ORIGINAL

GRU

GAINESVILLE REGIONAL UTILITIES
STRATEGIC PLANNING

030000-PU

March 28, 2003

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

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 2003 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 or:

Roger Westphal (Generation Planning)	(352) 393-1289
Todd Kamhoot (Forecasting)	(352) 393-1280

Sincerely,

Ed Regan
Strategic Planning Director

Enclosures

File: PSC - Ten Year Site Plan

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GAINESVILLE REGIONAL UTILITIES

2003 TEN-YEAR SITE PLAN

GRU[SM]

More than Energy[TM]

Submitted to:

The Florida Public Service Commission

April 1, 2003

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1. INTRODUCTION

The 2003 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 2003 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 433 megawatts on July 17, 2002. The repowering of J. R. Kelly Unit 8 to a 112 megawatt combined-cycle unit increased net summer capability to 610 megawatts in May 2001. 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 vertically 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 82,622 customers (2002 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, 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. GRU's combined cycle unit, which is a combination of a gas turbine, a heat recovery steam generator (to capture the waste heat from the gas turbine and generate steam), and a steam turbine, is located at the John R. Kelly Station.

The present summer net capability is 610 MW and the winter net capability is 629 MW[1]. Currently, the System's energy is produced by three fossil fuel steam turbines, six simple-cycle combustion turbines, one combined-cycle unit, and a 1.4% ownership share of the Crystal River 3 nuclear unit, which is operated by Florida Power Corporation (FPC).

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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.

2.1.1 Generating Units

2.1.1.1 Steam Turbines. The System's three operational steam turbines are powered by fossil fuels and Crystal River 3 is nuclear powered. The fossil fueled steam turbines comprise 54.7% of the System's net summer capability and produced 76.0% of the electric energy supplied by the System in 2002. These units range in size from 23.2 MW to 228.4 MW. The recently installed combined-cycle unit comprises 18.4% of the System's net summer capability and produced 14.9% of the electric energy supplied by the System in 2002. The System's 11.0 MW share of Crystal River 3 nuclear unit comprises 1.8% of the System's net summer capability and produced 5.1% of total electric energy in 2002.

Both Deerhaven 2 and Crystal River 3 are used for base load purposes, while Kelly 7 and Kelly CC1 and Deerhaven 1 are used for intermediate loading.

2.1.1.2 Gas Turbines. The System's six industrial gas turbines make up 25.1% of the System's summer generating capability and produced 4.0% of the electric energy supplied by the System in 2002. 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, one steam turbine, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment.

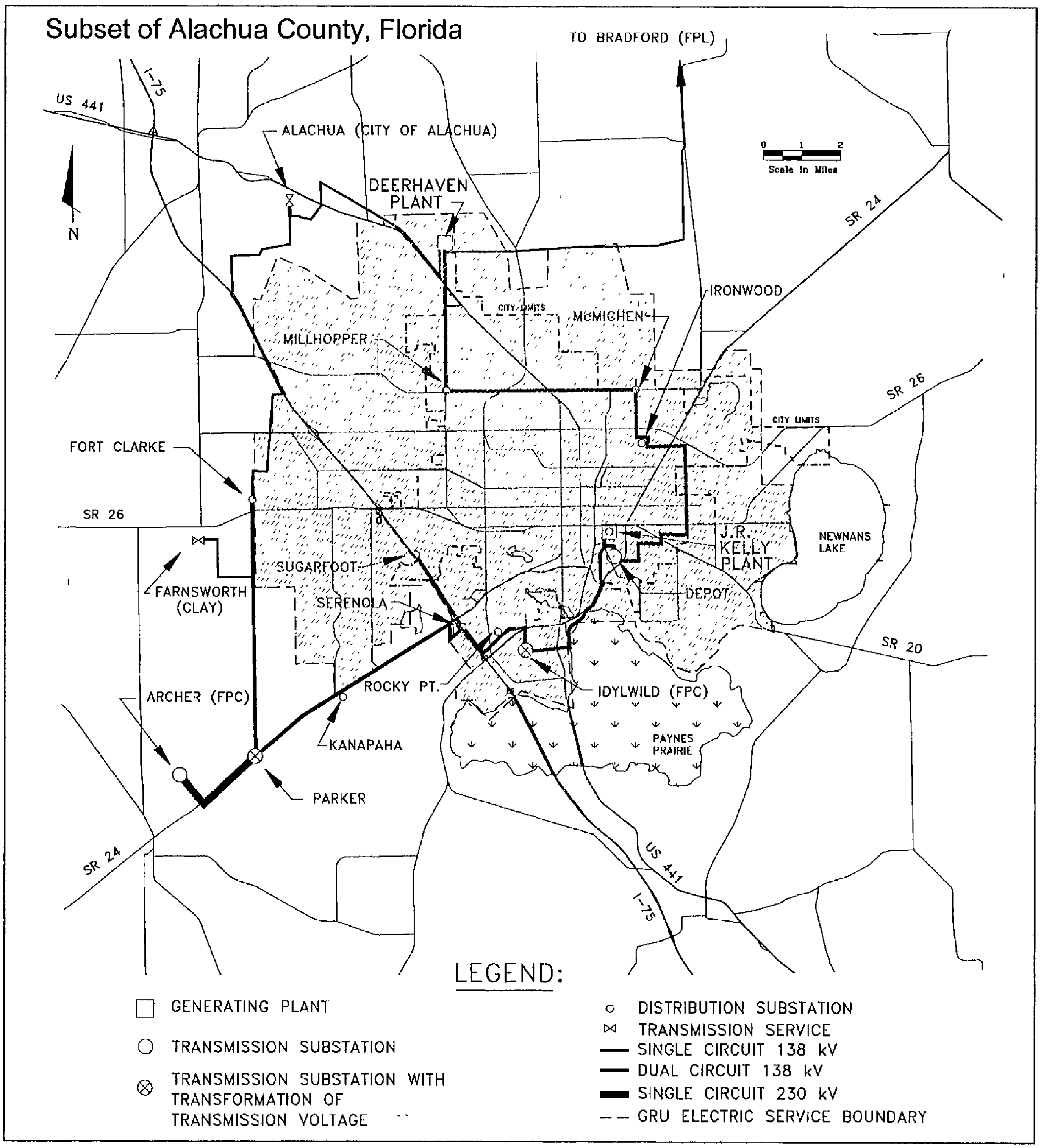


Figure 2.1, Gainesville Regional Utilities Electric Facilities

2.1.2.2 Deerhaven Plant. The Deerhaven Station is located six miles northwest of Gainesville. The site is a 1,146 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. A buffer/potential expansion area consisting of 1,153 acres parcel A, 1,123.79 acres parcel B, and 40.8 acres parcel C (2,317.59 acres of buffer) was purchased on the east side of Deerhaven Station.

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 nine 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	100.20	795 MCM ACSR
138 KV single circuit	16.74	1192 MCM ACSR
138 KV single circuit	20.74	795 MCM ACSR
230 KV single circuit	2.60	795 MCM ACSR
Total	140.28	

As part of an analysis in September and October of 2002 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 with GRU's 138 kV/24 MVAR capacitor on line.

(c) Meeting future load and interchange requirements -- No identifiable problems through 2009.

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 six major and three minor distribution substations connected to the transmission network: Ft. Clarke, Kelly, McMichen, Millhopper, Serenola, Sugarfoot, Ironwood, Kanapaha, and Rocky Point substations, respectively. 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 Ironwood, Kanapaha, and Rocky Point are served by a single tap to the 138 kV network. This prevents the outage of a single transmission line from causing major outages in the distribution system. 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, Ironwood, was brought on-line in 2003 to serve the growing load in the area of State Road 24 and NE 31st Avenue and to provide backup support for the Kelly and McMichen substations. Ft. Clarke, Kelly, McMichen, and Serenola 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),

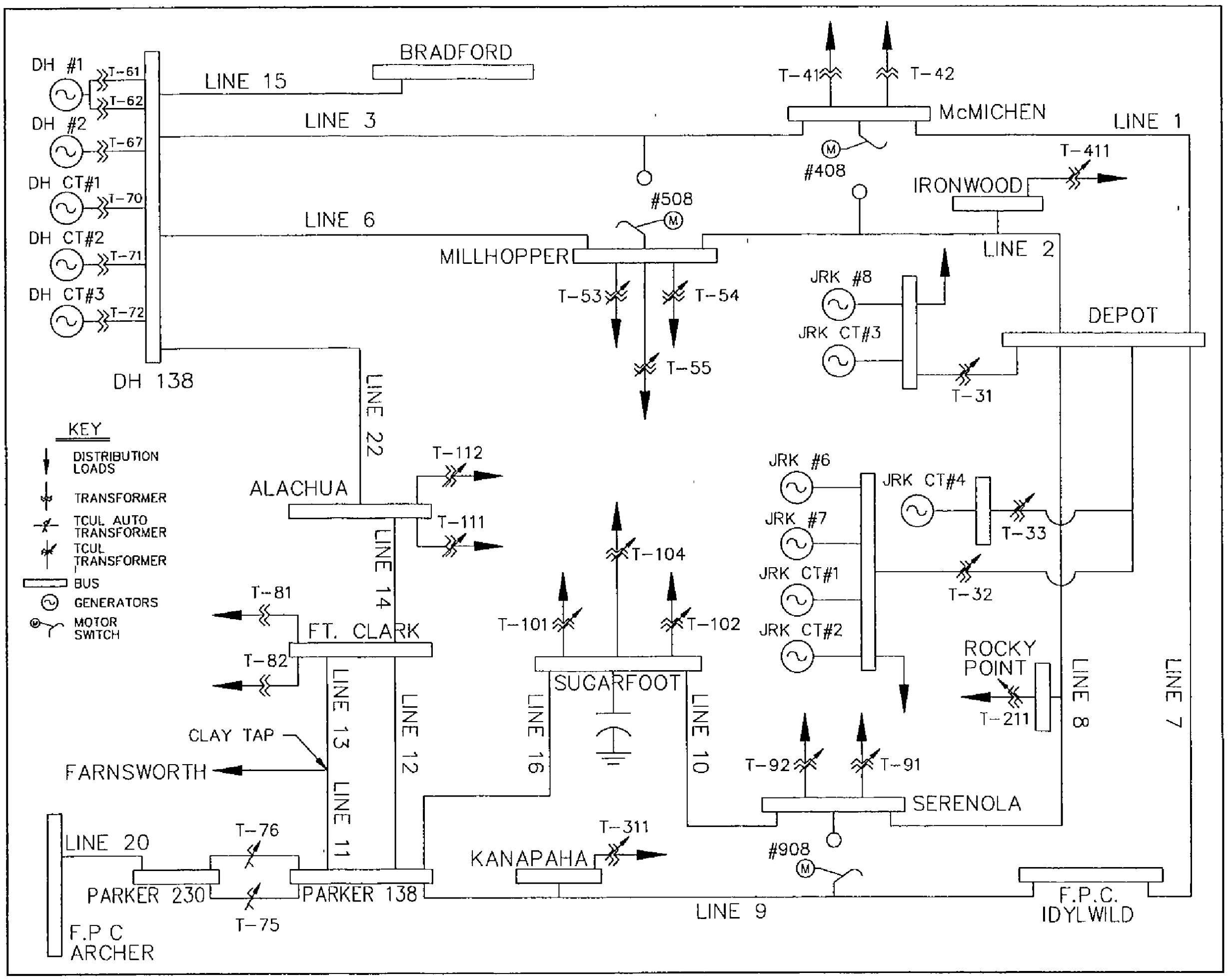


FIGURE 2.2 Gainesville Regional Utilities Electric System One-Line Diagram.

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.

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 90% 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.

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
Ft. Clarke	44.8 MVA	4
J. R. Kelly[2]	112.0 MVA	17
McMichen	44.8 MVA	6
Millhopper	100.8 MVA	10
Serenola	67.2 MVA	8
Sugarfoot	100.8 MVA	8
Ironwood	33.6 MVA	3
Kanapaha	33.6 MVA	2
Rocky Point	33.6 MVA	3

2 J. R. Kelly is a generating station as well as a distribution substation. The CT portion (75 MW) of JRK CC 1 is connected directly to the 138 kV distribution line from Depot Transmission Substation to J. R. Kelly Distribution Substation/Generation Station and the steam portion is connected to the substation bus along with the remaining generation capacity at J. R. Kelly Station (102 MW).

Schedule 1

EXISTING GENERATING FACILITIES

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Primary Fuel Type	(6) Primary Fuel Trans.	(7) Alternate Fuel Type	(8) Alternate Fuel Trans.	(9) Alt. Fuel Storage (Days)	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gross Capability Summer MW	(13) Gross Capability Winter MW	(14) Net Capability Summer MW	(15) Net Capability Winter MW	(16) Status
J. R. Kelly		12-001											177	186	
		(Alachua Co.,													
	FS08	Section 4, Township	CA	WH	PL				[4/65 ; 5/01]	Unknown	38	38	37	37	OP
	FS07	10 S, Range 20E)	ST	NG	PL	RFO	TK		8/61	Unknown	24	24	23	23	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	Unknown	76	82	75	81	OP
	GT03		GT	NG	PL	DFO	TK		5/69	Unknown	14	15	14	15	OP
	GT02		GT	NG	PL	DFO	TK		9/68	Unknown	14	15	14	15	OP
	GT01		GT	NG	PL	DFO	TK		2/68	Unknown	14	15	14	15	OP
Deerhaven		12-001									451	461	422	432	
		(Alachua Co., Sections													
	FS02	26,27,35, Township	ST	BIT	RR				10/81	Unknown	249	249	228	228	OP
	FS01	8 S, Range 19 E)	ST	NG	PL	RFO	TK		8/72	Unknown	88	88	83	83	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	Unknown	76	82	75	81	OP
	GT02		GT	NG	PL	DFO	TK		8/76	Unknown	19	21	18	20	OP
	GT01		GT	NG	PL	DFO	TK		7/76	Unknown	19	21	18	20	OP
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	OP
System Total													610	629	

Unit Type
CA = Combined Cycle Steam Part
CT = Combined Cycle Combustion Turbine Part
GT = Gas Turbine
ST = Steam Turbine

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

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

Status
OP = Operational

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 1993-2012. 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 2001. 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 <u>Florida Population Studies,</u> February 2002 (Bulletin No. 132), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

(3) Normal weather conditions were assumed. Forecast values of heating degree days and cooling degree days equal the mean (rounded to the nearest hundred) of data reported to NOAA by the Gainesville Municipal Airport station.

(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 2001.

(6) The Florida Long Term Economic Forecast 2001 and Florida Population Studies, Bulletin 131, were used to estimate and project the number of persons per household (household size) in Alachua County.

(7) The Florida Long Term Economic Forecast 2001 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. 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 (9%) 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 2003 through 2012. 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:

$$RESAVUSE = 4589.0 + 0.074\,(HHY98) - 11.08\,(RESPR98) + 0.70\,(HDD) + 0.94\,(CDD)$$

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

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

Adjusted R^2	=	0.8895
DF (error)	=	26
t - statistics:		
Intercept	=	3.74
HHY98	=	6.94
RESPR98	=	-2.42
HDD	=	3.96
CDD	=	4.84

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	=	*-27396 + 443.01 (LAGPOP)*
Where:		
RESCUS	=	Number of Residential Customers
LAGPOP	=	Alachua County Population (thousands), lagged one year
Adjusted R^2	=	0.9968
DF (error)	=	22
t - statistics:		
Intercept	=	-28.53
LAGPOP	=	82.56

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 enter the General Service Demand (GSD) class. This option offers potential benefit to GSN customers that use high amounts of energy, and 240 customers have elected to voluntarily transfer to the GSD class since 1990. 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:

$$GSNAVUSE = 23.81 - 0.01(OPTDCUST) + 0.001(CDD)$$

Where:

GSNAVUSE	=	Average annual energy usage by GSN customers
OPTDCUST	=	Cumulative number of Optional Demand Customers
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.5401
DF (error)	=	20
t - statistics:		
Intercept	=	11.92
OPTDCUST	=	-4.54
CDD	=	2.03

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:

$$GSNCUS = -4867.8 + 58.74\ (LAGPOP)$$

Where:

GSNCUS = Number of General Service Non-Demand Customers

LAGPOP = Alachua County Population (thousands), lagged on year

Adjusted R^2 = 0.9889

DF (error) = 22

t - statistics:

Intercept = -20.92

LAGPOP = 45.18

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:

GSDAVUSE = 365.41 + 0.0084 (PCY98) – 0.16 (OPTDCUST)

Where:

GSDAVUSE = Average annual energy use by GSD Customers

PCY98 = Per Capita Income in Alachua County

OPTDCUST = Cumulative number of Optional Demand Customers

Adjusted R^2 = 0.7761

DF (error) = 20

t - statistics:

Intercept	=	17.84
PCY98	=	7.76
OPTDCUST	=	-2.70

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:

$$GSDCUS = -473.9 + 5.73\,(LAGPOP)$$

Where:

GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands), lagged one year
Adjusted R^2	=	0.9739
DF (error)	=	21

t - statistics:

Intercept	=	-13.11
POP	=	28.65

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 2001. 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	=	*10391 + 17.93 (NONAG) - 40.91 (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	=	0.9014
DF (error)	=	23
t - statistics:		
INTERCEPT	=	6.09
NONAG	=	1.97
LPPR98	=	-3.22

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 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 number of residential customers. The specifications of this model are as follows:

LGTMWH	=	*-8029.7 + 0.43 (RESCUS)*
Where:		
LGTMWH	=	Outdoor Lighting Energy Sales

RESCUS = Number of Residential Customers

Adjusted R^2 = 0.9638

DF (error) = 10

t - statistics:

Intercept = -5.05

RESCUS = 17.15

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 9% of Alachua's 2002 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 = -17952 + 16.99 (COY98)

Where:

CLYMWH = Megawatt-Hour Sales to Clay

COY98 = Total Personal Income (Alachua County)

Adjusted R^2 = 0.9582

DF (error) = 25

t - statistics:

Intercept = -6.99

COY98 = 24.44

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	=	*-29030 + 0.60 (ALAY98) + 6.03 (CDD)*
Where:		
ALANEL	=	Net Energy Requirements of Alachua
ALAY98	=	City of Alachua Total Income
CDD	=	Cooling Degree Days
Adjusted R^2	=	0.9752
DF (error)	=	19
t - statistics:		
Intercept	=	-3.32
ALAPOP	=	28.54
CDD	=	2.06

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 1984 through 2001, and is projected to be approximately 95%.

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 July of each year, although historical data suggests the summer peak is nearly as likely to occur in August. The average ratio of the most recent 19 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 19 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 1982 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 Programs

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 historical program implementations recorded from 1980 through 2002, as well as projected program implementations scheduled through 2012. GRU's DSM programs were designed for the purpose of conserving the resources utilized by the System in a manner most cost effective to the customers of GRU. 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.

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 developing a 10 kW photovoltaic project at the Gainesville Regional Airport to promote the use of renewable energy. This project will be funded through voluntary customer contributions and avoided utility costs. GRU is pursuing grant funding for photovoltaic installations through the Department of Community Affairs' PV for Schools Educational Enhancement Program. GRU is also working to offer green energy to its customers from a blend of renewable energy sources including landfill gas, solar, and wind.

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 energy usage of DSM program participants and non-participants. The methodology upon which existing DSM programs 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 9 MW of summer peak reduction, 19 MW of winter peak reduction and 70 GWh of annual energy savings by the year 2012. 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 Systems Control Center (SCC). 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. Most recently, 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.

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 2002, oil-fired generation comprised 2.8% of total net generation, natural gas-fired generation contributed 31.4%, nuclear fuel contributed 4.9%, and coal-fired generation provided 60.9% of total net generation. The PV system at SCC 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 2.4 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 2003 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 2002. 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 dollars" 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.

During calendar year 2002, No. 2 oil was used to produce 0.16% of GRU's total net generation. Over the next 10 years, the price of No.2 oil delivered to GRU is expected to increase 4.0% annually while the actual volume of oil used remains small.

During calendar year 2002, No. 6 oil was used to produce 2.46% of GRU's total net generation. Over the next 10 years, the price of No.6 oil delivered to GRU is expected to increase 2.0% 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, comprising 60.7% of total net generation during calendar year 2002. Historically, GRU has purchased a low sulfur, high Btu eastern coal for use at its Deerhaven site. An increased demand for coal by utilities beginning in 2001, combined with a tightened supply, contributed to an increase in the market price for coal. Consequently, prices for coal are expected to be higher in the future than in previous forecasts. 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 1.2% for low sulphur compliance coal, pulverized coal for flue gas desulphurization, and fluidized bed compatible coal from 2003 through 2012.

3.5.3 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2002, GRU purchased approximately 7.6 million MMBtu for use by both systems. GRU power plants used 73% of the total purchased for GRU during 2002, while the LDC used the remaining 27%.

GRU 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 3.8% from 2003 through 2012.

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 Florida Power Corporation's (FPC) forecast of nuclear fuel prices. The projection for the cost of fuel disposal is based on a trend analysis of actual costs to GRU. Overall nuclear fuel price is projected to increase at a rate of approximately 3.9% 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
1993	140,572	2.38	637	59,064	10,778	524	6,998	74,824
1994	144,852	2.38	649	60,862	10,670	558	7,059	79,024
1995	147,248	2.37	704	62,130	11,329	590	7,305	80,767
1996	150,322	2.37	718	63,427	11,313	594	7,539	78,813
1997	153,759	2.36	705	65,152	10,817	598	7,750	77,193
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	176,577	2.34	863	75,460	11,434	751	9,022	83,295
2004	182,072	2.34	896	77,809	11,514	773	9,225	83,814
2005	185,182	2.34	919	79,138	11,612	795	9,418	84,411
2006	188,292	2.34	943	80,467	11,722	818	9,612	85,085
2007	191,402	2.34	968	81,796	11,835	841	9,805	85,774
2008	194,408	2.34	991	83,080	11,931	863	9,992	86,382
2009	197,518	2.34	1,015	84,409	12,030	886	10,186	86,959
2010	199,667	2.33	1,038	85,694	12,115	908	10,372	87,575
2011	202,661	2.33	1,060	86,979	12,189	930	10,559	88,078
2012	204,772	2.32	1,077	88,264	12,205	950	10,746	88,417

* 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 **				Street and	Other Sales	Total Sales
		Average	Average	Railroads	Highway	to Public	to Ultimate
		Number of	MWh per	and Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Customer	GWh	GWh	GWh	GWh
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	173	17	10,162	0	23	0	1,696
2002	178	18	10,178	0	24	0	1,774
2003	181	18	10,079	0	25	0	1,820
2004	183	18	10,152	0	26	0	1,877
2005	184	18	10,247	0	26	0	1,925
2006	186	18	10,313	0	27	0	1,973
2007	187	18	10,393	0	27	0	2,023
2008	188	18	10,439	0	28	0	2,070
2009	189	18	10,483	0	28	0	2,118
2010	189	18	10,521	0	29	0	2,165
2011	190	18	10,555	0	30	0	2,210
2012	190	18	10,581	0	30	0	2,248

** Industrial represents Large Power Rate Class.

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

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales For Resale GWh	Utility Use and Losses GWh	Net Energy for Load GWh	Other Customers	Total Number of Customers
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	125	62	1,882	0	81,011
2002	142	92	2,008	0	82,623
2003	138	103	2,062	0	84,500
2004	145	106	2,129	0	87,051
2005	87	106	2,118	0	88,574
2006	92	108	2,174	0	90,096
2007	96	111	2,231	0	91,619
2008	100	114	2,284	0	93,091
2009	104	117	2,339	0	94,613
2010	108	119	2,393	0	96,085
2011	113	122	2,445	0	97,556
2012	117	124	2,489	0	99,028

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
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	423	28	381	0	0	7	0	7	409
2002	446	32	401	0	0	7	0	7	433
2003	463	32	419	0	0	6	0	6	451
2004	478	33	433	0	0	6	0	6	466
2005	475	19	445	0	0	6	0	5	464
2006	488	20	457	0	0	6	0	5	477
2007	500	21	469	0	0	6	0	4	490
2008	511	22	480	0	0	6	0	3	502
2009	523	23	491	0	0	6	0	3	514
2010	533	24	502	0	0	5	0	2	526
2011	547	25	513	0	0	6	0	3	538
2012	557	26	522	0	0	6	0	3	548

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
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	423	28	381	0	0	7	0	7	409
2002	446	32	401	0	0	7	0	7	433
2003	467	32	423	0	0	6	0	6	455
2004	486	34	440	0	0	6	0	6	474
2005	486	20	455	0	0	6	0	5	475
2006	502	21	470	0	0	6	0	5	491
2007	518	22	486	0	0	6	0	4	508
2008	534	23	501	0	0	6	0	4	524
2009	549	24	516	0	0	6	0	3	540
2010	565	26	530	0	0	6	0	3	556
2011	581	27	545	0	0	6	0	3	572
2012	596	28	559	0	0	6	0	3	587

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
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	423	28	381	0	0	7	0	7	409
2002	446	32	401	0	0	7	0	7	433
2003	459	31	416	0	0	6	0	6	447
2004	471	33	426	0	0	6	0	6	459
2005	466	19	436	0	0	6	0	5	455
2006	475	20	444	0	0	6	0	5	464
2007	484	20	454	0	0	6	0	4	474
2008	490	21	461	0	0	5	0	3	482
2009	499	22	469	0	0	5	0	3	491
2010	507	23	477	0	0	5	0	2	500
2011	515	23	485	0	0	5	0	2	508
2012	522	24	490	0	0	6	0	2	514

Schedule 3.2
History and Forecast of Winter Peak Demand
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
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	401	33	336	0	0	27	0	6	369
2002 / 2003	425	33	361	0	0	26	0	5	394
2003 / 2004	410	34	346	0	0	25	0	5	380
2004 / 2005	408	20	360	0	0	24	0	4	380
2005 / 2006	417	21	370	0	0	23	0	3	391
2006 / 2007	428	21	383	0	0	21	0	3	404
2007 / 2008	436	22	393	0	0	19	0	2	415
2008 / 2009	445	23	404	0	0	17	0	1	427
2009 / 2010	456	24	415	0	0	16	0	1	439
2010 / 2011	465	25	422	0	0	17	0	1	447
2011 / 2012	474	26	429	0	0	18	0	1	455
2012 / 2013	483	27	436	0	0	19	0	1	463

Schedule 3.2H
History and Forecast of Winter Peak Demand
High 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
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	401	33	336	0	0	27	0	6	369
2002 / 2003	425	33	361	0	0	26	0	5	394
2003 / 2004	416	35	351	0	0	25	0	5	386
2004 / 2005	418	20	369	0	0	25	0	4	389
2005 / 2006	430	21	382	0	0	23	0	4	403
2006 / 2007	444	22	397	0	0	22	0	3	419
2007 / 2008	456	24	410	0	0	20	0	2	434
2008 / 2009	468	25	424	0	0	18	0	1	449
2009 / 2010	482	26	438	0	0	17	0	1	464
2010 / 2011	495	27	449	0	0	18	0	1	476
2011 / 2012	507	28	459	0	0	19	0	1	487
2012 / 2013	520	29	470	0	0	20	0	1	499

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
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	401	33	336	0	0	27	0	6	369
2002 / 2003	425	33	361	0	0	26	0	5	394
2003 / 2004	405	33	342	0	0	25	0	5	375
2004 / 2005	400	19	353	0	0	24	0	4	372
2005 / 2006	406	20	361	0	0	22	0	3	381
2006 / 2007	414	21	370	0	0	20	0	3	391
2007 / 2008	421	21	379	0	0	19	0	2	400
2008 / 2009	426	22	386	0	0	17	0	1	408
2009 / 2010	433	23	394	0	0	15	0	1	417
2010 / 2011	440	24	399	0	0	16	0	1	423
2011 / 2012	445	25	402	0	0	17	0	1	427
2012 / 2013	451	25	407	0	0	18	0	1	432

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 %
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	1,953	50	20	1,696	125	62	1,882	52.54%
2002	2,079	51	19	1,774	142	92	2,008	52.95%
2003	2,132	52	18	1,821	138	103	2,062	52.19%
2004	2,199	53	17	1,878	145	106	2,129	52.15%
2005	2,188	54	16	1,925	87	106	2,118	52.11%
2006	2,242	54	14	1,973	92	109	2,174	52.03%
2007	2,298	55	12	2,023	96	112	2,231	51.98%
2008	2,349	54	11	2,070	100	114	2,284	51.94%
2009	2,403	54	10	2,118	104	117	2,339	51.95%
2010	2,455	54	8	2,165	108	120	2,393	51.93%
2011	2,512	58	9	2,210	113	122	2,445	51.88%
2012	2,559	61	9	2,248	117	124	2,489	51.85%

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 %
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	1,953	50	20	1,696	125	62	1,882	52.54%
2002	2,079	51	19	1,774	142	92	2,008	52.95%
2003	2,150	52	18	1,835	141	104	2,080	52.19%
2004	2,235	54	17	1,907	149	108	2,164	52.12%
2005	2,238	55	16	1,969	90	108	2,167	52.08%
2006	2,311	56	15	2,033	95	112	2,240	52.08%
2007	2,385	57	13	2,099	100	116	2,315	52.02%
2008	2,454	57	11	2,162	105	119	2,386	51.98%
2009	2,526	57	10	2,227	110	122	2,459	51.98%
2010	2,597	57	9	2,290	115	126	2,531	51.97%
2011	2,673	61	10	2,352	121	129	2,602	51.93%
2012	2,741	65	10	2,407	126	133	2,666	51.85%

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 %
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	1,953	50	20	1,696	125	62	1,882	52.54%
2002	2,079	51	19	1,774	142	92	2,008	52.95%
2003	2,117	52	18	1,808	136	103	2,047	52.28%
2004	2,169	53	17	1,852	142	105	2,099	52.20%
2005	2,144	53	15	1,887	85	104	2,076	52.08%
2006	2,184	53	14	1,922	89	106	2,117	52.08%
2007	2,224	53	12	1,959	92	108	2,159	52.00%
2008	2,259	52	10	1,993	95	109	2,197	52.03%
2009	2,297	52	9	2,025	99	112	2,236	51.99%
2010	2,333	51	8	2,059	102	113	2,274	51.92%
2011	2,371	54	8	2,088	106	115	2,309	51.89%
2012	2,401	57	8	2,111	109	116	2,336	51.88%

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			
	2002		2003		2004	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	369	152	394	160	380	166
FEB	329	128	350	139	361	143
MAR	311	144	302	145	312	150
APR	366	162	325	146	336	151
MAY	388	183	388	176	401	182
JUN	415	179	429	195	443	201
JUL	433	195	451	213	466	220
AUG	406	195	450	217	464	224
SEP	400	200	423	197	436	204
OCT	368	177	370	167	382	172
NOV	299	142	320	147	330	151
DEC	317	151	350	160	361	165

Schedule 5
FUEL REQUIREMENTS
As Of JANUARY 1, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL	ACTUAL									
	FUEL REQUIREMENTS		UNITS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	NUCLEAR		TRILLION BTU	1	1	1	1	1	1	1	1	1	1	1
(2)	COAL		1000 TON	574	580	596	590	587	611	622	615	620	639	642
	RESIDUAL													
(3)		STEAM	1000 BBL	70	2	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	70	2	0	0	0	0	0	0	0	0	0
	DISTILLATE													
(7)		STEAM	1000 BBL	0	1	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	7	4	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	7	3	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	14	8	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(11)		STEAM	1000 MCF	2,677	2,587	1,040	1,318	1,152	1,023	1,421	1,523	1,780	1,630	1,677
(12)		CC	1000 MCF	1,425	1,911	3,526	3,480	3,802	3,815	3,611	4,014	4,046	4,022	4,493
(13)		CT	1000 MCF	810	862	453	1,117	964	852	1,187	1,157	1,462	1,465	1,373
(14)		TOTAL:	1000 MCF	4,912	5,360	5,019	5,915	5,918	5,690	6,219	6,694	7,288	7,117	7,543
(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, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL	ACTUAL									
	ENERGY SOURCES		UNITS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		GWH	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR		GWH	92	103	81	93	81	93	81	93	81	93	81
(3)	COAL		GWH	1,384	1,217	1,486	1,476	1,466	1,529	1,559	1,543	1,559	1,608	1,614
	RESIDUAL													
(4)		STEAM	GWH	36	50	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	36	50	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	3	2	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	2	1	0	0	0	0	0	0	0	0	0
(11)		TOTAL:	GWH	5	3	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(12)		STEAM	GWH	223	258	92	117	100	91	125	136	160	145	149
(13)		CC	GWH	158	296	381	378	416	415	395	445	451	450	511
(14)		CT	GWH	59	80	29	65	55	46	71	67	88	97	90
(15)		TOTAL:	GWH	440	634	502	560	571	552	591	648	699	692	750
(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	-75	1	-7	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWH	1,882	2,008	2,062	2,129	2,118	2,174	2,231	2,284	2,339	2,393	2,445

Schedule 6.2
ENERGY SOURCES (%)
As Of JANUARY 1, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				ACTUAL	ACTUAL										
	ENERGY SOURCES		UNITS	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(2)	NUCLEAR		%	4.89%	5.13%	3.93%	4.37%	3.82%	4.28%	3.63%	4.07%	3.46%	3.89%	3.31%	3.74%
(3)	COAL		%	73.54%	60.61%	72.07%	69.33%	69.22%	70.33%	69.88%	67.56%	66.65%	67.20%	66.01%	63.64%
	RESIDUAL														
(4)		STEAM	%	1.91%	2.49%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	%	1.91%	2.49%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE														
(8)		STEAM	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	%	0.16%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	%	0.11%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	%	0.27%	0.15%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NATURAL GAS														
(12)		STEAM	%	11.85%	12.85%	4.46%	5.50%	4.72%	4.19%	5.60%	5.95%	6.84%	6.06%	6.09%	6.67%
(13)		CC	%	8.40%	14.74%	18.48%	17.75%	19.64%	19.09%	17.71%	19.48%	19.28%	18.80%	20.90%	21.45%
(14)		CT	%	3.13%	3.98%	1.41%	3.05%	2.60%	2.12%	3.18%	2.93%	3.76%	4.05%	3.68%	4.50%
(15)		TOTAL:	%	23.38%	31.57%	24.35%	26.30%	26.96%	25.39%	26.49%	28.37%	29.88%	28.92%	30.67%	32.62%
(16)	NUG		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(17)	HYDRO		%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(18)	OTHER (SPECIFY)		%	-3.99%	0.05%	-0.34%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(19)	NET ENERGY FOR LOAD		%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

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 2012. 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, 112 MW) at the J.R. Kelly Station. It began commercial operation on May 3, 2001.

GRU is performing an integrated least-cost planning study to determine the best plan for our customers' long-term needs. This process will take months to complete and will involve consideration of: Requests for Proposals (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 demand response options. The modeling tools to be used for the least-cost planning study are the EGEAS model described in Chapter 3 and EXPAN or equivalent software that uses analytical, probabilistic, and graphical tools and provides enhanced expansion plan risk analysis. GRU uses a planning criteria of 15% capacity 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 within the optimization time frame. Schedule 9 identifies key parameters for evaluating additional generating capacity and is included at the end of this section.

In consideration of the load forecast, reserve margin requirements, and system reliability, GRU's Electric System will require additional generating capacity by 2011. Based on the analyses and factors described in the above paragraph, GRU is proposing to add a 75 MW combustion turbine at its Deerhaven plant site to meet future capacity needs. Construction on this proposed unit would begin in May of 2006, and the unit would be available for service in May of 2010. Specifications of the proposed Deerhaven GT4 are defined in Schedule 8 at the end of this section.

The landfill gas to energy (LFGTE) project at the Alachua County Southwest Landfill mentioned in last year's TYSP is on track and expected to be wheeling power over the Progress Energy Florida's distribution network in early Fall (2003). This LFGTE project will provide up to 2.4 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

GRU is developing a green pricing program to sell green energy produced at the Southwest landfill to interested customers. GRU plans to market the output in discrete blocks of energy to residential and commercial customers. This energy may be packaged with other renewable sources, such as solar or wind, and marketed collectively.

GRU's customers have demonstrated a philosophical commitment to renewable energy by participating in a continuing contribution campaign that 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 Systems Control Center. The Gainesville City Commission has authorized GRU to proceed with installing a new 10 kW PV system at the Gainesville Regional Airport. This project will be supported by voluntary customer contributions and avoided utility costs. GRU is also pursuing grant funding from the Florida Department of Community Affairs/Florida Energy Office for installation of photovoltaic systems on local schools.

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 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% in 2011. GRU plans to add capacity by summer of 2010 to address its reserve margin requirements.

4.3 DISTRIBUTION SYSTEM ADDITIONS

Five new identical mini-power delivery substations (PDS) were planned for the GRU system back in 1999. 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, Kanapaha, is located in the 8800 block of SW Archer Road and was installed spring of 2002. The third, Ironwood, located at 1800 NE 31st was most recently connected in March 2003. The fourth will be located in the Springhill area in NW Gainesville and is scheduled for late 2004. The fifth and last of this series is located within the transmission right-of-way one-half mile north of NW 39th Avenue east of 43rd Avenue and 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.

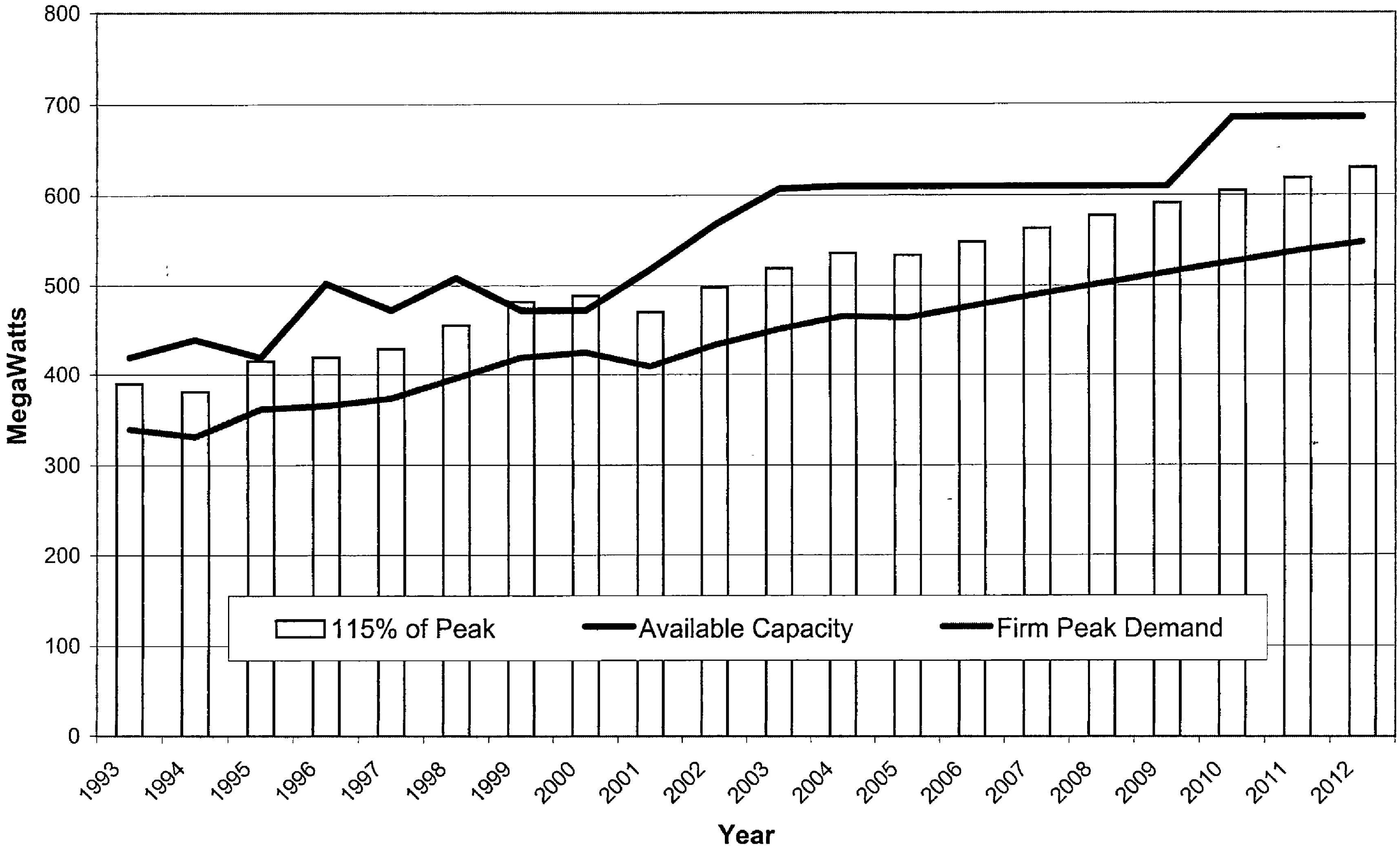
Each PDS will consist of one or more 138-12.47 KV, 33.6 MVA, wye-wye substation transformer with a maximum of eight distribution circuits. The proximity of these new PDSs to other, existing adjacent area substations will allow for backup in the event of a substation transformer failure.

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
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	610	0	93	0	517	409	108	26%	0	108	26%
2002	610	0	43	0	567	433	134	31%	0	134	31%
2003	610	0	3	0	607	451	156	35%	0	156	35%
2004	610	0	0	0	610	466	144	31%	0	144	31%
2005	610	0	0	0	610	464	146	31%	0	146	31%
2006	610	0	0	0	610	477	133	28%	0	133	28%
2007	610	0	0	0	610	490	120	24%	0	120	24%
2008	610	0	0	0	610	502	108	22%	0	108	22%
2009	610	0	0	0	610	514	96	19%	0	96	19%
2010	685	0	0	0	685	526	159	30%	0	159	30%
2011	685	0	0	0	685	538	147	27%	0	147	27%
2012	685	0	0	0	685	548	137	25%	0	137	25%

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

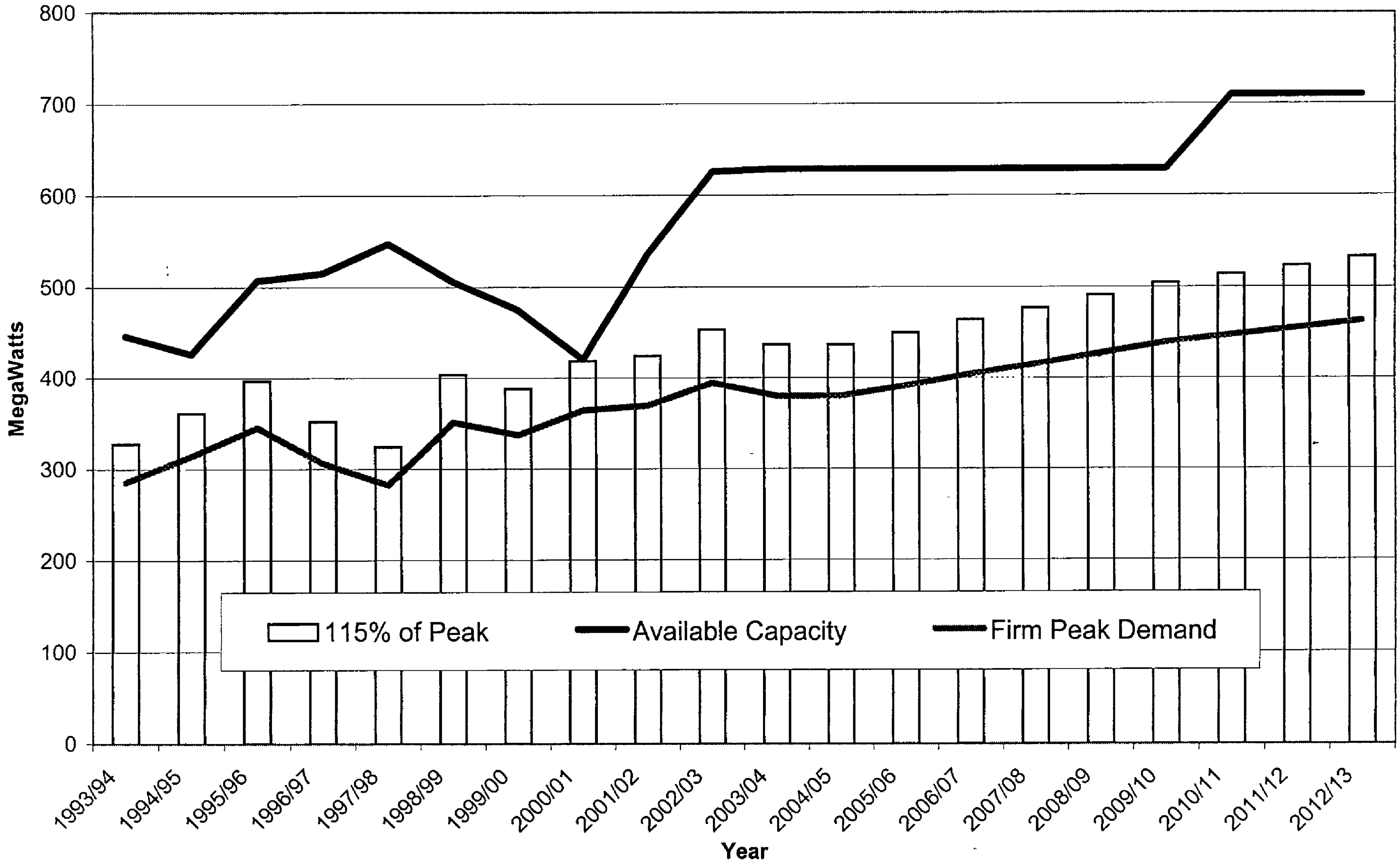
Gainesville Regional Utilities
Summer Peak Demand and Generation Capacity



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
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	629	0	93	0	536	369	167	45%	0	167	45%
2002/03	629	0	3	0	626	394	232	59%	0	232	59%
2003/04	629	0	0	0	629	380	249	66%	0	249	66%
2004/05	629	0	0	0	629	380	249	66%	0	249	66%
2005/06	629	0	0	0	629	391	238	61%	0	238	61%
2006/07	629	0	0	0	629	404	225	56%	0	225	56%
2007/08	629	0	0	0	629	415	214	52%	0	214	52%
2008/09	629	0	0	0	629	427	202	47%	0	202	47%
2009/10	629	0	0	0	629	439	190	43%	0	190	43%
2010/11	710	0	0	0	710	447	263	59%	0	263	59%
2011/12	710	0	0	0	710	455	255	56%	0	255	56%
2012/13	710	0	0	0	710	463	247	53%	0	247	53%

Gainesville Regional Utilities
Winter Peak Demand and Generation Capacity



Schedule 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								Const.	Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No,	Location	Type	Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	(MW)	(MW)	(MW)	(MW)	Status
Deerhaven	4	12-001 (Alachua Co., Sections 26,27,35, Township 8 S, Range 19 E) (GRU)	GT	NG	DFO	PL	TK	05/01/2006	05/01/2010	Unknown	76	82	75	81	P

Unit Type
GT = Combustion Turbine

Fuel Type
NG = Natural Gas
DFO = Fuel Oil #2 (Distillate)

Transportation Method
PL = Pipe Line
TK = Truck

Status
P = Planned, Not Approved

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Deerhaven GT04
(2)	Capacity	
	a. Summer	75 MW
	b. Winter	81 MW
(3)	Technology Type:	Combustion Turbine
(4)	Anticipated Construction Timing	
	a. Field construction start-date:	05/01/2006
	b. Commercial in-service date:	05/01/2010
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	Fuel Oil #2 (Distillate)
(6)	Air Pollution Control Strategy:	Low NOx Burners Water Injection on Diesel
(7)	Cooling Method:	Air cooled
(8)	Total Site Area (ft^2):	45,000
(9)	Construction Status:	Planned, Not Approved
(10)	Certification Status:	Not Applicable
(11)	Status with Federal Agencies:	Not Applicable
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF):	1.1%
	Forced Outage Factor (FOF):	1.0%
	Equivalent Availability Factor (EAF):	94.2%
	Resulting Capacity Factor (CF)	10.0%
	Average Net Operating Heat Rate (ANOHR):	11,989
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW):	450.00
	Direct Construction Cost ($/kW):	33.30
	AFUDC Amount ($/kW):	2.00
	Escalation:	3.00%
	Fixed O&M ($/kW-Yr):	1.40
	Variable O&M ($/MWh):	3.30
	K Factor:	Not Applicable

5. ENVIRONMENTAL AND LAND USE INFORMATION

5.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

Not applicable.

5.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

The proposed 75 MW combustion turbine will be located at the Deerhaven plant site, shown in Figure 2.1 and Figure 5.1, located north of Gainesville off U.S. Highway 441.

The proposed new unit is a simple-cycle combustion turbine (GT) that will be fired with either natural gas (primary fuel) and/or distillate oil (backup fuel). Construction on the proposed GT is expected to begin in May of 2006 and the unit is projected to be in commercial service by May of 2010.

<u>Land Use and Environmental Features</u>

a. The location of the Deerhaven Generating Station ("Site") is indicated on Figure 2.1 and Figure 5.1.
b. The general layout of the proposed combustion turbine unit on the Site is yet to be determined.
c. Figure 5.2 provides a photographic depiction of the land use and cover of the existing site and adjacent areas.
d. The existing land use of the site is industrial; surrounding land uses are primarily low-density residential, rural and agricultural.
e. The Deerhaven site encompasses approximately 1,146 acres, much of which is a natural buffer. Approximately 200 acres consist of wetlands. Surrounding areas are lightly urbanized and include natural habitat and agricultural lands.
f. Not applicable.

g. The City of Gainesville's land use designation for the Site is "public facilities", in reference to GRU. Adjacent areas include a mixture of residential, commercial, industrial and agricultural land uses. The Site and surrounding area is shown in Figure 5.2.
h. This site was selected for access to fuels and fuel storage and because impacts to the existing site and surrounding area will be minimal.
i. The site is located in the Suwanee River Water Management District.
j. There are no notable geologic features on this site or adjacent areas.
k. No increase in water quantities for potable uses is projected. However, there will be an increase in potable water usage if water injection is required as a NOx control measure. The groundwater allocation in the existing permit should be sufficient to accommodate the requirements of the Site in the future with the proposed new unit.
l. Water for potable use and for NOx control, if required, will be supplied via the City's potable water system. Groundwater is extracted from the Floridan aquifer.
m. Process water is collected, treated and reused on-site to the extent feasible.
n. No new discharges are anticipated.
o. Natural gas is delivered to the Deerhaven site by pipeline. Oil can be delivered to the site by rail or truck. The addition of the new unit will require additional natural gas pipeline capacity from the FGT mainline to the Deerhaven gate for the new unit.

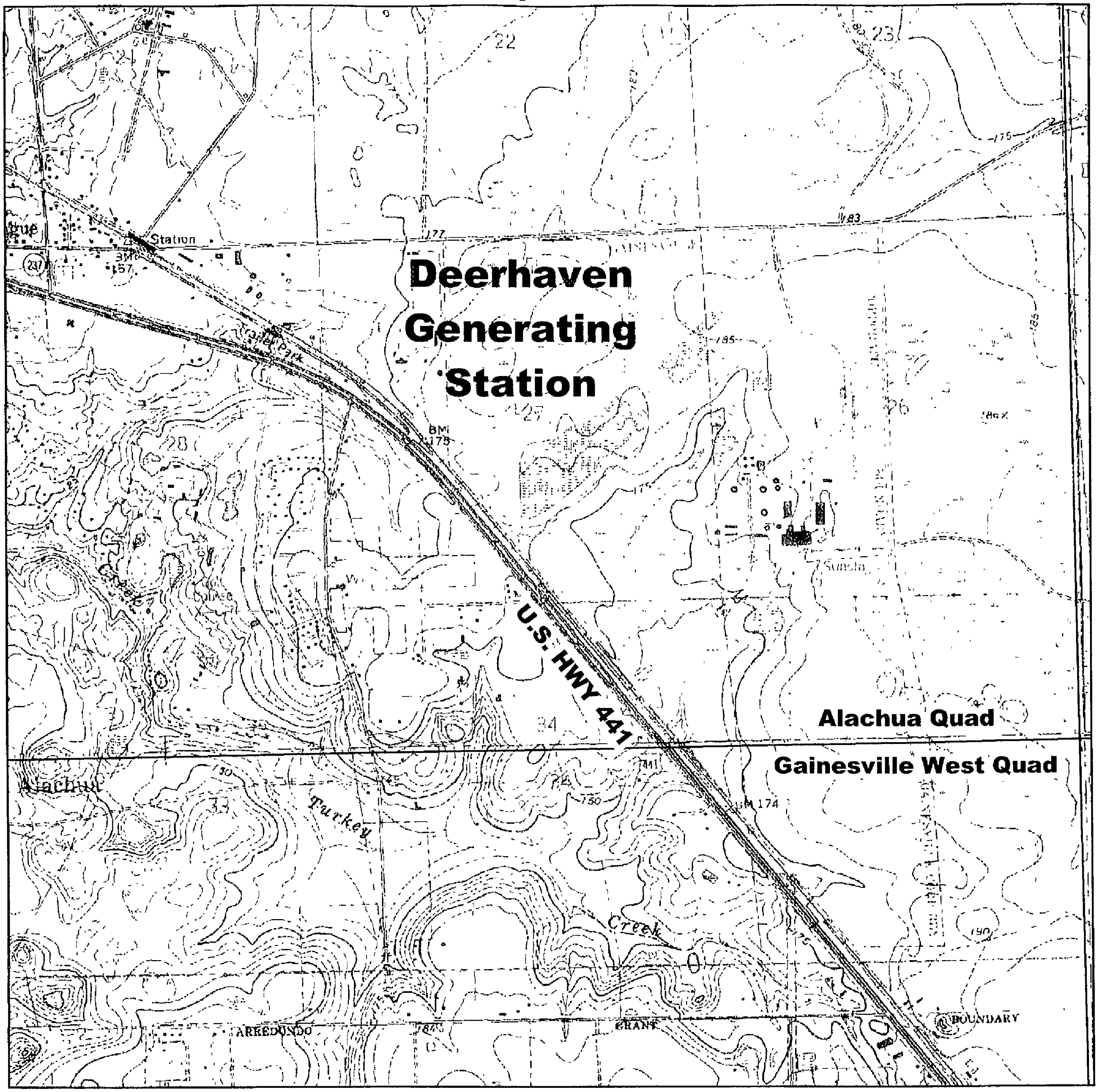
Air and Noise Emissions

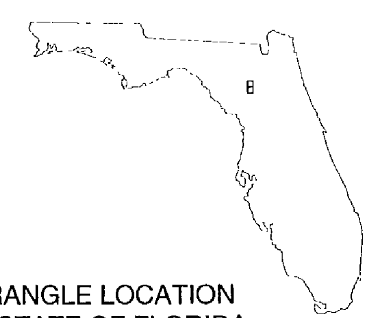
p. The new unit will be equipped with Best Available Control Technology for air emissions. This may consist of dry low-NO_x combustors and water injection for NO_x control while firing natural gas and distillate fuel oil, respectively, or catalytic reduction and/or oxidation for NOx and CO control, respectively.
q. The new unit will be equipped with noise abatement equipment including silencers and an acoustic barrier wall. The predicted noise impact is insignificant.

5.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Not applicable.

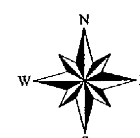
Figure 5-1





QUADRANGLE LOCATION
WITHIN STATE OF FLORIDA

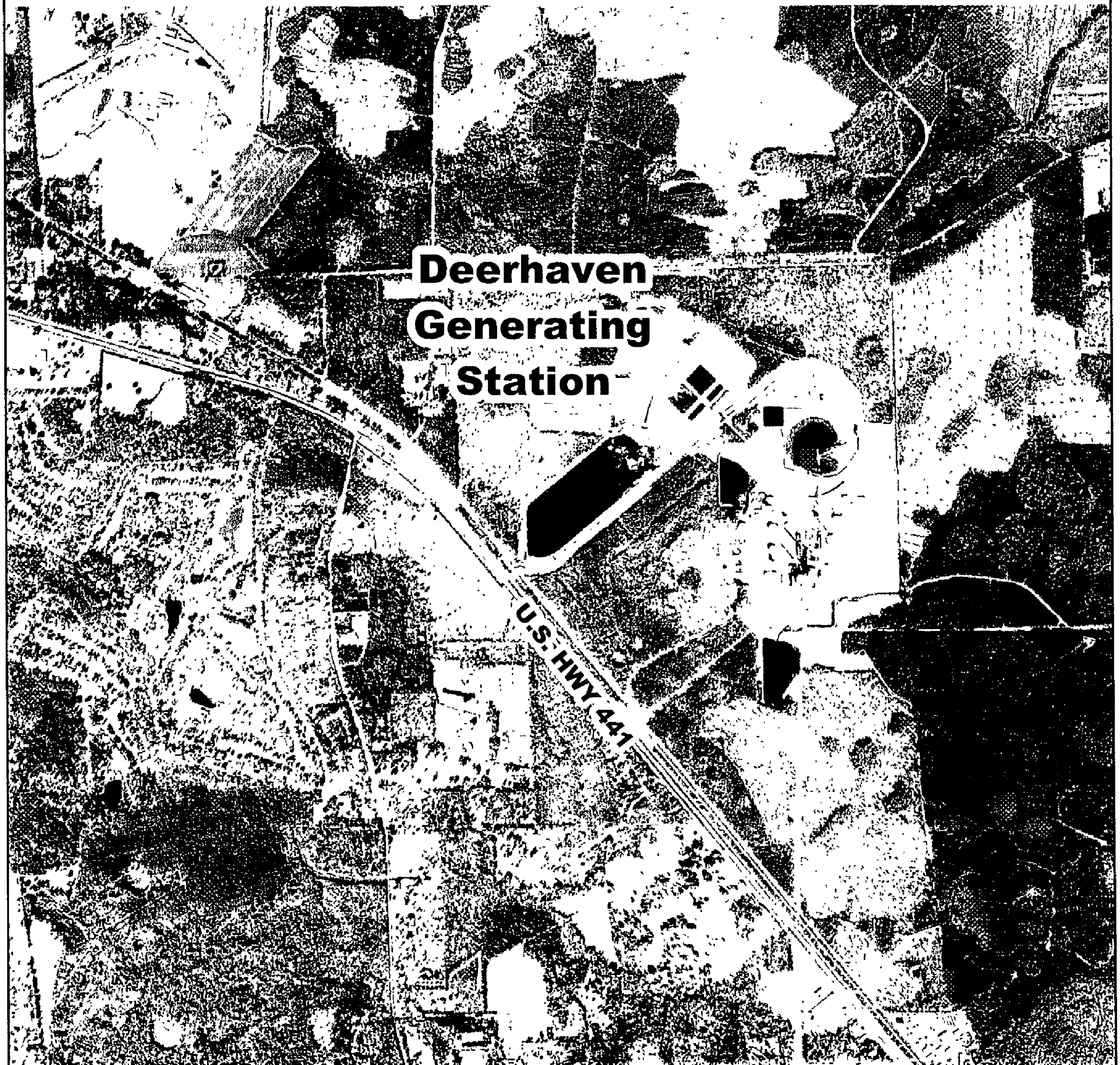
Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')

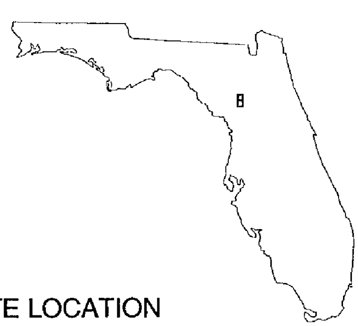


Location Map:
Deerhaven Generating Station

Data Source: USGS 7.5 Minute Quadrangle Maps :
Quad name-Alachua
Quad name-Gainesville West

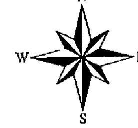
Figure 5-2





SITE LOCATION
WITHIN STATE OF FLORIDA

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



Aerial Photos:
Deerhaven Generating Station