Florida Municipal Power Agency

Ten Year Site Plan

April 1999

Florida Municipal Power Agency
Ten Year Power Plant Site Plan
1999-2008

submitted to

Florida Public Service Commission

Orlando, Florida
April 1, 1999

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EXECUTIVE SUMMARY

The following information is provided in accordance with Florida Public Service Commission rules 25-22.070, 25-22.071, and 25-22.072 which requires certain electric utilities in the State of Florida to submit a Ten Year Site Plan. The plan is required to describe the estimated electric power generating needs and to identify the general location of any proposed power plant sites.

The Florida Municipal Power Agency is a project-oriented, joint-action agency where each project is, in essence, a separate utility. The aggregate ownership of operational generation facilities for five separate Agency projects at December 31, 1998 was 478 MW of which 216 MW are owned by the All-Requirements Project.

The FMPA generation plans for municipal systems included in this report are as follows:

1999 Combustion Turbine (#2) at Stock Island	19 MW
1999 Combustion Turbine (#3) at Stock Island	19 MW
2001 Combined Cycle at Cane Island	125 MW
2007 Combustion Turbine (possible site - Cane Island)	80 MW

FMPA's direct responsibility for power supply planning can be separated into two parts. For the All-Requirements Project, where the Agency has committed to supply all the power requirements of several cities, the Agency is solely responsible for power supply planning. For member systems which are not in the All-Requirements Project, the Agency's role has been to evaluate joint action opportunities and make the findings available to the membership where each member can elect whether or not to participate. This report presents information on the aggregate of the existing and planned generation for all of the established Agency projects. The specific descriptions of existing and planned facilities include the current status of the aggregate of all the Agency projects. The sections on load forecasts and conservation programs provide information on the All-Requirements Project participants only.

In April 1996, FMPA and Florida Power & Light Company (FPL) consummated a network transmission agreement which initially served to implement network transmission service to the three existing FMPA All-Requirements Project members located in FPL's service area. In July 1996, FPL filed a proforma Open Access Transmission Tariff in compliance with Federal Energy Regulatory Commission (FERC) requirements which then superseded its April 1996 Agreement with FMPA. Under the new Tariff, any FMPA members connected to FPL's transmission grid may now integrate their loads and resources with FMPA's All-Requirements Project.

In the past calendar year, FMPA has added two additional members to the All-Requirements Project. They include the Ft. Pierce Utilities Authority and the Key West City Electric System. FMPA plans to add one additional member, the City of Lake Worth, in 2000. All of the firm power purchases and generating resources owned by Lake Worth will be incorporated into the All-Requirements Project as purchased capacity and energy contracts. As is done for its current All-Requirements members, FMPA will collectively plan for and provide all the power requirements (above certain excluded resources) for this city.

Section I
Description of FMPA

DESCRIPTION OF FMPA

General

The Florida Municipal Power Agency ("FMPA" or "Agency") was created on February 24, 1978, by the signing of the Interlocal Agreement among its 27 members, which agreement specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution; the Joint Power Act, which constitutes Chapter 361, Part II, as amended; and the Florida Interlocal Cooperation Act of 1969, which begins at Section 163.01 of the Florida Statutes, as amended. The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Organization and Management

Each city commission, utility commission, or authority which is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of the Agency. The Board has the responsibility of developing and approving the Agency's budget, hiring a General Manager, and establishing both bylaws which govern how the Agency operates and policies which implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary-Treasurer, Assistant Secretary-Treasurer, and an Executive Committee. The Executive Committee consists of nine representatives elected by the Board plus the then-current Chairman and Vice Chairman of the Board.

The Executive Committee meets regularly to control the Agency's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for assuring that budgeted expenditure levels are not exceeded and that authorized work is completed in a timely manner.

Agency Projects

FMPA currently has five power supply projects in operation: (i) the St. Lucie Project; (ii) the Stanton Project; (iii) the Tri-City Project; (iv) the All-Requirements Project and (v) the Stanton II Project.

St. Lucie Project: On May 12, 1983, the Agency purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit with a summer Seasonal Net Capability of approximately 839 MW and a winter Seasonal Net Capability of approximately 853 MW. St. Lucie Unit No. 2 was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of the Agency's members are participants in the St. Lucie Project.

Stanton Project: On August 13, 1984, the Agency purchased from the Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit No. 1, a coal-fired electric generation unit with a nominally-rated net high dispatch capacity of 428 MW. Stanton Unit No. 1 went into commercial operation July 1, 1987. Six of the Agency's members are participants in the Stanton Project.

Tri-City Project: On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton Unit No. 1. Three of the Agency's members are participants in the Tri-City Project.

All-Requirements Project: Under the All-Requirements Project, the Agency currently serves all the power requirements (above certain excluded resources) for ten of its members. In 1997, the cities of Vero Beach and Starke joined the All-Requirements

Project. In January, 1998, Fort Pierce Utilities Authority became an All-Requirements member. Key West joined the Project in April, 1998. The City of Lake Worth is anticipated to be included in the All-Requirements Project sometime in 2000. The current supply resources of the Project include: (i) the purchase of a 6.5060 percent undivided ownership interest in Stanton Unit No. 1 from OUC; (ii) capacity and energy from FMPA's 39 percent undivided ownership interest in two 37 MW combustion turbines (Units A and B) at the OUC Indian River Plant; (iii) capacity and energy from FMPA's 21 percent undivided ownership interest in two 129 MW combustion turbines (Units C and D) at the OUC Indian River Plant; (iv) capacity and energy from FMPA's 50 percent undivided ownership interest in a 30 MW combustion turbine (Cane Island Unit 1) and a 120 MW combined cycle (Cane Island Unit 2) at Kissimmee Utility Authority's (KUA) Cane Island Power Park; (v) capacity and energy purchases from other utilities including OUC, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), Tampa Electric Company (TECo), the City of Lake Worth, Gainesville Regional Utilities and others; (vi) necessary transmission arrangements; and (vii) required dispatching services. On June 6, 1991, the Agency for the All-Requirements Project purchased from OUC a 5.1724 percent undivided ownership interest in OUC's Stanton Unit No. 2, which went into commercial operation in June, 1996. Additional capacity that will be available in the near future includes two reconditioned combustion turbines currently being installed in the Key West City Electric System. Expected to go into commerical operation in the summer of 1999, FMPA will assume ownership of these two 19 MW (each) units at that time. With the addition of the four cities to the All-Requirements Project in 1997 and 1998, the supply resources of the All-Requirements Project include capacity and energy purchases from each of these cities for city-owned generation and/or firm power resources.

Stanton II Project: On June 6, 1991, the Agency, under the Stanton II Project, purchased from OUC a 23.2 percent undivided ownership interest in OUC's Stanton Unit No. 2, a coal-fired unit virtually identical to Stanton Unit No. 1. The unit commenced commercial operation in June, 1996. Seven of the Agency's members are participants in the Stanton II Project. Table I-1 gives a summary of member participation by project.

Summary of Project Participants
Table I-1

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All Requirements Project	Stanton II Project
City of Alachua	X				
City of Bartow					
City of Bushnell				X	
City of Clewiston	X			X	
City of Ft Meade	X				
Ft Pierce Utilities Authority	X	X	X	X	X
Gainesville Regional Utilities					
City of Green Cove Springs	X			X	
Town of Havana					
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Key West City Electric System			X	X	X
Kissimmee Utility Authority	X	X			X
City of Lakeland Electric & Water					
City of Lake Worth	X	X		P (2000)	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Mt Dora					
City of Newberry	X				
City of New Smyrna Beach	X				
City of Ocala				X	
Orlando Utilities Commission					
City of St. Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X	X
City of Wauchula					
City of Williston					

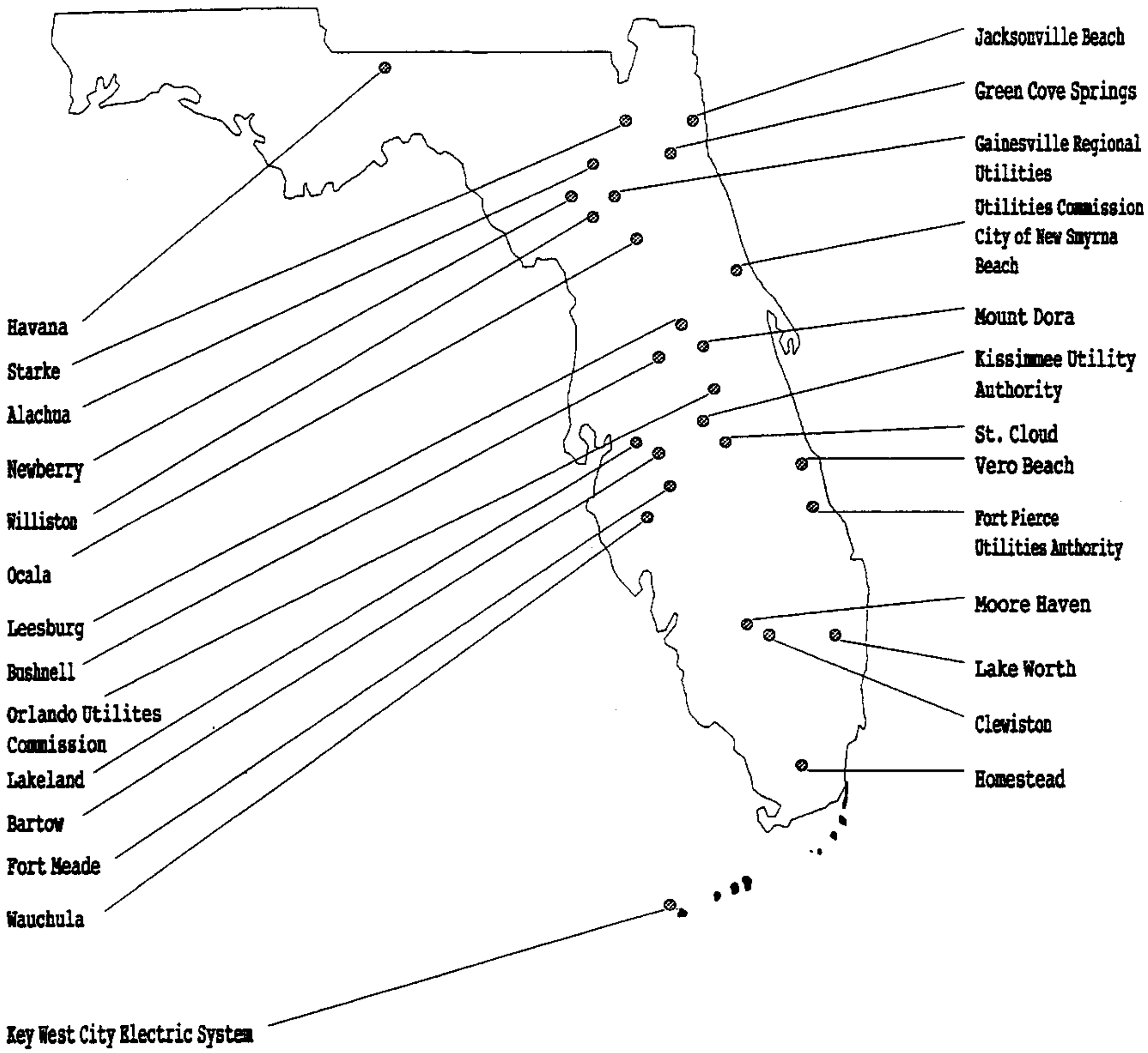
Section II

Description of Existing Facilities

DESCRIPTION OF EXISTING FACILITIES

Section II contains a map showing the location of FMPA members and descriptive data for FMPA generating facilities.

FLORIDA MUNICIPAL POWER AGENCY



Schedule 1
Existing Generating Facilities
As of December 31, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.				Net Capability	
Plant Name	Unit No.	Location	Unit Type	Fuel Primary	Fuel Alternate	Fuel Transport Primary	Fuel Transport Alternate	Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate kW	Summer MW	Winter MW
St. Lucie	2	12-111	NP	UR		TK			8/83	UNK	839,000	74.0	75.0
Stanton Energy Center	1	12-095	BIT	BIT		RR			7/87	UNK	464,580	115.0	115.0
	2	12-095	BIT	BIT		RR			6/96	UNK	464,580	122.0	122.0
Indian River	CT A	12-009	GT	NG	FO2	PL	TK		6/89	UNK	41,400	14.5	18.5
Indian River	CT B	12-009	GT	NG	FO2	PL	TK		7/89	UNK	41,400	14.5	18.5
Indian River	CT C	12-009	GT	NG	FO2	PL	TK		8/92	UNK	112,040	22.0	27.0
Indian River	CT D	12-009	GT	NG	FO2	PL	TK		10/92	UNK	112,040	22.0	27.0
Cane Island	1		GT	NG	FO2	PL	TK		1/95	UNK	40,000	15.2	15.2
Cane Island	2		CC	NG	FO2	PL	TK		6/95	UNK	122,000	54.4	60.2

Section III

Forecast of Demand and Energy
for the All-Requirements
Power Supply Project

FORECAST OF DEMAND AND ENERGY FOR THE ALL-REQUIREMENTS POWER SUPPLY PROJECT

Introduction

The basis for any determination of additional capacity commitments is the load forecast. This necessitates that great care be exercised when projecting future demand and energy requirements. FMPA is responsible for preparing load and energy projections for each of the All-Requirements Project participants. The forecast process includes existing ARP member cities and identifies future cities that are likely to become Project members. Forecasts are prepared on an individual city basis and then aggregated into projections of FMPA demand and energy requirements.

Compared to more simplistic linear trend forecasting models, statistical models such as those used by FMPA are more costly to implement but allow the analyst greater insight into the factors that actually drive the demand for electricity. The type of forecasting processes used by FMPA strikes an appropriate balance between cost and the level of sophistication required to adequately plan for future power supply requirements. The tools utilized by FMPA allow great flexibility in assessing the impact of numerous driving factors on electric load growth and provide the ability to assess alternative growth scenarios.

Methodology

In preparing forecasts, FMPA analyzes and projects the major driving factors that are related to the demand for electricity by its members. These factors include demographic factors (population and customer growth), weather impacts on loads, economic conditions, conservation programs and large incremental changes (new cities) which may impact the forecast. FMPA projects energy required for load using recognized modeling techniques and then estimates winter and summer peak demands using load factor analysis.

To estimate All-Requirements Project member energy requirements, several relatively standardized techniques are utilized including:

- Econometric modeling of member customer class requirements
- Aggregate econometric modeling of system requirements
- Statistical Time Series Analysis Techniques (Box Jenkins, ARIMA, Regression)
- Incremental load analysis
- Informed Judgement.

In analyzing the relationship between energy requirements and driving variables, FMPA utilizes a commercially available software package to perform statistical analysis and prepare standardized tests of statistical significance to evaluate alternative forecast models. Once a model is selected, energy forecasts are prepared using the selected model and forecast assumptions for driving variables used by the model (customers, weather, economics, etc.). Forecasted energy is then analyzed for reasonableness, compared to historical patterns and modified as appropriate using informed judgement and appropriate incremental load additions or reductions.

As part of the forecasting process, FMPA evaluates standardized statistical measurements to assess:

- The overall significance of the forecast model
- The statistical significance of individual driving variables
- The relative explanatory performance of the model
- The validation of model structure for complexity and dynamics
- The utilization of these types of tests to permit the development of forecast models which are statisitically valid and appropriate for use in forecasting.

It is important to note that no matter how sophisticated and reliable a model appears to be based upon historical relationships and statistical validation, a model is a simplification of the actual process and cannot capture every nuance of cause and effect relations. Thus, differences between load forecasts and actual realized loads will always occur. Additionally, since we live in a dynamic world that is constantly changing, the occurrence of forecasting error is unavoidable. However, every effort is be made to minimize error through the use of sensitivity or uncertainty analysis.

The primary method for dealing with load forecast uncertainty is to prepare alternative forecasts by assuming different scenarios of events that will impact the forecast. FMPA has chosen to capture the potential levels of forecast uncertainty by establishing bandwidths around the base case demand and energy forecasts. This procedure corresponds with statistical theory that indicates that, in absolute terms, the level of forecast uncertainty will increase as the forecast progresses into future years. For example, in 2000 the uncertainty range for the FMPA/ARP summer peak load is 53 MW. By 2010 the uncertainty range has grown to 368 MW.

Results

FMPA forecasts continued economic growth for the service territory based largely on the projected growth in the U.S. Gross Domestic Product (GDP) of approximately two to three percent per year. Inflation is projected to remain at low levels and the price of electricity is expected to remain constant throughout the forecast period. Normal weather conditions are assumed for this forecast. Final forecast results give the All-Requirements Project an average annual compounded growth of 2.0% for Net Energy for Load and 1.7% for Peak Demand.

Schedule 2.1
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential					Commercial	
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
1989								
1990								
1991								
1992			857	72,303	11.86	1,000	13,082	76.44
1993			910	73,460	12.39	1,044	13,259	78.71
1994			962	74,817	12.86	1,091	14,179	76.96
1995			1,041	76,070	13.69	1,146	13,766	83.25
1996			1,072	77,423	13.84	1,163	14,141	82.21
1997			1,234	103,507	11.92	1,380	19,723	69.96
1998			1,878	141,969	13.23	1,919	27,302	70.28
1999			2,009	149,770	13.41	2,333	27,719	84.15
2000			2,073	175,089	11.84	2,498	31,277	79.88
2001			2,115	176,868	11.96	2,595	31,734	81.76
2002			2,155	178,633	12.06	2,646	32,161	82.27
2003			2,193	180,311	12.16	2,696	32,563	82.80
2004			2,230	181,890	12.26	2,745	32,955	83.30
2005			2,265	183,382	12.35	2,793	33,338	83.79
2006			2,298	184,741	12.44	2,840	33,705	84.26
2007			2,329	186,005	12.52	2,885	34,047	84.72
2008			2,358	187,135	12.60	2,927	34,354	85.20

Schedule 2.2
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
All-Requirements Project

(1) Year	(2) GWh	(3) Industrial Average No. of Customers	(4) Average kWh Consumption Per Customer	(5) Railroads and Railways GWh	(6) Street & Highway Lighting GWh	(7) Other Sales to Public Authorities GWh	(8) Total Sales to Ultimate Consumers GWh
1989							0
1990							0
1991							0
1992					52	7	1,916
1993					48	9	2,011
1994					59	10	2,122
1995					65	11	2,263
1996					76	10	2,321
1997					62	14	2,690
1998					75	15	3,887
1999					78	15	4,436
2000					84	15	4,670
2001					85	15	4,810
2002					86	16	4,903
2003					87	16	4,991
2004					88	16	5,078
2005					88	16	5,162
2006					89	16	5,243
2007					90	16	5,320
2008					90	16	5,392

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
1989			0		0
1990			0		0
1991			0		0
1992		127	2,043		85,385
1993		134	2,145		86,719
1994		66	2,188		88,996
1995		80	2,343		89,836
1996		84	2,405		91,564
1997		162	2,850		123,230
1998		670	4,557		169,271
1999		225	4,661		177,489
2000		394	5,064		206,366
2001		479	5,283		208,602
2002		487	5,384		210,794
2003		496	5,481		212,874
2004		503	5,575		214,845
2005		509	5,665		216,720
2006		515	5,752		218,446
2007		520	5,834		220,052
2008		526	5,912		221,489

Schedule 3.1
History and Forecast of Summer Peak Demand
All-Requirements Project - 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 Load Conservation	(10) Net Firm Demand
1989	----				----				----
1990	405				----				405
1991	418				----				418
1992	451				----				451
1993	468				----				468
1994	454				----				454
1995	504				----				504
1996	509				----				509
1997	644				----				644
1998	946				----				946
1999	940				3.8				936
2000	1,041				4.0				1,037
2001	1,062				4.2				1,058
2002	1,082				4.5				1,078
2003	1,102				4.7				1,098
2004	1,121				4.8				1,117
2005	1,140				5.0				1,135
2006	1,158				5.1				1,152
2007	1,174				5.2				1,169
2008	1,190				5.3				1,185

Schedule 3.2
History and Forecast of Winter Peak Demand
All-Requirements Project - 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 Load Conservation	(10) Net Firm Demand
1989	----				----				----
1990	453				----				453
1991	373				----				373
1992	426				----				426
1993	410				----				410
1994	442				----				442
1995	503				----				503
1996	553				----				553
1997	499				----				499
1998	686				----				686
1999	962				6.3				956
2000	984				6.8				977
2001	1,084				7.2				1,077
2002	1,106				7.6				1,098
2003	1,127				7.9				1,119
2004	1,147				8.2				1,139
2005	1,167				8.5				1,158
2006	1,185				8.7				1,176
2007	1,203				8.9				1,194
2008	1,219				9.0				1,210

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWh
All-Requirements Project - Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1989	----						----	----
1990	1,846						1,846	47%
1991	1,980						1,980	54%
1992	2,043						2,043	52%
1993	2,145						2,145	52%
1994	2,188						2,188	55%
1995	2,343						2,343	53%
1996	2,405						2,405	50%
1997	2,845						2,845	50%
1998	4,457						4,457	54%
1999	4,661						4,661	55%
2000	5,064						5,064	59%
2001	5,283						5,283	56%
2002	5,384						5,384	56%
2003	5,481						5,481	56%
2004	5,575						5,575	55%
2005	5,665						5,665	55%
2006	5,752						5,752	55%
2007	5,834						5,834	55%
2008	5,912						5,912	55%

Schedule 3.1
History and Forecast of Summer Peak Demand
All Requirements Project - High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
1989	----				----				----
1990	----				----				----
1991	----				----				----
1992	----				----				----
1993	----				----				----
1994	----				----				----
1995	----				----				----
1996	----				----				----
1997	----				----				----
1998	----				----				----
1999	953				3.7				949
2000	1,077				3.9				1,073
2001	1,121				4.1				1,117
2002	1,164				4.3				1,160
2003	1,207				4.6				1,203
2004	1,249				4.8				1,244
2005	1,291				4.9				1,286
2006	1,331				5.1				1,326
2007	1,370				5.2				1,365
2008	1,408				5.3				1,402

Schedule 3.2
History and Forecast of Winter Peak Demand
All Requirements Project - High 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 Load Conservation	(10) Net Firm Demand
1989	----				----				----
1990	----				----				----
1991	----				----				----
1992	----				----				----
1993	----				----				----
1994	----				----				----
1995	----				----				----
1996	----				----				----
1997	----				----				----
1998	----				----				----
1999	977				6.0				971
2000	1,021				6.4				1,015
2001	1,147				6.9				1,140
2002	1,193				7.3				1,186
2003	1,239				7.8				1,231
2004	1,283				8.1				1,275
2005	1,327				8.4				1,319
2006	1,370				8.7				1,361
2007	1,411				8.9				1,402
2008	1,450				9.1				1,441

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWh
All-Requirements Project - High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1989							----	----
1990							----	----
1991							----	----
1992							----	----
1993							----	----
1994							----	----
1995							----	----
1996							----	----
1997							----	----
1998							----	----
1999							4,712	56%
2000							5,224	58%
2001							5,557	55%
2002							5,769	55%
2003							5,978	55%
2004							6,184	55%
2005							6,386	55%
2006							6,583	55%
2007							6,773	55%
2008							6,955	55%

Schedule 3.1
History and Forecast of Summer Peak Demand
All-Requirements Project - Low 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 Load Conservation	(10) Net Firm Demand
1989	----				----				----
1990	----				----				----
1991	----				----				----
1992	----				----				----
1993	----				----				----
1994	----				----				----
1995	----				----				----
1996	----				----				----
1997	----				----				----
1998	----				----				----
1999	934				3.5				931
2000	1,024				3.7				1,020
2001	1,035				3.9				1,031
2002	1,045				4.1				1,040
2003	1,054				4.4				1,050
2004	1,063				4.6				1,059
2005	1,072				4.7				1,067
2006	1,080				4.9				1,076
2007	1,088				5.0				1,083
2008	1,096				5.1				1,091

Schedule 3.2
History and Forecast of Winter Peak Demand
All-Requirements Project - Low 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 Load Conservation	(10) Net Firm Demand
1989	----				----				----
1990	----				----				----
1991	----				----				----
1992	----				----				----
1993	----				----				----
1994	----				----				----
1995	----				----				----
1996	----				----				----
1997	----				----				----
1998	----				----				----
1999	956				5.8				950
2000	967				6.2				961
2001	1,055				6.7				1,048
2002	1,066				7.1				1,059
2003	1,076				7.4				1,068
2004	1,086				7.7				1,078
2005	1,095				8.0				1,087
2006	1,103				8.3				1,095
2007	1,112				8.5				1,103
2008	1,119				8.7				1,111

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWh
All-Requirements Project - Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1989							----	----
1990							----	----
1991							----	----
1992							----	----
1993							----	----
1994							----	----
1995							----	----
1996							----	----
1997							----	----
1998							----	----
1999							4,636	57%
2000							4,984	59%
2001							5,150	56%
2002							5,199	56%
2003							5,247	56%
2004							5,291	56%
2005							5,334	56%
2006							5,375	56%
2007							5,414	56%
2008							5,450	56%

Schedule 4

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

All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 1998		Forecast - 1999		Forecast - 2000	
	Peak Demand	NEL	Peak Demand	NEL	Peak Demand	NEL
Month	MW	GWh	MW	GWh	MW	GWh
January	570	284	962	362	984	370
February	651	263	806	319	807	326
March	686	291	702	345	717	352
April	690	333	692	337	707	344
May	860	409	833	408	851	417
June	946	484	886	429	985	479
July	892	483	907	475	1,004	529
August	939	476	940	489	1,041	545
September	855	416	866	436	964	486
October	832	398	754	378	839	422
November	655	329	658	323	735	359
December	632	349	787	360	866	398

Section IV

Conservation Programs

CONSERVATION PROGRAMS

Introduction

FMPA's demand side programs are designed to improve efficiency, implement direct control of residential appliances, encourage time-of-use rates, and achieve additional conservation through commercial and industrial audits.

FMPA's members promote their conservation programs by providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, and so forth. These presentations are given both in person and on video tape. Additionally, bill inserts are utilized to keep customers aware of available conservation programs. FMPA will continue to expand services as needed to assist members in increasing the promotion and use of conservation programs to retail customers and will assist all of its members in the evaluation of any new programs to ensure their cost effectiveness.

FMPA is also assisting in the development of renewable energy resources by participating in the Utility Photovoltaic Group (UPG). UPG is a non-profit organization formed to accelerate the commercialization of photovoltaic systems for the benefit of electric utilities and their customers.

Existing Conservation Programs

FMPA's All-Requirements Participants offer some or all of the following conservation programs:

1) Residential Energy Audits Program: This Program offers a walk-through audit to identify energy savings opportunities. Energy Star program planned to be offered October 1999.

2) High-Pressure Sodium Outdoor Lighting Conversion: This program replaces mercury-vapor street lights with high-pressure sodium lights.

3) Assistance for Commercial/Industrial Audits: Free on-site audits are conducted for all interested customers and recommendations are made for energy efficiency improvements. ESCO referral is also provided upon request.

4) Commercial Time-of-Use Program: Time-of-use rates are offered to commercial and industrial customers with the intention of shifting demand from peak to off-peak periods.

5) Natural Gas Promotion: During Energy Audits, recommend the conversion of old, inefficient electric heat and water heaters to natural gas when the conversion would benefit the customer.

6) Residential Load Management Program: This program is offered to customers with central electric heating, central air conditioning and electric water heating. The utility is allowed to control some or all of these appliances during periods of peak demand and the customer receives a fixed monthly credit on their bill for each device under control. The following table indicates the amount of summer and winter peak demand reduction and total net energy reduction attributable to this program.

7) Fix-Up Program for the Elderly and Handicapped: Weatherization measures that target low-income housing.

Section V

Forecast of Facilities Requirements

FORECAST OF FACILITIES REQUIREMENTS

For member cities not involved in the All-Requirements Project, the responsibility for planning their future generation and transmission requirements lies ultimately with the individual utility. For the FMPA St. Lucie, Stanton, Stanton II and Tri-City Projects, FMPA has no power supply planning responsibility. However, FMPA periodically reviews the supply plans that might be worthwhile for FMPA or the cities to consider.

FMPA's planning process involves evaluating new generating capacity, along with new purchased power options, if appropriate, and conservation measures that are planned and implemented by the All-Requirements Project participants. The planning process has also included periodic Requests for Proposals in an effort to consider all possible options. FMPA normally performs its generation expansion planning on a least-cost basis considering both new purchased-power options, as well as, options on construction of generating capacity. The generation expansion plan optimizes the planned mix of possible supply-side resources by simulating their dispatch for each year of the study period while considering variables including fixed and variable resource costs, fuel costs, planned maintenance outages, terms of purchase contracts, minimum reserve requirements and options for future resources. FMPA plans on an annual reserve level of approximately 18% of the summer peak, which is in compliance with the reserve margin criteria of the Florida Public Service Commission.

Currently, the Agency on behalf of the All-Requirements Project, is planning to add additional capacity in 1999, 2001 and 2007. In June, 1999 FMPA will assume ownership of two 19 MW combustion turbines currently being installed in the Key West City Electric System. Additionally, with the ability to add generation at the Cane Island Power Park, future new capacity will consist of 125 MW from a 250 MW "F" class combined cycle unit in 2001 and the entire capacity of an 80 MW combustion turbine planned to be on line in 2007. FMPA is actively working with the Kissimmee Utility Authority (KUA) on the construction of the combined cycle unit which is expected to commence commercial operation in June, 2001.

This "self-build" option was determined to be the best long-term alternative as a result of Requests for Proposals issued independently by KUA and FMPA in May, 1997. Although numerous competitive bids were considered, a new combined-cycle unit at the Cane Island site clearly "won" the competition as the most efficient, cost-effective option to provide much needed power for both utilities in 2001.

On September 17, 1998 the proposed Cane Island Unit 3 combined cycle unit was approved by the Florida Public Service Commission.

FMPA is continually reviewing its options, seeking joint participation when feasible, and may change the megawatts required, the year of installment, the type of generation, and/or the site as conditions change.

Schedule 5
Fuel Requirements - All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		**Units**	**Actual 1997**	**Actual 1998**	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	**Nuclear (a)**		Trillion BTU	5,687	7,955	3,810	4,785	5,887	4,769	5,887	4,785	5,887	4,769	5,887	5,120
(2)	**Coal**		1000 Ton	663	678	404	469	467	475	475	480	479	480	480	482
(3)	**Residual**	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	**Distillate**	Total	1000 BBL	0	23	1	4	1	1	1	1	13	6	20	57
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	0	23	1	4	1	1	1	1	13	6	20	57
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	**Natural Gas**	Total	1000 MCF	2,642	3,573	6,871	8,786	11,067	13,292	13,455	14,275	14,787	15,718	16,116	17,309
(14)		Steam	1000 MCF	0	0	797	1,247	600	417	482	705	991	1,481	1,515	2,285
(15)		CC	1000 MCF	2,072	2,478	4,377	5,485	8,621	11,239	11,290	11,731	11,758	12,050	12,254	12,457
(16)		CT	1000 MCF	570	1,095	1,697	2,054	1,846	1,636	1,684	1,839	2,038	2,187	2,348	2,567
(17)	**Other (Specify)**		Trillion BTU												

(a) Nuclear generation is not part of the All-Requirements Project power supply. It is owned directly by some Project participants.

Schedule 6.1
Energy Sources - All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Energy Sources		Units	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		GWh	362	1,700	2,512	2,443	2,186	2,027	2,003	2,096	2,039	2,138	2,067	2,092
(2)	Nuclear (a)		GWh	529	740	354	445	548	444	548	445	548	444	548	476
(3)	Residual	Total	GWh	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(4)		Steam	GWh												
(5)		CC	GWh												
(6)		CT	GWh												
(7)		Diesel	GWh												
(8)	Distillate	Total	GWh	0	4	0.3	2.7	0.5	0.7	0.8	1.3	5.5	4.0	8.8	21.0
(9)		Steam	GWh								0	0	0	0	0
(10)		CC	GWh								0	0	0	0	0
(11)		CT	GWh		4	0.1	0.6	0.1	0.2	0.1	0.2	2.3	1.0	3.4	9.8
(12)		Diesel	GWh			0.2	2.0	0.4	0.5	0.7	1.1	3.2	3.0	5.4	11.2
(13)	Natural Gas	Total	GWh	334	427	805	1,024	1,405	1,749	1,765	1,857	1,898	1,991	2,033	2,141
(14)		Steam	GWh			66	104	50	35	40	59	83	123	126	190
(15)		CC	GWh	296	354	625	784	1,232	1,606	1,613	1,676	1,680	1,721	1,751	1,780
(16)		CT	GWh	38	73	113	137	123	109	112	123	136	146	157	171
(17)	Other (Coal)		GWh	1,625	1,661	989	1,149	1,144	1,163	1,164	1,176	1,174	1,175	1,177	1,182
(18)	Net Energy for Load		GWh	2,850	4,532	4,661	5,064	5,283	5,384	5,481	5,575	5,665	5,752	5,834	5,912

a) Nuclear generation is not part of the All-Requirements Project power supply. It is owned directly by some Project participants.

Schedule 6.2

Energy Sources - All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1997	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		%			53.9%	48.2%	41.4%	37.7%	36.5%	37.6%	36.0%	37.2%	35.4%	35.4%
(2)	Nuclear (a)		%			7.6%	8.8%	10.4%	8.2%	10.0%	8.0%	9.7%	7.7%	9.4%	8.1%
(3)	Residual	Total	%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(4)		Steam	%												
(5)		CC	%												
(6)		CT	%												
(7)		Diesel	%												
(8)	Distillate	Total	%			0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.4%
(9)		Steam	%												
(10)		CC	%												
(11)		CT	%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%
(12)		Diesel	%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.2%
(13)	Natural Gas	Total	%			17.3%	20.2%	26.6%	32.5%	32.2%	33.3%	33.5%	34.6%	34.9%	36.2%
(14)		Steam	%			1.4%	2.1%	0.9%	0.6%	0.7%	1.1%	1.5%	2.1%	2.2%	3.2%
(15)		CC	%			13.4%	15.5%	23.3%	29.8%	29.4%	30.1%	29.7%	29.9%	30.0%	30.1%
(16)		CT	%			2.4%	2.7%	2.3%	2.0%	2.0%	2.2%	2.4%	2.5%	2.7%	2.9%
(17)	Other (Coal)		%			21.2%	22.7%	21.7%	21.6%	21.2%	21.1%	20.7%	20.4%	20.2%	20.0%

(a) Nuclear generation is not part of the All-Requirements Project power supply. It is owned directly by some Project participants.

Schedule 7.1
Forecast of Capacity, Demand and Scheduled Maintenance at Time of Summer Peak
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity (2)	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Availability	System Firm Summer Peak Demand	Reserve Margin (1) before Maintenance		Scheduled Maintenance	Reserve Margin (1) after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1999	378	766	0	0	1,144	940	204	25	0	204	25
2000	407	840	0	0	1,247	1,041	206	21	0	206	21
2001	527	740	0	0	1,267	1,062	205	20	0	205	20
2002	527	756	0	0	1,283	1,082	201	18	0	201	18
2003	527	782	0	0	1,309	1,102	207	18	0	207	18
2004	527	802	0	0	1,329	1,121	208	18	0	208	18
2005	527	826	0	0	1,353	1,140	213	18	0	213	18
2006	527	844	0	0	1,371	1,158	213	18	0	213	18
2007	607	782	0	0	1,389	1,174	215	18	0	215	18
2008	607	807	0	0	1,414	1,190	224	18	0	224	18

(1) Reserve Margin includes resrves associated with partial requirements purchases.
(2) Includes nuclear capacity owned directly by some Project participants.

Schedule 7.2
Forecast of Capacity, Demand and Scheduled Maintenance at Time of Winter Peak
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (2) MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Availability MW	Winter Firm Summer Peak Demand MW	Reserve Margin (1) before Maintenance MW	Reserve Margin (1) before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin (1) after Maintenance MW	Reserve Margin (1) after Maintenance % of Peak
1999	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2000	404	766	0	0	1,170	984	186	21	0	186	21
2001	432	866	0	0	1,298	1,084	214	20	0	214	20
2002	552	737	0	0	1,289	1,106	183	16	0	183	16
2003	552	748	0	0	1,300	1,127	173	15	0	173	15
2004	552	773	0	0	1,325	1,147	178	15	0	178	15
2005	552	792	0	0	1,344	1,167	177	15	0	177	15
2006	552	815	0	0	1,367	1,185	182	15	0	182	15
2007	632	758	0	0	1,390	1,203	187	15	0	187	15
2008	632	778	0	0	1,410	1,219	191	15		191	15

(1) Reserve Margin includes resrves associated with partial requirements purchases.
(2) Includes nuclear capacity owned directly by some Project participants.

Section VI
Site and Facility Descriptions

SITE AND FACILITY DESCRIPTIONS

Cane Island Power Park

The planned Cane Island combined cycle unit will be located at Kissimmee's Cane Island Power Park south and west of the Kissimmee Utility Authority's (KUA) service area.

Environmental Considerations

The environmental impact of the Cane Island #3 unit will be minimal. The combined cycle plant will have emissions controlled to limit the impact on ambient air quality. Dry NOx technology is expected to be employed for control of nitrogen oxides. The increase in groundwater use should be minimal.

A detailed description of existing environmental conditions at the Cane Island site, along with environmental impacts and mitigation measures is presented in the "Need for Power" and "Site Certification" applications previously submitted for Cane Island #3 to the FPSC by KUA and FMPA. Cane Island Units 1 and 2 are in commercial operation at this site. Unit 1 is a 40 MW (nameplate) simple-cycle combustion turbine. Unit 2 is a 120 MW (nameplate) combined cycle. The site is suitable for approximately 1,000 MW of capacity.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Alt.						
								Fuel	Commercial	Expected	Gen Max	Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Days	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Primary	Alternate	Primary	Alternate	Use	Month/Year	Month/Year	kW	MW	MW	Status
Stock Island	CT2	Monroe Co.	CT	FO2	FO2	TK	TK		6/99	UNK	19,000	17.5	17.5	V
Stock Island	CT3	Monroe Co.	CT	FO2	FO2	TK	TK		6/99	UNK	19,000	17.5	17.5	V
Cane Island	3	Osceola Co.	CC	NG	FO2	PL	TK		6/01	UNK	250,000	120.0	125.0	P
Cane Island	4	Osceola Co.	CT	NG	FO2	PL	TK		1/07	UNK	80,000	80.0	80.0	P

Schedule 9
Status Report and Specifications of Proposed Generating Facilities - All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number:**	Stock Island CT2
(2)	**Capacity**	
	a. Summer:	17.5
	b. Winter:	17.5
(3)	**Technology Type:**	Combustion Turbine
(4)	**Anticipated Construction Timing**	
	a. Field construction start date:	10/97
	b. Commercial in-service date:	6-01-99
(5)	**Fuel**	
	a. Primary fuel:	No. 2 oil
	b. Alternate fuel:	No. 2 oil
(6)	**Air Pollution Control Strategy:**	Water Injection
(7)	**Cooling Method:**	NA
(8)	**Total Site Area:**	
(9)	**Construction Status:**	Completion 5/99
(10)	**Certification Status:**	Approved
(11)	**Status with Federal Agencies:**	Permitted
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF):	8.0%
	Forced Outage Factor (FOF):	2.0%
	Equivalent Availability Factor (EAF):	90.0%
	Resulting Capacity Factor:	0.0%
	Average Net Operating Heat Rate (ANOHR):	15,000 BTU/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	21
	Total Installed Cost (In-service year $/kW):	300
	Direct Construction Cost ($/kW):	
	AFUDC Amount ($/kW):	11
	Escalation ($/kW):	
	Fixed O&M ($kW-Yr):	
	Variable O&M ($/MWh):	
	K Factor:	NA

Schedule 9
Status Report and Specifications of Proposed Generating Facilities - All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number:**	Stock Island CT3
(2)	**Capacity**	
	a. Summer:	17.5
	b. Winter:	17.5
(3)	**Technology Type:**	Combustion Turbine
(4)	**Anticipated Construction Timing**	
	a. Field construction start date:	10/97
	b. Commercial in-service date:	6-01-99
(5)	**Fuel**	
	a. Primary fuel:	No. 2 oil
	b. Alternate fuel:	No. 2 oil
(6)	***Air Pollution Control Strategy:***	Water Injection
(7)	**Cooling Method:**	NA
(8)	**Total Site Area:**	
(9)	***Construction Status:***	Completion 5/99
(10)	**Certification Status:**	Approved
(11)	**Status with Federal Agencies:**	Permitted
(12)	***Projected Unit Performance Data***	
	Planned Outage Factor (POF):	8.0%
	Forced Outage Factor (FOF):	2.0%
	Equivalent Availability Factor (EAF):	90.0%
	Resulting Capacity Factor:	0.0%
	Average Net Operating Heat Rate (ANOHR):	15,000 BTU/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	21
	Total Installed Cost (In-service year $/kW):	300
	Direct Construction Cost ($/kW):	
	AFUDC Amount ($/kW):	11
	Escalation ($/kW):	
	Fixed O&M ($kW-Yr):	
	Variable O&M ($/MWh):	
	K Factor:	NA

Schedule 9
Status Report and Specifications of Proposed Generating Facilities - All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number:**	Cane Island Unit 3
(2)	**Capacity**	
	a. Summer:	244 (95 F)
	b. Winter:	262 (59 F)
(3)	**Technology Type:**	Combined Cycle
(4)	**Anticipated Construction Timing**	
	a. Field construction start date:	10-01-99
	b. Commercial in-service date:	6-01-01
(5)	**Fuel**	
	a. Primary fuel:	Natural Gas
	b. Alternate fuel:	No. 2 oil
(6)	**Air Pollution Control Strategy:**	Dry NOx
(7)	**Cooling Method:**	Mechanical Cooling Towers
(8)	**Total Site Area:**	1,024 acres
(9)	**Construction Status:**	Not started
(10)	**Certification Status:**	Application approved by FPSC
(11)	**Status with Federal Agencies:**	Permitted for Units 1 & 2
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF):	4.3%
	Forced Outage Factor (FOF):	4.1%
	Equivalent Availability Factor (EAF):	91.8%
	Resulting Capacity Factor:	88.0%
	Average Net Operating Heat Rate (ANOHR):	6815 BTU/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	30
	Total Installed Cost (In-service year $/kW):	449
	Direct Construction Cost ($/kW):	320
	AFUDC Amount ($/kW):	21
	Escalation ($/kW):	---
	Fixed O&M ($kW-Yr):	2.27
	Variable O&M ($/MWh):	2.82
	K Factor:	NA

Schedule 9

Status Report and Specifications of Proposed Generating Facilities - All-Requirements Project

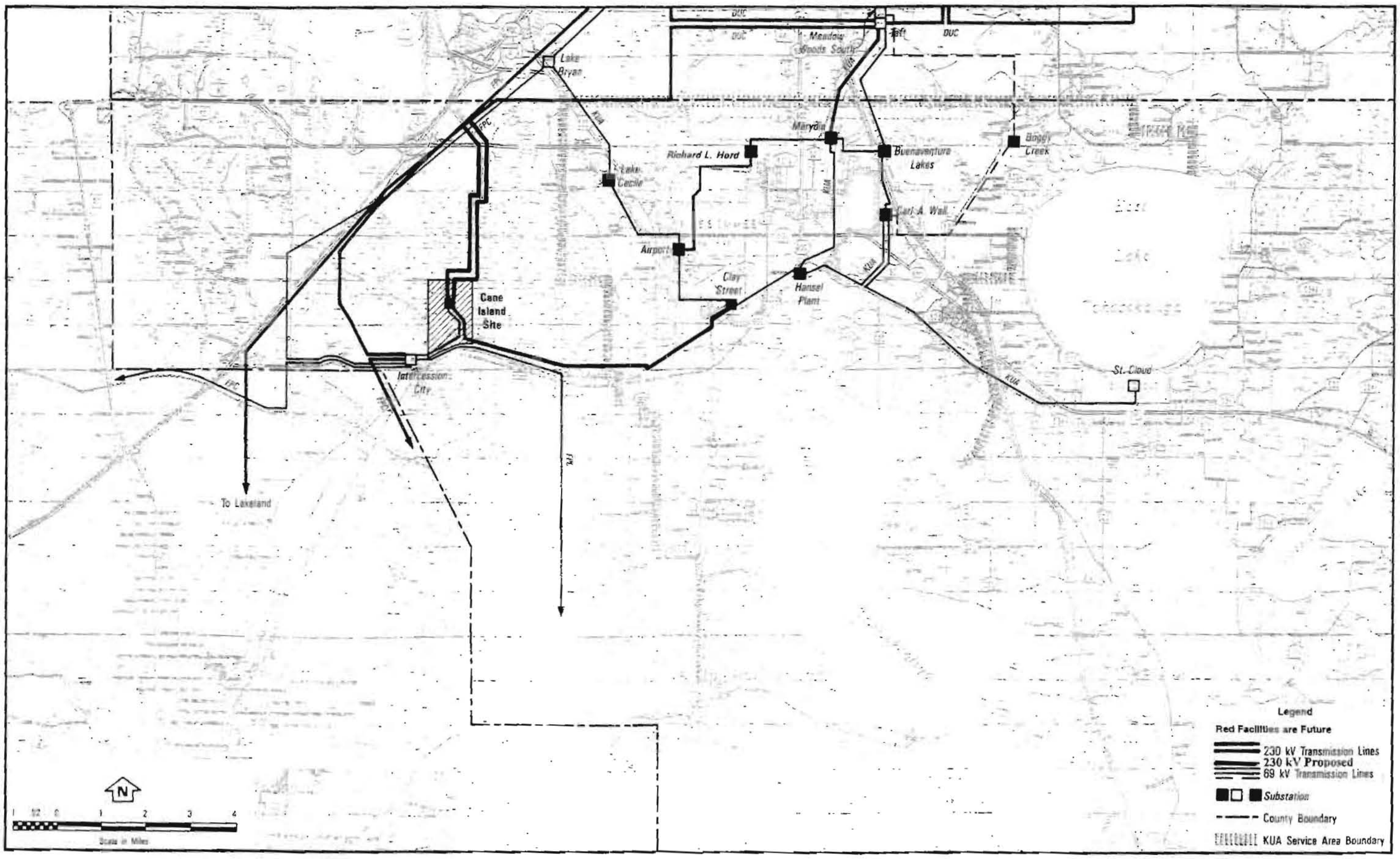
(Preliminary Information)

(1)	**Plant Name and Unit Number:**	Cane Island Unit 4
(2)	**Capacity**	
	a. Summer:	72 (95 F)
	b. Winter:	82 (59 F)
(3)	**Technology Type:**	Combustion Turbine
(4)	**Anticipated Construction Timing**	
	a. Field construction start date:	11-01-05
	b. Commercial in-service date:	01-01-07
(5)	**Fuel**	
	a. Primary fuel:	Natural Gas
	b. Alternate fuel:	No. 2 oil
(6)	**Air Pollution Control Strategy:**	Dry NOx
(7)	**Cooling Method:**	Not Applicable
(8)	**Total Site Area:**	1,024 acres
(9)	**Construction Status:**	Not started
(10)	**Certification Status:**	Not Applicable
(11)	**Status with Federal Agencies:**	Permitted for Units 1 & 2
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF):	2.4%
	Forced Outage Factor (FOF):	2.1%
	Equivalent Availability Factor (EAF):	95.6%
	Resulting Capacity Factor:	0.06%
	Average Net Operating Heat Rate (ANOHR):	11959 BTU/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	30
	Total Installed Cost (In-service year $/kW):	447
	Direct Construction Cost ($/kW):	291
	AFUDC Amount ($/kW):	11
	Escalation ($/kW):	62
	Fixed O&M ($kW-Yr):	3.32
	Variable O&M ($/MWh):	23.56
	K Factor:	NA

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines
All-Requirements Project

(1)	**Point of Origin and Termination:**	Cane Island Plant to Intercession City Plant (FPC)
(2)	**Number of Lines:**	one
(3)	**Right-of-Way:**	see map
(4)	**Line Length:**	3.0 miles
(5)	**Voltage:**	230 kV
(6)	**Anticipated Construction Timing:**	begin const 6/2000
(7)	**Anticipated Capital Investment:**	$6 million including substation work
(8)	**Substations:**	see above
(9)	**Participation with Other Utilities:**	KUA



Lake Bryan
Meadow Woods South
Taft
OUC
FPC
KUA
Richard L. Hord
Marydia
Buenaventura Lakes
Boggy Creek
Lake Cecile
Carl A. Wall
Airport
Clay Street
Hansel Plant
Cane Island Site
Intercession City
St. Cloud
East Lake Tohopekaliga
To Lakeland
FPL
Legend
Red Facilities are Future
230 kV Transmission Lines
230 kV Proposed
69 kV Transmission Lines
Substation
County Boundary
KUA Service Area Boundary
N
1 1/2 0 1 2 3 4
Scale in Miles