Stanton Energy Center Combined Cycle Unit A

010142-EM

Need for Power Application

Florida Municipal Power Agency – Volume 1D

January 29, 2001

BLACK & VEATCH

11401 Lamar, Overland Park, Ka

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1D.1.0 Overview and Summary

1D.1.1 Overview

Stanton A is planned as a new combined cycle addition to the existing Stanton Energy Center site, located 12 miles southeast of Orlando, Florida. The Stanton Energy Center site was originally certified for an ultimate capacity of approximately 2,000 MW based on four coal-fired units. The existing Stanton Unit 1 is a 444 MW net coal-fired facility and Stanton 2 is a 446 MW net coal-fired generating facility. Stanton 1 was placed in operation on July 1, 1987 followed by Stanton 2 which was placed in operation on June 1, 1996. Stanton A will provide very economical power for the Florida Municipal Power Agency (FMPA or Agency) All-Requirements Project members with a minimal environmental impact. Stanton A will be a 2 x 1 GE 7FA combined cycle unit. The net output of the unit is estimated to be 633 MW at 70 F under new and clean conditions and will be jointly owned by Kissimmee Utility Authority (KUA), Orlando Utility Commission (OUC), FMPA and Southern Company – Florida LLC (Southern-Florida). FMPA will be a 10 percent joint owner of the 35 percent (221.6 MW) capacity to be owned by the utility applicants. FMPA's portion of generation from Stanton A will be approximately 22 MW. FMPA will also receive 10 percent of the 65 percent capacity owned by Southern-Florida and supplied under the power purchase agreement (PPA). Details specific to the project are presented in Volume 1A. This volume, Volume 1D, 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 is committed to meet its All-Requirements customers' needs and identify projects that will provide economical power to its members 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.

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.

FMPA's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with Stanton A. Stanton A will burn natural gas as the primary fuel with Selective Catalytic Reduction providing a very clean burning, highly efficient unit.

As discussed in the remainder of this application, FMPA has evaluated appropriate alternatives to Stanton A to determine if they are lower in cumulative present worth revenue requirements.

FMPA believes that Stanton A 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, Stanton A has proven to be FMPA's most cost-effective through exhaustive evaluations as well as a thorough test of the marketplace.

1D.1.2 Summary

FMPA's All-Requirements has been growing rapidly through the addition of new members, with Lake Worth projected to join in 2002. FMPA's peak demand is projected to grow at a 1.8 percent average annual rate from 2000 through the end of the planning period in 2019. The projected load growth assumes no new members will join after Lake Worth in 2002.

FMPA uses an 18 percent summer reserve margin and a 15 percent winter reserve margin as reliability criterion. FMPA's reserve margin is projected to drop to 14.1 percent during the summer of 2003, dictating the need to add capacity.

FMPA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the least-cost alternative under both base and all but one sensitivity analysis.

1D.2.0 Description of System

The Florida Municipal Power Agency (FMPA) was created on February 24, 1978, by signing of the Interlocal Agreement among its 29 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.

1D.2.1 Generation System

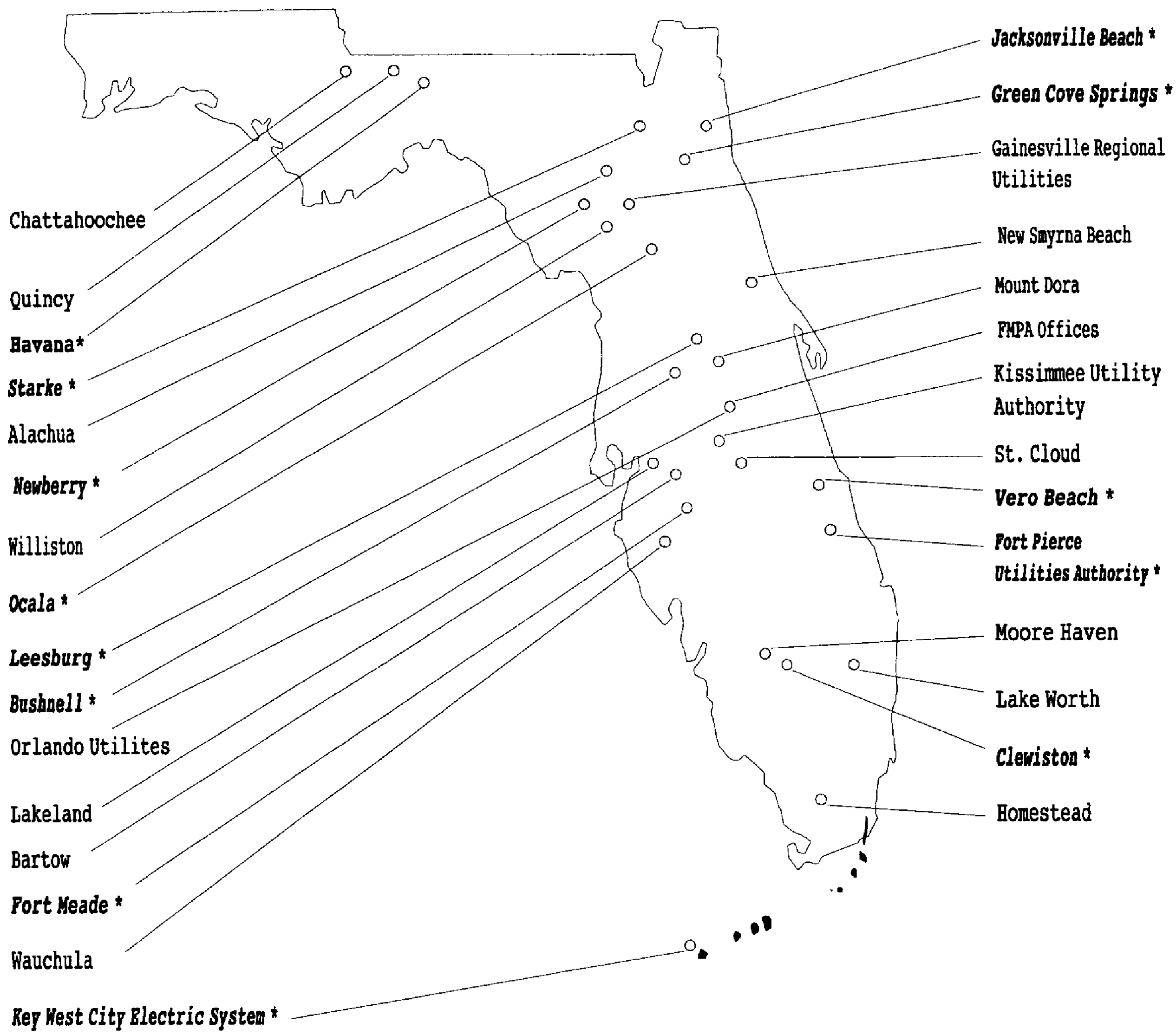
FMPA is a project-oriented, joint action agency where each project stands on its own. FMPA currently has five power supply projects in operation: (i) the St. Lucie Project, (ii) the Stanton I Project, (iii) the Tri-City Project, (iv) the All-Requirements Project (ARP), and (v) the Stanton II Project. Each of the projects is summarized in Subsections 1D.2.1.1 through 1D.2.1.5. Table 1D.2-1 provides a summary of the member participation for each project. Figure 1D 2-1 illustrates the location of the

Table 1D.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 Chattahoochee					
City of Clewiston	X			X	
City of Ft. Meade	X			X	
Ft. Pierce Utilities Authority	X	X	X	X	X
Gainesville Regional Utilities					
City of Green Cove Springs	X			X	
Town of Havana				X	
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 (2002)	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Mt. Dora					
City of Newberry	X			X	
City of New Smyrna Beach	X				
City of Ocala				X	
Orlando Utilities Commission					
City of Quincy					
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.

FLORIDA MUNICIPAL POWER AGENCY



** All-Requirements Project Members*

FMPA member cities within Peninsular Florida. Table 1D.2-2 provides a summary of the existing FMPA generating facilities with project capacities combined where appropriate.

1D.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 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 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 eight of the fifteen (ten of the fifteen including the City of Lake Worth which is projected to become a member in 2002) are also members of the All-Requirements Project.

1D.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 1. Stanton 1 is a pulverized coal unit that 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.

1D.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 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.

1D.2.1.4 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 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.

Table 1D.2-2
Florida Municipal Power Agency
Existing and Planned Generating Facilities

Plant	Unit No.	Location (County)	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	FMPA Net Capability[1]		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
Existing Generating Facilities												
St Lucie	2	St Lucie	N	N	None	08/83	Unknown	839.00	74.0	75.0	TK	None
Stanton Energy Center (SEC)	1	Orange	FS	C	None	07/87	Unknown	464.58	115.0	115.0	RR	None
	2		FS	C	None	06/96		464.58	122.0	122.0	RR	None
Indian River	CT A	Brevard	CT	NG	LO	06/89	Unknown	41.40	14.6	18.6	PL	TK
	CT B		CT	NG	LO	07/89	Unknown	41.40	14.6	18.6	PL	TK
	CT C		CT	NG	LO	08/92	Unknown	122 04	21.7	27.0	PL	TK
	CT D		CT	NG	LO	10/92	Unknown	122.04	21.7	27.0	PL	TK
Cane Island	1	Osceola	CT	NG	LO	01/95	Unknown	40.00	15 2	15.2	PL	TK
	2		CCT	NG	LO	06/95	Unknown	122 00	54.2	60.2	PL	TK
Stock Island	CT 2	Monroe	CT	LO	LO	06/99	Unknown	21.00	17.0	17.0	TK	TK
	CT 3		CT	LO	LO	06/99	Unknown	21.00	17.0	17.0	TK	TK
Planned Generating Facilities												
Cane Island	3	Osceola	CC	NG	LO	06/01 (planned)	Unknown	250.00	120	120	PL	TK
SEC[2]	1	Orange	FS	C	None	01/02	Unknown	464 58	10.1	10 1	RR	None
St. Lucie[2]	1	St. Lucie	N	N	None	01/02	Unknown	850 00	9 17	9.17	TK	None
	2					01/02	Unknown	839.00	9.17	9.17	TK	None
SEC	3	Orange	CC	NG	LO	10/03 (planned)	Unknown	633	20 8	22.6	PL	TK
McIntosh	4	Polk	FS	PET	C	06/05 (planned)	Unknown	288.00	100	100	TR	TR

[1] FMPA's ownership share. Does not include City of Newberry's capacity in St. Lucie 2.
[2] Result of addition of Lake Worth to ARP in January of 2002.
Source FMPA Ten Year Site Plan April 2000.

1D.2.1.5 All-Requirements Project

The All-Requirements Project was formed on May 1, 1986, with five members; other members have joined through the years, and the total will be 14 members when the City of Lake Worth joins in 2001. The All-Requirements Project participants now consist of City of Bushnell, City of Clewiston, City of Fort Meade, Fort Pierce Utilities Authority, City of Green Cove Springs, Town of Havana, City of Jacksonville Beach, City of Key West, City of Leesburg, City of Newberry, Ocala Electric Utility, City of Starke, and City of Vero Beach. Table 1D.2-3 shows the date that each member joined the All-Requirements Project. Under the All-Requirements Project, the Agency currently serves all the power requirements (above certain excluded resources) for the members Table 1D.2-4 provides a summary of the existing and planned generating resources of the All-Requirements Project. This table does not include member generating resources. The member generating resources are shown in Table 1D.2-5. Table 1D.2-4 indicates approximately 18 MW of generating capacity from Crystal River 3 for the All-Requirements Project. This capacity in Crystal

Table 1D.2-3
Date ARP Member Joined

Agency Member	Date Member Joined
City of Bushnell	May 1, 1986
City of Clewiston	May 8, 1991
City of Fort Pierce Utilities Authority	January 1, 1998
City of Fort Meade	February 1, 2000
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 Vero Beach	June , 1997
City of Leesburg	May 1, 1986
City of Ocala	May 1, 1986
City of Starke	October 1, 1997
Town of Havana	July 1, 2000
City of Lake Worth	January 1,2002
City of Newberry	December 2000

Table 1D.2-4
FMPA All-Requirements Project Existing and Planned Generating Facilities

Plant	Unit No.	Location (County)	Type	Fuel Primary	Fuel Alternate	Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability[1] Summer (MW)	Net Capability[1] Winter (MW)	Fuel Transportation Primary	Fuel Transportation Alternate
St. Lucie	1	St. Lucie	N	N	None	05/76	Unknown	850 00	16.7	16.7	TK	None
	2		N	N	None	08/83	Unknown	839.00	18.3	18.3	TK	None
Crystal River	3	Citrus	N	N		03/77	Unknown	890.46	17.8	17.8		
Stanton Energy Center (SEC)	1	Orange	FS	C	None	07/87	Unknown	464.58	82.3	82.3	RR	None
	2		FS	C	None	06/96	Unknown	464.58	66.0	66.0	RR	None
Indian River	CT A	Brevard	CT	NG	LO	06/89	Unknown	41 40	14.6	18.6	PL	TK
	CT B		CT	NG	LO	07/89	Unknown	41.40	14.6	18.6	PL	TK
	CT C		CT	NG	LO	08/92	Unknown	122 04	21.7	27.0	PL	TK
	CT D		CT	NG	LO	10/92	Unknown	122.04	21.7	27.0	PL	TK
Cane Island	1	Osceola	CT	NG	LO	01/95	Unknown	40.00	15.2	15.2	PL	TK
	2		CCT	NG	LO	06/95	Unknown	122.00	54.2	60.2	PL	TK
Stock Island	CT 2	Monroe	CT	LO	LO	06/99	Unknown	21 00	17.0	17.0	TK	TK
	CT 3		CT	LO	LO	06/99	Unknown	21.00	17.0	17.0	TK	TK
FMPA ARP Total Generation Capacity for 2000									377.0	401.6		
Cane Island	3	Osceola	CC	NG	LO	06/01 (planned)	Unknown	250.00	120	120	PL	TK
FMPA ARP Total Generation Capacity for 2001									497.0	401 6		
SEC[2]	1	Orange	FS	C	None	01/02	Unknown	464.58	10 1	10 1	RR	None
St. Lucie[2]	1	St. Lucie	N	N	None	01/02	Unknown	850.00	9 2	9.2	TK	None
	2					01/02	Unknown	839 00	9.2	9.2	TK	None
FMPA ARP Total Generation Capacity for 2002									525.5	550.1		
SEC[3]	A	Orange	CC	NG	LO	10/03 (planned)	Unknown	633	20 8	22 6	PL	TK
FMPA ARP Total Generation Capacity for 2003									525.5	550.1		
FMPA ARP Total Generation Capacity for 2004									525.5	550.1		
McIntosh	4	Polk	FS	PET	C	06/05 (planned)	Unknown	288.00	100	100	TR	TR
FMPA ARP Total Generation Capacity for 2005									625.5	650.1		
FMPA ARP Total Generation Capacity for 2006									625.5	650.1		

[1] FMPA All-Requirements Project members' ownership share
[2] Result of addition of Lake Worth to ARP in January of 2002.
[3] SEC A's capacity has not been included in the total capacity available to FMPA.

Table 1D.2-5
FMPA All Requirements Project Existing Member Generating Facilities

Plant	Unit No.	Location (County)	Type	Fuel Primary	Fuel Alternate	Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability Summer (MW)	Net Capability Winter (MW)	Fuel Transportation Primary	Fuel Transportation Alternate
H D. King	7	St. Lucie	FS	NG	HO	01/64	Unknown	33 00	32.0	32.0	PL	TK
	8		FS	NG	HO	05/76	Unknown	56.116	50.0	50.0	PL	TK
	9		CCT	NG	LO	05/90	Unknown	30.895	31.0	31.0	PL	TK
	D1		D	LO	None	04/70	Unknown	2.75	2.5	2.5	TK	
	D2		D	LO	None	04/70	Unknown	2.75	2.5	2.5	TK	
Big Pine	1	Monroe	D	LO	None	02/69	Unknown	2.75	2.5	2.5	TK	
Cudjoe	2	Monroe	D	LO	None	08/68	Unknown	2.75	2.25	2.25	TK	
	3		D	LO		08/68	Unknown	2.30	2.25	2.25	TK	
Stock Island	CT1	Monroe	CT	LO	None	11/78	Unknown	23.45	20.0	23.0	WA	
	IC1		D	LO	None	01/65	Unknown	2.50	2.0	2.0	WA	
	IC2		D	LO	None	01/65	Unknown	2.50	2.0	2.0	WA	
	IC3		D	LO	None	01/65	Unknown	2.50	2.0	2.0	WA	
Medium Speed Diesel	IC4	Monroe	D	LO	None	06/91	Unknown	9.60	8.7	8.7	WA	
	IC5		D	LO	None	06/91	Unknown	9.60	8.7	8.7	WA	
Vero Beach	1	Indian River	FS	NG	HO	11/61	Unknown	12.50	12.0	13.0	PL	TK
	3		FS	NG	HO	09/71	Unknown	33.00	34.0	34.0	PL	TK
	4		FS	NG	HO	08/76	Unknown	55.00	56.0	56.0	PL	TK
	5		CCW	NG	LO	12/92	Unknown	57.90	47.5	54.5	PL	TK
FMPA ARP Total Generation Capacity for 2000									317.9	328.9		
FMPA ARP Total Generation Capacity for 2001									317.9	328.9		
Lake Worth* Tom G Smith	S-1	Palm Beach	FS	NG	HO	01/61	Unknown	7.50	7.0	8.0	PL	TK
	S-3		FS	NG	HO	11/67	Unknown	26.50	24.8	27.0	PL	TK
	MU1		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU2		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU3		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU4		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU5		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	CT-1		CT	LO	None	12/76	Unknown	30.80	26.0	32.0	TK	
	S-5		CCW	NG	LO	03/78	Unknown	31 41	28 0	33.0	PL	TK
FMPA ARP Total Generation Capacity for 2002									412.8	438.9		

*Lake Worth anticipates joining ARP January of 2002.

Source: FMPA

River 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 1D.2-5 indicates St. Lucie 2 generating capacity that is also actually owned by several of the individual All-Requirements Project members and is also dispatched by FMPA. Table 1D.2-5 also indicates capacity from St. Lucie 1. Certain All-Requirements Project members actually have ownership in St. Lucie 2, but power is supplied equally from St. Lucie 1 and 2 through a reliability exchange agreement. The Stanton 1 and 2 capacity shown in Table 1D.2-5 includes the capacity owned by individual members as well as the capacity owned directly by the All-Requirements Project itself.

The All-Requirements Project provides its members with all of their capacity and energy requirements above excluded resources that are the members' ownership in Crystal River 3 and St. Lucie 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

1D.2.1.6 All-Requirements Project Participants

A brief description of each of the participants is provided in the following subsections Table 1D.2-5 provides a summary of each member's existing generation sources.

1D.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.

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.

1D.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.

1D.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.

1D.2.1.6.4 City of Fort Meade. The City of Fort Meade is located in Polk County along the Peace River and is the oldest town in that particular region of Florida, established in 1851. Its 5,600 citizens reside within an area of 4.5 square miles. The City operates under a commission/manager form of government that controls the delivery of essential services. The City became an All-Requirements Project member in February of 2000.

1D.2.1.6.5 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.

1D.2.1.6.6 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.

1D.2.1.6.7 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 Unit No. 1 and 10 MW from Stanton Unit No. 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 went into service at Key West's Stock Island Plant, and are owned by FMPA's All-Requirements Project.

1D.2.1.6.8 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.

1D.2.1.6.9 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.

1D.2.1.6.10 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.

1D.2.1.6.11 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.

1D.2.1.6.12 Town of Havana. Located in Gadsden County, the Town of Havana is a small town approximately 12 miles north of Tallahassee with a population near 1,800. The Town of Havana has no generating capacity.

1D.2.1.6.13 City of Newberry. Located in Alchua County, the City of Newberry has nearly 1,700 residents. The City of Newberry has no generating capacity.

1D.2.1.6.14 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 winter capacity amounts to 13.8 MW (excluding units on extended cold standby), primarily fueled by natural gas (71 percent). Lake Worth purchases gas pursuant to a contract for interruptible gas service with Florida Public Utilities Company. Lake Worth has entitlements of 18.35 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 January of 2002.

1D.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 1D.2.2.1 through 1D.2.2.3 outline the purchase power contracts in detail.

1D.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 1D.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 413 MW in summer and 439 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 in 2002. 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 1D.2-5.

1D.2.2.2 Firm Power Purchases from Other Utilities

The All-Requirements Project has ten firm purchase power contracts with other utilities. The contracts exist with Lake Worth, Gainesville Regional Utilities, Orlando Utility Commission, Tampa Electric Company, Lakeland Electric, and Florida Power and Light. Each of the firm purchase power contracts is discussed in detail below and displayed in Table 1D.2-6.

1D.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.

Table 1D.2-6
FMPA Power Purchase Capacity

	2000		2001		2002		2003		2004		2005		2006		2007		2008		2009	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
FIRM POWER PURCHASE																				
TECO	150	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC – Ind. River	93	93	93	93	71	71	50	50	28	28	6	6	0	0	0	0	0	0	0	0
OUC – Ind River	37	37	37	37	37	37	37	37	37	37	37	37	22	22	0	0	0	0	0	0
OUC	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	0	0	0	0	0
GRU	10	40	40	40	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stark	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0
FPL	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Lakeland	0	0	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
FPL	0	0	0	0	0	75	75	75	75	75	75	75	75	75	75	75	0	0	0	0
Lake Worth[1]	15	15	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	373	403	448	348	316	391	330	330	285	285	263	263	242	242	220	220	145	145	145	145
PARTIAL REQUIREMENTS PURCHASE																				
FPC[2]	80	80	40	40	27	27	15	15	15	15	40	40	0	0	0	0	0	0	0	0
Total	80	80	40	40	27	27	15	15	15	15	40	40	0	0	0	0	0	0	0	0
TOTAL PURCHASE POWER																				
Total	453	483	488	388	343	418	345	345	300	300	303	303	242	242	220	220	145	145	145	145

[1]Lake Worth assumed to join FMPA January of 2002.
[2]Capacity varies based on the time of day. Maximum capacity available is listed.

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

	2010		2011		2012		2013		2014		2015		2016		2017		2018		2019	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
FIRM POWER PURCHASE																				
TECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC – Ind. River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC – Ind. River	0	0	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	0	0
GRU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stark	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL	0	0	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	0	0
FPL	45	45	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lake Worth	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	145	145	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTIAL REQUIREMENTS PURCHASE																				
FPC	0	0	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**	**0**	**0**
TOTAL PURCHASE POWER																				
Total	**145**	**145**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

1D.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 43 MW for the summer period of 2000. 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 40 MW through the year 2001.

1D.2.2.2.3 Orlando Utilities Commission Contracts. FMPA currently has three contracts with OUC for firm capacity and energy. The contracts extend through the year 2006 and total 150 MW for the summer period of 2000. The first contract is for 20 MW and extends through 2003. The second contract is for 93 MW through 2001. Thereafter, the capacity is decreased by 21.667 MW annually through 2005. The third contract is for 37 MW through 2005, decreasing to 22 MW in 2006. Table 1D.2-6 displays the contract capacities for these two purchases.

1D.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 through the month of March 2001. The contract specifies that 150 MW of capacity is available for 2000 until the contract is terminated.

1D.2.2.2.5 Lakeland Electric Contract. The All-Requirements Project currently has one contract with Lakeland for capacity and energy. The contract is for 50 MW through June 14, 2001, then 100 MW through December 15, 2010.

1D.2.2.2.6 Florida Power and Light Contracts. The All-Requirements Project currently has two contracts with FPL. The first existing contract is for 45 MW terminating end of 2010. The second contract is effective beginning June 2002 and terminates October 2009. Reserves are included with the capacity in both contracts.

1D.2.2.3 Partial Requirements Purchases

The All-Requirements Project has one partial requirements purchase from Florida Power Corporation (FPC), which varies from 80 MW in 2000 to 40 MW in 2005 after which it terminates. Tables 1D.2-7 and 1D.2-8 display the values for the partial requirements purchases.

1D.2.3 Committed Units

Currently, FMPA and Lakeland are planning to submit a Need for Power Application for the construction of McIntosh Unit 4. The McIntosh Unit 4 unit type has not yet been decided. Lakeland and FMPA are currently evaluating proposals received

Table 1D.2-7
All-Requirements Total Capacity - Summer (MW)

Year	All-Requirements Member Capacity	Generating Member Firm Purchases	Existing Firm Power Purchases	Partial Requirements Purchase	Total Capacity
2000	377.0	317.9	403.0	80.0	1,177.9
2001	497.0	317.9	348.0	40.0	1,202.9
2002	525.5	412.8	391.0	27.0	1,356.3
2003	525.5	412.8	330.0	15.0	1,283.3
2004	525.5	412.8	285.0	15.0	1,238.3
2005	625.5	412.8	263.0	40.0	1,341.3
2006	625.5	412.8	242.0	0.0	1,280.3
2007	625.5	412.8	220.0	0.0	1,258.3
2008	625.5	412.8	145.0	0.0	1,183.3
2009	625.5	412.8	145.0	0.0	1,183.3
2010	625.5	412.8	145.0	0.0	1,183.3
2011	625.5	412.8	0.0	0.0	1,038.3
2012	625.5	412.8	0.0	0.0	1,038.3
2013	625.5	412.8	0.0	0.0	1,038.3
2014	625.5	412.8	0.0	0.0	1,038.3
2015	625.5	412.8	0.0	0.0	1,038.3
2016	625.5	412.8	0.0	0.0	1,038.3
2017	625.5	412.8	0.0	0.0	1,038.3
2018	625.5	412.8	0.0	0.0	1,038.3
2019	625.5	412.8	0.0	0.0	1,038.3

Lake Worth Capacity included beginning 2002.
Proposed Stanton A not included.

Table 1D.2-8
All-Requirements Total Capacity - Winter (MW)

Year	All-Requirements Member Capacity	Generating Member Firm Purchases	Existing Firm Power Purchases	Partial Requirements Purchase	Total Capacity
1999/00	401.6	328.9	373.0	80.0	1,183.5
2000/01	401.6	328.9	448.0	40.0	1,218.5
2001/02	550.1	438.9	316.0	27.0	1,332.0
2002/03	550.1	438.9	330.0	15.0	1,334.0
2003/04	550.1	438.9	285.0	15.0	1,289.0
2004/05	550.1	438.9	263.0	40.0	1,292.0
2005/06	650.1	438.9	242.0	0.0	1,331.0
2006/07	650.1	438.9	220.0	0.0	1,309.0
2007/08	650.1	438.9	145.0	0.0	1,234.0
2008/09	650.1	438.9	145.0	0.0	1,234.0
2009/10	650.1	438.9	145.0	0.0	1,234.0
2010/11	650.1	438.9	0.0	0 0	1,089.0
2011/12	650.1	438.9	0.0	0.0	1,089.0
2012/13	650.1	438.9	0.0	0.0	1,089.0
2013/14	650.1	438.9	0.0	0.0	1,089.0
2014/15	650.1	438.9	0.0	0.0	1,089.0
2015/16	650.1	438.9	0.0	0.0	1,089.0
2016/17	650.1	438.9	0.0	0.0	1,089.0
2017/18	650.1	438.9	0.0	0.0	1,089.0
2018/19	650.1	438.9	0.0	0.0	1,089.0

Lake Worth Capacity included beginning 2002.
Proposed Stanton A not included.

from their Request for Proposal issued last summer. The nameplate capacity of the unit is currently unknown. Therefore, for modeling purposes, FMPA has assumed a 288 MW unit, in which Lakeland owns 188 MW and FMPA owns 100 MW. Field construction of McIntosh 4 is planned to start in June of 2002 with a commercial operation date of June 2005. For modeling purposes, FMPA has assumed the Pressurized Fluidized Bed Combined Cycle, as shown in Lakeland's 2000 Ten Year Site Plan. Petroleum coke was assumed as the primary fuel.

1D.2.4 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 that are served off of FPL's transmission system and members west of Orlando that are served off of FPC's transmission system. 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, Bushnell, Ft. Meade, Havana, and Newberry.

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 6 year battle in the courts and regulatory forums. FMPA strived to obtain network service in order to integrate the operations of several members.

Network transmission for the west members is provided under an agreement with FPC. Network transmission service is also purchased under an agreement with OUC.

1D.3.0 Evaluation Criteria

1D.3.1 Economic Parameters

1D.3.1.1 Escalation Rates

The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital cost and Operations and Maintenance (O&M) expenses is also assumed to be 2.5 percent.

1D.3.1.2 Bond Interest Rates

The long-term tax-exempt bond interest rate is assumed to be 6.0 percent. For smaller financing requirements, such as the Stanton A joint development project, FMPA can utilize the FMPA Pooled Loan Project, which has a 5.0 percent interest rate.

1D.3.1.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the 6.0 percent long-term bond interest rate.

1D.3.1.4 Interest During Construction

The interest during construction interest rate is assumed to be 6.0 percent.

1D.3.1.5 Levelized Fixed Charge Rate

FMPA plans to use the FMPA Pooled Loan Project for small financing requirements such as the equity portion of Stanton A. The fixed charge rate for the equity portion of Stanton A is merely the capital recovery factor over a 20 year period at the FMPA Pooled Loan Project interest rate of 5.0 percent or 8.02 percent.

For larger financing requirements, FMPA issues tax-exempt bonds. The fixed charge rate for these larger requirements is 8.602 percent based on a bond term of 30 years with a 6.0 percent bond interest rate, 2.9 percent bond issuance fee, a 1 year debt service reserve fund earning interest at the 6.0 percent bond interest rate, and one percent for insurance.

1D.4.0 Forecast of Demand and Energy

1D.4.1 Introduction

Under the All-Requirements Project structure, FMPA agrees to meet all of its members' power requirements. To secure sufficient capacity and energy, 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 forecast of electrical power demand and energy consumption includes current member cities plus cities that are planning to become members of the All-Requirements Project.

1D.4.2 Forecast Methodology

The load forecast attempts to predict peak capacity and total energy requirements of member cities over time. The forecast considers a number of variables including changes in population, historical trends, weather patterns, conservation programs, account types, economic conditions, and customer growth Several techniques are utilized to develop certain portions of the load forecast including:

- Econometric modeling of member customer class requirements.
- Aggregate econometric modeling of system requirements.
- Statistical Analysis Techniques (time series, multiple regression, auto-regression, Box Jenkins).
- Incremental Load Analysis.
- Informed Judgement.

The FMPA forecasting process involves applying some or all of these methods to develop individual peak demand and energy requirement forecasts for each All-Requirements Project member. The forecast methodology varies from member to member to provide the most reliable forecast possible consistent with available data. Generally, FMPA uses Forecast Pro to forecast peak demand and energy requirement loads for its member cities. Forecast Pro is a commercially available software package that conducts econometric and other statistical analyses 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 by FMPA and any known unusual incremental load additions or reductions are integrated into the forecast.

1D.4.3 Base Case Load Forecast

The Town of Havana joined the All-Requirements Project on July 1, 2000. The City of Newberry joined the All-Requirements Project in December 2000. Both cities joined the All-Requirements Project after the load forecast was conducted and, therefore, are not included in FMPA's forecast. The Town of Havana's peak demand for 2000 was 6.0 MW, and the peak demand for the City of Newberry for 2000 was 7.0 MW. The high load forecast case, however, more than covers the addition of the Town of Havana and the City of Newberry with a 57 MW increase in peak demand for 2000.

1D.4.3.1 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. 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.

Table 1D.4-1 displays each member's net energy for load forecast for the planning horizon. The projected average annual growth rate (AAGR) for the base case including the addition of the City of Lake Worth in January of 2002 and Fort Meade in 2009 is 1.84 percent. The growth rate includes not only growth in the All-Requirements Project, but also the increased participation in the All-Requirements Project. For forecasts using regression analysis, the minimum coefficient of determination was 93 percent, implying a strong correlation of historical information.

1D.4.3.2 Summer Peak Demand Forecast

To forecast the summer peak demand for each member city, average annual 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. The summer peak demands are for noncoincidental peak demand. For the forecast of summer peak demand for FMPA's All-Requirements Project, to consider diversity among the individual members, FMPA applies seasonal factors to the All-Requirement Project net energy for load forecast to arrive at the forecast.

Table 1D.4-2 shows the projected summer peak demand for the individual All-Requirements Project members. Table 1D.4-3 displays the FMPA forecasted summer peak demand for the base case and presents the projected demand reduction due to residential load management. The projected average annual growth rate (AAGR) for the base case including the addition of the City of Lake Worth in January of 2002 and Fort Meade in 2009 is 1.84 percent The growth rate includes not only the projected growth in

Table 1D.4-1
All-Requirements Project Member Net Electric Load

Calendar Year	City of Bushnell (GWh)	City of Clewiston (GWh)	City of Fort Meade (GWh)	City of Fort Pierce (GWh)	City of Green Cove Springs (GWh)	City of Jacksonville Beach (GWh)	City of Key West (GWh)	City of Leesburg (GWh)	City of Ocala (GWh)	City of Starke (GWh)	City of Vero Beach (GWh)	City of Lake Worth (GWh)	Total[1,2] (GWh)	Total With Transmission Losses[1,2] (GWh)
Projected														
2000	24	126	43	585	119	735	702	476	1,256	75	733	418	4,831	4,903
2001	24	127	44	593	115	759	715	484	1,295	76	750	424	4,939	5,013
2002	25	129	44	601	118	783	728	492	1,322	77	766	430	5,470	5,552
2003	26	130	44	609	121	806	741	499	1,353	78	781	436	5,579	5,663
2004	26	132	44	617	124	828	753	507	1,382	79	796	441	5,684	5,769
2005	27	133	44	625	127	848	765	515	1,410	80	810	447	5,786	5,873
2006	27	135	44	631	130	868	775	523	1,436	81	823	452	5,880	5,968
2007	27	136	44	638	132	887	786	530	1,461	82	835	457	5,971	6,061
2008	28	138	44	644	134	906	795	538	1,484	83	847	463	6,059	6,150
2009	28	139	45	650	137	923	805	545	1,506	84	858	468	6,188	6,281
2010	29	140	45	656	139	940	814	553	1,527	85	868	473	6,269	6,363
2011	29	142	45	661	141	957	822	560	1,546	87	878	478	6,346	6,441
2012	29	143	45	666	142	973	830	568	1,564	88	887	483	6,418	6,514
2013	30	144	45	671	144	988	838	576	1,581	89	895	488	6,489	6,586
2014	30	146	45	676	146	1,003	845	583	1,596	90	903	493	6,556	6,654
2015	30	147	45	680	147	1,017	852	591	1,610	91	910	497	6,617	6,716
2016	30	149	45	684	149	1,031	858	598	1,623	92	916	502	6,677	6,777
2017	31	150	45	688	150	1,044	864	606	1,634	93	921	507	6,733	6,834
2018	31	151	46	691	151	1,056	869	613	1,644	94	926	512	6,784	6,886
2019	31	153	46	694	153	1,068	874	621	1,653	95	930	516	6,834	6,937

[1] Fort Meade's load included beginning 2009.
[2] Lake Worth's load included beginning January of 2002.
The Town of Havana and City of Newberry are not included in the forecast.

Table 1D.4-2
ARP Member Summer Peak Demand (Noncoincident Demand Peak)

Calendar Year	City of Bushnell (MW)	City of Clewiston (MW)	City of Fort Meade[1] (MW)	City of Fort Pierce (MW)	City of Green Cove Springs (MW)	City of Jacksonville Beach (MW)	City of Key West (MW)	City of Leesburg (MW)	City of Ocala (MW)	City of Starke (MW)	City of Vero Beach (MW)	City of Lake Worth[2] (MW)
Historical												
1999	5.0	25.8	8.8	114.0	27.5	169.3	126.0	102.2	273.0	16.5	147.0	80.0
Projected												
2000	5.3	26.2	9.0	114.1	23.9	173.1	126.4	105.5	280.4	16.6	151.5	83.5
2001	5 4	26.5	9.1	115.7	24.1	178.8	128.8	107.2	289.0	16.9	155.0	84.7
2002	5.5	26.8	9.1	117 2	24.7	184.4	131.2	109.0	295.1	17.1	158.3	85.9
2003	5.6	27 1	9.1	118.8	25.4	189.8	133 4	110.7	301.9	17.4	161.5	87 0
2004	5.7	27.4	9.2	120.3	26.0	195.0	135.6	112.5	308.4	17.6	164.5	88.1
2005	5.8	27.7	9.2	121.7	26.6	199.8	137.7	114.3	314.7	17.9	167.4	89 2
2006	5.9	28.0	9.2	123.1	27.1	204.4	139.6	115.9	320.5	18.1	170.1	90.3
2007	6.0	28.3	9.2	124.3	27.6	208.8	141.5	117.6	326.0	18.3	172.7	91.4
2008	6.1	28.6	9.3	125.5	28.1	213.3	143.3	119.3	331.3	18.6	175.1	92.4
2009	6.2	28.9	9.3	126.7	28.5	217.4	144.9	120.9	336.2	18.8	177.4	93.4
2010	6.3	29.2	9.3	127.8	29.0	221.4	146.6	122.6	340.8	19.0	179.5	94.5
2011	6 4	29.5	9.3	128.9	29.4	225.4	148.1	124.3	345.1	19.3	181 5	95.5
2012	6 4	29.8	9.4	129.9	29.8	229.1	149.5	125.9	349.2	19.5	183.3	96.5
2013	6.5	30.1	9.4	130.8	30.1	232.7	150.9	127.6	352.9	19.8	185.0	97.5
2014	6.6	30.3	9 4	131.7	30.5	236 2	152.2	129.3	356.3	20.0	186.6	98.4
2015	6.6	30 6	9 4	132 5	30.8	239.5	153.4	130.9	359.4	20.2	188.0	99.4
2016	6.7	30.9	9.4	133.3	31.1	242.8	154.5	132.6	362.3	20.5	189.3	100.3
2017	6.7	31 2	9.5	134.0	31 4	245.8	155.6	134 3	364.8	20.7	190.4	101 3
2018	6.8	31.5	9.5	134.7	31.7	248.6	156.5	136.0	367.0	20.9	191.4	102.2
2019	6.8	31.8	9.5	135.3	31.9	251.4	157.4	137.6	369.0	21.2	192.3	103.1

[1] Fort Meade's load included beginning 2009.
[2] Lake Worth's load included beginning January of 2002.
The Town of Havana and the City of Newberry are not included in the forecast.

Table 1D.4-3
Forecast of Summer Peak Demand – Base Case

Year	Total Demand (MW)	Residential Load Management (MW)	Net Firm Demand (MW)
2000	996	4.0	992
2001	1,024	4.2	1,020
2002	1,123	4.5	1,119
2003	1,146	4.7	1,141
2004	1,168	4.8	1,163
2005	1,189	5.0	1,184
2006	1,209	5.1	1,204
2007	1,228	5.2	1,223
2008	1,246	5.3	1,241
2009	1,273	5.3	1,268
2010	1,290	5.0	1,285
2011	1,306	5.0	1,301
2012	1,322	5.0	1,317
2013	1,336	5.0	1,331
2014	1,350	5.0	1,345
2015	1,363	5.0	1,358
2016	1,376	5.0	1,371
2017	1,387	5.0	1,382
2018	1,398	5.0	1,393
2019	1,408	5.0	1,403

Forecast includes addition of Lake Worth beginning January of 2002 and Fort Meade beginning 2009.

The Town of Havana and City of Newberry are not included in the forecast.

the current All-Requirements Project membership, but also includes the expected increased member city participation in the All-Requirements Project.

1D.4.3.3 Winter Peak Demand Forecast

Winter peak demand forecasts are conducted in a similar fashion to the summer peak demand 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. 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 forecast. Because the City of Lake Worth is expected to join the All-Requirements Project in January of 2002, the demand for Lake Worth is not included in the forecast until the winter of 2002.

Table 1D.4-4 shows the projected winter peak demand for the individual All-Requirements Project members. Table 1D.4-5 displays the FMPA forecasted winter peak demand for the base case and presents the projected demand reduction due to residential load management. The projected average annual growth rate (AAGR) for the base case including the addition of the City of Lake Worth in January of 2002 and Fort Meade in 2009 is 1.85 percent. The growth rate includes not only the projected growth in the current All-Requirements Project membership, but also includes the expected increased member city participation in the All-Requirements Project.

1D.4.4 Sensitivities

Uncertainties in the assumptions for future conditions dictate the development of high and low band forecasts to ensure that the addition of Stanton A is the least cost option under alternative but reasonable conditions that might be encountered in the future.

The high load growth sensitivity assumes an initial value that is 2.9 percent higher than the base case value, as this has been the historical standard deviation from predicted values. For following years, there is an increase in nominal projected growth of 100 percent of the base case increase for that year.

The low load growth sensitivity assumes an initial value that is 2.9 percent lower than the base case value, as this has been the historical standard deviation from predicted values. For following years, there is a decrease in nominal projected growth of 50 percent of the base case increase for that year The high and low forecasts are presented in Tables 1D.4-6 and 1D.4-7.

Table 1D.4-4
ARP Member Winter Peak Demand (Noncoincident Demand Peak)

Calendar Year	City of Bushnell (MW)	City of Clewiston (MW)	City of Fort Meade (MW)	City of Fort Pierce (MW)	City of Green Cove Springs (MW)	City of Jacksonville Beach (MW)	City of Key West (MW)	City of Leesburg (MW)	City of Ocala (MW)	City of Starke (MW)	City of Vero Beach (MW)	City of Lake Worth (MW)
Historical												
1999	5.8	22.2	11.7	121.0	27 2	172.5	97.0	95.1	247 7	14.6	151.0	74.0
Projected												
2000	5.8	22.2	11.8	128.5	26.9	180.2	101.9	94.9	235.6	13.4	169.1	78.9
2001	5.9	22.5	11.9	130.3	25.2	186.2	103.8	96.5	242.8	13.6	173.0	80.0
2002	6.0	22.7	11.9	132.0	25.9	192.0	105.7	98.1	247.9	13.8	176.7	81.1
2003	6.1	23.0	11 9	133 7	26.6	197.6	107.5	99.7	253.6	14.0	180.2	82 1
2004	6 3	23.3	11.9	135.4	27.2	203.1	109.3	101.3	259.1	14.2	183.6	83.2
2005	6.4	23.5	12.0	137.1	27.8	208.0	111.0	102.9	264.4	14.3	186.8	84.2
2006	6.5	23.8	12.0	138.6	28.4	212.8	112.6	104.4	269.3	14.5	189.8	85.3
2007	6.6	24.0	12.0	140.0	28.9	217.4	114.0	105.9	273.9	14.7	192.7	86.3
2008	6 7	24.3	12.0	141.4	29 4	222.0	115.5	107.4	278.3	14.9	195.4	87.2
2009	6 8	24 5	12.1	142.7	29 9	226.4	116.8	108.9	282.4	15.1	197.9	88 2
2010	6.9	24.8	12.1	143.9	30.3	230.5	118.1	110 4	286.3	15.3	200.3	89 2
2011	7.0	25.0	12.1	145.1	30.8	234.7	119.4	111.9	290.0	15.5	202.6	90.1
2012	7.0	25.2	12.2	146.2	31.2	238.6	120 5	113.4	293.4	15.7	204.6	91.1
2013	7.1	25.5	12.2	147.3	31.5	242.3	121.6	114.9	296.5	15.9	206.5	92.0
2014	7.2	25.7	12.2	148.3	31.9	246.0	122.7	116.4	299.4	16.1	208.3	92.9
2015	7 2	26.0	12.3	149.2	32.2	249.4	123.6	117.9	302.0	16.2	209 8	93.8
2016	7.3	26.2	12.3	150.1	32 6	252.7	124.5	119.4	304.4	16.4	211.3	94.7
2017	7.3	26.5	12.3	150.9	32.9	255.9	125.4	120.9	306.5	16.6	212.5	95.6
2018	7.4	26 7	12.4	151.7	33.1	258.9	126.2	122.4	308.4	16.8	213.7	96.5
2019	7.4	27.0	12.4	152.3	33.4	261.8	126.9	123.9	310.0	17.0	214.6	97.4

The Town of Havana and City of Newberry are not included in the forecast.

Table 1D.4-5
Forecast of Winter Peak Demand – Base Case

Year	Total Demand (MW)	Residential Load Management (MW)	Net Firm Demand (MW)
2000	936	6.8	929
2001	1,026	7.2	1,019
2002	1,047	7.6	1,039
2003	1,068	7.9	1,060
2004	1,089	8.2	1,081
2005	1,109	8.5	1,101
2006	1,127	8.7	1,118
2007	1,145	8 9	1,136
2008	1,162	9.0	1,153
2009	1,191	9.0	1,182
2010	1,215	9.0	1,206
2011	1,230	9.0	1,221
2012	1,245	9.0	1,236
2013	1,258	9.0	1,249
2014	1,271	9.0	1,262
2015	1,284	9.0	1,275
2016	1,295	9.0	1,286
2017	1,306	9.0	1,297
2018	1,317	9.0	1,308
2019	1,326	9.0	1,317

Forecast includes addition of Lake Worth beginning January of 2002 and Fort Meade beginning 2009.

The Town of Havana and City of Newberry are not included in the forecast.

Table 1D.4-6
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)
2000	1,049	1,048	5,144
2001	1,098	1,089	5,298
2002	1,226	1,213	5,964
2003	1,271	1,256	6,182
2004	1,316	1,298	6,394
2005	1,357	1,337	6,596
2006	1,397	1,374	6,784
2007	1,435	1,409	6,968
2008	1,471	1,444	7,144
2009	1,515	1,489	7,365
2010	1,548	1,521	7,526
2011	1,581	1,551	7,680
2012	1,611	1,580	7,827
2013	1,640	1,608	7,967
2014	1,668	1,634	8,102
2015	1,694	1,659	8,226
2016	1,719	1,682	8,344
2017	1,742	1,704	8,456
2018	1,764	1,824	8,561
2019	1,784	1,743	8,657

Forecast includes addition of Lake Worth beginning January of 2001 and Fort Meade beginning 2009.

The Town of Havana and City of Newberry are not included in the forecast.

Table 1D.4-7
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)
2000	943	816	4,622
2001	956	826	4,707
2002	1,043	905	5,166
2003	1,055	915	5,221
2004	1,066	926	5,274
2005	1,076	935	5,325
2006	1,086	944	5,372
2007	1,095	953	5,418
2008	1,104	962	5,462
2009	1,122	982	5,544
2010	1,131	990	5,584
2011	1,139	997	5,623
2012	1,146	1,005	5,660
2013	1,154	1,011	5,695
2014	1,160	1,048	5,729
2015	1,167	1,024	5,760
2016	1,173	1,030	5,790
2017	1,179	1,038	5,818
2018	1,184	1,041	5,844
2019	1,189	1,045	5,868

Forecast includes addition of Lake Worth beginning January of 2002 and Fort Meade beginning 2009.

The Town of Havana and City of Newberry are not included in the forecast.

The high demand growth sensitivity assumes a 1999 value that is 11.7 percent higher than the base case value, as this has been the historical standard deviation from predicted values. For following years, there is an increase in nominal projected growth by 100 percent.

The low demand growth sensitivity assumes a 1999 value that is 11.7 percent lower than the base case value, as this has been the historical standard deviation from predicted values. For following years, there is a decrease in nominal projected growth by 50 percent. The high and low forecasts are also presented in Tables 1D.4-6 and 1D.4-7.

1D.5.0 Demand-Side Programs

According to Section 403.519, Florida Statutes, in its determination of need, the Florida Public Service Commission (PSC) must take into consideration conservation measures that could mitigate or delay the need of the proposed plant. Based on this requirement, FMPA has tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the PSC approved Florida Integrated Resource Evaluator (FIRE) model. The FIRE model evaluates the economic impact of existing and proposed conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

1D.5.1 Existing Conservation Programs

FMPA is a strong supporter of the conservation of electricity where cost-effective, and promotes such programs to its members. FMPA will continue to assist members in increasing the promotion and use of such conservation programs to retail customers and will assist its members in the evaluation of any new programs to ensure their cost-effectiveness. FMPA staff and member cities promote conservation programs through a number of methods including 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 non-profit organization formed to accelerate the commercialization of photovoltaic systems for the benefit of electric utilities and their customers.

The following is a combined list of conservation programs offered by FMPA members:

- Residential Energy Audits Program
- 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
- Residential Load Management Program

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

1D.5.1.1 Residential Energy Audits Program

Residential energy audits are offered to residential customers. The program offers walk-through audits to identify energy savings opportunities. 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. The Energy Star program has been incorporated and offered since October 1999.

1D.5.1.2 High Pressure Sodium Outdoor Lighting Conversion

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

1D.5.1.3 Assistance for Commercial/ Industrial Audits

Free on-site audits are available to industrial and commercial customers with the intention of shifting demand from peak to off-peak periods. ESCO referral is also provided upon request.

1D.5.1.4 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.

1D.5.1.5 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.

1D.5.1.6 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 recommend homes for the weatherization program.

1D.5.1.7 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. Savings from the two programs are shared among all All-Requirements members when activated.

1D.5.2 Analysis of Demand-Side Management Alternatives

The FIRE model evaluates the economic impact of conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

1D.5.2.1 FIRE Model Output

FIRE model results are presented in the form of three cost-effectiveness tests. All the DSM cost-effectiveness tests are based on the comparison of discounted present worth benefits to costs for a specific DSM measure. Each test is designed to measure costs and benefits from a different perspective.

The Total Resource Cost Test measures the benefit to cost ratio by comparing the total program benefits (both the participant's and the utility's) to the total program costs (equipment costs, supply costs, and participant costs).

The Participant's Test measures the impact of the DSM program on the participating customer. Benefits to the participant may include bill reductions, incentives paid, and tax credits. Participant's costs may include equipment costs, operation and maintenance expenses, equipment removal, etc. The Participant's Test is important because customers will not participate in a program unless it is beneficial to them.

The Rate Impact Test is a measure of the expected impact on customer rates resulting from a DSM program. The test statistic is the ratio of the utility's benefits (avoided supply costs and increased revenues) compared to the utility's costs (program costs, incentives paid, increased supply costs, and revenue losses). A value of less than one indicates an upward pressure an electricity rates as a result of the DSM program. FMPA views the Rate Impact Test as the primary test for determining the cost-effectiveness of a DSM measure on its system.

OUC used the FIRE model to evaluate the most cost-effective DSM measures from FPL's 2000 Demand-Side Management Plan as discussed in Section 1A.8. The results of that analysis are as follows.

1D.5.2.2 FIRE Model Output Analysis

FMPA requires all measures to pass the Rate Impact Test to be considered cost-effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, FMPA has concluded that there are no cost-effective DSM measures reasonable available that would avoid or defer the need for Stanton A. Table 1D.5-1 presents the FIRE model results of the DSM analysis.

Table 1D.5-1
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
Direct Load Control	0.4	1.0	1.81
Commercial			
Off-Peak Battery Charging	0.53	0.02	0.49

The results of the DSM analysis are not surprising due to the previously performed analysis for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for Kissimmee Utility Authority (KUA) and FMPA for Cane Island Unit 3 (Docket No. 980802) and Lakeland Electric's conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand-Side Management Ten Year Plans for Orlando Utilities Commission (OUC) (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost-effectiveness of the DSM measures can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

1D.6.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand plus maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated availability of capacity. This section presents the development of the reliability criteria used by FMPA.

1D.6.1 Development of Reliability Criteria

A number of methods are used in the electric utility industry to calculate a utility's system reliability. Two basic methods, known as the Traditional Reserve Margin and the Loss of Load Probability, apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. FMPA utilizes an adjusted traditional reserve margin for planning purposes, which accounts for partial requirement and other purchases that include reserves. The methods are discussed below.

1D.6.1.1 Traditional Reserve Margin

The most commonly used deterministic method is the Traditional Reserve Margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity} - \text{System Net Peak Demand}}{\text{System Net Peak Demand}}$$

From the equation, it is seen that should the net capacity or net peak demand deviate from the predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. A weakness with the formula is that it does not indicate what the appropriate reserve margin is for a given system; the appropriate reserve level must be determined elsewhere. Nevertheless, given the nature of the FMPA All Requirements Project members (numerous members geographically dispersed) a modified version of this formula is used.

In establishing the appropriate reserve margin levels, FMPA considers the Florida Reliability Coordinating Council (FRCC) minimum planned reserve margin criteria of 15 percent. The Florida Public Service Commission (FPSC) has also established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Fla. Admin. Code, for the purposes of sharing responsibility for grid reliability. Consequently, FMPA has established a 15 percent minimum planned reserve margin criteria for the winter period, and has adopted a reserve margin of 18 percent in the summer. The formula used by FMPA to calculate its reserve margin is based on the following formula which considers that the partial requirements purchases include their own reserves.

$$\frac{\text{System Net Capacity} - \text{System Net Peak Demand}}{\text{System Net Peak Demand} - \text{Partial Requirements}}$$

1D.6.1.2 Loss of Load Probability

The second commonly-used method of calculating the reliability of a utility system is the Loss of Load Probability (LOLP) method. This method has the advantage in that it can result in a measure of how much capacity (and reserves) are needed to meet a target level of reliability (most utilities adopt a LOLP of one day in ten years). Given the unique nature of FMPA's geographically dispersed membership, it is not practical to use this method for its member cities and the adjusted traditional reserve margin method is used.

1D.6.2 Reliability Need

Table 1D.6-1 (winter) and 1D.6-2 (summer) compare FMPA's net system capacity with the peak demand during the forecast period. The tables display the reserve margin for both winter and summer assuming no capacity additions other than Cane Island 3 and the proposed McIntosh Unit 4, of which FMPA is assumed to receive 100 MW. The capacity required in order for FMPA to achieve its reserve margin requirements is also shown.

For the winter peak, the reserve margin is projected to fall below the required 15 percent in the winter of 2007/08. The reserve margin falls to 7.3 percent, creating an 85 MW deficit in that year. This deficit increases the next winter, with the system falling 119 MW below the level needed to maintain adequate reserves. By 2009/1010, the capacity deficit increases to 146 MW.

Summer reserve margins are expected to fall below the required 18 percent level by the summer of 2003. In 2003 the reserve margin would fall to an estimated 14.1 percent, which is equivalent to a 39 MW capacity shortfall. The deficit would increase to 325 MW by the summer of 2010 if no additional capacity is added.

Table 1D.6-1
Projected Reliability Levels - Winter/Base Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Purchases That Contain Reserve Margin	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/(Deficit) to Maintain 15%	
						Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	401.6	656.9	125.0	0.0	1,183.5	935.8	929.0	30.6	31.7	126.1	133.9
2001	401.6	731.9	85.0	0.0	1,218.5	1,026.2	1,019.0	20.4	21.4	51.1	59.4
2002	550.1	709.9	72.0	0.0	1,332.0	1,046.6	1,039.0	29.3	30.3	139.2	148.0
2003	550.1	648.9	135.0	0.0	1,334.0	1,067.9	1,060.0	28.5	29.6	126.2	135.3
2004	550.1	603.9	135.0	0.0	1,289.0	1,089.2	1,081.0	20.9	22.0	56.7	66.1
2005	550.1	581.9	160.0	0.0	1,292.0	1,109.5	1,101.0	19.2	20.3	40.1	49.9
2006	650.1	560.9	120.0	0.0	1,331.0	1,126.7	1,118.0	20.3	21.3	53.3	63.3
2007	650.1	538.9	120.0	0.0	1,309.0	1,144.9	1,136.0	16.0	17.0	10.4	20.6
2008	650.1	538.9	45.0	0.0	1,234.0	1,162.0	1,153.0	6.4	7.3	-95.6	-85.2
2009	650.1	538.9	45.0	0.0	1,234.0	1,191.0	1,182.0	3.8	4.6	-128.9	-118.6
2010	650.1	538.9	45.0	0.0	1,234.0	1,215.0	1,206.0	1.6	2.4	-156.5	-146.2
2011	650.1	438.9	0.0	0.0	1,089.0	1,230.0	1,221.0	-11.5	-10.8	-325.5	-315.2
2012	650.1	438.9	0.0	0.0	1,089.0	1,245.0	1,236.0	-12.5	-11.9	-342.8	-332.4
2013	650.1	438.9	0.0	0.0	1,089.0	1,258.0	1,249.0	-13.4	-12.8	-357.7	-347.4
2014	650.1	438.9	0.0	0.0	1,089.0	1,271.0	1,262.0	-14.3	-13.7	-372.7	-362.3
2015	650.1	438.9	0.0	0.0	1,089.0	1,284.0	1,275.0	-15.2	-14.6	-387.6	-377.3
2016	650.1	438.9	0.0	0.0	1,089.0	1,295.0	1,286.0	-15.9	-15.3	-400.3	-389.9
2017	650.1	438.9	0.0	0.0	1,089.0	1,306.0	1,297.0	-16.6	-16.0	-412.9	-402.6
2018	650.1	438.9	0.0	0.0	1,089.0	1,317.0	1,308.0	-17.3	-16.7	-425.6	-415.2
2019	650.1	438.9	0.0	0.0	1,089.0	1,326.0	1,317.0	-17.9	-17.3	-435.9	-425.6

Table 1D.6-2
Projected Reliability Levels - Summer/Base Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Purchases That Contain Reserve Margin	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/(Deficit) to Maintain 18%	
						Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	377.0	675.9	125.0	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8
2001	497.0	620.9	85.0	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	9.4	14.4
2002	525.5	683.8	147.0	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3
2003	525.5	622.8	135.0	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	-44.3	-38.8
2004	525.5	577.8	135.0	0.0	1,238.3	1,167.8	1,163.0	6.8	7.3	-115.4	-109.7
2005	625.5	555.8	160.0	0.0	1,341.3	1,189.0	1,184.0	14.8	15.4	-32.9	-27.0
2006	625.5	534.8	120.0	0.0	1,280.3	1,209.1	1,204.0	6.5	7.0	-124.8	-118.8
2007	625.5	512.8	120.0	0.0	1,258.3	1,228.2	1,223.0	2.7	3.2	-169.4	-163.2
2008	625.5	512.8	45.0	0.0	1,183.3	1,246.3	1,241.0	-5.2	-4.8	-279.2	-273.0
2009	625.5	512.8	45.0	0.0	1,183.3	1,273.3	1,268.0	-7.3	-6.9	-311.1	-304.8
2010	625.5	512.8	45.0	0.0	1,183.3	1,290.0	1,285.0	-8.6	-8.2	-330.8	-324.9
2011	625.5	412.8	0.0	0.0	1,038.3	1,306.0	1,301.0	-20.5	-20.2	-502.8	-496.9
2012	625.5	412.8	0.0	0.0	1,038.3	1,322.0	1,317.0	-21.5	-21.2	-521.7	-515.8
2013	625.5	412.8	0.0	0.0	1,038.3	1,336.0	1,331.0	-22.3	-22.0	-538.2	-532.3
2014	625.5	412.8	0.0	0.0	1,038.3	1,350.0	1,345.0	-23.1	-22.8	-554.7	-548.8
2015	625.5	412.8	0.0	0.0	1,038.3	1,363.0	1,358.0	-23.8	-23.5	-570.0	-564.1
2016	625.5	412.8	0.0	0.0	1,038.3	1,376.0	1,371.0	-24.5	-24.3	-585.4	-579.5
2017	625.5	412.8	0.0	0.0	1,038.3	1,387.0	1,382.0	-25.1	-24.9	-598.4	-592.5
2018	625.5	412.8	0.0	0.0	1,038.3	1,398.0	1,393.0	-25.7	-25.5	-611.3	-605.4
2019	625.5	412.8	0.0	0.0	1,038.3	1,408.0	1,403.0	-26.3	-26.0	-623.1	-617.2

1D.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of FMPA's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine FMPA's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluations were discussed in 1D.5.0. The sensitivity analyses are discussed in Section 1D.8.0. The proposal evaluations were discussed in Section 1A.5.0.

1D.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. The program operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options while maintaining user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 18 percent. All capacity expansion plans were analyzed over a twenty-year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO was used to obtain the annual production cost for the expansion plan.

1D.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation were discussed in Section 1A.7.0. Table 1D.7-1 Summarizes the expansion alternatives considered for FMPA in the optimization study for supply-side alternatives.

Table 1D.7-1
Summary of FMPA Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs Variable	O&M Costs Fixed	Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal (50%)	256,581	212.5	3.73	14.17	Coal	9,979	3.0	30	2005
501F 2x1 CC (50%) (standard)	129,594[2]	257	3.68[3]	6.32[3]	Nat. Gas	7,074	1.0	14	2005
501F 1x1 CC (50%)	73,984	125	2.49	4.66	Nat. Gas	10,841	2.86	15	2005
7FA SC	76,681	156	2.24	3.63	Nat. Gas	10,940	1.96	7	2005
7FA 2x1 CC (self-build)[4]	29,021[2]	61	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[4]	[redacted]	21	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	14	2003[5]

1. At 70 – 72° F, depending on the generation alternative (after degradation).
2. Mixed year dollars to reflect commercial operation date of October 1, 2003.
3. (2003 $)
4. Reflects FMPA's portion of total generation alternative capacity.
5. October 1, 2003.

1D.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7.0 and summarized in Table 1D.7-1. The expansion plan outlined in Table 1D.7-2 represents the least-cost capacity addition plan for FMPA under the base case scenario. The units comprising the least-cost capacity addition plan are listed in the table according to their year of commercial operation. Table 1D.7-3 displays the reserve margins for the base case after the construction of the generating resources identified.

Table 1D.7-4 provides the runner up to the least-cost expansion plan identified in Table 1D.7-2. Comparing the two plans indicates that the plan with the Southern-Florida joint development project is $33.9 million lower in cumulative present worth costs over the 20 year evaluation period.

Table 1D.7-2
FMPA Base Case Expansion Plan

Year	Expansion Plan	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		147,757	259,207
2002		156,804	398,762
2003	21 MW Joint Development with Southern-Florida (10/03)		
	40 MW Southern-Florida Power Purchase (10/03)	162,496	535,197
2004		162,960	664,276
2005		163,919	786,766
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	176,530	911,213
2007		186,719	1,035,392
2008		201,339	1,161,715
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	214,359	1,288,594
2010		227,656	1,415,716
2011		236,388	1,540,242
2012		249,955	1,664,462
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	258,513	1,785,663
2014	156 MW GE 7FA Simple Cycle (06/14)	273,844	1,906,784
2015		286,895	2,026,495
2016		300,114	2,144,634
2017		312,764	2,260,783
2018		327,658	2,375,576
2019		343,844	2,489,221

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.7-3
Projected Reliability Levels – Summer/Base Case with Expansion Plan Identified in Table 1D.7-2

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand (MW)		Reserve Margin (MW)		Excess / (Deficit) to Maintain 18 % Reserve Margin (MW)	
					Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management
2000	377.0	675.9	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8
2001	497.0	620.9	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	9.4	14.4
2002	525.5	683.8	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3
2003	525.5	622.8	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	-44.3	-38.8
2004	546.3	616.5	0.0	1,297.8	1,167.8	1,163.0	12.6	13.1	-55.9	-50.3
2005	646.3	594.5	0.0	1,400.8	1,189.0	1,184.0	20.6	21.2	26.5	32.4
2006	887.3	573.5	0.0	1,580.8	1,209.1	1,204.0	34.1	34.8	175.6	181.6
2007	887.3	551.5	0.0	1,558.8	1,228.2	1,223.0	29.8	30.4	131.1	137.2
2008	887.3	551.5	0.0	1,483.8	1,246.3	1,241.0	19.8	20.3	21.2	27.5
2009	1,128.3	551.5	0.0	1,724.8	1,273.3	1,268.0	36.8	37.3	230.4	236.6
2010	1,128.3	551.5	0.0	1,724.8	1,290.0	1,285.0	34.9	35.5	210.7	216.6
2011	1,128.3	451.5	0.0	1,579.8	1,306.0	1,301.0	21.0	21.4	38.7	44.6
2012	1,128.3	451.5	0.0	1,579.8	1,322.0	1,317.0	19.5	20.0	19.8	25.7
2013	1,128.3	451.5	0.0	1,579.8	1,336.0	1,331.0	18.2	18.7	3.3	9.2
2014	1,268.3	412.8	0.0	1,681.1	1,350.0	1,345.0	24.5	25.0	88.1	94.0
2015	1,268.3	412.8	0.0	1,681.1	1,363.0	1,358.0	23.3	23.8	72.8	78.7
2016	1,268.3	412.8	0.0	1,681.1	1,376.0	1,371.0	22.2	22.6	57.4	63.3
2017	1,268.3	412.8	0.0	1,681.1	1,387.0	1,382.0	21.2	21.6	44.5	50.4
2018	1,268.3	412.8	0.0	1,681.1	1,398.0	1,393.0	20.3	20.7	31.5	37.4
2019	1,268.3	412.8	0.0	1,681.1	1,408.0	1,403.0	19.4	19.8	19.7	25.6

Table 1D.7-4
FMPA Base Case Runner Up Expansion Plan

Year	Expansion Plan	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		147,757	259,207
2002		156,804	398,762
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (61 MW)	162,560	535,250
2004		162,262	663,777
2005		163,268	785,780
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	175,957	909,823
2007		186,119	1,033,603
2008		200,800	1,159,587
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	214,044	1,286,279
2010		227,069	1,413,073
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	242,784	1,540,969
2012		263,715	1,672,027
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	272,567	1,799,817
2014		288,022	1,927,209
2015		296,887	2,051,090
2016		309,859	2,173,065
2017		320,074	2,291,929
2018		333,276	2,408,690
2019		346,421	2,523,187

Note: Capacity is stated at average annual temperature for FMPA.

1D.8.0 Sensitivity Analysis

FMPA performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1D.8.1 through 1D.8.7 and includes high and low fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are 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.

1D.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1D.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1D.8-2 presents the runner-up expansion plan. The plan including joint development is $42.5 million lower than the plan with the self build alternative.

1D.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1D.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1D.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $2.9 million cumulative present worth savings over the self build plan.

1D.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1D.8-5 and Table 1D.8-6 presents the runner-up expansion plan. Under this scenario, the expansion plan with the joint development project is $49.8 million lower in cumulative present worth cost.

1D.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1D.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1D.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows a $73.4 million savings over the plan with the self build project.

1D.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1D.8-9 and Table 1D.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $61.6 million.

1D.8.6 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 is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1D.4.0. Table 1D.8-11 indicates the summer need for capacity based upon the high load and energy forecast.

As indicated in Table 1D.8-11, the high load and energy growth scenario results in capacity shortfall beginning the summer of 2000. Since there are no capacity alternatives identified which can be placed in operation until Stanton A, it has been assumed that FMPA will purchase power on the spot market to make up the resultant deficits.

Table 1D.8-12 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1D.8-13 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the joint development project is slightly higher in cost ($1.192 million) than the plan including self build alternative.

1D.8.7 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 is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1D.4.0. Table 1D.8-14 indicates the summer need for capacity based upon the low load and energy forecast.

Capacity additions are not required for the low load and energy forecast until 2006. Nevertheless, for evaluation purposes, Table 1D.8-15 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1D.8-16 presents the runner-up expansion plan with the joint development and self build projects installed for October 1, 2003 commercial operation. The plan with the joint development project is slightly lower in cumulative present worth cost ($257,000) over the 20 year period.

1D.8.8 Sensitivity Analysis Summary

The plan with the Southern-Florida joint development project is the lowest cost in all but one of the sensitivity analyses. However, it should be noted that for the sensitivity scenario in which the self build alternative shows as the more cost-effective approach the margin is only slightly higher than $1 million. This cumulative present worth savings does not even compare to those provided by participation in the joint development project with Southern-Florida for the remaining five sensitivity cases.

Table 1D.8-1
FMPA High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		148,641	260,040
2002		158,828	401,396
2003	21 MW Joint Development with Southern-Florida (10/03)	163,063	538,307
	40 MW Southern-Florida Power Purchase (10/03)		
2004		168,952	672,133
2005		179,579	806,325
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	188,608	939,286
2007		202,252	1,073,795
2008		220,377	1,212,063
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	239,142	1,353,610
2010		257,178	1,497,217
2011		273,653	1,641,374
2012		290,694	1,785,840
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	309,331	1,930,867
2014	223 MW Pulverized Coal (06/14)	329,953	2,076,805
2015		352,569	2,223,920
2016		370,678	2,369,836
2017		386,208	2,513,260
2018		407,930	2,656,176
2019		440,095	2,801,633

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-2
FMPA High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		148,641	260,040
2002		158,828	401,396
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	163,160	538,389
2004		168,268	671,673
2005		178,974	805,412
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	188,031	937,967
2007		201,683	1,072,097
2008		219,855	1,210,037
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	239,001	1,351,501
2010		256,449	1,494,701
2011	156 MW GE 7FA Simple Cycle (06/11)	284,316	1,644,475
2012		306,776	1,796,934
2013		323,703	1,948,699
2014		344,269	2,100,969
2015	223 MW Pulverized Coal (06/15)	359,749	2,251,080
2016		382,926	2,401,817
2017		399,545	2,550,194
2018		421,743	2,697,949
2019		442,193	2,844,100

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-3
FMPA Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		146,933	258,429
2002		154,364	395,813
2003	21 MW Joint Development with Southern-Florida (10/03)	157,595	528,132
	40 MW Southern-Florida Power Purchase (10/03)		
2004		157,038	652,521
2005		160,704	772,609
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	165,021	888,942
2007		172,318	1,003,543
2008		181,148	1,117,198
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	192,538	1,231,160
2010		202,721	1,344,359
2011		206,273	1,453,021
2012		216,426	1,560,578
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	219,249	1,663,370
2014	125 MW WH 501F 1x1 Combined Cycle (06/14)	228,885	1,764,606
2015		237,544	1,863,725
2016		244,297	1,959,892
2017		249,001	2,052,362
2018		256,587	2,142,256
2019	125 MW WH 501F 1x1 Combined Cycle	273,177	2,232,545

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-4
FMPA Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		146,933	258,429
2002		154,364	395,813
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	157,662	528,189
2004		156,355	652,037
2005		160,114	771,683
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	164,438	887,605
2007		171,721	1,001,809
2008		180,594	1,115,116
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	191,889	1,228,695
2010		201,108	1,340,992
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	211,245	1,452,273
2012		225,600	1,564,390
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	226,707	1,670,679
2014		233,198	1,773,822
2015		237,246	1,872,817
2016		243,417	1,968,637
2017		247,535	2,060,562
2018		254,250	2,149,637
2019		259,483	2,235,400

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		107,973	107,973
2001		122,212	223,267
2002		137,446	345,594
2003	21 MW Joint Development with Southern-Florida (10/03)	147,902	469,776
	40 MW Southern-Florida Power Purchase (10/03)		
2004		160,235	596,697
2005		171,057	724,521
2006	223 MW Pulverized Coal (06/06)	173,553	846,869
2007		181,503	967,579
2008		197,190	1,091,298
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	210,190	1,215,709
2010		221,539	1,339,416
2011		231,872	1,461,563
2012		241,643	1,581,652
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	250,179	1,698,946
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	265,093	1,816,196
2015		279,691	1,932,902
2016		290,045	2,047,077
2017		297,852	2,157,688
2018		310,437	2,266,448
2019		322,374	2,372,997

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-6
FMPA AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		107,973	107,973
2001		122,212	223,267
2002		137,446	345,594
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	147,976	469,837
2004		159,558	596,223
2005		170,470	723,608
2006	223 MW Pulverized Coal (06/06)	172,990	845,558
2007		180,932	965,889
2008		196,751	1,089,332
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	211,155	1,214,315
2010		222,459	1,338,535
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	243,935	1,467,037
2012		264,948	1,598,708
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	266,618	1,723,709
2014		279,615	1,847,383
2015		287,928	1,967,525
2016		299,916	2,085,586
2017		308,507	2,200,154
2018		320,895	2,312,578
2019		333,329	2,422,748

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		140,008	251,814
2002		157,339	391,845
2003	21 MW Joint Development with Southern-Florida (10/03)	171,336	535,702
	40 MW Southern-Florida Power Purchase (10/03)		
2004		188,702	685,172
2005		208,258	840,794
2006	223 MW Pulverized Coal (06/06)	208,995	988,127
2007		216,544	1,132,141
2008		242,358	1,284,199
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	258,258	1,437,061
2010		272,588	1,589,273
2011		300,453	1,747,548
2012		314,914	1,904,051
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	327,584	2,057,635
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	346,065	2,210,700
2015		363,253	2,362,273
2016		378,885	2,511,420
2017		390,292	2,656,360
2018		408,460	2,799,461
2019		426,851	2,940,541

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		140,008	251,814
2002		157,339	391,845
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	171,427	535,778
2004		188,233	684,876
2005		207,772	840,135
2006	223 MW Pulverized Coal (06/06)	208,696	987,258
2007		216,186	1,131,034
2008		242,136	1,282,953
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	260,925	1,437,395
2010		276,077	1,591,555
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	320,749	1,760,521
2012		350,327	1,934,623
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	347,233	2,097,419
2014		362,985	2,257,968
2015		374,974	2,414,432
2016		392,229	2,568,831
2017		405,094	2,719,268
2018		423,688	2,867,705
2019		442,536	3,013,969

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		139,717	251,540
2002		156,909	391,188
2003	21 MW Joint Development with Southern-Florida (10/03)	170,076	533,988
	40 MW Southern-Florida Power Purchase (10/03)		
2004		185,519	680,936
2005		203,173	832,758
2006	223 MW Pulverized Coal (06/06)	206,483	978,320
2007		216,679	1,122,424
2008		239,428	1,272,644
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	255,212	1,423,704
2010		268,656	1,573,720
2011		287,937	1,725,402
2012		299,714	1,874,350
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	309,454	2,019,435
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	325,133	2,163,241
2015		338,864	2,304,637
2016		349,809	2,442,339
2017		356,799	2,574,841
2018		369,030	2,704,128
2019		380,471	2,829,879

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		139,717	251,540
2002		156,909	391,188
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	170,213	534,102
2004		185,052	680,680
2005		202,682	832,136
2006	223 MW Pulverized Coal (06/06)	206,152	977,465
2007		216,288	1,121,309
2008		239,135	1,271,345
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	257,042	1,423,488
2010		270,816	1,574,710
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	304,360	1,735,043
2012		328,714	1,898,404
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	327,786	2,052,083
2014		341,125	2,202,963
2015		348,776	2,348,495
2016		361,007	2,490,604
2017		369,657	2,627,881
2018		381,413	2,761,507
2019		393,338	2,891,510

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-11
FMPA Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 18% Reserve Margin (MW)
2000	1,049.0	0	0	377.0	800.9	1,177.9	151	189	(37.4)
2001	1,098.1	0	0	497.0	705.9	1,202.9	120	198	(77.6)
2002	1,226.0	0	0	525.5	830.8	1,356.3	157	221	(63.9)
2003	1,271.0	0	0	525.5	757.8	1,283.3	37	229	(192.2)
2004	1,316.0	0	0	525.5	712.8	1,238.3	0	237	(290.3)
2005	1,357.0	0	0	625.5	715.8	1,341.3	13	244	(231.2)
2006	1,397.0	0	0	625.5	654.8	1,280.3	0	251	(346.6)
2007	1,435.0	0	0	625.5	632.8	1,258.3	0	258	(413.4)
2008	1,471.0	0	0	625.5	557.8	1,183.3	0	265	(544.4)
2009	1,515.0	0	0	625.5	557.8	1,183.3	0	273	(596.3)
2010	1,548.0	0	0	625.5	557.8	1,183.3	0	279	(635.2)
2011	1,581.0	0	0	625.5	412.8	1,038.3	0	285	(827.3)
2012	1,611.0	0	0	625.5	412.8	1,038.3	0	290	(862.7)
2013	1,640.0	0	0	625.5	412.8	1,038.3	0	295	(896.9)
2014	1,668.0	0	0	625.5	412.8	1,038.3	0	300	(929.9)
2015	1,694.0	0	0	625.5	412.8	1,038.3	0	305	(960.6)
2016	1,719.0	0	0	625.5	412.8	1,038.3	0	309	(990.1)
2017	1,742.0	0	0	625.5	412.8	1,038.3	0	314	(1,017.3)
2018	1,764.0	0	0	625.5	412.8	1,038.3	0	318	(1,043.2)
2019	1,784.0	0	0	625.5	412.8	1,038.3	0	321	(1,066.8)

Table 1D.8-12
FMPA High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		130,844	130,844
2001		163,286	284,887
2002		176,044	441,566
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	184,501	596,477
2004		190,479	747,354
2005	257 MW WH 501F 2x1 Combined Cycle (06/05)	191,154	890,195
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	209,917	1,038,178
2007		226,458	1,188,786
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	248,249	1,344,540
2009		268,488	1,503,458
2010		281,841	1,660,837
2011	223 MW Pulverized Coal (06/11)	305,528	1,821,785
2012		331,994	1,986,776
2013		342,014	2,147,125
2014		358,015	2,305,475
2015		370,177	2,459,937
2016		385,367	2,611,635
2017	125 MW WH 501F 1x1 Combined Cycle (06/17)	405,013	2,762,043
2018		427,567	2,911,838
2019		441,760	3,057,846

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-13
FMPA High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		130,844	130,844
2001		163,286	284,887
2002		176,044	441,566
2003	21 MW Joint Development with Southern-Florida (10/03)	184,416	596,405
	40 MW Southern-Florida Power Purchase (10/03)		
2004		191,016	747,707
2005	257 MW WH 501F 2x1 Combined Cycle (06/05)	191,782	891,017
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	210,421	1,039,356
2007		227,087	1,190,382
2008	156 MW GE 7FA Simple Cycle (06/08)	247,424	1,345,619
2009		266,026	1,503,079
2010		279,648	1,659,232
2011	223 MW Pulverized Coal (06/11)	301,732	1,818,181
2012		325,800	1,980,094
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	336,885	2,138,039
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	358,012	2,296,388
2015		377,844	2,454,049
2016		394,292	2,609,260
2017		406,124	2,760,080
2018		435,508	2,912,658
2019		442,888	3,059,038

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-14
FMPA Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 18% Reserve Margin (MW)
2000	943.0	0	0	377.0	800.9	1,177.9	257.4	170	87.7
2001	959.6	0	0	497.0	705.9	1,202.9	258.6	173	85.9
2002	1,043.0	0	0	525.5	830.8	1,356.3	339.8	188	152.0
2003	1,055.0	0	0	525.5	757.8	1,283.3	252.6	190	62.7
2004	1,066.0	0	0	525.5	712.8	1,238.3	196.6	192	4.7
2005	1,076.0	0	0	625.5	715.8	1,341.3	294.1	194	100.4
2006	1,086.0	0	0	625.5	654.8	1,280.3	215.9	195	20.4
2007	1,095.0	0	0	625.5	632.8	1,258.3	184.9	197	(12.2)
2008	1,104.0	0	0	625.5	557.8	1,183.3	87.4	199	(111.3)
2009	1,122.0	0	0	625.5	557.8	1,183.3	69.4	202	(132.6)
2010	1,131.0	0	0	625.5	557.8	1,183.3	60.4	204	(143.2)
2011	1,139.0	0	0	625.5	412.8	1,038.3	0	205	(305.7)
2012	1,146.0	0	0	625.5	412.8	1,038.3	0	206	(314.0)
2013	1,154.0	0	0	625.5	412.8	1,038.3	0	208	(323.4)
2014	1,160.0	0	0	625.5	412.8	1,038.3	0	209	(330.5)
2015	1,167.0	0	0	625.5	412.8	1,038.3	0	210	(338.8)
2016	1,173.0	0	0	625.5	412.8	1,038.3	0	211	(345.8)
2017	1,179.0	0	0	625.5	412.8	1,038.3	0	212	(352.9)
2018	1,184.0	0	0	625.5	412.8	1,038.3	0	213	(358.8)
2019	1,189.0	0	0	625.5	412.8	1,038.3	0	214	(364.7)

Table 1D.8-15
FMPA Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		108,436	108,436
2001		133,241	234,135
2002		140,565	359,238
2003	21 MW Joint Development with Southern-Florida (10/03)	141,789	478,287
	40 MW Southern-Florida Power Purchase (10/03)		
2004		144,551	592,785
2005		143,507	700,021
2006		152,672	807,649
2007		161,203	914,858
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	172,282	1,022,950
2009		181,922	1,130,630
2010		188,597	1,235,941
2011	223 MW Pulverized Coal (06/11)	205,143	1,344,008
2012		221,344	1,454,009
2013		225,881	1,559,911
2014		231,453	1,662,283
2015		237,165	1,761,244
2016		245,615	1,857,929
2017		250,954	1,951,125
2018		260,216	2,042,290
2019		267,895	2,130,833

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-16
FMPA Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		108,436	108,436
2001		133,241	234,135
2002		140,565	359,238
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	141,891	478,373
2004		143,852	592,317
2005		142,864	699,073
2006		152,068	806,275
2007		160,596	913,080
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	171,711	1,020,814
2009		181,352	1,128,156
2010		188,069	1,233,173
2011	223 MW Pulverized Coal (06/11)	204,675	1,340,994
2012		220,962	1,450,805
2013		225,931	1,556,730
2014		233,238	1,659,891
2015		238,714	1,759,498
2016		247,087	1,856,763
2017		252,383	1,950,489
2018		261,532	2,042,115
2019		269,201	2,131,090

Note: Capacity is stated at average annual temperature for FMPA.

1D.9.0 Financial Analysis

FMPA is a project oriented, joint-action agency and, therefore, relies on debt financing to fund capital additions to its system. The All-Requirements Project is planning to use the FMPA Pooled Loan Project to obtain the financing for FMPA's 3.5 percent equity share of Stanton A. The FMPA Pooled Loan Project is a financing pool in which participating members can obtain loans for electric system projects. The All-Requirements Project can borrow up to $10 million at an interest rate of approximately
5 percent for a period of 20 years.

The All-Requirements Project is financially sound and could obtain traditional tax-exempt bond financing if it chose to do so for Stanton A. FMPA's bonds are Ambac insured with an AAA rating. For fiscal 2000, the All-Requirements Project had operating revenues of $226.2 million with a net operating income of $8.6 million.

Appendix 1D.A
Economic Evaluation Spreadsheets

Florida Municipal Power Agency

Case	
Scenario: Southern-Florida FMPA Base	

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
WH 501F 2x1	257	129,241	24	2006 417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009 417	168,643	14,507
GE 7FA SC	156	76,681	12	2014 417	111,323	9,576

Finance	
Fixed Charge Rate	*8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost* *($1,000)*	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	137,695	10,062	0	0	147,757	0	147,757	259,207
2002	144,902	11,902	0	0	156,804	0	156,804	398,762
2003	148,867	12,646	807	(30)	162,290	206	162,496	535,197
2004	145,360	13,691	3,203	(119)	162,135	825	162,960	664,276
2005	145,203	14,805	3,205	(119)	163,094	825	163,919	786,766
2006	146,361	17,372	4,234	(120)	167,847	8,683	176,530	911,213
2007	148,601	18,940	5,004	(120)	172,423	14,296	186,719	1,035,392
2008	160,600	21,513	5,052	(121)	187,043	14,296	201,339	1,161,715
2009	162,750	22,768	6,205	(122)	191,601	22,758	214,359	1,288,594
2010	168,033	23,861	7,081	(122)	198,853	28,803	227,656	1,415,716
2011	175,053	25,474	7,181	(123)	207,585	28,803	236,388	1,540,242
2012	187,575	26,417	7,284	(123)	221,152	28,803	249,955	1,664,462
2013	195,599	27,363	6,873	(124)	229,710	28,803	258,513	1,785,663
2014	206,390	28,310	4,879	(124)	239,455	34,389	273,844	1,906,784
2015	214,100	29,200	5,341	(125)	248,516	38,379	286,895	2,026,495
2016	225,888	30,498	5,474	(126)	261,735	38,379	300,114	2,144,634
2017	237,751	31,149	5,611	(126)	274,385	38,379	312,764	2,260,783
2018	251,430	32,225	5,752	(127)	289,279	38,379	327,658	2,375,576
2019	266,570	33,128	5,895	(128)	305,465	38,379	343,844	2,489,221

Notes

* FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case

Scenario Self Build FMPA Base

Economic

CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006 417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009 417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011 417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013 417	186,150	16,013

Finance

Fixed Charge Rate	8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	137,695	10,062	0	0	147,757	0	147,757	259,207
2002	144,902	11,902	0	0	156,804	0	156,804	398,762
2003	148,900	12,646	325	13	161,884	677	162,560	535,250
2004	145,503	13,669	333	51	159,556	2,706	162,262	663,777
2005	145,386	14,783	341	53	160,562	2,706	163,268	785,780
2006	146,599	17,365	1,375	54	165,393	10,564	175,957	909,823
2007	148,798	18,938	2,151	55	169,942	16,177	186,119	1,033,603
2008	160,852	21,510	2,204	57	184,623	16,177	200,800	1,159,587
2009	168,106	22,179	2,687	58	193,030	21,014	214,044	1,286,279
2010	176,356	23,121	3,063	59	202,599	24,470	227,069	1,413,073
2011	185,631	23,951	3,588	61	213,232	29,552	242,784	1,540,969
2012	201,664	24,804	4,003	62	230,533	33,182	263,715	1,672,027
2013	197,724	26,935	5,321	64	230,044	42,523	272,567	1,799,817
2014	204,330	28,096	6,336	66	238,827	49,195	288,022	1 927,209
2015	212,092	29,040	6,494	67	247,693	49,195	296,887	2,051,090
2016	223,656	30,283	6,656	69	260,665	49,195	309,859	2,173,065
2017	232,788	31,198	6,823	71	270,880	49,195	320,074	2,291,929
2018	244,680	32,336	6,993	72	284,082	49,195	333,276	2,408,690
2019	256,832	33,152	7,168	74	297,226	49,195	346,421	2,523,187

Notes

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Southern-Florida FMPA High Fuel

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
WH 501F 2x1	257	129,241	24	2006 417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009 417	168,643	14,507
Pulverized Coal	223	256,581	42	2014 417	388,463	33,416

Finance	
Fixed Charge Rate	*8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	138,579	10,062	0	0	148,641	0	148,641	260,040
2002	146,935	11,892	0	0	158,828	0	158,828	401,396
2003	149,567	12,513	807	(30)	162,857	206	163,063	538,307
2004	151,495	13,548	3,203	(119)	168,127	825	168,952	672,133
2005	159,368	16,300	3,205	(119)	178,753	825	179,579	806,325
2006	158,569	17,243	4,234	(120)	179,925	8,683	188,608	939,286
2007	164,255	18,818	5,004	(120)	187,956	14,296	202,252	1,073,795
2008	179,396	21,755	5,052	(121)	206,081	14,296	220,377	1,212,063
2009	187,372	22,928	6,205	(122)	216,383	22,758	239,142	1,353,610
2010	197,445	23,971	7,081	(122)	228,375	28,803	257,178	1,497,217
2011	211,809	25,982	7,181	(123)	244,850	28,803	273,653	1,641,374
2012	227,721	27,010	7,284	(123)	261,891	28,803	290,694	1,785,840
2013	245,878	27,902	6,873	(124)	280,529	28,803	309,331	1,930,867
2014	244,903	29,734	7,145	(124)	281,658	48,295	329,953	2,076,805
2015	250,030	31,144	9,302	(125)	290,351	62,218	352,569	2,223,920
2016	266,659	32,393	9,534	(126)	308,460	62,218	370,678	2,369,836
2017	281,039	33,304	9,773	(126)	323,989	62,218	386,208	2,513,260
2018	301,283	34,538	10,017	(127)	345,712	62,218	407,930	2,656,176
2019	332,457	35,280	10,268	(128)	377,877	62,218	440,095	2,801,633

Notes

* FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case

Scenario Self Build FMPA High Fuel

Economic

CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006 417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009 417	96,404	8,293
GE 7FA SC	156	76,681	12	2011 417	103,374	8,892
Pulverized Coal	223	256,581	42	2015 417	398,174	34,251

Finance

Fixed Charge Rate	8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	138,579	10,062	0	0	148,641	0	148,641	260,040
2002	146,935	11,892	0	0	158,828	0	158,828	401,396
2003	149,636	12,513	807	13	162,484	677	163,160	538,389
2004	151,635	13,548	3,203	51	165,562	2,706	168,268	671,673
2005	159,588	16,300	3,205	53	176,268	2,706	178,974	805,412
2006	158,780	17,243	4,234	54	177,467	10,564	188,031	937,967
2007	164,474	18,818	5,004	55	185,506	16,177	201,683	1,072,097
2008	179,662	21,755	5,052	57	203,678	16,177	219,855	1,210,037
2009	192,940	22,928	6,205	58	217,987	21,014	239,001	1,351,501
2010	205,419	23,971	7,081	59	231,980	24,470	256,449	1,494,701
2011	226,607	25,982	7,181	61	254,659	29,657	284,316	1,644,475
2012	244,068	27,010	7,284	62	273,415	33,362	306,776	1,796,934
2013	259,826	27,902	6,873	64	290,342	33,362	323,703	1,948,699
2014	279,412	29,734	7,145	66	310,907	33,362	344,269	2,100,969
2015	269,717	31,144	9,302	67	306,407	53,342	359,749	2,251,080
2016	274,441	32,393	9,534	69	315,313	67,613	382,926	2,401,817
2017	289,975	33,304	9,773	71	331,932	67,613	399,545	2,550,194
2018	310,762	34,538	10,017	72	354,130	67,613	421,743	2,697,949
2019	329,909	35,280	10,268	74	374,580	67,613	442,193	2,844,100

Notes

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Southern-Florida FMPA Low Fuel

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
WH 501F 2x1	257	129,241	24	2006 417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009 417	168,643	14,507
WH 501F 1x1	125	73,984	23	2014 417	109,072	9,382
WH 501F 1x1	125	73,984	23	2019 417	123,406	10,615

Finance	
Fixed Charge Rate	*8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	136,867	10,066	0	0	146,933	0	146,933	258,429
2002	142,073	12,291	0	0	154,364	0	154,364	395,813
2003	143,859	12,753	807	(30)	157,389	206	157,595	528,132
2004	139,125	14,004	3,203	(119)	156,213	825	157,038	652,521
2005	140,441	16,352	3,205	(119)	159,879	825	160,704	772,609
2006	134,440	17,785	4,234	(120)	156,338	8,683	165,021	888,942
2007	133,658	19,481	5,004	(120)	158,022	14,296	172,318	1,003,543
2008	140,544	21,377	5,052	(121)	166,852	14,296	181,148	1,117,198
2009	141,179	22,517	6,205	(122)	169,779	22,758	192,538	1,231,160
2010	143,237	23,722	7,081	(122)	173,918	28,803	202,721	1,344,359
2011	144,983	25,428	7,181	(123)	177,470	28,803	206,273	1,453,021
2012	154,206	26,257	7,284	(123)	187,623	28,803	216,426	1,560,578
2013	156,427	27,271	6,873	(124)	190,446	28,803	219,249	1,663,370
2014	161,889	27,951	4,893	(124)	194,609	34,276	228,885	1,764,606
2015	165,226	28,893	5,365	(125)	199,359	38,185	237,544	1,863,725
2016	170,666	30,072	5,499	(126)	206,112	38,185	244,297	1,959,892
2017	174,498	30,808	5,637	(126)	210,816	38,185	249,001	2,052,362
2018	180,774	31,977	5,778	(127)	218,402	38,185	256,587	2,142,256
2019	190,098	32,361	6,469	(128)	228,800	44,377	273,177	2,232,545

Notes

* FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case

Scenario Self Build FMPA Low Fuel

Economic

CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006 417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009 417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011 417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013 417	186,150	16,013

Finance

Fixed Charge Rate	8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	136,867	10,066	0	0	146,933	0	146,933	258,429
2002	142,073	12,291	0	0	154,364	0	154,364	395,813
2003	143,913	12,736	325	13	156,985	677	157,662	528,189
2004	139,286	13,979	333	51	153,649	2,706	156,355	652,037
2005	140,660	16,354	341	53	157,408	2,706	160,114	771,683
2006	134,664	17,781	1,375	54	153,874	10,564	164,438	887,605
2007	133,861	19,477	2,151	55	155,544	16,177	171,721	1,001,809
2008	140,779	21,377	2,204	57	164,417	16,177	180,594	1,115,116
2009	146,344	21,786	2,687	58	170,875	21,014	191,889	1,228,695
2010	151,025	22,491	3,063	59	176,638	24,470	201,108	1,340,992
2011	154,193	23,851	3,588	61	181,693	29,552	211,245	1,452,273
2012	163,594	24,759	4,003	62	192,418	33,182	225,600	1,564,390
2013	149,915	27,434	6,771	64	184,184	42,523	226,707	1,670,679
2014	146,054	29,013	8,870	66	184,003	49,195	233,198	1,773,822
2015	148,919	29,972	9,092	67	188,051	49,195	237,246	1,872,817
2016	153,640	31,194	9,319	69	194,223	49,195	243,417	1,968,637
2017	156,543	32,174	9,552	71	198,340	49,195	247,535	2,060,562
2018	162,156	33,036	9,791	72	205,055	49,195	254,250	2,149,637
2019	166,000	34,178	10,036	74	210,288	49,195	259,483	2,235,400

Notes

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Southern-Florida FMPA AEO

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
Pulverized Coal	223	256,581	42	2006 417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009 417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014 417	190,804	16,413

Finance	
Fixed Charge Rate.	*8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	101,705	6,268	0	0	107,973	0	107,973	107,973
2001	111,995	10,218	0	0	122,212	0	122,212	223,267
2002	125,685	11,762	0	0	137,446	0	137,446	345,594
2003	134,364	12,555	807	(30)	147,696	206	147,902	469,776
2004	142,841	13,486	3,203	(119)	159,410	825	160,235	596,697
2005	150,963	16,183	3,205	(119)	170,232	825	171,057	724,521
2006	133,144	18,252	5,453	(120)	156,729	16,823	173,553	846,869
2007	126,112	20,125	7,136	(120)	153,252	28,251	181,503	967,579
2008	139,184	22,638	7,237	(121)	168,939	28,251	197,190	1,091,298
2009	141,310	23,844	8,445	(122)	173,477	36,713	210,190	1,215,709
2010	144,644	24,882	9,378	(122)	178,782	42,758	221,539	1,339,416
2011	153,086	26,616	9,535	(123)	189,114	42,758	231,872	1,461,563
2012	161,661	27,652	9,696	(123)	198,886	42,758	241,643	1,581,652
2013	169,499	28,701	9,346	(124)	207,421	42,758	250,179	1,698,946
2014	174,766	29,927	8,194	(124)	212,761	52,332	265,093	1,816,196
2015	180,244	31,100	9,302	(125)	220,521	59,170	279,691	1,932,902
2016	189,058	32,407	9,534	(126)	230,874	59,170	290,045	2,047,077
2017	195,679	33,356	9,773	(126)	238,681	59,170	297,852	2,157,688
2018	206,800	34,577	10,017	(127)	251,267	59,170	310,437	2,266,448
2019	217,412	35,652	10,268	(128)	263,203	59,170	322,374	2,372,997

Notes
* FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate
[1] Includes start-up costs
[2] Fixed costs are included only for new units
[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Self Build FMPA AEO

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
Pulverized Coal	223	256,581	42	2006 417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009 417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011 417	101,285	8,713
WH 501F 2x1	257	129,241	12	2013 417	183,051	15,746

Finance	
Fixed Charge Rate	8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	101,705	6,268	0	448	0	0	107,973	107,973
2001	111,995	10,218	0	381	0	0	122,212	223,267
2002	125,685	11,762	0	351	0	0	137,446	345,594
2003	134,409	12,554	325	481	13	677	147,976	469,837
2004	142,998	13,470	333	547	51	2,706	159,558	596,223
2005	151,205	16,166	341	718	53	2,706	170,470	723,608
2006	133,392	18,245	2,594	604	54	18,704	172,990	845,558
2007	126,338	20,124	4,283	605	55	30,132	180,932	965,889
2008	139,542	22,631	4,390	705	57	30,132	196,751	1,089,332
2009	147,906	23,296	4,927	695	58	34,969	211,155	1,214,315
2010	154,604	24,012	5,359	810	59	38,424	222,459	1,338,535
2011	169,397	25,028	5,942	1,200	61	43,507	243,935	1,467,037
2012	185,181	26,153	6,415	1,330	62	47,137	264,948	1,598,708
2013	174,537	27,901	7,794	2,043	64	56,322	266,618	1,723,709
2014	178,463	29,333	8,870	1,667	66	62,883	279,615	1,847,383
2015	185,630	30,256	9,092	1,542	67	62,883	287,928	1,967,525
2016	196,136	31,508	9,319	1,815	69	62,883	299,916	2,085,586
2017	203,595	32,406	9,552	1,692	71	62,883	308,507	2,200,154
2018	214,711	33,437	9,791	1,618	72	62,883	320,895	2,312,578
2019	225,836	34,501	10,036	1,867	74	62,883	333,329	2,422,748

Notes

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case

Scenario Southern-Florida FMPA OUC + AEO

Economic

CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
Pulverized Coal	223	256,581	42	2006 417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009 417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014 417	190,804	16,413

Finance

Fixed Charge Rate	*8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,723	10,284	0	0	140,008	0	140,008	251,814
2002	145,527	11,812	0	0	157,339	0	157,339	391,845
2003	157,642	12,711	807	(30)	171,130	206	171,336	535,702
2004	170,934	13,860	3,203	(119)	187,877	825	188,702	685,172
2005	188,055	16,291	3,205	(119)	207,433	825	208,258	840,794
2006	167,744	19,094	5,453	(120)	192,171	16,823	208,995	988,127
2007	160,047	21,231	7,136	(120)	188,293	28,251	216,544	1,132,141
2008	183,083	23,907	7,237	(121)	214,107	28,251	242,358	1,284,199
2009	188,223	24,998	8,445	(122)	221,544	36,713	258,258	1,437,061
2010	194,627	25,948	9,378	(122)	229,830	42,758	272,588	1,589,273
2011	221,448	26,835	9,535	(123)	257,696	42,758	300,453	1,747,548
2012	234,724	27,860	9,696	(123)	272,156	42,758	314,914	1,904,051
2013	246,667	28,938	9,346	(124)	284,827	42,758	327,584	2,057,635
2014	255,573	30,091	8,194	(124)	293,733	52,332	346,065	2,210,700
2015	263,713	31,192	9,302	(125)	304,082	59,170	363,253	2,362,273
2016	277,766	32,540	9,534	(126)	319,715	59,170	378,885	2,511,420
2017	288,039	33,436	9,773	(126)	331,121	59,170	390,292	2,656,360
2018	304,754	34,645	10,017	(127)	349,289	59,170	408,460	2,799,461
2019	321,785	35,757	10,268	(128)	367,681	59,170	426,851	2,940,541

Notes

* FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case

Scenario Self Build FMPA OUC + AEO

Economic

CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
Pulverized Coal	223	256,581	42	2006 417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009 417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011 417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013 417	186,150	16,013

Finance

Fixed Charge Rate	8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,723	10,284	0	0	140,008	0	140,008	251,814
2002	145,527	11,812	0	0	157,339	0	157,339	391,845
2003	157,705	12,708	325	13	170,750	677	171,427	535,778
2004	171,296	13,846	333	51	185,527	2,706	188,233	684,876
2005	188,401	16,271	341	53	205,066	2,706	207,772	840,135
2006	168,248	19,096	2,594	54	189,992	18,704	208,696	987,258
2007	160,476	21,241	4,283	55	186,054	30,132	216,186	1,131,034
2008	183,656	23,902	4,390	57	212,004	30,132	242,136	1,282,953
2009	196,411	24,561	4,927	58	225,956	34,969	260,925	1,437,395
2010	206,837	25,397	5,359	59	237,653	38,424	276,077	1,591,555
2011	245,826	25,413	5,942	61	277,242	43,507	320,749	1,760,521
2012	270,132	26,580	6,415	62	303,190	47,137	350,327	1,934,623
2013	254,563	28,335	7,794	64	290,756	56,478	347,233	2,097,419
2014	261,319	29,581	8,870	66	299,836	63,150	362,985	2,257,968
2015	272,159	30,507	9,092	67	311,825	63,150	374,974	2,414,432
2016	287,861	31,829	9,319	69	329,079	63,150	392,229	2,568,831
2017	299,699	32,622	9,552	71	341,944	63,150	405,094	2,719,268
2018	316,932	33,743	9,791	72	360,539	63,150	423,688	2,867,705
2019	334,520	34,757	10,036	74	379,387	63,150	442,536	3,013,969

Notes

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Southern-Florida FMPA No Real

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
Pulverized Coal	223	256,581	42	2006 417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009 417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014 417	190,804	16,413

Finance	
Fixed Charge Rate	*8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,433	10,285	0	0	139,717	0	139,717	251,540
2002	144,959	11,950	0	0	156,909	0	156,909	391,188
2003	156,195	12,898	807	(30)	169,870	206	170,076	533,988
2004	167,660	13,950	3,203	(119)	184,694	825	185,519	680,936
2005	182,845	16,416	3,205	(119)	202,348	825	203,173	832,758
2006	165,238	19,087	5,453	(120)	189,659	16,823	206,483	978,320
2007	160,200	21,212	7,136	(120)	188,428	28,251	216,679	1,122,424
2008	180,184	23,877	7,237	(121)	211,177	28,251	239,428	1,272,644
2009	185,202	24,973	8,445	(122)	218,499	36,713	255,212	1,423,704
2010	190,746	25,897	9,378	(122)	225,898	42,758	268,656	1,573,720
2011	208,945	26,822	9,535	(123)	245,180	42,758	287,937	1,725,402
2012	219,536	27,848	9,696	(123)	256,957	42,758	299,714	1,874,350
2013	228,536	28,939	9,346	(124)	266,696	42,758	309,454	2,019,435
2014	234,649	30,083	8,194	(124)	272,801	52,332	325,133	2,163,241
2015	239,322	31,195	9,302	(125)	279,694	59,170	338,864	2,304,637
2016	248,732	32,498	9,534	(126)	290,639	59,170	349,809	2,442,339
2017	254,564	33,418	9,773	(126)	297,628	59,170	356,799	2,574,841
2018	265,354	34,615	10,017	(127)	309,860	59,170	369,030	2,704,128
2019	275,427	35,734	10,268	(128)	321,300	59,170	380,471	2,829,879

Notes

* FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case

Scenario Self Build FMPA No Real

Economic

CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
Pulverized Coal	223	256,581	42	2006 417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009 417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011 417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013 417	186,150	16,013

Finance

Fixed Charge Rate	8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,433	10,285	0	0	139,717	0	139,717	251,540
2002	144,959	11,950	0	0	156,909	0	156,909	391,188
2003	156,304	12,895	325	13	169,536	677	170,213	534,102
2004	168,018	13,943	333	51	182,346	2,706	185,052	680,680
2005	183,182	16,401	341	53	199,976	2,706	202,682	832,136
2006	165,706	19,093	2,594	54	187,447	18,704	206,152	977,465
2007	160,610	21,208	4,283	55	186,156	30,132	216,288	1,121,309
2008	180,678	23,878	4,390	57	209,003	30,132	239,135	1,271,345
2009	192,603	24,485	4,927	58	222,073	34,969	257,042	1,423,488
2010	201,733	25,241	5,359	59	232,392	38 424	270,816	1,574,710
2011	229,472	25,379	5,942	61	260,853	43,507	304,360	1,735,043
2012	248,492	26,607	6,415	62	281,577	47,137	328,714	1,898,404
2013	235,148	28,302	7,794	64	271,309	56,478	327,786	2,052,083
2014	239,406	29,634	8,870	66	277,976	63,150	341,125	2,202 963
2015	245,907	30,561	9,092	67	285,627	63,150	348,776	2,348,495
2016	256,737	31,732	9,319	69	297,857	63,150	361,007	2,490,604
2017	264,211	32,673	9,552	71	306,507	63,150	369,657	2,627,881
2018	274,680	33,720	9,791	72	318,264	63,150	381,413	2,761,507
2019	285,239	34,839	10,036	74	330,188	63,150	393,338	2,891,510

Notes

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Self Build FMPA High Load

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
WH 501F 2x1	257	129,241	24	2005 417	152,782	13,142
WH 501F 2x1	257	129,241	24	2006 417	156,602	13,471
WH 501F 2x1	257	129,241	24	2008 417	164,529	14,153
Pulverized Coal	223	256,581	42	2011 417	360,726	31,030
WH 501F 1x1	125	73,984	23	2017 417	117,459	10,104

Finance	
Fixed Charge Rate	8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,613	6,230	0	0	130,844	0	130,844	130,844
2001	152,515	10,771	0	0	163,286	0	163,286	284,887
2002	163,022	13,022	0	0	176,044	0	176,044	441,566
2003	169,249	14,239	325	13	183,825	677	184,501	596,477
2004	171,547	15,842	333	51	187,773	2,706	190,479	747,354
2005	161,062	18,325	1,341	53	180,781	10,372	191,154	890,195
2006	162,262	20,772	3,123	54	186,211	23,706	209,917	1,038,178
2007	170,426	22,715	3,943	55	197,139	29,319	226,458	1,188,786
2008	179,488	26,011	5,118	57	210,674	37,575	248,249	1,344,540
2009	191,383	27,550	6,025	58	225,016	43,472	268,488	1,503,458
2010	203,108	29,026	6,176	59	238,369	43,472	281,841	1,660,837
2011	203,301	31,723	8,870	61	243,955	61,573	305,528	1,821,785
2012	212,916	33,585	10,929	62	257,492	74,502	331,994	1,986,776
2013	221,139	35,107	11,202	64	267,512	74,502	342,014	2,147,125
2014	235,427	36,538	11,482	66	283,513	74,502	358,015	2,305,475
2015	245,739	38,099	11,769	67	295,675	74,502	370,177	2,459,937
2016	258,937	39,796	12,064	69	310,865	74,502	385,367	2,611,635
2017	270,580	41,081	12,886	71	324,617	80,396	405,013	2,762,043
2018	286,514	42,790	13,584	72	342,961	84,606	427,567	2,911,838
2019	298,848	44,309	13,924	74	357,155	84,606	441,760	3,057,846

Notes

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Southern-Florida FMPA High Load

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
WH 501F 2x1	257	129,241	24	2005 417	152,782	13,142
WH 501F 2x1	257	129,241	24	2006 417	156,602	13,471
GE 7FA SC	156	76,681	12	2008 417	95,993	8,257
Pulverized Coal	223	256,581	42	2011 417	360,726	31,030
WH 501F 2x1	257	129,241	23	2014 417	190,537	16,390

Finance	
Fixed Charge Rate	*8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,613	6,230	0	0	130,844	0	130,844	130,844
2001	152,515	10,771	0	0	163,286	0	163,286	284,887
2002	163,022	13,022	0	0	176,044	0	176,044	441,566
2003	169,186	14,247	807	(30)	184,209	206	184,416	596,405
2004	171,257	15,849	3,203	(119)	190,190	825	191,016	747,707
2005	160,860	18,344	4,206	(119)	183,290	8,491	191,782	891,017
2006	161,958	20,775	5,982	(120)	188,595	21,825	210,421	1,039,356
2007	169,876	22,703	7,191	(120)	199,649	27,438	227,087	1,190,382
2008	181,898	25,813	7,579	(121)	215,169	32,255	247,424	1,345,619
2009	195,433	27,327	7,692	(122)	230,330	35,696	266,026	1,503,079
2010	207,560	28,707	7,807	(122)	243,952	35,696	279,648	1,659,232
2011	206,194	31,400	10,465	(123)	247,936	53,796	301,732	1,818,181
2012	213,359	33,353	12,486	(123)	259,075	66,725	325,800	1,980,094
2013	223,236	34,843	12,205	(124)	270,160	66,725	336,885	2,138,039
2014	234,332	36,394	11,125	(124)	281,726	76,286	358,012	2,296,388
2015	244,510	38,037	12,306	(125)	294,729	83,115	377,844	2,454,049
2016	259,005	39,683	12,614	(126)	311,176	83,115	394,292	2,609,260
2017	269,145	41,060	12,929	(126)	323,008	83,115	406,124	2,760,080
2018	297,003	42,264	13,253	(127)	352,393	83,115	435,508	2,912,658
2019	302,149	44,168	13,584	(128)	359,773	83,115	442,888	3,059,038

Notes

* FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Southern-Florida FMPA Low Load

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
WH 501F 2x1	257	129,241	24	2008 417	164,529	14,153
Pulverized Coal PC	223	256,581	42	2011 417	360,726	31,030

Finance	
Fixed Charge Rate	*8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	103,096	5,340	0	0	108,436	0	108,436	108,436
2001	123,881	9,360	0	0	133,241	0	133,241	234,135
2002	129,660	10,905	0	0	140,565	0	140,565	359,238
2003	129,669	11,138	807	(30)	141,583	206	141,789	478,287
2004	128,251	12,391	3,203	(119)	143,726	825	144,551	592,785
2005	126,341	13,255	3,205	(119)	142,682	825	143,507	700,021
2006	133,877	14,881	3,208	(120)	151,847	825	152,672	807,649
2007	141,111	16,176	3,212	(120)	160,378	825	161,203	914,858
2008	140,274	18,757	4,292	(121)	163,201	9,081	172,282	1,022,950
2009	142,419	19,546	5,101	(122)	166,944	14,978	181,922	1,130,630
2010	148,281	20,308	5,151	(122)	173,619	14,978	188,597	1,235,941
2011	142,003	22,441	7,743	(123)	172,064	33,079	205,143	1,344,008
2012	141,972	23,791	9,696	(123)	175,336	46,008	221 344	1,454,009
2013	146,156	24,496	9,346	(124)	179,874	46,008	225,881	1,559,911
2014	153,488	25,137	6,945	(124)	185,445	46,008	231,453	1,662,283
2015	158,332	25,832	7,118	(125)	191,158	46,008	237,165	1,761,244
2016	165,536	26,900	7,296	(126)	199,607	46,008	245,615	1,857,929
2017	170,136	27,458	7,479	(126)	204,947	46,008	250,954	1,951,125
2018	178,290	28,380	7,666	(127)	214,209	46,008	260,216	2,042,290
2019	184,949	29,209	7,857	(128)	221,887	46,008	267,895	2,130,833

Notes

* FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case	
Scenario	Self Build FMPA Low Load

Economic	
CPW Discount Rate	6 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
WH 501F 2x1	257	129,241	24	2008 417	164,529	14,153
Pulverized Coal PC	223	256,581	42	2011 417	360,726	31,030

Finance	
Fixed Charge Rate	8 60%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	103,096	5,340	0	0	108,436	0	108,436	108,436
2001	123,881	9,360	0	0	133,241	0	133,241	234,135
2002	129,660	10,905	0	0	140,565	0	140,565	359,238
2003	129,741	11,136	325	13	141,215	677	141,891	478,373
2004	128,388	12,375	333	51	141,146	2,706	143,852	592,317
2005	126,518	13,246	341	53	140,158	2,706	142,864	699,073
2006	134,083	14,876	350	54	149,362	2,706	152,068	806,275
2007	141,303	16,174	358	55	157,890	2,706	160,596	913,080
2008	140,491	18,758	1,444	57	160,749	10,962	171,711	1,020,814
2009	142,629	19,547	2,259	58	164,493	16,859	181,352	1,128,156
2010	148,528	20,307	2,316	59	171,211	16,859	188,069	1,233,173
2011	142,304	22,437	4,914	61	169,716	34,959	204,675	1,340,994
2012	142,356	23,781	6,873	62	173,073	47,889	220,962	1,450,805
2013	146,428	24,505	7,045	64	178,042	47,889	225,931	1,556,730
2014	152,850	25,213	7,221	66	185,350	47,889	233,238	1,659,891
2015	157,458	25,898	7,402	67	190,825	47,889	238,714	1,759,498
2016	164,562	26,980	7,587	69	199,198	47,889	247,087	1,856,763
2017	169,080	27,567	7,777	71	204,495	47,889	252,383	1,950,489
2018	177,143	28,457	7,971	72	213,643	47,889	261,532	2,042,115
2019	183,745	29,322	8,170	74	221,312	47,889	269,201	2,131,090

Notes

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water