Cane Island Power Park
Unit 3

BLACK & VEATCH LLP

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1C.1.0 Overview and Summary

1C.1.1 Overview

Cane Island Unit 3 is planned as a new combined cycle addition to the existing Cane Island site, located in Osceola County. Cane Island Units 1 and 2, a combustion turbine and combined cycle burning natural gas, are currently operating. The Cane Island Site was licensed for an ultimate capacity of approximately 1,000 MW. Cane Island Unit 3 will provide very economical power for the Florida Municipal Power Agency (FMPA or Agency) All-Requirements Project members with a minimal environmental impact. Cane Island Unit 3 will be a 1x1 "F" class combined cycle unit. The actual output of the unit will depend upon the combustion turbine vendor selected and the design and size of the steam turbine. Output will also vary with degradation and ambient conditions. FMPA will be a 50 percent joint owner in Cane Island Unit 3. FMPA's portion of the nominal 250 MW of generation from Cane Island Unit 3 will be approximately 125 MW. Details specific to the project are presented in Volume 1A. This volume, Volume 1C, contains information specific to FMPA's need for the project.

FMPA strives to meet their responsibility to supply their member's loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. FMPA's rates to its All-Requirements members are among the lowest in the state due to strategic planning and ability to provide economies of scale to its smaller members.

FMPA is committed to meet its All-Requirements customers' needs and identify projects that will provide economical power to Peninsular Florida residents through the combination of demand-side and supply-side resources. Through the member cities, FMPA has been a strong supporter of conservation and demand-side programs where cost-effective. With FMPA's ability to pursue very economical supply-side resources, it is difficult for demand-side programs to be cost-effective.

A diversified mix of fuels for generation provides methods to reduce risk associated with fuel price volatility and supply risk. Cane Island Unit 3 provides the best alternative for fuel diversification for FMPA with the price of natural gas projected to remain low and the availability of natural gas to remain high throughout the planning horizon.

FMPA achieves savings through economy interchange and central dispatch which are obtained through participation in the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland, Kissimmee, and the FMPA All-Requirements Project. Since 1988, FMPP has saved its members an estimated $101.8 million.

FMPA's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with the Cane Island Unit 3 project. Cane Island Unit 3 will burn natural gas as the primary fuel with dry low NO_x burners providing a very clean burning high efficiency unit.

As discussed in the remainder of this application, FMPA has evaluated appropriate alternatives to Cane Island Unit 3 to determine if they are lower in cumulative present worth revenue requirements. As part of the evaluation process, FMPA together with KUA, issued a joint request for proposals (RFP) for power supply as an alternative to Cane Island Unit 3 in May 1997. FMPA's RFP requested bids for short-, mid-, and long-term power. Numerous bids were received and evaluated. All long-term bids received, that were feasible under current regulations in Peninsular Florida, resulted in an increase in present worth revenue requirements over Cane Island Unit 3. As a result, FMPA rejected all long-term bids and is pursuing the construction of Cane Island Unit 3. Short- and mid-term bids were evaluated from the RFP resulting in their selection for purchase power for short- and mid-term periods. Contracts for the purchase power are currently being pursued by FMPA.

FMPA believes that Cane Island Unit 3 represents the minimal cost and performance risk to its members due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Cane Island Unit 3 represents FMPA's least cost alternative that has been demonstrated through exhaustive evaluations as well as a thorough test of the marketplace.

1C.1.2 Summary

FMPA's All-Requirements has been growing rapidly through the addition of new members with Lake Worth projected to join in 1999. FMPA's peak demand is projected to grow at a 1.5 percent average annual rate from 1999 through the end of the planning period in 2017. The projected load growth assumes no new members will join after Lake Worth in 1999.

FMPA uses an 18 percent reserve margin as a reliability criteria. FMPA's reserve margin is projected to drop to 7.4 percent during the summer of 2001, dictating the need to add capacity.

FMPA received 33 proposals from 17 bidders from their May 1997 request for proposals (RFP) for purchase power. Proposals were received for short-, medium-, and long-term power. After an extensive evaluation, two of the bidders were short-listed for long-term power. Ultimately, both long-term bidders were rejected because both bidders proposed merchant plant projects using Westinghouse 501G combined cycle units. Recent FPSC decisions regarding requests for Declaratory Statements regarding merchant plants draw into serious question the ability of merchant plants to be constructed in time to meet FMPA's need for capacity in the summer of 2001. Furthermore, the Westinghouse 501G combustion turbine is not yet in commercial operation in the United States resulting in significant reliability and performance risk. As a result, FMPA selected Cane Island 3 to provide long-term power requirements.

After evaluation, FMPA short-listed six short- and medium-term bidders for negotiations. Ultimately, three of the bidders were eliminated since their proposals involved the development of merchant plants. FMPA is currently negotiating for short- and medium-term power with Lakeland Electric & Water, Lee County Solid Waste Management, and Orlando Utilities Commission representing all of the short-listed bidders that were not proposing merchant plants. In addition, FMPA is also negotiating with Tampa Electric Company for purchase power.

FMPA evaluated 10 generating unit alternatives with the EGEAS optional generation expansion model. EGEAS selected the installation of Cane Island 3 as a 501F combined cycle as the least cost alternative for the base case. In addition, FMPA evaluated seven sensitivity cases and EGEAS selected the 501F combined cycle in 2001 for all the sensitivity cases as the least cost alternative.

1C.2.0 Description of Existing Facilities

The Florida Municipal Power Agency (FMPA) was created on February 24, 1978, by signing of the Interlocal Agreement among its 27 members, which specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution, 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.

Each city 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 for 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 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.

1C.2.1 Generation System

FMPA is a project-oriented, joint action agency where each project stands on its own. 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. Each of the projects is summarized in Sections 1C.2.1.1 through 1C.2.1.5.

Table 1C.2-1 provides a summary of the member participation for each project. Figure 1C.2-1 illustrates the location of the FMPA member cities within Peninsular Florida. Table 1C.2-2 provides a summary for the existing FMPA generating facilities with project capacities combined where appropriate.

The 50 percent ownership share of Cane Island Unit 3 will be owned by the All-Requirements Project as is the 50 percent ownership share of Cane Island Units 1 and 2. As such, the need for Cane Island Unit 3 will be demonstrated by the All-Requirements Project.

1C.2.1.1 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 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 2 was declared in commercial operation 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 and seven of the fifteen are also members of the All-Requirements Project.

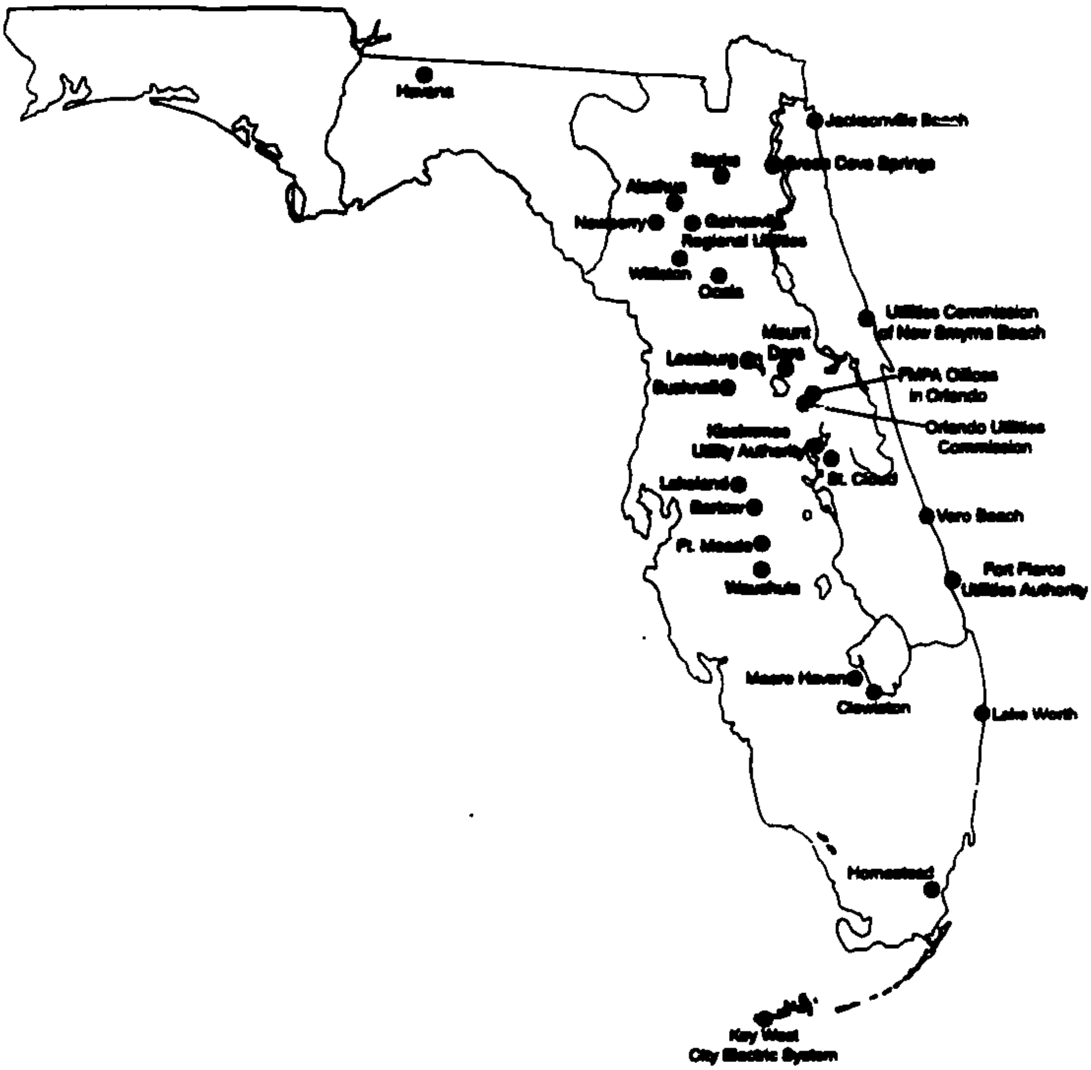
1C.2.1.2 Stanton Project

On August 13, 1984, the Agency purchased from Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit 1, a coal fired electric generation unit with a nominally rated, net high dispatch capacity of 465 MW. Stanton Unit 1 went into commercial operation July 1, 1987. Six of the Agency's members are participants in the Stanton Project and three of the six are also members of the All-Requirements Project.

1C.2.1.3 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 and two of the three are also members of the All-Requirements Project.

Table 1C.2-1 Summary of Project Participants					
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					
City of Lake Worth	X	X		P (1999)	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Mt. Dora					
City of Newberry	X				
Utilities Commission of New Smyrna Beach	X				
City of Ocala				X	
Orlando Utility 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					
P - Planned addition of new member.					



Member Cities
Figure 1C.2-1

Table 1C.2-2
Existing FMPA Generating Facilities
As of December 31, 1997 (1)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel		Fuel Transport					Net Capability[2]	
Plant Name	Unit No.	Location (County)	Unit Type	Pri	Alt	Pri	Alt	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate kW	Summer MW	Winter MW
St. Lucie	2	St. Lucie	NP	UR	--	TK	--	8/83	Unknown	839,000	74.0	75.0
Stanton Energy Center	1	Orange	ST	BIT	--	RR	--	7/87	Unknown	464,580	115.0	115.0
	2		ST	BIT	--	RR	--	6/96	Unknown	464,580	122.0	122.0
Indian River	CT A	Brevard	GT	NG	FO2	PL	TK	6/89	Unknown	41,400	14.0	18.5
	CT B		GT	NG	FO2	PL	TK	7/89	Unknown	41,400	14.0	18.5
	CT C		GT	NG	FO2	PL	TK	8/92	Unknown	112,040	22.0	27.0
	CT D		GT	NG	FO2	PL	TK	10/92	Unknown	112,040	22.0	27.0
Cane Island	1	Osceola	GT	NG	FO2	PL	TK	1/95	Unknown	42,000	15	20
	2		GT	NG	FO2	PL	TK	6/95	Unknown	120,000	54	60
Key West	2	Monroe	GT	FO2	--	WA	--	6/98	Unknown	19,000	17.7	17.7
	3		GT	FO2	--	WA	--	6/98	Unknown	19,000	17.7	17.7
Total											487.4	518.4

1. Also includes Key West GT's 2 and 3 with planned commercial operation dates in June 1998.
2. FMPA ownership share.

1C.2.1.4 All-Requirements Project

The All-Requirements Project was formed on May 1, 1986, with five members; other members have joined through the years. The All-Requirements Project participants now consist of City of Bushnell, City of Clewiston, Fort Pierce Utilities Authority, City of Green Cove Springs, City of Jacksonville Beach, City of Key West, City of Leesburg, Ocala Electric Utility, City of Starke, City of Vero Beach, with the City of Lake Worth Utilities planned to join in 1999. Under the All-Requirements Project, the Agency currently serves all the power requirements (above certain excluded resources) for the 10 members. In May 1991, the City of Clewiston became a member of the All-Requirements Project. In 1997, the Cities of Vero Beach and Starke joined, with Fort Pierce joining in January 1998 and Key West in April 1998. The City of Lake Worth is anticipated to join the All-Requirements Project sometime in 1999. Table 1C.2-3 shows the date that each member joined the All-Requirements Project. The current supply resources of the Project include: (i) the purchase of a 6.5060 percent undivided ownership interest in Stanton Unit 1 from OUC; (ii) capacity and energy from FMPA's 39 percent undivided ownership interest in two 41 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 112 MW combustion turbines (Units C and D) at the OUC Indian River Plant; (iv) capacity and energy from FMPA's 50 percent undivided interest in the 42 MW Cane Island Unit 1 combustion turbine and the 120 MW Cane Island Unit 2 combined cycle at the Cane Island Power Park; (v) the purchase of a 5.1724 percent undivided ownership interest in Stanton Unit 2 from OUC, (vi) capacity and energy purchases from other utilities including OUC, FPL, Florida Power Corporation (FPC), Tampa Electric Company (TECO), City of Lake Worth, and Gainesville Regional Utilities; (vii) necessary transmission arrangements; and (viii) required dispatching services. With Key West's recent decision to join the All-Requirements Project, FMPA awarded a contract for the turnkey purchase of two reconditioned combustion turbine generating units that total 38 MW nameplate that will be located at an existing Key West site. Both combustion turbines are Frame 5 GE models reconditioned back to zero hours of operation. With the addition of four generating cities to the All-Requirements Project in 1997 and 1998, the supply resources of the All-Requirements Project now include capacity and energy purchases from the

Table 1C.2-3
Summary of All-Requirements Project Participants
Date Member Joined

Agency Member	Date Member Joined
City of Bushnell	May 1, 1986
City of Clewiston	May 8, 1991
Ft. Pierce Utilities Authority	January 1, 1998
City of Green Cove Springs	May 1, 1986
City of Jacksonville Beach	May 1, 1986
Key West City Electric System	April 1, 1998
City of Lake Worth	1999
City of Leesburg	May 1, 1986
City of Ocala	May 1, 1986
City of Starke	October 1, 1997
City of Vero Beach	June 1, 1997

generation owned by each of these cities and/or firm power resources. Table 1C.2-4 provides a summary of the generating resources of the All-Requirements Project. This table does not include member generating resources, which are considered firm capacity purchases. The member generating resources are included in Section 1C.2.2.1. Table 1C.2-4 indicates 18 MW of generating capacity from Crystal River Unit 3 for the All-Requirements Project. This capacity in Crystal River Unit 3 is actually owned by several of the individual All-Requirements Project members, but FMPA is responsible for dispatching its capacity along with all other FMPA All-Requirement Project resources. Table 1C.2-4 indicates St. Lucie Unit 2 generating capacity which is also actually owned by several of the individual All-Requirements Project members and is also dispatched by FMPA. Table 1C.2-4 also indicates capacity from St. Lucie Unit 1. Certain All-Requirements Project members actually have ownership in St. Lucie Unit 2, but power is supplied equally from Units 1 and 2 through a reliability exchange agreement. The Stanton 1 and 2 capacity shown in Table 1C.2-4 includes the capacity owned by individual members as well as the capacity owned directly by the All-Requirements Project itself.

Table 1C.2-4
Existing All-Requirements Generating Facilities
As of December 31, 1997 (1)

(1) Plant Name	(2) Unit No.	(3) Location (County)	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Commercial In-Service Month/Year	(10) Expected Retirement Month/Year	(11) Gen Max Nameplate MW	(12) Net Capability² Summer MW	(13) Net Capability² Winter MW
Crystal River	3	Citrus	N	UR	--	TK	--	3/77	Unknown	890	18.0	18.0
Stanton Energy Center	1	Orange	ST	BIT	--	RR	-	7/87	Unknown	465	83	83
	2		ST	BIT	--	RR	--	6/96	Unknown	465	65	65
St. Lucie	1	St. Lucie	N	UR	-	TK	-	8/83	Unknown	839	17.5	18.0
	2		N	UR	--	TK	--		Unknown	839	17.5	18.0
Indian River	CT A	Brevard	GT	NG	FO2	PL	TK	6/89	Unknown	41.40	14.0	18.5
	CT B		GT	NG	FO2	PL	TK	7/89	Unknown	41.40	14.0	18.5
	CT C		GT	NG	FO2	PL	TK	8/92	Unknown	112.0	22.0	27.0
	CT D		GT	NG	FO2	PL	TK	10/92	Unknown	112.0	22.0	27.0
Cane Island	1	Osceola	GT	NG	FO2	PL	TK	1/95	Unknown	42	15	20
	2		CC	NG	FO2	PL	TK	6/95	Unknown	120	54	60
Key West	2	Monroe	GT	FO2	-	WA	-	6/98	Unknown	19.0	17.7	17.7
	3		GT	FO2	-	WA	-	6/98	Unknown	19.0	17.7	17.7
Total											377.4	408.4

1. Also includes Key West GT's 2 and 3 with planned commercial operation dates in June 1998.
2. All-Requirements Project ownership share.

The All-Requirements Project provides its members with all of their capacity and energy requirements above excluded resources which are the members' ownership in Crystal River Unit 3 and St. Lucie Unit 2. All-Requirements Project members which have joint ownership in other FMPA projects make available their joint ownership interests to the All-Requirements Project and the All-Requirements Project incorporates the capacity into the total project power supply. For All-Requirements Project members that own on-system generation, the All-Requirements Project purchases the capacity and energy from the on-system generation for use by the All-Requirements Project and then, in turn, supplies the members their full capacity and energy requirements. The All-Requirements Project members are responsible for maintenance and operation of their on-system generating units. The All-Requirements Project schedules the commitment and dispatch of the units. As a member of the Florida Municipal Power Pool (FMPP), the actual commitment and dispatch of units is conducted by FMPP for the All-Requirements Project.

1C.2.1.5 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 2, a coal fired unit virtually identical to Stanton Unit 1. The unit commenced commercial operation in June 1996. Seven of the Agency's members are participants in the Stanton II Project and four of the seven are also members of the All-Requirements Project.

1C.2.1.6 All-Requirements Project Participants

A brief description of each of the participants is provided in the following subsections.

1C.2.1.6.1 City of Bushnell. Bushnell, "Seat of Sumter County," is located in west central Florida, 55 miles from Orlando and 50 miles north of Tampa. The City operates under a Council-Manager form of government. Bushnell owns and operates its own electric and water system, the revenues from which are combined for financial purposes; thus, these utility services are integrated for purposes of the All-Requirements Power Supply Project Contract.

Bushnell is predominantly a rural community and local employment is mostly provided through retail establishments, government agencies, light manufacturing, service companies and agriculture. Bushnell usually has a slight population growth during the winter months due to returning visits of part-time residents from northern states.

The City of Bushnell entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Energy is delivered through a delivery point in the City at 12 kV. Excluded Power Supply Resources for the City of Bushnell include only its partial ownership in FPC's Crystal River 3 nuclear unit, which equals 0.0388 percent of that unit (or 306 kW based on current net summer rating).

The City of Bushnell's electric utility service area covers approximately 3 square miles and has a territorial agreement with a neighboring cooperative. Ninety-two percent of the customers served reside within the city limits.

1C.2.1.6.2 City of Clewiston. The City of Clewiston is located in Hendry County on the southwest tip of Lake Okeechobee, mid-way between West Palm Beach on the east and Fort Myers on the west. Clewiston is the headquarters of the United States Sugar Corporation. The City operates and maintains electric, water, and wastewater utilities.

The City of Clewiston purchased its electric system in May 1942, from U.S. Sugar Corporation. On May 8, 1991, Clewiston became an All-Requirements Project Participant. Excluded Power Supply Resources for the City of Clewiston include only its entitlement share in the Agency's St. Lucie Project (approximately 1,624 kW). The City's 138 kV transmission system interconnects with FPL. One substation supplies voltage at 12 kV to a predominantly overhead distribution system.

The City's electric utility service area encompasses approximately 8.5 square miles with 70 percent of the customers served residing within city limits. Clewiston has a territorial agreement with Glades Electric Cooperative and has a franchise from Hendry County to serve its current service area.

1C.2.1.6.3 City of Fort Pierce Utilities Authority. The City of Fort Pierce is located in St. Lucie County on the east coast of Florida approximately 125 miles north of Miami. The Fort Pierce Utilities Authority was established in 1972 for the purpose of governing and operating the City's electric, water, wastewater, and natural gas distribution utilities as a separate unit of City government. The City Commission appoints Utility Authority Members to overlapping 4 year terms, and each Authority Member is limited to two consecutive terms of office. The Authority employs the Director of Utilities.

The Fort Pierce Utilities Authority owns and operates electric generating facilities capable of supplying a portion of its system requirements. The existing on-system capacity, which amounts to 119 MW (excluding units on extended cold standby), is primarily fueled by natural gas (99.85 percent) pursuant to a contract with Florida Gas Transmission Company (FGT). On January 1, 1998, Fort Pierce became an All-Requirements Project participant. Additionally, the Authority has the right to receive up to 11.217 MW from FMPA's St. Lucie Project. The Fort Pierce Utilities Authority is also a participant in FMPA's Stanton Project and Tri-City Project with a total interest of approximately 20 MW from Stanton 1 for both projects. Fort Pierce's electric utility service area encompasses approximately 40 square miles with 78 percent of electric utility customers residing within the City limits. Fort Pierce's transmission system includes a 138 kV interconnection with FPL, a 138 kV line connecting Fort Pierce with the City of Vero Beach, and a 69 kV line completely looping the Fort Pierce service area. Six major substations supply voltage at 13 kV to a predominantly overhead distribution system.

1C.2.1.6.4 City of Green Cove Springs. The City of Green Cove Springs is located on the St. John's River in Clay County, 26 miles south of Jacksonville. The City operates and maintains the electric, water, and wastewater utilities. The City operates under the City Council/Manager form of government. The five member City Council is elected at large and appoints the City Manager, who serves as the City's chief administrative officer and directs the operation of the City's utility service.

Green Cove Springs became an All-Requirements Project Participant when the project was originally implemented on May 1, 1986. The City's electric utility service area encompasses approximately 10 square miles with 85 percent of customers residing within city limits and 15 percent residing outside of city limits. The City has a territorial agreement with a neighboring cooperative utility.

1C.2.1.6.5 City of Jacksonville Beach. The City of Jacksonville Beach is located in Duval County approximately 18 miles east of Jacksonville. The City operates under the City Council/City Manager form of government. The City operates and maintains electric, water, and wastewater utility operations. As the Chief Administrative Officer, the City Manager appoints the Directors of Electric and Water Utilities.

Jacksonville Beach is predominantly a residential community whose citizens, for the most part, work in the metropolitan Jacksonville area. Additionally, the City is a major recreation area for the people of Duval County, Florida.

The City of Jacksonville Beach entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Jacksonville Beach include only its entitlement share in the Agency's St. Lucie Project (approximately 5,406 kW). Jacksonville Beach owns one 230 kV transmission substation that ties to Florida Power & Light and has available a transmission tie to Jacksonville Electric Authority. They also have 12 distribution substations, which deliver energy at 26 kV, 12 kV, and 4 kV levels. Approximately 50 percent of the distribution circuits are underground installations.

The City of Jacksonville Beach electric utility service area encompasses approximately 45 square miles including the neighboring town of Neptune Beach, and the unincorporated areas of Ponte Vedra and Palm Valley located in St. Johns County. Portions of this territory have been assigned to the City by the Florida PSC. Forty-four percent of the customers served reside within City limits.

1C.2.1.6.6 City of Key West Utilities Board. The City of Key West was first incorporated in 1828 and is the county seat of Monroe County, Florida. It is located near the southern extreme of the Florida keys, a string of coral islands extending in a southwesterly arc from Biscayne Bay to the Dry Tortugas, and lies further south than any other point in the continental United States. The Utility Board of the City of Key West operates the municipally owned electric generating and distribution system of the City. The Utility Board is composed of a chairman who is elected for a term of two years and four members who are elected for a term of four years by the voters of the City of Key West. The Utility Board employs the Manager of the Electric System.

The Utility Board operates and maintains the on-system electric generating facilities of the electric system which consist of diesel generating units and one combustion turbine generating unit, with a total capacity of 50.4 MW. On April 1, 1998, the Utility Board became a member of the All-Requirements Project. The Utility Board is also a participant in FMPA's Tri-City Project and Stanton II Project with entitlements of approximately 12 MW from Stanton 1 and 10 MW from Stanton 2.

The electric system currently uses No. 2 and No. 6 fuel oil for all of its on-system generation facilities. The generating units of the system are not capable of using alternative fuels.

Key West obtains a major portion of its power via a 138 kV transmission line that extends up the causeway through Florida Keys Electric Cooperative Association, Inc. (FKEC) service territory and ties in with FPL on the mainland. Key West's portion of this main transmission line consists of 46.11 miles of 138 kV overhead line from Key West's Stock Island Substation to FKEC's Marathon Key Substation. Subtransmission is provided in Key West through various 69 kV overhead transmission lines with an aggregate total of 15.2 miles. Transformation between the 138 kV and 69 kV transmission lines is obtained by a 105 MVA autotransformer at the Stock Island Substation.

Key West's distribution system is comprised of approximately 202 miles of 13.8 kV and 19 miles of three-phase equivalent 4.16 kV feeder lines from Key West's power generation units and substation power transformers. In order to reduce system losses, Key West has an ongoing program to convert all of its 4.16 kV distribution lines to 13.8 kV.

Key West's service area consists of the lower Florida Keys, extending approximately 44 miles in an east-west direction from Pigeon Key, adjacent to the service area of FKEC to the City of Key West. Within its area, the electric system currently services the area between Ohio Key and the City. The FKEC and Key West have a Florida Public Service Commission approved territorial agreement.

Two additional 17.7 MW combustion turbines are planned to go into service at Key West's Stock Island Plant, but they will be owned by FMPA's All-Requirements Project.

1C.2.1.6.7 City of Leesburg. The City of Leesburg is located in Lake County, 41 miles north of Orlando and 36 miles south of Ocala. The City operates under a Commission/Manager form of government. The five member City Commission is elected at large and employs the City Manager, who serves as the City's chief administrative officer. The City operates and maintains electric, water, sewer, and natural gas distribution utilities. Each of the City's utility operations is supervised by a Director.

The City of Leesburg entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Leesburg include its partial ownership in FPC's Crystal River 3 nuclear unit, which equals 0.8244 percent of that unit (or 6,496 kW based on current net summer rating), and its entitlement in the Agency's St. Lucie Project (approximately 1,716 kW). The City owns four substations which convert the 69 kV voltage delivered by Florida Power Commission (FPC) down to the system distribution voltage of 13 kV. These substations and their attendant transmission systems completely loop the service area and assure dependable system operation. The city-owned distribution system has a 190 MVA capacity and delivers all the system energy at the 13 kV level. Approximately 15 percent of electric service is provided in underground circuits. A load management and SCADA system was installed during 1985.

The City's electric utility service area includes the incorporated cities of Leesburg and Fruitland Park and encompasses approximately 59 square miles with 40 percent of the customers served residing within the 23.5 square mile city limits of Leesburg. The City has received Florida PSC approval of a territorial agreement with FPC and the local electric cooperative.

1C.2.1.8.8 Ocala Electric Utility. The City of Ocala is located in Marion County near the geographic center of the State of Florida, approximately 35 miles south of Gainesville and 75 miles north of Orlando. The City operates under the City Council/City Manager form of government. The City operates and maintains electric, water, and wastewater utility operations which are not integrated for purposes of the All-Requirements Power Supply Project Contract. As the Chief Administrative Officer, the City Manager appoints the Directors of Electric and Water Utilities.

The economy of Ocala and Marion County is diversified. The three major payroll classifications in the private sector are: services (tourism), manufacturing, and retail trade, in that order. Next are wholesale trade and construction. Agriculture and the thoroughbred horse industry are also major contributors to the area economy. As the center of retail trade for a four county area, the City of Ocala and Marion County have each experienced significant growth in both retail sales and in the number of establishments catering to the retail sector.

The City of Ocala entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Ocala include only its partial ownership in FPC's Crystal River 3 nuclear unit, which equals 1.3333 percent of that unit (or 10,504 kW based on current net summer rating). The City owns and operates its bulk power supply system which consists of 70 miles of 230 kV transmission line, three 230 kV to 69 kV substations, an 80 mile 69 kV transmission loop, and 15 distribution substations delivering power at 12 kV. The distribution system consists of approximately 800 miles of overhead lines and 100 miles of underground.

The City's service area encompasses approximately 171 square miles. The service area is generally rectangular in shape, extending approximately 21 miles east and west and 17 miles north and south. The City of Ocala has received Florida PSC approval of territorial agreements with Clay Electric Cooperative and Sumter Electric Cooperative. Sixty-one percent of the customers served reside within the City limits.

1C.2.1.6.9 City of Starke. The City of Starke, in Bradford County, is located in northeast Florida, approximately 50 miles southwest of the City of Jacksonville. The City, established in 1875, operates under the Mayor/Commissioner form of government. The City operates and maintains electric, water, sewer, and gas distribution utilities. An elected city clerk serves as the City's chief administrative officer, and utility operations are under the supervision of an appointed Electric System Director.

The City of Starke owns and operates electric distribution facilities. The City receives up to 1.634 MW from FMPA's St. Lucie Project and up to approximately 1.5 MW from FMPA's Stanton Project. In order to meet its total electric system requirements, the City is a member of the All-Requirements Project. The City has one 13 kV interconnection with FPL and one substation reduces this voltage to 4 kV for predominantly overhead delivery to electric system customers.

1C.2.1.6.10 City of Vero Beach. The City of Vero Beach, the county seat of Indian River County, is located on the east coast of Florida midway between Miami and Jacksonville. The City was incorporated in 1919 and established a City Council/City Manager organization in 1951. The City Manager also serves as the Director of Utilities. The City owns and operates electric, water, and sewer utilities.

The City of Vero Beach owns and operates on-system electric generating facilities. The existing on-system capacity amounts to 150 MW (excluding units on extended cold standby) of oil and gas fired units predominantly fueled by natural gas. The City paid FGT to expand the fuel gas pipeline to allow the City's existing capacity to be totally gas fired. Natural gas is currently supplied pursuant to a contract with FGT. In addition to its existing on-system generating capacity, the City has entitlements of 11.214 MW of nuclear power and 20 MW of coal fired power from Stanton 1 from FMPA's St. Lucie and Stanton Projects, respectively. The City's 69 kV transmission system includes interconnections with FPL and the Fort Pierce Utilities Authority. The transmission system completely loops the service area, enhancing service reliability. Eight substations supply voltage at 13 kV to a predominantly overhead distribution system.

1C.2.1.6.11 City of Lake Worth. The City of Lake Worth is located in Palm Beach County on the east coast of Florida, 7 miles south of West Palm Beach and 61 miles north of Miami. The City was incorporated in 1913 and has been supplying electric power to the area since 1916. The City of Lake Worth assumed the operation of, and all obligations for, the electric, water, and wastewater utilities in 1985 through state of Florida legislative action.

Lake Worth owns on-system electric generating facilities. The existing on-system capacity amounts to 89.8 MW (excluding units on extended cold standby), primarily fueled by natural gas (98 percent). Lake Worth purchases gas pursuant to a contract for interruptible gas service with Florida Public Utilities Company. Lake Worth has entitlements of 18.347 MW of nuclear power and approximately 10 MW of coal fired power from FMPA's St. Lucie and Stanton Projects, respectively. Lake Worth is interconnected with the transmission facilities of FPL and, through them, to the State transmission grid. Five 26 kV transmission lines presently serve nine 26/4 kV distribution substations; however, the distribution system in the western portion of the service area has been upgraded to 26 kV concurrent with the transmission system improvement program and is served by a 138/26 kV substation. While the distribution system is predominantly overhead, new installations, serving platted developments, are installed underground. FMPA is planning for Lake Worth to join the All-Requirements Project in 1999.

1C.2.2 Purchased Power

FMPA currently has several power purchase contracts. These contracts exist with members as firm power purchases, from other utilities as firm power purchases, and from other utilities as partial requirements contracts. Subsections 1C.2.2.1 through 1C.2.2.3 outline the purchase power contracts in detail.

1C.2.2.1 Firm Power Purchases from All-Requirements Project Members

Generating members of the All-Requirements Project have firm purchase power contracts with FMPA for the purchase of capacity and energy from the members' generating units. Generating members of the All-Requirements Project consist of City of Vero Beach, City of Fort Pierce, and Key West City Utility Board. Table 1C.2-5 displays the generating units each of the member cities owns and operates. The total capacity of the firm power purchases from the generating members is 410 MW in summer and 427 MW in the winter after the addition of Lake Worth. FMPA is currently planning to add the City of Lake Worth as a member to the All-Requirements Project sometime in the year 1999. Lake Worth will be a generating member at the time of addition. The generation capacity of Lake Worth's units is also shown in Table 1C.2-5.

1C.2.2.2 Firm Power Purchases from Other Utilities

The All-Requirements Project has six firm purchase power contracts with other utilities as of June 1, 1998. The contracts exist with Lake Worth, Gainesville Regional Utilities, Orlando Utility Commission, and Tampa Electric Company. Each of the firm purchase power contracts is discussed in detail below and displayed in Table 1C.2-6.

1C.2.2.2.1 Lake Worth. The All-Requirements Project currently has a firm power purchase for capacity and energy through 2001. The capacity is for 15 MW for the years 1998 through 2000 and for 10 MW in 2001. The contract falls under Schedule D of the interchange agreements. While the existing contract extends through 2001, effectively, the contract will terminate from a power supply standpoint when Lake Worth joins the All-Requirements Project in 1999.

1C.2.2.2.2 Gainesville Regional Utilities Contracts. The All-Requirements Project currently has two contracts with GRU for firm power purchase capacity and energy that total 23 MW for the summer period of 1998. The first contract for 3 MW is a firm power purchase contract that the All-Requirements Project took over with the addition of the City of Starke to the Project. This contract is for 3 MW annually until the year 2004, after which time FMPA does not plan on extending the contract. The second contract is for 20 MW, reducing to 10 MW in 1999, and terminating thereafter.

1C.2.2.2.3 Orlando Utilities Commission Contracts. FMPA currently has two contracts with OUC for firm capacity and energy. The contracts extend through the year

Table 1C.2-5
Existing All-Requirements On-System Generating Facilities
As of December 31, 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel		Fuel Transport					Net Capability	
Plant Name	Unit No.*	Location	Unit Type	Pri	Alt	Pri	Alt	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate MW	Summer MW	Winter MW
Vero Beach	1	Indian River	ST	NG	FO6	PL	TK	11/61	Unknown	12.5	12.0	12.0
	3		ST	NG	FO6	PL	TK	9/71	Unknown	33.0	34.0	34.0
	4		ST	NG	FO6	PL	TK	8/76	Unknown	55.0	56.0	56.0
	5		GT	NG	FO2	PL	TK	12/92	Unknown	57.9	52.0	60.0
Henry D. King	2	St. Lucie	ST	FO2	NG	TK	PL	4/70	Unknown	5.0	5.0	5.0
	7		ST	FO6	NG	TK	PL	1/64	Unknown	32.0	32.0	32.0
	8		ST	FO6	NG	TK	PL	5/76	Unknown	50.0	50.0	50.0
	9		ST	FO2	NG	TK	PL	5/90	Unknown	31.0	31.0	31.0
Big Pine	1	Monroe	DS	FO2	--	TK	WA	2/64	Unknown	2.5	2.5	2.5
Cudjoe	3		DS	FO2	-	TK	WA	8/68	Unknown	4.5	4.5	4.5
Key West	GT		GT	FO2	-	WA	-	11/78	Unknown	20.0	20.0	20.0
Stock Island	IC 1-3		DS	FO2	-	WA	-	1/65	Unknown	6.0	6.0	6.0
	MS 1-2		DS	FO2	-	WA	-	6/91	Unknown	18.0	17.4	17.4
Smith	1-5 D**	Palm Beach	DS	FO2	-	TK	-	12/65	Unknown	10.0	10.0	10.0
	GT 1**		GT	FO2	-	TK	-	12/76	Unknown	30.8	26.0	31.0
	GT 2**		GT	NG	FO2	PL	TK	3/78	Unknown	21.41	21.0	23.0
	3**		ST	NG	FO6	PL	TK	11/67	Unknown	26.5	22.0	24.0
	5**		CW	WH	-	-	-	3/78	Unknown	10.0	9.0	9.0
										Total	410.4	427.4

*Units are generating utility members units. Capacity and energy sold to All-Requirements members under a firm purchase contract.
**Units are generating units from City of Lake Worth anticipated to be incorporated into the All-Requirements Project in 1999. Capacity will not show until January 1999 as firm purchase.

Table 1C.2-6
Purchase Power Capacity

	1998	1999		2000		2001		2002		2003		2004		2005		2006		2007		2008	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
Lake Worth D	15	15*	15*	15*	10*	10*	10*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Starke (GRU)	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0
GRU	20	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0
OUC	130	130	130	130	130	130	130	108	108	87	87	65	65	43	43	22	22	0	0	0	0
TECO	85	105	105	150	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	273	268	268	303	303	303	153	131	131	110	110	85	85	63	63	22	22	0	0	0	0
FPC PR	100	120	120	80	80	40	40	40	40	2	2	0	0	0	0	0	0	0	0	0	0
FPL PR	55	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Total	155	165	165	125	125	85	85	85	85	47	47	45	45	45	45	45	45	45	45	45	45
OUC	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0
Lee CO.	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	20	0	0	0	0	0
Lakeland	0	0	0	0	0	0	0	60	35	125	125	165	155	185	190	235	270	260	250	282	255
TECO	0	0	0	0	0	0	0	50	55	75	75	75	75	90	90	100	100	100	100	100	100
Total	0	0	0	0	0	70	70	180	160	270	270	310	300	345	350	405	370	360	350	382	355
Total Purchase Power	428	433	433	428	428	458	308	396	376	427	427	440	430	463	458	472	437	405	395	427	400

*Lake Worth D contract capacity not in totals beginning in 1999 when they become members in the All-Requirements Project.

Table 1C.2-6 (Continued)
Purchase Power Capacity

	2009		2010		2011		2012		2013		2014		2015		2016		2017	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
Lake Worth D	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stanton (GRU)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPC PR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PR	45	45	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0
Total	45	45	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0
OUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lee CO.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakeland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Purchase Power	45	45	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0

2006 and total 150 MW in 1998. The first contract is for 20 MW and extends through 2003. The second contract is for 130 MW through 2001. Thereafter, the capacity is decreased by 1/6 of the 130 MW (21.667 MW) annually through 2006. Table 1C.2-6 displays the contract capacities for these two purchases.

1C.2.2.2.4 Tampa Electric Company Contract. The All-Requirements Project currently has one contract with TECO for firm capacity and energy. The contract is for an escalating capacity and energy amount through the month of March 2001. The contract specifies that 85 MW of capacity is available for 1998 escalating to 105 MW in 1999, and 150 MW thereafter until the contract is terminated.

1C.2.2.3 Partial Requirements Purchases

The All-Requirements Project has two partial requirements purchases: one from Florida Power & Light (FPL) and the other from Florida Power Corporation. The partial requirements purchase through FPL is for 45 MW through the winter season of 2013, except the capacity for 1998 is 55 MW. The contract for partial requirements with FPC is for an escalating/declining capacity through 2003. FMPA may choose to increase/decrease capacity under these contracts in increments of 25 MW per contract each year on May 1. FMPA has identified the capacities in Table 1C.2-6 as the optimal amount under this contract. Table 1C.2-6 displays the values for the partial requirements purchases.

1C.2.2.4 New Purchases Identified in 1997 RFP

FMPA identified three purchases for the All-Requirements Project as part of the process of economic evaluation of the 1997 RFP. The three purchases would include the purchase power from an existing unit from Lee County, sales from existing OUC units, and sales from a new unit to be installed by the City of Lakeland. A purchase from TECO was identified in parallel to the RFP process.

The purchase of power from Lee County for 20 MW starting in 2001 through 2006 would be from Lee County's municipal solid waste burner which produces power in the range of 21 to 24 MW from a single steam generator with two boilers. Currently, Lee County sells the power to FPL on an as-available basis. Lee County has proposed that FMPA buy the entire output of the plant.

The purchase from Lakeland would be from the construction of two new units, McIntosh Unit 4 and 5. The City of Lakeland would have excess capacity to sell as a result of building

Unit 5, a simple cycle 501G combustion turbine in 1999, and Unit 4, a pressurized fluidized bed unit in 2003.

The capacity from these purchases would begin in 2001 and escalate over time. Table 1C.2-6 displays the proposed capacities for the planned new purchases. While these firm purchases are not under contract, FMPA is in the process of pursuing the contracts, and therefore included the purchases in the expansion plan. Tables 1C.2-7 and 1C.2-8 display a summary of the total All-Requirements Project capacity for summer and winter, respectively.

1C.2.3 Transmission System

Electric capacity and energy for the All-Requirements Project will be transmitted to the All-Requirements members utilizing the transmission systems of FPL, FPC, and OUC. FMPA divides the All-Requirements members into two categories: members east of Orlando and members west of Orlando. Members east of Orlando include: Jacksonville Beach, Green Cove Springs, Clewiston, Vero Beach, Starke, Fort Pierce, Key West, and Lake Worth. Members west of Orlando include Ocala, Leesburg, and Bushnell.

Network transmission service for east members is provided under an existing agreement FMPA currently has in place with FPL. FMPA began purchasing network transmission service from FPL effective April 1, 1996, culminating a six-year battle in the courts and regulatory forums. FMPA strived to obtain network service in order to integrate the operations of several members. Details of the network transmission service agreement are on file with the FPSC.

Network transmission for the west members is provided under an agreement with FPC. Network transmission service is also purchased under an agreement with OUC. The capacity from Cane Island Unit 3 will be delivered to west members through FPC.

Table 1C.2-7 All-Requirements Total Capacity - Summer (MW)						
Year	All-Requirements Capacity	Generating Member Firm Purchases	Existing Firm Purchases	Partial Requirements Purchase	New Purchases	Total Capacity
1998	377	325	273	155	0	1130
1999	377	410	268	165	0	1220
2000	377	410	303	125	0	1215
2001	377	410	153	85	70	1095
2002	377	410	131	85	160	1163
2003	377	410	110	47	270	1214
2004	377	410	85	45	300	1217
2005	377	410	63	45	350	1245
2006	377	410	22	45	370	1224
2007	377	410	0	45	350	1182
2008	377	410	0	45	355	1187
2009	377	410	0	45	0	832
2010	377	410	0	45	0	832
2011	377	410	0	45	0	832
2012	377	410	0	45	0	832
2013	377	410	0	0	0	787
2014	377	410	0	0	0	787
2015	377	410	0	0	0	787
2016	377	410	0	0	0	787
2017	377	410	0	0	0	787

Table 1C.2-8 All-Requirements Total Capacity - Winter (MW)						
Year	All-Requirements Capacity	Generating Member Firm Purchases	Existing Firm Purchases	Partial Requirements Purchase	New Purchases	Total Capacity
1997/98	373	330	273	155	0	1131
1998/99	411	427	268	165	0	1271
1999/00	411	427	303	125	0	1266
2000/01	411	427	303	85	70	1296
2001/02	411	427	131	85	180	1234
2002/03	411	427	110	47	270	1265
2003/04	411	427	85	45	310	1278
2004/05	411	427	63	45	345	1291
2005/06	411	427	22	45	405	1310
2006/07	411	427	0	45	360	1243
2007/08	411	427	0	45	382	1265
2008/09	411	427	0	45	0	883
2009/10	411	427	0	45	0	883
2010/11	411	427	0	45	0	883
2011/12	411	427	0	45	0	883
2012/13	411	427	0	45	0	883
2013/14	411	427	0	45	0	883
2014/15	411	427	0	0	0	838
2015/16	411	427	0	0	0	838
2016/17	411	427	0	0	0	838

1C.3.0 Methodology

This section provides a general description of the methodology used to analyze the Cane Island Unit 3 expansion for FMPA's All-Requirements Project power supply requirements and is arranged according to the sequence of the remaining sections of this volume. The purpose of the power supply planning study and determination of need is to develop evaluation criteria, a range of load and fuel forecasts, and potential capacity additions that will meet the least-cost power generation needs of its consumers while providing consideration for reliability, fuel diversity, environmental impacts, strategic goals, and regulatory requirements. To this end, FMPA has provided in-depth analysis and evaluation of supply-side and demand-side resources to determine the least-cost plan which is in the collective best interest of all parties involved.

1C.3.1 Evaluation Criteria

The first step in the power supply planning process is to establish evaluation criteria, that is, to identify the assumptions about important parameters used in the analysis. Evaluation criteria presented in Section 1C.4.0 include the following:

- Economic forecast assumptions.
- Financial assumptions.
- Natural gas availability assumptions.
- Fuel price projections.

1C.3.2 Forecast of Electrical Power Demand and Energy Consumption

The load forecast for the FMPA All-Requirements members is summarized in Section 1C.5.0 and shown in detail in Appendix 1C.16.1. The Appendix describes the development of the econometric models which forecast system peak demands and energy requirements. The load forecast takes into account FMPA members' existing conservation plans. Demand-side program reductions are forecast separately.

1C.3.3 Conservation and Demand-Side Management

The FMPA All-Requirements members conservation and demand-side management programs are discussed in Section 1C.6.0. Estimates of capacity avoided by the various programs are provided.

1C.3.4 Reliability Criteria

Section 1C.7.0 presents the reliability criteria used to identify timing of capacity additions. The All-Requirements Project uses an 18 percent minimum reserve margin for summer peak as the reliability criteria.

1C.3.5 Supply-Side Alternatives

Supply-side alternatives that are candidates for meeting the All-Requirements Projects capacity expansion requirements are outlined in Volume 1A.6.0. A variety of plant sizes, capital costs, and operating parameters of conventional alternatives as well as advanced and renewable technologies are considered.

1C.3.6 Supply-Side Screening

The economics of the supply-side alternatives were evaluated on a screening level before modeling in detail in production cost programs. The screening analysis provides a method to eliminate alternatives that possess no potential of being economically viable under any operating parameters for the All-Requirements Project. The details of the screening analysis are provided in Volume 1A.6.0.

1C.3.7 Economic Analyses

In Section 1C.10.0, the economics of the expansion alternatives are evaluated from the characteristics in Section 1A.6.0. The plans are evaluated on a comparative basis. Comparative costs include only those costs which are affected by differences in the plans. The economic analyses determine the annual revenue requirements of items which are affected by the alternative plans. Annual comparative revenue requirements include the following components:

- Fuel costs.
- Purchased power costs.

- Operation and maintenance (O&M) costs.
- Capital costs for new generation.
- Transmission costs for new units.

An optimization program, EGEAS, is used to model the All-Requirements Project system for the expansion alternatives developed in Section 1C.8.0. Annual system fuel and O&M costs are developed for each plan. Production cost simulation is necessary to incorporate the effect upon the operation of the existing units due to the new unit additions.

The objective of the economic analysis is to determine the total present worth of the annual comparative revenue requirements. This refers to the sum of the annual comparative revenue requirements discounted to 1998 using FMPA's present worth discount rate.

1C.3.8 Sensitivity Analyses

Several sensitivity analyses were conducted to verify the robustness of the least-cost plan to altered conditions. The sensitivity analyses include a high load and energy forecast, low load and energy forecast, high fuel price forecast, low fuel price forecast, a case where the differential fuel prices of coal versus natural gas/oil are held constant over the planning horizon, a 15 percent reserve margin case, and a case where the cost of Cane Island Unit 3 is increased. The results of the analysis are included in Section 1C.11.0.

1C.3.9 Strategic Considerations

Section 1C.12.0 outlines the strategic considerations involved in the alternative power supply plans. Such considerations include fuel mix, fuel supply, and availability of sites. The strategic considerations factor heavily into the analysis of the least-cost plan. While the least-cost plan might provide the least-cost under the applied assumptions, the "best" plan may be different depending on strategic considerations.

1C.3.10 Consequences of Delay

Section 1C.13.0 addresses the adverse consequences of not building or delaying Cane Island Unit 3. This section addresses the adverse impacts on system reliability, system cumulative present worth costs, and emission impacts of a delay.

1C.3.11 Financial Analysis

Section 1C.14.0 addresses the financial feasibility of constructing Cane Island 3 with FMPA's current financial position. This section highlights FMPA's strong standing among Florida utilities and high outlook for future growth.

1C.3.12 Analysis of 1990 Clean Air Act Amendments

Section 1C.15.0 addresses the impact of the 1990 Clean Air Act Amendments on the Cane Island 3 project. This section discusses FMPA's strategy for compliance with the amendments.

1C.4.0 Evaluation Criteria

Economic evaluation is conducted over a 20 year period from 1998 through 2017. The economic evaluation is based on the cumulative present worth of annual costs for capital costs, non-fuel O&M costs, fuel costs, purchase power demand, energy, and transmission costs. Costs that are common to all expansion alternatives, such as demand charges for existing power purchases or existing transmission and distribution system costs, and administrative and general costs are not included.

1C.4.1 Economic Parameters and Evaluation Criteria

1C.4.1.1 Escalation Rate

The general inflation rate applied in the economic evaluation is 2.5 percent. A 3.0 percent annual escalation rate is applied for operation and maintenance (O&M) costs. The escalation rate applied to capital costs is 2.5 percent.

1C.4.1.2 Bond Interest Rate

The bond interest rate is assumed to be 5.50 percent for FMPA.

1C.4.1.3 Bond Issuance Fee

A bond issuance fee of 2.90 percent is assumed to apply to FMPA bond issues.

1C.4.1.4 Interest During Construction

Interest during construction is assumed to be equal to the bond interest rate of 5.50 percent.

1C.4.1.5 Present Worth Discount Rate

The base case present worth discount rate is equal to the bond interest rate of 5.50 percent.

1C.4.1.6 Fixed Charge Rate

The fixed charge rate is 8.2 percent. The fixed charge rate was developed based upon a 30 year bond term including principal and interest, a 1 year debt service reserve fund, interest earnings credit based on the bond interest rate, a 2.9 percent bond issuance rate, and 1.0 percent for property insurance.

1C.4.2 Fuel Price Projections

Fuel price projections for FMPA are based on the projections in Section 1A.3.2 of Volume 1A. The fuel price escalation rates for coal, gas, and oil were developed by DRI. With fuel expenses representing the largest portion of the FMPA budget, reliable fuel price forecasts are of great importance. Table 1C.4-1 provides a summary of the base case fuel forecast that is developed in Volume 1A.

Three fuel price sensitivity projections were developed. The first two are high and low price projections. The description of the high and low fuel price projections is presented in 1A.3.2. The third fuel price sensitivity projection is based on holding natural gas/oil versus coal prices constant throughout the planning period. For this sensitivity, coal prices from the base case were chosen as the fixed component. Fuel prices were held at a constant differential (same as differential in base year) over the forecast horizon.

1C.4.3 Fuel Availability

Fuel availability for FMPA, including coal, natural gas, oil, and nuclear fuel are discussed in detail in Volume 1A with this subsection presenting a brief overview of information specific to FMPA.

FMPA is currently a member of Florida Gas Utility (FGU) which is a joint action agency gas supply organization. Membership in FGU allows aggregation of member contracts which provides better economy for purchases, mitigates demand changes, and simplifies the problems of individual systems balancing consumption against supply. FMPA plans to purchase commodity for Cane Island Unit 3 under FGU. The portion of natural gas that will be purchased under spot purchases or under contract is still being evaluated.

FMPA currently receives transportation from Florida Gas Transmission Company (FGT) for its existing unit share in Cane Island 1 and 2. Since FMPA is a member in FGU, it has the

Table 1C.4-1 Delivered Fuel Price Forecast–Base Case ($/MBtu)						
Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas(1) Existing Units	Natural Gas(2) New Units
1998	1.70	2.68	4.47	0.55	2.39	3.20
1999	1.71	2.66	4.45	0.56	2.31	3.12
2000	1.74	2.75	4.59	0.57	2.22	3.03
2001	1.77	2.89	4.82	0.59	2.25	3.06
2002	1.81	3.03	5.05	0.60	2.38	3.19
2003	1.86	3.16	5.28	0.62	2.46	3.27
2004	1.90	3.31	5.52	0.63	2.53	3.34
2005	1.93	3.49	5.82	0.65	2.61	3.42
2006	1.97	3.65	6.09	0.67	2.70	3.51
2007	2.02	3.82	6.37	0.68	2.79	3.60
2008	2.06	4.00	6.68	0.70	2.92	3.73
2009	2.10	4.18	6.99	0.72	3.02	3.83
2010	2.15	4.36	7.29	0.73	3.17	3.98
2011	2.20	4.57	7.63	0.75	3.32	4.13
2012	2.23	4.78	7.98	0.77	3.45	4.26
2013	2.29	5.00	8.34	0.79	3.59	4.40
2014	2.34	5.23	8.72	0.81	3.77	4.58
2015	2.40	5.46	9.12	0.83	3.92	4.73
2016	2.46	5.70	9.52	0.85	4.09	4.90
2017	2.51	5.97	9.96	0.87	4.30	

(1) Delivered natural gas price less demand reservation costs.
(2) Includes demand reservation costs

ability to supply additional volumes of gas to other locations by utilizing members' firm transportation rights when available. This allows FMPA flexibility to schedule and run units more efficiently. FMPA has firm transportation rights from FGT under FTS-1 and FTS-2. Table 1C.4-2 displays FMPA's totaled fixed transportation on a monthly basis. The existing transportation volumes are generally adequate to operate Cane Island Unit 3 at full load around the clock. As part of FGT's open season to schedule firm transportation for new supplies under FTS-3, FMPA requested an additional 25,000 MBtu/day.

Table 1C.4-2
FMPA's Total Firm Transportation
(MBtu/day)

	Totals	
	FTS-1	FTS-2
January	14,121	26,500
February	14,121	26,500
March	14,421	26,500
April	17,789	26,500
May	20,139	26,500
June	20,139	26,500
July	20,139	26,500
August	20,139	26,500
September	20,139	26,500
October	23,084	26,500
November	14,271	26,500
December	14,121	26,500

1C.5.0 Forecast of Electrical Power Demand and Energy Consumption

Under the All-Requirements Project structure, FMPA agrees to meet its members resource planning requirements. The forecast of electrical power demand and energy consumption includes current member cities and identified future cities that will become members to the All-Requirements Project. FMPA forecasts each of its members loads on an individual basis and integrates the results into a FMPA forecast of electrical power demand and energy consumption. The results of the forecast are provided in this section and Appendix 1C.16.1.

1C.5.1 Load Forecasting Assumptions

The load forecast attempts to predict how certain changes within the members cities will affect power consumption. This is accomplished by reviewing and analyzing these changes and their impact on load growth. Changes evaluated include: population, historical trends, weather patterns, conservation programs, account types, economic conditions, and number of customers. Several techniques were applied for the load forecast including:

- By-class econometric modeling,
- Aggregate econometric modeling,
- Time series / Time trend modeling.

By-class econometric modeling forecasts kilowatt hour sales for individual rate classifications. Economics and demographics for each city are used as determinates for projection of energy sales. The total kilowatt hour sales for the system can then be determined by summing all individual rate classifications and losses.

Aggregate econometric modeling attempts to forecast net energy for load for a system. This technique projects total net energy for load without segregating energy usage into individual rate classifications. One equation is developed using independent variables to predict net energy for load for a system.

Time series/Time trend modeling attempts to use past trends in net energy for load to forecast future net energy for load.

The FMPA forecasting process involves applying some or all of these models to develop individual forecasts for each All-Requirements Project member. FMPA uses Forecast Pro to forecast loads for its member cities. Forecast Pro is a commercially developed software package that conducts analysis considering moving averages, exponential smoothing, Box-Jenkins, event models, and multiple level models. The model considers the statistical relevance of input variables and forecasts based on the highest correlation. The forecasts are then compared and checked for reasonableness. Finally, any unusual incremental load additions or reductions are integrated into the forecast.

1C.5.2 Base Case Load Forecast

Based on the data from the member cities, The Kiplinger Washington Letter, The Florida Outlook, Florida Statistical Abstract, Florida Estimates of Population, and Monthly Energy Review, it is concluded that Florida will remain one of the fastest growing states in the United States. The economy will remain strong with the unemployment rate declining and the price of electricity projected to remain steady. In the following subsections details of the net energy for load summer peak demand and winter peak demand are discussed.

1C.5.2.1 Net Energy for Load Forecast

FMPA forecasts net energy for load for each member taking into account all conservation programs that were active over the historical period. The forecast methodology, as outlined in the previous subsection, varies from member to member to provide the most reliable forecast possible consistent with available data. For forecasts using regression analysis the minimum coefficient of determination was 93 percent, implying a strong correlation of historical information. Once the net energy for load forecasts are compiled for all the member cities, the loads are integrated into an FMPA net energy for load forecast. The FMPA projected net energy for load including conservation for the base case is presented in Tables 1C.5-1 through 1C.5-3. The projected average annual growth rate (AAGR) for the base case is 1.5 percent for 1999 after the addition of the City of Lake Worth through 2017. Table 1C.5-4 displays each member's net energy for load forecast for the planning horizon. Details of each member's forecast are described in detail in Appendix 1C.A.

1C.5.2.2 Summer Peak Demand Forecast

Summer peak demand forecasts are conducted in a similar fashion to the net energy for load forecast. To forecast the summer peak demand for each member city average annual

Table 1C.5-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	Residential Sales GWh	Residential Average No. of Customers	Residential Average MWh Consumption Per Customer	Commercial and Industrial Sales GWh	Commercial and Industrial Average No. of Customers	Commercial and Industrial Average MWh Consumption Per Customer
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	1,229	98,726	12.45	1,380	18,510	74.54
1998*	1,847	147,511	12.52	2,152	26,832	80.19
1999*	2,170	170,702	12.71	2,434	30,390	80.11
2000*	2,221	172,723	12.86	2,493	30,822	80.88
2001*	2,271	174,727	13.00	2,550	31,238	81.64
2002*	2,319	176,651	13.13	2,606	31,634	82.38
2003*	2,365	178,545	13.25	2,659	32,005	83.08
2004*	2,410	180,338	13.36	2,711	32,361	83.78
2005*	2,451	182,060	13.46	2,761	32,695	84.46
2006*	2,489	183,667	13.55	2,809	33,005	85.11
2007*	2,525	185,197	13.63	2,855	33,294	85.75

* Forecast includes new All-Requirements Project members.

Table 1C.5-2 History and Forecast of Energy Consumption and Number of Customers by Customer Class All-Requirements Project			
(1)	(2)	(3)	(4)
Year	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales Ultimate Consumers GWh
1992	52	7	1,916
1993	48	9	2,011
1994	59	10	2,122
1995	65	11	2,263
1996	57	10	2,302
1997	60	14	2,683
1998*	78	14	4,091
1999*	76	14	4,694
2000*	77	14	4,805
2001*	78	15	4,915
2002*	78	15	5,018
2003*	79	15	5,118
2004*	80	15	5,216
2005*	81	15	5,308
2006*	81	15	5,394
2007*	82	15	5,477

* Forecast includes new all requirements projects members.

Table 1C.5-3 History and Forecast of Energy Consumption and Number of Customers by Customer Class All-Requirements Project			
(1)	(2)	(3)	(4)
Year	Utility Use & Losses GWh	Net Energy for Load GWh	Total No. of Customers
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	103	2,405	91,564
1997	167	2,850	117,236
1998*	226	4,317	174,343
1999*	271	4,965	201,092
2000*	276	5,081	203,545
2001*	280	5,194	205,965
2002*	287	5,305	208,285
2003*	293	5,411	210,550
2004*	297	5,513	212,699
2005*	303	5,611	214,755
2006*	309	5,703	216,672
2007*	313	5,790	218,491

* Forecast includes new all requirements projects members.

Table IC.5-4
Net Energy for Load for each of All-Requirements Members (MWh)

Year	City of Bushnell	City of Clewiston	Fort Pierce	City of Green Cove Springs	City of Jacksonville Beach	City of Key West	City of Leesburg	Ocala	City of Starke	City of Vero Beach	City of Lake Worth	Total
1998	21,456	116,978	560,120	128,838	646,019	481,657	430,983	1,158,645	71,390	647,684	0	4,317,43
1999	21,843	119,401	572,150	131,472	670,502	696,100	441,799	1,185,277	73,485	666,139	387,003	4,965,17
2000	22,228	121,800	583,845	134,068	695,252	708,179	452,461	1,211,527	75,589	684,460	391,442	5,080,827
2001	22,607	124,158	595,008	136,642	719,198	720,433	463,016	1,237,213	77,637	702,622	395,615	5,194,147
2002	22,988	126,453	605,223	139,170	742,536	732,884	473,361	1,262,268	79,683	720,584	399,512	5,304,64
2003	23,354	128,681	613,798	141,683	765,163	744,783	483,586	1,287,133	81,704	737,589	403,061	5,410,52
2004	23,713	130,853	621,931	144,159	787,011	756,158	493,920	1,311,911	83,641	753,558	406,527	5,513,38
2005	24,062	132,987	628,962	146,610	807,419	766,957	504,118	1,336,071	85,511	768,390	409,701	5,610,75
2006	24,409	136,006	635,174	148,983	826,164	777,150	514,166	1,359,434	87,336	781,988	412,601	5,702,60
2007	24,746	136,989	640,918	151,281	843,108	786,708	524,050	1,382,423	89,029	794,684	415,685	5,789,60
2008	25,077	138,893	645,808	153,550	858,968	795,604	533,596	1,405,166	90,663	806,765	418,490	5,872,59
2009	25,405	140,777	650,461	155,740	873,131	803,806	543,084	1,427,487	92,204	818,263	421,309	5,951,66
2010	25,720	142,602	654,784	157,882	885,904	811,296	552,373	1,449,313	93,621	828,727	423,729	6,025,93
2011	26,031	144,342	658,655	159,963	897,997	818,493	561,514	1,470,244	94,931	838,065	426,160	6,096,61
2012	26,327	146,011	662,301	161,936	909,363	824,940	570,477	1,490,092	96,165	846,717	428,356	6,162,68
2013	26,618	147,592	665,769	163,844	919,982	830,619	579,261	1,509,543	97,319	856,765	430,460	6,227,78
2014	26,894	149,157	668,954	165,667	929,243	835,964	588,062	1,528,357	98,326	860,078	432,319	6,283,04
2015	27,163	150,657	671,863	167,362	937,674	840,512	596,686	1,546,900	99,248	865,561	434,163	6,337,81
2016	27,425	152,132	674,118	168,980	945,256	844,705	605,096	1,564,316	100,042	870,650	435,797	6,388,52
2017	27,681	153,448	676,383	170,449	951,986	848,536	613,271	1,582,223	100,742	874,936	437,419	6,437,05

summer load factors are determined from the historical information and applied to the forecasted net energy for load to arrive at the forecasted summer peak demand. Table 1C.5-5 shows the projected summer peak demand for the individual All-Requirements Project members. The summer peak demands are for non-coincidental peak demand. For the forecast of summer peak demand for FMPA's All-Requirements Project, considering diversity among the individual members, FMPA applies seasonal factors to the All-Requirement Project net energy for load forecast to arrive at the summer peak demand forecast. Table 1C.5-6 displays the FMPA forecasted summer peak demand for the base case. Table 1C.5-6 also presents the projected demand reduction due to residential load management. The projected AAGR for summer peak demand from 1999 after the addition of the City of Lake Worth to 2017 is 1.5 percent.

1C.5.2.3 Winter Peak Demand Forecast

Winter peak demand forecasts are conducted in a similar fashion to the net energy for load forecast. To forecast the winter peak demand for each member city, average annual winter load factors are determined from the historical information and applied to the forecasted net energy for load to arrive at the forecasted winter peak demand. Table 1C.5-7 shows the projected winter peak demand for the individual All-Requirements Project members. The winter peak demands are for non-coincidental peak demand. For the forecast of winter peak demand for FMPA's All-Requirements Project, considering diversity among the individual members, FMPA applies seasonal factors to the All-Requirements Project net energy for load forecast to arrive at the winter peak demand forecast. Table 1C.5-8 displays the FMPA forecasted winter peak demand for the base case. Table 1C.5-8 also presents the projected demand reduction due to residential load management. The projected AAGR for winter peak demand from 1999 after the addition of the City of Lake Worth to 2017 is 1.5 percent.

1C.5.3 Sensitivities

FMPA develops the most accurate base case load forecast possible based on the date available. However, uncertainty in the assumptions for future conditions dictate the development of high and low band forecasts to ensure that the addition of Cane Island Unit 3 results in the least cost under the full range of conditions that might be encountered in the future.

Table IC.5-5
All-Requirements Project Members Projected Summer Peak Demand

Year	City of Bushnell	City of Clewiston	Fort Pierce	City of Green Cove Springs	City of Jacksonville Beach	City of Key West	City of Leesburg	Ocala	City of Starke	City of Vero Beach	City of Lake Worth
1998	4.5	23.1	102.6	23.8	140.8	116.3	95.7	247.4	13.2	131	72.0
1999	4.5	23.6	104.8	24.3	146.1	118.5	98.1	253.0	13.6	135	72.8
2000	4.6	24.0	106.9	24.8	151.5	120.5	100.5	258.6	14.0	139	73.7
2001	4.7	24.5	109.0	25.2	156.7	122.6	102.8	264.1	14.4	142	74.5
2002	4.8	25.0	110.9	25.7	161.8	124.7	105.1	269.5	14.8	146	75.2
2003	4.9	25.4	112.4	26.2	166.8	126.8	107.4	274.8	15.1	149	75.9
2004	4.9	25.8	113.9	26.6	171.5	128.7	109.7	280.1	15.5	153	76.5
2005	5.0	26.2	115.2	27.1	176.0	130.5	112.0	285.2	15.8	156	77.1
2006	5.1	26.7	116.3	27.5	180.0	132.3	114.2	290.2	16.2	158	77.7
2007	5.2	27.0	117.4	27.9	183.7	133.9	116.4	295.1	16.5	161	78.2
2008	5.2	27.4	118.3	28.4	187.2	135.4	118.5	300.0	16.8	164	78.8
2009	5.3	27.8	119.1	28.8	190.3	136.8	120.6	304.7	17.1	166	79.3
2010	5.4	28.2	119.9	29.2	193.1	138.1	122.7	309.4	17.3	168	79.8
2011	5.4	28.5	120.7	29.5	195.7	139.3	124.7	313.9	17.6	170	80.2
2012	5.5	28.8	121.3	29.9	198.2	140.4	126.7	318.1	17.8	172	80.6
2013	5.5	29.1	122.0	30.3	200.5	141.4	128.7	322.3	18.0	173	81.0
2014	5.6	29.4	122.5	30.6	202.5	142.3	130.6	326.3	18.2	174	81.4
2015	5.7	29.7	123.1	30.9	204.3	143.1	132.5	330.2	18.4	175	81.7
2016	5.7	30.0	123.5	31.2	206.0	143.8	134.4	334.0	18.5	176	82.0
2017	5.8	30.3	123.9	31.5	207.5	144.4	136.2	337.8	18.7	177	82.3

Table 1C.5-6
Forecast of Summer Peak Demand--Base Case

Year	Total Demand MW	Residential Load Management MW	Net Firm Demand MW
1998	896	3.6	892
1999	992	3.8	988
2000	1,015	4.0	1,011
2001	1,038	4.2	1,034
2002	1,061	4.5	1,056
2003	1,082	4.7	1,077
2004	1,103	4.8	1,098
2005	1,123	5.0	1,118
2006	1,141	5.1	1,136
2007	1,159	5.2	1,154
2008	1,176	5.3	1,171
2009	1,192	5.4	1,187
2010	1,207	5.4	1,202
2011	1,222	5.5	1,217
2012	1,235	5.6	1,229
2013	1,248	5.6	1,242
2014	1,260	5.7	1,254
2015	1,271	5.7	1,265
2016	1,282	5.7	1,276
2017	1,292	5.8	1,286

Table 1C.5-7
All-Requirements Project Members Projected Winter Peak Demand

Year	City of Bushnell	City of Clewiston	Fort Pierce	City of Green Cove Springs	City of Jacksonville Beach	City of Key West	City of Leesburg	Ocala	City of Starke	City of Vero Beach	City of Lake Worth
1997/98	5.6	21.8	119.3	23.7	176.6	80.4	91.0	236.4	11.6	165.7	73.4
1998/99	5.7	22.2	121.8	24.2	183.3	81.8	93.3	241.8	12.0	170.4	74.3
1999/00	5.8	22.7	124.3	24.6	190.0	83.3	95.5	247.2	12.3	175.1	75.2
2000/01	5.9	23.1	126.7	25.1	196.6	84.7	97.8	252.4	12.7	179.8	76.0
2001/02	6.0	23.6	128.9	25.6	203.0	86.2	100.0	257.5	13.0	184.4	76.7
2002/03	6.1	24.0	130.7	26.0	209.2	87.6	102.1	262.6	13.3	188.7	77.4
2003/04	6.2	24.4	132.4	26.5	215.1	88.9	104.3	267.6	13.6	192.8	78.1
2004/05	6.2	24.8	133.9	26.9	220.7	90.2	106.5	272.6	14.0	196.6	78.7
2005/06	6.3	25.2	135.3	27.4	225.8	91.4	108.6	277.3	14.2	200.1	79.3
2006/07	6.4	25.5	136.5	27.8	230.5	92.5	110.7	282.0	14.5	203.3	79.8
2007/08	6.5	25.9	137.5	28.2	234.8	93.5	112.7	286.7	14.8	206.4	80.4
2008/09	6.6	26.2	138.5	28.6	238.7	94.5	114.7	291.2	15.0	209.4	80.9
2009/10	6.7	26.6	139.4	29.0	242.2	95.4	116.6	295.7	15.3	212.0	81.4
2010/11	6.8	26.9	140.3	29.4	245.5	96.2	118.6	299.9	15.5	214.4	81.9
2011/12	6.8	27.2	141.0	29.8	248.6	97.0	120.5	304.0	15.7	216.6	82.3
2012/13	6.9	27.5	141.8	30.1	251.5	97.6	122.3	307.9	15.9	218.4	82.7
2013/14	7.0	27.8	142.5	30.4	254.0	98.3	124.2	311.8	16.0	220.0	83.0
2014/15	7.1	28.1	143.1	30.8	256.3	98.8	126.0	315.6	16.2	221.4	83.4
2015/16	7.1	28.3	143.6	31.1	258.4	99.3	127.8	319.1	16.3	222.8	83.7
2016/17	7.2	28.6	144.0	31.3	260.2	99.8	129.5	322.8	16.4	223.8	84.0

Table IC.5-8 Forecast of Winter Peak Demand--Base Case			
Year	Total Demand MW	Residential Load Management MW	Net Firm Demand MW
1997/98	852	5.9	846
1998/99	1,031	6.3	1,025
1999/00	1,056	6.8	1,049
2000/01	1,081	7.2	1,074
2001/02	1,105	7.6	1,097
2002/03	1,128	7.9	1,120
2003/04	1,150	8.2	1,142
2004/05	1,171	8.5	1,163
2005/06	1,191	8.7	1,182
2006/07	1,210	8.9	1,201
2007/08	1,227	9.0	1,218
2008/09	1,244	9.2	1,235
2009/10	1,260	9.3	1,251
2010/11	1,275	9.4	1,266
2011/12	1,289	9.5	1,280
2012/13	1,303	9.6	1,293
2013/14	1,315	9.7	1,305
2014/15	1,327	9.8	1,317
2015/16	1,338	9.9	1,328
2016/17	1,348	10.0	1,338

FMPA's load forecasts reported in FMPA Ten Year Site Plans have been very accurate compared to actual net energy for load and peak demand. Forecasts for net energy for load and summer peak demand have always been within 5 percent of the actual net energy for load and summer peak demand. Actual winter peak demand which is much more temperature dependent has varied as much as almost 20 percent from projected values. The larger level of variation is primarily due to different temperatures occurring at the time of peak instead of inaccuracy with the forecast. Therefore, for purposes of selecting high and low bands for sensitivity analysis, a difference of ±5 percent from the base forecast has been selected. The high and low forecasts are presented in Tables 1C.5-9 and 1C.5-10, respectively.

Table 1C.5-9 Forecast of Summer and Winter Peak Demand with NEL—High Case			
Year	Net Firm Summer Demand MW	Net Firm Winter Demand MW	Net Energy For Load GWH
1998	938	889	4,533
1999	1,038	1,076	5,213
2000	1,062	1,102	5,335
2001	1,086	1,128	5,454
2002	1,109	1,153	5,570
2003	1,132	1,176	5,681
2004	1,154	1,200	5,789
2005	1,174	1,221	5,891
2006	1,194	1,242	5,988
2007	1,212	1,261	6,079
2008	1,230	1,280	6,166
2009	1,247	1,298	6,249
2010	1,263	1,314	6,327
2011	1,278	1,330	6,401
2012	1,292	1,345	6,471
2013	1,305	1,359	6,539
2014	1,318	1,371	6,597
2015	1,329	1,384	6,655
2016	1,340	1,395	6,708
2017	1,351	1,405	6,759

Table 1C.5-10 Forecast of Summer and Winter Peak Demand with NEL--Low Case			
Year	Net Firm Summer Demand MW	Net Firm Winter Demand MW	Net Energy For Load GWH
1998	849	805	4,112
1999	940	975	4,729
2000	962	999	4,839
2001	984	1,022	4,947
2002	1,005	1,044	5,052
2003	1,025	1,056	5,153
2004	1,045	1,087	5,251
2005	1,064	1,106	5,344
2006	1,081	1,125	5,431
2007	1,098	1,143	5,514
2008	1,114	1,159	5,593
2009	1,130	1,175	5,668
2010	1,144	1,190	5,739
2011	1,158	1,205	5,806
2012	1,170	1,218	5,869
2013	1,183	1,231	5,931
2014	1,194	1,242	5,984
2015	1,205	1,253	6,036
2016	1,215	1,263	6,084
2017	1,224	1,273	6,131

1C.6.0 Demand-Side Programs

1C.6.1 Existing Conservation Programs

FMPA is a strong supporter of the conservation of energy and promotes effective programs to its members. 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 members promote their conservation programs by providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, and so forth. Additionally, bill inserts are utilized to keep customers aware of available conservation programs.

FMPA is also assisting in the development of renewable energy resources by participating in the Utility Photovoltaic Group (UPG). UPG is a 89-member non-profit organization formed to accelerate the commercialization of photovoltaic systems for the benefit of electric utilities and their customers.

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

- Residential Energy Audits including the 5-Star Award
- High-Pressure Sodium Outdoor Lighting Conservation
- Assistance for Commercial/ Industrial Audits
- Commercial Time-of-Use Program
- Natural Gas Promotion
- Fix-Up Program for the Elderly and Handicapped

A brief description of each of the conservation programs is provided in the following subsections.

1C.6.1.1 Residential Energy Audits Including the 5-Star Award

Residential energy audits are offered to residential customers. Audits are conducted in accordance with FPSC rules. The audits consist of a walk-through Home Energy Survey with the following materials available upon customer request.

- Electric outlet gaskets
- Socket protectors

- Water flow restrictors
- Electric water heater jacket
- Low flow shower heads

Home Energy Surveys also include water heater temperature reduction and the installation of the water heater insulating blanket upon customer request.

1C.6.1.2 High Pressure Sodium Outdoor Lighting Conversion

This program involves eliminating mercury vapor street and yard lighting. The fixtures are converted whenever maintenance is required.

1C.6.1.3 Assistance for Commercial/ Industrial Audits

On-site audits are available to industrial and commercial customers with the intention of shifting demand from peak to off-peak periods.

1C.6.1.4 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.

1C.6.1.5 Natural Gas Promotion

This program was established to replace older electric heat and water heaters with natural gas when the conversion would benefit the customers.

1C.6.1.6 Fix-Up Program for the Elderly and Handicapped

The program seeks and receives grants for the Community Block Development Program and Weatherization Program. This is a low-income program with participants as directed by the grants. Energy auditors submit homes for the weatherization program.

1C.6.2 Residential Load Management Program

Residential Load Management Program is intended for customers that have electric water heaters, central air conditioning units, and central heating units. This program allows the city to regulate the usage of the appliances as a way to reduce weather sensitive peak demands. Two of the All-Requirements members currently have direct load control programs in place.

The members are City of Ocala and City of Leesburg. The City of Leesburg's load management program was analyzed and started under the direction of the City. The City of Ocala's load management program was analyzed and started under the direction of FMPA. Table 1C.6-1 provides the forecasted load management projections for the two programs for both summer and winter periods. The savings from the two programs are shared among all All-Requirements members when activated.

1C.6.3 New Conservation and Demand-Side Programs

FMPA along with KUA evaluated approximately 70 new conservation and demand-side programs in order to ensure that Cane Island Unit 3 is the least cost alternative. Details of the evaluations are contained in Volume 1A.5.0. Each of the programs were evaluated using the FPSC approved Florida Integrated Resource Evaluator (FIRE) model. The analysis indicates that none of the demand-side alternatives are cost effective at this juncture. Therefore FMPA is not pursuing new conservation or demand-side management programs at this time.

Table 1C.6-1
All-Requirements Total Forecast Load Management Capability
(As of January 1997)

Year	Summer						Winter		Total MW
	Ocala MW	Ocala Gwh	Leesburg MW	Leesburg Gwh	Total MW	Total GWh	Ocala MW	Leesburg MW	
1997	1.7	0.017	1.5	0.015	3.2	0.03	2.6	2.8	5.4
1998	1.9	0.019	1.7	0.017	3.6	0.04	2.9	3.0	5.9
1999	2.0	0.020	1.8	0.018	3.8	0.04	3.1	3.2	6.3
2000	2.1	0.021	1.9	0.019	4.0	0.04	3.3	3.4	6.8
2001	2.2	0.022	2.0	0.020	4.2	0.04	3.6	3.6	7.2
2002	2.4	0.024	2.1	0.021	4.5	0.04	3.8	3.8	7.6
2003	2.5	0.025	2.2	0.022	4.7	0.05	4.0	3.9	7.9
2004	2.6	0.026	2.3	0.023	4.8	0.05	4.2	4.1	8.2
2005	2.7	0.027	2.3	0.023	5.0	0.05	4.4	4.2	8.5
2006	2.7	0.027	2.4	0.024	5.1	0.05	4.4	4.3	8.7
2007	2.8	0.028	2.4	0.024	5.2	0.05	4.5	4.4	8.9
2008	2.8	0.028	2.5	0.025	5.3	0.05	4.5	4.5	9.0
2009	2.8	0.028	2.5	0.025	5.4	0.05	4.6	4.6	9.2
2010	2.8	0.028	2.6	0.026	5.4	0.05	4.6	4.7	9.3
2011	2.9	0.029	2.6	0.026	5.5	0.06	4.7	4.7	9.4
2012	2.9	0.029	2.7	0.027	5.6	0.06	4.7	4.8	9.5
2013	2.9	0.029	2.7	0.027	5.6	0.06	4.8	4.8	9.6
2014	3.0	0.030	2.7	0.027	5.7	0.06	4.8	4.9	9.7
2015	3.0	0.030	2.7	0.027	5.7	0.06	4.9	4.9	9.8
2016	3.0	0.030	2.7	0.027	5.7	0.06	4.9	4.9	9.9
2017	3.0	0.030	2.7	0.027	5.7	0.06	4.9	4.9	9.9

1C.7.0 Reliability Criteria

1C.7.1 Development of Reliability Criteria

There are two basic methods used in the utility industry to calculate a system's reliability indices. The two methods are deterministic and probabilistic methods. The most often used deterministic method is reserve margin which is calculated as the system net capacity less system net peak demand, divided by the system peak demand.

The probabilistic method of system planning incorporates the probability of individual unit outages and emergency assistance from other systems and involves calculations that are more mathematically complex. The probabilistic index most frequently used is the loss of load probability (LOLP) which is the expected number of days per year when the utility is projected to have insufficient capacity on-line with tie-line assistance to meet its peak daily load. The calculation of LOLP is very strongly driven by the values of tie-line assistance. For systems with multiple interconnections these tie-line assistance values are very difficult to develop and as such comparisons to commonly accepted LOLP values such as 1 day in 10 years are very hard to develop for individual systems. The use of a LOLP criteria is much better suited to a larger integrated system with limited tie-line assistance such as Peninsular Florida. For a diverse transmission system dependent system like the All-Requirements Project, LOLP would likely result in a misleading reliability criteria since the tie-line assistance would likely overpower the influence of generating capacity in the LOLP calculation. For these reasons, FMPA does not use LOLP as a reliability criterion.

FMPA is a member of the Florida Reliability Coordinating Council (FRCC). FRCC has specific criteria for determining each utility's operating and spinning reserve requirements, but does not have specific planning reserve requirements. The selection of specific planning reserve requirements is up to the individual utility.

The Florida Public Service Commission (FPSC) has set a minimum planned reserve margin criteria of 15 percent in 25-6.035 (1,) Fla. Admin. Code, for the purposes of sharing reserves. The 15 percent planned reserve margin criteria is generally consistent with utility practice throughout the industry. Many pools and reliability councils require reserve margins ranging from 15 to 20 percent. FMPA is currently using an 18 percent minimum reserve criteria for determining the need for capacity additions. The 18 percent criteria is slightly more conservative than the FPSC's 15 percent criteria, and is consistent with general utility practice throughout the industry.

1C.7.2 Reliability Need for Cane Island Unit 3

Applying the base case forecast for electrical demand, FMPA will need additional capacity by the year 2001 to maintain a 18 percent reserve margin for summer. Table 1C.7-1 presents the projected reliability levels for FMPA's system without resource additions (excluding projected contract power purchase capacity) for summer, while Table 1C.7-2 is for winter. Table 1C.7-1 clearly indicates that capacity is needed in 2001.

Table 1C.7-1
Projected Reliability Levels with
Demand-Side Management and Conservation - Summer

Year	Total Installed Capacity (MW)	Power Purchases (MW)	Total Capacity (MW)	Peak Demand (MW)	Reserve Margin (1) (percent)
1998	377	753	1,130	892	29.81
1999	377	843	1,220	988	26.49
2000	377	838	1,215	1,011	22.40
2001	377	718	1,095	1,034	7.38
2002	377	786	1,163	1,056	11.58
2003	377	837	1,214	1,077	13.51
2004	377	840	1,217	1,098	11.58
2005	377	868	1,245	1,118	12.08
2006	377	847	1,224	1,136	8.46
2007	377	805	1,182	1,154	3.13
2008	377	810	1,187	1,171	2.06
2009	377	455	832	1,187	(29.22)
2010	377	455	832	1,202	(30.11)
2011	377	455	832	1,217	(30.97)
2012	377	455	832	1,229	(31.64)
2013	377	410	787	1,242	(36.63)
2014	377	410	787	1,254	(37.24)
2015	377	410	787	1,265	(37.79)
2016	377	410	787	1,276	(38.32)
2017	377	410	787	1,286	(38.80)

(1) Reserve margin includes reserves associated with PR purchases.

Table 1C.7-2 Projected Reliability Levels with Demand-Side Management and Conservation - Winter					
Year	Total Installed Capacity (MW)	Power Purchases (MW)	Total Capacity (MW)	Peak Demand (MW)	Reserve Margin (1) (percent)
1997/98	373	758	1,131	846	36.99
1998/99	408	860	1,268	1,025	26.43
1999/00	408	855	1,263	1,049	23.06
2000/01	408	885	1,293	1,074	22.99
2001/02	408	823	1,231	1,097	14.76
2002/03	408	854	1,262	1,120	15.17
2003/04	408	867	1,275	1,142	14.09
2004/05	408	880	1,288	1,163	13.15
2005/06	408	899	1,307	1,182	12.94
2006/07	408	832	1,240	1,201	5.57
2007/08	408	854	1,262	1,218	5.90
2008/09	408	472	880	1,235	(26.49)
2009/10	408	472	880	1,251	(27.43)
2010/11	408	472	880	1,266	(28.29)
2011/12	408	472	880	1,280	(29.07)
2012/13	408	472	880	1,293	(29.78)
2013/14	408	472	880	1,305	(30.43)
2014/15	408	472	880	1,317	(31.06)
2015/16	408	427	835	1,328	(35.02)
2016/17	408	427	835	1,338	(35.51)

(1) Reserve margin includes reserves associated with PR purchases.

1C.8.0 Supply-Side Alternatives

FMPA conducted a very thorough search for supply-side alternatives that would best fit the planning needs for future demands. The alternatives considered and briefly discussed below included self-build generation alternatives and purchased power alternatives. Details of the self-build generation alternatives are provided in Section 1A.6.0.

1C.8.1 Self-Build Generation Alternatives

Self-build generation alternatives were identified based on system characteristics, existing generating alternatives, and projected need for capacity. The alternatives identified in Section 1A.6.0 were developed to be applied jointly by KUA and FMPA in the economic evaluation of potential resources. FMPA has applied the supply-side resources that passed the screening analysis in its economic modeling of system production costs over the 20 year planning horizon. There were ultimately 10 self-build generating alternatives modeled in the EGEAS evaluations. The alternatives are listed in Section 1C.9.0. Details of the generating unit alternative characteristics and performance are contained in Section 1A.6.0.

1C.8.2 Purchase Power Alternatives

FMPA conducted a three-phase evaluation of several power supply proposals received in response to a request for proposals (RFP), RFP # 9720 issued May 28, 1997, for supply of capacity and energy in various quantities for different time periods. The RFP was issued concurrent with a similar RFP by KUA. The comparison of power supply bids took into consideration many applicable pricing parameters including fixed and variable O&M charges, fuels commodity and transportation costs, applicable transmission rates, transmission upgrade costs, and system losses. Certain non-price parameters were also considered in the evaluation including contract term, firmness of supply and commercial viability.

The Stage I evaluation focused on the completeness of each proposal package and satisfaction of specified minimum requirements but did not address the price and non-price substantive criteria in each bid.

The Stage II evaluation centered primarily on the relative pricing of each proposal as compared to each of the other similar proposals. A busbar analysis was conducted to determine the cumulative present value on a $/MWH basis relative to each other similar term bid and a) for the short- and medium-term proposals, to the cost of purchased power based on projected market based rates and b) for the long-term proposals, the cost of FMPA's self-build project alternative.

In the Stage III evaluation, both price and non-price factors were considered in the evaluation of the most competitive remaining proposals in each of the short, medium and long-term categories. Non-price factors considered at this stage included contract term, dispatchability, existing generation versus planned, ability to finance new facilities, fuel risk, firmness of supply, transmission capability/availability, viability of technology, environmental considerations, and regulatory considerations. Each of these items represented an important risk factor in selecting both the short-list of proposals and, ultimately, the companies with which FMPA desired to contract.

FMPA received 33 proposals from 17 different bidders in response to the RFP for up to 360 MW of power from 2001 through 2021. The capacity of all proposals in the initial screening phase totaled approximately 3,500 MW. The RFP specified that FMPA was seeking three separate purchases each for up to 120 MW with varying contract periods. Table 1C.8-1 displays the contract periods requested.

Table 1C.8-1
FMPA Power Supply RFP

Capacity	Commence Service	Contract Period
120 MW	Dec. 16, 2000	Apprx. 5 yrs. ("short-term")
120 MW	Dec. 16, 2001	Apprx. 7 yrs. ("medium-term")
120 MW	June 1, 2001	Min. 20 yrs. ("long-term")

The following entities submitted responses to the RFP issued by FMPA:

1. Constellation Power Development
2. Indeck Energy Services
3. Lakeland Electric & Water Utilities
4. Lee County Solid Waste Management
5. LG&E Power Marketing
6. LS Power, LLC
7. NorAm Energy Services
8. NP Energy
9. Orlando Utilities Commission
10. Panda Energy International

11. PECO Energy Company
12. Polsky Energy Corporation
13. Progress Energy Corporation
14. SEMCOR Energy
15. Southern Wholesale Energy
16. Tarpon Power Partners
17. Tenaska Energy Partners

Once the Stage III evaluations were complete, a short-list of bidders was prepared with seven bidders representing nine separate proposals being selected for further negotiations:

Long-Term Proposals
Constellation Power Development
Tarpon Power Partners

Medium-Term Proposals
Constellation Power Development
Lakeland Electric & Water Utilities
Panda Energy International
Progress Energy Corporation

Short-Term Proposals
Lee County Solid Waste Management
Orlando Utilities Commission
Panda Energy International

The two entities that were short-listed as possible providers of long-term capacity, i.e. Constellation Power Development and Tarpon Power Partners, both proposed building a 2 x 1 "G" class combined cycle to be located in Hardee County. FMPA eliminated these two long-term bids due primarily to two very important factors: questionable viability of the proposed new generation technology and a negative regulatory atmosphere regarding "merchant plants", as were both proposals.

The "G" class technology is one of the latest technologies available from Westinghouse with very little demonstrated operating time. There is one such "G" class machine now operating in Japan and there are two more being installed: one in Europe and one at the City of Lakeland, but neither is in operation today. From a strategic point of view, although this new technology promises greater efficiencies and potentially lower cost power, the lack of operating experience with this new design raises serious questions about plant reliability and poses a significant risk to the FMPA All-Requirements Project participants. The reported efficiency improvements as compared to the commercially proven "F" class technology does not in FMPA's opinion outweigh the higher risk with the new "G" class combustion turbines.

Regarding regulatory considerations, last year the Florida Public Service Commission (FPSC) formally decided to not address the question of whether or not independent power producers (IPPs) would be allowed to build "merchant plants" in Florida. If approved, merchant plants could simply be constructed, without necessarily demonstrating an actual need to meet load growth in Florida, for the primary purpose of competing in the generation market against other existing power suppliers. The FPSC turned down a recommendation from the FPSC staff to issue a declaratory statement that would have allowed IPPs building merchant plants to qualify as applicants under the Power Plant Siting Act. If nothing else, the FPSC decision will definitely delay the possibility of "merchant plants" becoming a reality in Florida. This makes the start and completion dates for the two long-term RFP proposals most uncertain.

Three of the six medium- and short-term bidders, i.e. Constellation Power Development, Panda Energy International and Progress Energy Corporation, were also eliminated from the RFP process primarily due to the fact that there proposals were also based on the construction of "merchant plants".

The remaining short-listed medium- and short-term bidders, i.e. Lakeland Electric & Water, Lee County Solid Waste Management and Orlando Utilities Commission are currently in negotiations with FMPA for possible power supply agreements based on their respective RFP.

In summary, all of the short-listed bidders whose proposals were not based on construction of a "merchant plant" are currently involved in contract discussions with FMPA.

1C.9.0 Supply-Side Screening

A detailed supply-side screening analysis was conducted in Section 1A.6.8 of Volume 1A to reduce the number of alternatives to be modeled in the economic evaluation. The conventional alternatives from Section 1A.6.0 which were considered appropriate for modeling with EGEAS are presented on Tables 1C.9-1 through 1C.9-10.

Table 1C.9-1 Estimated Cost and Performance of 250 MW Pulverized Coal Unit	
Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 2001 $1,000	194,115
Indirect Capital Cost, 2001 $1,000	84,958
Total Capital Cost, 2001 $1,000	279,073 (1)
O&M Cost-Baseload Duty	
Fixed O&M Cost, 2001 $/kW-y	33.83
Variable O&M Cost, 2001 $/MWh	4.71
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	9
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	1,750
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	240,749/10,157
75 Percent of Full Load	180,562/10,275
50 Percent of Full Load	120,374/10,967
25 Percent of Full Load	60,187/13,302

1. Includes interest during construction.

Table IC.9-2
Estimated Cost and Performance of 250 MW Fluidized Bed Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 2001 $1,000	180,415
Indirect Capital Cost, 2001 $1,000	81,710
Total Capital Cost, 2001 $1,000	262,125 (1)
O&M Cost-Baseload Duty	
Fixed O&M Cost, 2001 $/kW-y	28.69
Variable O&M Cost, 2001 $/MWh	4.87
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	9
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	4,800
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	242,794/10,250
75 Percent of Full Load	182,095/10,353
50 Percent of Full Load	121,397/11,025
25 Percent of Full Load	60,698/13,295

1. Includes interest during construction.

Table 1C.9-3 Generating Unit Characteristics 7EA 1 x 1 Combined Cycle		
Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	56,981	
Indirect Capital Cost, 2001 $1,000	20,923	
Total Capital Cost, 2001 $1,000	77,904 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 $/kW-y	3.59	
Variable O&M Cost, 2001 $/MWh	2.59	
Equivalent Availability, percent	92.1	
Equivalent Forced Outage Rate, percent	3.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	59	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	109,939/8,114	124,166/7,849
79 Percent of Full Load	86,852/8,454	98,091/8,100
59 Percent of Full Load	64,864/9,219	73,258/8,738
35 Percent of Full Load	38,479/11,288	43,458/10,478

1. Includes interest during construction.

Table 1C.9-4 Generating Unit Characteristics 7EA 2 x 1 Combined Cycle		
Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	95,069	
Indirect Capital Cost, 2001 $1,000	39,115	
Total Capital Cost, 2001 $1,000	134,184 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 $/kW-y	2.45	
Variable O&M Cost, 2001 $/MWh	2.36	
Equivalent Availability, percent	94.1	
Equivalent Forced Outage Rate, percent	1.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	119	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	222,096/7,938	250,416/7,791
75 Percent of Full Load	166,572/8,258	187,812/8,025
50 Percent of Full Load	111,048/8,178	125,208/7,869
25 Percent of Full Load	55,524/9,865	62,604/9,309

1. Includes interest during construction.

Table 1C.9-5 Generating Unit Characteristics Westinghouse 1 x 1 501F Combined Cycle		
Item		
Steam Pressure, psia	1,800	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2001 $1,000	83,622	
Indirect Capital Cost, 2001 $1,000	33,944	
Total Capital Cost, 2001 $1,000	117,566 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 $/kW-y	2.27	
Variable O&M Cost, 2001 $/MWh	2.82	
Equivalent Availability, percent	91.8	
Equivalent Forced Outage Rate, percent	4.1	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	84	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	236,630/6,945	261,792/6,815
75 Percent of Full Load	175,106/7,483	196,344/7,141
52 Percent of Full Load	123,048/8,011	138,750/7,699
27 Percent of Full Load	63,890/10,474	73,302/9,894

1. Includes interest during construction.

Table 1C.9-6
Generating Unit Characteristics
Westinghouse 1 x 1 501G Combined Cycle

Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2001 $1,000	107,386	
Indirect Capital Cost, 2001 $1,000	39,976	
Total Capital Cost, 2001 $1,000	147,362 (1) (2)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 $/kW-y	2.13	
Variable O&M Cost, 2001 $/MWh	2.48 (3)	
Equivalent Availability, percent	83.0	
Equivalent Forced Outage Rate, percent	13.3	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	92	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	294,960/7,062	333,456/6,784
75 Percent of Full Load	221,220/7,437	250,092/7,083
50 Percent of Full Load	147,480/8,190	166,728/7,714
25 Percent of Full Load	73,740/10,788	83,364/9,967

1. Includes interest during construction.
2. After 2001, SCR is not included and total capital cost is reduced to $145,157 in 2001 dollars.
3. After 2001, SCR is not included and variable O&M is reduced to $2.33 in 2001 dollars.

Table 1C.9-7
Generating Unit Characteristics
General Electric LM6000 Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	16,209	
Indirect Capital Cost, 2001 $1,000	5,956	
Total Capital Cost, 2001 $1,000	22,165 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 $/kW-y	5.96	
Variable O&M Cost, 2001 $/MWh	7.56	
Equivalent Availability, percent	95.8	
Equivalent Forced Outage Rate, percent	2.3	
Planned Maintenance Outage, weeks/y	1	
Startup Fuel (cold start), MBtu	6	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	33,360/9,893	41,664/9,417
75 Percent of Full Load	25,020/10,475	31,248/9,806
50 Percent of Full Load	16,680/11,639	20,832/10,650
25 Percent of Full Load	8,340/15,136	10,416/13,183

1. Includes interest during construction.

Table 1C.9-8
Generating Unit Characteristics
General Electric 7EA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	22,527	
Indirect Capital Cost, 2001 $1,000	8,924	
Total Capital Cost, 2001 $1,000	31,451 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 $/kW-y	3.63	
Variable O&M Cost, 2001 $/MWh	25.74	
Equivalent Availability, percent	95.6	
Equivalent Forced Outage Rate, percent	2.1	
Planned Maintenance Outage, weeks/y	1.25	
Startup Fuel (cold start), MBtu	12	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	72,432/12,335	81,552/11,959
75 Percent of Full Load	54,324/13,504	61,164/13,050
50 Percent of Full Load	36,216/15,844	40,776/15,300
25 Percent of Full Load	18,108/23,515	20,388/22,097

1. Includes interest during construction.

Table 1C.9-9 Generating Unit Characteristics Westinghouse 501G Simple Cycle		
Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	51,871	
Indirect Capital Cost, 2001 $1,000	22,823	
Total Capital Cost, 2001 $1,000	74,694 (1) (2)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 $/kW-y	2.33	
Variable O&M Cost, 2001 $/MWh	12.68 (3)	
Equivalent Availability, percent	84.2	
Equivalent Forced Outage Rate, percent	13.3	
Planned Maintenance Outage, weeks/y	1.5	
Startup Fuel (cold start), MBtu	18	
Construction Period, months	15	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	197,040/10,502	223,872/10,047
75 Percent of Full Load	147,780/11,377	167,904/10,854
50 Percent of Full Load	98,520/13,128	111,936/12,470
25 Percent of Full Load	49,260/18,757	55,968/17,322

1. Includes interest during construction.
2. After 2001, SCR is not included and total capital cost is reduced to $72,522 in 2001 dollars.
3. After 2001, SCR is not included and variable O&M is reduced to $11.19/Mwh in 2001 dollars.

Table 1C.9-10
Generating Unit Characteristics
General Electric 7FA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	35,300	
Indirect Capital Cost, 2001 $1,000	13,457	
Total Capital Cost, 2001 $1,000	48,757 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 $/kW-y	2.70	
Variable O&M Cost, 2001 $/MWh	11.33	
Equivalent Availability, percent	94.5	
Equivalent Forced Outage Rate, percent	2.7	
Planned Maintenance Outage, weeks/y	1.5	
Startup Fuel (cold start), MBtu	35	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	147,168/11,063	165,312/10,698
75 Percent of Full Load	110,376/12,030	123,984/11,546
50 Percent of Full Load	73,584/14,090	82,656/13,400
25 Percent of Full Load	36,792/20,339	41,328/19,122

1. Includes interest during construction.

1C.10.0 Economic Analysis

The economic analysis for the All-Requirements Project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of its participants. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

1C.10.1 Methodology

The economic analysis consists of essentially three phases: demand-side, supply-side, and sensitivity analysis. Supply-side and demand-side are discussed in this subsection, whereas, sensitivity analysis will be addressed in Section 1C.11.0

Demand-side alternatives evaluated in 1A.5.0 using the FIRE model did not prove to be cost effective. Therefore, no further analysis will be considered in the production cost modeling. Details of the FIRE modeling are discussed in 1A.5.0.

Supply-side alternatives are evaluated using the Electric Generation Expansion Analysis System (EGEAS) modeling software. EGEAS evaluates all combinations of generating unit alternatives and purchase power options to determine the combination of alternatives that exhibit the lowest cumulative present worth revenue requirements while maintaining user-defined reliability criteria. The reserve criteria utilized is a minimum of 18 percent reserves and a maximum of 30 percent reserves.

The supply-side alternatives that passed the screening analysis in Section 1A.6.8 were analyzed on a comparative cost basis. Comparative costs include only those costs which are affected by differences in the plans. The comparative cost analysis will yield the optimal alternative, but should not be used to project actual total costs.

The plans were analyzed over twenty year period from 1998 to 2017. FMPA views this planning horizon to reflect the appropriate time interval for resource evaluation in today's energy market. While resources are evaluated over a 20 year period, FMPA does not formally plan beyond a 10 year period. With load growth, economic parameters, technology development, regulatory issues, and all other future conditions changing rapidly it is very uncertain what future conditions will be like. Therefore, FMPA has forecasted what it expects as reasonable assumptions for the future, but views the period beyond 2007 as too uncertain to begin formal planning. Because an EGEAS 20 year resource optimization study needs capacity to fulfill the reserve margin requirements in the years beyond 2007, generating units were selected by the model based upon EGEAS's least-cost analysis to meet future load growth. It is uncertain whether FMPA would actually pursue the construction of the selected units beyond 2007, but such options will be frequently reviewed as the 10 year planning horizon encompasses those future years.

Several sensitivities are addressed in Section 1C.11.0 to demonstrate the robustness of the expansion plan. Sensitivities addressed include: low load growth, high load growth, low fuel prices, high fuel prices, constant differential between natural gas/oil and coal, 15 percent reserve margin criteria, and an increase in the capital cost of Cane Island Unit 3.

1C.10.2 Expansion Candidates

The expansion candidates for the EGEAS evaluation were taken directly from the screening analysis in Section 1A.6.8. The expansion candidates were developed to be applied jointly by KUA and FMPA. Table 1C.10-1 provides a summary of the expansion alternatives considered, with details provided in Section 1C.9.0. FMPA evaluated all of the expansion candidates in the year 2001 as 50 percent ownership with KUA, after which time the units were modeled as 100 percent ownership. The expansion candidates represent generic unit performance and characteristics and are subject to slight increases and/or decreases in specific parameters. The performance is dependent upon configurations and equipment utilized

1C.10.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case FMPA All-Requirements load forecast, base case fuel price forecast, and minimum reserve margin for FMPA at 18 percent. Results of the base case scenario economic evaluation are summarized in this subsection.

Based upon the cost and performance characteristics described in detail in Section 1C.9.0 and summarized in Table 1C.10-1, the expansion plan outlined in Table 1C.10-2 represents the least-cost plan for FMPA under the base case scenario. The least-cost plan consists of the construction of an "F" class combined cycle turbine in which FMPA will share 50 percent ownership, purchase power opportunities identified from the 1997 RFP process as well as additional purchase power for which FMPA is negotiating, the construction of a 7EA simple

Table 1C.10-1
Summary of Generation Alternatives (2001 $)

Description	Capital Costs **	Capacity**		O&M Costs**		Fuel Type	Full Load Heat Rate*	Forced Outage Rate	Planned Maintenance	First Year Available
		Summer	Winter	Variable	Fixed					
	$1,000	MW	MW	$/MWh	$kW-Yr		Btu/kWh	percent	weeks	
Pulverized Coal	279,873	240.75	240.75	4.71	33.83	Coal	10,157	9.0	4.00	2002
Fluidized Bed	262,125	242.78	242.78	4.87	28.69	Coal	10,250	9.0	4.00	2002
7EA 1x1 CC	77,984	109.94	124.166	2.59	3.59	Nat. Gas	7,849	3.7	2.25	2001
7EA 2x1 CC	134,184	222.10	250.42	2.36	2.45	Nat. Gas	7,791	1.7	2.25	2001
501F 1x1 CC	117,566	236.63	261.79	2.82	2.27	Nat. Gas	6,815	4.1	2.25	2001
501G 1x1 CC ***	147,362/ 145,157	294.96	333.46	2.48/ 2.34	2.13	Nat. Gas	6,784	13.3	2.25	2001/ 2002
LM6000 SC	22,165	33.36	41.66	7.56	5.96	Nat. Gas	9,417	2.3	1.00	2000
7EA SC	31,451	72.43	81.55	25.74	3.63	Nat. Gas	11,959	2.1	1.25	2001
501G SC ***	74,684 / 72,522	197.04	223.87	12.68/ 11.19	2.33	Nat. Gas	10,047	13.3	1.50	2001/ 2002
7FA SC	48,757	147.17	165.31	11.33	2.78	Nat. Gas	10,698	2.7	1.50	2001

*At ISO conditions including degradation.
** FMPA would retain 50 percent ownership in the expansion alternative for additions through 2001; beyond 2001 it is assumed that FMPA would have full ownership.
*** Capital and operating costs assume SCR through 2001; beyond 2001 SCR is not included in capital and operating costs.

Table 1C.10-2
Base Case Expansion Plan

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007	Build 7EA Simple Cycle (72 MW)	246,145	1,488,590
2008		256,765	1,638,908
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	255,415	1,780,641
2010		265,002	1,920,027
2011		278,201	2,058,727
2012	Build 7EA Simple Cycle (72 MW)	291,706	2,196,578
2013	Build 7EA Simple Cycle (72 MW)	312,416	2,336,520
2014		324,860	2,474,450
2015		341,307	2,611,808
2016	Build 7EA Simple Cycle (72 MW)	355,717	2,747,502
2017		373,919	2,882,703

* Indicates FMPA share of 50 percent ownership with KUA

cycle combustion turbine in 2007, and several other resources beyond 2007. All capacities listed in the tables are summer capacities. Table 1C.10-3 displays the reserve margins for the base case after the construction of the resources identified.

Tables 1C.10-4 through 1C.10-6 provide the top three expansion plans that were runner-ups to the top plan with their associated higher cumulative present worth revenue requirements. These plans were very similar in nature to the base case plan with minor changes in the years beyond 2007. All of the top plans selected the construction of the combined cycle "501F" machine in the year 2001 and the "7EA" combustion turbine in 2007 as the least-cost alternative.

The capacities listed next to the generating unit expansion units are summer capacities. The economic evaluation modeled the generating alternatives using their respective summer and winter ratings for the two seasons. Since the All-Requirements project is a system that is driven by summer peak demand for reserve criteria, the associated summer capacity is listed for convenience. The modeling of the capacities for seasonal variations provides a more accurate estimate for the least-cost expansion plan for FMPA.

Table 1C.10-3 Projected Reliability Levels with Demand-Side Management and Conservation Including Identified Generating Alternatives - Base Case					
Year	Total Installed Capacity (MW)	Power Purchases (MW)	Total Capacity (MW)	Peak Demand (MW)	Reserve Margin (percent)
1998	377	753	1,130	892	29.81
1999	377	843	1,220	988	26.49
2000	377	838	1,215	1,011	22.40
2001	495	718	1,213	1,034	18.79
2002	495	786	1,281	1,056	22.76
2003	495	837	1,332	1,077	24.46
2004	495	840	1,335	1,098	22.32
2005	495	868	1,363	1,118	22.64
2006	495	847	1,342	1,136	18.85
2007	567	805	1,372	1,154	19.59
2008	567	810	1,377	1,171	18.28
2009	934	455	1,389	1,187	18.31
2010	934	455	1,389	1,202	18.15
2011	934	455	1,389	1,217	18.01
2012	1006	455	1,461	1,229	19.54
2013	1078	410	1,488	1,242	19.81
2014	1078	410	1,488	1,254	18.66
2015	1078	410	1,488	1,265	18.01
2016	1150	410	1,560	1,276	22.26
2017	1150	410	1,560	1,286	21.31

Table 1C.10-4
Base Case Expansion Plan - Runner-Up #1

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007	Build 7EA Simple Cycle (72 MW)	246,145	1,488,590
2008		256,765	1,638,908
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	255,415	1,780,641
2010		265,002	1,920,027
2011		278,201	2,058,727
2012	Build 7EA Simple Cycle (72 MW)	291,706	2,196,578
2013	Build 7EA Simple Cycle (72 MW)	312,416	2,336,520
2014		324,860	2,474,450
2015	Build 7EA Simple Cycle (72 MW)	344,127	2,612,943
2016		355,717	2,748,637
2017		373,919	2,883,838

* Indicates FMPA share of 50 percent ownership with KUA

Table 1C.10-5
Base Case Expansion Plan - Runner-Up #2

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007	Build 7EA Simple Cycle (72 MW)	246,145	1,488,590
2008		256,765	1,638,908
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	255,415	1,780,641
2010		265,002	1,920,027
2011	Build 7EA Simple Cycle (72 MW)	280,919	2,060,082
2012		291,706	2,197,934
2013	Build 7EA Simple Cycle (72 MW)	312,416	2,337,875
2014		324,860	2,475,805
2015		341,307	2,613,163
2016	Build 7EA Simple Cycle (72 MW)	355,717	2,748,857
2017		373,919	2,884,059

* Indicates FMPA share of 50 percent ownership with KUA

Table 1C.10-6 Base Case Expansion Plan - Runner-Up #3			
Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007	Build 7EA Simple Cycle (72 MW)	246,145	1,488,590
2008		256,765	1,638,908
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	255,415	1,780,641
2010		265,002	1,920,027
2011		278,201	2,058,727
2012	Build 7EA Simple Cycle (72 MW)	291,706	2,196,578
2013	Build 7EA Simple Cycle (72 MW)	312,416	2,336,520
2014		324,860	2,474,450
2015		341,307	2,611,808
2016	Build 7EA Simple Cycle (72 MW)	355,717	2,747,502
2017	Build 7EA 1x1 Combined Cycle (109 MW)	380,983	2,885,257

* Indicates FMPA share of 50 percent ownership with KUA.

1C.11.0 Sensitivity Analyses

FMPA performed several sensitivities to measure the impact of key assumptions on the least-cost plan. The sensitivities are presented in Sections 1C.11.1 through 1C.11.7 which include: low load and energy growth, high load and energy growth, low fuel price escalation, high fuel price escalation, constant differential between oil/gas and coal prices over the planning horizon, fifteen percent reserve margin sensitivity, and a case where Cane Island 3 capital cost is increased. For each sensitivity the least-cost plan over the planning horizon is identified.

The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs. While the tables indicate the resources necessary to maintain system reserve margins above 18 percent in all years (excluding the 15 percent reserve margin sensitivity), FMPA does not formally plan for resource additions beyond 10 years due to the large uncertainties of the future. Therefore, the resources identified by EGEAS as least-cost resources beyond 2007 represent units that are place holders in the economic analysis.

All capacities listed in the expansion plan summary tables are the summer ratings of the units. The summer capacity is listed because reserve margins are driven by the summer peak demand. The modeling of the units applied both the summer and winter ratings of the units in their respective seasons. As demonstrated in the sensitivities and the base case expansion plans, the construction of Cane Island 3 is the best resource addition for the All-Requirements Project.

1C.11.1 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth are less than the expected base case forecast. The low load and energy growth requires less generation resources than the base case forecast. Table 1C.11-1 indicates the need for power based upon the low load and energy forecast. Capacity is still required in 2001 for the low load and energy forecast. Table 1C.11-2 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity. With the lower load and energy projections, EGEAS still selects the 501F combined cycle in 2001.

Table 1C.11-1
Projected Reserve Margin Levels with
Demand-Side Management and Conservation
***Before Expansion Plan* - Low Growth**

Year	Summer Total Installed Capacity (MW)	Summer Power Purchases (MW)	Summer Total Capacity (MW)	Summer Peak Demand (MW)	Summer Reserve Margin[1] (percent)
1998	377	753	1,130	849	36.38
1999	377	843	1,220	940	32.95
2000	377	838	1,215	962	28.64
2001	377	718	1,095	984	12.84
2002	377	786	1,163	1,005	17.24
2003	377	837	1,214	1,025	19.26
2004	377	840	1,217	1,045	17.23
2005	377	868	1,245	1,064	17.77
2006	377	847	1,224	1,081	13.98
2007	377	805	1,182	1,098	8.39
2008	377	810	1,187	1,114	7.28
2009	377	455	832	1,130	(25.65)
2010	377	455	832	1,144	(26.56)
2011	377	455	832	1,158	(27.45)
2012	377	455	832	1,170	(28.20)
2013	377	410	787	1,183	(33.47)
2014	377	410	787	1,194	(34.09)
2015	377	410	787	1,205	(34.69)
2016	377	410	787	1,215	(35.23)
2017	377	410	787	1,224	(35.70)

(1) Reserve margin includes reserves associated with PR purchases.

Table 1C.11-2
Low Load and Energy Growth Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		129,256	129,256
1999		141,613	263,486
2000		147,649	396,142
2001	Build 501F 1x1 Combined Cycle (118 MW *)	171,260	541,989
2002		182,205	689,068
2003		193,558	837,166
2004		200,730	982,745
2005		211,304	1,128,003
2006		220,791	1,271,870
2007		231,175	1,414,651
2008		241,138	1,555,820
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7FA Simple Cycle (147 MW)	242,101	1,690,165
2010		250,820	1,822,092
2011		262,748	1,953,088
2012		272,358	2,081,796
2013		287,545	2,210,597
2014		298,524	2,337,345
2015	Build 7EA Simple Cycle (72 MW)	315,527	2,464,327
2016		325,480	2,588,487
2017		341,331	2,711,905

* Indicates FMPA share of 50 percent ownership with KUA

1C.11.2 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth are greater than the expected forecast. The high load and energy growth requires the addition of more generation and thus the increase in cumulative present worth for the supply plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Subsection 1C.5.4.1. Table 1C.11-3 indicates the need for power based upon the high load and energy forecast.

As indicated in Table 1C.11-3, the need for power to maintain an 18 percent reserve margin occurs in 2000. Since the planning alternatives evaluated are not available until 2001, purchased power from an existing partial requirements purchase is assumed be made in 2000 to maintain system reserves. The least-cost plan selected for the high load sensitivity is a combination of units in 2001, a 501G 1x1 combined cycle and a 7EA 1x1 combined cycle that FMPA would retain 50 percent ownership. Table 1C.11-4 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity.

A sensitivity analysis was conducted for the high load case to determine what the cumulative present worth impact would be if FMPA proceeded with the construction of the 501F 1x1 combined cycle in 2001. Table 1C.11-5 displays the results of the analysis. As indicated in the cumulative present worth, a savings of 12.5 million dollars is achieved by constructing the 501G 1x1 combined cycle for the high load case. With the unproven results of the 501G, FMPA feels that the construction of the 501G in 2001 will present high risks on availability, operating costs, and potential system reserves. Therefore, FMPA will proceed with the construction of Cane Island 3 501F 1x1 combined cycle.

1C.11.3 Low Fuel Price Escalation

The low fuel price scenario applies the low fuel price forecast to the generation planning assumptions. The low fuel price forecast is provided in Section 1A.3.2. With the low fuel price forecast, the resource plan indicates increased amounts of energy from generation resources and decreased reliance on purchased power as low cost power sources. Table 1C.11-6 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity.

Table 1C.11-3
Projected Reserve Margin Levels with
Demand-Side Management and Conservation
***Before Expansion Plan* - High Load Growth**

Year	Summer Total Installed Capacity (MW)	Summer Power Purchases (MW)	Summer Total Capacity (MW)	Summer Peak Demand (MW)	Summer Reserve Margin[1] (percent)
1998	377	753	1,130	938	23.44
1999	377	843	1,220	1,038	20.40
2000	377	838	1,215	1,062	16.53
2001	377	718	1,095	1,086	2.24
2002	377	786	1,163	1,109	6.25
2003	377	837	1,214	1,132	7.99
2004	377	840	1,217	1,154	6.16
2005	377	868	1,245	1,174	6.74
2006	377	847	1,224	1,194	3.19
2007	377	805	1,182	1,212	(1.81)
2008	377	810	1,187	1,230	(2.84)
2009	377	455	832	1,247	(32.63)
2010	377	455	832	1,263	(33.48)
2011	377	455	832	1,278	(34.26)
2012	377	455	832	1,292	(34.98)
2013	377	410	787	1,305	(39.69)
2014	377	410	787	1,318	(40.29)
2015	377	410	787	1,329	(40.78)
2016	377	410	787	1,340	(41.27)
2017	377	410	787	1,351	(41.75)

(1) Reserve Margin includes reserves associated with PR purchases.

Table 1C.11-4
High Load and Energy Growth Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		142,779	142,779
1999		156,540	291,158
2000	Increase Partial Requirements (25MW)	163,844	438,364
2001	Build 501G 1x1 Combined Cycle (147 MW)* Build 7EA 1x1 Combined Cycle (55 MW) *	187,711	598,221
2002		199,228	759,041
2003		211,092	920,555
2004		218,912	1,079,320
2005		230,033	1,237,454
2006		240,226	1,393,985
2007		251,292	1,549,190
2008		262,113	1,702,639
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	264,935	1,849,655
2010		274,635	1,994,108
2011		287,579	3,137,484
2012		298,186	2,278,397
2013	Build 7EA Simple Cycle (72 MW)	317,046	2,420,413
2014		329,202	2,560,186
2015		344,625	2,698,879
2016	Build 7EA Simple Cycle (72 MW)	358,488	2,835,630
2017		375,692	2,971,472

* Indicates FMPA share of 50 percent ownership with KUA

Table 1C.11-5
High Load and Energy Growth Sensitivity - 501F Installed

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		142,779	142,779
1999		156,540	291,158
2000	Increase Partial Requirements (25MW)	163,844	438,364
2001	Build 501F 1x1 Combined Cycle (118 MW) * Build 7EA 1x1 Combined Cycle (55 MW)* Build 7EA Simple Cycle (36 MW)*	189,147	599,444
2002		200,660	761,420
2003		212,610	924,095
2004		220,485	1,084,001
2005		231,686	1,243,270
2006		241,944	1,400,921
2007		253,038	1,557,205
2008		263,857	1,711,675
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7FA Simple Cycle (147 MW)	265,981	1,859,270
2010		275,688	2,004,277
2011		288,664	2,148,194
2012		299,296	2,289,632
2013	Build 7EA Simple Cycle (72 MW)	318,229	2,432,178
2014		330,351	2,572,439
2015		345,796	2,711,603
2016		356,891	2,847,745
2017	Build 7EA Simple Cycle (72 MW)	376,836	2,984,001

* Indicates FMPA share of 50 percent ownership with KUA

Table 1C.11-6 Low Fuel Price Escalation Sensitivity			
Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		134,063	134,063
1999		146,070	272,518
2000		151,194	408,358
2001	Build 501F 1x1 Combined Cycle (118 MW) *	172,075	554,900
2002		180,775	700,824
2003		190,871	846,867
2004		196,940	989,697
2005		204,766	1,130,460
2006		212,601	1,268,991
2007	Build 7EA Simple Cycle (72 MW)	223,191	1,406,840
2008		230,938	1,542,038
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	226,966	1,667,984
2010		232,277	1,790,158
2011		241,271	1,910,446
2012	Build 7EA Simple Cycle (72 MW)	249,295	2,028,256
2013	Build 7EA Simple Cycle (72 MW)	264,651	2,146,802
2014		271,669	2,262,147
2015		282,846	2,375,978
2016	Build 7EA Simple Cycle (72 MW)	293,258	2,487,846
2017		304,566	2,597,970

* Indicates FMPA share of 50 percent ownership with KUA

1C.11.4 High Fuel Price Escalation

The high fuel price scenario applies the high fuel price forecast to the generation planning assumptions. The high fuel price forecast is provided in Section 1A.3.2. Table 1C.11-7 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity.

1C.11.5 Constant Differential of Oil/Gas Price Versus Coal Price

This scenario assumes the differential price between oil/gas and coal remains constant over the planning horizon based on current fuel prices. This fuel price sensitivity is outlined in Section 1A.3.2 with the fuel prices used are shown in Table 1C.11-8. The evaluation results indicate the following plan in Table 1C.11-9.

1C.11.6 Fifteen Percent Minimum Reserve Margin

FMPA maintains a system minimum reserve margin of 18 percent to provide adequate system reliability. If FMPA chose to lower the minimum reserve margin to 15 percent, the level the FPSC has identified as the general minimum reserve margin, additional capacity would still be required in 2001. This is demonstrated in the base case load forecast and system reliability criteria in Sections 1C.5.0 and 1C.7.0. Table 1C.11-10 summarizes the economic evaluation for the 15 percent minimum reserve margin scenario.

1C.11.7 Cane Island Unit 3 Capital Cost Increase

FMPA analyzed a scenario where the capital cost of a new 501F 1x1 combined cycle plant would increase in total capital cost by 20 percent. The increase in cost would be the result of increasing equipment or construction costs. After increasing the total capital costs by 20 percent the economic evaluation in EGEAS chose the expansion plan in Table 1C.11-12 which results in the least-cost supply plan. The expansion plan still indicates that the construction of Cane Island 3 with the 501F 1x1 combined cycle results in the least-cost expansion plan for the All-requirements Project.

The increase in capital cost also serves as a sensitivity analysis for an increase in interest rates. The 20 percent increase in capital costs is equivalent to a 20 percent increase in the fixed charge rate applied to the base case capital cost of the 501F 1x1 combined cycle. The 20 percent increase in the fixed charge rate represents an increase from 8.2 percent to 9.8 percent. The 20 percent increase in fixed charge rate corresponds to an increase in the bond rate from 5.5 percent to 7.5 percent.

Table 1C.11-7
High Fuel Price Escalation Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		137,632	137,632
1999		151,543	281,275
2000		159,627	424,692
2001	Build 501F 1x1 Combined Cycle (118 MW) *	187,651	584,498
2002		202,192	747,711
2003		216,322	913,227
2004		227,011	1,077,866
2005		239,412	1,242,447
2006		252,138	1,406,740
2007	Build 7EA Simple Cycle (72 MW)	268,406	1,572,515
2008		281,629	1,737,389
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	290,137	1,898,390
2010		304,148	2,058,366
2011		323,911	2,219,855
2012	Build 7EA Simple Cycle (72 MW)	343,068	2,381,979
2013	Build 7EA Simple Cycle (72 MW)	376,083	2,550,439
2014		395,988	2,718,568
2015		422,84[illegible]	2,888,741
2016	Build 7EA Simple Cycle (72 MW)	445,527	3,058,694
2017		475,481	3,230,618

* Indicates FMPA share of 50 percent ownership with KUA

Table 1C.11-8
Delivered Fuel Price Forecast–
Constant Differential Between Coal versus Natural Gas/Oil
($/MBtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas(1) *Existing Units*	Natural Gas(2) *New Units*
1998	1.70	2.68	4.47	0.55	2.39	3.20
1999	1.71	2.69	4.48	0.56	2.40	3.21
2000	1.74	2.72	4.51	0.59	2.43	3.24
2001	1.77	2.75	4.54	0.62	2.46	3.27
2002	1.81	2.79	4.58	0.66	2.50	3.31
2003	1.86	2.84	4.63	0.71	2.55	3.36
2004	1.90	2.88	4.67	0.75	2.59	3.40
2005	1.93	2.91	4.70	0.78	2.62	3.43
2006	1.97	2.95	4.74	0.82	2.66	3.47
2007	2.02	3.00	4.79	0.87	2.71	3.52
2008	2.06	3.04	4.83	0.91	2.75	3.56
2009	2.10	3.08	4.87	0.95	2.79	3.60
2010	2.15	3.13	4.92	1.00	2.84	3.65
2011	2.20	3.18	4.97	1.05	2.89	3.70
2012	2.23	3.21	5.00	1.08	2.92	3.73
2013	2.29	3.27	5.06	1.14	2.98	3.79
2014	2.34	3.32	5.11	1.19	3.03	3.84
2015	2.40	3.38	5.17	1.25	3.09	3.90
2016	2.46	3.44	5.23	1.31	3.15	3.96
2017	2.51	3.49	5.28	1.36	3.20	4.01

(1) Delivered natural gas price less demand reservation.
(2) Includes demand reservation costs.

Table 1C.11-9
Constant Differential of Oil/Gas Versus Coal Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		135,731	135,731
1999		149,663	277,700
2000		158,662	420,250
2001	Build 501F 1x1 Combined Cycle (118 MW) *	185,429	578,164
2002		195,095	735,648
2003		206,275	893,476
2004		213,289	1,048,163
2005		222,885	1,201,383
2006		231,441	1,352,190
2007	Build 7EA Simple Cycle (72 MW)	244,098	1,502,952
2008		251,784	1,650,354
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	247,826	1,787,876
2010		254,246	1,921,605
2011		263,395	2,052,923
2012	Build 7EA Simple Cycle (72 MW)	273,050	2,181,958
2013	Build 7EA Simple Cycle (72 MW)	288,161	2,311,035
2014		295,437	2,436,472
2015		306,663	2,559,888
2016	Build 7EA Simple Cycle (72 MW)	316,959	2,680,797
2017		327,093	2,799,067

* Indicates FMPA share of 50 percent ownership with KUA

Table 1C.11-10
Projected Reserve Margin Levels with
Demand-Side Management and Conservation - 15 Percent Reserve Margin

Year	Summer Total Installed Capacity (MW)	Summer Power Purchases (MW)	Summer Total Capacity (MW)	Summer Peak Demand (MW)	Summer Reserve Margin[1] (percent)
1998	377	753	1,130	892	29.81
1999	377	843	1,220	988	26.49
2000	377	838	1,215	1,011	22.40
2001	377	718	1,095	1,034	7.38
2002	377	786	1,163	1,056	11.58
2003	377	837	1,214	1,077	13.51
2004	377	840	1,217	1,098	11.58
2005	377	868	1,245	1,118	12.08
2006	377	847	1,224	1,136	8.46
2007	377	805	1,182	1,154	3.13
2008	377	810	1,187	1,171	2.06
2009	377	455	832	1,187	(29.22)
2010	377	455	832	1,202	(30.11)
2011	377	455	832	1,217	(30.97)
2012	377	455	832	1,229	(31.64)
2013	377	410	787	1,242	(36.63)
2014	377	410	787	1,254	(37.24)
2015	377	410	787	1,265	(37.79)
2016	377	410	787	1,276	(38.32)
2017	377	410	787	1,286	(38.80)

(1) Reserve margin includes reserves associated with PR purchases.

Table 1C.11-11 Fifteen Percent Minimum Reserve Margin			
Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007		243,270	1,486,814
2008		253,883	1,635,446
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7FA Simple Cycle (147MW)	253,338	1,776,025
2010		262,819	1,914,263
2011		275,770	2,051,752
2012		286,366	2,187,079
2013	Build 7FA Simple Cycle (147 MW)	306,731	2,324,474
2014		318,769	2,459,818
2015		334,366	2,594,382
2016		345,538	2,726,193
2017		362,914	2,857,416

* Indicates FMPA share of 50 percent ownership with KUA

Table 1C.11-12 Cane Island Unit 3 Capital Cost Increase by 20 Percent			
Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	180,776	570,176
2002		192,453	725,527
2003		204,305	881,848
2004		211,976	1,035,583
2005		223,112	1,188,959
2006		233,167	1,340,890
2007	Build 7EA Simple Cycle (72 MW)	247,109	1,493,512
2008		257,729	1,644,395
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	256,379	1,786,662
2010		265,966	1,926,556
2011		279,165	2,065,736
2012	Build 7EA Simple Cycle (72 MW)	292,670	2,204,043
2013	Build 7EA Simple Cycle (72 MW)	313,380	2,344,417
2014		325,824	2,482,756
2015		342,271	2,620,502
2016	Build 7EA Simple Cycle (72 MW)	356,681	2,756,563
2017		374,883	2,892,113

* Indicates FMPA share of 50 percent ownership with KUA

1C.12.0 Strategic Considerations

In selecting a power supply alternative, a utility must consider certain strategic factors which reflect the utility's long-term ability to provide economical and reliable electric capacity and energy to its consumers. There are a number of strategic considerations which favor the installation of Cane Island 3 over other alternatives. The strategic considerations include low installation cost on a $/kW basis, low operating costs, domestically produced fuel, existing site which can support the project capacity, electric industry deregulation, environmental benefits, and efficiency.

Cane Island 3 is one of the lowest cost alternatives on a $/kW basis in comparison to other resource additions. Unit No. 3 enjoys the lower cost of an existing site, a point in time where capital costs for combined cycle "F" technology are at the lowest price in history, and funds available for financing are at a low interest rate. These factors contribute to Cane Island 3 having a lower installed cost over other alternatives.

Cane Island Unit 3's "F" technology has the lowest heat rate of any of the generating units that are in commercial operation in the United States. The proposed "G" technology only has a slightly better heat rate than the "F" technology and is not yet in commercial operation in the United States. The efficiency of the "F" technology ensures that Cane Island Unit 3 will produce competitively priced generation for many years. If deregulation were to happen in Florida, Cane Island Unit 3 with its low heat rate would remain a competitive resource.

The ability to utilize the existing Cane Island site offers many strategic advantages. Only two additional personnel will be required for the operation and maintenance of Cane Island Unit 3 which will result in very low fixed O&M costs. Cane Island Unit 3 will also have the advantage of a skilled and trained staff for operation and maintenance.

The use of the existing site minimizes environmental impacts and reduces the time and effort required for licensing. The low level of emissions with Cane Island Unit 3 provides assurance from risk from future environmental regulations while reducing emissions within the state.

Cane Island Unit 3 will utilize domestic natural gas which minimizes risks from interruption of supply that can be associated with imported fuels.

1C.13.0 Consequences of Delay

The initial consequences of delaying the proposed generating plant is the cost impact of construction costs due to price escalation, the need to supply an alternative resource or purchase to maintain the same level of system reliability that would be provided to the system, and the potential for capital costs to rise above escalation.

With the equipment costs for "F" technology combined cycles at their lowest point in history and industry expert opinions indicating cost may begin to increase again, there could be significant impacts to the cumulative present worth revenue requirements on the project.

Cane Island 3 provides generation from a low cost fuel source of natural gas that will in part displace higher cost, higher emission output oil burning units. Potentially if Cane Island 3 is delayed, FMPA will be required to obtain additional purchased power to meet the needs of its All-Requirements Project members. This could provide significant impacts to cumulative present worth revenue requirements due to the potential for unavailability of new purchase power opportunities.

Peninsula Florida's need for power is growing at one of the fastest rates in the nation; thus supply of power is decreasing. To maintain a reliable system for the FMPA All-Requirements Project additional sources of power are required. With the lack of available purchased power on the market, FMPA must build a new facility. The consequence's of delaying the project could have potentially large impacts on system reliability.

1C.13.1 Economic Benefits

If the construction of Cane Island 3 was delayed or canceled, there would be several consequences that would occur. Some of the consequences would include: impacts on possible escalation of capital costs above inflation, the need to purchase power on the market or under emergency conditions, the higher fuel costs associated with running older units, and the environmental impacts of the emissions from the older units.

Ignoring the very realistic possibility of increasing costs for equipment and the effects of higher emissions on the environment, FMPA has conducted an economic evaluation to provide the impact on cumulative present worth if the project was delayed 1 year and purchased power was required to maintain the 18 percent reserve margin.

Without the construction of Cane Island Unit 3 in 2001, FMPA will be presented with a shortfall of capacity. With Florida's reserve margin projected to fall below 15 percent for 2001, the impact on system reliability could be large.

With the delay of Cane Island 3, FMPA would need to reserve capacity either from the market or under existing power purchase contracts. With the projections from Florida Reliability Coordinating Councils 1997 Ten-Year Plan for Peninsular Florida's reserve margin for summer of 2001 to be 15% after exercising all of the load management and interruptible loads, it is uncertain if purchase power from the market will be available. Therefore, FMPA analyzed a one year delay of Cane Island 3 to 2002 by assuming that capacity for 2001 would be supplied from existing partial requirements contracts with FPC and FPL. The contracts state that FMPA can reserve additional capacity in increments of up to 25 MW per contract each May 1. Therefore FMPA would need to begin requiring additional capacity for 2000 for both contracts to build up to the need in 2001 of approximately 93 MW to maintain an 18 percent reserve margin. Table 1C.13-1 displays the results of the economic evaluation if a delay in the construction of Cane Island 3 occurred. The delay would result in an increased present worth cost of $1.8 million.

Table 1C.13-1 Consequences of Delay			
Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1998		135,731	135,731
1999		148,625	276,609
2000	Secure additional 43 MW from FPC and FPL	156,021	416,785
2001	Secure additional 50 MW from FPC and FPL	175,666	566,385
2002	Build 501F 1x1 Combined Cycle (118 MW)* Remove 50 MW from FPC and FPL contracts	196,525	725,023
2003	Remove 43 MW from FPC and FPL contracts	204,251	881,303
2004		211,012	1,034,338
2005		222,148	1,187,051
2006		232,203	1,338,354
2007	Build 7EA Simple Cycle (81 MW)	246,145	1,490,380
2008		256,765	1,640,698
2009	Build 501F 1x1 Combined Cycle (262 MW) Build 7EA 1x1 Combined Cycle (124 MW)	255,415	1,782,431
2010		265,002	1,921,817
2011		278,201	2,060,517
2012	Build 7EA Simple Cycle (81 MW)	291,706	2,198,368
2013		312,416	2,338,310
2014	Build 7EA Simple Cycle (81 MW)	324,860	2,476,239
2015		341,307	2,613,597
2016		355,717	2,749,291
2017	Build 7EA Simple Cycle (81 MW)	373,919	2,884,492

*Indicates FMPA share of 50 percent ownership with KUA.

1C.14.0 Financial Analysis

The All-Requirements Project is in its 13th year of operation and continuing a very strong financial performance while supplying low-cost power to its members. The project has a track record of strong financial performance which has exceeded projections. Since its inception, the All-Requirements Project has reduced its participants' annual power supply costs by 10 to 20 percent, compared to what they would have paid their previous power suppliers. For the foreseeable future, FMPA expects its rates to remain below regional power costs medians and below what the state's investor-owned utilities charge for comparable service. Table 1C.14-1 displays the All-Requirements Project historical cost per kilowatt-hour power costs.

Table 1C.14-1
All-Requirements Project Power Costs

Year	Power Costs (cents/kWh)
1992	4.34
1993	4.56
1994	4.55
1995	4.89
1996	4.51
1997	4.50

Fitch Investors Service reviewed the project's outstanding bonds in 1997 and issued a credit rating of "A+" up from "A, positive outlook." Fitch said "The ratings reflect a sound management team, competitive wholesale rates, court-validated power supply contracts and Florida's slower transition to deregulation, which allows FMPA time to better position itself for competition. Other strengths include management's debt reduction plan and historically good financial performance." Fitch stated the rating increase was a result of several factors. The two main factors included the addition of new members to the project and the diversified mix of resources. The All-Requirements Project maintains a diverse portfolio of energy sources to serve its members most cost-effectively. Section 2.0 describes the portfolio of energy sources in detail for the Project.

Based upon FMPA's All-Requirements historical performance and positive outlook for future power supply opportunities, the financial ability to finance the construction of new generating facilities is very good.

1C.15.0 Analysis of 1990 Clean Air Act Amendments

1C.15.1 Compliance Strategy

Cane Island Unit 3 will emit small amounts of sulfur dioxide while running on either natural gas or fuel oil. As an affected unit, Unit 3 must have allowances available for emissions of sulfur dioxide to comply with its Title IV Acid Rain permit. FMPA All-Requirements Project is proposing to limit sulfur dioxide emissions to 40 tons per year for Unit 3. The 40 ton per year maximum emissions level minimizes permitting requirements for Unit 3. Forty tons per year of sulfur dioxide emissions for Unit 3 is equivalent to approximately 720 hours of full load operation on distillate oil (0.05 percent sulfur) and 8,040 hours of full load operation on fuel gas. The current operating plan for the Cane Island Power Park, including Unit 3, includes operation on fuel oil only during emergency situations. To date Cane Island Units 1 and 2 have not had to operate on fuel oil.

FMPA All-Requirements Project has identified two possible sulfur dioxide emissions compliance strategies. The first and preferred compliance strategy involves re-allocation of excess allowances currently maintained by the OUC Stanton Energy Center to cover the Cane Island Unit 3 sulfur dioxide emissions. FMPA All-Requirements Project owns 17.84 percent of Stanton Unit 1 and 13.97 percent of Stanton Unit 2. Therefore, FMPA All-Requirements Project has entitlements to a proportionate amount of the excess allowances of the Stanton Energy Center. Stanton Unit 1 currently receives 11,199 allowances per year while Stanton Unit 2 receives 0 allowances per year. Current operation of Stanton Unit 1 and Unit 2 results in a combined sulfur dioxide emissions rate of approximately 10,200 tons per year, leaving approximately 1,000 excess allowances. Therefore, in accordance with the FMPA All-Requirements Project ownership entitlements, over 318 allowances per year are currently available for reallocation from Stanton to Cane Island by FMPA All-Requirements Project. The second possible compliance strategy involves purchasing allowances. Purchasing allowances will be the compliance strategy utilized if, for any reason, re-allocation proves to supply insufficient quantities of allowances.

Appendix 1C.16.1

Energy and Demand Forecast

Florida Municipal Power Agency

Energy and Demand Forecast

Florida Municipal Power Agency

Energy and Demand Forecast

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744

CELEBRATING 20 YEARS

March 10, 1998

Mr. Vince Ruano
City Manager
City of Bushnell
P.O. Box 115
Bushnell, FL 33513

Introduction	For your information, attached is a report for the City of Bushnell Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

City of Bushnell, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Bushnell for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincedent Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 1.6% for the period of 1998-2007 and 1.1% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1988 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

General Service Demand Class Model

The explanatory variable used to determine general service demand sales is general service demand customers. The series is trended and seasonal; therefore the model used is exponential smoothing.

City Usage

The series for city usage is trend and seasonal. Exponential smoothing is used to project future sales.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. Box-Jenkins model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988		563	5,411	9.61
	1989		588	5,726	9.74
	1990		601	5,869	9.77
	1991		615	5,888	9.57
	1992		636	6,283	9.88
	1993		644	6,493	10.08
	1994		653	6,293	9.64
	1995		658	6,981	10.61
	1996		688	7,251	10.54
	1997	[1]	702	6,292	8.96
AGGR '88 - '97			2.5%	1.7%	-0.8%
Projected:					
	1998		717	6,449	9.00
	1999		731	6,612	9.04
	2000		746	6,776	9.08
	2001		761	6,941	9.12
	2002		776	7,111	9.16
	2003		790	7,272	9.20
	2004		804	7,432	9.24
	2005		818	7,588	9.28
	2006		830	7,740	9.32
	2007		843	7,887	9.36
AGGR '98 – '07			1.8%	2.3%	0.4%
	2008		854	8,029	9.40
	2009		865	8,165	9.44
	2010		875	8,296	9.48
	2011		885	8,421	9.52
	2012		893	8,538	9.56
	2013		901	8,649	9.60
	2014		908	8,753	9.64
	2015		914	8,850	9.68
	2016		920	8,938	9.72
	2017		924	9,018	9.76
AGGR '08 – '17			0.9%	1.3%	0.4%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988		182	3,975	21.84
	1989		179	3,796	21.21
	1990		176	4,146	23.56
	1991		169	3,700	21.90
	1992		177	3,852	21.76
	1993		180	4,125	22.92
	1994		184	4,182	22.73
	1995		215	4,955	23.05
	1996		220	6,447	29.30
	1997	[1]	219	6,754	30.84
AGGR '88 - '97			2.1%	6.1%	3.9%
Projected:					
	1998		220	6,889	31.38
	1999		221	7,020	31.78
	2000		222	7,146	32.18
	2001		223	7,268	32.58
	2002		224	7,384	32.98
	2003		225	7,495	33.38
	2004		226	7,600	33.68
	2005		227	7,699	33.98
	2006		228	7,799	34.23
	2007		229	7,892	34.48
AGGR '98 - '07			0.4%	1.5%	1.1%
	2008		230	7,987	34.73
	2009		231	8,083	34.98
	2010		232	8,172	35.23
	2011		233	8,262	35.48
	2012		234	8,344	35.73
	2013		235	8,428	35.93
	2014		236	8,504	36.09
	2015		237	8,580	36.25
	2016		238	8,657	36.41
	2017		239	8,735	36.57
AGGR '08 - '17			0.4%	1.0%	0.6%

[1] October, November, and December are estimated.

General Service Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988	6	4,385	731
	1989	7	4,809	687
	1990	7	4,946	707
	1991	7	5,014	716
	1992	7	5,236	748
	1993	7	5,172	739
	1994	7	5,137	734
	1995	6	4,984	831
	1996	6	5,305	884
	1997 [1]	7	5,809	830
AGGR '88 - '97		1.7%	3.2%	1.4%
Projected:				
	1998	7	5,867	838
	1999	7	5,926	847
	2000	7	5,985	855
	2001	7	6,045	864
	2002	7	6,105	872
	2003	7	6,166	881
	2004	7	6,228	890
	2005	7	6,290	899
	2006	7	6,353	908
	2007	7	6,417	917
AGGR '98 - '07		0.0%	1.0%	1.0%
	2008	7	6,481	926
	2009	7	6,546	935
	2010	7	6,611	944
	2011	7	6,677	954
	2012	7	6,744	963
	2013	7	6,812	973
	2014	7	6,880	983
	2015	7	6,948	993
	2016	7	7,018	1,003
	2017	7	7,088	1,013
AGGR '08 - '17		0.0%	1.0%	1.0%

[1] October, November, and December are estimated.

	CY Year		Lighting Sales MWh	City Usage MWh
Historical	1988		95	390
	1989		96	402
	1990		101	434
	1991		102	428
	1992		100	429
	1993		103	413
	1994		107	591
	1995		110	646
	1996		108	666
	1997	[1]	107	676
AGGR '88 - '97			1.3%	6.3%
Projected:				
	1998		108	683
	1999		109	690
	2000		110	697
	2001		111	704
	2002		112	711
	2003		113	718
	2004		115	725
	2005		116	732
	2006		117	740
	2007		118	747
AGGR '98 – '07			1.0%	1.0%
	2008		119	754
	2009		120	762
	2010		122	770
	2011		123	777
	2012		124	785
	2013		125	793
	2014		127	801
	2015		128	809
	2016		129	817
	2017		130	825
AGGR '08 - '17			1.0%	1.0%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1988		14,257	15,402	3.5	4.3
	1989		14,829	16,320	3.8	4.5
	1990		15,496	16,654	3.7	4.3
	1991		15,131	16,571	3.6	3.4
	1992		15,901	17,251	3.7	4.5
	1993		16,306	17,718	3.6	4.3
	1994		16,310	17,694	3.8	4.5
	1995		17,676	19,514	4.5	5.1
	1996		19,776	20,408	4.4	5.7
	1997	[1]	19,638	21,078	4.6	5.0
AGGR '88 - '97			3.6%	3.8%	3.2%	1.7%
Projected:						
	1998		19,997	21,456	4.6	5.6
	1999		20,357	21,843	4.7	5.7
	2000		20,714	22,226	4.8	5.8
	2001		21,069	22,607	4.9	5.9
	2002		21,424	22,988	4.9	6.0
	2003		21,765	23,354	5.0	6.1
	2004		22,100	23,713	5.1	6.2
	2005		22,425	24,062	5.2	6.3
	2006		22,748	24,409	5.2	6.4
	2007		23,061	24,745	5.3	6.5
AGGR '98 – '07			1.6%	1.6%	1.6%	1.6%
	2008		23,371	25,077	5.4	6.6
	2009		23,676	25,405	5.5	6.7
	2010		23,970	25,720	5.5	6.8
	2011		24,260	26,031	5.6	6.8
	2012		24,536	26,327	5.7	6.9
	2013		24,807	26,618	5.7	7.0
	2014		25,064	26,894	5.8	7.1
	2015		25,315	27,163	5.8	7.1
	2016		25,559	27,425	5.9	7.2
	2017		25,797	27,681	6.0	7.3
AGGR '08 – '17			1.1%	1.1%	1.1%	1.1%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	1,715.9	1,746.8	1,777.4	1,807.9	1,838.3
FEBRUARY	1,500.1	1,527.1	1,553.9	1,580.6	1,607.2
MARCH	1,634.5	1,663.9	1,693.1	1,722.2	1,751.1
APRIL	1,476.8	1,503.4	1,529.7	1,556.0	1,582.2
MAY	1,893.5	1,927.6	1,961.4	1,995.1	2,028.7
JUNE	1,920.5	1,955.1	1,989.4	2,023.6	2,057.6
JULY	2,117.0	2,155.1	2,193.0	2,230.6	2,268.1
AUGUST	2,223.7	2,263.8	2,303.5	2,343.0	2,382.4
SEPTEMBER	2,017.9	2,054.2	2,090.2	2,126.1	2,161.9
OCTOBER	1,746.5	1,778.0	1,809.2	1,840.2	1,871.2
NOVEMBER	1,583.5	1,612.0	1,640.3	1,668.4	1,696.5
DECEMBER	1,626.3	1,655.6	1,684.6	1,713.5	1,742.4
TOTAL	21,456.3	21,842.5	22,225.9	22,607.1	22,987.6
FY	21,127.1	21,753.3	22,137.3	22,519.0	22,899.7

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	5.6	5.7	5.8	5.9	6.0
FEBRUARY	4.9	5.0	5.0	5.1	5.2
MARCH	4.1	4.1	4.2	4.3	4.4
APRIL	3.6	3.6	3.7	3.8	3.8
MAY	4.4	4.5	4.5	4.6	4.7
JUNE	4.5	4.6	4.6	4.7	4.8
JULY	4.5	4.6	4.7	4.8	4.8
AUGUST	4.6	4.7	4.8	4.9	4.9
SEPTEMBER	4.5	4.6	4.7	4.8	4.8
OCTOBER	3.8	3.9	4.0	4.0	4.1
NOVEMBER	3.8	3.9	3.9	4.0	4.1
DECEMBER	4.4	4.5	4.6	4.7	4.8
TOTAL	52.7	53.7	54.6	55.6	56.5
FY	53.0	53.5	54.4	55.4	56.3

Florida Municipal Power Agency

Energy and Demand Forecast

7201 Lake Eleanor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744

CELEBRATING 20 YEARS

March 10, 1998

Mr. George Mathis
Utilities Director
City of Clewiston
141 Central Avenue
Clewiston, FL 33440

Introduction	For your information, attached is a report for the City of Clewiston Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

City of Clewiston, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Clewiston for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP- MW) are projected to increase at compound annual growth rates of approximately 1.8% for the period of 1998-2007 and 1.1% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1983 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

General Service Non-Demand

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and nonseasonal; therefore the exponential smoothing model is used to project future sales.

General Service Demand

The explanatory variable used to determine general service demand sales is general service demand customers. The series is trended and nonseasonal; therefore an exponential smoothing model is used to project future sales.

US Sugar Corp

The series is stationary and nonseasonal; therefore the Box-Jenkins model is used to project future sales.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. The Box-Jenkins model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986		3,007	38,278	12.73
	1987		3,036	38,720	12.75
	1988		3,043	40,194	13.21
	1989		3,066	41,626	13.58
	1990		3,137	42,712	13.61
	1991		3,162	42,863	13.56
	1992		3,191	42,290	13.25
	1993		3,215	43,267	13.46
	1994		3,238	46,580	14.39
	1995		3,272	48,392	14.79
	1996		3,268	49,110	15.03
	1997	[1]	3,299	49,857	15.11
AGGR '86 - '97			1.2%	2.4%	2.0%
Projected:					
	1998		3,335	50,754	15.22
	1999		3,373	51,668	15.32
	2000		3,410	52,546	15.41
	2001		3,444	53,387	15.50
	2002		3,476	54,188	15.59
	2003		3,506	54,947	15.67
	2004		3,534	55,661	15.75
	2005		3,563	56,329	15.81
	2006		3,588	56,948	15.87
	2007		3,613	57,518	15.92
AGGR '98 - '07			0.9%	1.4%	0.5%
	2008		3,634	58,036	15.97
	2009		3,655	58,558	16.02
	2010		3,673	59,026	16.07
	2011		3,690	59,440	16.11
	2012		3,705	59,796	16.14
	2013		3,719	60,095	16.16
	2014		3,733	60,396	16.18
	2015		3,743	60,637	16.20
	2016		3,763	60,880	16.22
	2017		3,760	61,062	16.24
AGGR '08 - '17			0.4%	0.6%	0.2%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer NCP's
Historical	1986		113	25,734	227.23
	1987		114	26,241	230.19
	1988		115	27,264	237.42
	1989		116	29,829	256.41
	1990		119	30,523	257.04
	1991		122	31,776	261.00
	1992		127	31,126	245.89
	1993		131	31,582	241.85
	1994		129	32,843	255.26
	1995		131	33,394	255.07
	1996		127	33,316	262.68
	1997	[1]	128	36,118	282.17
AGGR '86 - '97			2.6%	4.4%	2.0%
Projected:					
	1998		129	37,165	288.10
	1999		130	38,206	293.89
	2000		131	39,276	299.82
	2001		132	40,356	305.72
	2002		133	41,433	311.53
	2003		134	42,509	317.23
	2004		135	43,583	322.83
	2005		136	44,654	328.34
	2006		137	45,724	333.75
	2007		138	46,792	339.07
AGGR '98 - '07			0.8%	2.6%	1.8%
	2008		139	47,858	344.30
	2009		140	48,922	349.44
	2010		141	49,984	354.50
	2011		142	51,044	359.46
	2012		143	52,102	364.35
	2013		144	53,158	369.15
	2014		145	54,212	373.88
	2015		146	55,265	378.52
	2016		147	56,315	383.09
	2017		148	57,329	387.35
AGGR '08 - '17			0.7%	2.0%	1.3%

[1] October, November, and December are estimated.

General Service Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer NCP's
Historical	1986		409	5,198	12.71
	1987		426	5,259	12.34
	1988		427	5,611	13.15
	1989		455	5,863	12.79
	1990		430	5,563	12.93
	1991		434	5,556	12.81
	1992		425	4,984	11.73
	1993		431	5,487	12.73
	1994		446	6,111	13.70
	1995		433	6,026	13.92
	1996		441	5,938	13.46
	1997	[1]	449	6,817	15.19
AGGR '86 - '97			1.0%	3.2%	2.1%
Projected:					
	1998		455	6,919	15.21
	1999		461	7,023	15.23
	2000		467	7,121	15.25
	2001		473	7,221	15.27
	2002		478	7,315	15.29
	2003		483	7,403	15.31
	2004		488	7,484	15.33
	2005		492	7,559	15.35
	2006		496	7,627	15.37
	2007		500	7,696	15.39
AGGR '98 - '07			1.1%	1.2%	0.1%
	2008		503	7,757	15.41
	2009		506	7,812	15.43
	2010		509	7,866	15.45
	2011		511	7,913	15.47
	2012		513	7,953	14.49
	2013		515	7,985	15.51
	2014		516	8,017	15.53
	2015		517	8,049	15.55
	2016		518	8,073	15.57
	2017		519	8,097	15.59
AGGR '08 - '17			0.3%	0.5%	0.1%

[1] October, November, and December are estimated.

	CY Year		US Sugar Corp Sales MWh	Lighting Sales MWh
Historical	1986		4,297	1,140
	1987		3,378	1,005
	1988		4,302	1,003
	1989		5,118	1,008
	1990		5,014	967
	1991		4,588	965
	1992		5,135	1,094
	1993		7,290	1,097
	1994		8,809	1,140
	1995		9,063	1,124
	1996		8,281	1,429
	1997	[1]	11,790	1,099
AGGR '86 - '97			9.4%	-0.3%
Projected:				
	1998		11,967	1,108
	1999		12,134	1,117
	2000		12,292	1,126
	2001		12,440	1,133
	2002		12,576	1,141
	2003		12,702	1,149
	2004		12,829	1,156
	2005		12,958	1,163
	2006		13,074	1,170
	2007		13,192	1,176
AGGR '98 - '07			1.1%	0.7%
	2008		13,297	1,182
	2009		13,390	1,187
	2010		13,484	1,191
	2011		13,565	1,195
	2012		13,646	1,199
	2013		13,715	1,202
	2014		13,770	1,205
	2015		13,825	1,207
	2016		13,866	1,209
	2017		13,894	1,212
AGGR '08 - '17			0.5%	0.3%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1989		82,388	89,224	18.0	17.7
	1990		83,813	89,916	18.2	21.4
	1991		85,748	88,562	18.8	16.8
	1992		84,628	90,786	18.5	15.3
	1993		88,724	95,643	20.4	15.5
	1994		95,484	101,533	19.3	18.5
	1995		97,999	105,035	20.8	21.0
	1996		98,074	103,949	21.4	22.4
	1997	[1]	105,681	114,533	23.0	21.6
AGGR '89 - '97			3.2%	3.4%	3.2%	1.3%
Projected:						
	1998		107,914	116,978	23.9	22.2
	1999		110,148	119,401	24.4	22.7
	2000		112,361	121,800	24.8	23.1
	2001		114,537	124,158	25.3	23.6
	2002		116,654	126,453	25.8	24.0
	2003		118,710	128,681	26.3	24.4
	2004		120,713	130,853	26.7	24.9
	2005		122,663	132,967	27.1	25.3
	2006		124,544	135,006	27.5	25.7
	2007		126,374	136,989	27.9	26.0
AGGR '98 – '07			1.8%	1.8%	1.8%	1.8%
	2008		128,130	138,893	28.3	26.4
	2009		129,868	140,777	28.7	26.7
	2010		131,552	142,602	29.1	27.1
	2011		133,157	144,342	29.4	27.4
	2012		134,696	146,011	29.8	27.7
	2013		136,155	147,592	30.1	28.0
	2014		137,599	149,157	30.4	28.3
	2015		138,982	150,657	30.7	28.6
	2016		140,343	152,132	31.0	28.9
	2017		141,594	153,448	31.3	29.2
AGGR '08 – '17			1.1%	1.1%	1.1%	1.1%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	9,089.7	9,277.9	9,464.3	9,647.5	9,825.9
FEBRUARY	8,755.8	8,937.1	9,116.7	9,293.2	9,465.0
MARCH	8,600.3	8,778.4	8,954.7	9,128.1	9,296.9
APRIL	8,372.7	8,546.1	8,717.8	8,886.6	9,050.9
MAY	10,299.7	10,513.0	10,724.2	10,931.8	11,133.9
JUNE	10,635.6	10,855.8	11,074.0	11,288.4	11,497.0
JULY	11,235.4	11,468.0	11,698.4	11,924.9	12,145.3
AUGUST	11,691.0	11,933.0	12,172.8	12,408.5	12,637.8
SEPTEMBER	10,987.8	11,215.3	11,440.7	11,662.2	11,877.8
OCTOBER	10,456.8	10,673.3	10,887.7	11,098.5	11,303.7
NOVEMBER	8,277.9	8,449.3	8,619.0	8,785.9	8,948.3
DECEMBER	8,575.9	8,753.4	8,929.3	9,102.2	9,270.4
TOTAL	116,978.5	119,400.6	121,799.6	124,157.9	126,452.9

FY	113,567.8	118,835.1	121,239.5	123,607.3	125,917.1

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	22.2	22.7	23.1	23.6	24.0
FEBRUARY	22.1	22.6	23.0	23.5	23.9
MARCH	19.3	19.7	20.1	20.5	20.9
APRIL	19.3	19.7	20.1	20.5	20.9
MAY	21.8	22.3	22.7	23.2	23.6
JUNE	21.9	22.4	22.8	23.3	23.7
JULY	22.0	22.5	22.9	23.4	23.8
AUGUST	23.9	24.4	24.8	25.3	25.8
SEPTEMBER	22.9	23.3	23.8	24.3	24.7
OCTOBER	22.2	22.7	23.1	23.6	24.0
NOVEMBER	20.0	20.4	20.8	21.2	21.6
DECEMBER	18.8	19.2	19.5	19.9	20.3
TOTAL	256.5	261.8	267.1	272.2	277.3
FY	251.9	260.5	265.8	271.0	276.1

Florida Municipal Power Agency

Energy and Demand Forecast

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6533
1 800 859-0744

CELEBRATING 20 YEARS

March 10, 1998

Mr. Elie J. Boudreaux III, P.E.
Director of Utilities
Fort Pierce Utilities Authority
P.O. Box 3191
Fort Pierce, FL 34948

Introduction	For your information, attached is a report for the Fort Pierce Utilities Authority Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744

CELEBRATING 20 YEARS

March 10, 1998

Mr. Thomas Richards
Director of Operations
Fort Pierce Utilities Authority
P.O. Box 3191
Fort Pierce, FL 34948

Introduction	For your information, attached is a report for the Fort Pierce Utilities Authority Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

Fort Pierce Utilities Authority, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the Fort Pierce Utilities Authority for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 1.5% for the period of 1998-2007 and 0.5% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1986 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is nonstationary and seasonal; therefore the model used is dynamic regression.

General Service

The explanatory variable used to determine general service sales is general service customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. A exponential smoothing is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986		18,988	189,830	10.00
	1987		19,443	196,436	10.10
	1988		19,576	200,931	10.26
	1989		19,726	210,757	10.68
	1990		19,721	207,688	10.53
	1991		19,582	219,144	11.19
	1992		19,575	205,084	10.48
	1993		19,732	205,658	10.42
	1994		19,790	210,082	10.62
	1995		20,018	216,604	10.82
	1996		20,137	223,330	11.09
	1997	[1]	20,216	210,387	10.41
AGGR '86 - '97			0.6%	0.9%	0.4%
Projected:					
	1998		20,337	216,699	10.66
	1999		20,459	222,983	10.90
	2000		20,582	229,226	11.14
	2001		20,706	234,957	11.35
	2002		20,830	240,361	11.54
	2003		20,955	245,409	11.71
	2004		21,060	250,071	11.87
	2005		21,165	254,323	12.02
	2006		21,271	258,137	12.14
	2007		21,377	261,493	12.23
AGGR '98 - '07			0.6%	2.1%	1.5%
	2008		21,463	264,370	12.32
	2009		21,548	267,013	12.39
	2010		21,635	269,684	12.47
	2011		21,721	272,111	12.53
	2012		21,786	274,288	12.59
	2013		21,852	276,482	12.65
	2014		21,895	278,417	12.72
	2015		21,939	280,088	12.77
	2016		21,983	281,488	12.80
	2017		22,027	282,896	12.84
AGGR '08 - '17			0.3%	0.8%	0.5%

[1] October, November, and December are estimated.

General Service

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986		3,671	216,712	59.03
	1987		3,790	224,589	59.25
	1988		3,829	233,037	60.86
	1989		3,989	254,112	63.70
	1990		3,980	253,003	63.57
	1991		3,933	260,873	66.33
	1992		3,896	271,191	69.61
	1993		3,935	283,202	71.97
	1994		3,923	290,530	74.06
	1995		3,830	295,922	77.26
	1996		3,960	299,516	75.64
	1997	[1]	4,015	295,489	73.60
AGGR '86 - '97			0.8%	2.9%	2.0%
Projected:					
	1998		4,062	301,103	74.13
	1999		4,106	306,523	74.65
	2000		4,147	311,734	75.17
	2001		4,188	316,410	75.55
	2002		4,227	320,523	75.83
	2003		4,259	323,729	76.01
	2004		4,287	326,642	76.19
	2005		4,307	328,929	76.37
	2006		4,327	330,902	76.48
	2007		4,346	332,888	76.59
AGGR '98 - '07			0.8%	1.1%	0.4%
	2008		4,362	334,552	76.70
	2009		4,377	336,225	76.81
	2010		4,389	337,570	76.92
	2011		4,400	338,920	77.03
	2012		4,410	339,937	77.09
	2013		4,419	340,957	77.15
	2014		4,429	341,979	77.21
	2015		4,439	343,005	77.27
	2016		4,444	343,691	77.33
	2017		4,450	344,379	77.39
AGGR '08 - '17			0.2%	0.3%	0.1%

[1] October, November, and December are estimated.

	CY Year		Lights Sales MWh
Historical	1986		6,952
	1987		7,140
	1988		7,253
	1989		7,608
	1990		7,986
	1991		8,160
	1992		8,503
	1993		8,944
	1994		9,098
	1995		9,292
	1996		9,685
	1997	[1]	9,480
AGGR '86 - '97			2.9%
Projected:			
	1998		9,618
	1999		9,749
	2000		9,877
	2001		9,996
	2002		10,112
	2003		10,218
	2004		10,313
	2005		10,400
	2006		10,482
	2007		10,559
AGGR '98 - '07			1.0%
	2008		10,631
	2009		10,704
	2010		10,767
	2011		10,830
	2012		10,888
	2013		10,945
	2014		10,992
	2015		11,040
	2016		11,081
	2017		11,122
AGGR '08 -'17			0.5%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1989		486,643	513,000	100.0	111.0
	1990		483,543	507,467	99.0	121.0
	1991		486,896	510,598	101.0	98.0
	1992		484,778	504,650	102.0	102.0
	1993		497,804	524,564	104.0	101.0
	1994		509,710	536,258	102.0	92.0
	1995		522,112	554,189	108.0	128.0
	1996		532,825	544,589	104.0	126.0
	1997	[1]	515,650	547,945	107.0	118.0
AGGR '89 - '97			0.8%	0.8%	0.8%	0.8%
Projected:						
	1998		527,420	560,120	109.2	124.3
	1999		539,255	572,150	111.6	127.0
	2000		550,537	583,845	113.8	129.6
	2001		561,063	595,008	116.0	132.1
	2002		570,696	605,223	118.0	134.4
	2003		579,055	613,798	119.7	136.3
	2004		586,727	621,931	121.3	138.1
	2005		593,351	628,952	122.6	139.6
	2006		599,221	635,174	123.9	141.0
	2007		604,640	640,918	125.0	142.3
AGGR '98 – '07			1.5%	1.5%	1.5%	1.5%
	2008		609,253	645,808	125.9	143.4
	2009		613,643	650,461	126.8	144.4
	2010		617,720	654,784	127.7	145.4
	2011		621,561	658,855	128.5	146.3
	2012		624,812	662,301	129.1	147.0
	2013		628,084	665,769	129.8	147.8
	2014		631,089	668,954	130.4	148.5
	2015		633,833	671,863	131.0	149.2
	2016		635,961	674,118	131.5	149.7
	2017		638,097	676,383	131.9	150.2
AGGR '08 – '17			0.5%	0.5%	0.5%	0.5%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	44,687.2	45,646.9	46,580.0	47,470.6	48,285.6
FEBRUARY	40,477.7	41,347.0	42,192.2	42,998.9	43,737.1
MARCH	42,863.5	43,784.1	44,679.1	45,533.3	46,315.1
APRIL	42,631.9	43,547.5	44,437.6	45,287.3	46,064.8
MAY	49,443.0	50,504.8	51,537.2	52,522.6	53,424.3
JUNE	49,092.5	50,146.8	51,171.8	52,150.2	53,045.6
JULY	53,683.0	54,835.9	55,956.8	57,026.7	58,005.7
AUGUST	54,980.5	56,161.3	57,309.3	58,405.0	59,407.8
SEPTEMBER	50,882.6	51,975.4	53,037.8	54,051.9	54,979.9
OCTOBER	47,369.9	48,387.2	49,376.3	50,320.4	51,184.3
NOVEMBER	39,735.7	40,589.1	41,418.8	42,210.7	42,935.4
DECEMBER	44,272.7	45,223.5	46,147.9	47,030.3	47,837.7
TOTAL	560,120.1	572,149.8	583,844.7	595,007.7	605,223.3

FY	551,991.8	569,328.2	581,101.6	592,389.4	602,827.2

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	124.3	127.0	129.6	132.1	134.4
FEBRUARY	97.1	99.2	101.3	103.2	105.0
MARCH	90.3	92.2	94.1	95.9	97.5
APRIL	92.3	94.3	96.2	98.0	99.7
MAY	103.1	105.3	107.5	109.6	111.4
JUNE	104.4	106.6	108.8	110.9	112.8
JULY	105.8	108.1	110.3	112.4	114.3
AUGUST	109.2	111.6	113.8	116.0	118.0
SEPTEMBER	103.3	105.6	107.7	109.8	111.7
OCTOBER	96.7	98.8	100.8	102.8	104.5
NOVEMBER	98.4	100.5	102.6	104.6	106.4
DECEMBER	104.6	106.9	109.1	111.1	113.1
TOTAL	1,229.7	1,256.1	1,281.8	1,306.3	1,328.7
FY	1,219.9	1,249.7	1,275.5	1,300.3	1,323.3

Florida Municipal Power Agency

Energy and Demand Forecast

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6853
1 800 859-0744

CELEBRATING 20 YEARS

March 10, 1998

Mr. Ted Biggs
Electric Utility Director
City of Green Cove Springs
229 Walnut St.
Green Cove Springs, FL 32043

Introduction	For your information, attached is a report for the City of Green Cove Springs Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

City of Green Cove Springs, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Green Cove Springs for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 1.8% for the period of 1998-2007 and 1.2% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1989 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and nonseasonal; therefore an exponential smoothing model is used to project future sales.

General Service Demand Class Model

The explanatory variable used to determine general service sales is general service demand customers. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

Large Demand Class Model

The explanatory variable used to determine large demand sales is large demand customers. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

City Accounts

City accounts are trended and seasonal. Box-Jenkins is use to project future sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989		1,922	20,312	10.57
	1990		1,962	21,534	10.98
	1991		2,004	22,534	11.24
	1992		2,036	23,370	11.48
	1993		2,068	24,403	11.80
	1994		2,103	24,922	11.85
	1995		2,156	27,380	12.70
	1996		2,190	28,738	13.12
	1997	[1]	2,230	25,798	11.57
AGGR '89 - '97			1.9%	3.0%	1.1%
Projected:					
	1998		2,268	26,443	11.66
	1999		2,305	27,086	11.75
	2000		2,340	27,700	11.84
	2001		2,373	28,310	11.93
	2002		2,407	28,933	12.02
	2003		2,439	29,540	12.11
	2004		2,470	30,131	12.20
	2005		2,498	30,703	12.29
	2006		2,525	31,256	12.38
	2007		2,549	31,787	12.47
AGGR '98 - '07			1.3%	2.1%	0.7%
	2008		2,571	32,296	12.56
	2009		2,591	32,781	12.65
	2010		2,609	33,239	12.74
	2011		2,627	33,705	12.83
	2012		2,643	34,143	12.92
	2013		2,656	34,553	13.01
	2014		2,667	34,933	13.10
	2015		2,675	35,282	13.19
	2016		2,681	35,600	13.28
	2017		2,684	35,884	13.37
AGGR '08 - '17			0.5%	1.2%	0.7%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989		361	7,359	20.39
	1990		401	7,912	19.73
	1991		426	7,944	18.65
	1992		439	8,345	19.01
	1993		439	8,368	19.06
	1994		435	8,061	18.53
	1995		441	8,433	19.12
	1996	[1]	457	8,818	19.30
	1997		453	9,494	20.96
AGGR '89 - '97			2.9%	3.2%	0.3%
Projected:					
	1998		460	9,731	21.15
	1999		466	9,965	21.38
	2000		472	10,194	21.61
	2001		477	10,418	21.86
	2002		482	10,637	22.09
	2003		486	10,850	22.32
	2004		490	11,056	22.55
	2005		494	11,255	22.78
	2006		497	11,446	23.01
	2007		500	11,630	23.24
AGGR '98 – '07			0.9%	2.0%	1.1%
	2008		503	11,804	23.47
	2009		505	11,981	23.73
	2010		506	12,149	23.99
	2011		508	12,319	24.25
	2012		509	12,479	24.53
	2013		510	12,641	24.79
	2014		511	12,793	25.05
	2015		512	12,946	25.31
	2016		513	13,102	25.55
	2017		514	13,246	25.79
AGGR '08 - '17			0.2%	1.3%	1.1%

[1] October, November, and December are estimated.

General Service Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989		76	23,677	311.54
	1990		84	25,398	302.35
	1991		86	25,021	290.94
	1992		85	27,382	322.14
	1993		90	28,540	317.11
	1994		91	29,481	323.96
	1995		88	31,255	355.17
	1996		89	32,324	363.19
	1997	[1]	91	34,268	376.57
AGGR '89 - '97			2.3%	4.7%	2.4%
Projected:					
	1998		93	35,296	380.00
	1999		93	36,320	390.53
	2000		94	37,337	397.20
	2001		95	38,345	403.63
	2002		96	39,342	409.81
	2003		97	40,325	415.72
	2004		98	41,333	421.77
	2005		99	42,325	427.53
	2006		100	43,299	432.99
	2007		101	44,251	438.13
AGGR '98 – '07			0.9%	2.5%	1.6%
	2008		102	45,225	443.38
	2009		103	46,175	448.30
	2010		104	47,098	452.87
	2011		105	47,993	457.08
	2012		106	48,857	460.91
	2013		107	49,687	464.37
	2014		108	50,482	467.43
	2015		109	51,240	470.09
	2016		110	51,957	472.34
	2017		111	52,632	474.17
AGGR '08 –'17			0.9%	1.7%	0.7%

[1] October, November, and December are estimated.

Large Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989		4	25,143	6285.69
	1990		4	26,507	6626.64
	1991		6	30,978	5162.94
	1992		6	33,690	5615.00
	1993		6	36,007	6001.14
	1994		6	38,966	6494.27
	1995		5	37,008	7401.60
	1996		6	37,936	6322.73
	1997	[1]	6	39,763	6627.17
AGGR '89 - '97			5.2%	5.9%	0.7%
Projected:					
	1998		6	40,161	6693.44
	1999		6	40,562	6760.37
	2000		6	40,968	6827.98
	2001		6	41,378	6896.26
	2002		6	41,750	6958.32
	2003		6	42,126	7020.95
	2004		6	42,505	7084.14
	2005		6	42,887	7147.89
	2006		6	43,230	7205.08
	2007		6	43,576	7262.72
AGGR '98 – '07			0.0%	0.9%	0.9%
	2008		6	43,925	7320.82
	2009		6	44,232	7372.06
	2010		6	44,542	7423.67
	2011		6	44,854	7475.63
	2012		6	45,123	7520.49
	2013		6	45,394	7565.61
	2014		6	45,666	7611.00
	2015		6	45,894	7649.06
	2016		6	46,124	7687.31
	2017		6	46,308	7718.05
AGGR '08 – '17			0.0%	0.6%	0.6%

[1] October, November, and December are estimated.

	CY Year		City Accounts Sales MWh
Historical	1989		1,516
	1990		1,510
	1991		1,503
	1992		1,529
	1993		1,627
	1994		1,674
	1995		1,702
	1996		1,650
	1997	[1]	1,765
AGGR '89 - '97			1.9%
Projected:			
	1998		1,783
	1999		1,800
	2000		1,817
	2001		1,833
	2002		1,848
	2003		1,862
	2004		1,876
	2005		1,887
	2006		1,898
	2007		1,908
AGGR '98 - '07			0.8%
	2008		1,917
	2009		1,927
	2010		1,934
	2011		1,942
	2012		1,948
	2013		1,954
	2014		1,960
	2015		1,964
	2016		1,968
	2017		1,971
AGGR '08 - '17			0.3%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1989		78,007	86,938	16.7	16.5
	1990		82,860	90,214	17.5	16.3
	1991		87,980	96,828	18.4	16.5
	1992		94,316	103,730	19.8	19.5
	1993		98,943	109,570	21.0	19.0
	1994		103,104	111,240	20.1	21.3
	1995		105,778	116,333	22.3	21.6
	1996		109,466	122,179	22.7	24.8
	1997	[1]	111,088	126,227	23.9	24.9
AGGR '89 - '97			4.5%	3.5%	3.0%	3.2%
Projected:						
	1998		113,414	128,838	24.4	24.2
	1999		115,733	131,472	24.8	24.7
	2000		118,016	134,066	25.3	25.2
	2001		120,283	136,642	25.8	25.7
	2002		122,509	139,170	26.3	26.2
	2003		124,703	141,663	26.8	26.6
	2004		126,901	144,159	27.2	27.1
	2005		129,058	146,610	27.7	27.6
	2006		131,130	148,963	28.2	28.0
	2007		133,152	151,261	28.6	28.4
AGGR '98 – '07			1.8%	1.8%	1.8%	1.8%
	2008		135,167	153,550	29.0	28.9
	2009		137,095	155,740	29.4	29.3
	2010		138,963	157,862	29.8	29.7
	2011		140,813	159,963	30.2	30.1
	2012		142,550	161,936	30.6	30.4
	2013		144,229	163,844	31.0	30.8
	2014		145,834	165,667	31.3	31.1
	2015		147,326	167,362	31.6	31.5
	2016		148,750	168,980	31.9	31.8
	2017		150,043	170,448	32.2	32.0
AGGR '08 – '17			1.2%	1.2%	1.2%	1.2%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	10,403.2	10,615.9	10,825.3	11,033.3	11,237.5
FEBRUARY	9,350.9	9,542.1	9,730.3	9,917.3	10,100.8
MARCH	9,769.5	9,969.3	10,165.9	10,361.3	10,553.0
APRIL	9,557.4	9,752.9	9,945.2	10,136.3	10,323.9
MAY	10,816.1	11,037.3	11,255.0	11,471.2	11,683.5
JUNE	11,182.4	11,411.0	11,636.1	11,859.7	12,079.1
JULY	12,597.2	12,854.8	13,108.4	13,360.3	13,607.5
AUGUST	12,832.8	13,095.3	13,353.6	13,610.2	13,862.0
SEPTEMBER	11,998.7	12,244.0	12,485.5	12,725.5	12,960.9
OCTOBER	10,537.5	10,753.0	10,965.1	11,175.8	11,382.6
NOVEMBER	9,246.0	9,435.0	9,621.1	9,806.0	9,987.5
DECEMBER	10,546.2	10,761.9	10,974.2	11,185.0	11,392.0
TOTAL	128,837.9	131,472.5	134,065.7	136,641.9	139,170.2
FY	125,090.9	130,852.3	133,455.2	136,035.4	138,575.0

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	24.2	24.7	25.2	25.7	26.2
FEBRUARY	21.2	21.6	22.1	22.5	22.9
MARCH	18.8	19.2	19.6	20.0	20.3
APRIL	18.8	19.2	19.5	19.9	20.3
MAY	21.9	22.4	22.8	23.3	23.7
JUNE	23.1	23.6	24.0	24.5	24.9
JULY	23.8	24.3	24.8	25.3	25.7
AUGUST	24.4	24.8	25.3	25.8	26.3
SEPTEMBER	23.0	23.5	23.9	24.4	24.9
OCTOBER	20.5	20.9	21.4	21.8	22.2
NOVEMBER	20.2	20.6	21.0	21.4	21.8
DECEMBER	23.5	23.9	24.4	24.9	25.4
TOTAL	263.4	268.8	274.1	279.4	284.6
FY	263.1	267.5	272.8	278.1	283.3

Florida Municipal Power Agency

Energy and Demand Forecast

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
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CELEBRATING 20 YEARS

March 10, 1998

Mr. Charles W. Smith, P.E.
Director of Electric Utilities
City of Jacksonville Beach
11 N. third St.
Jacksonville Beach, FL 32240-1389

Introduction	For your information, attached is a report for the City of Jacksonville Beach Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

City of Jacksonville Beach, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Jacksonville Beach for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 3.0% for the period of 1998-2007 and 1.1% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1992 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

General Service Demand Class Model

The explanatory variable used to determine general service sales is general service demand customers. The series is trended and seasonal; therefore the model used is dynamic regression.

City Accounts

City accounts are trended and nonseasonal. Exponential smoothing is use to project future sales.

Lighting

Lighting is tied to customer growth and it is nonstational and seasonal. Exponential smoothing model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1992		19,923	258,951	13.00
	1993		21,404	293,495	13.71
	1994		21,944	324,915	14.81
	1995		22,393	351,161	15.68
	1996		23,209	378,002	16.29
	1997	[1]	23,928	363,877	15.21
AGGR '92 - '97			3.7%	7.0%	3.2%
Projected:					
	1998		24,447	378,432	15.48
	1999		24,965	393,191	15.75
	2000		25,476	408,132	16.02
	2001		25,995	422,417	16.25
	2002		26,478	436,357	16.48
	2003		26,955	449,884	16.69
	2004		27,409	462,930	16.89
	2005		27,841	474,966	17.06
	2006		28,249	485,891	17.20
	2007		28,615	495,608	17.32
AGGR '98 – '07			1.8%	3.0%	1.3%
	2008		28,958	505,025	17.44
	2009		29,249	513,610	17.56
	2010		29,503	521,315	17.67
	2011		29,731	528,613	17.78
	2012		29,932	535,485	17.89
	2013		30,106	541,911	18.00
	2014		30,223	547,330	18.11
	2015		30,310	552,256	18.22
	2016		30,370	556,674	18.33
	2017		30,400	560,571	18.44
AGGR '08 – '17			0.5%	1.2%	0.6%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1992		3,301	42,748	12.95
	1993		3,353	51,850	15.46
	1994		4,155	61,147	14.72
	1995		3,446	62,545	18.15
	1996	[1]	3,633	69,968	19.26
	1997		3,700	70,918	19.17
AGGR '92 - '97			2.3%	10.7%	8.2%
Projected:					
	1998		3,766	73,400	19.49
	1999		3,829	75,896	19.82
	2000		3,891	78,400	20.15
	2001		3,951	80,752	20.44
	2002		4,005	83,013	20.73
	2003		4,056	85,172	21.00
	2004		4,104	87,216	21.25
	2005		4,150	89,135	21.48
	2006		4,191	90,828	21.67
	2007		4,229	92,281	21.82
AGGR '98 – '07			1.3%	2.6%	1.3%
	2008		4,263	93,481	21.93
	2009		4,292	94,416	22.00
	2010		4,317	95,266	22.07
	2011		4,337	96,028	22.14
	2012		4,358	96,700	22.19
	2013		4,374	97,280	22.24
	2014		4,390	97,767	22.27
	2015		4,402	98,158	22.30
	2016		4,409	98,452	22.33
	2017		4,412	98,649	22.36
AGGR '08 - '17			0.4%	0.6%	0.2%

[1] October, November, and December are estimated.

General Service Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1992		236	107,834	456.92
	1993		246	110,020	447.23
	1994		255	117,198	459.60
	1995		270	123,708	458.18
	1996		276	134,660	487.90
	1997	[1]	278	135,298	486.68
AGGR '92 - '97			3.3%	4.6%	1.3%
Projected:					
	1998		284	140,710	495.38
	1999		290	146,198	504.08
	2000		296	151,753	512.98
	2001		302	157,368	521.88
	2002		308	162,876	529.58
	2003		314	168,251	536.58
	2004		320	173,467	542.58
	2005		325	178,497	548.58
	2006		330	183,316	555.08
	2007		335	187,899	561.08
AGGR '98 – '07			1.9%	3.3%	1.4%
	2008		339	192,033	566.08
	2009		343	195,682	571.08
	2010		346	199,008	575.08
	2011		349	202,193	579.08
	2012		352	205,225	583.08
	2013		354	208,099	587.08
	2014		357	210,804	591.08
	2015		358	213,334	595.08
	2016		360	215,680	599.08
	2017		361	217,837	603.08
AGGR '08 – '17			0.7%	1.4%	0.7%

[1] October, November, and December are estimated.

	CY Year		City Accounts Sales MWh	Lighting Sales MWh
Historical	1992			5,135
	1993			4,390
	1994		5,788	6,560
	1995		6,106	7,505
	1996		6,718	4,594
	1997	[1]	6,071	4,729
AGGR '92 - '97			1.6%	-1.6%
Projected:				
	1998		6,132	4,800
	1999		6,193	4,867
	2000		6,249	4,930
	2001		6,305	4,990
	2002		6,350	5,039
	2003		6,394	5,090
	2004		6,432	5,136
	2005		6,465	5,182
	2006		6,497	5,223
	2007		6,529	5,265
AGGR '98 – '07			0.7%	1.0%
	2008		6,555	5,302
	2009		6,582	5,339
	2010		6,601	5,371
	2011		6,621	5,403
	2012		6,634	5,430
	2013		6,647	5,458
	2014		6,661	5,485
	2015		6,667	5,507
	2016		6,674	5,523
	2017		6,681	5,534
AGGR '08 -'17			0.2%	0.5%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1992		414,668	498,309	116.6	121.8
	1993		459,755	534,133	120.7	120.1
	1994		515,608	538,609	116.8	130.2
	1995		551,025	603,680	136.8	149.6
	1996		593,942	621,276	137.6	188.0
	1997	[1]	580,893	622,034	140.8	158.6
AGGR '92 - '97			7.0%	4.5%	3.8%	5.4%
Projected:						
	1998		603,474	646,019	145.4	180.2
	1999		626,345	670,502	150.9	187.1
	2000		649,465	695,252	156.4	194.0
	2001		671,832	719,196	161.8	200.7
	2002		693,635	742,536	167.1	207.2
	2003		714,790	765,183	172.2	213.5
	2004		735,181	787,011	177.1	219.6
	2005		754,245	807,419	181.7	225.3
	2006		771,755	826,164	185.9	230.5
	2007		787,584	843,108	189.7	235.2
AGGR '98 - '07			3.0%	3.0%	3.0%	3.0%
	2008		802,397	858,966	193.3	239.7
	2009		815,629	873,131	196.5	243.6
	2010		827,561	885,904	199.3	247.2
	2011		838,858	897,997	202.0	250.5
	2012		849,475	909,363	204.6	253.7
	2013		859,395	919,982	207.0	256.7
	2014		868,046	929,243	209.1	259.3
	2015		875,921	937,674	211.0	261.6
	2016		883,004	945,256	212.7	263.7
	2017		889,272	951,966	214.2	265.6
AGGR '08 - '17			1.1%	1.1%	1.1%	1.1%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	53,176.7	55,192.0	57,229.4	59,200.3	61,121.5
FEBRUARY	44,420.3	46,103.8	47,805.6	49,452.0	51,056.8
MARCH	43,530.0	45,179.7	46,847.4	48,460.8	50,033.5
APRIL	42,088.9	43,684.0	45,296.5	46,856.4	48,377.1
MAY	53,765.7	55,803.3	57,863.2	59,855.9	61,798.4
JUNE	60,246.6	62,529.8	64,838.0	67,071.0	69,247.6
JULY	68,478.0	71,073.2	73,696.8	76,234.8	78,708.8
AUGUST	69,729.1	72,371.7	75,043.2	77,627.6	80,146.8
SEPTEMBER	61,329.1	63,653.4	66,008.1	68,276.1	70,491.9
OCTOBER	51,064.1	52,999.4	54,955.7	56,848.3	58,693.2
NOVEMBER	43,543.3	45,193.6	46,861.8	48,475.7	50,048.8
DECEMBER	54,647.2	56,718.2	58,811.9	60,837.3	62,811.6
TOTAL	646,019.1	670,502.2	695,252.5	719,196.3	742,536.1
FY	630,879.1	664,845.7	689,534.2	713,664.3	737,143.7

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	180.2	187.1	194.0	200.7	207.2
FEBRUARY	146.2	151.7	157.3	162.7	168.0
MARCH	109.7	113.9	118.1	122.1	126.1
APRIL	99.1	102.9	106.7	110.3	113.9
MAY	120.7	125.3	129.9	134.4	138.7
JUNE	139.8	145.1	150.4	155.6	160.7
JULY	143.2	148.6	154.1	159.4	164.6
AUGUST	145.4	150.9	156.4	161.8	167.1
SEPTEMBER	133.3	138.3	143.4	148.4	153.2
OCTOBER	117.1	121.6	126.1	130.4	134.6
NOVEMBER	105.2	109.2	113.2	117.1	120.9
DECEMBER	153.2	159.0	164.9	170.5	176.1
TOTAL	1,593.1	1,653.4	1,714.5	1,773.5	1,831.1
FY	1,581.8	1,639.2	1,700.1	1,759.6	1,817.5

Florida Municipal Power Agency

Energy and Demand Forecast

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Orlando, Florida 32809-5769
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CELEBRATING 20 YEARS

March 10, 1998

Mr. Larry J. Thompson
General Manager
Utility Board, City of Key West
1001 James St.
Key West, FL 33041-6100

Introduction	For your information, attached is a report for the City Electric System Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

Utility Board, City of Key West, Florida
City Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the City Electric System customers and sales by rate class and the City Electric System energy and demand forecast for the Utility Board, City of Key West for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 1.6% for the period of 1998-2007 and 0.7% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the City Electric System customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1988 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service

The explanatory variable used to determine general service sales is general service customers. The series is nonstationary and seasonal; therefore dynamic regression is used to project future sales.

Lighting

Lighting is tied to customer growth and it is nonstationary and seasonal. The Box-Jenkins model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988		18,071	161,800	8.95
	1989		18,520	177,800	9.60
	1990		19,067	188,500	9.89
	1991		19,598	197,400	10.07
	1992		19,999	196,800	9.84
	1993		20,432	213,900	10.47
	1994		20,744	216,900	10.46
	1995		21,170	251,202	11.87
	1996		21,548	256,236	11.89
	1997	[1]	21,639	271,205	12.53
AGGR '88 - '97			2.0%	5.9%	3.6%
Projected:					
	1998		21,898	277,443	12.67
	1999		22,135	283,546	12.81
	2000		22,373	289,501	12.94
	2001		22,593	295,291	13.07
	2002		22,830	300,901	13.18
	2003		23,049	306,318	13.29
	2004		23,248	311,525	13.40
	2005		23,463	316,510	13.49
	2006		23,657	321,257	13.58
	2007		23,847	325,755	13.66
AGGR '98 – '07			1.0%	1.8%	0.8%
	2008		24,017	329,990	13.74
	2009		24,182	333,949	13.81
	2010		24,342	337,623	13.88
	2011		24,462	340,999	13.94
	2012		24,576	344,068	14.00
	2013		25,702	346,821	14.04
	2014		24,805	349,248	14.08
	2015		24,900	351,344	14.11
	2016		24,972	353,101	14.14
	2017		25,019	354,513	14.17
AGGR '08 – '17			0.5%	0.8%	0.3%

[1] October, November, and December are estimated.

General Service

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988		2,470	250,000	101.21
	1989		2,503	270,000	107.87
	1990		2,593	281,000	108.37
	1991		2,660	289,000	108.65
	1992		2,723	281,000	103.20
	1993		2,799	289,000	106.47
	1994		2,853	298,000	110.41
	1995		2,960	315,000	110.55
	1996		3,089	327,241	105.78
	1997	[1]	3,129	326,744	109.20
AGGR '88 - '97			2.8%	3.4%	0.6%
Projected:					
	1998		3,165	348,531	110.12
	1999		3,199	355,153	111.01
	2000		3,231	361,546	111.90
	2001		3,262	367,692	112.72
	2002		3,290	373,575	113.54
	2003		3,318	379,179	114.29
	2004		3,343	384,487	115.00
	2005		3,366	389,486	115.71
	2006		3,388	394,159	116.33
	2007		3,407	398,495	116.95
AGGR '98 - '07			0.8%	1.5%	0.7%
	2008		3,427	402,480	117.43
	2009		3,444	406,102	117.91
	2010		3,460	409,351	118.31
	2011		3,476	412,626	118.71
	2012		3,490	415,514	119.07
	2013		3,500	418,008	119.43
	2014		3,510	420,516	119.79
	2015		3,517	422,618	120.15
	2016		3,524	424,731	120.51
	2017		3,532	426,855	120.87
AGGR '08 - '17			0.3%	0.7%	0.3%

[1] October, November, and December are estimated.

	CY Year		Lighting Sales MWh
Historical	1988		7,000
	1989		6,700
	1990		7,100
	1991		6,600
	1992		6,600
	1993		6,900
	1994		8,200
	1995		5,596
	1996		5,430
	1997	[1]	4,020
AGGR '88 - '97			-3.1%
Projected:			
	1998		4,036
	1999		4,052
	2000		4,068
	2001		4,085
	2002		4,101
	2003		4,117
	2004		4,134
	2005		4,150
	2006		4,167
	2007		4,184
AGGR '98 – '07			0.4%
	2008		4,200
	2009		4,213
	2010		4,226
	2011		4,238
	2012		4,251
	2013		4,264
	2014		4,277
	2015		4,289
	2016		4,302
	2017		4,315
AGGR '08 - '17			0.3%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1988		418,800	452,100	79.5	72.8
	1989		454,500	490,700	82.6	68.2
	1990		476,600	514,500	87.5	82.9
	1991		493,000	532,200	90.0	83.1
	1992		484,400	523,000	93.4	78.9
	1993		518,800	560,100	101.0	81.3
	1994		540,100	605,700	104.9	87.0
	1995		584,039	628,765	110.7	89.2
	1996		588,410	631,391	109.9	93.5
	1997	[1]	616,922	670,616	119.7	95.4
AGGR '88 - '97			4.3%	4.5%	4.7%	3.0%
Projected:						
	1998		630,010	683,561	121.7	97.7
	1999		642,752	696,100	123.9	99.5
	2000		655,115	708,179	126.1	101.3
	2001		667,068	720,433	128.2	103.0
	2002		678,578	732,864	130.4	104.8
	2003		689,614	744,783	132.6	106.5
	2004		700,146	756,158	134.6	108.1
	2005		710,146	766,957	136.5	109.7
	2006		719,584	777,150	138.3	111.1
	2007		728,434	786,708	140.0	112.5
AGGR '98 – '07			1.6%	1.6%	1.6%	1.6%
	2008		736,670	795,604	141.6	113.8
	2009		744,265	803,806	143.1	114.9
	2010		751,200	811,296	144.4	116.0
	2011		757,864	818,493	145.7	117.0
	2012		763,834	824,940	146.8	118.0
	2013		769,092	830,619	147.9	118.8
	2014		774,041	835,964	148.8	119.5
	2015		778,252	840,512	149.6	120.2
	2016		782,134	844,705	150.4	120.8
	2017		785,683	848,538	151.0	121.3
AGGR '08 – '17			0.7%	0.7%	0.7%	0.7%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	46,918.2	47,778.9	48,608.0	49,449.0	50,302.2
FEBRUARY	46,391.0	47,242.0	48,061.8	48,893.4	49,737.0
MARCH	54,928.6	55,936.2	56,906.9	57,891.5	58,890.4
APRIL	53,665.9	54,650.3	55,598.7	56,560.7	57,536.6
MAY	62,103.6	63,242.8	64,340.3	65,453.6	66,582.9
JUNE	65,394.0	66,593.6	67,749.2	68,921.5	70,110.7
JULY	69,175.7	70,444.7	71,667.1	72,907.2	74,165.2
AUGUST	71,134.5	72,439.4	73,696.5	74,971.6	76,265.2
SEPTEMBER	63,562.6	64,728.6	65,851.8	66,991.3	68,147.2
OCTOBER	55,586.6	56,606.3	57,588.6	58,585.1	59,593.0
NOVEMBER	47,584.7	48,457.6	49,298.5	50,151.5	51,016.9
DECEMBER	47,115.2	47,979.5	48,812.1	49,656.7	50,513.5
TOTAL	683,560.6	696,100.1	708,179.5	720,433.1	732,863.9
FY	677,188.0	693,343.2	705,523.7	717,739.1	730,130.9

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	97.7	99.5	101.3	103.0	104.8
FEBRUARY	97.5	99.3	101.1	102.8	104.6
MARCH	101.4	103.2	105.0	106.8	108.7
APRIL	101.7	103.6	105.4	107.2	109.1
MAY	109.6	111.6	113.6	115.5	117.5
JUNE	118.8	121.0	123.1	125.2	127.4
JULY	119.8	122.0	124.1	126.3	128.4
AUGUST	121.7	123.9	126.1	128.2	130.4
SEPTEMBER	116.4	118.5	120.6	122.7	124.8
OCTOBER	102.3	104.2	106.0	107.9	109.7
NOVEMBER	102.9	104.8	106.6	08.5	110.3
DECEMBER	94.4	96.2	97.8	9.5	101.2
TOTAL	1,284.4	1,307.9	1,330.6	1,353.7	1,377.0
FY	1,273.5	1,302.4	1,325.3	1,348.3	1,371.6

Florida Municipal Power Agency

Energy and Demand Forecast

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744

CELEBRATING 20 YEARS

March 10, 1998

Mr. Joseph M. Tardugno
Superintendent of Electric Utilities
City of Leesburg
P.O. Box 490630
Leesburg, FL 34749-0630

Introduction	For your information, attached is a report for the City of Leesburg Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

City of Leesburg, Florida
City Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the City Electric System customers and sales by rate class and the City Electric System energy and demand forecast for the City of Leesburg for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincedent Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 2.2% for the period of 1998-2007 and 1.6% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the City Electric System customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1989 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

Commerical

The explanatory variable used to determine commercial sales is general service commercial customers. The series is trended and nonseasonal; therefore exponential smoothing is used to project future sales.

Municpal

Municipal sales are trended and nonseasonal. The exponential smoothing model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989		13,213	144,792	10.96
	1990		13,543	153,554	11.34
	1991		13,867	157,283	11.34
	1992		13,900	154,094	11.09
	1993		14,141	160,258	11.33
	1994		14,303	165,301	11.56
	1995		14,542	178,283	12.26
	1996		14,630	179,365	12.26
	1997	[1]	14,830	182,161	12.28
AGGR '89 - '97			1.5%	2.9%	1.4%
Projected:					
	1998		15,119	186,715	12.35
	1999		15,397	191,383	12.43
	2000		15,666	195,976	12.51
	2001		15,930	200,556	12.59
	2002		16,183	205,033	12.67
	2003		16,432	209,510	12.75
	2004		16,679	213,987	12.83
	2005		16,922	218,465	12.91
	2006		17,163	222,942	12.99
	2007		17,400	227,419	13.07
AGGR '98 - '07			1.6%	2.2%	0.6%
	2008		17,623	231,740	13.15
	2009		17,832	235,911	13.23
	2010		18,043	240,158	13.31
	2011		18,241	244,240	13.39
	2012		18,422	248,148	13.47
	2013		18,588	251,870	13.55
	2014		18,756	255,648	13.63
	2015		18,908	259,228	13.71
	2016		19,043	262,597	13.79
	2017		19,160	265,749	13.87
AGGR '08 - '17			0.9%	1.5%	0.6%

[1] October, November, and December are estimated.

Commerical

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989		2,616	183,356	70.09
	1990		2,667	192,976	72.36
	1991		2,632	189,867	72.14
	1992		2,608	185,340	71.07
	1993		2,623	191,287	72.93
	1994		2,593	196,342	75.72
	1995		2,620	200,976	76.72
	1996		2,640	210,090	79.58
	1997	[1]	2,688	215,519	80.18
AGGR '89 - '97			0.3%	2.0%	1.7%
Projected:					
	1998		2,739	220,907	80.65
	1999		2,795	226,650	81.10
	2000		2,849	232,317	81.55
	2001		2,901	237,892	82.00
	2002		2,952	243,364	82.45
	2003		3,000	248,718	82.90
	2004		3,050	254,189	83.35
	2005		3,097	259,527	83.80
	2006		3,142	264,718	84.25
	2007		3,185	269,748	84.70
AGGR '98 - '07			1.7%	2.2%	0.5%
	2008		3,225	274,603	85.15
	2009		3,266	279,546	85.60
	2010		3,303	284,257	86.05
	2011		3,341	288,968	86.50
	2012		3,378	293,679	86.95
	2013		3,414	298,390	87.40
	2014		3,450	303,102	87.85
	2015		3,486	307,813	88.30
	2016		3,521	312,524	88.75
	2017		3,556	317,235	89.20
AGGR '08 - '17			1.1%	1.6%	0.5%

[1] October, November, and December are estimated.

	CY Year		Muni Sales MWh
Historical	1995		12,019
	1996		11,235
	1997	[1]	11,912
AGGR '95 - '97			-0.4%
Projected:			
	1998		12,031
	1999		12,151
	2000		12,272
	2001		12,395
	2002		12,519
	2003		12,644
	2004		12,758
	2005		12,873
	2006		12,989
	2007		13,106
AGGR '98 – '07			1.0%
	2008		13,224
	2009		13,329
	2010		13,436
	2011		13,544
	2012		13,652
	2013		13,761
	2014		13,871
	2015		13,968
	2016		14,066
	2017		14,165
AGGR '08 -'17			0.8%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1989		328,149	349,397	76.7	72.4
	1990		346,530	355,936	79.2	87.0
	1991		347,150	364,373	82.5	67.4
	1992		339,434	354,713	81.4	70.8
	1993		351,545	371,725	81.2	73.4
	1994		361,643	389,151	88.5	75.9
	1995		391,279	413,756	90.1	86.0
	1996		400,690	415,887	88.8	96.9
	1997	[1]	409,592	420,157	95.0	83.0
AGGR '89 - '97			2.8%	2.3%	2.7%	1.7%
Projected:						
	1998		419,653	430,983	96.5	91.4
	1999		430,184	441,799	99.0	93.7
	2000		440,565	452,461	101.4	95.9
	2001		450,843	463,016	103.7	98.2
	2002		460,916	473,361	106.0	100.4
	2003		470,872	483,586	108.3	102.5
	2004		480,935	493,920	110.6	104.7
	2005		490,865	504,118	112.9	106.9
	2006		500,649	514,166	115.2	109.0
	2007		510,272	524,050	117.4	111.1
AGGR '98 - '07			2.2%	2.2%	2.2%	2.2%
	2008		519,567	533,595	119.5	113.1
	2009		528,787	543,064	121.6	115.1
	2010		537,851	552,373	123.7	117.1
	2011		546,752	561,514	125.8	119.0
	2012		555,479	570,477	127.8	120.9
	2013		564,022	579,251	129.8	122.8
	2014		572,621	588,082	131.7	124.7
	2015		581,009	596,696	133.7	126.5
	2016		589,197	605,096	135.5	128.3
	2017		597,148	613,271	137.4	130.0
AGGR '08 - '17			1.6%	1.6%	1.6%	1.6%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	35,535.9	36,427.8	37,306.8	38,177.1	39,030.1
FEBRUARY	29,520.3	30,261.2	30,991.4	31,714.4	32,422.9
MARCH	31,649.3	32,443.6	33,226.5	34,001.6	34,761.3
APRIL	30,405.7	31,168.8	31,920.9	32,665.6	33,395.4
MAY	38,931.2	39,908.3	40,871.3	41,824.8	42,759.2
JUNE	39,109.6	40,091.1	41,058.6	42,016.4	42,955.2
JULY	44,391.3	45,505.3	46,603.4	47,690.6	48,756.1
AUGUST	45,721.4	46,868.8	47,999.8	49,119.6	50,217.0
SEPTEMBER	40,664.2	41,684.8	42,690.7	43,686.6	44,662.6
OCTOBER	33,828.9	34,677.9	35,514.7	36,343.2	37,155.2
NOVEMBER	29,107.8	29,838.3	30,558.3	31,271.2	31,969.8
DECEMBER	32,117.7	32,923.7	33,718.2	34,504.8	35,275.7
TOTAL	430,983.3	441,799.4	452,460.7	463,015.9	473,360.5
FY	427,437.3	439,413.9	450,109.3	460,687.9	471,079.0

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	91.4	93.7	95.9	98.2	100.4
FEBRUARY	76.3	78.2	80.1	82.0	83.8
MARCH	74.2	76.1	77.9	79.7	81.5
APRIL	72.4	74.2	76.0	77.7	79.5
MAY	87.5	89.7	91.9	94.0	96.1
JUNE	89.9	92.2	94.4	96.6	98.7
JULY	93.0	95.3	97.6	99.9	102.1
AUGUST	96.5	99.0	101.4	103.7	106.0
SEPTEMBER	88.1	90.3	92.5	94.7	96.8
OCTOBER	77.2	79.2	81.1	83.0	84.8
NOVEMBER	66.9	68.6	70.3	71.9	73.5
DECEMBER	79.2	81.2	83.1	85.1	87.0
TOTAL	992.7	1,017.6	1,042.1	1,066.4	1,090.3
FY	989.8	1,012.0	1,036.6	1,061.0	1,084.9

Coincident Peak with West Group
MW

	1998	1999	2000	2001	2002
JANUARY	91.3	93.6	95.8	98.1	100.3
FEBRUARY	76.2	78.2	80.0	81.9	83.7
MARCH	73.0	74.8	76.6	78.4	80.1
APRIL	72.3	74.1	75.9	77.7	79.4
MAY	86.9	89.1	91.3	93.4	95.5
JUNE	88.9	91.1	93.3	95.5	97.7
JULY	92.1	94.4	96.6	98.9	101.1
AUGUST	95.3	97.7	100.1	102.4	104.7
SEPTEMBER	86.5	88.7	90.8	93.0	95.0
OCTOBER	77.2	79.2	81.1	83.0	84.8
NOVEMBER	66.2	67.9	69.5	71.2	72.8
DECEMBER	79.2	81.2	83.1	85.1	87.0
TOTAL	985.2	1,009.9	1,034.3	1,058.4	1,082.0

FY	981.4	1,004.3	1,028.8	1,052.9	1,076.7

Florida Municipal Power Agency

Energy and Demand Forecast

FMPA

FMPA

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(40) 859-7310 Fax (407) 859-4553
1 8) 859-0744

20 CELEBRATING 20 YEARS

March 10, 1998

Mr. Dean Shaw
Director of Electric Utility
Ocala Electric Utility
P.O. Box 1270
Ocala, FL 34478

Introduction	For your information, attached is a report for the Ocala Electric Utility Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

Ocala Electric Utility, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the Ocala Electric Utility for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 2.0% for the period of 1998-2007 and 1.3% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1982 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

General Service Demand Class Model

The explanatory variable used to determine general service demand sales is general service demand customers. The series is trended and seasonal; therefore the model used is exponential smoothing.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. Exponential smoothing model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1987		28,465	338,282	11.88
	1988		29,324	340,390	11.61
	1989		30,205	361,505	11.97
	1990		30,735	365,160	11.88
	1991		31,081	367,773	11.83
	1992		31,490	372,420	11.83
	1993		32,067	389,346	12.14
	1994		32,576	393,804	12.09
	1995		33,056	429,200	12.98
	1996		33,438	429,112	12.83
	1997	[1]	33,760	430,861	12.76
AGGR '87 - '97			1.7%	2.4%	0.7%
Projected:					
	1998		34,059	437,324	12.84
	1999		34,356	443,883	12.92
	2000		34,623	450,098	13.00
	2001		34,885	455,949	13.07
	2002		35,116	461,420	13.14
	2003		35,349	466,958	13.21
	2004		35,576	472,094	13.27
	2005		35,770	476,815	13.33
	2006		35,930	481,106	13.39
	2007		36,092	485,436	13.45
AGGR '98 – '07			0.6%	1.2%	0.5%
	2008		36,219	489,320	13.51
	2009		36,347	493,234	13.57
	2010		36,477	497,180	13.63
	2011		36,571	500,660	13.69
	2012		36,683	503,664	13.73
	2013		36,760	506,183	13.77
	2014		36,837	508,714	13.81
	2015		36,877	510,749	13.85
	2016		36,864	512,040	13.89
	2017		36,865	513,525	13.93
AGGR '08 – '17			0.2%	0.3%	0.3%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1987		4,741	86,738	18.30
	1988		4,925	90,589	18.39
	1989		5,072	96,822	19.09
	1990		5,181	100,283	19.36
	1991		5,134	96,338	18.76
	1992		5,105	94,967	18.60
	1993		5,164	99,018	19.17
	1994		5,291	104,774	19.80
	1995		5,431	111,069	20.45
	1996	[1]	5,562	116,645	20.97
	1997		5,656	120,512	21.31
AGGR '87 - '97			1.8%	3.3%	1.5%
Projected:					
	1998		5,735	123,525	21.54
	1999		5,816	126,489	21.75
	2000		5,898	129,525	21.96
	2001		5,977	132,504	22.17
	2002		6,051	135,419	22.38
	2003		6,121	138,263	22.59
	2004		6,185	141,028	22.80
	2005		6,252	143,849	23.01
	2006		6,313	146,582	23.22
	2007		6,369	149,220	23.43
AGGR '98 - '07			1.2%	2.1%	0.9%
	2008		6,420	151,757	23.64
	2009		6,465	154,185	23.85
	2010		6,504	156,498	24.06
	2011		6,545	158,846	24.27
	2012		6,580	161,069	24.48
	2013		6,608	163,163	24.69
	2014		6,631	165,121	24.90
	2015		6,655	167,103	25.11
	2016		6,675	169,018	25.32
	2017		6,696	170,949	25.53
AGGR '08 - '17			0.5%	1.3%	0.9%

[1] October, November, and December are estimated.

General Service Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1987		682	320,214	470
	1988		706	334,514	474
	1989		723	364,319	504
	1990		762	380,752	500
	1991		794	403,460	508
	1992		815	424,130	520
	1993		833	438,734	527
	1994		834	451,754	542
	1995		860	478,522	556
	1996		904	501,120	554
	1997	[1]	914	510,193	558
AGGR '87 - '97			3.0%	4.8%	1.7%
Projected:					
	1998		935	525,498	562
	1999		956	541,263	566
	2000		977	556,960	570
	2001		997	572,555	574
	2002		1,017	588,014	578
	2003		1,037	603,302	582
	2004		1,056	618,988	586
	2005		1,075	634,463	590
	2006		1,094	649,690	594
	2007		1,111	664,633	598
AGGR '98 – '07			1.9%	2.6%	0.7%
	2008		1,129	679,919	602
	2009		1,147	694,877	606
	2010		1,163	709,470	610
	2011		1,179	723,659	614
	2012		1,193	737,409	618
	2013		1,208	751,420	622
	2014		1,222	764,945	626
	2015		1,236	778,714	630
	2016		1,250	792,209	634
	2017		1,263	805,967	638
AGGR '08 –'17			1.3%	1.9%	0.6%

[1] October, November, and December are estimated.

	CY Year		Lighting Sales MWh
Historical	1987		20,796
	1988		22,448
	1989		22,755
	1990		24,049
	1991		24,144
	1992		25,006
	1993		25,141
	1994		25,126
	1995		26,366
	1996		29,001
	1997	[1]	29,509
AGGR '87 - '97			3.8%
Projected:			
	1998		29,882
	1999		30,249
	2000		30,591
	2001		30,912
	2002		31,204
	2003		31,490
	2004		31,773
	2005		32,032
	2006		32,289
	2007		32,525
AGGR '98 – '07			0.9%
	2008		32,730
	2009		32,932
	2010		33,107
	2011		33,255
	2012		33,399
	2013		33,515
	2014		33,626
	2015		33,704
	2016		33,781
	2017		33,859
AGGR '08 -'17			0.4%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1987		766,030	804,800	184.9	155.1
	1988		788,841	846,500	185.8	178.5
	1989		836,499	905,928	196.9	179.7
	1990		871,218	915,752	205.2	199.4
	1991		892,803	952,022	206.5	164.4
	1992		917,832	977,889	215.1	195.6
	1993		953,340	1016,103	227.7	184.2
	1994		975,459	1029,952	220.7	196.9
	1995		1,045,157	1104,562	240.2	222.6
	1996		1,075,878	1121,456	248.3	239.3
	1997	[1]	1,091,074	1132,202	244.6	212.6
AGGR '87 - '97			3.8%	3.5%	2.8%	3.2%
Projected:						
	1998		1,116,228	1158,645	249.1	236.4
	1999		1,141,885	1185,277	254.8	241.8
	2000		1,167,174	1211,527	260.5	247.2
	2001		1,191,920	1237,213	266.0	252.4
	2002		1,216,058	1262,268	271.4	257.5
	2003		1,240,013	1287,133	276.7	262.6
	2004		1,263,884	1311,911	282.1	267.6
	2005		1,287,159	1336,071	287.3	272.6
	2006		1,309,667	1359,434	292.3	277.3
	2007		1,331,814	1382,423	297.2	282.0
AGGR '98 - '07			2.0%	2.0%	2.0%	2.0%
	2008		1,353,726	1405,168	302.1	286.7
	2009		1,375,229	1427,487	306.9	291.2
	2010		1,396,255	1449,313	311.6	295.7
	2011		1,416,420	1470,244	316.1	299.9
	2012		1,435,541	1490,092	320.4	304.0
	2013		1,454,280	1509,543	324.6	307.9
	2014		1,472,406	1528,357	328.6	311.8
	2015		1,490,269	1546,900	332.6	315.6
	2016		1,507,048	1564,316	336.3	319.1
	2017		1,524,300	1582,223	340.2	322.8
AGGR '08 - '17			1.3%	1.3%	1.3%	1.3%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	90,861.4	92,949.9	95,008.4	97,022.7	98,987.6
FEBRUARY	81,530.4	83,404.4	85,251.5	87,058.9	88,822.0
MARCH	85,154.1	87,111.4	89,040.6	90,928.4	92,769.8
APRIL	82,495.2	84,391.4	86,260.3	88,089.2	89,873.1
MAY	100,559.7	102,871.1	105,149.3	107,378.6	109,553.2
JUNE	105,715.2	108,145.1	110,540.2	112,883.7	115,169.8
JULY	115,298.3	117,948.5	120,560.6	123,116.7	125,610.0
AUGUST	118,886.1	121,618.8	124,312.2	126,947.8	129,518.7
SEPTEMBER	109,171.8	111,681.1	114,154.5	116,574.7	118,935.5
OCTOBER	93,839.5	95,996.4	98,122.4	100,202.7	102,232.0
NOVEMBER	82,915.1	84,820.9	86,699.4	88,537.5	90,330.5
DECEMBER	92,218.3	94,338.0	96,427.3	98,471.6	100,465.8
TOTAL	1,158,645.0	1,185,277.0	1,211,526.8	1,237,212.5	1,262,268.0

FY	1,142,001.9	1,179,094.6	1,205,433.0	1,231,249.7	1,256,451.5

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	236.4	241.8	247.2	252.4	257.5
FEBRUARY	213.2	218.1	223.0	227.7	232.3
MARCH	188.7	193.0	197.3	201.5	205.5
APRIL	194.2	198.7	203.1	207.4	211.6
MAY	228.1	233.4	238.6	243.6	248.5
JUNE	243.5	249.1	254.6	260.0	265.2
JULY	245.2	250.8	256.4	261.8	267.1
AUGUST	249.1	254.8	260.5	266.0	271.4
SEPTEMBER	235.1	240.5	245.8	251.0	256.1
OCTOBER	218.2	223.2	228.1	233.0	237.7
NOVEMBER	179.7	183.9	187.9	191.9	195.8
DECEMBER	213.4	218.3	223.2	227.9	232.5
TOTAL	2,644.8	2,705.6	2,765.5	2,824.1	2,881.3
FY	2,618.5	2,691.5	2,751.6	2,810.6	2,868.1

Florida Municipal Power Agency

Energy and Demand Forecast

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744

CELEBRATING 20 YEARS

March 10, 1998

Mr. William M. Weldon.
Utility Director
City of Starke
P.O. Drawer "C"
Starke, FL 32091

Introduction	For your information, attached is a report for the City of Starke Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

City of Starke, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following are the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Starke for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 2.5% for the period of 1998-2007 and 1.2% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency (FMPA) uses ForecastPro as the application to project the electric system customers and sales by rate class. However, because FMPA only has two years of historical data, a time series / time trend analysis is used to project future electric sales. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. A description of the variables and considerations used in developing the forecast are described on the following pages.

Methodology

The period of 1996 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are taken into consideration. Future sales projections are calculated for each class. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly demand peaks are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer
Historical	1996		1,953	22,249	11.39
	1997	[1]	1,961	22,940	11.70
AGGR '96 - '97			0.4%	3.1%	2.7%
Projected:					
	1998		1,976	23,651	11.97
	1999		1,990	24,361	12.24
	2000		2,004	25,067	12.51
	2001		2,018	25,769	12.77
	2002		2,030	26,465	13.04
	2003		2,042	27,153	13.30
	2004		2,054	27,832	13.55
	2005		2,065	28,472	13.79
	2006		2,075	29,098	14.02
	2007		2,086	29,680	14.23
AGGR '98 - '07			0.6%	2.6%	1.9%
	2008		2,094	30,244	14.44
	2009		2,102	30,758	14.63
	2010		2,110	31,250	14.81
	2011		2,117	31,688	14.97
	2012		2,124	32,100	15.11
	2013		2,130	32,485	15.25
	2014		2,134	32,842	15.39
	2015		2,139	33,171	15.51
	2016		2,143	33,436	15.60
	2017		2,147	33,670	15.68
AGGR '08 - '17			0.3%	1.2%	0.9%

[1] October, November, and December are estimated.

General Service

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer
Historical	1996		589	40,185	68.23
	1997	[1]	593	41,333	69.70
AGGR '96 - '97			0.7%	2.9%	2.2%
Projected:					
	1998		598	42,573	71.21
	1999		603	43,808	72.69
	2000		607	45,034	74.17
	2001		611	46,250	75.65
	2002		615	47,453	77.13
	2003		619	48,639	78.61
	2004		623	49,758	79.93
	2005		627	50,852	81.13
	2006		631	51,920	82.33
	2007		634	52,907	83.48
AGGR '98 - '07			0.7%	2.4%	1.8%
	2008		637	53,859	84.56
	2009		640	54,775	85.64
	2010		642	55,596	86.62
	2011		644	56,375	87.50
	2012		646	57,107	88.38
	2013		648	57,793	89.16
	2014		649	58,371	89.94
	2015		650	58,896	90.62
	2016		651	59,367	91.20
	2017		652	59,783	91.68
AGGR '08 - '17			0.3%	1.2%	0.9%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1992		53,779	61,112	12.5	11.6
	1993		54,515	63,209	13.2	10.1
	1994		56,000	63,769	12.5	11.0
	1995		60,022	68,234	13.9	12.4
	1996		62,434	69,954	13.4	13.4
	1997	[1]	64,273	69,294	13.9	11.9
AGGR '92- '97			3.8%	2.5%	2.1%	0.5%
Projected:						
	1998		66,224	71,390	14.1	12.6
	1999		68,168	73,485	14.6	13.0
	2000		70,101	75,569	15.0	13.4
	2001		72,019	77,637	15.4	13.7
	2002		73,917	79,683	15.8	14.1
	2003		75,792	81,704	16.2	14.5
	2004		77,589	83,641	16.6	14.8
	2005		79,324	85,511	16.9	15.1
	2006		81,018	87,338	17.3	15.5
	2007		82,587	89,029	17.6	15.8
AGGR '98 – '07			2.5%	2.5%	2.5%	2.5%
	2008		84,103	90,663	18.0	16.0
	2009		85,533	92,204	18.3	16.3
	2010		86,847	93,621	18.5	16.6
	2011		88,062	94,931	18.8	16.8
	2012		89,207	96,165	19.0	17.0
	2013		90,278	97,319	19.3	17.2
	2014		91,213	98,328	19.5	17.4
	2015		92,067	99,248	19.7	17.6
	2016		92,803	100,042	19.8	17.7
	2017		93,453	100,742	19.9	17.8
AGGR '08 – '17			1.2%	1.2%	1.2%	1.2%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	5,553.2	5,716.2	5,878.3	6,039.2	6,198.3
FEBRUARY	4,915.8	5,060.1	5,203.6	5,346.0	5,486.9
MARCH	5,225.1	5,378.5	5,531.0	5,682.3	5,832.1
APRIL	4,866.9	5,009.7	5,151.8	5,292.8	5,432.3
MAY	6,267.2	6,451.2	6,634.1	6,815.6	6,995.2
JUNE	6,485.8	6,676.2	6,865.5	7,053.3	7,239.2
JULY	7,340.8	7,556.3	7,770.6	7,983.2	8,193.6
AUGUST	7,555.8	7,777.6	7,998.1	8,217.0	8,433.5
SEPTEMBER	6,796.8	6,996.3	7,194.7	7,391.6	7,586.4
OCTOBER	5,719.3	5,887.2	6,054.2	6,219.8	6,383.7
NOVEMBER	5,344.3	5,501.2	5,657.2	5,812.0	5,965.2
DECEMBER	5,318.6	5,474.8	5,630.0	5,784.1	5,936.5
TOTAL	71,389.6	73,485.4	75,569.3	77,636.7	79,683.0

FY	71,132.3	73,004.5	75,091.1	77,162.2	79,213.4

Peak Demands
MW

	1998	1999	2000	2001	2002
JANUARY	12.6	13.0	13.4	13.7	14.1
FEBRUARY	11.0	11.4	11.7	12.0	12.3
MARCH	10.1	10.4	10.7	10.9	11.2
APRIL	9.8	10.1	10.4	10.6	10.9
MAY	12.4	12.7	13.1	13.5	13.8
JUNE	12.9	13.2	13.6	14.0	14.3
JULY	13.2	13.6	14.0	14.4	14.8
AUGUST	14.1	14.6	15.0	15.4	15.8
SEPTEMBER	12.8	13.2	13.6	13.9	14.3
OCTOBER	11.1	11.4	11.8	12.1	12.4
NOVEMBER	10.4	10.7	11.0	11.3	11.6
DECEMBER	11.2	11.5	11.8	12.2	12.5
TOTAL	141.6	145.8	149.9	154.0	158.1
FY	142.1	144.8	149.0	153.1	157.2

Florida Municipal Power Agency

Energy and Demand Forecast

7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
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1 800 859-0744

CELEBRATING 20 YEARS

March 10, 1998

Mr. Rex Taylor
City Manager/Utilities Director
City of Vero Beach
P.O. Box 3191
Vero Beach, FL 32961-1389

Introduction	For your information, attached is a report for the City of Vero Beach Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

City of Vero Beach, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Vero Beach for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincdent Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 2.3% for the period of 1998-2007 and 0.9% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1986 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is nonstationary and seasonal; therefore the model used is exponential smoothing.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

General Service Demand Class Model

The general service demand class has only one customer. Its sales are nonstationary and seasonal; therefore the model used is exponential smoothing.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. A dynamic regression model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986		18,900	221,117	11.70
	1987		19,442	227,528	11.70
	1988		20,272	238,838	11.78
	1989		20,720	253,439	12.23
	1990		21,128	266,072	12.59
	1991		21,452	283,620	13.22
	1992		21,607	262,540	12.15
	1993		21,864	268,675	12.29
	1994		22,130	279,587	12.63
	1995		22,409	297,736	13.29
	1996		22,742	301,358	13.25
	1997	[1]	22,918	294,802	12.86
AGGR '86 - '97			1.8%	2.6%	0.9%
Projected:					
	1998		23,322	303,646	13.02
	1999		23,743	312,452	13.16
	2000		24,150	321,200	13.30
	2001		24,562	329,873	13.43
	2002		24,959	338,450	13.56
	2003		25,353	346,572	13.67
	2004		25,722	354,197	13.77
	2005		26,085	361,281	13.85
	2006		26,421	367,784	13.92
	2007		26,729	373,668	13.98
AGGR '98 – '07			1.5%	2.3%	0.8%
	2008		27,014	379,273	14.04
	2009		27,275	384,583	14.10
	2010		27,525	389,198	14.14
	2011		27,741	393,090	14.17
	2012		27,932	396,628	14.20
	2013		28,068	399,405	14.23
	2014		28,177	401,801	14.26
	2015		28,258	403,810	14.29
	2016		28,340	405,829	14.32
	2017		28,394	407,452	14.35
AGGR '08 – '17			0.6%	0.8%	0.2%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986		3,395	182,356	53.71
	1987		3,619	193,300	53.41
	1988		3,769	198,124	52.57
	1989		3,873	206,599	53.34
	1990		3,971	211,996	53.39
	1991		3,909	212,588	54.38
	1992		3,941	210,596	53.44
	1993		3,981	220,670	55.43
	1994		4,102	231,793	56.51
	1995		4,163	241,605	58.04
	1996		4,253	252,917	59.47
	1997	[1]	4,324	286,758	66.32
AGGR '86 - '97			2.2%	4.2%	1.9%
Projected:					
	1998		4,412	295,361	66.95
	1999		4,501	303,926	67.52
	2000		4,589	312,436	68.09
	2001		4,673	320,872	68.66
	2002		4,755	329,215	69.23
	2003		4,835	337,116	69.72
	2004		4,912	344,532	70.14
	2005		4,985	351,423	70.50
	2006		5,049	357,749	70.86
	2007		5,109	363,830	71.22
AGGR '98 - '07			1.6%	2.3%	0.7%
	2008		5,164	369,652	71.58
	2009		5,215	375,196	71.94
	2010		5,262	380,449	72.30
	2011		5,304	385,395	72.66
	2012		5,341	390,020	73.02
	2013		5,372	393,920	73.33
	2014		5,397	397,465	73.64
	2015		5,418	400,645	73.95
	2016		5,433	403,449	74.26
	2017		5,443	405,870	74.57
AGGR '08 - '17			0.6%	1.0%	0.5%

[1] October, November, and December are estimated.

General Service Demand

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986		1	24,635	24,635
	1987		1	21,496	21,496
	1988		1	25,311	25,311
	1989		1	29,238	29,238
	1990		1	17,454	17,454
	1991		1	8,222	8,222
	1992		1	8,679	8,679
	1993		1	10,339	10,339
	1994		1	10,615	10,615
	1995		1	11,940	11,940
	1996		1	11,881	11,881
	1997	[1]	1	13,398	13,398
AGGR '86 - '97			0.0%	-5.4%	-5.4%
Projected:					
	1998		1	13,532	13,532
	1999		1	13,667	13,667
	2000		1	13,790	13,790
	2001		1	13,914	13,914
	2002		1	14,040	14,040
	2003		1	14,152	14,152
	2004		1	14,265	14,265
	2005		1	14,365	14,365
	2006		1	14,451	14,451
	2007		1	14,523	14,523
AGGR '98 - '07			0.0%	0.8%	0.8%
	2008		1	14,582	14,582
	2009		1	14,640	14,640
	2010		1	14,684	14,684
	2011		1	14,728	14,728
	2012		1	14,757	14,757
	2013		1	14,787	14,787
	2014		1	14,816	14,816
	2015		1	14,831	14,831
	2016		1	14,846	14,846
	2017		1	14,861	14,861
AGGR '08 - '17			0.0%	0.2%	0.2%

[1] October, November, and December are estimated.

	CY Year		Street Lights Sales MWh	City Accounts Sales MWh
Historical	1986		2,000	
	1987		2,056	
	1988		2,341	
	1989		2,535	
	1990		2,674	
	1991		2,789	
	1992		2,784	314
	1993		2,451	315
	1994		2,027	310
	1995		2,121	309
	1996		2,178	311
	1997	[1]	2,190	336
AGGR '86 - '97			0.8%	1.3%
Projected:				
	1998		2,208	338
	1999		2,225	340
	2000		2,241	342
	2001		2,254	344
	2002		2,265	346
	2003		2,277	348
	2004		2,286	349
	2005		2,295	351
	2006		2,302	353
	2007		2,309	354
AGGR '98 - '07			0.5%	0.5%
	2008		2,316	356
	2009		2,320	357
	2010		2,325	359
	2011		2,330	360
	2012		2,334	361
	2013		2,339	362
	2014		2,344	362
	2015		2,346	363
	2016		2,348	364
	2017		2,351	365
AGGR '08 - '17			0.2%	0.3%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1990		498,195	517,629	109.0	138.0
	1991		507,219	514,062	107.0	125.0
	1992		484,913	512,815	110.0	122.0
	1993		502,450	528,150	112.0	125.0
	1994		524,333	544,412	111.0	113.0
	1995		553,710	583,397	119.0	156.0
	1996		568,645	590,800	118.0	174.0
	1997	[1]	597,484	629,145	130.0	155.0
AGGR '90 - '97			2.6%	2.2%	2.0%	1.3%
Projected:						
	1998		615,084	647,684	134.1	169.7
	1999		632,611	666,139	137.9	174.5
	2000		650,010	684,460	141.7	179.3
	2001		667,258	702,622	145.4	184.1
	2002		684,315	720,584	149.2	188.8
	2003		700,464	737,589	152.7	193.2
	2004		715,630	753,558	156.0	197.4
	2005		729,715	768,390	159.1	201.3
	2006		742,638	781,998	161.9	204.9
	2007		754,685	794,684	164.5	208.2
AGGR '98 – '07			2.3%	2.3%	2.3%	2.3%
	2008		766,178	806,785	167.0	211.4
	2009		777,097	818,283	169.4	214.4
	2010		787,015	828,727	171.5	217.1
	2011		795,902	838,085	173.5	219.6
	2012		804,100	846,717	175.3	221.8
	2013		810,812	853,785	176.7	223.7
	2014		816,789	860,078	178.0	225.3
	2015		821,995	865,561	179.2	226.8
	2016		826,837	870,659	180.2	228.1
	2017		830,899	874,936	181.1	229.2
AGGR '08 – '17			0.9%	0.9%	0.9%	0.9%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	52,163.8	53,650.2	55,125.8	56,588.5	58,035.1
FEBRUARY	47,456.9	48,809.1	50,151.6	51,482.3	52,798.4
MARCH	47,142.7	48,486.0	49,819.5	51,141.5	52,448.8
APRIL	47,489.8	48,843.0	50,186.4	51,518.0	52,835.0
MAY	55,364.9	56,942.5	58,508.6	60,061.1	61,596.5
JUNE	57,637.8	59,280.2	60,910.6	62,526.8	64,125.2
JULY	62,631.5	64,416.1	66,187.8	67,944.1	69,681.0
AUGUST	64,085.2	65,911.2	67,724.1	69,521.1	71,298.3
SEPTEMBER	60,403.6	62,124.7	63,833.4	65,527.2	67,202.3
OCTOBER	55,229.1	56,802.8	58,365.1	59,913.8	61,445.5
NOVEMBER	48,286.6	49,662.5	51,028.4	52,382.4	53,721.5
DECEMBER	49,791.8	51,210.5	52,619.0	54,015.3	55,396.1
TOTAL	647,683.8	666,138.9	684,460.2	702,622.2	720,583.8
FY	633,456.3	661,770.5	680,123.6	698,323.2	716,332.3

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	169.7	174.5	179.3	184.1	188.8
FEBRUARY	140.1	144.1	148.0	152.0	155.9
MARCH	119.9	123.3	126.7	130.0	133.4
APRIL	109.5	112.7	115.8	118.8	121.9
MAY	121.4	124.8	128.2	131.6	135.0
JUNE	131.8	135.6	139.3	143.0	146.7
JULY	130.5	134.2	137.9	141.5	145.1
AUGUST	134.1	137.9	141.7	145.4	149.2
SEPTEMBER	131.9	135.6	139.4	143.1	146.7
OCTOBER	117.8	121.2	124.5	127.8	131.1
NOVEMBER	107.8	110.9	113.9	117.0	120.0
DECEMBER	145.1	149.3	153.4	157.4	161.5
TOTAL	1,559.6	1,604.0	1,648.1	1,691.9	1,735.1
FY	1,537.8	1,593.4	1,637.6	1,681.5	1,724.8

Florida Municipal Power Agency

Energy and Demand Forecast

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CELEBRATING 20 YEARS

March 10, 1998

Mr. Harvey Wildschuetz
Utilities Director
City of Lake Worth Utilities
1900 2nd Ave. North
Lake Worth, FL 33461 - 4298

Introduction	For your information, attached is a report for the City of Lake Worth Utilities Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

City of Lake Worth Utilities, Florida
Electric System

Customers, Sales, Energy and Demand Forecast
1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Lake Worth Utilities for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 0.9% for the period of 1998-2007 and 0.5% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1991 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service Class Model

The explanatory variable used to determine general service sales is general service customers. The series is trended and seasonal; therefore dynamic regression model is used to project future sales.

Lighting

Lighting is tied to customer growth. The series is nonstationary and nonseasonal; therefore, Box-Jenkins is use to project future sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1991		20,206	181,181	8.97
	1992		20,092	176,559	8.79
	1993		20,219	177,671	8.79
	1994		20,516	192,700	9.39
	1995		20,758	202,872	9.77
	1996		20,877	205,954	9.87
	1997	[1]	20,994	206,979	9.86
AGGR '91 - '97			0.6%	2.2%	1.6%
Projected:					
	1998		21,120	209,877	9.94
	1999		21,247	212,605	10.01
	2000		21,353	215,156	10.08
	2001		21,460	217,523	10.14
	2002		21,567	219,698	10.19
	2003		21,675	221,676	10.23
	2004		21,783	223,671	10.27
	2005		21,870	225,460	10.31
	2006		21,958	227,264	10.35
	2007		22,046	228,855	10.38
AGGR '98 – '07			0.5%	1.0%	0.5%
	2008		22,134	230,457	10.41
	2009		22,222	232,070	10.44
	2010		22,289	233,462	10.47
	2011		22,356	234,863	10.51
	2012		22,423	236,037	10.53
	2013		22,468	237,217	10.56
	2014		22,513	238,166	10.58
	2015		22,558	239,119	10.60
	2016		22,603	239,836	10.61
	2017		22,648	240,556	10.62
AGGR '08 – '17			0.3%	0.5%	0.2%

[1] October, November, and December are estimated.

General Service

	CY Year		Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1991		2,971	154,597	52.04
	1992		2,962	148,596	50.17
	1993		2,958	146,777	49.62
	1994		2,985	153,770	51.51
	1995		3,010	148,310	49.27
	1996		3,052	143,248	46.94
	1997	[1]	3,071	146,422	47.68
AGGR '91 - '97			0.6%	-0.9%	-1.4%
Projected:					
	1998		3,102	148,196	47.77
	1999		3,131	149,847	47.86
	2000		3,159	151,437	47.94
	2001		3,185	152,963	48.03
	2002		3,211	154,420	48.09
	2003		3,233	155,739	48.17
	2004		3,256	156,983	48.21
	2005		3,276	158,149	48.28
	2006		3,296	159,235	48.31
	2007		3,316	160,329	48.35
AGGR '98 - '07			0.7%	0.9%	0.1%
	2008		3,336	161,339	48.36
	2009		3,353	162,357	48.42
	2010		3,370	163,218	48.43
	2011		3,387	164,086	48.45
	2012		3,404	164,958	48.46
	2013		3,418	165,740	48.49
	2014		3,432	166,526	48.52
	2015		3,446	167,316	48.55
	2016		3,459	168,111	48.60
	2017		3,473	168,909	48.63
AGGR '08 - '17			0.4%	0.5%	0.1%

[1] October, November, and December are estimated.

	CY Year		Lighting Sales MWh
Historical	1991		4,200
	1992		4,181
	1993		4,261
	1994		4,353
	1995		2,430
	1996		4,505
	1997	[1]	4,576
AGGR '91 - '97			1.4%
Projected:			
	1998		4,651
	1999		4,723
	2000		4,793
	2001		4,860
	2002		4,925
	2003		4,987
	2004		5,046
	2005		5,101
	2006		5,154
	2007		5,205
AGGR '98 - '07			1.3%
	2008		5,253
	2009		5,297
	2010		5,339
	2011		5,378
	2012		5,414
	2013		5,448
	2014		5,477
	2015		5,503
	2016		5,523
	2017		5,544
AGGR '08 - '17			0.6%

[1] October, November, and December are estimated.

	CY Year		Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1991		323,978	344,865	65.8	60.8
	1992		318,569	337,396	66.4	61.6
	1993		321,202	347,318	69.5	61.8
	1994		345,911	364,509	69.1	59.8
	1995		353,612	377,104	73.7	76.3
	1996		353,715	375,805	73.7	82.0
	1997	[1]	357,985	377,288	74.0	74.0
AGGR '91 - '97			1.7%	2.0%	3.0%	3.3%
Projected:						
	1998		362,724	382,311	74.9	76.5
	1999		367,175	387,003	75.9	77.4
	2000		371,387	391,442	76.7	78.3
	2001		375,346	395,615	77.5	79.1
	2002		379,044	399,512	78.3	79.9
	2003		382,401	403,051	79.0	80.6
	2004		385,700	406,527	79.7	81.3
	2005		388,710	409,701	80.3	81.9
	2006		391,652	412,801	80.9	82.6
	2007		394,388	415,685	81.5	83.1
AGGR '98 - '07			0.9%	0.9%	0.9%	0.9%
	2008		397,049	418,490	82.0	83.7
	2009		399,724	421,309	82.6	84.3
	2010		402,020	423,729	83.1	84.7
	2011		404,326	426,160	83.5	85.2
	2012		406,410	428,356	84.0	85.7
	2013		408,406	430,460	84.4	86.1
	2014		410,169	432,319	84.7	86.5
	2015		411,938	434,183	85.1	86.8
	2016		413,470	435,797	85.4	87.2
	2017		415,009	437,419	85.7	87.5
AGGR '08 - '17			0.5%	0.5%	0.5%	0.5%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	29,107.5	29,464.8	29,802.8	30,120.5	30,417.2
FEBRUARY	25,399.6	25,711.3	26,006.3	26,283.5	26,542.4
MARCH	28,313.1	28,660.6	28,989.3	29,298.4	29,587.0
APRIL	27,902.1	28,244.6	28,568.6	28,873.1	29,157.5
MAY	33,763.2	34,177.5	34,569.6	34,938.1	35,282.3
JUNE	35,209.5	35,641.6	36,050.5	36,434.7	36,793.7
JULY	39,560.9	40,046.4	40,505.8	40,937.5	41,340.8
AUGUST	39,8[illegible]9.6	40,358.9	40,821.8	41,257.0	41,663.4
SEPTEMBER	36,884.8	37,337.5	37,765.8	38,168.4	38,544.4
OCTOBER	32,574.7	32,974.4	33,352.7	33,708.2	34,040.3
NOVEMBER	26,431.9	26,756.2	27,063.2	27,351.7	27,621.1
DECEMBER	27,293.9	27,628.9	27,945.8	28,243.7	28,522.0
TOTAL	382,310.7	387,002.7	391,442.1	395,614.8	399,512.1
FY	379,939.3	385,943.6	390,440.0	394,672.9	398,632.3

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	76.5	77.4	78.3	79.1	79.9
FEBRUARY	66.2	67.0	67.8	68.5	69.2
MARCH	61.9	62.6	63.4	64.0	64.7
APRIL	59.3	60.0	60.7	61.4	62.0
MAY	66.9	67.8	68.5	69.3	69.9
JUNE	70.2	71.0	71.9	72.6	73.3
JULY	73.3	74.2	75.1	75.9	76.6
AUGUST	74.9	75.9	76.7	77.5	78.3
SEPTEMBER	72.7	73.6	74.5	75.3	76.0
OCTOBER	60.5	61.2	61.9	62.6	63.2
NOVEMBER	51.7	52.3	53.0	53.5	54.0
DECEMBER	65.1	65.9	66.6	67.3	68.0
TOTAL	799.3	809.1	818.4	827.1	835.2
FY	782.0	806.9	816.3	825.1	833.4