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GRU
GAINESVILLE REGIONAL UTILITIES
Strategic Planning

March 30, 2001

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MAIL ROOM

Blanca S. Bayo, Director
Florida Public Service Commission
Division of Records & Reporting
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

undocketed

Dear Ms. Bayo:

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 2001 Ten Year Site Plan for your review. Should you have any questions regarding this Ten Year Site Plan, please contact me at (352) 334-3400 x1272 or:

Roger Westphal (Generation Planning)	352.334.3400x1289
Todd Kamhoot (Forecasting)	352.334.3400x1280

Sincerely,

Ed Regan
Strategic Planning Director

Enclosures

File: PSC - Ten Year Site Plan

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GRU

Gainesville Regional Utilities

2001 Ten Year Site Plan

Submitted to:

The Public Service Commission

April 1, 2001

DOCUMENT NUMBER-DATE
04049 APR-2 [illegible]
FPSC-RECORDS/REPORTING

GAINESVILLE REGIONAL UTILITIES

2001 TEN-YEAR SITE PLAN

Submitted to:

The Florida Public Service Commission

April 1, 2001

TABLE OF CONTENTS

1. INTRODUCTION

The 2001 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 2001 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 is a municipal electric, natural gas, water, wastewater, and telecommunications utility system. 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 425 megawatts on July 20, 2000. Net summer capability is presently 550 megawatts. The repowering of J. R. Kelly Unit 8 to a 110 megawatt combined-cycle unit was recently completed and increased net summer capability to 608 megawatts. The new JRK CC1 provides benefit to the system in improved operating efficiency; reduced emission rates; reduced total emissions; and participation in the redevelopment of downtown Gainesville, while increasing system capacity at a time when the reserve margin for Peninsular Florida is relatively tight.

2. DESCRIPTION OF EXISTING FACILITIES

The City of Gainesville owns a fully integrated electric power production, transmission, and distribution system (herein referred to as "the System"). GRU is the City of Gainesville enterprise arm that has the responsibility to operate and maintain the System. In addition to retail electric service, GRU also provides wholesale electric service to the City of Alachua (Alachua) and to Clay Electric Cooperative, Inc. (Clay). GRU's distribution system serves approximately 130 square miles and 78,866 customers (December, 2000). 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, found at the end of this chapter. Two types of generating units are located at the System's two generating plant sites: steam turbines and gas turbines.

The present summer net capability is 550 MW and the winter net capability is 563 MW[1]. Currently, the System's energy is produced by four fossil fuel steam turbines, six combustion turbines, and a 1.4% ownership share of the Crystal River 3 nuclear unit, which is operated by Florida Power Corporation (FPC).

2.1.1 Generating Units

2.1.1.1 Steam Turbines. The System's four operational steam turbines are powered by fossil fuels and Crystal River 3 is nuclear powered. John R. Kelly (Kelly) 6, a fossil steam turbine, was placed in cold standby in August, 1989 and is no longer considered operational for planning purposes. The fossil fueled steam turbines

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[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.

comprise 70.1% of the System's net summer capability and produced 89.6% of the electric energy supplied by the System in 2000. These units range in size from 23.2 MW to 228.4 MW. The System's 11.0 MW share of Crystal River 3 nuclear unit comprises 2.0% of the System's net summer capability.

Both Deerhaven 2 and Crystal River 3 are used for base load purposes, while Kelly 7 and 8 and Deerhaven 1 are used for intermediate loading.

2.1.1.2 Gas Turbines. The System's six industrial gas turbines make up 27.8% of the System's summer generating capability. These units 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 in thirty minutes or less. 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 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 has flue gas cleaning equipment.

2.1.2 Generating Plant Sites

The locations of the two generating plants owned by the City of Gainesville 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, two steam turbines (including Kelly 6, which is in cold standby), three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment.

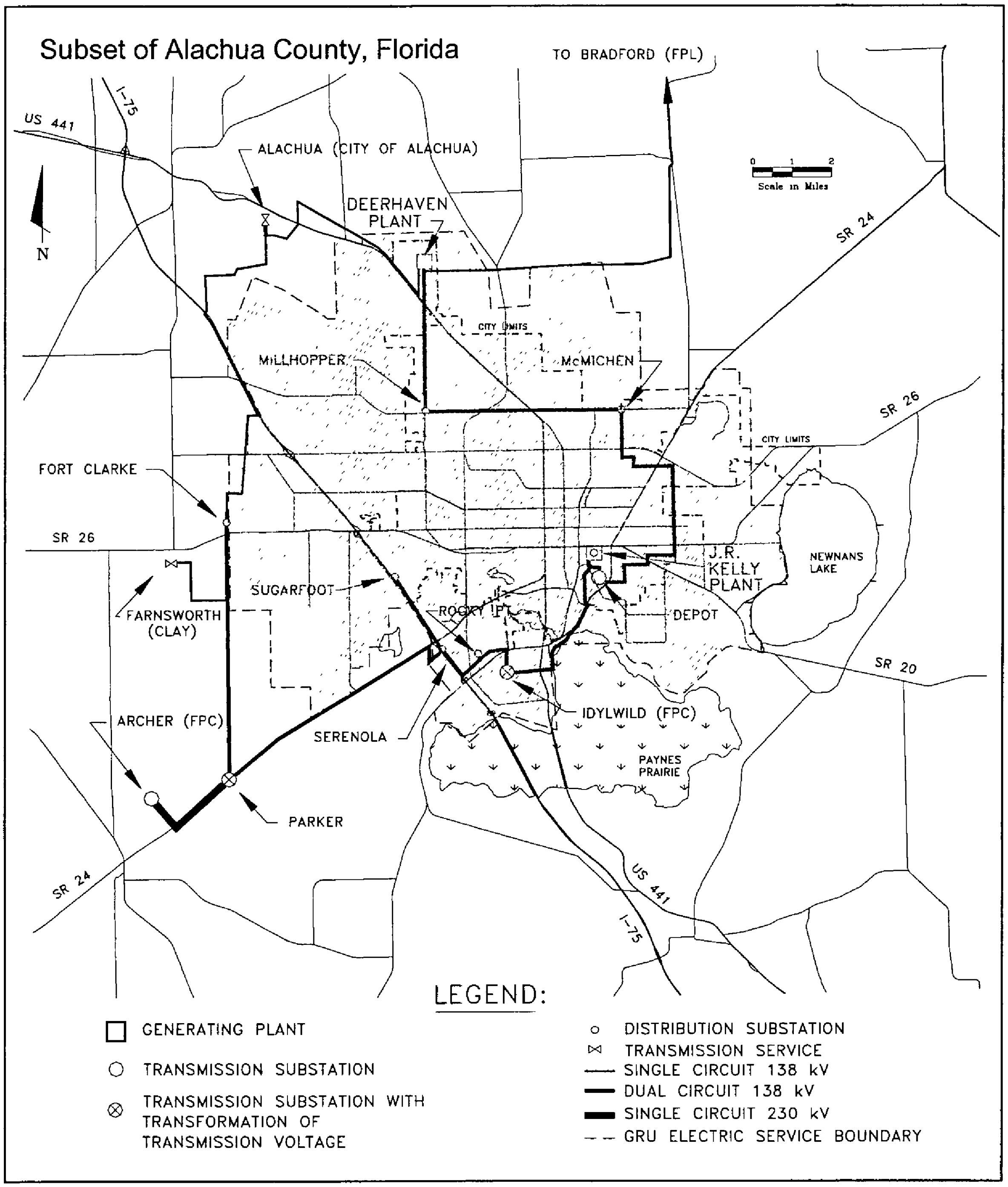

Figure 2.1, Gainesville Regional Utilities Electric Facilities

2.1.2.2 Deerhaven Plant. The Deerhaven Station is located six miles northwest of Gainesville. The site is a 1,116 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. With the addition of Deerhaven 2 in 1981, the site now includes coal unloading and storage facilities and a zero discharge water treatment plant, which treats water effluent from both steam units.

2.2 TRANSMISSION

2.2.1 The Transmission Network

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

1) GRU's two generating stations,
2) GRU's seven distribution substations,
3) Three interties with Florida Power Corporation,
4) An intertie with Florida Power and Light Company,
5) An interconnection with Clay at Farnsworth Substation, and
6) An 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 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	80.87	795 MCM ACSR
138 KV single circuit	16.47	1192 MCM ACSR
138 KV single circuit	20.60	795 MCM ACSR
230 KV single circuit	2.51	795 MCM ACSR
Total	120.45	

As part of the Long-Range Transmission Planning Study, March 1991, the transmission system was subjected to scenario analysis. Each scenario represents a system configuration with different contingencies modeled. A contingency is an occurrence that depends on chance or uncertain conditions and, as used here, represents various equipment failures that may occur. The following conclusions were drawn from this analysis:

Reliability contingencies:

(a) Single contingency transmission line and generator outages (the failure of any one generator or any one transmission line) -- No identifiable problems.

(b) All right-of-way outages (two lines - common pole) -- No problems if a 20 MVAR capacitor bank is installed at Sugarfoot Substation. GRU's 138 kV/24 MVAR capacitor installation at Sugarfoot Substation was completed July, 1993.

(c) Meeting future load and interchange requirements -- No identifiable problems.

2.2.3 State Interconnections

The System is currently interconnected with FPC and Florida Power and Light (FPL) at a total of four separate points. The System interconnects with FPC'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 FPC's Idylwild Substation with two separate circuits via a 168 MVA 138/69 kV transformer at the Idylwild Substation. The System interconnects with FPL via a 138 kV tie between FPL's Bradford Substation and the System's Deerhaven Substation. This interconnection has a thermal capacity of 222 MVA.

2.3 DISTRIBUTION

The System has seven major distribution substations connected to the transmission network: Ft. Clarke, Kelly, McMichen, Millhopper, Rocky Point, Serenola, and Sugarfoot substations. The locations of these substations are shown on Figure 2.1.

Six of GRU's distribution substations are connected to the 138 kV bulk power transmission network with dual feeds, while Rocky Point is served by a single tap to the 138 kV network. This prevents the outage of a single transmission line from causing the outage of a distribution station. GRU serves its retail customers through a 12.47 kV distribution network. The distribution substations, their present rated transformer capabilities and present number of circuits are listed in Table 2.2.

The last substation added by GRU, Rocky Point, was brought on-line in 2000 to serve the growing load in the area of State Road 24 and Interstate Highway I-75 and to provide backup support for the Serenola substation. McMichen, Serenola, Ft. Clarke, and Kelly substations currently consist of two transformers of 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.

2.4 WHOLESALE ENERGY

The System provides 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 2.4 mile radial line connected to the System's transmission facilities.

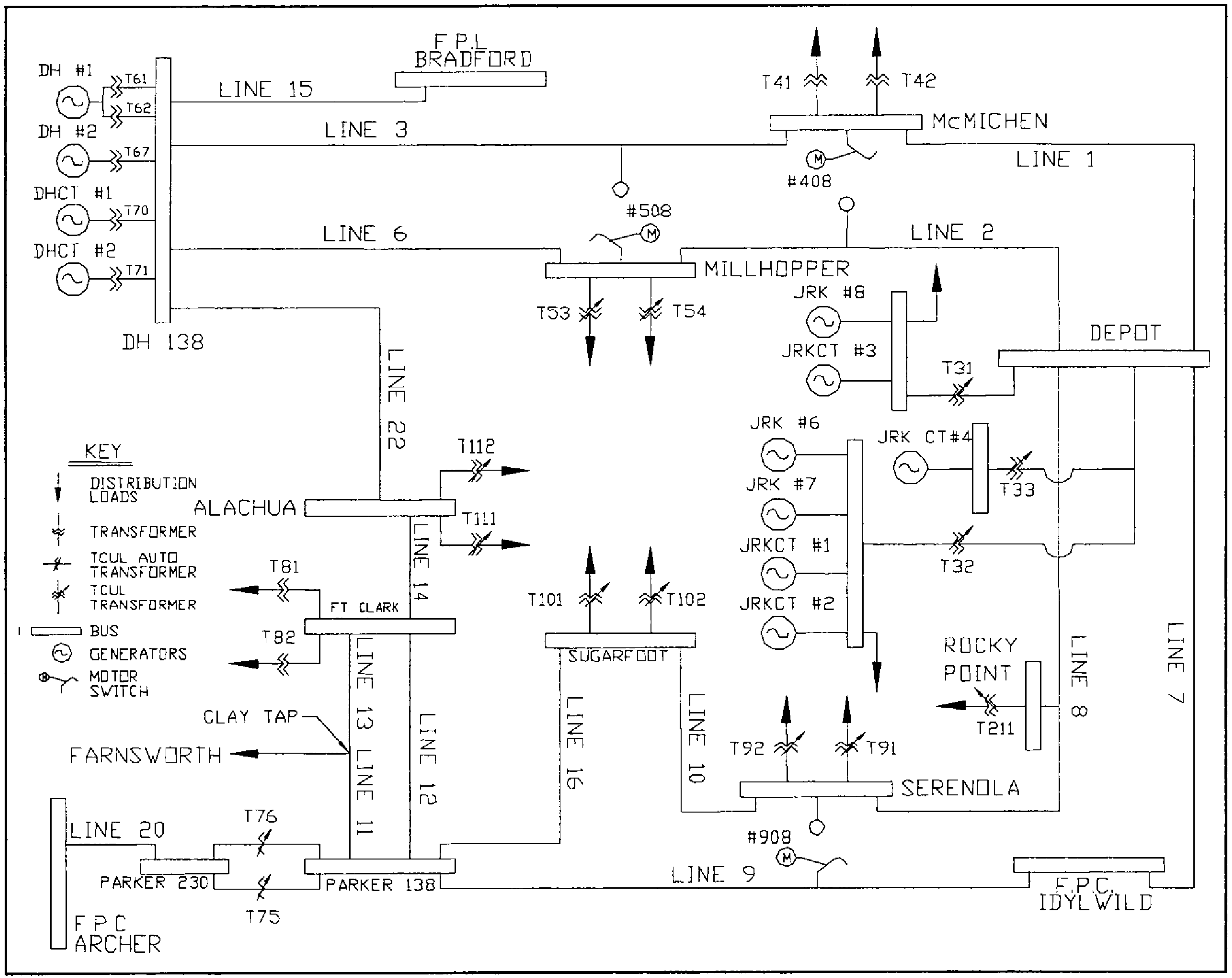

FIGURE 2.2 Gainesville Regional Utilities Electric System One-Line Diagram.

The System also provides wholesale electric service to the City of Alachua at two points of service. The Alachua No. 1 Substation is supplied with GRU's looped 138 kV transmission system. Approximately 400 residences and a few commercial customers within Alachua's city limits are served by a 12.47 kV distribution circuit, known as the Hague point of service. The System provides approximately 89% of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from the Crystal River 3 and St. Lucie 2 nuclear units. Energy supplied to 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.

2.5 EXPORT COMMITMENTS

GRU has a Schedule D firm interchange service commitment with the City of Starke (Starke). The agreement with Starke is non-unit specific and provides for the sale of System capacity (includes reserves). This agreement was renewed January 1, 1994 and continues through 2003, with optional three year extensions available indefinitely and allows Starke the option to expand the capacity commitment. This agreement was assigned to the FMPA in 1998 when Starke became an "All Requirements" member of FMPA.

GRU has a Schedule D firm interchange service commitment with the Florida Municipal Power Agency (FMPA). The agreement with FMPA is unit specific with Deerhaven Unit 2 (DH2) and provides capacity through 2002.

GRU has a negotiated Transaction with The Energy Authority, Inc. to provide electric capacity and associated energy to JEA from its generation and purchased power resources from December of 2000 through February of 2001

These sale schedules are contemplated herein and are consistent with GRU's needs for generating capacity and associated reserve margins. Schedules 7.1 and 7.2 at the end of Section 4 summarize GRU's reserve margins.

TABLE 2.1

SUMMER POWER FLOW LIMITS

Line Number	Description	Normal (MVA)	Limiting Device	Emergency (MVA)	Limiting Device
1	McMichen - Depot East	245.7	Conductor	288.3	Conductor
2	Millhopper - Depot West	245.7	Conductor	288.3	Conductor
3	Deerhaven - McMichen	245.7	Conductor	288.3	Conductor
6	Deerhaven - Millhopper	245.7	Conductor	288.3	Conductor
7	Depot East - Idylwild	205.6	Line Trap	205.6	Line Trap
8	Depot West - Serenola	245.7	Conductor	288.3	Conductor
9	Idylwild - Parker	205.6	Line Trap	205.6	Line Trap
10	Serenola - Sugarfoot	245.7	Conductor	288.3	Conductor
11	Parker - Clay Tap	245.7	Conductor	288.3	Conductor
12	Parker - Ft. Clarke	245.7	Conductor	288.3	Conductor
13	Clay Tap - Ft. Clarke	245.7	Conductor	288.3	Conductor
14	Ft. Clarke - Alachua	313.0	Conductor	369.1	Conductor
15	Deerhaven - Bradford	222.0	Transformer	222.0	Transformer
16	Sugarfoot - Parker	245.7	Conductor	288.3	Conductor
20	Parker - Archer	179.2	Transformer	224.0	Transformer
22	Alachua - Deerhaven	313.0	Conductor	369.1	Conductor
xx	Clay Tap - Farnsworth	245.7	Conductor	288.3	Conductor
xx	Idylwild - FPC	168.0	Transformer	168.0	Transformer

TABLE 2.2

CURRENT SUBSTATION TRANSFORMATION AND CIRCUITS

STATION	TRANSFORMER RATED CAPABILITY	NUMBER OF CIRCUITS
Millhopper	100.8 MVA	10
McMichen	44.8 MVA	6
J. R. Kelly[2]	112.0 MVA	18
Rocky Point	33.6 MVA	3
Serenola	67.2 MVA	8
Sugarfoot	100.8 MVA	8
Ft. Clarke	44.8 MVA	4

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[2] J. R. Kelly is a generating station as well as a distribution substation. The CT portion (72 MW) of JRK CC 1 is connected directly to the 138 kV transmission line and the steam portion is connected to the substation bus along with the remaining generation capacity at J. R. Kelly Station (105 MW).

Schedule 1

EXISTING GENERATING FACILITIES
(As of December 31, 2000)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Primary Fuel		Alternate Fuel					Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Type	Trans.	Type	Trans.	Alt. Fuel Storage (Days)	Commercial In-Service Month/Year	Expected Retirement Month/Year	Summer MW	Winter MW	Summer MW	Winter MW	Status
J. R. Kelly		12-001 (Alachua Co., Section 4, Township 10 S, Range 20E) (GRU)									119	122	115	118	
	FS08		ST	NG	PL	RFO	TK		4/65	Unknown	53	53	50	50	
	FS07		ST	NG	PL	RFO	TK		8/61	Unknown	24	24	23	23	
	FS06		ST	NG	PL	RFO	TK		3/58	Unknown	14	15	14	15	SB
	GT03		GT	NG	PL	DFO	TK		5/69	Unknown	14	15	14	15	
	GT02		GT	NG	PL	DFO	TK		9/68	Unknown	14	15	14	15	
	GT01		GT	NG	PL	DFO	TK		2/68	Unknown	14	15	14	15	
Deerhaven		12-001 (Alachua Co., Sections 26,27,35, Township 8 S, Range 19 E) (GRU)									451	461	424	434	
	FS02		ST	BIT	RR				10/81	Unknown	249	249	228	228	
	FS01		ST	NG	PL	RFO	TK		8/72	Unknown	88	88	85	85	
	GT03		GT	NG	PL	DFO	TK		1/96	Unknown	76	82	75	81	
	GT02		GT	NG	PL	DFO	TK		8/76	Unknown	19	21	18	20	
	GT01		GT	NG	PL	DFO	TK		7/76	Unknown	19	21	18	20	
Crystal River (818/815)	3	12-017 (Citrus Co., Section 33, Township 17 S, Range 16 E) (FPC)	ST	NUC	TK				3/77	Unknown	11	11	11	11	
System Total											581	594	550	563	

Unit Type
GT = Gas Turbine
ST = Steam

Fuel Type
NG = Natural Gas
BIT = Bituminous Coal
NUC = Uranium
RFO = Residual Fuel Oil
DFO = Distillate Fuel Oil

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

Status
SB=Cold Standby,
extended cold shutdown,
or long-term reserve shutdown.

Notes: (1) JRK Unit 6 was placed in cold standby in August, 1989.

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, as well as 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 1991-2010. Energy sales and number of customers are tabulated in Schedules 2.1, 2.2 and 2.3. Schedules 3.1, 3.1H and 3.1L give components of summer peak demand for the base case, high band forecast and low band forecast. Schedules 3.2, 3.2H and 3.2L present the components of winter peak demand for each forecast scenario. Schedules 3.3, 3.3H and 3.3L similarly present components of net energy for load. 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 were assimilated for calendar years 1970 through 1999. System data, such as net energy for load, seasonal peak demands, customer counts and energy sales, were obtained from GRU records and sources.

(2) Estimates and projections of Alachua County population were obtained from the Florida Population Studies, February 2000 (Bulletin No. 126), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

(3) Normal weather conditions were assumed. Normal heating degree days and cooling degree days are projected to equal the median value of the available data for the Gainesville Municipal Airport weather station (1984-1999).

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 1998, using a price index developed to represent inflationary trends in Alachua County. This "Alachua County Price Index" is developed by comparing changes in the Consumer Price Index (U.S. Bureau of Labor Statistics) and the Florida Price Level Index (Florida Department of Education). Inflation is assumed to be 3% 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. The BEBR projected income levels for Alachua County in The Florida Long Term Economic Forecast 1999.

(6) The Florida Long Term Economic Forecast 1999 and Florida Population Studies, Bulletin 125, were used to estimate and project the number of persons per household (household size) in Alachua County.

(7) The Florida Long Term Economic Forecast 1999 was the source for historical estimates and projections of non-agricultural employment in Alachua County.

(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, pricing changes are programmed in and become GRU's official pricing program plan. Programmed price increases from the model for all retail customer classes are projected to be less than the rate of inflation, yielding declining real prices of electricity over the forecast horizon.

(9) Estimates of energy and demand reductions resulting from demand-side management programs were incorporated into all retail forecasts. Programs outlined in both GRU's 1990 Energy Conservation Plan and GRU's 1996 Demand-Side Management Plan, both submitted to the FPSC, are incorporated in this forecast. GRU's demand-side management programs are described in more detail later in this section.

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

3.2 DOCUMENTATION OF CUSTOMER, ENERGY AND SEASONAL PEAK DEMAND FORECASTS

Number of customers, energy sales and seasonal peak demands were forecast from 2001 through 2010. Separate energy sales forecasts were developed for each of the following customer classes: 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 and weather variation, measured by heating degree days and cooling degree days. The form of this equation is as follows:

$$\mathit{RESAVUSE} = 4474.9 + 0.08\,(\mathit{HHY98}) - 12.59\,(\mathit{RESPR98}) + 0.72\,(\mathit{HDD}) + 0.92\,(\mathit{CDD})$$

Where:

RESAVUSE = Average Annual Residential Energy Use

HHY98 = Average Household Income

RESPR98 = Residential Price, Dollars per 1000 kWh

HDD = Annual Heating Degree Days

CDD = Annual Cooling Degree Days

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

Adjusted R^2 = 0.8903
DF (error) = 24
t - statistics:
Intercept = 3.74
HHY98 = 7.25
RESPR98 = -2.98
HDD = 4.12
CDD = 4.80

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, lagged one year. The residential customer model specifications are:

$$RESCUS = -24678 + 426.0\,(LAGPOP)$$

Where:
RESCUS = Number of Residential Customers
LAGPOP = Alachua County Population (thousands), lagged one year

Adjusted R^2 = 0.9948
DF (error) = 20
t - statistics:
Intercept = -20.95
POP = 63.63

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 customer class includes non-residential customers with maximum annual demands generally less than 50 kilowatts (kW). Average annual energy use per general service non-demand customer has exhibited neither an increasing nor decreasing trend over the past 20 years. From 1979 through 1999, average annual consumption ranged from a low of 26,049 kWh in 1997 to a high of 28,968 kWh in 1990. Some, but not a sufficient amount, of the variation in historical use was fit using regression models. Therefore, average use was projected to remain constant at 27,544 kWh (the median of the historical series) per customer per year.

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

$$GNDCUS = -5210.9 + 59.44 (LAGPOP)$$

Where:

GNDCUS = Number of General Service Non-Demand Customers
LAGPOP = Alachua County Population (thousands), lagged on year
Adjusted R^2 = 0.9821
DF (error) = 20
t - statistics:
Intercept = -15.65
POP = 33.96

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 for residents of Alachua County. 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:

$$DEMAVUSE = 366.95 + 0.0087\,(PCY98)$$

Where:

DEMAVUSE = Average Annual Energy Use for General Service Demand Customers (MWh per Year)

PCY98 = Per Capita Income in Alachua County

Adjusted R^2 = 0.7679

DF (error) = 19

t - statistics:

Intercept = 18.22

PCY98 = 8.20

The annual average number of customers was projected based on the results of a regression model in which Alachua County population, lagged one year, was the independent variable. The specifications of the general service demand customer model are as follows:

$$DEMCUS = -478.65 + 5.75\,(LAGPOP)$$

Where:

DEMCUS = Number of General Service Demand Customers

POP = Alachua County Population (thousands), lagged one year

Adjusted R^2 = 0.9714
DF (error) = 19
t - statistics:
Intercept = -12.21
POP = 26.09

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 includes 17 customers with billing demands of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1976 through 1999. 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, is expected to increase due to the periodic expansion 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:

$$LPAVUSE = 9910 + 21.35\,(NONAG) - 38.19\,(LPPR98)$$

Where:
LPAVUSE = Average Annual Energy Consumption (MWh per Year)
NONAG = Alachua County Nonagricultural Employment (000's)
LPPR98 = Average Price for 1,000 kWh in the Large Power Sector
Adjusted R^2 = 0.8946
DF (error) = 21

t - statistics:

INTERCEPT = 5.47

NONAG = 2.15

LPPR98 = -2.89

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.

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 less than 1.5% of total energy sales. Outdoor lighting energy sales were forecast using a model which specified lighting energy as a function of the number of residential customers. The specifications of this model are as follows:

$$LGTMWH = -7892.8 + 0.43\,(RESCUS)$$

Where:

LGTMWH = Outdoor Lighting Energy Sales

RESCUS = Number of Residential Customers

Adjusted R^2 = 0.9372

DF (error) = 8

t - statistics:

Intercept = -3.48

RESCUS = 11.64

3.2.6 Wholesale Energy Sales

The System presently serves two wholesale customers: Clay Electric Cooperative, Inc. (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 11% of Alachua's 2000 energy requirements were met through generation entitlements of nuclear generating units operated by Florida Power Corporation and Florida Power and Light. Each wholesale delivery point serves an urban area that is either included in, or adjacent to the Gainesville Urban Area.

Sales to Clay were modeled with an equation in which total county income was the independent variable. The form of this equation is as follows:

$$CLYMWH = -30510 + 21.33\,(COY98)$$

Where:

CLYMWH = Megawatt-Hour Sales to Clay

COY98 = Total Personal Income (Alachua County)

Adjusted R^2 = 0.9331

DF (error) = 16

t - statistics:

Intercept = -5.95

COY98 = 15.44

Net energy requirements for Alachua were estimated using a model in which City of Alachua total income and cooling degree days were the independent variables. City of Alachua total income is the product of City of Alachua population and Alachua County per capita income. Population projections were developed by modeling City of Alachua population as a function of Alachua County population. The model used to develop projections of sales to the City of Alachua is of the following form:

$ALANEL = -30888 + 0.63\,(ALAY98) + 6.29\,(CDD)$

Where:

ALANEL = Net Energy Requirements of Alachua

ALAY98 = City of Alachua Total Income

CDD = Cooling Degree Days

Adjusted R^2 = 0.9774

DF (error) = 15

t - statistics:

Intercept = -4.35

ALAPOP = 26.95

CDD = 2.56

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 was determined from an analysis of observed historical values from 1982 through 1999. There is a subtle trend that DEL has improved in recent years.

The forecasts of seasonal peak demands were derived from forecasts of annual net energy for load and assumed that the winter peak will occur in January of each year and the summer peak will occur in July of each year. The average ratio of the most recent 18 years' monthly net energy for load for January and July, as a portion of annual net energy for load, was applied to projected annual net energy for load to obtain estimates of January and July net energy for load over the forecast horizon. The medians of the past 18 years' load factors for January and July were applied to January and July net energy for load projections, yielding seasonal peak demand projections. Load data has converged over time to a point that winter peak demands are forecast to be nearly equal for January and February. Likewise, the historical data indicates that summer peak demands are likely to be nearly equal in July and August. Adjustments to seasonal peak demands were included explicitly to account for impacts from demand-side management programs.

Transmission and distribution line loss improvement programs undertaken by GRU have resulted in relatively stable losses ranging from 4% to 6% of net generation. Post 1981 load factors and energy allocation factors are believed to reflect the most recent trends in appliance efficiencies, appliance penetrations, response to electricity prices and response to customer and utility induced conservation efforts.

3.2.8 Low Band and High Band Forecast Scenarios

Much of the error in long-term forecasts results from variation in expected customer growth, while a primary determinant of short-term forecast error is weather variation. GRU bands its forecasts with a long-term perspective for resource planning purposes by allowing assumptions underlying customer growth to vary. Projections of one independent variable in each customer class were allowed to vary from the base case assumptions in order to develop the banded forecasts. The fundamental variable used to develop alternative forecast scenarios was the series of population projections for Alachua County. Low band and high band forecast scenarios were derived from the same equations used to develop the base case forecasts. Low band and high band population scenarios were set to approximately equal the midpoints of the BEBR low-to-medium and medium-to-high population projections, respectively.

In the residential, general service non-demand, and general service demand revenue sectors, banded energy sales forecasts resulted from banded customer forecasts, which were developed from banded county population projections. Forecasts of average annual energy use per customer were not modified. In the large power sector, non-agricultural employment was the primary explanatory variable used to forecast use per customer. Employment projections were originally derived from population projections. Banded employment projections were input into the original equation yielding alternative energy sales scenarios for this class. Sales to Clay were modeled as a function of total county income. Total county income was projected as the product of per capita income and population. Banded income projections were input into the original equation yielding alternative forecasts of sales to Clay. Sales to Alachua were modeled as a function of City of Alachua total income, which was derived from City of Alachua population and county per capita income. City of Alachua population was projected from a model which stated City population to be a function of county population. Banded City of Alachua population projections, yielding banded City of Alachua income projections, were input into the original equation to obtain alternative scenarios of energy sales to the City of Alachua. Impacts of demand-side management programs were also allowed to vary based upon the ratio of low-to-base and base-to-high band population projections, respectively.

3.3 DOCUMENTATION OF 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. The System expects to market coal and natural gas based electric energy to other utilities in an expanding and increasingly open marketplace. To the extent that the System realizes these extra “outside” sales, actual consumption of these fuels will likely exceed the base case requirements indicated in Table 3.5.

3.3.2 Methodology

The fuel use projections were produced using the Electric Generation Expansion Analysis System (EGEAS) developed under Electric Power Research Institute guidance and maintained by Stone & Webster Management Consultants. This is the same software the System uses to perform long-range integrated resource planning. EGEAS has the ability to model a variety of technologies from thermal units to DSM options and include the effects of environmental limits, of dual fuel units, of reliability constraints, and of maintenance scheduling, to list only a few. The optimization process uses piece-wise linear and cumulants techniques. The production modeling process uses a load-duration curve convolution and probability process.

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, yearly and total out-of-pocket operating fuel expenses and their dispersion among various generating units; and

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

3.4 DEMAND-SIDE MANAGEMENT

3.4.1 Demand-Side Management Plan

Demand and energy forecasts and generation expansion plans outlined in this Ten Year Site Plan are consistent with GRU's 1990 Energy Conservation Plan and

GRU's 1996 Demand-Side Management Plan. The System forecast reflects historical program implementations recorded under both plans and projected program implementations scheduled in the 1996 DSM Plan. Both plans address a similar array of DSM measures and both plans were designed for the purpose of conserving the resources utilized by the System in a manner most cost effective to the customers of GRU.

The 1996 DSM Plan contains programs which increase the efficiency of energy consumption and reduce the consumption of scarce natural resources. DSM programs are available for all native 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.

GRU is active in the following residential conservation efforts: energy audits; low income household weatherization and natural gas extension; promotion of natural gas in residential construction; promotion of natural gas for displacement of electric water heating, space heating and space cooling in existing structures; and promotion of solar water heating. GRU offers the following conservation services to its non-residential customers: energy audits; lighting efficiency and maintenance services; and promotion of natural gas for water heating, space cooling and dehumidification.

GRU continues to monitor the potential for additional conservation efforts including programs addressing high-efficiency air conditioning, heat recovery, duct leakage, heat pipes, reflective roof coatings, thermal storage and window shading. GRU is also promoting the installation of solar photovoltaic arrays with local schools over the next three years using a combination of funding from customer contributions and grant money made available through the Department of Community Affairs.

GRU has also produced numerous *factsheets,* publications and videos which are available at no charge to customers to assist them in making informed decisions effecting 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.

The expected effect of DSM program participation was derived from a comparative analysis of historical load and energy consumption of DSM program participants and non-participants. The methodology upon which the currently approved plan is based includes consideration of what would happen anyway, 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 when possible. At the end of each device's life cycle, the energy and demand savings assumed to have been induced by GRU are reduced to zero to represent the retirement of the given device. Projected penetration rates were based on historical levels of program implementations and tied to escalation rates paralleling service area population growth.

DSM program implementations are expected to provide 7 MW of summer peak reduction, 16 MW of winter peak reduction and 60 GWh of annual energy savings by the year 2010. These figures represent cumulative impacts of programs since 1980. The System's projections of energy sales and peak demands reflect the effects of these DSM programs.

3.4.2 Gainesville Energy Advisory Committee

The Gainesville Energy Advisory Committee (GEAC) is a nine-member citizen group that is charged with formulating recommendations concerning national, state and local energy-related issues. The GEAC offers advice and guidance on energy management studies and consumer awareness programs. 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. The GEAC was initially involved in the ratemaking process in 1980 which ultimately lead to the approval of an inverted block residential rate and a voluntary residential time-of-use rate. The GEAC recognized *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, FPC, 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 a 10 kilowatt PV system at the Electric System Control Center (ESCC). 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 helped GRU earn EPA's 1998 Utility Ally of the Year award.

3.4.3 Supply Side Programs

Deerhaven 2 is also contributing to reduced oil use by other utilities through the Florida energy market. 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 2000, oil-fired generation comprised 2.8% of total net generation, natural gas-fired generation contributed 20.5%, nuclear fuel contributed 5.2%, and coal-fired generation provided 71.5% of total net generation. The PV system at ESCC provides slightly more than 10 kilowatts of capacity at solar noon on clear days. The proposed landfill gas to energy (LFGTE) project could provide approximately 3 MW of capacity 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. Each year the major distribution feeders are evaluated to determine whether the costs of reconductoring will produce an internal rate of return sufficient to justify expenses when compared to the savings realized from reduced distribution losses, and if so, reconductoring is recommended. Generating units are continually evaluated to ensure that they are maintaining design efficiencies. Transmission facilities are also studied to determine the potential savings from loss reductions achieved by the installation of capacitor banks. System losses have stabilized near 5% of net generation as reflected in the forecasted relationship of total energy sales to net energy for load.

3.5 FUEL PRICE FORECAST ASSUMPTIONS

Forecast prices for each type of fossil fuel analyzed by GRU were generally developed in two parts. Short-term monthly forecasts extending through 2001 were developed in-house by GRU's Fuels Department staff. Long-term fuel price forecasts were developed based upon forecasts of the U.S. Department of Energy's Energy Information Administration (EIA) as published in the Annual Energy Outlook 2000. In essence, the end-point of the GRU short-term forecasts became the starting point for the long-term forecasts, subject to adjustment such that escalation rates within the long-term forecasts were consistent with those in EIA forecasts. EIA's real price projections were converted to "nominal" by application of EIA's forecast Implicit Price Deflator. Fossil fuel transportation costs were forecast separately from fuel commodity costs. Forecast fuel commodity costs and transportation costs were aggregated to develop forecast delivered fuel costs. The following documentation describes GRU's fuel price forecasts by fuel type.

3.5.1 Oil

GRU does not have access to waterborne deliveries of oil and there are no pipelines in this area. Consequently, GRU relies on "spot" or as needed purchases from nearby vendors. The cost for purchasing and then trucking relatively insignificant quantities of oil to GRU's generating sites usually makes oil the most expensive and less favored of fuel sources available to GRU. Accordingly, short-term oil price forecasts for No.6 (residual oil) and No.2 (distillate or diesel oil) were based on actual costs to GRU over the past five years and on near term expectations for this limited market. An additional cost component, representing freight charges, was added to yield the final delivered oil price forecasts.

There was a significant increase in the price of crude oil from 1999 to 2000. Over the next 10 years, the price of No.2 oil delivered to GRU is expected to increase 4.6% annually while the actual volume of oil used remains small. Based on the above factors, the price of No.6 oil delivered to GRU is expected to increase 3.6% annually while the actual volume of oil used remains small.

3.5.2 Coal

Coal is the primary fuel used by GRU to generate electricity. Abundant U.S. supplies of coal and increasing technological improvement in mining methods as well as the cost of new coal plants, competition from other fuels and a better labor environment will tend to limit the price increases of coal. Resource planning studies require forecasts of three types of coal: low sulfur compliance coal, which is presently used by the System; pulverized coal for flue gas desulfurization; and fluidized bed combustion coal.

The short-term forecast price of low sulfur compliance coal was based on GRU's contractual options with its coal supplier. The long-term forecast price of low sulfur compliance coal was developed by applying the long term EIA forecast in the same manner as explained previously. Base line prices were determined for pulverized coal for flue gas desulfurization and fluidized bed compatible coal by utilizing a combination of acknowledged transactions and confidential state of the trade discussions with buyers and sellers of coal as reported in Coal Week. The base line prices were then escalated by applying the long term EIA forecast in the same manner as described previously.

GRU's long term contract with CSXT allows for delivery of coal through 2019. The short-term forecast transportation rate for all coals was based on actual rates from the pertinent coal supply districts for aluminum cars and four-hour loading facilities and on known contractual provisions. The long-term forecast of transportation rates was developed by applying the long term Rail Cost Adjustment Factor indices, adjusted and unadjusted, to the short term forecast. The indices were based on forecasts supplied by Fieldston, a coal transportation consulting company.

Based on the above factors, the price for coal delivered to GRU is expected to increase at an average annual rate of 0.4% for low sulphur compliance coal, pulverized coal for flue gas desulphurization, and fluidized bed compatible coal from 2001 through 2010.

3.5.3 Natural Gas

Natural gas is expected to experience a higher rate of growth in demand than other fuels. Following a period of low and stable prices, the forecast reflects the beginning of a modest increase in the price for natural gas.

GRU's purchases natural gas via arrangements with producers and marketers connected with the Florida Gas Transmission (FGT) interstate pipeline. The starting point for GRU's gas cost is the weighted average cost of gas (WACOG). The sum of the following components make up GRU's delivered cost of natural gas: the WACOG; Florida Gas Transmission's (FGT) fuel charge; FGT's transportation charge; and FGT's reservation charge.

Short-term natural gas prices were projected based upon recent trends in historical prices and price trends in the NYMEX gas futures market. The long-term forecast was then developed by applying the long term EIA forecast in the same manner as described previously.

Based on the above factors, the price of natural gas delivered to GRU is expected to increase at an annual rate of 3.5% from 2001 through 2010.

3.5.4 Nuclear Fuel

GRU's nuclear fuel price forecast is based on Florida Power Corporation's (FPC) forecast of nuclear fuel prices. The FPC forecast projects the price of nuclear fuel to increase approximately 3.0% per year through the forecast horizon.

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)
	RURAL AND 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
1991	131,873	2.39	602	55,177	10,906	491	6,527	75,222
1992	135,678	2.39	610	56,769	10,739	507	6,730	75,284
1993	141,163	2.39	637	59,064	10,778	524	6,998	74,824
1994	145,460	2.39	649	60,862	10,670	558	7,059	79,024
1995	148,491	2.39	704	62,130	11,329	590	7,305	80,767
1996	151,591	2.39	718	63,427	11,313	594	7,539	78,813
1997	155,713	2.39	705	65,152	10,817	598	7,750	77,193
1998	159,466	2.39	777	66,722	11,649	640	7,868	81,363
1999	164,503	2.40	763	68,543	11,137	648	8,095	80,036
2000	168,804	2.40	788	70,335	11,202	674	8,368	80,490
2001	172,323	2.40	805	71,801	11,208	698	8,543	81,652
2002	175,901	2.40	824	73,292	11,248	717	8,764	81,769
2003	179,377	2.40	843	74,741	11,284	735	8,979	81,911
2004	182,854	2.40	862	76,189	11,320	754	9,193	82,020
2005	186,228	2.40	881	77,595	11,359	773	9,402	82,166
2006	189,704	2.40	902	79,043	11,406	792	9,616	82,312
2007	193,078	2.40	921	80,449	11,454	811	9,825	82,513
2008	196,349	2.40	942	81,812	11,510	829	10,027	82,705
2009	199,621	2.40	962	83,175	11,560	847	10,229	82,836
2010	202,893	2.40	982	84,539	11,610	865	10,431	82,965

* Commercial represents GS Non-Demand and GS 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
1991	128	14	9,392	0	16	0	1,237
1992	128	13	9,853	0	16	0	1,261
1993	132	13	10,121	0	16	0	1,308
1994	134	13	10,344	0	18	0	1,359
1995	137	13	10,521	0	18	0	1,449
1996	148	15	9,893	0	19	0	1,479
1997	151	15	10,059	0	21	0	1,475
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	190	18	10,554	0	23	0	1,715
2002	191	18	10,632	0	24	0	1,756
2003	193	18	10,702	0	24	0	1,796
2004	194	18	10,787	0	25	0	1,836
2005	195	18	10,861	0	26	0	1,875
2006	197	18	10,937	0	26	0	1,916
2007	198	18	11,010	0	27	0	1,957
2008	200	18	11,085	0	27	0	1,998
2009	201	18	11,156	0	28	0	2,038
2010	202	18	11,227	0	29	0	2,078

** Industrial represents 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
1991	90	85	1,411	0	61,718
1992	93	70	1,424	0	63,512
1993	94	100	1,502	0	66,075
1994	91	69	1,519	0	67,934
1995	101	97	1,648	0	69,448
1996	105	75	1,659	0	70,981
1997	104	82	1,661	0	72,917
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	117	89	1,921	0	80,362
2002	122	91	1,969	0	82,074
2003	127	93	2,016	0	83,737
2004	132	95	2,063	0	85,400
2005	137	97	2,109	0	87,015
2006	142	99	2,157	0	88,678
2007	147	102	2,205	0	90,292
2008	152	104	2,253	0	91,857
2009	157	106	2,300	0	93,422
2010	162	108	2,347	0	94,987

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1991	310	21	276	0	0	9	0	4	297
1992	334	23	297	0	0	9	0	5	320
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	434	27	393	0	0	7	0	7	420
2002	445	28	404	0	0	7	0	6	432
2003	454	29	413	0	0	6	0	6	442
2004	464	30	423	0	0	6	0	5	453
2005	475	31	433	0	0	6	0	5	464
2006	485	33	442	0	0	6	0	4	475
2007	495	34	452	0	0	6	0	3	486
2008	505	35	461	0	0	6	0	3	496
2009	515	36	471	0	0	6	0	2	507
2010	525	37	481	0	0	5	0	2	518

Schedule 3.1H
History and Forecast of Summer Peak Demand
High Band

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1991	310	21	276	0	0	9	0	4	297
1992	334	23	297	0	0	9	0	5	320
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	439	27	398	0	0	7	0	7	425
2002	452	29	410	0	0	7	0	6	439
2003	466	30	424	0	0	6	0	6	454
2004	480	31	438	0	0	6	0	5	469
2005	494	33	450	0	0	6	0	5	483
2006	508	34	464	0	0	6	0	4	498
2007	523	35	479	0	0	6	0	3	514
2008	538	37	492	0	0	6	0	3	529
2009	552	38	506	0	0	6	0	2	544
2010	567	39	521	0	0	5	0	2	560

Schedule 3.1L
History and Forecast of Summer Peak Demand
Low Band

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1991	310	21	276	0	0	9	0	4	297
1992	334	23	297	0	0	9	0	5	320
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	431	27	390	0	0	7	0	7	417
2002	438	28	397	0	0	7	0	6	425
2003	444	29	403	0	0	6	0	6	432
2004	451	30	410	0	0	6	0	5	440
2005	458	30	417	0	0	6	0	5	447
2006	464	31	423	0	0	6	0	4	454
2007	470	32	429	0	0	6	0	3	461
2008	477	33	435	0	0	6	0	3	468
2009	483	34	441	0	0	6	0	2	475
2010	488	35	446	0	0	5	0	2	481

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(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
1991 / 1992	306	25	253	0	0	23	0	5	278
1992 / 1993	290	22	237	0	0	25	0	6	259
1993 / 1994	319	23	262	0	0	27	0	7	285
1994 / 1995	350	25	289	0	0	29	0	7	314
1995 / 1996	381	28	317	0	0	29	0	7	345
1996 / 1997	343	26	280	0	0	30	0	7	306
1997 / 1998	319	23	259	0	0	30	0	7	282
1998 / 1999	389	28	323	0	0	31	0	7	351
1999 / 2000	373	27	310	0	0	29	0	7	337
2000 / 2001	398	33	331	0	0	28	0	6	364
2001 / 2002	383	29	322	0	0	27	0	6	351
2002 / 2003	391	30	330	0	0	26	0	5	360
2003 / 2004	400	31	339	0	0	25	0	5	370
2004 / 2005	407	32	347	0	0	24	0	4	379
2005 / 2006	416	33	357	0	0	23	0	3	390
2006 / 2007	424	35	365	0	0	21	0	3	400
2007 / 2008	432	36	375	0	0	19	0	2	411
2008 / 2009	440	37	384	0	0	17	0	1	421
2009 / 2010	447	38	393	0	0	16	0	1	431
2010 / 2011	455	39	399	0	0	17	0	1	438

Schedule 3.2H
History and Forecast of Winter Peak Demand
High Band

(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
1991 / 1992	306	25	253	0	0	23	0	5	278
1992 / 1993	290	22	237	0	0	25	0	6	259
1993 / 1994	319	23	262	0	0	27	0	7	285
1994 / 1995	350	25	289	0	0	29	0	7	314
1995 / 1996	381	28	317	0	0	29	0	7	345
1996 / 1997	343	26	280	0	0	30	0	7	306
1997 / 1998	319	23	259	0	0	30	0	7	282
1998 / 1999	389	28	323	0	0	31	0	7	351
1999 / 2000	373	27	310	0	0	29	0	7	337
2000 / 2001	398	33	331	0	0	28	0	6	364
2001 / 2002	390	29	328	0	0	27	0	6	357
2002 / 2003	401	31	339	0	0	26	0	5	370
2003 / 2004	413	32	350	0	0	26	0	5	382
2004 / 2005	424	33	362	0	0	25	0	4	395
2005 / 2006	436	35	374	0	0	24	0	3	409
2006 / 2007	448	36	387	0	0	22	0	3	423
2007 / 2008	460	38	400	0	0	20	0	2	438
2008 / 2009	472	39	413	0	0	19	0	1	452
2009 / 2010	484	40	426	0	0	17	0	1	466
2010 / 2011	496	42	435	0	0	18	0	1	477

Schedule 3.2L
History and Forecast of Winter Peak Demand
Low Band

(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
1991 / 1992	306	25	253	0	0	23	0	5	278
1992 / 1993	290	22	237	0	0	25	0	6	259
1993 / 1994	319	23	262	0	0	27	0	7	285
1994 / 1995	350	25	289	0	0	29	0	7	314
1995 / 1996	381	28	317	0	0	29	0	7	345
1996 / 1997	343	26	280	0	0	30	0	7	306
1997 / 1998	319	23	259	0	0	30	0	7	282
1998 / 1999	389	28	323	0	0	31	0	7	351
1999 / 2000	373	27	310	0	0	29	0	7	337
2000 / 2001	398	33	331	0	0	28	0	6	364
2001 / 2002	377	28	317	0	0	26	0	6	345
2002 / 2003	382	29	323	0	0	25	0	5	352
2003 / 2004	387	30	329	0	0	24	0	4	359
2004 / 2005	393	31	335	0	0	23	0	4	366
2005 / 2006	398	32	341	0	0	22	0	3	373
2006 / 2007	402	33	347	0	0	20	0	2	380
2007 / 2008	407	34	353	0	0	18	0	2	387
2008 / 2009	411	35	359	0	0	16	0	1	394
2009 / 2010	417	36	365	0	0	15	0	1	401
2010 / 2011	421	37	367	0	0	16	0	1	404

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 %
1991	1,460	37	12	1,236	90	85	1,411	54.23%
1992	1,479	41	14	1,261	93	70	1,424	50.80%
1993	1,563	44	17	1,308	94	100	1,502	50.58%
1994	1,581	44	18	1,359	91	69	1,519	52.39%
1995	1,711	43	20	1,449	101	98	1,648	52.11%
1996	1,721	42	21	1,479	105	75	1,659	51.89%
1997	1,726	44	21	1,475	104	82	1,661	50.83%
1998	1,847	47	21	1,595	108	76	1,779	51.28%
1999	1,869	50	21	1,606	109	83	1,798	48.99%
2000	1,939	50	21	1,656	120	93	1,868	50.19%
2001	1,991	50	20	1,716	117	88	1,921	52.21%
2002	2,038	51	18	1,756	122	91	1,969	52.03%
2003	2,085	52	17	1,796	127	93	2,016	52.07%
2004	2,132	53	16	1,836	132	95	2,063	51.99%
2005	2,177	54	14	1,875	137	97	2,109	51.89%
2006	2,224	54	13	1,916	142	99	2,157	51.84%
2007	2,270	54	11	1,957	147	101	2,205	51.79%
2008	2,316	54	9	1,997	152	104	2,253	51.85%
2009	2,361	54	7	2,037	157	106	2,300	51.79%
2010	2,406	53	6	2,077	162	108	2,347	51.72%

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

(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 %
1991	1,460	37	12	1,236	90	85	1,411	54.23%
1992	1,479	41	14	1,261	93	70	1,424	50.80%
1993	1,563	44	17	1,308	94	100	1,502	50.58%
1994	1,581	44	18	1,359	91	69	1,519	52.39%
1995	1,711	43	20	1,449	101	98	1,648	52.11%
1996	1,721	42	21	1,479	105	75	1,659	51.89%
1997	1,726	44	21	1,475	104	82	1,661	50.83%
1998	1,847	47	21	1,595	108	76	1,779	51.28%
1999	1,869	50	21	1,606	109	83	1,798	48.99%
2000	1,939	50	21	1,656	120	93	1,868	50.19%
2001	2,010	50	20	1,732	119	89	1,940	52.11%
2002	2,074	52	18	1,787	125	92	2,004	52.11%
2003	2,139	53	17	1,843	130	96	2,069	52.02%
2004	2,205	55	17	1,899	136	98	2,133	51.92%
2005	2,270	56	15	1,955	142	102	2,199	51.97%
2006	2,336	57	14	2,014	147	104	2,265	51.92%
2007	2,402	57	12	2,072	153	108	2,333	51.81%
2008	2,470	58	10	2,132	159	111	2,402	51.83%
2009	2,536	58	8	2,191	165	114	2,470	51.83%
2010	2,601	57	6	2,250	171	117	2,538	51.74%

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

(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 %
1991	1,460	37	12	1,236	90	85	1,411	54.23%
1992	1,479	41	14	1,261	93	70	1,424	50.80%
1993	1,563	44	17	1,308	94	100	1,502	50.58%
1994	1,581	44	18	1,359	91	69	1,519	52.39%
1995	1,711	43	20	1,449	101	98	1,648	52.11%
1996	1,721	42	21	1,479	105	75	1,659	51.89%
1997	1,726	44	21	1,475	104	82	1,661	50.83%
1998	1,847	47	21	1,595	108	76	1,779	51.28%
1999	1,869	50	21	1,606	109	83	1,798	48.99%
2000	1,939	50	21	1,656	120	93	1,868	50.19%
2001	1,976	50	20	1,702	116	88	1,906	52.18%
2002	2,008	50	18	1,730	120	90	1,940	52.11%
2003	2,039	51	17	1,755	125	91	1,971	52.08%
2004	2,069	51	16	1,781	129	92	2,002	51.94%
2005	2,098	52	13	1,806	133	94	2,033	51.92%
2006	2,128	52	12	1,832	137	95	2,064	51.90%
2007	2,155	51	10	1,857	141	96	2,094	51.85%
2008	2,185	51	8	1,883	145	98	2,126	51.86%
2009	2,212	51	7	1,906	149	99	2,154	51.77%
2010	2,238	49	6	1,929	153	101	2,183	51.81%

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			
	2000		2001		2002	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	337	138	341	149	351	153
FEB	288	126	335	129	343	132
MAR	238	129	287	136	294	139
APR	268	129	303	136	311	139
MAY	376	174	358	162	367	167
JUN	380	176	406	182	416	186
JUL	425	193	420	198	432	203
AUG	386	198	418	202	428	207
SEP	369	173	396	186	406	189
OCT	354	143	339	157	347	161
NOV	295	135	299	137	306	140
DEC	345	153	326	148	334	152

Schedule 5
FUEL REQUIREMENTS
As Of JANUARY 1, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	FUEL REQUIREMENTS		UNITS	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	NUCLEAR		TRILLION BTU	1	1	1	1	1	1	1	1	1	1	1
(2)	COAL		1000 TON	572	577	578	590	581	589	610	603	609	628	617
	RESIDUAL													
(3)		STEAM	1000 BBL	96	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	96	0	0	0	0	0	0	0	0	0	0
	DISTILLATE													
(7)		STEAM	1000 BBL	1	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	2	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	3	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(11)		STEAM	1000 MCF	3,488	1,504	971	680	687	724	740	799	826	827	848
(12)		CC	1000 MCF	0	2,977	3,958	3,693	3,753	3,885	3,907	4,030	4,069	4,191	4,277
(13)		CT	1000 MCF	1,336	1,075	783	750	749	751	759	758	770	756	778
(14)		TOTAL:	1000 MCF	4,824	5,556	5,712	5,123	5,189	5,360	5,406	5,587	5,665	5,774	5,903
(15)	OTHER (SPECIFY)		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0

Schedule 6.1
ENERGY SOURCES (GWH)
As Of JANUARY 1, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		GWH	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR		GWH	101	71	82	71	82	71	82	71	82	71	82
(3)	COAL		GWH	1,379	1,441	1,443	1,474	1,453	1,475	1,530	1,514	1,530	1,582	1,554
	RESIDUAL													
(4)		STEAM	GWH	54	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	54	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	296	127	80	54	54	57	59	64	66	66	68
(13)		CC	GWH	0	332	453	406	415	435	438	457	463	482	495
(14)		CT	GWH	100	54	39	37	37	37	38	38	39	38	39
(15)		TOTAL:	GWH	396	513	572	497	506	529	535	559	568	586	602
(16)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0
(17)	HYDRO		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	OTHER (NET INTRA-REGION INTERCHANGE)		GWH	-62	-104	-128	-26	22	34	10	61	73	61	109
(19)	NET ENERGY FOR LOAD		GWH	1,868	1,921	1,969	2,016	2,063	2,109	2,157	2,205	2,253	2,300	2,347

Schedule 6.2
ENERGY SOURCES (%)
As Of JANUARY 1, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(2)	NUCLEAR		%	5%	4%	4%	4%	4%	3%	4%	3%	4%	3%	3%
(3)	COAL		%	74%	75%	73%	73%	70%	70%	71%	69%	68%	69%	66%
	RESIDUAL													
(4)		STEAM	%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(5)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(6)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(7)		TOTAL:	%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	DISTILLATE													
(8)		STEAM	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(9)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(10)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		TOTAL:	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	NATURAL GAS													
(12)		STEAM	%	16%	7%	4%	3%	3%	3%	3%	3%	3%	3%	3%
(13)		CC	%	0%	17%	23%	20%	20%	21%	20%	21%	21%	21%	21%
(14)		CT	%	5%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%
(15)		TOTAL:	%	21%	27%	29%	25%	25%	25%	25%	25%	25%	25%	26%
(16)	NUG		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(17)	HYDRO		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(18)	OTHER (SPECIFY)		%	-3%	-5%	-7%	-1%	1%	2%	0%	3%	3%	3%	5%
(19)	NET ENERGY FOR LOAD		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

4. FORECAST OF FACILITIES REQUIREMENTS

4.1 GENERATION RETIREMENTS AND ADDITIONS

4.1.1 Least-Cost Planning Selection

The System does not expect to retire any of its currently operating generating units prior to 2011. One of the recommendations from the Integrated Resource Least-Cost Planning Study, prepared by Stone & Webster Management Consultants, Inc. (S&W), New York, March 1992, was to "continue the current level of operation and maintenance at the Kelly Station and implement the maintenance suggestions contained in Stone & Webster Engineering Corporation's report." Further, Stone & Webster Engineering Corporation found no reason to recommend the System retire any currently operating units and suggested that these units should continue to operate through 2010. The System's newest capacity addition was a repowering of JRK Unit 8 (49.5 MW) to a combined cycle unit (JRK CC1, 110 MW) at the J.R. Kelly Station. It began commercial operation on April 1, 2001.

GRU performed an integrated least-cost planning study to determine the best plan for serving our customers well into the next century. This process took several years and involved: several RFPs to discover unknown options from other Utilities and Power Marketers; multiple sensitivities using combinations of high, base, low, and constant differential fuel price forecasts and high, base, and low load and energy forecasts; combinations of investors, purchase, partnership, and sole ownership of new generating facilities, reconfiguring and repowering of existing facilities; as well as, continuing to evaluate and refine, as necessary, existing conservation and load control options. The modeling tools used for the least-cost planning was the EGEAS model described in Chapter 3 and EXPAN which uses analytical, probabilistic, and graphical tools and provides enhanced expansion plan risk analysis. GRU used a planning criteria of 15% operating reserve margin (suggested for emergency power pricing purposes by Florida Public Service Commission Rule 25-6.035). The optimization is based on lowest net present value of revenue requirements, considering the net present value of the optimization time frame.

GRU is evaluating the technical and economic feasibility of developing a landfill gas to energy (LFGTE) project at the Alachua County Southwest Landfill. This LFGTE project, if feasible, could provide up to 3 MW of green power on a continuous basis during the first year of operation. The generation capacity of the LFGTE system will diminish through time as the landfill gas production rate slows.

4.1.2 Green Pricing

Photovoltaic systems have demonstrated remarkable reductions in cost over the last decade and have the potential to somewhat offset GRU's summer peaks. Although not considered cost-effective in the planning horizon, the Community has demonstrated a philosophical commitment to such systems by participating in a contribution campaign which has allowed customers to either make direct contributions or enroll to contribute on a monthly basis via their utility bill. Green-pricing was used, in conjunction with State and Federal grants, to build the 10 kilowatt photovoltaic array at ESCC. The Gainesville City Commission has authorized GRU to proceed with offering a new PV program in a joint project with the Florida Municipal Electric Association and the Florida Solar Energy Center. GRU plans to install eight, 4 kW PV systems over the next three years at middle schools served by energy supplied by GRU. The PV systems will function as an interactive teaching tool; used in conjunction with a solar energy science curriculum developed by the Florida Solar Energy Center. The energy produced by this system may be purchased by customers on the basis of a capacity-based subscription.

4.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

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 efficiencies in summer result in lower reserve margins during the summer season than in winter. Summer reserve margins are forecast to be at least 17% (of peak demand) through 2010.

4.3 DISTRIBUTION SYSTEM ADDITIONS

Four new identical mini-power delivery substations (PDS) are planned for the GRU system. The first Rocky Point, located near the intersection of SW Williston Road and SW 23rd Terrace in Gainesville, was installed the summer of 2000. The second, to be located in the 8500 block of SW Archer Road, is planned for the summer of 2002. The third to be located at 1800 NE 31st Avenue is planned for 2003. The fourth and last of this series to be located within the transmission right-of-way one-half mile north of NW 39th Avenue is planned for 2005. This last PDS will require the modification of the transmission structures. These new PDSs have been planned in response to heavy loading on the existing substations, with more major load development planned for GRU's service territory.

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 PDSs to other, existing adjacent area substations will allow for backup in the event of a substation transformer failure.

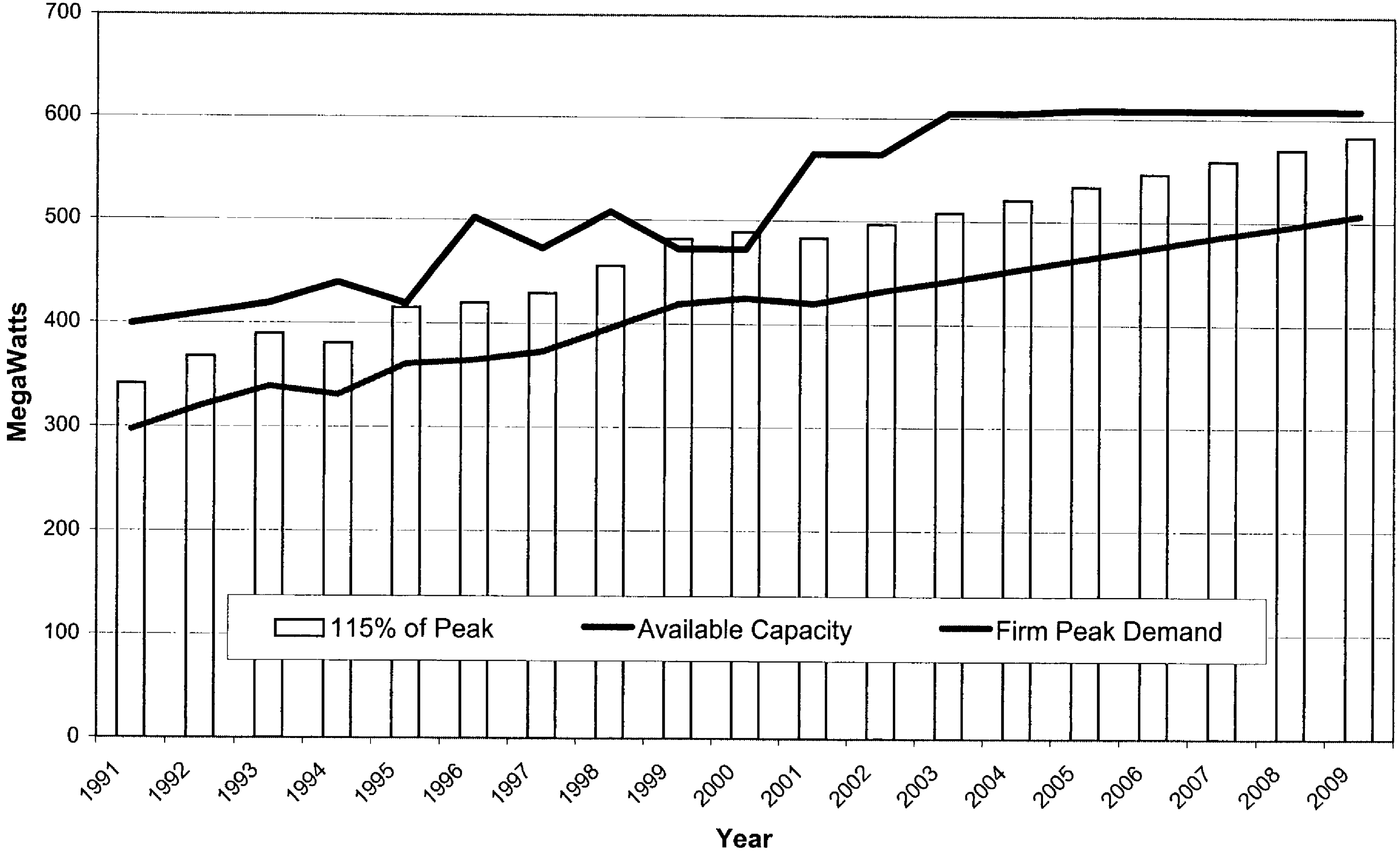
Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin1 before Maintenance		Scheduled Maintenance	Reserve Margin1 after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1991	452	0	53	0	399	297	102	34%	0	102	34%
1992	452	0	43	0	409	320	89	28%	0	89	28%
1993	452	0	33	0	419	339	80	24%	0	80	24%
1994	452	0	13	0	439	331	108	33%	0	108	33%
1995	452	0	33	0	419	361	58	16%	0	58	16%
1996	527	18	43	0	502	365	137	38%	0	137	38%
1997	527	30	85	0	472	373	99	27%	0	99	27%
1998	550	31	73	0	508	396	112	28%	0	112	28%
1999	550	32	110	0	472	419	53	13%	14	39	9%
2000	550	0	78	0	472	425	47	11%	0	47	11%
2001	608	0	43	0	565	420	145	35%	0	145	35%
2002	608	0	43	0	565	432	133	31%	0	133	31%
2003	608	0	3	0	605	442	163	37%	0	163	37%
2004	608	0	3	0	605	453	152	34%	0	152	34%
2005	608	0	0	0	608	464	144	31%	0	144	31%
2006	608	0	0	0	608	475	133	28%	0	133	28%
2007	608	0	0	0	608	486	122	25%	0	122	25%
2008	608	0	0	0	608	496	112	23%	0	112	23%
2009	608	0	0	0	608	507	101	20%	0	101	20%
2010	608	0	0	0	608	518	90	17%	0	90	17%

(1) GRU provides reserve margin backup for 3 MW Schedule D contract with the City of Starke.

Gainesville Regional Utilities

Summer Peak Demand and Generation Capacity

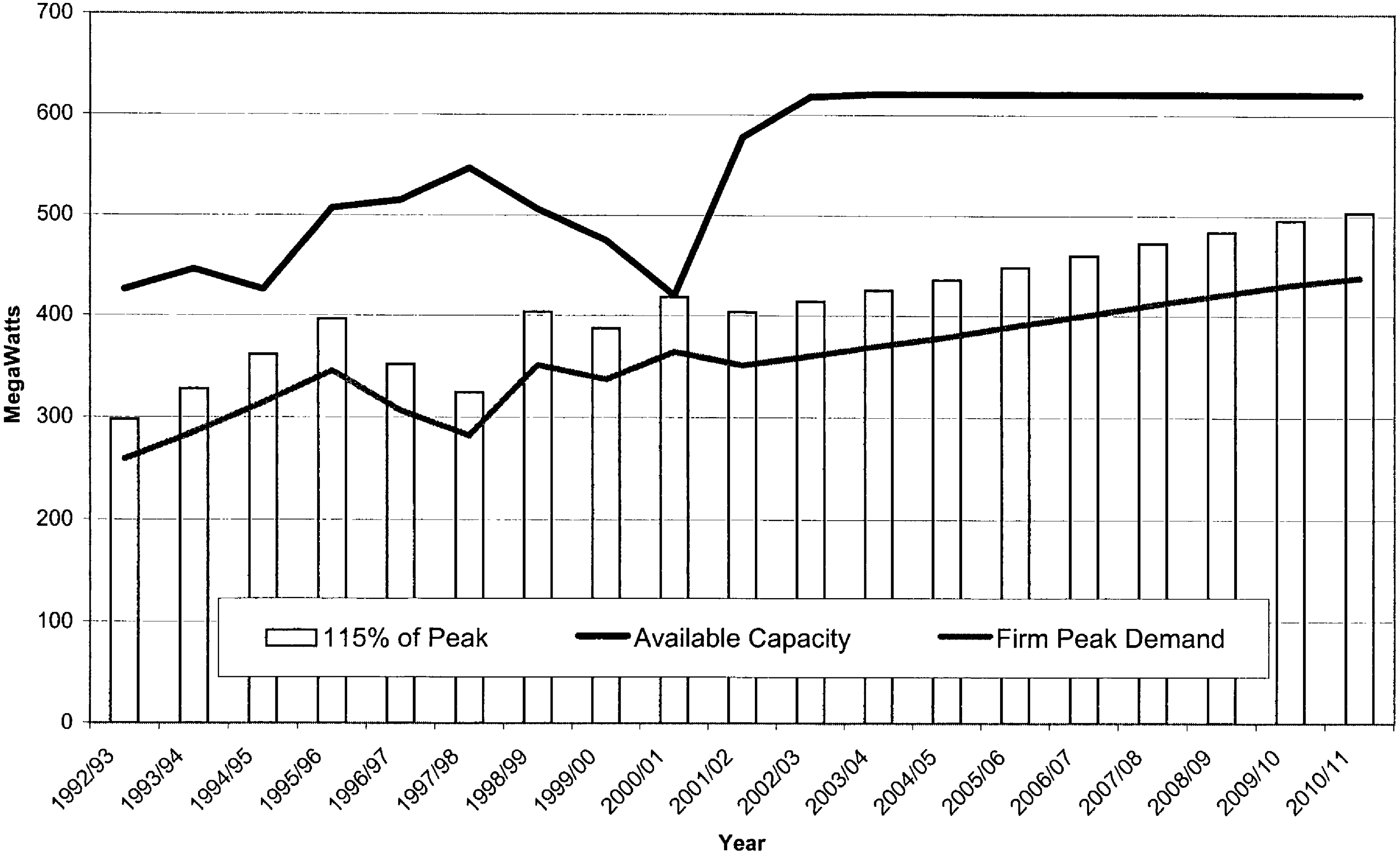


Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin1 before Maintenance		Scheduled Maintenance	Reserve Margin1 after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1991/92	459	0	43	0	416	278	138	50%	0	138	50%
1992/93	459	0	33	0	426	259	167	64%	0	167	64%
1993/94	459	0	13	0	446	285	161	56%	0	161	56%
1994/95	459	0	33	0	426	314	112	36%	0	112	36%
1995/96	540	0	33	0	507	345	162	47%	0	162	47%
1996/97	540	18	43	0	515	306	209	68%	0	209	68%
1997/98	540	30	23	0	547	282	265	94%	0	265	94%
1998/99	563	31	88	0	506	351	155	44%	0	155	44%
1999/00	563	0	88	0	475	337	138	41%	15	123	36%
2000/01	513	0	93	0	420	364	56	15%	0	56	15%
2001/02	621	0	43	0	578	351	227	65%	0	227	65%
2002/03	621	0	3	0	618	360	258	72%	0	258	72%
2003/04	621	0	0	0	621	370	251	68%	0	251	68%
2004/05	621	0	0	0	621	379	242	64%	0	242	64%
2005/06	621	0	0	0	621	390	231	59%	0	231	59%
2006/07	621	0	0	0	621	400	221	55%	0	221	55%
2007/08	621	0	0	0	621	411	210	51%	0	210	51%
2008/09	621	0	0	0	621	421	200	48%	0	200	48%
2009/10	621	0	0	0	621	431	190	44%	0	190	44%
2010/11	621	0	0	0	621	438	183	42%	0	183	42%

GRU provides reserve margin backup for 3 MW Schedule D contract with the City of Starke.

Winter Peak Demand and Generation Capacity



5. ENVIRONMENTAL AND LAND USE INFORMATION

5.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

There are no new generating facilities planned.

5.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

Not applicable.

5.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Not applicable.