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GAINESVILLE REGIONAL UTILITIES
STRATEGIC PLANNING

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Dear Ms. Cole:

In accordance with Section 186.801, Florida Statutes and Rule 25-22.071, Florida Administrative Code, Gainesville Regional Utilities hereby submits 25 copies of its 2008 Ten Year Site Plan for your review. Should you have any questions regarding this Ten Year Site Plan, please contact me at (352) 393-1272.

Sincerely,

Ed Regan, P.E.
Assistant General Manager
Strategic Utility Planning

Enclosures

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GAINESVILLE REGIONAL UTILITIES

2008 TEN-YEAR SITE PLAN

GRU℠
More than Energy™

Submitted to:

The Florida Public Service Commission

April 2008

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1. INTRODUCTION

The 2008 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/EAG 43, as specified by Rule 25-22.072, Florida Administrative Code. The five sections of the 2008 Ten-Year Site Plan are:

- Introduction
- 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.

2. 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 Clay Electric Cooperative (Clay). These wholesale contracts will terminate after December 31, 2008 and December 31, 2012 respectively, unless renewed. GRU's distribution system serves its retail territory of approximately 124 square miles and 90,939 customers (2007 average). The general locations of GRU electric facilities and the electric system service area are shown in Figure 2.1.

2.1 GENERATION

The existing generating facilities operated by GRU are tabulated in Schedule 1 at the end of this chapter. The present summer net capability is 611 MW and the winter net capability is 632 MW[1]. Currently, the System's energy is produced by three fossil fuel steam turbines, six simple-cycle combustion turbines, one combined-cycle unit, a 1.4079 % ownership share of the Crystal River 3 (CR3) nuclear unit operated by Progress Energy Florida (PEF), and two internal combustion engines that run on landfill gas.

The System has two primary generating plant sites -- Deerhaven and John R. Kelly (JRK). Each site comprises both steam-turbine and gas-turbine generating units. The JRK station also utilizes a combined cycle unit. A small amount of generation capacity is provided by two internal combustion engines located at the Alachua County Southwest Landfill.

[1] Net capability is that specified by the "SERC Guideline Number Two for Uniform Generator Ratings for Reporting." The winter rating will normally exceed the summer rating because generating plant efficiencies are increased by lower ambient air temperatures and lower cooling water temperatures.

2.1.1 Generating Units

2.1.1.1 Steam Turbines. The System's three operational simple-cycle steam turbines are powered by fossil fuels and CR3 is nuclear powered. The fossil fueled steam turbines comprise 54.7% of the System's net summer capability and produced 80.2% of the electric energy supplied by the System in 2007. These units range in size from 23.2 MW to 228.4 MW. The combined-cycle unit, which includes a heat recovery steam generator/turbine and combustion turbine set, comprises 18.3% of the System's net summer capability and produced 12.6% of the electric energy supplied by the System in 2007. The System's 11.43 MW share of CR3 comprises 1.9% of the System's net summer capability and produced 5.0% of total electric energy in 2007. The System's share of CR3 will increase to 11.595 MW in 2008, to 11.981 MW in 2010, and to 13.911 MW in 2012 as the result of capacity upgrades planned by PEF. Deerhaven Unit 2 and CR3 are used for base load purposes, while JRK Unit 7, JRK CC1, and Deerhaven Unit 1 are used for intermediate loading.

2.1.1.2 Gas Turbines. The System's six industrial gas turbines make up 24.9% of the System's summer generating capability and produced 2.2% of the electric energy supplied by the System in 2007. These simple-cycle combustion turbines are utilized for peaking purposes only because their energy conversion efficiencies are considerably lower than steam units. As a result, they yield higher operating costs and are consequently unsuitable for base load operation. Gas turbines are advantageous in that they can be started and placed on line quickly. The System's gas turbines are most economically used as peaking units during high demand periods when base and intermediate units cannot serve all of the System loads.

2.1.1.3 Internal Combustion (Piston/Diesel). The System operates two reciprocating internal combustion engines at the Southwest Landfill producing 1.3 MW. Fueled by gas produced by the landfill, these units represent 0.2% of the

System's summer capability and produced 0.02% of total energy in 2007. They are operated as continuously as possible.

2.1.1.4 Environmental Considerations. All of the System's steam turbines, except for Crystal River 3, utilize recirculating cooling towers with a mechanical draft for the cooling of condensed steam. Crystal River 3 uses a once-through cooling system aided by helper towers. Only Deerhaven 2 currently has flue gas cleaning equipment consisting of a "hot-side" electrostatic precipitator. Construction is currently underway on a selective catalytic reduction system to reduce NO_x, and a dry flue gas desulfurization unit with fabric filters, which will reduce SO_2, mercury, and particulates. This equipment will result in a net decrease of 3 MW for Deerhaven 2.

2.1.2 Generating Plant Sites

The locations of the System's generating plant sites are shown on Figure 2.1.

2.1.2.1 John R. Kelly Plant. The Kelly Station is located in southeast Gainesville near the downtown business district and consists of one combined cycle, one steam turbine, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment.

2.1.2.2 Deerhaven Plant. The Deerhaven Station is located six miles northwest of Gainesville. The original site, which was certified pursuant to the Power Plant Siting Act, includes an 1146 acre parcel of partially forested land. The facility consists of two steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment and transmission equipment. As amended to include the addition of Deerhaven Unit 2 in 1981, the certified site now includes coal unloading and storage facilities and a zero discharge water treatment plant, which treats water effluent from both steam units. A potential expansion area, owned by the System and adjacent to the certified Deerhaven plant site, was incorporated into the Gainesville City limits February 12, 2007 (ordinance 0-06-130), consists of an additional 2328 acres, for a total of 3474 acres.

2.1.2.3 Southwest Landfill. The Southwest Landfill is located west of the Town of Archer on SR 24 near the Alachua county / Levy county line. The landfill is owned by Alachua County. An inter-local agreement between the City of Gainesville and Alachua County approved the concept of using landfill gas to power two internal combustion engine generators. The County granted a special use permit and an easement for GRU to operate and access the generators. The landfill gas to energy project (LFGTE) at the Alachua County Southwest Landfill was commissioned in December of 2003 and is wheeling power over the Progress Energy Florida's (PEF) distribution network to GRU's 230 kV transmission intertie with PEF. The LFGTE facility presently operates two internal combustion generating sets with a combined capacity of 1.3 MW of renewable energy. The generation capacity of the LFGTE system will diminish through time as the landfill gas production rate slows, and generating sets are taken off-line. This Ten Year Site Plan assumes that available capacity from the LFGTE system will fall to 0.5 MW in summer 2008 and zero by summer 2016.

2.2 TRANSMISSION

2.2.1 The Transmission Network

GRU's bulk power transmission network (System) consists of a 138 kV loop connecting the following:

1) GRU's two generating stations,
2) GRU's nine distribution substations,
3) Three interties with Progress Energy of Florida (PEF),
4) An 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 2.1 for line geographical locations and Figure 2.2 for electrical connectivity and line numbers.

2.2.2 Transmission Lines

The ratings for all of GRU's transmission lines are given in Table 2.1. The load ratings for GRU's transmission lines were developed in Appendix 6.1 of GRU's Long-Range Transmission Planning Study, March 1991. Refer to Figure 2.2 for a one-line diagram of GRU's electric system. The criteria for normal and emergency loading are taken to be:

- Normal loading: conductor temperature not to exceed 100° C (212° F).
- Emergency 8 hour loading: conductor temperature not to exceed 125° C (257° F).

The present transmission network consists of the following:

Line	Circuit Miles	Conductor
138 kV double circuit	80.01	795 MCM ACSR
138 kV single circuit	16.30	1192 MCM ACSR
138 kV single circuit	20.91	795 MCM ACSR
230 kV single circuit	2.53	795 MCM ACSR
Total	119.75	

Annually, GRU participates in Florida Reliability Coordinating Council, Inc. (FRCC) studies that analyze multi-level contingencies. Contingencies are occurrences that depend on changes or uncertain conditions and, as used here, represent various equipment failures that may occur. All single and two circuits-common pole contingencies have no identifiable problems.

Contingency simulations revealed the system effects of serving peak summer load with assumed outages of both Deerhaven Unit 2 and the Archer 230 kV tie line.

The results identified GRU bus voltages that would fall below acceptable levels. In an effort to address this issue, two 3-phase, 138kV, 24 MVAr capacitor banks were budgeted - one for Parker Transmission Substation (installation summer 2008) and one for McMichen Substation (installation summer 2009).

According to the state system security coordinator, who is responsible for the integrity and stability of the entire Florida transmission grid, GRU could plan to import about 150-170 MW before exceeding the bus voltage standard for reliability. The budgeted capacitor banks mentioned above will provide additional benefit to GRU by allowing increased reliable import capacity.

2.2.3 State Interconnections

The System is currently interconnected with PEF and FPL at four separate points. The System interconnects with PEF's Archer Substation via a 230 kV transmission line to the System's Parker Substation with 224 MVA of transformation capacity from 230 kV to 138 kV. The System also interconnects with PEF's Idylwild Substation with two separate circuits via a 150 MVA 138/69 kV transformer at the Idylwild Substation. 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.

2.3 DISTRIBUTION

The System has six loop-fed and three radial distribution substations connected to the transmission network: Ft. Clarke, Kelly, McMichen, Millhopper, Serenola, Sugarfoot, Ironwood, Kanapaha, and Rocky Point substations, respectively. Parker is GRU's only 230 kV transmission voltage substation. The locations of these substations are shown on Figure 2.1.

The six major distribution substations are connected to the 138 kV bulk power transmission network with looped feeds which prevent the outage of a single transmission line from causing major outages in the distribution system. Ironwood, Kanapaha and Rocky Point are served by a single tap to the 138 kV network which would require distribution switching to restore customer power if the single transmission line tapped experiences an outage. GRU serves its retail customers through a 12.47 kV distribution network. The distribution substations, their present rated transformer capabilities, and the number of circuits for each are listed in Table 2.2.

The System has three Power Delivery Substations (PDS) with single 33.6 MVA transformers that are directly radial-tapped to our looped 138 kV system. PDS's provide service to our growing load as well as providing backup support to our loop served transformers. Ft. Clarke, Kelly, McMichen, and Serenola substations currently consist of two transformers of basically equal size allowing these stations to be loaded under normal conditions to 80 percent of the capabilities shown in Table 2.2. Millhopper and Sugarfoot Substations currently consist of three transformers of equal size allowing both of these substations to be loaded under normal conditions to 100 percent of the capability shown in Table 2.2. One of the two 22.4 MVA transformers at Ft. Clarke has been repaired with rewinding to a 28.0 MVA rating. This makes the normal rating for this substation 50.4 MVA.

In 2007 GRU expanded its John R. Kelly Plant generation-transmission-distribution substation configuration to include a third 56 MVA 138-12.47 kV transformer located on the south side of the plant (referred to as Kelly-West). This expansion has enhanced reliability by reassigning load to a point on the system not directly tied to the generator buses of the plant. The additional transformer capacity will allow for load growth in Gainesville's downtown area.

2.4 WHOLESALE ENERGY

The System provides full requirements wholesale electric service to Clay Electric Cooperative (Clay) through a contract between GRU and Seminole Electric Cooperative (Seminole), of which Clay is a member. The System began the 138 kV service at Clay's Farnsworth Substation in February 1975. This substation is supplied through a 2.37 mile radial line connected to the System's transmission facilities at Parker Road near SW 24th Avenue.

The System also 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. Two small residential neighborhoods and a few commercial customers within Alachua's city limits are provided backup service from a GRU 12.47 kV distribution circuit, known as the Hague point of service. The System provides approximately 93% of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from the PEF's Crystal River 3 and FPL's St. Lucie 2 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 outages of these nuclear units.

As the result of the City of Alachua's Request for Proposal (RFP) for energy resources, GRU has notified the City of Alachua of its plan to terminate its existing contract effective December 31, 2008. GRU has submitted a response to the City of Alachua's RFP and if GRU prevails will negotiate to provide their energy needs under a new contract configuration.

Wholesale sales to Clay and the City of Alachua have been included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins. This forms a conservative basis for planning purposes in the event these contracts are renewed. Schedules 7.1 and 7.2 at the end of Section 4 summarize GRU's reserve margins.

2.5 DISTRIBUTED GENERATION

GRU is contracting with the engineering, architecture and construction firm of Burns and McDonnell to design and build the GRU South Energy Center, which will provide multiple onsite utility services to the new Shands at UF Cancer Hospital. The new facility will house a natural-gas-fired combustion turbine providing 4.1 megawatts (summer rating). The Energy Center is expected to be online by 2009.

In addition to providing needed electricity, it will also provide chilled water and steam which will make it one of GRU's most efficient generating units.

Figure 2.1, Gainesville Regional Utilities Electric Facilities
Alachua County, Florida

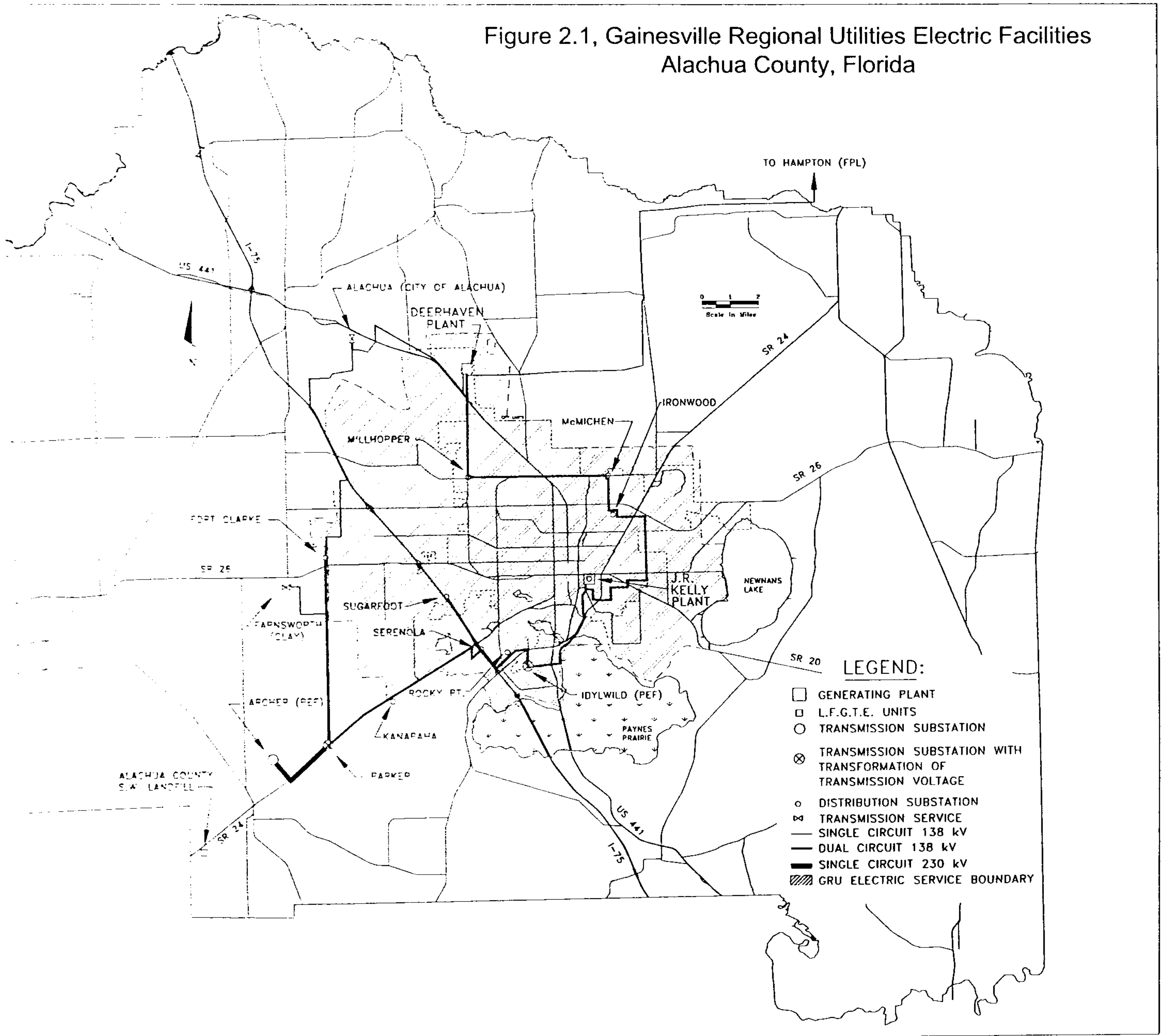
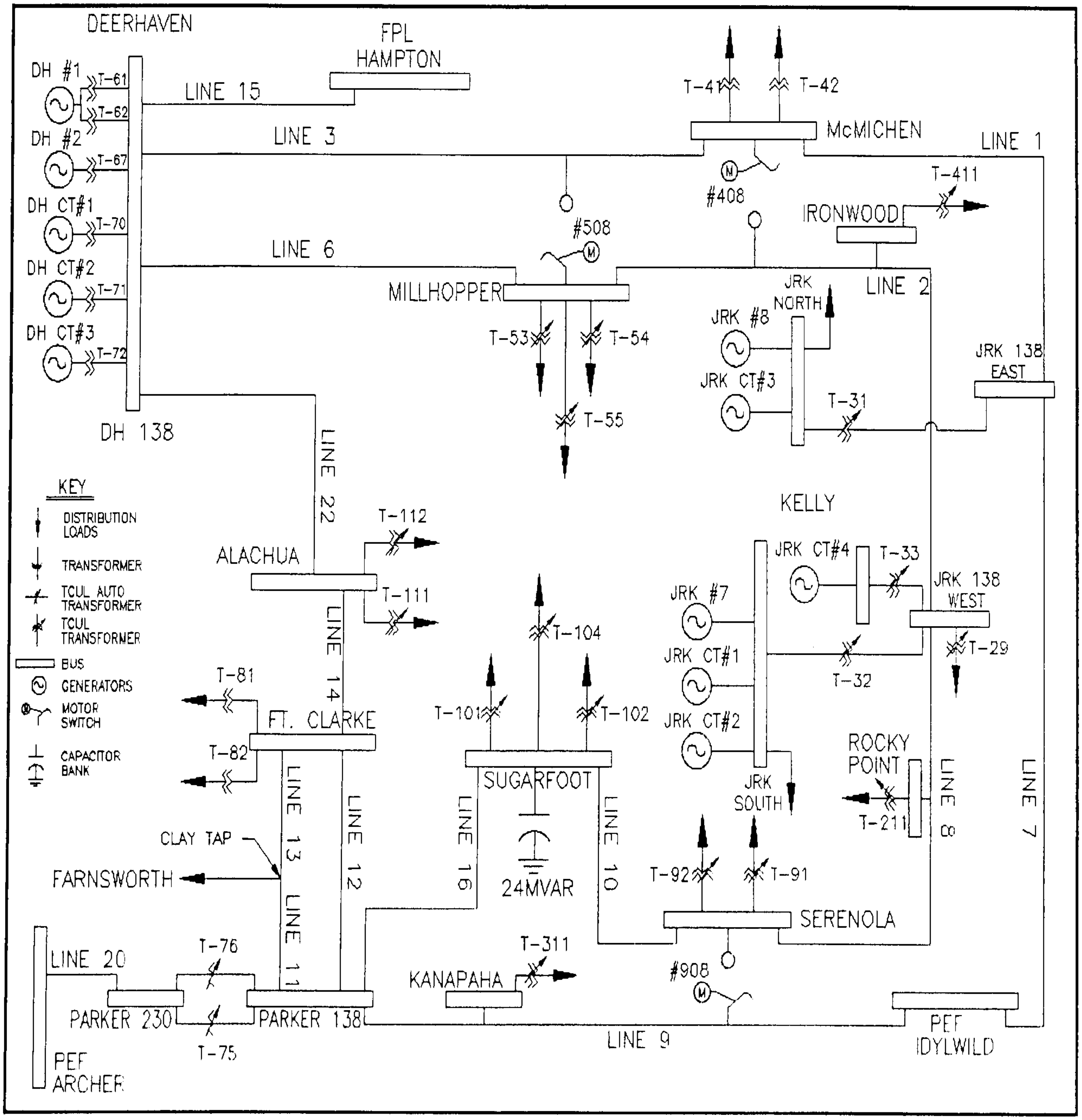


FIGURE 2.2 Gainesville Regional Utilities Electric System One-Line Diagram.



Schedule 1

EXISTING GENERATING FACILITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Primary Fuel		Alternate Fuel		Alt. Fuel	Commercial	Expected	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Type	Trans.	Type	Trans.	Storage (Days)	In-Service Month/Year	Retirement Month/Year	Summer MW	Winter MW	Summer MW	Winter MW	Status
J. R. Kelly		Alachua County									**180.00**	**189.00**	**177.20**	**186.20**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL				[4/65 ; 5/01]	2051	38.00	38.00	37.00	37.00	OP
	FS07	(GRU)	ST	NG	PL	RFO	TK		8/61	10/13	24.00	24.00	23.20	23.20	OP
	GT04		CT	NG	PL	DFO	TK		5/01	2051	76.00	82.00	75.00	81.00	OP
	GT03		GT	NG	PL	DFO	TK		5/69	05/19	14.00	15.00	14.00	15.00	OP
	GT02		GT	NG	PL	DFO	TK		9/68	09/18	14.00	15.00	14.00	15.00	OP
	GT01		GT	NG	PL	DFO	TK		2/68	02/18	14.00	15.00	14.00	15.00	OP
Deerhaven		Alachua County									**441.00**	**451.00**	**421.40**	**432.40**	
	FS02	Secs. 26,27,35	ST	BIT	RR				10/81	2031	239.00	239.00	228.40	228.40	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	08/22	88.00	88.00	83.00	83.00	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	76.00	82.00	75.00	81.00	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	19.00	21.00	17.50	20.00	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	19.00	21.00	17.50	20.00	OP
Crystal River [illegible]	3	Citrus County Sec. 33, T17S, R16E (PEF)	ST	NUC	TK				3/77	2037	**12.07**	**12.24**	**11.43**	**11.71**	OP
SW Landfill		Alachua County									**1.30**	**1.30**	**1.30**	**1.30**	
	SW-1	Sec. 19, T11S, R18E	IC	LFG	PL				12/03	12/09	0.65	0.65	0.65	0.65	OP
	SW-2	(GRU)	IC	LFG	PL				12/03	12/15	0.65	0.65	0.65	0.65	OP
System Total													**611.33**	**631.61**	

Unit Type
CA = Combined Cycle Steam Part
CT = Combined Cycle Combustion Turbine Part
GT = Gas Turbine
ST = Steam Turbine
IC = Internal Combustion (diesel, piston) Engine

Fuel Type
NG = Natural Gas
BIT = Bituminous Coal
NUC = Uranium
RFO = Residual Fuel Oil
DFO = Distillate Fuel Oil
WH = Waste Heat
LFG = Landfill Gas

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

Status
OP = Operational

TABLE 2.1

TRANSMISSION LINE RATINGS
SUMMER POWER FLOW LIMITS

Line Number	Description	Normal 100°C (MVA)	Limiting Device	8-Hour Emergency 125°C (MVA)	Limiting Device
1	McMichen - Depot East	236.2	Conductor	282.0	Conductor
2	Millhopper - Depot West	236.2	Conductor	282.0	Conductor
3	Deerhaven - McMichen	236.2	Conductor	282.0	Conductor
6	Deerhaven - Millhopper	236.2	Conductor	282.0	Conductor
7	Depot East - Idylwild	191.2[1]	Line Tap	191.2[1]	Line Trap
8	Depot West - Serenola	236.2	Conductor	282.0	Conductor
9	Idylwild - Parker	191.2[1]	Line Tap	191.2[1]	Line Trap
10	Serenola - Sugarfoot	236.2	Conductor	282.0	Conductor
11	Parker - Clay Tap	236.2	Conductor	282.0	Conductor
12	Parker - Ft. Clarke	236.2	Conductor	282.0	Conductor
13	Clay Tap - Ft. Clarke	236.2	Conductor	282.0	Conductor
14	Ft. Clarke - Alachua	299.7	Conductor	356.0	Conductor
15	Deerhaven - Hampton	224.0[2]	Transformers	282.0	Conductor
16	Sugarfoot - Parker	236.2	Conductor	282.0	Conductor
20	Parker-Archer(T75,T76)	224.0	Transformers	300.0	Transformers
22	Alachua - Deerhaven	299.7	Conductor	356.0	Conductor
xx	Clay Tap - Farnsworth	236.2	Conductor	282.0	Conductor
xx	Idylwild – PEF	150.0[3]	Transformer	168.0[3]	Transformer

1) Rating effective through Spring 2008 (scheduled). At this point in time, the 800 ampere wave traps on the JRK East – Idylwild 138 KV and Parker – Idylwild 138 KV circuit at Idylwild are scheduled to be removed by PEF. Thereafter, the normal and emergency rating will be 236.2 MVA and 282.0 MVA, respectively.

2) These two transformers are located at the FPL Bradford Substation and are the limiting elements in the Normal rating for this intertie.

3) This transformer is owned and maintained by PEF.

Assumptions:

100 °C for normal conductor operation
125 °C for emergency 8 hour conductor operation
40 °C ambient air temperature
2 ft/sec wind speed
Transformers T75 & T76 normal limits are based on a 65 °C oil temperature rise

TABLE 2.2

SUBSTATION TRANSFORMATION AND CIRCUITS

Distribution Substation	Normal Transformer Rated Capability	Current Number of Circuits
Ft. Clarke	50.4 MVA	4
J.R. Kelly[2]	168.0 MVA	17
McMichen	44.8 MVA	5
Millhopper	100.8 MVA	10
Serenola	67.2 MVA	8
Sugarfoot	100.8 MVA	9
Ironwood	33.6 MVA	3
Kanapaha	33.6 MVA	3
Rocky Point	33.6 MVA	3

Transmission Substation	Normal Transformer Rated Capability	Number of Circuits
Parker	224 MVA	5
Deerhaven	No transformations- All 138 kV circuits	4

2 J.R. Kelly is a generating station as well as 2 distribution substations. One substation has 12 distribution feeders directly fed from the 2- 12.47 kV generator buses with connection to the 138 kV loop by 2- 56 MVA transformers. The other substation (Kelly West) has 5 distribution feeders fed from a single, loop-fed 56 MVA transformer

3. FORECAST OF ELECTRIC ENERGY AND DEMAND REQUIREMENTS

Section 3 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 1998-2017. Energy sales and number of customers are tabulated in Schedules 2.1, 2.2 and 2.3. Schedule 3.1 gives summer peak demand for the base case forecast by reporting category. Schedule 3.2 presents winter peak demand for the base case forecast by reporting category. Schedule 3.3 presents net energy for load for the base case forecast by reporting category. Short-term monthly load data is presented in Schedule 4. Projected net energy requirements for the System, by method of generation, are shown in Schedule 6.1. The percentage breakdowns of energy 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.

3.1 FORECAST ASSUMPTIONS AND DATA SOURCES

(1) All regression analyses were based on annual data. Historical data was compiled for calendar years 1970 through 2007. 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 obtained from the Florida Population Studies, February 2007 (Bulletin No. 147), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

(3) Historical weather data was used to fit regression models. The forecast assumes normal weather conditions. Normal heating degree days and cooling degree days equal the mean of data reported to NOAA by the Gainesville Municipal Airport station from 1984-2007.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2007, using the U.S. Consumer Price Index for All Urban Consumers from the U.S. Department of Labor, Bureau of Labor Statistics. Inflation is assumed to average approximately 2.5% per year for each year of the forecast.

(5) The U. S. Department of Commerce provided historical estimates of total income and per capita income for Alachua County. Forecast values of per capita income for Alachua County were obtained from Global Insight.

(6) Historical estimates of household size were obtained from BEBR, and projected levels were derived from a forecast provided by Global Insight.

(7) The Florida Agency for Workforce Innovation and the U.S. Department of Labor provided historical estimates of non-agricultural employment in Alachua County. A forecast of non-agricultural employment was developed by Global Insight.

(8) GRU's corporate model was the basis for projections of the average price of 1,000 kWh of electricity for all customer classes. GRU's corporate model evaluates projected revenue and revenue requirements for the forecast horizon and determines revenue sufficiency under prevailing prices. If revenue from present pricing is insufficient for projected operations, pricing changes are programmed and become GRU's official pricing program plan. The price of electricity is expected to slightly outpace inflation over the forecast horizon.

(9) Estimates of energy and demand reductions resulting from planned demand-side management programs (DSM) were subtracted from all retail forecasts. GRU's involvement with DSM is described in more detail later in this section.

(10) The City of Alachua will generate (via generation entitlement shares of Progress Energy and Florida Power and Light nuclear units) approximately 8,077 MWh (7 %) of its annual energy requirements.

3.2 FORECASTS OF NUMBER OF CUSTOMERS, ENERGY SALES AND SEASONAL PEAK DEMANDS

Number of customers, energy sales and seasonal peak demands were forecast from 2008 through 2017. Separate energy sales forecasts were developed for each of the following customer segments: residential, general service non-demand, general service demand, large power, outdoor lighting, sales to Clay, and sales to 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)[3]. The following text describes the regression equations utilized to forecast energy sales and number of customers.

3.2.1 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 household income in Alachua County, residential price of electricity, heating degree days, and cooling degree days. The form of this equation is as follows:

$$RESAVUSE = 5554 + 0.054\,(HHY07) - 14.09\,(RESPR07) + 0.79\,(HDD) + 0.90\,(CDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use Per Customer
HHY07	=	Average Household Income
RESPR07	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
CDD	=	Annual Cooling Degree Days

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

Adjusted R^2	=	0.8879
DF (error)	=	31 (period of study, 1971-2007)
t - statistics:		
Intercept	=	4.20
HHY07	=	4.96
RESPR07	=	-4.33
HDD	=	4.34
CDD	=	4.38

Projections of the average annual number of residential customers were developed from a linear regression model stating the number of customers as a function of Alachua County population, the number of persons per household, the historical series of Clay customer transfers, and an indicator variable for customer counts recorded under the billing system used prior to 1992. The residential customer model specifications are:

$$RESCUS = 48295 + 330.5\,(POP) - 22501\,(HHSize) + 0.66\,(CLYRCus) - 1934\,(OldSys)$$

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
HHSize	=	Number of Persons per Household
CLYRCus	=	Clay Customer Transfers
OldSys	=	Older Billing System (1978-1991)
Adjusted R^2	=	0.9993
DF (error)	=	24 (period of study, 1978-2007)
t - statistics:		
Intercept	=	8.75
POP	=	45.43
HHSize	=	-11.80
CLYRCus	=	3.74

OldSys = -4.77

The product of forecasted values of average use and number of customers yielded the projected energy sales for the residential sector.

3.2.2 General Service Non-Demand Sector

The general service non-demand (GSN) customer class includes non-residential customers with maximum annual 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 and have good load factors. Since 1990, 375 customers have elected to transfer to the GSD rate class. The forecast assumes that additional GSN customers will voluntarily elect 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 and cooling degree days. The specifications of this model are as follows:

GSNAVUSE = 23.96 – 0.011 (OPTDCus) + 0.0014 (CDD)

Where:

GSNAVUSE = Average annual energy usage by GSN customers

OPTDCus = Cumulative number of Optional Demand Customers

CDD = Annual Cooling Degree Days

Adjusted R^2 = 0.8320

DF (error) = 25 (period of study, 1979-2007) t - statistics:

Intercept	=	12.61
OPTDCus	=	-11.21
CDD	=	2.05

The number of general service non-demand customers was projected using an equation specifying customers as a function of Alachua County population, Clay non-demand transfer customers, and the number of optional demand customers. The specifications of the general service non-demand customer model are as follows:

GSNCUS = *-5843 + 63.2(POP) + 2.35(CLYNCus) – 4.01(OptDCus)*

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
CLYNCus	=	Clay Non-Demand Transfer Customers
OptDCus	=	Optional Demand Customers
Adjusted R^2	=	0.9965
DF (error)	=	25 (period of study, 1978-2007)

t - statistics:

Intercept	=	-11.48
POP	=	19.73
CLYNCus	=	2.38
OptDCus	=	-7.19

Forecasted energy sales to general service non-demand customers were derived from the product of projected number of customers and the projected average annual use per customer.

3.2.3 General Service Demand Sector

The general service demand customer class includes non-residential customers with established annual maximum 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 per capita income (Alachua County) and the number of optional demand customers. A significant portion of the energy load in this sector is from large retailers such as department stores and grocery stores, whose business activity is related to income levels of area residents. Average energy use projections for general service demand customers result from the following model:

$$GSDAVUSE = 326.8 + 0.0084\,(PCY07) - 0.20\,(OPTDCust)$$

Where:

GSDAVUSE = Average annual energy use by GSD Customers

PCY07 = Per Capita Income in Alachua County

OPTDCust = Cumulative number of Optional Demand Customers

Adjusted R^2 = 0.7145

DF (error) = 25 (period of study, 1979-2007)

t - statistics:

Intercept = 13.13

PCY07 = 8.16

OPTDCust = -7.18

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

$$GSDCUS = -433.3 + 5.34(POP) + 19.60(CLYDCus) + 0.49(OptDCus)$$

Where:

GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
CLYDCus	=	Clay Demand Transfer Customers
OptDCus	=	Optional Demand Customers
Adjusted R^2	=	0.9953
DF (error)	=	25 (period of study, 1978-2007)
t - statistics:		
Intercept	=	-5.52
POP	=	11.02
CLYDCus	=	4.32
OptDCus	=	5.92

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

3.2.4 Large Power Sector

The large power customer class currently includes approximately 18 customers with billing demands of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1976 through 2007. The model developed to project average use by large power customers includes Alachua County nonagricultural employment and large power price of electricity as independent variables. Energy use per customer has been observed to increase over time, presumably due to the periodic expansion or increased utilization of existing facilities. This growth is measured in the model by local employment levels. The specifications of the large power average use model are as follows:

$$LPAVUSE = 9154 + 22.7\,(NONAG) - 23.1\,(LPPR07)$$

Where:

LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
NONAG	=	Alachua County Nonagricultural Employment (000's)
LPPR07	=	Average Price for 1,000 kWh in the Large Power Sector
Adjusted R^2	=	0.9171
DF (error)	=	29 (period of study, 1976-2007)

t - statistics:

INTERCEPT	=	8.40
NONAG	=	4.02
LPPR07	=	-3.60

The forecast of energy sales to the large power sector was derived from the product of projected average use per customer and the projected number of large power customers, which are projected to remain constant at eighteen.

3.2.5 Outdoor Lighting Sector

The outdoor lighting sector consists of streetlight, traffic light, and rental light accounts. Outdoor lighting energy sales account for approximately 1.25% of total energy sales. Outdoor lighting energy sales were forecast using a model which specified lighting energy as a function of the natural log of the number of residential customers. The specifications of this model are as follows:

$$LGTMWH = 288466 + 27984\,(LNRESCUS)$$

Where:

LGTMWH	=	Outdoor Lighting Energy Sales
LNRESCUS	=	Number of Residential Customers (natural log)
Adjusted R^2	=	0.9905
DF (error)	=	12 (period of study, 1994-2007)

t - statistics:

Intercept	=	-34.19
RESCUS	=	36.85

3.2.6 Wholesale Energy Sales

As previously described, the System provides control area services to two wholesale customers: Clay Electric Cooperative (Clay) at the Farnsworth Substation; and the City of Alachua (Alachua) at the Alachua No. 1 Substation, and at the Hague Point of Service. Approximately 7% of Alachua's 2007 energy requirements were met through generation entitlements of nuclear generating units operated by PEF and FPL. These wholesale delivery points serve an urban area that is either included in, or adjacent to the Gainesville urban area. These loads are considered part of the System's native load for facilities planning through the forecast horizon. GRU provides other utilities services in the same geographic areas served by Clay and Alachua, and continued electrical service will avoid duplicating facilities. Furthermore, the populations served by Clay and Alachua benefit from services provided by the City of Gainesville, which are in part supported by transfers from the System.

Clay-Farnsworth net energy requirements were modeled with an equation in which Alachua County population was the independent variable. Output from this model was adjusted to account for the history of load that has been transferred between GRU and Clay-Farnsworth, yielding energy sales to Clay. Historical boundary adjustments between Clay and GRU have reduced the duplication of facilities in both companies' service areas. The form of the Clay-Farnsworth net energy requirements equation is as follows:

$$CLYNEL = -49562 + 557.6\,(POP)$$

Where:

CLYNEL = Farnsworth Substation Net Energy (MWh)

POP = Alachua County Population (000's)

Adjusted R^2 = 0.9351

DF (error) = 16 (period of study, 1990-2007)

t - statistics:

Intercept = -6.53

POP = 15.68

Net energy requirements for Alachua were estimated using a model in which City of Alachua population was the independent variable. BEBR provided historical estimates of City of Alachua Population. This variable was projected from a trend analysis of the component populations within Alachua County. The model used to develop projections of sales to the City of Alachua is of the following form:

$$ALANEL = -64259 + 23256\,(ALAPOP)$$

Where:

ALANEL = City of Alachua Net Energy (MWh)

ALAPOP = City of Alachua Population (000's)

Adjusted R^2 = 0.9872

DF (error) = 24 (period of study, 1982-2007)

t - statistics:

Intercept = -21.77

ALAPOP = 43.95

To obtain a final forecast of the System's sales to Alachua, projected net energy requirements were reduced by 8,077 MWh reflecting the City of Alachua's nuclear generation entitlements.

3.2.7 Total System Sales, Net Energy for Load, Seasonal Peak Demands and DSM 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, sales to Clay, and sales to Alachua. Net energy for load was then forecast by applying a delivered efficiency factor for the System to total energy sales. The projected delivered efficiency factor (0.96) is the median of observed historical values from 1995 through 2007. The impact of energy savings from conservation programs was accounted for in energy sales to each customer class, prior to calculating net energy for load.

The forecasts of seasonal peak demands were derived from forecasts of annual net energy for load. Winter peak demands are projected to occur in January of each year, and summer peak demands are projected to occur in August of each year, although historical data suggests the summer peak is nearly as likely to occur in July. The average ratio of the most recent 25 years' monthly net energy for load for January and August, as a portion of annual net energy for load, was applied to projected annual net energy for load to obtain estimates of January and August net energy for load over the forecast horizon. The medians of the past 25 years' load factors for January and August were applied to January and August net energy for load projections, yielding seasonal peak demand projections. Forecast seasonal peak demands include the net impacts from planned demand-side management programs.

3.3 ENERGY SOURCES AND FUEL REQUIREMENTS

3.3.1 Fuels Used by System

Presently, the system is capable of using coal, residual oil, distillate oil, natural gas, and a small percentage of nuclear fuel to satisfy its fuel requirements. Since the completion of the Deerhaven 2 coal-fired unit, the System has relied upon coal to fulfill much of its fuel requirements. To the extent that the System participates in interchange sales and purchases, actual consumption of these fuels will likely differ from the base case requirements indicated in Schedule 5. These projections are based on a fuel price forecast prepared in March 2007.

3.3.2 Methodology for Projecting Fuel Use

The fuel use projections were produced using the Electric Generation Expansion Analysis System (EGEAS) developed under Electric Power Research Institute guidance. Ng Engineering provides support, maintenance, and training for the EGEAS software. This is the same software the System uses to perform long-range integrated resource planning. EGEAS has the ability to model each of the System's generating units as well as optimize the selection of new capacity and technologies (see Section 4), and include the effects of environmental limits, dual fuel units, reliability constraints, and maintenance schedules. The production modeling process uses a load-duration curve convolution and conjoint probability model to simulate optimal hourly dispatch of the System's generating resources.

The input data to this model includes:

(1) Long-term forecast of System electric energy and power demand needs;

(2) Projected fuel prices, outage parameters, nuclear refueling cycle (as needed), and maintenance schedules for each generating unit in the System;

(3) Similar data for the new plants that will be added to the system to maintain system reliability.

The output of this model includes:

(1) Monthly and yearly operating fuel expenses by fuel type and unit; and

(2) Monthly and yearly capacity factors, energy production, hours of operation, fuel utilization, and heat rates for each unit in the system.

3.3.3 Purchased Power Agreements

3.3.3.1 G2 Energy Baseline Landfill Gas. GRU has entered into a contract to receive 3 MW of landfill gas fueled capacity at the Marion County Baseline Landfill, from G2 Energy Marion, LLC. The generation facility is expected to begin commercial operation in mid 2008.

3.3.3.2 Progress Energy 50 MW. GRU is negotiating a contract with Progress Energy Florida (PEF) for 50 MW of base load capacity. This contract will begin (pending FERC approval of PEF's contract structure) January 1, 2009 and continue through December 31, 2013. Extensions of this contract are subject to negotiation.

3.3.3.3 Biomass RFP for PPA. Eleven responses to GRU's "Request for Proposals" (RFP) for a biomass fueled facility in the 30-100 MW range were received on December 15, 2007. Addendum Two has been issued to solicit binding proposals from the top three proposals from the initial RFP. The responses to Addendum Two will be received April 11, 2008 and are to include biomass fueled capacity and energy through a purchase power agreement (PPA), with an option to buy the plant at a later date, or cost estimates for an engineer, procure, and construct (EPC) contract to build a new biomass unit for GRU to own and operate.

3.4 DEMAND-SIDE MANAGEMENT

3.4.1 Demand-Side Management Program History and Current Status

Demand and energy forecasts and generation expansion plans 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 2007. DSM programs are available for all retail customers, including commercial and industrial customers, and are designed to effectively reduce and control the growth rates of electric consumption and weather sensitive peak demands.

DSM direct services currently available to the System's residential customers, or expected to be implemented during fiscal year 2008, include energy audits, low income household whole house energy efficiency improvements, and air conditioning sizing calculations. GRU also offers rebates and other financial incentives for the promotion of:

- high efficiency central air conditioning
- high efficiency room air conditioning
- central air conditioner maintenance
- heat recovery water heating
- reflective roof coating for mobile homes
- solar water heating
- solar photovoltaic systems
- natural gas in new construction
- Home Performance with the federal Energy Star program
- Energy Star building practices of the EPA
- Green Building practices in multi-family dwellings
- heating/cooling duct repair
- energy efficiency for low-income households
- adequate insulation
- removing second refrigerators from homes and recycling the materials
- compact fluorescent light bulbs
- energy efficiency low-interest loans
- natural gas for displacement of electric in water heating, space heating, and space cooling in existing structures.

DSM services available to the System's non-residential customers include energy audits, lighting efficiency and lighting maintenance services. In addition GRU offers rebates and other considerations for the promotion of:

- solar water heating
- solar photovoltaic
- natural gas for water heating, space heating and dehumidification
- vending machine motion sensors
- efficient exit lighting
- energy efficiency retrofits

The System continues to offer standardized interconnection procedures and compensation for excess energy production for both residential and non-residential customers who install distributed resources and offers rebates for the installation of photovoltaic generation.

GRU secured grant funding through the Department of Community Affairs' PV for Schools Educational Enhancement Program for PV systems that were installed at two middle schools in 2003. GRU began offering green energy (i.e., GRUGreen^{sm}) to its customers when the LFGTE project became operational in 2003. The majority of the energy available under this program comes from landfill gas, but also includes some solar and wind energy credits. GRUGreen^{sm} is available to all GRU customers at a cost equivalent to two cents per kWh. A combination of customer contributions and State and Federal grants allowed GRU to add its 10 kW photovoltaic array at the Electric System Control Center in 1996.

GRU has also produced numerous *factsheets*, publications and videos which are available at no charge to customers to assist them in making informed decisions affecting their energy utilization patterns. Examples include: Passive Solar Design-Factors for North Central Florida, a booklet which provides detailed solar and environmental data for passive solar designs in this area; Solar Guidebook, a brochure which explains common applications of solar energy in Gainesville; and The Energy Book, a guide to saving home energy dollars.

3.4.2 Future Demand-Side Management Programs

GRU continues to monitor the potential for additional DSM efforts including programs addressing thermal storage, district chilled water cooling, window shading, additional energy efficiency in low-income households and demand response. GRU continues to review the efforts of conservation leaders in the industry, and has conducted fact finding trips to California, Texas, Vermont and New York to maximize these efforts. GRU plans to continue to expand its DSM programs as a way to cost-effectively meet customer needs and hedge against potential future carbon tax and trade programs. GRU has budgeted funds to proceed with installing a 250 kW PV system in the parking lot of a Wal-Mart super center in Gainesville. This demonstration project will showcase both fixed mounted and tracking PV technology.

3.4.3 Demand-Side Management Methodology and Results

The expected effect of DSM program participation was derived from a comparative analysis of historical energy usage of DSM program participants and non-participants. The methodology upon which existing DSM programs is based includes consideration of what would happen under current conditions, the fact that the conservation induced by utility involvement tends to "buy" conservation at the margin, adjustment for behavioral rebound and price elasticity effects and effects of abnormal weather. Known interactions between measures and programs were accounted for where possible. Projected penetration rates were based on historical levels of program implementations and tied to escalation rates paralleling service area population growth.

The implementation of DSM programs planned for 2008-2017 is expected to provide 48 MW of summer peak reduction, and 128 GWh of annual energy savings by the year 2017. Total DSM program achievements from 1980-2017 are shown in Table 3.1.

3.4.4 Gainesville Energy Advisory Committee

The Gainesville Energy Advisory Committee (GEAC) is a nine-member citizen group that is charged with formulating recommendations to the Gainesville City Commission concerning national, state and local energy-related issues. The GEAC offers advice and guidance on energy management studies and consumer awareness programs.

Background and Achievements

The GEAC's efforts have resulted in numerous contributions, accomplishments, and achievements for the City of Gainesville. Specifically, the GEAC helped establish a residential energy audit program in 1979, and was involved in the 1980 ratemaking process resulting in the creation of an inverted block residential rate and a voluntary residential time-of-use rate. The GEAC promoted *Solar Month* in October of 1991 by sponsoring a seminar to foster the viability of solar energy as an alternative to conventional means of energy supply. Representatives from Sandia National Laboratories, the Florida Solar Energy Center, PEF, and GRU gave presentations on various solar projects and technologies. A recommendation from GEAC followed the Solar Day Seminars for GRU to investigate offering its citizen-ratepayers the option of contributing to photovoltaic power production through monthly donations on their utility bills. The interest generated by the seminars along with grant money from the State of Florida Department of Community Affairs and the Utility Photovoltaic Group and donations from GRU customers and friends of solar energy resulted in the 10 kilowatt PV system at the System Control Center. GRU solicited public input on its solar water heater rebate program through the GEAC, and the committee in turn formally supported the program. The GEAC sponsored a Biomass

Seminar for a joint meeting of the Gainesville City Commission and the Alachua County Commission. The GEAC has strongly supported the EPA's Energy Star program, and has helped GRU earn EPA's 1998 Utility Ally of the Year award. GEAC contributed to the development of a Green Builder program for existing multi-family dwellings as a long-range load reduction strategy. Multi-family dwellings represent approximately 35% of GRU's total residential load. GEAC has also supported GRU's IRP efforts through their sponsorship of community workshops and review of the IRP.

3.4.5 Supply Side Programs

Prior to the addition of Deerhaven Unit 2 in 1982, the System was relying on oil and natural gas for over 90% of native load energy requirements. In 2007, oil-fired generation comprised 1.6% of total net generation, natural gas-fired generation contributed 26.2%, nuclear fuel contributed 4.6%, and coal-fired generation provided 67.6% of total net generation. Deerhaven 2 is also contributing to reduced oil use by other utilities by offering coal-generated energy on the Florida energy market. The PV system at the System Control Center provides slightly more than 10 kilowatts of capacity at solar noon on clear days. Finally, the landfill gas to energy (LFGTE) project is capable of providing 1.3 MW of renewable energy on a continuous basis.

The System has several programs to improve the adequacy and reliability of the transmission and distribution systems, which will also result in decreased energy losses. These include the installation of distribution capacitors, purchase of high-efficiency distribution transformers, and the reconductoring of the feeder system.

Transformers

GRU has been purchasing overhead and underground transformers with a higher efficiency than the NEMA TP-1 Standard for the past 18 years. Higher efficiency means less kW losses or power lost due the design of the transformer.

Since 1988, there have been 15,903 high-efficiency transformers installed on GRU's distribution system.

A study was initiated to compare the kW losses of GRU's transformer design to a design based on NEMA TP-1 Efficiency Standard for Transformers. The results of this investigation showed that relative to the standard design, GRU experienced these savings:

Average Annual Demand Loss Savings	2.5 MW
Average Annual Energy Saved	21,900 MWh
Peak Demand Savings	5.5 MW

Reconductoring

GRU has been continuously improving the feeder system by reconductoring feeders from 4/0 Copper to 795 MCM aluminum overhead conductor. Also, in specific areas the feeders have been installed underground using 1000 MCM underground cable.

Following is a comparison of the resistance for the types of conductors used on GRU's electric distribution system:

795 MCM Aluminum Overhead Conductor	0.13 ohms/mile
1000 MCM Aluminum Underground Cable	0.13 ohms/mile
4/0 Copper Overhead Conductor	0.31 ohms/mile

Calculations with average loading on the conductors show the total savings due to moving from 4/0 copper to an aluminum conductor (795 or 1000 MCM):

Average Annual Demand Savings	2.4 MW
Average Annual Energy Saved	21,000 MWh
Peak Demand Savings	7.9 MW

Capacitors

GRU strives to maintain an average power factor of 0.98 by adding capacitors where necessary on the distribution feeder. Without these capacitors the average uncorrected power factor is 0.92.

The percentage of loss reduction can be calculated as shown:

% Loss Reduction=[1-(Uncorrected pf/Corrected pf)^2] x 100

% Loss Reduction=[1-(0.92/0.98)^2] x 100

% Loss Reduction = 11.9

In general, overall system losses have stabilized near 4% of net generation as reflected in the forecasted relationship of total energy sales to net energy for load.

3.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU consults a variety of reputable sources to compile projections of fuel prices for fuels currently used and those that are evaluated for potential future use. Oil prices are obtained from the Annual Energy Outlook 2008 (AEO2008), published in February 2008 by the U.S. Department of Energy's Energy Information Administration (EIA). Natural gas price projections are derived from several forecasts published by the PIRA Energy Group. The source for projected coal prices is Hill & Associates (a Wood Mackenzie Company). Projected prices for nuclear fuel were provided by PEF. These forecasts are often provided in constant-year (real) dollars, and GRU translates these prices to nominal dollars using the projected Gross Domestic Product – Implicit Price Deflator from AEO2008. Fuel prices are analyzed in two parts: the cost of the fuel (commodity), and the cost of transporting the fuel to GRU's generating stations. The external forecasts typically address the commodity prices, and GRU's specific transportation costs are included to derive delivered prices. A summary of historical and projected fuel prices is provided in Table 3.3.

3.5.1 Oil

GRU relies on No. 6 Oil (residual) and No. 2 Oil (distillate or diesel) as back-up fuels for natural gas fired generation. These fuels are delivered to GRU generating stations by truck. Forecast prices for these two types of oil are derived directly from AEO2008.

During calendar year 2007, distillate fuel oil was used to produce 0.03% of GRU's total net generation. Distillate fuel oil is expected to be the most expensive fuel available to GRU. During calendar year 2007, residual fuel oil was used to produce 1.6% of GRU's total net generation. The quantity of fuel oils used by GRU is expected to remain low.

3.5.2 Coal

Coal is the primary fuel used by GRU to generate electricity, comprising 67.6% of total net generation during calendar year 2007. GRU purchases low-sulfur (0.7%), high Btu eastern coal for use in Deerhaven Unit 2. In 2009, Deerhaven Unit 2 will begin operating following the retrofit of an air quality control system, which is being added as a means of complying with new environmental regulations. Deerhaven Unit 2 will be able to utilize coals with up to approximately 1.7% sulfur content following the retrofit, therefore GRU also projects prices for both low and medium sulfur coals for evaluation in Deerhaven Unit 2 following the air quality control retrofit.

Prices for compliance coal for 2008 were based on GRU's contractual options with its coal suppliers. Projected prices for compliance coal for 2009 and beyond are based on Hill & Associates' forecast for a low sulfur coal from the central Appalachian region. GRU has a contract with CSXT for delivery of coal to the Deerhaven plant site through 2019. Prices for medium sulfur coals from the central

Appalachian region and the Illinois basin were also derived from the Hill & Associates forecast.

3.5.3 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2007, GRU purchased approximately 7.6 million MMBtu for use by both systems. GRU power plants used 75% of the total purchased for GRU during 2007, while the LDC used the remaining 25%.

GRU purchases natural gas via arrangements with producers and marketers connected with the Florida Gas Transmission (FGT) interstate pipeline. GRU's delivered cost of natural gas includes the commodity component, Florida Gas Transmission's (FGT) fuel charge, FGT's usage (transportation) charge, FGT's reservation (capacity) charge, and basis adjustments.

Prices for 2008 and 2009 were derived from PIRA Energy Group's February 2008 Short-Term Henry Hub Gas Price Forecast. Prices for 2010-2017 were derived from PIRA Energy Group's August 2007 long-term Henry Hub forecast.

3.5.4 Nuclear Fuel

GRU's nuclear fuel price forecast includes a component for fuel and a component for fuel disposal. The projection for the price of the fuel component is based on Progress Energy Florida's (PEF) forecast of nuclear fuel prices. The projection for the cost of fuel disposal is based on a trend analysis of actual costs to GRU.

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
1998	156,797	2.35	777	66,722	11,649	640	7,868	81,363
1999	161,076	2.35	763	68,543	11,137	648	8,095	80,036
2000	164,584	2.34	788	70,335	11,202	674	8,368	80,490
2001	169,395	2.34	803	72,391	11,092	697	8,603	80,986
2002	172,755	2.34	851	73,827	11,527	721	8,778	82,112
2003	174,227	2.34	854	74,456	11,467	726	8,959	81,090
2004	179,459	2.33	878	77,021	11,398	739	9,225	80,143
2005	182,904	2.34	888	78,164	11,358	752	9,378	80,199
2006	183,430	2.31	877	79,407	11,047	746	9,565	78,042
2007	187,406	2.31	878	81,128	10,817	778	9,793	79,398
2008	190,349	2.31	898	82,402	10,893	790	10,029	78,731
2009	192,974	2.30	909	83,865	10,838	803	10,262	78,229
2010	195,580	2.29	921	85,257	10,804	817	10,490	77,884
2011	198,141	2.29	934	86,600	10,785	832	10,712	77,649
2012	200,661	2.28	946	87,894	10,761	846	10,929	77,380
2013	203,108	2.28	956	89,161	10,717	857	11,140	76,970
2014	205,521	2.27	965	90,379	10,683	869	11,345	76,633
2015	207,864	2.27	976	91,570	10,658	882	11,545	76,378
2016	210,137	2.27	986	92,735	10,631	894	11,740	76,124
2017	212,384	2.26	996	93,851	10,613	906	11,929	75,933

* 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
1998	157	15	10,443	0	21	0	1,595
1999	173	17	10,188	0	22	0	1,606
2000	172	17	10,114	0	22	0	1,656
2001	173	17	10,162	0	23	0	1,696
2002	178	18	10,178	0	24	0	1,774
2003	181	19	9,591	0	24	0	1,786
2004	188	18	10,444	0	25	0	1,830
2005	189	18	10,477	0	25	0	1,854
2006	200	20	10,093	0	25	0	1,849
2007	196	18	10,891	0	26	0	1,877
2008	192	18	10,653	0	26	0	1,906
2009	191	18	10,614	0	27	0	1,930
2010	190	18	10,571	0	27	0	1,955
2011	190	18	10,537	0	28	0	1,984
2012	189	18	10,500	0	28	0	2,009
2013	188	18	10,458	0	29	0	2,030
2014	187	18	10,412	0	29	0	2,050
2015	187	18	10,367	0	29	0	2,074
2016	186	18	10,322	0	30	0	2,096
2017	185	18	10,277	0	30	0	2,117

** 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
1998	108	76	1,779	0	74,605
1999	109	83	1,798	0	76,655
2000	120	93	1,868	0	78,720
2001	125	62	1,882	0	81,011
2002	142	92	2,008	0	82,623
2003	146	83	2,015	0	83,434
2004	149	70	2,049	0	86,264
2005	163	66	2,082	0	87,560
2006	174	75	2,099	0	88,992
2007	188	57	2,122	0	90,939
2008	191	87	2,184	0	92,449
2009	196	88	2,214	0	94,146
2010	201	91	2,247	0	95,765
2011	206	90	2,280	0	97,330
2012	210	92	2,311	0	98,840
2013	215	93	2,338	0	100,318
2014	219	96	2,365	0	101,742
2015	224	95	2,393	0	103,133
2016	228	96	2,420	0	104,493
2017	232	98	2,447	0	105,798

Schedule 3.1
History and Forecast of Summer Peak Demand - MW
Base Case

(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
1998	416	26	370	0	0	12	0	8	396
1999	439	26	393	0	0	12	0	8	419
2000	446	28	397	0	0	13	0	8	425
2001	430	28	381	0	0	13	0	8	409
2002	454	32	401	0	0	13	0	8	433
2003	439	33	384	0	0	14	0	8	417
2004	455	33	399	0	0	14	0	9	432
2005	489	37	428	0	0	15	0	9	465
2006	488	39	425	0	0	15	0	9	464
2007	507	44	437	0	0	16	0	10	481
2008	505	44	431	0	0	18	0	12	475
2009	515	45	436	0	0	20	0	14	481
2010	524	46	440	0	0	22	0	16	486
2011	535	47	444	0	0	25	0	19	491
2012	544	48	447	0	0	28	0	21	495
2013	552	49	449	0	0	30	0	24	498
2014	560	50	450	0	0	33	0	27	500
2015	569	51	452	0	0	36	0	30	503
2016	578	52	456	0	0	38	0	32	508
2017	586	53	459	0	0	40	0	34	512

Schedule 3.2
History and Forecast of Winter Peak Demand - MW
Base Case

(1) Winter	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1998 / 1999	393	28	323	0	0	35	0	7	351
1999 / 2000	380	27	310	0	0	36	0	7	337
2000 / 2001	408	33	331	0	0	37	0	7	364
2001 / 2002	416	33	336	0	0	39	0	8	369
2002 / 2003	442	37	357	0	0	40	0	8	394
2003 / 2004	398	31	319	0	0	40	0	8	350
2004 / 2005	426	36	341	0	0	41	0	8	377
2005 / 2006	436	40	346	0	0	42	0	8	386
2006 / 2007	412	38	324	0	0	42	0	8	362
2007 / 2008	438	44	344	0	0	42	0	8	388
2008 / 2009	444	45	349	0	0	42	0	8	394
2009 / 2010	449	46	353	0	0	42	0	8	399
2010 / 2011	455	47	358	0	0	42	0	8	405
2011 / 2012	461	48	363	0	0	42	0	8	411
2012 / 2013	466	49	367	0	0	42	0	8	416
2013 / 2014	470	50	370	0	0	42	0	8	420
2014 / 2015	475	51	374	0	0	42	0	8	425
2015 / 2016	480	52	378	0	0	42	0	8	430
2016 / 2017	485	53	382	0	0	42	0	8	435
2017 / 2018	490	54	386	0	0	42	0	8	440

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

(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 %
1998	1.863	63	21	1,595	108	76	1,779	51%
1999	1.887	67	22	1,606	109	83	1,798	49%
2000	1.961	70	23	1,656	120	93	1,868	50%
2001	1.979	74	23	1,696	125	62	1,882	53%
2002	2.110	78	24	1,774	142	92	2,008	53%
2003	2.121	82	24	1,786	146	83	2,015	55%
2004	2.158	84	25	1,830	149	70	2,049	54%
2005	2.196	88	26	1,854	163	66	2,082	51%
2006	2.215	90	26	1,849	174	75	2,099	52%
2007	2.252	97	33	1,877	188	57	2,122	50%
2008	2.332	106	42	1,906	191	87	2,184	52%
2009	2.374	112	48	1,930	196	88	2,214	53%
2010	2.419	118	54	1,955	201	91	2,247	53%
2011	2.464	124	60	1,984	206	90	2,280	53%
2012	2.508	131	66	2,009	210	92	2,311	53%
2013	2.548	137	73	2,030	215	93	2,338	54%
2014	2.587	143	79	2,050	219	96	2,365	54%
2015	2.627	149	85	2,074	224	95	2,393	54%
2016	2.666	155	91	2,096	228	96	2,420	54%
2017	2.705	161	97	2,117	232	98	2,447	55%

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2007		FORECAST 2008		FORECAST 2009	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	362	158	361	162	394	171
FEB	334	144	319	147	365	149
MAR	302	152	320	154	325	156
APR	335	153	347	156	352	158
MAY	372	178	414	188	420	191
JUN	441	199	451	206	458	208
JUL	452	220	471	225	478	228
AUG	481	238	475	230	481	233
SEP	432	205	447	209	453	212
OCT	385	182	386	178	391	181
NOV	290	144	335	155	340	157
DEC	300	149	361	167	366	170

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
FUEL REQUIREMENTS			UNITS	ACTUAL 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	NUCLEAR		TRILLION BTU	0.964	1.059	0.794	1.094	0.968	1.270	1.149	1.270	1.149	1.270	1.149
(2)	0.7% COAL		1000 TON	552.699	607.402	114.833								
(2.1)	1.7% COAL		1000 TON			462.835	620.484	622.616	637.642	627.727	645.434	647.539	664.218	638.549
	RESIDUAL													
(3)		STEAM	1000 BBL	51.341	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(4)		CC	1000 BBL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(5)		CT	1000 BBL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(6)		TOTAL:	1000 BBL	51.341	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	DISTILLATE													
(7)		STEAM	1000 BBL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(8)		CC	1000 BBL	0.145	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(9)		CT	1000 BBL	1.111	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(10)		TOTAL:	1000 BBL	1.256	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	NATURAL GAS													
(11)		STEAM	1000 MCF	2.620.740	1.003.781	1,303.724	1,023.474	1,069.733	834.093	1,000.022	1,946.012	2,037.784	1,859.784	2,136.940
(12)		CC	1000 MCF	2.122.300	3.246.892	3,587.883	3,108.014	3,361.043	3,198.719	3,494.484	3,908.347	4,115.395	4,088.390	4,473.646
(13)		CT	1000 MCF	542.568	347.734	686.069	517.482	642.397	513.951	557.939	1,130.194	1,258.346	1,084.779	1,404.497
(14)		TOTAL:	1000 MCF	5.285.608	4.598.407	5,577.676	4,648.970	5,073.173	4,546.763	5,052.445	6,984.553	7,411.525	7,032.953	8,015.083
(15)	Landfill Gas		1000 MCF	17.884	11.424	11.424	11.424	11.424	11.424	11.424	11.424	11.424	0.000	0.000

Schedule 6.1
ENERGY SOURCES (GWH)
As of January 1, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(2)	NUCLEAR		GWH	93.948	100.832	75.648	104.188	92.220	120.972	109.439	120.972	109.439	120.972	109.439
(3)	COAL		GWH	1,280.195	1,464.893	1,358.648	1,459.991	1,465.550	1,501.296	1,478.875	1,521.610	1,527.098	1,567.155	1,507.090
	RESIDUAL													
(4)		STEAM	GWH	29.488	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(5)		CC	GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(6)		CT	GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(7)		TOTAL:	GWH	29.488	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	DISTILLATE													
(8)		STEAM	GWH	0.029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(9)		CC	GWH	0.065	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(10)		CT	GWH	0.275	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(11)		TOTAL:	GWH	0.369	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	NATURAL GAS													
(12)		STEAM	GWH	210.013	84.240	110.711	85.442	90.620	70.314	83.851	165.417	174.607	157.785	182.829
(13)		CC	GWH	239.097	338.747	380.621	317.815	340.389	327.177	360.972	439.793	454.606	458.408	507.858
(14)		CT	GWH	40.491	24.449	58.430	46.977	55.172	47.173	50.026	88.858	98.113	86.430	106.350
(15)		TOTAL:	GWH	489.600	447.436	549.762	450.234	486.181	444.664	494.849	694.068	727.326	702.623	797.037
(16)	NUG		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(17)	HYDRO		GWH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(18)	Landfill Gas		GWH	0.409	0.428	0.428	0.428	0.428	0.428	0.428	0.428	0.428	0.000	0.000
(19)	Purchased Energy		GWH	292.247	170.163	229.779	231.680	235.673	244.096	254.647	28.208	28.836	29.036	33.250
(20)	Energy Sales		GWH	64.212	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(21)	NET ENERGY FOR LOAD		GWH	2,122.043	2,183.752	2,214.265	2,246.521	2,280.052	2,311.456	2,338.238	2,365.286	2,393.127	2,419.786	2,446.816

Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
ENERGY SOURCES			UNITS	ACTUAL 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(2)	NUCLEAR		GWH	4.43%	4.62%	3.42%	4.64%	4.04%	5.23%	4.68%	5.11%	4.57%	5.00%	4.47%
(3)	COAL		GWH	60.33%	67.08%	61.36%	64.99%	64.28%	64.95%	63.25%	64.33%	63.81%	64.76%	61.59%
	RESIDUAL													
(4)		STEAM	GWH	1.39%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	GWH	1.39%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWH	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	GWH	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NATURAL GAS													
(12)		STEAM	GWH	9.90%	3.86%	5.00%	3.80%	3.97%	3.04%	3.59%	6.99%	7.30%	6.52%	7.47%
(13)		CC	GWH	11.27%	15.51%	17.19%	14.15%	14.93%	14.15%	15.44%	18.59%	19.00%	18.94%	20.76%
(14)		CT	GWH	1.91%	1.12%	2.64%	2.09%	2.42%	2.04%	2.14%	3.76%	4.10%	3.57%	4.35%
(15)		TOTAL:	GWH	23.07%	20.49%	24.83%	20.04%	21.32%	19.24%	21.16%	29.34%	30.39%	29.04%	32.57%
(16)	NUG		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(17)	HYDRO		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(18)	Landfill Gas		GWH	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.00%	0.00%
(19)	Purchased Energy		GWH	13.77%	7.79%	10.38%	10.31%	10.34%	10.56%	10.89%	1.19%	1.20%	1.20%	1.36%
(20)	Energy Sales		GWH	3.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(21)	NET ENERGY FOR LOAD		GWH	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

TABLE 3.1

DEMAND-SIDE MANAGEMENT IMPACTS
Total Program Achievements

Year	MWh	Summer kW
1980	254	168
1981	575	370
1982	1,054	674
1983	2,356	1,212
1984	8,024	2,801
1985	16,315	4,619
1986	25,416	7,018
1987	30,279	8,318
1988	34,922	9,539
1989	38,824	10,554
1990	43,661	11,753
1991	48,997	12,936
1992	54,898	14,317
1993	61,356	15,752
1994	66,725	16,871
1995	72,057	18,022
1996	75,894	18,577
1997	79,998	19,066
1998	84,017	19,541
1999	88,631	20,055
2000	93,132	20,654
2001	97,428	21,185
2002	102,159	21,720
2003	106,277	22,222
2004	109,441	22,676
2005	113,182	23,405
2006	116,544	24,078
2007	130,871	26,510
2008	147,876	29,710
2009	160,176	33,910
2010	172,476	38,510
2011	184,776	43,510
2012	197,076	48,910
2013	209,376	54,510
2014	221,676	60,210
2015	233,976	66,010
2016	246,321	70,310
2017	258,666	74,610

TABLE 3.2

DELIVERED FUEL PRICES
$/MMBtu

Year	Residual Fuel Oil	Distillate Fuel Oil	Natural Gas	0.7% Sulfur Coal (1)	1.7% Sulfur Coal (2)	Nuclear
1998	2.73	3.97	2.87	1.66		0.40
1999	2.79	3.47	2.86	1.66		0.44
2000	4.52	5.99	4.53	1.62		0.38
2001	4.15	6.53	4.94	1.88		0.38
2002	4.58	5.69	3.95	2.06		0.38
2003	4.87	6.59	5.97	2.04		0.43
2004	5.17	5.17	6.40	2.03		0.41
2005	7.15	18.67	9.15	2.38		0.45
2006	8.07	15.24	8.51	3.00		0.45
2007	7.68	16.35	8.37	2.89		0.42
2008	9.42	16.40	10.40	2.99	2.37	0.44
2009	9.49	14.09	9.09	2.44	2.41	0.45
2010	9.38	13.94	8.09	2.57	2.50	0.67
2011	9.37	13.62	8.14	2.61	2.56	0.68
2012	9.32	13.41	8.25	2.68	2.65	0.88
2013	9.33	13.32	8.49	2.85	2.76	0.89
2014	9.24	13.20	8.85	2.93	2.83	0.93
2015	9.15	13.17	9.13	3.06	2.94	0.93
2016	9.04	13.06	9.52	3.16	3.03	0.92
2017	9.27	13.47	9.89	3.27	3.18	0.92

(1) Approximate heat content of 0.7% sulfur coal is 12,500 Btu/lb.
(2) Approximate heat content of 1.7% sulfur coal is 12,300 Btu/lb.

4. FORECAST OF FACILITIES REQUIREMENTS

4.1 GENERATION RETIREMENTS

The System plans to retire three of its currently operating generating units prior to the end of 2015 (see Schedule 8). In December of 2003 GRU commissioned its newest units at the Southwest Landfill. Engines installed at the landfill gas to electric energy project will be retired as the gas production decreases through time. The first engine is expected to be removed in December 2009, and the second in December 2015. The John R. Kelly steam unit #7 (JRK #7) (23 MW) will be 50 years old in 2011. After an extensive examination during the last maintenance outage, JRK #7 was found in excellent condition and suitable for operation through October 2013.

4.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

GRU uses a planning criterion of 15% capacity reserve margin (suggested for emergency power pricing purposes by Florida Public Service Commission Rule 25-6.035). Available generating capacities are compared with System summer peak demands in Schedule 7.1 (and Figure 4.1) and System winter peak demands in Schedule 7.2 (and Figure 4.2). Higher peak demands in summer and lower unit operating capacities in summer result in lower reserve margins during the summer season than in winter. Summer reserve margins without capacity additions are forecast to fall below 15% starting in 2018. The Gainesville community is discussing the ramifications of adding additional resources during the next ten to fifteen years to address its reserve margin requirements. GRU will import firm capacity as needed in future years. With the implementation of the Total Resource Cost (TRC) test and the resulting demand side management projects the need for generating capacity has been pushed beyond 2017. A direct load control program is also being considered, to maintain adequate reserves even longer.

4.3 GENERATION ADDITIONS

Due to new EPA regulations promulgated in March 2005, the retrofit of our Deerhaven #2 Air Quality Control System (AQCS) is proceeding as one means of complying with the new regulations. The upgraded AQCS will consist of a selective catalytic reduction (SCR) system and a dry flue gas desulfurization system (FGD) which will include a baghouse (BH). It is expected that the SCR and the FGD/BH will be operational by early 2009. The power to operate this system will reduce the overall net output of the Deerhaven #2 unit by approximately 3 MW.

Construction has begun on the distributed generation project, GRU South Energy Center located at the new Shands Healthcare Cancer Hospital (4.1 MW combustion turbine). Characteristics of the combustion turbine are summarized in Schedule 9 at the end of this section.

As part owner in the Crystal River 3 nuclear unit, GRU will benefit from three uprates of the unit's capacity approved by the Nuclear Regulatory Commission (NRC). GRU's share (1.4079%) of the uprates (first 11 MW in 2008, second 28 MW in 2009, and 140 MW in 2011) will net the System 2.5 MW of additional base load capacity.

Responses to GRU's "Request for Letters of Interest" (RFLOI) were received November 15, 2006. The fuel types and the technologies proposed were varied and interesting. The fuel proposed included coal, biomass, municipal solid waste, landfill gases and others; some are finite in quantity and others are renewable and sustainable. The technologies included traditional steam turbine generator sets as well as gassifiers, both plasma driven and integrated gasification systems. Other responses included sources of machinery and offers of partial power contracts on existing and future units.

Eleven responses to GRU's "Request for Proposals" (RFP) for a biomass fueled facility in the 30-100 MW range were received on December 15, 2007. Addendum Two has been issued to solicit binding proposals from the top three proposals from the initial RFP. The responses to Addendum Two will be received April 11, 2008 and are to include biomass fueled capacity and energy through a purchase power agreement (PPA), with an option to buy the plant at a later date, or cost estimates for an engineer, procure, and construct (EPC) contract to build a new biomass unit for GRU to own and operate.

4.4 DISTRIBUTION SYSTEM ADDITIONS

Up to five new, identical, mini-power delivery substations (PDS) were planned for the GRU system back in 1999. Three of the five; Rocky Point, Kanapaha, and Ironwood were installed by 2003. A fourth PDS is planned for 2009. The location for this PDS, which will be known as Springhill, will be a parcel owned by GRU west of Interstate 75 and north of 39th Avenue along our existing 138 kV transmission line. A fifth PDS is being considered for addition to the System no earlier than 2011. The location of this proposed fifth PDS would be in the northern part of the service territory near U.S. Highway 441. These new mini-power delivery substations have been planned to redistribute the load from the existing substations as new load centers grow and develop within the System.

Each PDS will consist of one (or more) 138-12.47 KV, 33.6 MVA, wye-wye substation transformer with a maximum of eight distribution circuits. The proximity of these new PDS's to other, existing adjacent area substations will allow for backup in the event of a substation transformer failure.

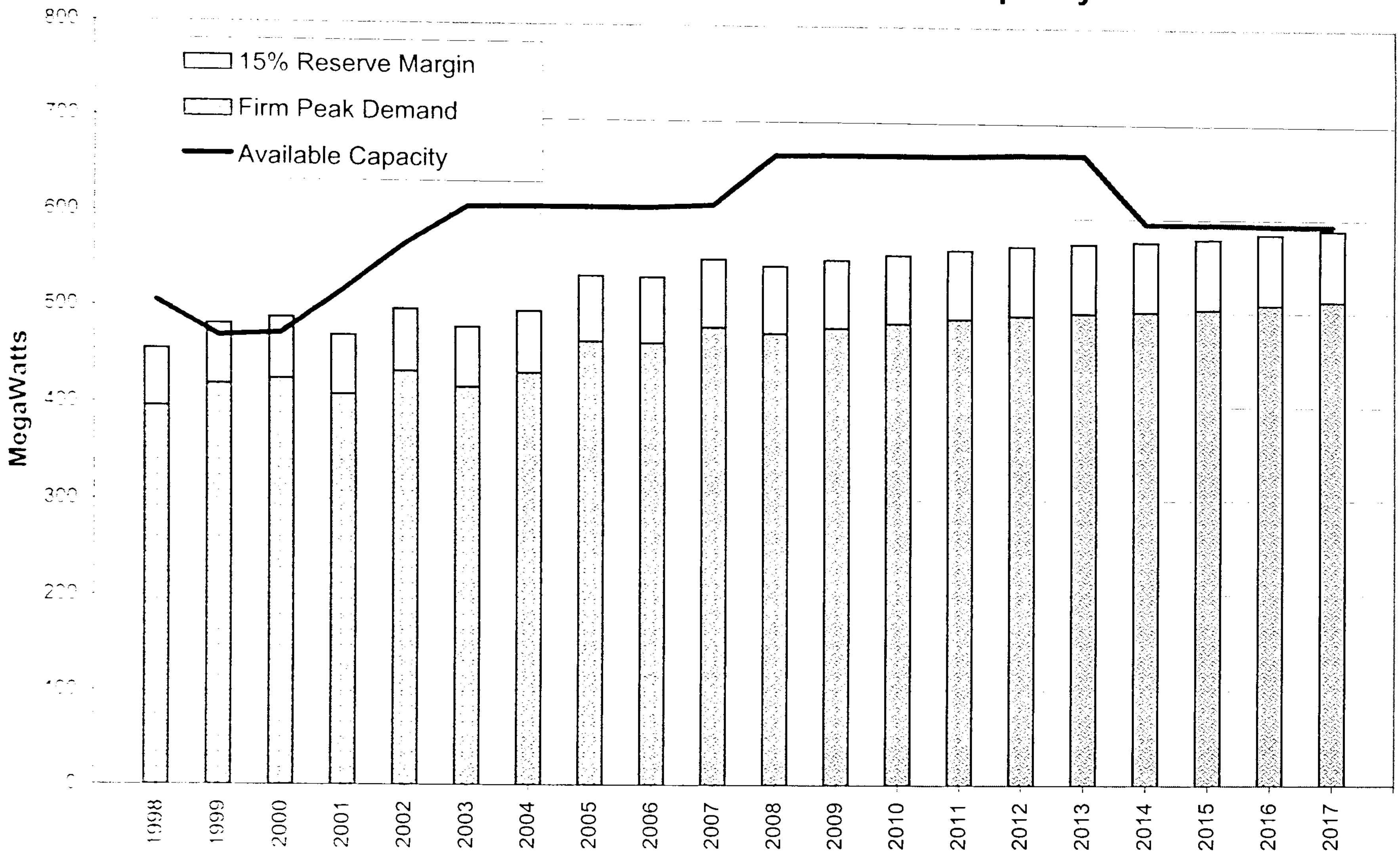
Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	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
1998	547	31	73	0	505	396	109	27.5%	0	109	27.5%
1999	547	32	110	0	469	419	50	11.9%	14	36	8.6%
2000	547	0	78	0	472	425	47	11.1%	0	47	11.1%
2001	610	0	93	0	517	409	108	26.4%	0	108	26.4%
2002	610	0	43	0	567	433	134	30.9%	0	134	30.9%
2003	610	0	3	0	607	417	190	45.6%	0	190	45.6%
2004	611	0	3	0	608	432	176	40.7%	0	176	40.7%
2005	611	0	3	0	608	465	143	30.8%	0	143	30.8%
2006	611	0	3	0	608	464	144	31.0%	0	144	31.0%
2007	611	0	0	0	611	481	130	27.0%	0	130	27.0%
2008	611	53	0	0	664	475	189	39.8%	0	189	39.8%
2009	612	53	0	0	665	481	184	38.3%	0	184	38.3%
2010	612	53	0	0	665	486	179	36.8%	0	179	36.8%
2011	612	53	0	0	665	491	174	35.4%	0	174	35.4%
2012	614	53	0	0	667	495	172	34.7%	0	172	34.7%
2013	614	53	0	0	667	498	169	33.9%	0	169	33.9%
2014	591	3	0	0	594	500	94	18.8%	0	94	18.8%
2015	591	3	0	0	594	503	91	18.1%	0	91	18.1%
2016	590	3	0	0	593	508	85	16.7%	1	84	16.5%
2017	590	3	0	0	593	512	81	15.8%	0	81	15.8%

(1) System Peak demands shown in this table reflect continued service to partial and full requirements wholesale customers. In the event these contracts are not renewed, reserve margins shown in this table will increase significantly.

(2) Details of planned changes to installed capacity from 2008-2017 are reflected in Schedule 8.

Figure 4.1
Summer Peak Demand and Generation Capacity

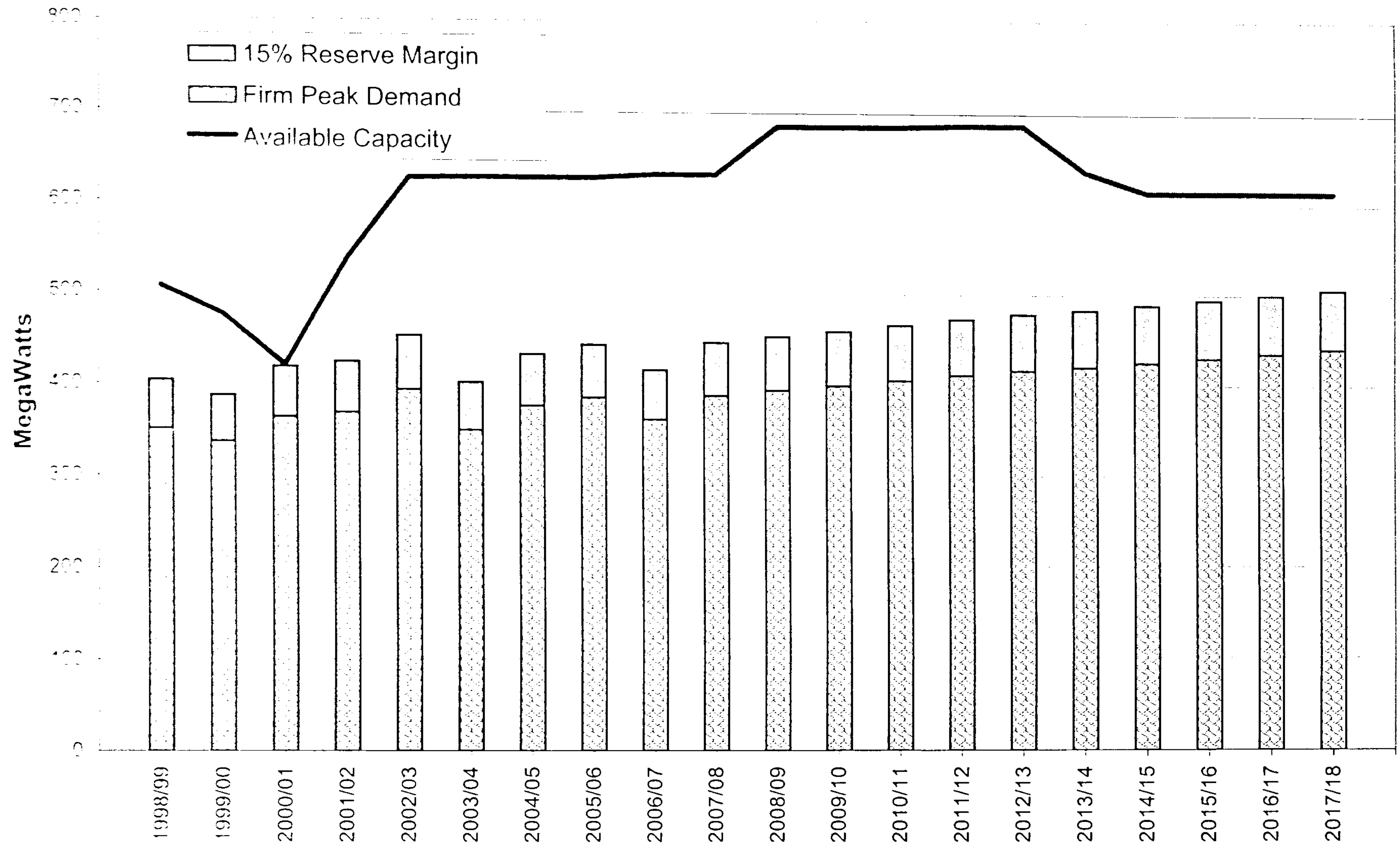


Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(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
1998/99	563	31	88	0	506	351	155	44.2%	0	155	44.2%
1999/00	563	0	88	0	475	337	138	40.9%	15	123	36.5%
2000/01	513	0	93	0	420	364	56	15.4%	0	56	15.4%
2001/02	630	0	93	0	537	369	168	45.5%	0	168	45.5%
2002/03	630	0	3	0	627	394	233	59.1%	0	233	59.1%
2003/04	631	0	3	0	628	350	278	79.4%	0	278	79.4%
2004/05	631	0	3	0	628	377	251	66.6%	0	251	66.6%
2005/06	631	0	3	0	628	386	242	62.7%	0	242	62.7%
2006/07	632	0	0	0	632	362	270	74.6%	0	270	74.6%
2007/08	632	0	0	0	632	361	271	75.1%	0	271	75.1%
2008/09	632	53	0	0	685	394	291	73.9%	0	291	73.9%
2009/10	632	53	0	0	685	399	286	71.7%	0	286	71.7%
2010/11	632	53	0	0	685	405	280	69.1%	0	280	69.1%
2011/12	634	53	0	0	687	411	276	67.2%	0	276	67.2%
2012/13	634	53	0	0	687	416	271	65.1%	0	271	65.1%
2013/14	634	3	0	0	637	420	217	51.7%	0	217	51.7%
2014/15	611	3	0	0	614	425	189	44.5%	0	189	44.5%
2015/16	611	3	0	0	614	430	184	42.8%	0	184	42.8%
2016/17	611	3	0	0	614	435	179	41.1%	1	178	40.9%
2017/18	611	3	0	0	614	440	174	39.5%	1	173	39.3%

(1) System Peak demands shown in this table reflect continued service to partial and full requirements wholesale customers. In the event these contracts are not renewed, reserve margins shown in this table will increase significantly.
(2) Details of planned changes to installed capacity from 2008-2017 are reflected in Schedule 8.

Figure 4.2
Winter Peak Demand and Generation Capacity



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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)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo/Yr	In-Service Mo/Yr	Retire Mo/Yr	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Status
CRYSTAL RIVER	3	Citrus County Sec. 33, T17S, R16E	ST	NUC		TK			Jan-08				0.165	0.169	I
DEERHAVEN	FS02	Alachua County Secs. 26,27 35 T8S, R19E	ST	BIT		RR		Jan-07	May-09		0	0	-3	-3	D
GRU ENERGY CENTER (Distributed generation)	GT1	Alachua County Sec. 10, T10S, R20E	GT	NG		PL		Apr-07	May-09		4.5	4.5	4.1	4.1	U
SOUTHWEST	LFG1	Alachua County Sec. 19, T11S, R18E	IC	LFG		PL				Dec-09	-0.65	-0.65	-0.65	-0.65	RT
CRYSTAL RIVER	3	Citrus County Sec. 33, T17S, R16E	ST	NUC		TK			Jan-10				0.386	0.396	I
CRYSTAL RIVER	3	Citrus County Sec. 33, T17S, R16E	ST	NUC		TK			Jan-12				1.930	1.978	I
J. R. KELLY	FS07	Alachua County Sec. 4, T10S, R20E	ST	NG	RFO	PL	TK			Oct-13	-24	-24	-23.2	-23.2	RT
SOUTHWEST	LFG2	Alachua County Sec. 19, T11S, R18E	IC	LFG		PL				Dec-15	-0.65	-0.65	-0.65	-0.65	RT

Unit Type
GT = Combustion (gas) Turbine
IC = Internal Combustion Engine (diesel, piston)
ST = Steam Turbine

Fuel Type
BIT = Bituminus Coal
LFG = Land Fill Gas
NG = Natural Gas
NUC = Nuclear
RFO = Residual Fuel Oil
WDS = Wood/Wood Waste Solids
(Wood Trimming, Logging Residue, Forest Restoration)

Transportation Method
PL = Pipeline
RR = Railroad
TK = Truck

Status
D = Decrease in capacity.
I = Increase in capacity.
L = Regulatory approval pending. Not under construction (started site preparation).
P = Proposed for installation but not City Commission authorized. Not under construction.
RT = Unit to be retired
U = Under construction, less than 50% complete.

Schedule 9

Description of Proposed Facility Under Discussion

(1)	Plant Name and Unit Number:	GRU Energy Center (Distributed Generation)
(2)	Net Capacity	
	a. Summer	4.1 MW
	b. Winter	4.1 MW
(3)	Technology Type:	Combustion Turbine (Solar)
(4)	Anticipated Construction Timing	
	a. Field construction start-date:	4/1/2007
	b. Commercial in-service date:	5/1/2009
(5)	Fuel	
	a. Primary Fuel (by Heat Input)	Natural Gas
	b. Alternate Fuel	na
(6)	Air Pollution Control Strategy:	Low NOx Burners
(7)	Cooling Method:	air cooled
(8)	Total Site Area (ft^2):	50,000
(9)	Construction Status:	Regulatory approval pending.
(10)	Certification Status:	Not Certified
(11)	Status with Federal Agencies:	Permitting in Progress
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF):	3.0%
	Forced Outage Factor (FOF):	6.0%
	Equivalent Availability Factor (EAF):	95.0%
	Resulting Capacity Factor (CF)	90.0%
	Average Net Operating Heat Rate (ANOHR):	10,100
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (2009$/kW)	930.49
	Direct Construction Cost ($2009/kW):	0.00
	Escalation ($2009/kW)	28.75
	Escalation:	3.00%
	Fixed O&M ($2009/kW-Yr)	0.00
	Variable O&M ($2009/MWh):	15.33

5. ENVIRONMENTAL AND LAND USE INFORMATION

5.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

Currently, there are no new potential generation sites planned.

5.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

New potential generating facilities (resulting from GRU's "Request for Proposals for Biomass-fueled Generation Facility") may be located at the existing Deerhaven plant site, shown in Figure 2.1 and Figure 5.1, located north of Gainesville off U.S. Highway 441. The potential offerings could be fired with woody biomass and some small amount of municipal solid waste. The Deerhaven site is preferred for the proposed project for several major reasons. Since it is an existing power generation site, future development is possible while minimizing impacts to the greenfield (undeveloped) areas. It also has an established access to fuel supply and power delivery; as well as fuel, water and combustion product management facilities.

5.2.1 Land Use and Environmental Features

The location of the Deerhaven Generating Station ("Site") is indicated on Figure 2.1 and Figure 5.1, overlain on USGS maps that were originally at a scale of 1 inch : 24,000 feet. Figure 5.2 provides a photographic depiction of the land use and cover of the existing site and adjacent areas. The existing land use of the certified portion of the site is industrial (i.e., electric power generation and transmission and ancillary uses such as fuel storage and conveyance; water, combustion product, and forest management). The areas acquired since 2002 have been annexed into the City of Gainesville. The current zoning remains County Agricultural, but a land use change application has been filed with the City of Gainesville. Eventually, the site will be zoned (city) Pubic Services with conservation areas. Surrounding land uses are primarily rural or agricultural with some low-density residential development. The Deerhaven site encompasses approximately 3474 acres.

The Site is located in the Suwannee River Water Management District. A small increase in water quantities for potable uses is projected. It is estimated that industrial water usage associated with the new unit could be as much as 3 million gallons per day (MGD). The groundwater allocation in the existing Site Certification may be sufficient to accommodate the requirements of the site in the future with the proposed new unit, if reclaimed water is used. Water for potable use will be supplied via the City's potable water system. Groundwater will continue to be extracted from the Floridian aquifer. A significant amount of reclaimed water from GRU's Main St. and/or Kanapaha wastewater treatment plants may be made available to the site to supply industrial process and cooling water needs. Process wastewater is currently collected, treated and reused on-site. The site has zero discharge of process wastewater to surface and ground waters, with a brine concentrator and on-site storage of water treatment and solid by-products. It is expected that this practice would continue with the addition of a new unit. Other water conservation measures may be identified during the design of the project.

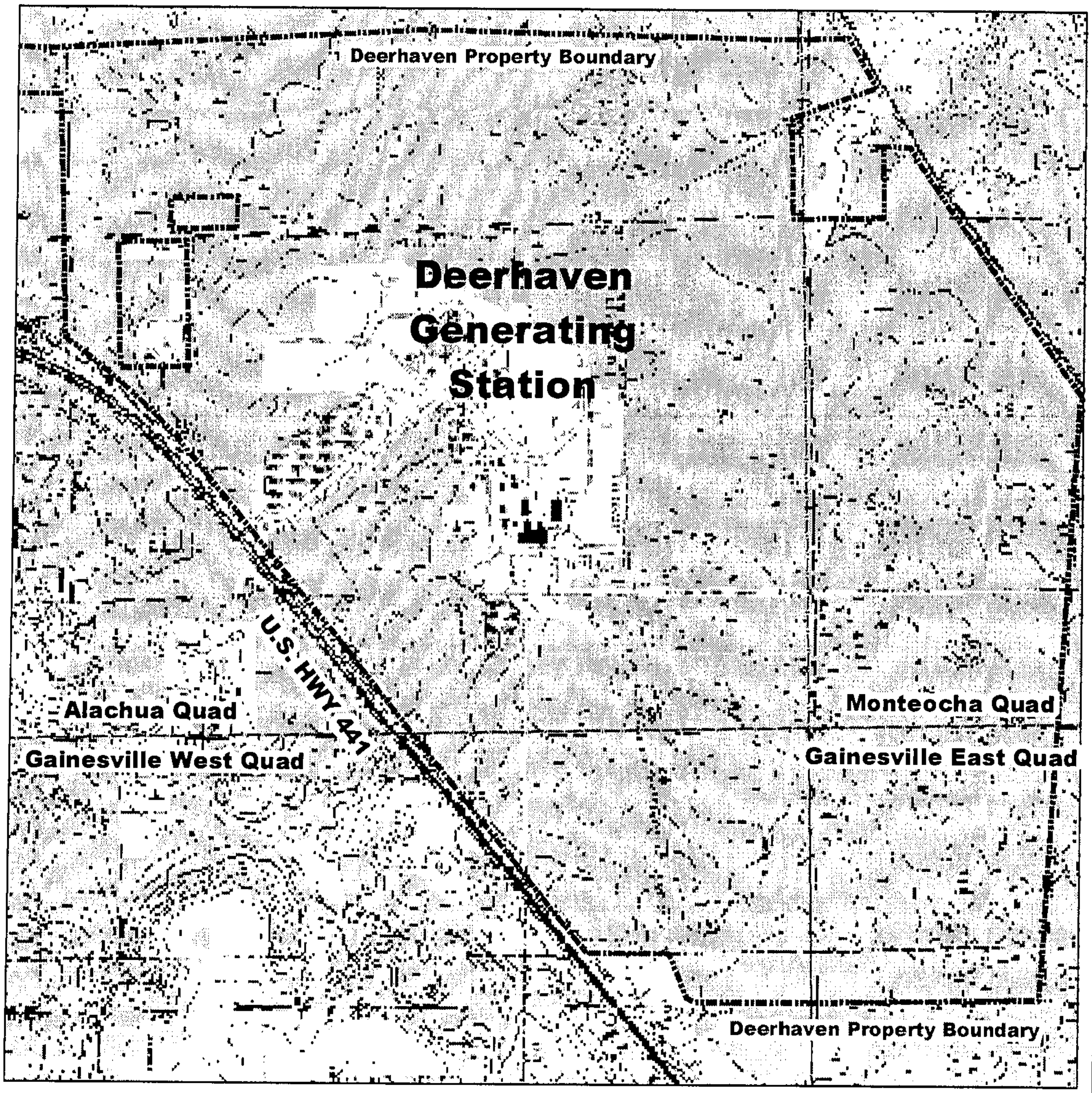
5.2.2 Air Emissions

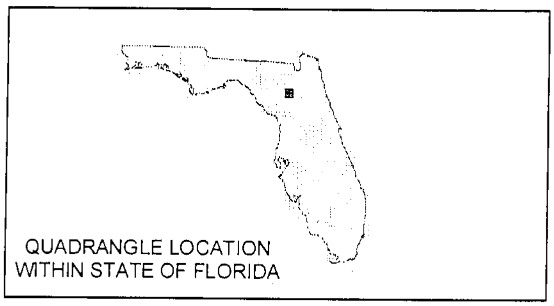
All of the proposed technologies minimize the formation of nitrogen oxides (i.e., NOx) and control any SO_2 emissions and trace metal emissions using BACT. Particulate matter emissions will most likely be controlled utilizing a fabric filter.

5.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Not applicable.

Figure 5.1



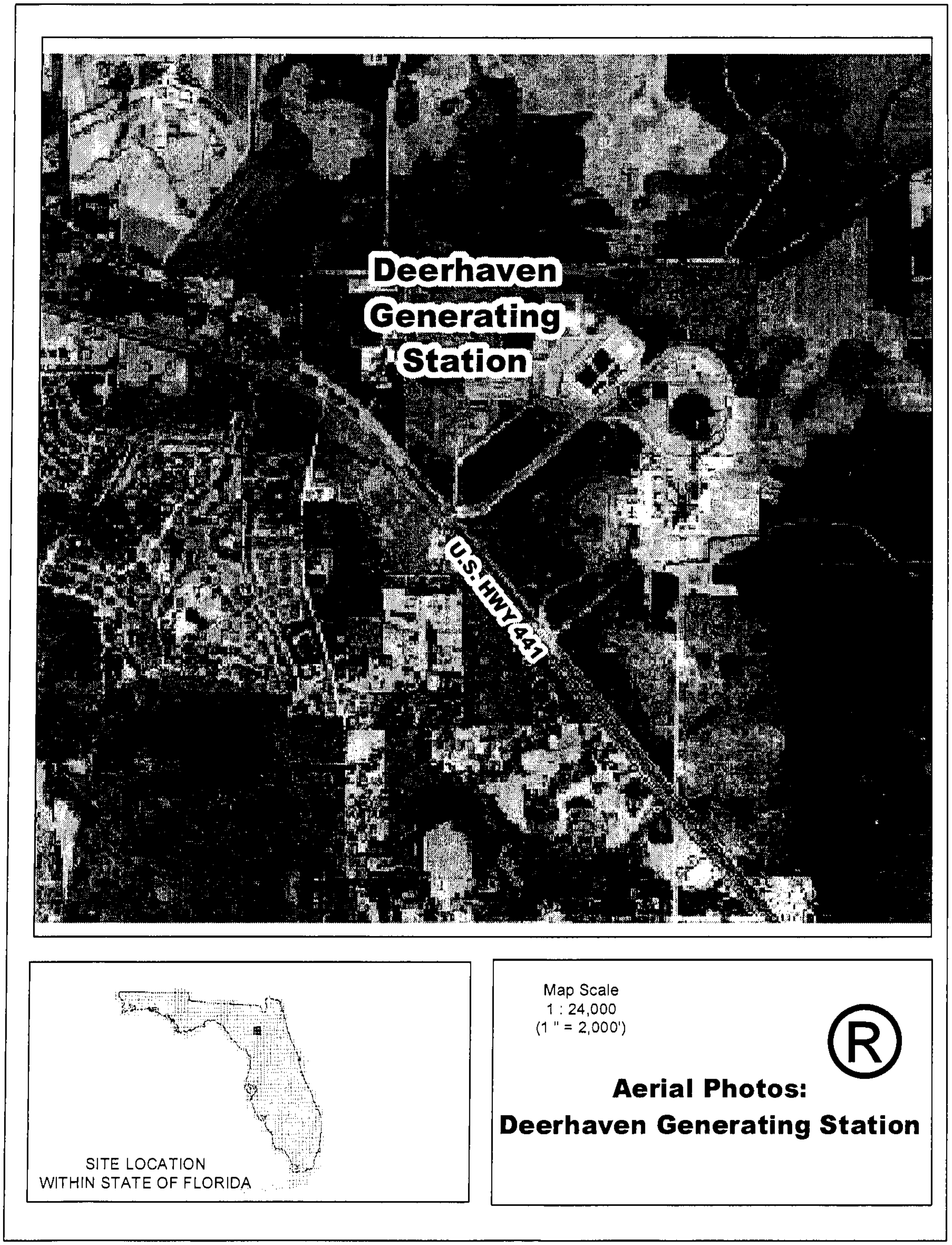


Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')

Location Map:
Deerhaven Generating Station

Data Source: USGS 7.5 Minute Quadrangle Maps :
Quad names-Alachua, Gainesville West,
Monteocha, Gainesville East

Figure 5.2


Deerhaven
Generating
Station
U.S. HWY 441
SITE LOCATION
WITHIN STATE OF FLORIDA
Map Scale
1 : 24,000
(1 " = 2,000')
Aerial Photos:
Deerhaven Generating Station