 Simple Cycle Combustion Gas Turbines. The System's four industrial combustion turbines that operate only in simple cycle comprise 17% of the System's Summer Net generating capacity and produced less than 2% of the electric energy supplied by the System in 2020. 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

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

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

of the time in combined cycle can also be operated in simple cycle to provide for peaking power.

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. The System's steam turbines utilize recirculating cooling towers with a mechanical draft for the cooling of condensed steam. DH 2 has an Air Quality Control System, consisting of a "hot-side" electrostatic precipitator for the removal of fly ash and 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. The entire Deerhaven site operates 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 gas turbines, and the associated cooling facilities, fuel storage, pumping equipment and transmission equipment. DH 2 is coal-fired and the site includes the coal unloading and storage facilities.

1.1.2.3 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 two 138 kV interties with Duke Energy Florida (DEF),
4) A 138 kV intertie with Florida Power and Light Company (FPL),
5) A radial interconnection with Clay at Farnsworth Substation, and
6) A loop-fed interconnection with the City of Alachua at Alachua No. 1 Substation.

Refer to Figure 1.1 for 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 with two separate circuits via their 168 MVA 138/69 kV transformer. The System interconnects with FPL via a 138 kV tie between FPL's Hampton Substation and the System's Deerhaven Substation. This interconnection has a transformation capacity at Bradford Substation of 224 MVA. All listed capacities are based on normal (Rating A) capacities. The System is 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 three 33.6 MVA transformers. Under normal peak conditions, our substation transformers are loaded in the range of 50% to 75% of their capacity. One of Serenola’s transformers is planned for replacement in the next two years, to restore the substation capacity back to 67.2 MVA.

1.4 WHOLESALE ENERGY

The System provides full-requirements wholesale electric service to the City of Alachua. The Alachua No. 1 Substation is supplied by GRU's looped 138 kV transmission system. The System provides approximately 98% of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from FPL’s St. Lucie nuclear units. Energy supplied to the City of

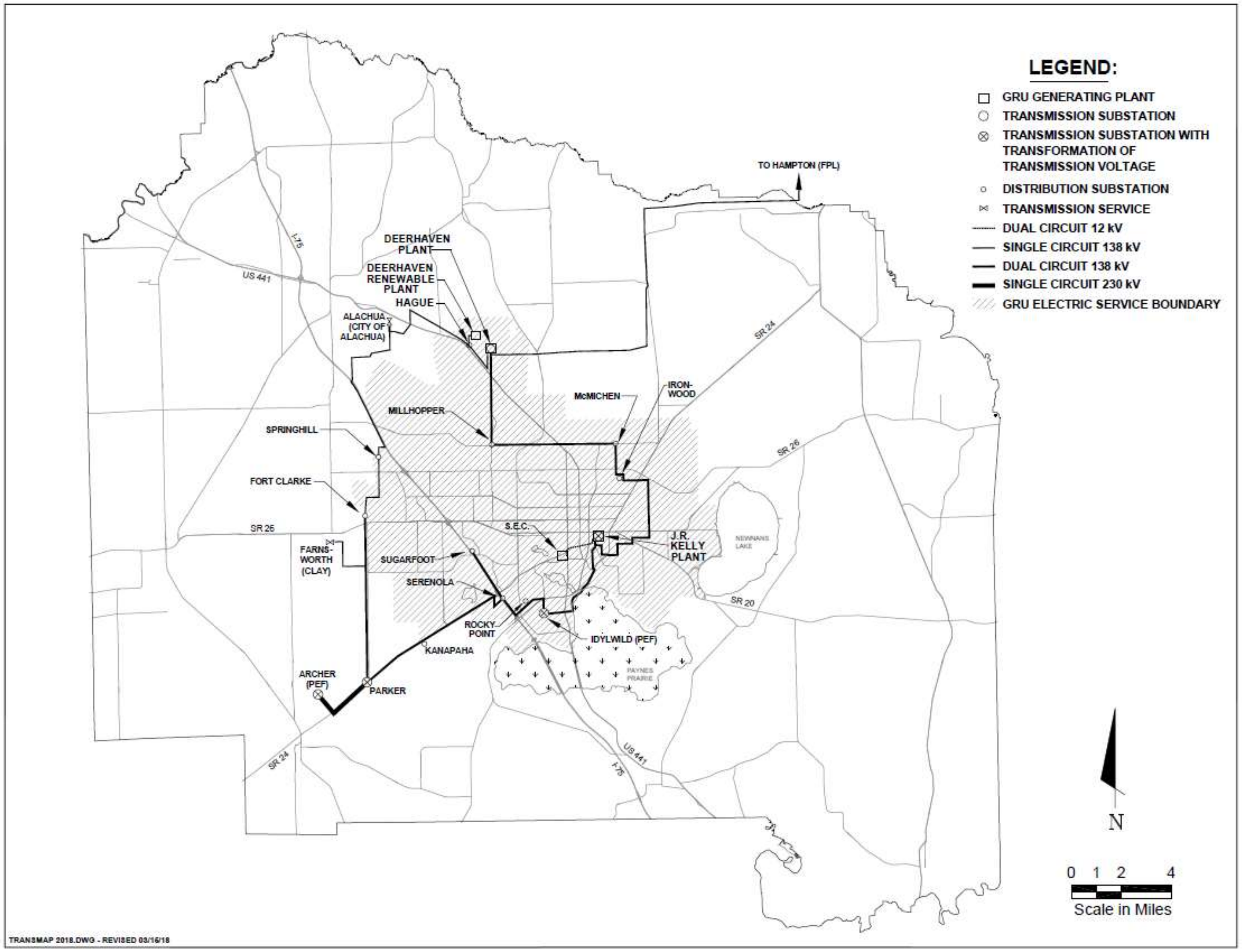
Alachua by these nuclear units is wheeled over GRU's transmission network, with GRU providing generation backup in the event of an outage of these nuclear units. The System began serving the City of Alachua in July 1985 and has provided full-requirements wholesale electric service since January 1988. An agreement was made in 2016 to extend GRU’s service to the City of Alachua until March 2022. Wholesale sales to the City of Alachua have been included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins through March 2022.

1.5 DISTRIBUTED GENERATION

The South Energy Center (SEC), a combined heat and power plant, began providing services to the UF Health Shands South Campus in 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 Shands South Campus.

Figure 1.1

Gainesville Regional Utilities Electric Facilities



Schedule 1
EXISTING GENERATING FACILITIES (as of January 1, 2021)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								Alt.							
								Fuel	Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Primary Fuel		Alternate Fuel		Storage	In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Type	Trans.	Type	Trans.	(Days)	Month/Year	Month/Year	MW	MW	MW	MW	Status
J. R. Kelly		Alachua County									**110.0**	**120.0**	**108.0**	**118.0**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL	DFO	TK		[5/01; 5/21]	2051	37.5	38.0	36.0	37.0	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	2051	72.5	82.0	72.0	81.0	OP
Deerhaven		Alachua County									**438.5**	**459.0**	**409.0**	**428.0**	
	FS02	Secs. 26,27,35	ST	BIT	RR				10/81	2031	251.0	251.0	228.0	228.0	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	2022	80.0	80.0	75.0	75.0	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	71.5	82.0	71.0	81.0	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	18.0	23.0	17.5	22.0	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	18.0	23.0	17.5	22.0	OP
South Energy Center		Alachua County									**12.3**	**12.3**	**11.2**	**11.5**	
	GT01 (*)	Sec. 10, T10S, R20E	GT	NG	PL				5/09	2039	4.5	4.5	3.8	4.1	OP
	IC02 (*)	(GRU)	IC	NG	PL				12/17	2047	7.8	7.8	7.4	7.4	OP
Deerhaven Renewable		Alachua County													
	FS01	Sec. 26, T08, R19	ST	WDS	TK				12/13	2043	**116.0**	**116.0**	**103.0**	**103.0**	OP
		(GRU)													
System Total													**631.2**	**660.5**	

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 2011-2030. 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 2020. 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 2020. Population projections used in this forecast were based on the median rates of change for Alachua County from BEBR Bulletins 171, 174, 177, 180, and 183.

(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 1984-2020. The median values from 2011-2020 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 2.0% 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 IHS Markit.

(6) Historical estimates of household size were obtained from BEBR Bulletin 188 (December 2020), 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 IHS Markit.

(8) Retail electric prices for each billing rate category were assumed to increase at a nominal rate of approximately 2.25% 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 1980-2020. 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 2020, results in a relatively small overall reduction in energy usage.

11) Sales to The City of Alachua were included in this forecast through March 2022. Alachua’s ownership of FPL nuclear capacity supplied approximately 2.4% of its annual energy requirements in 2020.

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 2021 through 2030. Separate energy sales forecasts were developed for each of the following customer segments: residential, general service non-demand, general service demand, large power, outdoor lighting, and sales to the City of Alachua. Separate forecasts of number of customers were developed for residential, general service non-demand, general service demand and large power retail rate classifications. The basis for these independent forecasts originated with the development of least-squares regression models. All modeling was performed in-house using the Statistical Analysis System (SAS)[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 = 14487 – *46.90 (RESPR12) + 1.338 (HDD)*

Where:

RESAVUSE	=	Average Annual Residential Energy Use per Customer
RESPR12	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days

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

Adjusted R^2	=	0.8007
DF (error)	=	25 (period of study, 1993-2020)
t - statistics:		
Intercept	=	20.68
RESPR18	=	-9.38
HDD	=	4.22

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:

$$RESCUS = 6636 + 261.0\,(POP) + 2.34\,(CLYRCUS)$$

Where:

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

Adjusted R^2	=	0.9910
DF (error)	=	17 (period of study, 2001-2020)
t - statistics:		
Intercept	=	4.00
POP	=	28.89
CLYRCUS	=	7.17

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= 24.06 - 0.0152 (OPTDCUS) - 0.0336 (GSNPR12) + 0.00244 (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	=	0.9545
DF (error)	=	24 (period of study, 1993-2020)

t - statistics:

Intercept	=	6.91
OPTDCUS	=	-8.29
GSNPR12	=	-2.15
CDD	=	2.73

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 = *-1482 + 41.8 (POP) + 0.90 (COXTRAN)*

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
COXTRAN	=	Cable TV Meters
Adjusted R^2	=	0.9804
DF (error)	=	17 (period of study, 2001-2020)

t - statistics:

Intercept	=	-2.18
POP	=	14.16
COXTRAN	=	4.26

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:

$$GSDAVUSE = 510.23 - 0.192\,(OPTDCUS) - 0.558\,(GSNPR12) + 0.037\,(CDD) + 55.5\,(POLICY)$$

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	=	0.8641
DF (error)	=	23 (period of study, 1993-2020)
t - statistics:		
Intercept	=	9.85
OPTDCUS	=	-5.75
GSNPR12	=	-2.38
CDD	=	2.76
POLICY	=	6.02

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	=	*-202.4 + 5.57 (POP)*
Where:		
GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.6482
DF (error)	=	18 (period of study, 2001-2020)
t - statistics:		
Intercept	=	-0.89
POP	=	6.00

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 ten 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 1.1% 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 Wholesale Energy Sales

The System provides full requirements wholesale electric service to the City of Alachua. Approximately 2.4% of Alachua's 2020 energy requirements were met through generation entitlements of nuclear generating units operated by FPL. The agreement to provide wholesale power to Alachua is in effect through March 2022. Energy sales to the City of Alachua are considered part of the System’s native load for facilities planning through the end of the current agreement.

Energy Sales to Alachua were estimated using a model including Alachua County population and heating degree days as the independent variables. The model used to develop projections of sales to the City of Alachua is of the following form:

$$ALAMWh = -226894 + 1334\,(POP) + 11.66\,(HDD)$$

Where:

ALAMWh	=	Energy Sales to the City of Alachua (MWh)
POP	=	Alachua County Population (000’s)
HDD	=	Heating Degree Days

Adjusted R^2 = 0.9703

DF (error)	=	24 (period of study, 1994-2020)
t - statistics:		
Intercept	=	-17.35
POP	=	28.78
HDD	=	2.58

2.2.7 Total System Sales, Net Energy for Load, Seasonal Peak Demands and Conservation Impacts

The forecast of total system energy sales was derived by summing energy sales projections for each customer class; residential, general service non-demand, general service demand, large power, outdoor lighting, and sales for resale. Net energy for load (NEL) was then forecast by applying a delivered efficiency factor for the System to total energy sales. The projected delivered efficiency factor used in this forecast is 0.9734. Historical delivered efficiencies from 1993 through 2020 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, and GRU receives approximately 3.7 MW net of distribution and transmission losses.

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. In 2020, GRU entered into a 20-year contract with Origis Energy for up to 50 MW of solar energy. This project is currently moving through local approvals and is expected to deliver power to GRU in 2023. For planning purposes, this facility is expected to contribute 27.5 MW (55% of nameplate) of capacity during GRU's summer peak and 4.5 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 2020.

The effectiveness of historical measures is reflected in usage data. Over the past 10 years, residential usage per customer has declined 0.24% per year and non-residential usage per customer has declined 1.2% 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 2020, GRU estimates that utility-sponsored DSM programs reduced energy sales by 224 GWh and lowered summer peak demand by 43 MW. In the forecast period, DSM-related savings are projected to be very small relative to system load due to the scaling back of programs in this and future years' budgets.

2.4.3 Supply Side Programs

The System has undertaken several initiatives to improve the adequacy and reliability of the transmission and distribution systems. GRU purchases overhead and underground transformers that exceed the efficiency specified by the NEMA TP-1 Standard. GRU has improved the feeder system by reconductoring feeders from 4/0 Copper to 795 MCM aluminum overhead conductor. In specific areas the feeders have been installed underground using 1000 MCM underground cable. GRU adds capacitors on its distribution feeders where necessary to support a high system-wide power factor. 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. This reduces the number of customers affected by any one outaged device. Efforts in distribution automation have included adding reclosers and automated switches, which decreases outage times by enabling GRU's system operators to remotely switch customers to adjacent feeders when outages occur.

2.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU relies on natural gas, biomass, and coal as primary fuels used to meet its generation needs. Both heavy and light fuel oils are used as backup for natural gas-fired generation, although in practice they are seldom used. GRU consults a number of reputable sources such as EIA, PIRA, Argus Coal Daily, Platts Gas Daily, Coaldesk, and the NYMEX futures market when assessing expected future commodity fuel prices. Costs associated with transporting coal and natural gas to GRU's generating stations are specific to arrangements with transportation entities. Coal is transported to GRU by CSX rail, and natural gas is transported over the Florida Gas Transmission Company (FGT) pipeline system.

2.5.1 Coal

Coal was used to generate approximately 11% of the energy produced by the system in calendar year 2020. Thus far, GRU has purchased low sulfur and medium sulfur, high Btu eastern coal for use in Deerhaven Unit 2. In 2009, Deerhaven Unit 2 was retrofitted with an air quality control system, which was added as a means of complying with new environmental regulations. Following this retrofit, Deerhaven Unit 2 is able to utilize coals with up to approximately 2.9% sulfur content. Given the impact of impending environmental regulations on coal generating units, reduced demand, and depressed prompt prices for Central Appalachian (CAPP) coal, GRU has continued to purchase relatively high quality Eastern coals. Rates available under GRU's rail transport contract also provide an incentive for GRU to purchase and transport its coal supplies from the East Coast. The forecast of coal prices is based on a blend of medium sulfur CAPP coal and high sulfur high Btu Illinois coal.

GRU's forecast of coal pricing assumes that 2021 coal procurement will primarily consist of high quality CAPP coals. GRU expects the favorable economics of rail transported CAPP coal to be diminished in the near term. Pricing of these coals was sourced from PIRA – 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 (e.g. pebble lime) required for 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 late 2020, GRU began a dual fuel upgrade on Deerhaven Unit 2 to allow it to be able to operate fully on natural gas. As natural gas prices are forecasted to remain relatively low over the 10-year horizon, coal consumption is forecasted to be minimal beyond 2021. However, if natural gas prices increase beyond coal prices, or if natural gas is unavailable, the unit will switch its fuel source back to coal.

2.5.2 Natural Gas

GRU procures natural gas for power generation and for distribution by its Local Distribution Company (LDC). In 2020, GRU purchased approximately 15.3 million MMBtu for use by both systems. GRU power plants used 86% of the total purchased for GRU during 2020, while the LDC used the remaining 14%. Natural gas was used to produce approximately 65% of the energy produced by GRU's electric generating units during calendar year 2020.

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 19% of the total energy produced by the system in calendar year 2020.

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
2011	189,782	2.32	805	81,881	9,831	772	10,373	74,424
2012	190,172	2.32	757	82,128	9,217	750	10,415	72,012
2013	191,169	2.31	753	82,638	9,112	757	10,484	72,205
2014	192,317	2.31	773	83,214	9,289	760	10,629	71,502
2015	193,838	2.31	799	83,953	9,517	784	10,663	73,525
2016	194,586	2.31	822	84,358	9,744	784	10,790	72,660
2017	198,413	2.30	806	86,100	9,361	775	11,132	69,619
2018	199,161	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	204,658	2.30	850	89,016	9,549	769	11,423	67,320
2022	205,988	2.30	854	89,628	9,528	774	11,530	67,129
2023	207,289	2.30	857	90,227	9,498	778	11,635	66,867
2024	208,560	2.30	860	90,812	9,470	782	11,738	66,621
2025	209,801	2.30	863	91,384	9,444	786	11,838	66,396
2026	211,013	2.30	867	91,943	9,430	789	11,936	66,103
2027	212,195	2.29	870	92,488	9,407	792	12,031	65,830
2028	213,348	2.29	873	93,020	9,385	796	12,124	65,655
2029	214,471	2.29	875	93,539	9,354	799	12,215	65,411
2030	215,564	2.29	878	94,044	9,336	801	12,303	65,106

* 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
2011	164	11	14,909	0	29	0	1,770
2012	168	13	12,923	0	25	0	1,700
2013	159	12	13,250	0	25	0	1,694
2014	151	12	12,583	0	25	0	1,709
2015	157	12	13,083	0	25	0	1,765
2016	165	13	12,692	0	25	0	1,796
2017	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	169	10	16,900	0	19	0	1,807
2022	170	10	17,000	0	19	0	1,817
2023	172	10	17,200	0	19	0	1,826
2024	174	10	17,400	0	19	0	1,835
2025	176	10	17,600	0	19	0	1,844
2026	177	11	16,091	0	19	0	1,852
2027	179	11	16,273	0	18	0	1,859
2028	181	11	16,455	0	18	0	1,868
2029	182	11	16,545	0	18	0	1,874
2030	184	11	16,727	0	18	0	1,881

** Industrial includes Large Power Rate Class

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

(1) Year	(2) Sales For Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers	(6) Total Number of Customers
2011	201	45	2,016	0	92,265
2012	195	57	1,952	0	92,556
2013	113	46	1,853	0	93,134
2014	121	45	1,875	0	93,855
2015	214	45	2,024	0	94,628
2016	221	37	2,054	0	95,161
2017	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	137	53	1,997	0	100,449
2022	30	54	1,901	0	101,168
2023	0	50	1,876	0	101,872
2024	0	50	1,885	0	102,560
2025	0	50	1,894	0	103,232
2026	0	50	1,902	0	103,890
2027	0	51	1,910	0	104,530
2028	0	50	1,918	0	105,155
2029	0	52	1,926	0	105,765
2030	0	52	1,933	0	106,358

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
2011	484	46	399	0	0	24	0	15	445
2012	456	43	372	0	0	26	0	15	415
2013	459	25	391	0	0	27	0	16	416
2014	452	26	383	0	0	27	0	16	409
2015	464	37	384	0	0	27	0	16	421
2016	471	38	390	0	0	27	0	16	428
2017	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	469	29	396	0	0	28	0	16	425
2022	442	0	398	0	0	28	0	16	398
2023	443	0	399	0	0	28	0	16	399
2024	445	0	401	0	0	28	0	16	401
2025	447	0	403	0	0	28	0	16	403
2026	449	0	405	0	0	28	0	16	405
2027	451	0	407	0	0	28	0	16	407
2028	452	0	408	0	0	28	0	16	408
2029	454	0	410	0	0	28	0	16	410
2030	456	0	412	0	0	28	0	16	412

Note: The System's decrease in Net Firm Demand in 2022 is due to the expiration of GRU's wholesale contract with the City of Alachua.

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
2011 / 2012	434	47	324	0	0	50	0	13	371
2012 / 2013	412	22	326	0	0	51	0	13	348
2013 / 2014	412	23	325	0	0	51	0	13	348
2014 / 2015	424	36	324	0	0	51	0	13	360
2015 / 2016	412	35	313	0	0	51	0	13	348
2016 / 2017	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	27	321	0	0	52	0	13	348
2021 / 2022	422	28	329	0	0	52	0	13	357
2022 / 2023	398	0	333	0	0	52	0	13	333
2023 / 2024	401	0	335	0	0	53	0	13	335
2024 / 2025	402	0	336	0	0	53	0	13	336
2025 / 2026	404	0	338	0	0	53	0	13	338
2026 / 2027	405	0	339	0	0	53	0	13	339
2027 / 2028	407	0	341	0	0	53	0	13	341
2028 / 2029	408	0	342	0	0	53	0	13	342
2029 / 2030	409	0	343	0	0	53	0	13	343
2030 / 2031	410	0	344	0	0	53	0	13	344

Note: The System's decrease in Net Firm Demand in 2022/2023 is due to the expiration of GRU's wholesale contract with the City of Alachua.

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
2011	2,212	133	63	1,770	201	45	2,016	52%
2012	2,162	142	68	1,700	195	57	1,952	54%
2013	2,068	145	70	1,694	113	46	1,853	51%
2014	2,091	146	70	1,709	121	45	1,875	52%
2015	2,241	147	70	1,765	214	45	2,024	55%
2016	2,271	147	70	1,796	221	37	2,054	55%
2017	2,249	148	70	1,774	220	37	2,031	55%
2018	2,297	148	70	1,830	222	27	2,079	58%
2019	2,219	149	70	1,830	134	36	2,000	53%
2020	2,197	150	70	1,790	134	53	1,977	53%
2021	2,217	150	70	1,807	137	53	1,997	54%
2022	2,122	151	70	1,817	30	54	1,901	55%
2023	2,097	151	70	1,826	0	50	1,876	54%
2024	2,107	152	70	1,835	0	50	1,885	54%
2025	2,116	152	70	1,844	0	50	1,894	54%
2026	2,125	153	70	1,852	0	50	1,902	54%
2027	2,133	153	70	1,859	0	51	1,910	54%
2028	2,141	153	70	1,868	0	50	1,918	54%
2029	2,150	154	70	1,874	0	52	1,926	54%
2030	2,157	154	70	1,881	0	52	1,933	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			
	2020		2021		2022	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	338	147	355	155	357	156
FEB	284	134	317	134	319	135
MAR	329	151	289	142	291	143
APR	329	141	322	146	302	136
MAY	384	163	381	175	357	164
JUN	415	184	416	190	390	178
JUL	422	204	420	205	394	192
AUG	425	205	425	208	398	195
SEP	407	185	399	190	374	178
OCT	353	172	351	164	328	154
NOV	288	140	285	139	266	130
DEC	312	151	308	149	284	140

Schedule 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
FUEL REQUIREMENTS			UNITS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	116	73	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	5,404	4,009	5,247	3,836	4,251	7,436	5,296	6,522	6,368	5,378	7,855
(12)		CC	1000 MCF	6,816	5,465	6,059	7,028	6,855	5,380	7,134	6,358	6,648	7,148	5,800
(13)		CT	1000 MCF	432	535	560	566	579	534	571	568	553	561	538
(14)		TOTAL:	1000 MCF	12,652	10,009	11,866	11,430	11,685	13,350	13,001	13,448	13,569	13,087	14,193
(15)	OTHER (specify)		1000 Tons Biomass	514	760	632	486	505	447	463	534	545	579	554

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	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
(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	215	135	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	424	301	392	286	338	598	422	513	497	414	639
(13)		CC	GWh	816	676	748	865	846	662	881	784	821	884	717
(14)		CT	GWh	38	53	54	54	55	53	55	56	55	56	54
(15)		TOTAL:	GWh	1278	1030	1194	1205	1239	1313	1358	1353	1373	1354	1410
(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	375	589	474	331	327	283	300	357	384	419	377
(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	19	35	35	35	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	124	124	124	124	124	124	124	124
(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	394	624	509	490	451	407	424	481	508	543	501
(27)	Market Purchases		GWh	90	208	198	181	195	174	120	76	37	29	22
(28)	NET ENERGY FOR LOAD		GWh	1977	1997	1901	1876	1885	1894	1902	1910	1918	1926	1933

Schedule 6.2
ENERGY SOURCES (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
(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	10.9%	6.8%	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	21.4%	15.1%	20.6%	15.2%	17.9%	31.6%	22.2%	26.9%	25.9%	21.5%	33.1%
(13)		CC	GWh	41.3%	33.9%	39.3%	46.1%	44.9%	35.0%	46.3%	41.0%	42.8%	45.9%	37.1%
(14)		CT	GWh	1.9%	2.7%	2.8%	2.9%	2.9%	2.8%	2.9%	2.9%	2.9%	2.9%	2.8%
(15)		TOTAL:	GWh	64.6%	51.6%	62.8%	64.2%	65.7%	69.3%	71.4%	70.8%	71.6%	70.3%	72.9%
(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	19.0%	29.5%	24.9%	17.6%	17.3%	14.9%	15.8%	18.7%	20.0%	21.8%	19.5%
(19)	GEOTHERMAL		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(20)	HYDRO		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(21)	LANDFILL GAS	PPA	GWh	1.0%	1.8%	1.8%	1.9%	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%	6.6%	6.6%	6.5%	6.5%	6.5%	6.5%	6.4%	6.4%
(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	19.9%	31.2%	26.8%	26.1%	23.9%	21.5%	22.3%	25.2%	26.5%	28.2%	25.9%
(27)	Market Purchases		GWh	4.6%	10.4%	10.4%	9.6%	10.3%	9.2%	6.3%	4.0%	1.9%	1.5%	1.1%
(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 and combustion turbines #1 and #2 are scheduled for retirement in 2022 and 2026, respectively. These planned changes to the System's generation mix are tabulated in Schedule 8. However, Deerhaven fossil steam unit #1 will have an engineering lifetime assessment completed in 2022 to determine the unit's remaining operational life based upon equipment condition.

The System's combined cycle unit is comprised of the gas-fired combustion turbine GT04 and the steam turbine FS08. GT04, and its associated heat recovery steam generator began operation in 2001 as part of a repowering of FS08, which began its original operation in 1965. GRU is replacing the FS08 turbine and its generator in 2021.

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 10 years.

3.3 GENERATION ADDITIONS

In 2019, the System completed an Integrated Resource Plan (IRP) which evaluated various generating and energy supply options for the System over a 20-year horizon. The System is evaluating the recommendations of this IRP for integration into its future energy supply plans. The System has also been issued a construction permit for the installation of 50 MW of peaking power. The need, timing and technology of this peaking power addition are under evaluation.

The System is anticipating adding 50 MW of photovoltaic power to its generation mix in January 2023. 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% (27.5 MW) contribution to the System's summer peak and a 9% (4.5 MW) contribution to the System's winter peak. The final location of this facility will be determined in 2021.

3.4 DISTRIBUTION SYSTEM ADDITIONS

Up to five new, compact power delivery systems (PDS) were planned for the GRU system in 1999. Three of the four - Rocky Point, Kanapaha, and Ironwood - were installed by 2003. A fourth PDS, Springhill, was brought on-line in January 2011; a third circuit from Springhill is anticipated as forecasted load develops in 2020. In addition, a second transformer is scheduled to be installed here in 2023. The fifth PDS, known at this time as the Northwest Sub, is planned for addition to the System in 2024. This PDS will be located in the 2000 block of NW 53rd Avenue. These new compact-power delivery systems have been planned to redistribute the load from the existing substations as new load centers grow and develop within the System.

The Rocky Point, Kanapaha, and Ironwood PDS utilize single 33 MVA class transformers that are radial-tapped to 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
2011	608	52	0	0	660	445	215	48.3%	0	215	48.3%
2012	609	52	0	0	662	415	247	59.5%	0	247	59.5%
2013	598	53	0	0	650	416	234	56.3%	0	234	56.3%
2014	533	106	0	0	639	409	230	56.2%	0	230	56.2%
2015	533	106	0	0	639	421	218	51.7%	0	218	51.7%
2016	525	106	0	0	631	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	425	210	49.4%	0	210	49.4%
2022	631	4	0	0	635	398	237	59.5%	0	237	59.5%
2023	556	31	0	0	587	399	188	47.2%	0	188	47.2%
2024	556	28	0	0	584	401	183	45.6%	0	183	45.6%
2025	556	28	0	0	584	403	181	44.8%	0	181	44.8%
2026	556	28	0	0	584	405	179	44.1%	0	179	44.1%
2027	521	28	0	0	549	407	142	34.8%	0	142	34.8%
2028	521	28	0	0	549	408	141	34.5%	0	141	34.5%
2029	521	28	0	0	549	410	139	33.8%	0	139	33.8%
2030	521	28	0	0	549	412	137	33.2%	0	137	33.2%

(1) System Peak demands shown in this table reflect service to partial and full requirements wholesale customers. The System's decrease in firm demand in 2022 is due to the expiration of GRU's wholesale contract with the City of Alachua.

(2) Details of planned changes to installed capacity from 2021-2030 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
2011/12	630	52	0	0	682	371	311	83.8%	0	311	83.8%
2012/13	618	52	0	0	670	348	322	92.5%	0	322	92.5%
2013/14	550	106	0	0	656	348	308	88.4%	0	308	88.4%
2014/15	550	106	0	0	656	360	296	82.1%	0	296	82.1%
2015/16	550	106	0	0	656	348	308	88.4%	0	308	88.4%
2016/17	554	106	0	0	660	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	661	4	0	0	664	357	307	86.1%	0	307	86.1%
2022/23	586	4	0	0	589	333	256	76.9%	0	256	76.9%
2023/24	586	5	0	0	590	335	255	76.1%	0	255	76.1%
2024/25	586	5	0	0	590	336	254	75.6%	0	254	75.6%
2025/26	586	5	0	0	590	338	252	74.6%	0	252	74.6%
2026/27	542	5	0	0	546	339	207	61.1%	0	207	61.1%
2027/28	542	5	0	0	546	341	205	60.1%	0	205	60.1%
2028/29	542	5	0	0	546	342	204	59.6%	0	204	59.6%
2029/30	542	5	0	0	546	343	203	59.2%	0	203	59.2%
2030/31	542	5	0	0	546	344	202	58.7%	0	202	58.7%

(1) System Peak demands shown in this table reflect service to partial and full requirements wholesale customers. The System's decrease in firm demand in 2022/2023 is due to the expiration of GRU's wholesale contract with the City of Alachua.

(2) Details of planned changes to installed capacity from 2021-2030 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	12/2022	-80.0	-80.0	-75.0	-75.0	RT
	GT01	Secs. 26, 27,35,	GT	NG	PL	DFO	TK		7/76	10/2026	-18.0	-23.0	-17.5	-22.0	RT
	GT02	T8S, R19E	GT	NG	PL	DFO	TK		8/76	10/2026	-18.0	-23.0	-17.5	-22.0	RT
		(GRU)													

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 has been issued a construction permit for up to approximately 50 MW of generation at the existing Deerhaven generation site, but GRU has not yet evaluated what type of generation, if any, will be added to the Deerhaven generating facility.

GRU anticipates purchasing up to 50 MW of solar energy through a power purchase agreement beginning in 2023. 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