Stanton Energy Center Combined Cycle Unit A

010192- 219

Need for Power Application

Florida Municipal Power Agency – Volume 1D

January 29, 2001



11401 Lamar, Overland Park, Ka

DOCUMENT NUMPER-DATE

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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

	Та	ble 1D.2-	.1	<u></u>	
	summary of	i Projeci i	Participant	IS	
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 memb	ber.				

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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.

Stancer Energy Center Combined Cycle Unit A Need for Power Application

				Exi	Florida isting and	Table 1D.2 Municipal Po I Planned Gen	-2 wer Agency erating Faci	lities				
				Fu	lel				FMPA Net	Capability ¹	Fuel Trans	portation
Plant	Unit No.	Location (County)	Type	Primary	Alternate	Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Summer (MW)	Winter (MW)	Primary	Alternat e
Existing Genera	ting Facilit	ties		-								
St Lucie	2	St Lucie	z	z	None	08/83	Unknown	839.00	74.0	75.0	TK	None
Stanton Energy Center (SEC)	7	Orange	FS	00	None None	07/87 06/96	Unknown	464.58 464.58	115.0 122.0	115.0 122.0	RR RR	None None
	CTA		5	ĐN	LO	06/89	Unknown	41.40	14.6	18.6	PL	TK
	CTB	-	сı	NG	ΓO	07/89	Unknown	41.40	14.6	18.6	PL	TK
Indian Kiver	стс	Brevard	ст	ŊĠ	ΓO	08/92	Unknown	122 04	21.7	27.0	PL	TK
	CTD		CT	DN	ΓO	10/92	Unknown	122.04	21.7	27.0	PL	TK
			CT	ŊĠ	ΓO	01/95	Unknown	40.00	15 2	15.2	PL	TK
Cane Island	2	Osceola	ССТ	ŊŨ	ΓO	06/95	Unknown	122 00	54.2	60.2	PL	TK
0	CT 2		cT	L0	L0	66/90	Unknown	21.00	17.0	17.0	TK	TK
Stock Island	CT 3	Monroe	сī	ΓO	ΓO	06/99	Unknown	21.00	17.0	17.0	TK	TK
Planned Genera	ting Facilit	ties										
Cane Island	3	Osceola	cc	ĐN	ΓO	06/01 (planned)	Unknown	250.00	120	120	PL	TK
SEC ²	-	Orange	FS	υ	None	01/02	Unknown	464 58	10.1	101	RR	None
St 1 unio ²	-	Ct Incia	2	Z	None	01/02	Unknown	850 00	9 17	9.17	TK	None
31. LUCIO	7	31. 1.4016	2	2		01/02	Unknown	839.00	9.17	9.17	TK	None
SEC	6	Orange	8	ĐN	ГО	10/03 (planned)	Unknown	633	20 8	22.6	PL	TK
McIntosh	4	Polk	FS	PET	c	06/0 5 (planned)	Unknown	288.00	100	100	TR	TR
¹ FMPA's owne ² Result of addi Source FMPA	rship shar tion of La Ten Year	e. Does not incl ke Worth to ARI r Sıte Plan April	ude City P in Janı 2000.	 of Newberr Jary of 2002. 	y's capacity	in St. Lucie 2.						

Black & Veatch

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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- Date ARP Member	3 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

Started Energy Center Combined Cycle Unit A Need for Power Application Table 1D.2-4



				H	uel			Generator	Net Ca	pability ¹	Fuel Tra	nsportation
Plant	Unit No.	Location (County)	T	Ргітан	Alternate	Commercial In-Service (Month/Vear)	Expected Retirement (Month/Vear)	Maximum Nameplate (MW)	Summer (MW)	Winter	Primarv	Alternate
	1		Z	Z	None	05/76	Unknown	850 00	16.7	16.7	TK	None
st. Lucie	7	St. Lucie	z	z	None	08/83	Unknown	839.00	18.3	18.3	TK	None
Crystal River	e	Citrus	z	z		03/77	Unknown	890.46	17.8	17.8		
Ctonton Energy	-		FS	J	None	07/87	Unknown	464.58	82.3	82.3	RR	None
Center (SEC)	- 7	Orange	FS	o	None	06/96	Unknown	464.58	66.0	66.0	RR	None
	CT A		ст	ŊĊ	ro	06/89	Unknown	41 40	14.6	18.6	PL	TK
Indian Direc	CTB	Decement	CT	ŊĊ	ГО	07/89	Unknown	41.40	14.6	18.6	PL	TK
	стс	DIEVAIU	ст	ŊŊ	ΓO	08/92	Unknown	122 04	21.7	27.0	PL	TK
	стр		ст	ĐN	ΓO	10/92	Unknown	122.04	21.7	27.0	PL	TK
Cono Lolond	-	00000	ст	NG	ΓO	01/95	Unknown	40.00	15.2	15.2	PL	TK
	7	Oscenta	сст	ŊĊ	ΓO	06/95	Unknown	122.00	54.2	60.2	PL	TK
Clark Island	CT 2	Marros	ст	ΓO	ΓO	06/99	Unknown	21 00	17.0	17.0	TK	TK
SIOCK ISTATIO	CT 3		СТ	ΓΟ	ΓO	06/90	Unknown	21.00	17.0	17.0	TK	TK
FMPA ARP To	tal Genera	tion Capacity for	- 2000						377.0	401.6		
Cane Island	3	Osceola	cc	ŊĊ	го	06/01 (planned)	Unknown	250.00	120	120	ΡL	TK
FMPA ARP To	tal Genera	tion Capacity for	- 2001						497.0	4016		
SEC ²		Orange	FS	U	None	01/02	Unknown	464.58	101	101	RR	None
St Lucie ²	_	St Lucie	z	z	None	01/02	Unknown	850.00	92	9.2	TK	None
	5		:	;		01/02	Unknown	839 00	9.2	9.2	TK	None
FMPA ARP To	tal Genera	tion Capacity for	- 2002						525.5	550.1		
SEC ³	A	Orange	СС	ÐN	ГО	10/03 (planned)	Unknown	633	208	22 6	PL	TK
FMPA ARP To	tal Genera	tion Capacity for	- 2003						525.5	550.1		
FMPA ARP To	tal Genera	tion Capacity for	2004						525.5	550.1		
McIntosh	4	Polk	FS	PET	c	06/05 (planned)	Unknown	288.00	100	001	TR	TR
FMPA ARP To	tal Genera	tion Capacity for	2005						625.5	650.I		
FMPA ARP To	tal Genera	tion Capacity for	- 2006						625.5	650.1		
¹ FMPA All-Re ² Result of addi ³ SFC A:	quirement tion of Lal	s Project membreke Worth to ARF	ers' owner ' in Januar	rship share y of 2002.	ENV ENV	Y G						
SEC A s capa	city nas n	of been included	in the tota	u capacity av	Vallable to F IVI	ľA.						

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						Table 1D.2-	5					
		FMF	IIA AI	Require	ments Pr	oject Existing	Member Ger	nerating Facilit	ies			
				Ľ			Evented	Ganarator	Net Can	ability	Fuel Trans	portation
		Location		Ę		Lommercial In-Service	Retirement	Maximum Namenlate (MW)	Summer	Winter	Primarv	Alternate
Plant	Unit No.	(County)	Type	Primary	Alternate	(Montn/ Y car)	(MUDILIN I CAL)	22 00	//	0.00	DI	TK
	7		FS	ΰx	ЮН	01/64	Unknown	33 00	0.25	0.46		
	~		FS	NG	ЮН	05/76	Unknown	56.116	50.0	50.0	PL	X I
UD Vina	0	St Turne	ccT	ÐN	ro	02/90	Unknown	30.895	31.0	31.0	PL	TK
giiny 'nı ti				01	None	04/70	Unknown	2.75	2.5	2.5	TK	
	10			10 1	None	04/70	Unknown	2.75	2.5	2.5	TK	
D.c Dian		Monroe	6	10	None	02/69	Unknown	2.75	2.5	2.5	TK	
DIG LINC	- (20 11011				08/68	Unknown	2.75	2.25	2.25	TK	
Cudjoe	7 6	Monroe	2 0	3 9	None	08/68	Unknown	2.30	2.25	2.25	TK	
	111		CT.	01	None	11/78	Unknown	23.45	20.0	23.0	WA	
			5 0	01	None	01/65	Unknown	2.50	2.0	2.0	WA	
Stock Island		Monroe		10	None	01/65	Unknown	2.50	2.0	2.0	WA	
	2 5		2	LO LO	None	01/65	Unknown	2.50	2.0	2.0	WA	
	101			01	None	06/91	Unknown	9.60	8.7	8.7	WA	
Medium apecu	+01	Monroe		10	None	06/91	Unknown	9.60	8.7	8.7	WA	
DICSCI	2.		БQ	UN	OH	11/61	Unknown	12.50	12.0	13.0	PL	TK
			E O	SN SN	OH	12/60	Unknown	33.00	34.0	34.0	PL	TK
Vero Beach	· · ·	Indian River	LC D		OH	08/76	Unknown	55.00	56.0	56.0	PL	TK
	4 4		COW	ČN N	01	12/92	Unknown	57.90	47.5	54.5	PL	TK
	c	To alter for 2000		2			-		317.9	328.9		
FMPA AKP 101a	Ceneration C	apacity tot 2000							317.9	328.9		
FMFA AKF 1013			БG	NIC	ПНО	01/61	Unknown	7.50	7.0	8.0	PL	TK
			Lo Lo		DH OH	11/67	Unknown	26.50	24.8	27.0	PL	TK
	6-6		2 6	2	None	12/65	Unknown	2.00	1.8	2.0	TK	
				2 0	None	12/65	Unknown	2.00	1.8	2.0	TK	
Lake Worth*		Palm Beach		01	None	12/65	Unknown	2.00	1.8	2.0	TK	
Tom G Smith	MU3				None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU4				None	12/65	Unknown	2.00	1.8	2.0	TK	
			5 E	01	None	12/76	Unknown	30.80	26.0	32.0	TK	
- 1 -	-1-1 2 2		CCW	DN DN	ΓO	03/78	Unknown	31 41	280	33.0	PL	TK
EVADA ADD Toto	Constinu	anacity for 2002							412.8	438.9		
		ADD Inninery of	2002									
*Lake worin and	cipates jume	AINI Jahumu v.										
Source: FMFA												

Black & Veatch

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January 29, 2001

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 onsystem 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.

vined Cycle Unit A	
y Center Comb	r Application
Stanton Energ	Need for Powe

							FMP	T A Pow	able 1 /er Pu	D.2-6 rchase	s Cap	acity									
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	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sun	n Wi	n Su	m Wi	n St	u N	Vin 1	Sum	Win	Sum	Win	Sum
FIRM POWER PURCH	IASE]	
TECO	150	150	150	0	0	0	0	0	0	0	0	0	0	0	0	Ē	6	0	0	0	0
OUC Ind. River	93	93	93	93	71	11	50	50	28	28	9	9	0	0	0		6	0	0	0	0
OUC - Ind River	37	37	37	37	37	37	37	37	37	37	37	37	22	22	0		6	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	ъ	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	4	5	45	45	45	45	45
Lakeland	0	0	50	100	100	100	100	100	100	100	100) 10	0 10	0 1(0 11	00	100	100	100	100	100
FPL	0	0	0	0	0	75	75	75	75	75	75	75	75	75	7.	5	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	. 26.	3 26	3 24:	2 24	2 2.	20	220	145	145	145	145
PARTIAL REQUIREM	ENTS P	URCHA	SE																		
FPC ²	80	80	40	40	27	27	15	15	15	15	40	40	0	0	0)	6	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 P	OWER																				
Total	453	483	488	388	343	418	345	345	300	300) 30	3 30.	3 24.	2 24	2 2:	20	220	145	145	145	145
¹ Lake Worth assumed to j ² Capacıty varies based on	oin FMP. the time	A Januar of day. 1	y of 200. Maximur	2. n capacil	y availa	ble is lis	ted.														

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Stanton Energy Need for Power	Cente Applic	r Com ation	bined	Cycle	Unit A	-									-	D.2.0	Descr	iption	of Sys	Ee
						بـتــ	Tab MPA	le 1D.: Power	2-6 (C Purch	ontinu aase C	led) apacit	y								
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	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
FIRM POWER PURCI	HASE																			
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 REQUIREN	IENTS F	URCHA	NSE							1										
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
TOTAL PURCHASE P	OWER																		-	
Total	145	145	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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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

	All-Rec	Tabl Juirements Tota	e 1D.2-7 1 Capacity - Su	ımmer (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 W Propose	orth Capacity included d Stanton A not include	beginning 2002. ed.			

	All-Requ	irements Tota	l Capacity - W	inter (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 Wort Proposed S	h Capacity included be Stanton A not included	ginning 2002.	<u> </u>		

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 longterm 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, autoregression, 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

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1D.4.0 Forecast of Demand and Energy

				All-	Requireme	Table ants Project	1D.4-1 Membe	er Net Ele	ectric Lo	oad	l			
	City of D. A. 11	City of	City of Fort	City of Fort	City of Green Cove	City of Jacksonville Baach	City of Key Wart	City of	City of	City of Starks	City of Vero Beach	City of Lake Worth	T'otal ¹ .2	Total With Transmission
Vear	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(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	18	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	169	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
Fort Meade	's load inclue	ded beginning	2009.											
⁴ Lake Wort The Town of	h's load inch f Havana and	uded beginnin I City of Newl	g January o herry are no	if 2002. It included i	n the forecast									

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iter Combined	lication
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Stanton	Need fo

			ARP	Member Su	immer Peal	Table 1D.4 c Demand (-2 Noncoincid	lent Dema	nd Peak)			
ılendar	City of Bushmell	City of Clewiston	City of Fort Meade ¹	City of Fort Pierce	City of Green Cove Springs	City of Jacksonville Beach	City of Key West	City of Leesburg	City of Ocala AAW	City of Starke MW)	City of Vero Beach MWV	City of Lake Worth ² (MW)
car istorical	(MM)	(MM)	(MM)	(M M)	(M TAI)	(/ 44 TAT \	7 100	(
666	5.0	25.8	8.8	114.0	27.5	169.3	126.0	102.2	273.0	16.5	147.0	80.0
rojected												
000	5.3	26.2	9.0	114.1	23.9	173.1	126.4	105.5	280.4	16.6	151.5	83.5
100	54	26.5	9.1	115.7	24.1	178.8	128.8	107.2	289.0	16.9	155.0	84.7
002	5.5	26.8	9.1	1172	24.7	184.4	131.2	109.0	295.1	17.1	158.3	85.9
003	5.6	271	9.1	118.8	25.4	189.8	133 4	110.7	301.9	17.4	161.5	870
004	5.7	27.4	9.2	120.3	26.0	195.0	135.6	112.5	308.4	17.6	164.5	88.1
005	5.8	27.7	9.2	121.7	26.6	199.8	137.7	114.3	314.7	17.9	167.4	89.2
006	5 9	28.0	9.2	123.1	27.1	204.4	139.6	115.9	320.5	18.1	170.1	90.3
007	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
6000	62	28.9	9.3	126.7	28.5	217.4	144.9	120.9	336.2	18.8	177.4	93.4
	5											
010	63	29.2	9.3	127.8	29.0	221.4	146.6	122.6	340.8	19.0	179.5	94.5
1100	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	64	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	94	131.7	30.5	2362	152.2	129.3	356.3	20.0	186.6	98.4
2015	6.6	30.6	94	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	314	245.8	155.6	1343	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
Fort Mead	e's load includ	led beginning 2	009. Jamiary of 2002									
Тhe Town o	ות s וטמט ווויניו of Havana and	the City of Ne	wherry are not in	ncluded in the for	recast.							
	the second second											

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	Forecast of Sum	Table 1D.4-3 mer Peak Demand – Base	e 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 in Fort Meade The Town	cludes addition of L beginning 2009. of Havana and City	ake Worth beginning Jan of Newberry are not inclu	uary of 2002 and uded 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.
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1D.4.0 Forecast of Demand and Energy

			ARP 1	Member	, Winter Peak	Table 1D.4- Demand (N	-4 Ioncoincid	ent Demai	nd Peak)			
Calendar	City of Bushnell	City of Clewiston	City of Fort Meade	City of Fort Pierce	City of Green Cove Springs	City of Jacksonville Beach	City of Key West	City of Leesburg	City of Ocala	City of Starke	City of Vero Beach	City of Lake Worth
Year	(MM)	(MM)	(MM)	(MM)	(MW)	(MM)	(MW)	(MM)	(MM)	(MM)	(MM)	(MW)
Historical												
1999	5.8	22.2	11.7	121.0	272	172.5	97.0	95.1	2477	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	119	133 7	26.6	197.6	107.5	99.7	253.6	14.0	180.2	82 1
2004	63	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	67	24.3	12.0	141.4	294	222.0	115.5	107.4	278.3	14.9	195.4	87.2
2009	68	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	1104	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	72	26.0	12.3	149.2	32.2	249.4	123.6	117.9	302.0	16.2	2098	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	267	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 a	nd City of Nev	ирепту аге 1	not included	l in the forecast.							

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	Forecast of Wi	Table 1D.4-5 nter 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	89	1,136								
2008	1,162	9.0	1,153								
2009	1,191	9.0	1,182								
2010	1,215	9.0	1,206								
2011	1,215 9.0 1,206 1,230 9.0 1,221										
2012	1 1,210 9.0 1,200 1 1,230 9.0 1,221 2 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 in Fort Meade	cludes addition of I e beginning 2009.	Lake Worth beginning Jan	uary of 2002 and								
The Town	of Havana and City	of Newberry are not incl	uded in the forecast.								

For	ecast of Summer and Wi	Table 1D.4-6 nter Peak Demand witl	h 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 Meade be The Tow	includes addition of Lak eginning 2009. n of Havana and Citv of	e Worth beginning Jan	uary of 2001 and Fort uded in the forecast.

Forec	cast of Summer and W	Table 1D.4-7 inter 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 in Meade beg The Town	icludes addition of Lak ginning 2009. of Havana and City of	te Worth beginning January for Newberry are not inclu	uary of 2002 and Fort

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 costeffectiveness. 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 costeffectiveness 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 costeffective. 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.

FI	Table 1D.5-1 RE Model Resu	ılts	
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:

System Net Capacity – System Net Peak Demand 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.

System Net Capacity – System Net Peak Demand System Net Peak Demand – 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.

1D.6.0 Reliability Criteria

Stanton Energy Center Combined Cycle A Need for Power Application

											_													
	t) to Maintain 15%	A fter Internintible	and Load	Management (MW)	133.9	59.4	148.0	135.3	66.1	49.9	63.3	20.6	-85.2	-118.6	-146.2	-315.2	-332.4	-347.4	-362.3	-377.3	-389.9	-402.6	-415.2	-425.6
	Excess/(Defici	Before Internintible	and Load	Management (MW)	126.1	51.1	139.2	126.2	56.7	40.1	53.3	10.4	-95.6	-128.9	-156.5	-325.5	-342.8	-357.7	-372.7	-387.6	-400.3	-412.9	-425.6	-435.9
0	: Margin	After Intermintible	and Load	Management (%)	31.7	21.4	30.3	29.6	22.0	20.3	21.3	17.0	7.3	4.6	2.4	-10.8	-11.9	-12.8	-13.7	-14.6	-15.3	-16.0	-16.7	-17.3
tter/Base Case	Reserve	Before	and Load	Management (%)	30.6	20.4	29.3	28.5	20.9	19.2	20.3	16.0	6.4	3.8	1.6	-11.5	-12.5	-13.4	-14.3	-15.2	-15.9	-16.6	-17.3	-17.9
ble 1D.6-1 / Levels - Wii	ak Demand	After Intermintible	and Load	Management (MW)	929.0	1,019.0	1,039.0	1,060.0	1,081.0	1,101.0	1,118.0	1,136.0	1,153.0	1,182.0	1,206.0	1,221.0	1,236.0	1,249.0	1,262.0	1,275.0	1,286.0	1,297.0	1,308.0	1,317.0
Ta Projected Reliabilit	System Pe	Before	and Load	Management (MW)	935.8	1,026.2	1,046.6	1,067.9	1,089.2	1,109.5	1,126.7	1,144.9	1,162.0	1,191.0	1,215.0	1,230.0	1,245.0	1,258.0	1,271.0	1,284.0	1,295.0	1,306.0	1,317.0	1,326.0
		Vet	System	Capacity (MW)	1,183.5	1,218.5	1,332.0	1,334.0	1,289.0	1,292.0	1,331.0	1,309.0	1,234.0	1,234.0	1,234.0	1,089.0	1,089.0	1,089.0	1,089.0	1,089.0	1,089.0	1,089.0	1,089.0	1,089.0
		Net	System	Sales (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Net System	Purchases That	Contain	Reserve Margin	125.0	85.0	72.0	135.0	135.0	160.0	120.0	120.0	45.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Net	System	Purchases (MW)	656.9	731.9	709.9	648.9	603.9	581.9	560.9	538.9	538.9	538.9	538.9	438.9	438.9	438.9	438.9	438.9	438.9	438.9	438.9	438.9
		Net	Generating	Capacity (MW)	401.6	401.6	550.1	550.1	550.1	550.1	650.1	650.1	650.1	650.1	650.1	650.1	650.1	650.1	650.1	650.1	650.1	650.1	650.1	650.1
				Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019

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1D.6.0 Reliability Criteria

										-
				System Pea	k Demand	Reserve	Margin	Excess/(Defic	it) to Maintain 18%	
Vet Syst	tem	Net	Net N	Before	After Internintible	Before	After Internintible	Before Internatible		· · · · ·
That Coi	ntain	System	System	and Load	and Load	and Load	and Load	and Load	After Interruptible	
keserve Aargin		Sales (MW)	Capacity (MW)	Management (MW)	Management (MW)	Management (%)	Management (%)	Management (MW)	and Load Management (MW)	
125	0.	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8	
85.	0	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	9.4	14.4	
147	0.	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3	
135	0.	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	-44.3	-38.8	
135	0	0.0	1,238.3	1,167.8	1,163.0	6.8	7.3	-115.4	-109.7	
160.	0	0.0	1,341.3	1,189.0	1,184.0	14.8	15.4	-32.9	-27.0	
120.	0	0.0	1,280.3	1,209.1	1,204.0	6.5	7.0	-124.8	-118.8	
120	0.	0.0	1,258.3	1,228.2	1,223.0	2.7	3.2	-169.4	-163.2	
45	0	0.0	1,183.3	1,246.3	1,241.0	-5.2	-4.8	-279.2	-273.0	
45.	0	0.0	1,183.3	1,273.3	1,268.0	-7.3	-6.9	-311.1	-304.8	
45	0.	0.0	1,183.3	1,290.0	1,285.0	-8.6	-8.2	-330.8	-324.9	
0	0.	0.0	1,038.3	1,306.0	1,301.0	-20.5	-20.2	-502.8	-496.9	
0	0.	0.0	1,038.3	1,322.0	1,317.0	-21.5	-21.2	-521.7	-515.8	
0	.0	0.0	1,038.3	1,336.0	1,331.0	-22.3	-22.0	-538.2	-532.3	
Ŭ).0	0.0	1,038.3	1,350.0	1,345.0	-23.1	-22.8	-554.7	-548.8	
	0.0	0.0	1,038.3	1,363.0	1,358.0	-23.8	-23.5	-570.0	-564.1	
-	0.0	0.0	1,038.3	1,376.0	1,371.0	-24.5	-24.3	-585.4	-579.5	
	0.0	0.0	1,038.3	1,387.0	1,382.0	-25.1	-24.9	-598.4	-592.5	
	0.0	0.0	1,038.3	1,398.0	1,393.0	-25.7	-25.5	-611.3	-605.4	
	0.0	0.0	1,038.3	1,408.0	1,403.0	-26.3	-26.0	-623.1	-617.2	1

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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.

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	Summar	y of FMPA (Generation	Table 1D Alternati	7-1 ves (2000 \$), unless oth	erwise note	(p:	
			O&M	Costs		Full Load	Forced		
	Capital	-				Heat Rate	Outage	Scheduled	First Year
Description	Costs	Capacity ¹	Variable	Fixed	Fuel Type	(HHV) ¹	Rate	Maintenance	Available
	\$1,000	MM	\$/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			Nat. Gas		4.0		2003 ⁵
7FA 2x1 CC (joint development)4	21			Nat. Gas			14	2003 ⁵
1. At 70 – 72° F 2. Mixed year di 3. (2003 \$)	, depending on ollars to reflect	the generation commercial of	alternative (a	after degrad of October	lation). 1, 2003.				

Reflects FMPA's portion of total generation alternative capacity. October 1, 2003. 4. %

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		
Vear	Expansion Plan	Annuał Costs (\$1000)	Cumulative Present Worth (\$1000)
2000		110.813	(\$1000)
2000		117,015	250 207
2001		156 804	398 762
2002	21 MW Joint Development with Southern Florida (10/03)	150,804	598,702
2005	40 MW Southern-Florida Power Purchase (10/03)	162 496	535 107
2004	40 WW Southern-Fronda Fower Fulchase (10/05)	162,490	664 276
2004		163 010	786 766
2005	257 MW WH 501F 2v1 Combined Cycle (06/06)	176 530	911 213
2000	237 MW WITSON 2XI Combined Cycle (00/00)	186 719	1 035 392
2007		201 339	1 161 715
2008	257 MW WH 501F 2x1 Combined Cycle (06/09)	214 359	1 788 594
2009	237 NIW WITSOIT 2XI Combined Cycle (00/07)	217,557	1,200,394
2010		236 388	1,415,710
2011		249 955	1,540,242
2012	Terminate 40 MW Southern-Florida Power Purchase (11/13)	258 513	1,004,402
2013	156 MW GE 7FA Simple Cycle (06/14)	273 844	1 906 784
2014		286 895	2.026 495
2015		300 114	2 144 634
2010		312 764	2,177,004
2017	i de la construcción de la constru	327 658	2,200,705
2010		343 844	2,575,570
2017	Connectivie stated at average annual temperature for EMDA	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	2,707,221
Note: C	apacity is stated at average annual temperature for FMPA.		

ycle Unit A	
Combined C tion	
ergy Center (wer Applica	
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1D.7.0 Economic Analysis

	cit) to Maintain Margin (MW)	After	Interruptible & Load	Management	29.8	14.4	62.3	-38.8	-50.3	32.4	181.6	137.2	27.5	236.6	216.6	44.6	25.7	9.2	94.0	78.7	63.3	50.4	37.4	25.6
e 1D.7-2	Excess / (Defic 18 % Reserve	Before	Interruptible & Load	Management	25.1	9.4	57.0	-44.3	-55.9	26.5	175.6	131.1	21.2	230.4	210.7	38.7	19.8	3.3	88.1	72.8	57.4	44.5	31.5	19.7
ntified in Tabl	ırgin (MW)	After	Interruptible & Load	Management	21.4	19.5	24.4	14.1	13.1	21.2	34.8	30.4	20.3	37.3	35.5	21.4	20.0	18.7	25.0	23.8	22.6	21.6	20.7	19.8
nsion Plan Ide	Reserve Ma	Before	Interruptible & Load	Management	20.9	19.0	23.8	13.6	12.6	20.6	34.1	29.8	19.8	36.8	34.9	21.0	19.5	18.2	24.5	23.3	22.2	21.2	20.3	19.4
: 1D.7-3 se with Expar	Demand (MW)	After	Interruptible & Load	Management	992.0	1,020.2	1,119.0	1,141.0	1,163.0	1,184.0	1,204.0	1,223.0	1,241.0	1,268.0	1,285.0	1,301.0	1,317.0	1,331.0	1,345.0	1,358.0	1,371.0	1,382.0	1,393.0	1,403.0
Table 1mer/Base Ca	System Peak I	Before	Interruptible & Load	Management	0.966	1,024.4	1,123.5	1,145.7	1,167.8	1,189.0	1,209.1	1,228.2	1,246.3	1,273.3	1,290.0	1,306.0	1,322.0	1,336.0	1,350.0	1,363.0	1,376.0	1,387.0	1,398.0	1,408.0
vels – Sun		Net	System Capacity	(MM)	1,177.9	1,202.9	1,356.3	1,283.3	1,297.8	1,400.8	1,580.8	1,558.8	1,483.8	1,724.8	1,724.8	1,579.8	1,579.8	1,579.8	1,681.1	1,681.1	1,681.1	1,681.1	1,681.1	1,681.1
iability Le		Net	System Sales	(MM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ojected Rel		Net	System Purchases	(MM)	6.279	620.9	683.8	622.8	616.5	594.5	573.5	551.5	551.5	551.5	551.5	451.5	451.5	451.5	412.8	412.8	412.8	412.8	412.8	412.8
Ρŗ		Net .	Generating Capacity	(MM)	377.0	497.0	525.5	525.5	546.3	646.3	887.3	887.3	887.3	1,128.3	1,128.3	1,128.3	1,128.3	1,128.3	1,268.3	1,268.3	1,268.3	1,268.3	1,268.3	1,268.3
				Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019

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	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: Ca	pacity 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.

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

	Table 1D.8-2	- • •	N1
	FMPA High Fuel Price Escalation Runner Up I	Expansion I	lan
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 Expan	ision 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: C	apacity is stated at average annual temperature for FMPA.		

	Table 1D.8-4		
	FMPA Low Fuel Price Escalation Runner-Up	Expansion P	lan
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: C	Capacity is stated at average annual temperature for FMPA.	ma ⁿ al da <u>ano</u> tico da la compositione de la compo	

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

	Table 1D.8-6	Evenneion	Dlan
	rmrA AEO ruei rnce riojection Rumer-Op	Expansion	rian
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: C	Capacity is stated at average annual temperature for FMPA.		

	Table 1D.8-7		
	OUC 2000 + 2001 AEO Escalation Fuel Price Projec	tion Expans	sion 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: C	Capacity is stated at average annual temperature for FMPA.		

	Table 1D.8-9 OLIC Constant 2000 Fuel Price Projection Fy	nansion Pla	'n
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		at an Dian
0	UC Constant 2000 Fuel Price Projection Runne	r-Op Expan	ISION 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: C	apacity is stated at average annual temperature for FMPA.		

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1D.8.0 Sensitivity Analysis

		FMPA S	Summer Re	serve Requ	Table 1D irements - H).8-11 ligh Load an	d Energy Gro	wth 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	(17.6)
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	(1.066)
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)

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	Table 1D.8-12		
	FMPA High Load and Energy Growth Exp	pansion 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: C	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: C	Capacity is stated at average annual temperature for FMPA.		

Stanton Energy Center Combined Cycle Unit A Need for Power Application

1D.8.0 Sensitivity Analysis

		FMPA S	Jummer Re	serve Requ	Table 1D irements - L	.8-14 ow Load and	1 Energy Grov	vth 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	929.6	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)

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1	Table 1D.8-15		
	FMPA Low Load and Energy Growth Expa	ansion 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: C	Capacity is stated at average annual temperature for FMPA.		

	Table 1D.8-16 FMPA Low Load and Energy Growth Runner-U	Jp Expansior	n 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: C	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 Mu	nicipal F	ower Age	sncy						
Case							Economic		
Scenario Souther	n-Florida FMF	A Base					CPW Discoun Capital Escala Base Year for	it Rate ttion Rate \$	6 0% 2 5% 2000
Generation Additio	SU								
		2000	Construction	Year	Installed	Levelized	Finance		
Unit	Size (MW)	Capital Cost (\$1,000)	Period (months)	Installed (year)	Cost (\$1,000)	Cost (\$1,000)	Fixed Charge	Rate	*8 60%
Southern WH 501F 2x1 WH 501F 2x1 GE 7FA SC	257 257 257	129,241 129,241 76,681	22 24 24	2003 833 2006 417 2009 417 2014 417	156,602 168,643 111 323	13,471 14,507 9,576	Interest Durin Finance Term Plant Life	g Const (yrs)	6% 30 30
	-		2		070 ⁻				
	Fuel and				Total	Total	Total	Cumulative Present Worth	
Year	Cost ¹	Variable	Fixed ²	Credits ³	Cost	Cost	Cost	Cost	
	(\$1,000)	(\$1,000)	(\$1,000)	(\$1000)	(\$1,000)	(\$1,000)	(\$1,000)	(\$1,000)	
2000	114,059	5,754	0	0	119,813	0 (119,813	119,813	
2001 COOC	137,695 1 4 4 902	10,062			14/,/5/ 156,804		15/,/21 156,804	398.762	
2003	148,867	12,646	807	(30)	162,290	206 206	162,496	535, 197	
2004	145,360	13,691	3,203	(119)	162,135	825	162,960	664,276 706 766	
2005	145,203 146 361	14,805 17,372	3,205	(9LT) (120)	163,094 167,847	623 8,683	176,530	911,213	
2007	148,601	18,940	5,004	(120)	172,423	14,296	186,719	1,035,392	
2008	160,600 162 750	21,513 22,768	5,052 6.205	(121) (122)	191,043 191,601	14,296 22,758	214,359 214,359	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 7,784	(123)	207, 152	28,803	230,388 249,955	1,040,242	
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 28,379	286,895	2.026.495	
2015	237,751	31,149	5,611 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	2,469,221 1	
Notes * FMPA assun	ned to finance	the Southern-Flu	orida project at a	6 02 percent rat	<u>a</u>				
I Includes star	t-up costs								
Fixed costs a	rre included or	nly for new units							-
³ Includes fees	tor site lease	as well as credit	for services and	cooling water					

Florida Mu	nicipal F	ower Age	ency						
Case							Economic		
Scenario Self Bu	ld FMPA Bas	ω					CPW Discour Capital Escal Base Year for	it Rate ation Rate \$	6 0% 2 5% 2000
Generation Additio	S								
Lunt	Size	2000 Capital Cost (\$1.000)	Construction Period (months)	Year Installed (vear)	Installed Cost (\$1.000)	Levelized Cost (\$1.000)	Finance Fixed Charge	Rate	8 60%
Self Build WH 501F 2x1 WH 501F 1x1 WH 501F 1x1		73,984 73,984	5 33 54	2003 833 2006 417 2009 417 2009 417 2011 417	31,458 156,602 96,404 101,285	2,706 13,471 8,293 8,713 46,013	Interest Durin Finance Ter n Plant Life	g Const I (yrs)	6% 30 30
	Fuel and Fnerov		τ ₂	Fees and	Total Production	Total Capital	Total Svstem	Cumulative Present Worth	
Year	Cost ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
2000	114,059	5,754	0	0	119,813	0	119,813	119,813	
2001	137,695	10,062	00	00	147,757 156,804	00	147,757 156,804	259,207 398.762	
2003	148,900	12,646	325	, 6 !	161,884	677 677	162,560	535,250	
2005	145,503 145,386	13,669 14,783	333 341	ខ	159,556 160,562	2,706	162, 268 163, 268	785,780	
2006	146,599	17,365	1,375	54 74	165,393 160 047	10,564	175,957 186 119	909,823 1 033 603	
2008	148,738 160,852	21,510	2,204	21 22	184,623	16,177	200,800	1, 159, 587	
2009	168,106 176 356	22,179	2,687 3 063	58 59	193,030 202,599	21,014 24,470	214,044 227,069	1,286,279	
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 24	230,533	33, 182 40 503	263,715 777 EE7	1,6/2,02/	
2013	197,724 204 330	26,935 28,096	5,321 6,336	66 66	230,044 238,827	42, 323 49, 195	212,307 288,022	1 927,209	
2015	212,092	29,040	6 494	67	247,693	49,195	296,887	2,051,090	
2016 2015	223,656 232 788	30,283 31 198	6,656 6,873	69 71	260,665 270,880	49, 195 49, 195	309,859 320.074	2,1/3,065	
2018	244,680	32,336	6,993	22	284,082	49, 195 40, 195	333,276 346 471	2,408,690	
Notes	700'007		001 1	t	100	221121	311010	1 121 1242 14	
¹ Includes star	t-up costs								
² Fixed costs a ³ Individue france	re included of	nly for new units	+ for conjege ar	nd modulor water					
Includes lees	TOL SILE IEASE	as well as circui	ו וחו מבוגורכס מי	IN COULD WARK					

Clear Control	Florida Mu	nicipal F	ower Age	incy						
Secretario Southenn-Florida Fuld Cervy Ubscount False 6 0% Centralition Additions. 25.3% 25.3% 25.9%	Case							Economic		
Generation Additions Construction Versite Final rest Final rest Final rest Final rest Final rest Final rest Page Page 960% Southern 21 2000 Installed Cost Cost 651 950% Southern 21 22241 24 2009 151,000	Scenario Souther	n-Florida FMF	A High Fuel					CPW Discour Capital Escala Base Year for	tt Rate ation Rate \$	6 0% 2 5% 2000
Unt Sae 2000 Construction Year Construction Network Construction Network Solution Sol	Generation Additio	SU SU					-			
Southerm (MN) (\$1000) (Imorths) (\$1000) (Imorths) (\$1000) (\$100) (\$100) (\$100) (\$100) (\$100) (\$100) (\$100) (\$100) (\$100) (\$100) (\$1000) (\$1000) (\$1000) (\$1000) (\$1000) (\$1000	Unit	Size	2000 Capital Cost	Construction Period	Year Installed	Instailed Cost	Levelized Cost	Finance		
Fuel and brengy Fuel and cost Total Free multiple Total Free multiple Total Free multiple Total Free multiple Cumulative Free multiple Year Energy Energy Oak Total Front Free multiple Present Year Energy Energy Cost Cost Cost Cost Cost Cost 2000 114,059 5,754 0 148,641 Cost Cost<	Southern WH 501F 2x1 WH 501F 2x1 Pulverized Coal		(\$1,000) 1 129,241 7 129,241 3 256,581	24 24 24 42	[(year) 2003 833 2006 417 2009 417 2014 417 2014 417	(\$1,000) 156,602 168,643 388,463	1(\$1,000) 13,471 14,507 33,416	Fixed Charge Interest Durin Finance Term Plant Life	Rate g Const (yrs)	*8 60% 6% 30 30
Year Cost (\$1,000) Fixed 2 (\$1,000) Cost (\$1,000) Cost (\$1,000)<		Fuel and Fnerrov	Ĉ	2	Lees and Fee	Total Production	Total Canital	Total Svstem	Cumulative Present Worth	
2000 114,059 5,754 0 0 119,813 0 119,813 260,040 0 148,641 260,040 0 148,641 260,040 0 148,641 260,040 0 148,641 260,040 0 148,641 260,040 0 148,641 260,040 0 148,641 260,040 0 148,641 260,040 0 148,641 260,040 0 148,255 188,663 3207 1073,755 2005 143,265 143,265 143,265 143,265 143,265 143,265 143,265 143,265 143,265 144,374 1221,063 144,374 1221,063 144,374 1221,063 144,374 1221,063 2013,1712 1212,063 226,	Year	Cost ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
2002 146,935 11,892 0 158,828 401,396 2003 149,567 12,513 907 (30) 162,857 206 163,053 583,307 2003 159,569 17,243 4,234 (19) 168,157 206 163,053 533,307 2005 159,569 17,243 4,234 (120) 167,157 825 168,608 393,286 2006 159,569 17,243 4,234 (120) 179,925 8,633 188,608 393,286 2007 164,255 18,818 5,004 (120) 187,375 206,311 14,296 202,357 1,210,053 2008 167,336 21,755 5,004 (120) 187,375 206,311 1,41296 203,351 1,497,217 2010 197,445 23,971 7,081 (122) 216,383 203,351 1,497,217 2011 217 201 172,32 244,850 28,803 309,331 1,930,667	2000	114,059 138,579	5,754 10.062	ф O	00	119,813 148,641	00	119,813 148,641	119,813 260,040	
2003 143,56/ 12,513 90/ (30) 163,127 825 163,952 672,133 2004 151,486 15,364 3,203 (119) 163,127 825 163,952 603,326 2005 159,568 17,243 4,234 (120) 178,753 825 179,579 806,326 2007 164,255 18,818 5,004 (120) 178,753 825 179,579 806,326 2008 179,396 21,755 5,004 (120) 178,753 825 1,073,795 2009 187,372 22,997 7,061 (122) 206,081 1,42,965 203,5610 2010 197,445 23,971 7,061 (122) 226,387 1,4374 355,610 2011 211,641,374 (122) 214,560 233,142 1,4374 355,610 2011 217,121 217,161 (122) 216,633 220,331 1,497,217 2012 221,183 327,102 7,281 (124) 236,610 233,6160 2013 245,788 27,143	2002	146,935	11,892	0	0	158,828	0 000	158,828	401,396	
2005 159,368 16,300 3,205 (119) 178,753 825 179,579 806,335 2006 158,569 17,243 4,234 (120) 179,925 8,683 186,00 393,266 2007 164,255 5,024 (120) 179,925 8,683 187,377 1,272,033 2008 179 336 17,243 4,234 (120) 187,956 1,42265 5,023 1,073,765 2009 187,372 22,971 7,081 (122) 216,383 22,756 239,142 1,353,610 2011 211,809 25,992 7,181 (122) 226,393 1,947,374 2012 221,721 27,010 7,284 (123) 261,803 290,694 1,497,217 2013 244,903 21,144 9,302 (124) 281,056 2,076,805 2,076,805 2014 244,903 23,144 9,302 (126) 331,142 1,393,610 366,666 2015 244,9	2003	149,567 151,495	12,513	807 3,203	(30) (119)	162,857 168,127	206	163,063 168,952	538,3U/ 672,133	
2000 164,255 18,818 5,004 (120) 17,325 1,210,053 1,211,013 220,137 1,212,053 1,641,374 1,210,053 221,137 1,212,053 1,641,374 1,212,053 1,641,374 1,212,053 1,641,374 1,212,053 1,641,374 1,212,053 1,641,374 1,212,053 1,641,374 1,213,053 1,641,374 1,212,053 1,641,374 1,212,053 1,641,374 1,213,053 1,641,374 1,212,053 1,641,374 1,212,053 1,641,374 1,212,053 2,218,840 2,216,840 2,216,840 2,216,840 2,216,840 2,216,840 2,216,840 2,216,840 2,216,840	2005	159,368 159,568	16,300	3,205	(119)	178,753	825 B 683	179,579 188 608	806,325 939,786	
2008 173,396 21,755 5,052 (121) 206,081 14,296 220,377 1,212,063 2009 187,372 22,929 6,205 (122) 216,383 227,758 1,937,417 1,930,467 2,948,63 2,948,53 1,930,467 2,946 2,236,940 1,930,467 2,946 2,233,34 2,113 2,495,93 2,016,93 2,309,331 1,930,467 2,309,331 1,930,467 2,309,331 1,930,467 2,309,331 1,930,467 2,309,331 1,930,467 2,309,331 1,930,467 2,309,332 2,016,933 2,016,933 2,016,933 2,016,933 2,016,933 2,016,933 2,016,933 2,016,943 2,306,935 2,216,9405 2,306,956	2002	158,255 164,255	18,818	5,004	(120)	187,956	0,000 14,296	202,252	1,073,795	
2010 197,445 23,971 7,081 (122) 228,375 28,803 257,178 1,497,217 2011 211,809 25,982 7,181 (122) 228,375 28,803 257,178 1,497,217 2012 227,721 27,010 7,284 (123) 261,891 28,003 31,641,374 2013 244,903 25,982 7,181 (124) 280,559 28,803 309,331 1,930,667 2014 244,903 23,144 9,302 (124) 281,656 48,296 329,953 2076,805 2015 250,030 31,144 9,302 (124) 281,656 42,296 239,930 2076,805 2016 266,559 32,304 9,773 (125) 309,351 (126) 320,956 253,320 2076,805 2017 281,039 33,304 9,773 (126) 329,466 62,218 307,0578 2,339,260 2018 301,283 3450 62,218 407,095 2,566,176 2,13,260 2019 332,457 35,289 62,218 40	2008	179,396	21,755	5,052 6.205	(121) (122)	206,081 216.383	14,296 22.758	220,377 239,142	1,212,063 1,353,610	
2011 211,809 25,982 7,181 (123) 244,850 29,005 1,641,3/4 2012 227,721 27,010 7,284 (123) 261,891 29,0594 1,765,840 2013 245,678 27,010 7,284 (123) 261,891 29,0534 1,765,840 2013 245,678 27,010 7,145 (124) 281,658 48,295 2,076,805 2015 250,030 31,144 9,302 (125) 290,351 62,218 370,678 5 2017 281,030 31,144 9,302 (126) 323,989 62,218 370,678 2566,505 2533,320 2017 281,030 33,104 9,773 (126) 323,989 62,218 370,678 2566,176 2019 332,457 35,30 10,017 (127) 345,712 62,218 440,095 2661,163 2019 332,457 35,208 10,017 (129) 377,877 62,218 440,095 2601,633 2019 332,457 35,208 10,017 (129) 377,877	2010	197,445	23,971	7,081	(122)	228,375	28,803	257,178	1,497,217	
2013 245,678 27,902 6,673 (124) 280,529 28,803 309,331 1,930,867 2014 244,903 29,734 7,145 (124) 281,656 48,295 329,953 2,076,805 2015 256,030 31,144 9,302 (125) 290,351 62,218 332,959 2,205,835 2016 256,659 33,304 9,534 (126) 304,460 62,218 332,656 2,563,336 2017 281,039 33,304 9,773 (126) 304,460 62,218 336,568 2,566,476 2019 301,283 301,283 10,017 (127) 345,712 62,218 367,058 2,566,476 2019 332,457 35,280 10,017 (127) 345,712 62,218 407,930 2,656,476 Notes * * FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate *	2011	211,809 227 721	25,982	7,181 7 284	(123)	244,850 261,891	28,803	2/3,653	1,641,374	
2014 244.903 29,734 7,145 (124) 281,656 48,285 329,953 2,016 260,030 31,144 9,302 (125) 290,351 62,218 375,669 2,223,920 2016 266,659 32,333 9,302 (125) 290,351 62,218 376,678 2,369,836 2017 281,039 33,304 9,534 (126) 323,989 62,218 370,678 2,369,836 2019 301,283 34,538 10,017 (127) 345,712 62,218 366,209 2,513,260 2019 332,457 35,280 10,017 (129) 377,877 62,218 407,930 2,656,176 2019 332,457 35,280 10,017 (129) 377,877 62,218 407,995 2,601,633 Notes - - FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate - 10,017 62,218 407,095 2,601,633 1noludes start-up costs - - 802 percent rate - - - - - - - - -	2013	245,878	27,902	6,873	(124)	280,529	28,803	309,331	1,930,867	
2016 266,659 32,393 9,534 (126) 308,460 62,218 370,678 2,369,336 2017 281,039 33,304 9,773 (126) 323,989 62,218 370,678 2,359,336 2018 301,283 34,538 10,017 (127) 345,712 62,218 36,208 2,513,260 2019 301,283 34,538 10,017 (127) 345,712 62,218 407,930 2,666,176 2019 332,457 35,280 10,017 (128) 377,877 62,218 440,095 2,601,633 Notes 12,819 377,877 62,218 440,095 2,601,633 Notes 12,817 62,218 440,095 2,601,633 Notes 12,877 62,218 440,095 2,601,633 Notes 802 percent rate 1,100,065 2,601,633 * FMPA assumed to fina	2014	244,903 250 030	31 144	7,145	(124)	281,658 290 351	48,295 62.218	329,953 352,569	2,0/6,805	
2017 281,039 33,304 9,773 (126) 323,989 62,218 36,208 2,513,260 2018 301,233 34,538 10,017 (127) 345,712 62,218 407,930 2,666,176 2019 332,457 35,280 10,017 (127) 345,712 62,218 407,930 2,666,176 Notes Notes (128) 377,877 62,218 440,095 2,601,633 Notes Includes start-up costs (10,016 2,101 632 2,601,633 * FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate 1 1 10,095 2,601,633 * Includes start-up costs * Includes fees for site lease as well as credit for services and cooling water 3 1 1 1	2016	266,659	32,393	9,534	(126)	308,460	62,218	370,678	2,369,836	
2018 301,283 34,57 345,77 54,77 54,712 54,712 54,719 510,1633 Notes 332,457 35,280 10,268 (128) 377,877 62,218 440,095 2,601,633 Notes • FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate • 1 includes start-up costs * 1 includes start-up costs * 1 includes start-up costs * 1 includes fees for site lease as well as credit for services and cooling water * 1 includes fees for site lease as well as credit for services and cooling water	2017	281,039	33,304	6'173	(126)	323,989	62,218	386,208	2,513,260	
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	2018 2019	301,283 332,457	54,538 55,280	10,017 10,268	(127) (128)	345,712 377,877	62,218 62,218	407,930 440,095	2,801,633	
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	Notes * FMPA assum	ned to finance	the Southern-Flo	vrida project at a	8 02 percent rat	Ð				
² Fixed costs are included only for new units ³ Includes fees for site lease as well as credit for services and cooling water	¹ Includes start	t-up costs		-	-					
³ Includes fees for site lease as well as credit for services and cooling water	² Fixed costs a	re included or	Ny for new units							
	Includes fees	tor site lease	as well as credit	for services and	cooling water					

Florida Mu	nicinal F	ower Age	ncv						
Case							Economic		
Scenario Self Bu	id FMPA High	Fuel					CPW Discour Capital Escala Base Year for	it Rate ation Rate ⋅\$	6 0% 2 5% 2000
Generation Additic	sus								
							Finance		
Cart	Size (MVV)	2000 Capital Cost (\$1,000)	Construction Period (months)	Year Installed (year)	Installed Cost (\$1,000)	Levelized Cost (\$1,000)	Fixed Charge	Rate	8 60%
Self Build WH 501F 2x1	22 251 01	129,241	24	2003 833 2006 417	31,458 156,602	2,706 13,471	Interest Durin Finance Term	ig Const i (yrs)	6% 20%
WH 501F 1X1 GE 7FA SC Pulvenzed Coal	156	76,681 256,581	42 42 42	2015 417 2015 417 2015 417	96,404 103,374 398,174	8,253 8,892 34,251			00
	Fuel and				Total	Total	Total	Cumulative Present	
	Energy	õ	βM	Fees and	Production	Capital	System	Worth	
Year	Cost ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cast (\$1,000)	Cost (\$1,000)	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	D	148,641	260,040	
2002	146,935	11,892	0 0	οţ	158,828 162 ABA	0 677	158,828 163 160	401,396 538 380	
2002	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 6,004	54 74	177,467 185 EDE	10,564 16,477	188,031 201 683	937,967	
2008	179,662	21.755	5,052	51 22	203,678	16, 177	219,855	1,210,037	
2009	192,940	22,928	6,205	58	217,987 231,080	21,014	239,001 256,449	1,351,501 1 AGA 701	
2011	226.607	25,982	7,181	619	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 22 252	323,703 244 760	1,948,699	
2015	219,412 269,717	31 144	0,145	60 67	306 407	53,342	359.749	2, 100,909 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 2019	310,762 329,909	34,538 35,280	10,017 10,268	72	354,130 374,580	67,613 67,613	421,743 442,193	2,697,949 2,844,100	
Notes									
Includes star	t-up costs	•							
Fixed costs a	re included of	nly for new units							
' includes tees	for site lease	e as well as credi	t for services ar	d cooling water					

						ĩ			
ase							Economic DPW Discount	t Rate	6 0%
Scenario Southern	ı-Florida FMP∕	A Low Fuel					Capital Escala Base Year for	s S	2 5%
Generation Addition	S								
Unit	Size	2000 Capital Cost	Construction Period	Year Installed	Installed Cost	Levelized Cost	Fixed Charge	Rate	•B 60%
Southern WH 501F 2x1 WH 501F 2x1 WH 501F 1x1	(MW) 21 257 125 125	((\$1,000) 129,241 73,984 73,984	24 23 23 23	2003 833 2003 833 2006 417 2009 417 2014 417 2019 417	156,602 168,643 109,072 123,406	13,471 14,507 9,382 10,615	Interest Durin Finance Term Plant Life	g Const (vrs)	6% 20 30
	Fuel and			Fees and	Total Production	Total Capital	Total System	Cumulative Present Worth	
Year	Cost ¹ (\$1 000)	Variable (\$1.000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
	10001101			c	110 013	C	119.813	119,813	
2000	114,059	5,754	00	. 0	146,933	0	146,933	258,429	
2001	136,867	12.291	0	0	154,364	0	154,364	395,813	
2003	143,859	12,753	807	(30)) 157,389	206 825	157 038	652,521	
2004	139,125	14,004	3,203	1901	159,879	825	160,704	772,609	
2005	140,441	17,785	4,234	(120	156,338	8,683	165,021	888,942	
2002	133,658	19,48	5,004	(120) 158,022	14,296	1/2/310	117,198	
2008	140,544	21,37	5,052	121)	169,779	22,758	192,538	1,231,160	
2009	141,179	22,51	7.081	(122	173,918	28,803	202,721	1,344,359	
2010	144,983	25,421	7 181	(123	() 177,470	28,803	206,273 216,426	1,453,021	
2012	154,206	3 26,25	7 7,284	(123	3) 187,623	28,6UG	219,249	1,663,370	
2013	156,427	7 27,27	1 6,8/0	3 (124 124	4) 194,605 4) 194,605	34,276	228,885	1,764,606	
2014	161,885	17, 90 28,12 28,12	1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	(125	5) 199,355	38,185	5 237,544	1,863,725	
2015	170.666	30.07	2 5,49(9 (126	5) 206,112	38,185	5 244,297	1,959,892	
2012	174,496	30,80	8 5,63	7 (12)	6) 210,816	38,185	248,001	2,142,256	
2018	180,77	4 31,97 a 32,36	7 5,77. 1 6.46	9 (12) 9 (12)	 218,40. 228,800 	0 44,377	273,177	2,232,545	
Votes * FMPA assu	med to finance	e the Southern-F	Florida project at	a 8 02 percent r	rate				
¹ Includes sta	irt-up costs								
² Fixed costs	are included c	only for new unit: a served as cred	s lit for services af	nd cooling water					
' includes fee	is for site lease	a as well as clev							

Florida Mun	icipal P	ower Agei	ncy						
							conomic		
Case Scenario Self Build	I FMPA Low I	Fuel					CPW Discount Capital Escalat Base Year for \$	Rate Ion Rate	6 0% 2 5% 2000
Generation Addition	2								
Unit	Size	2000 Capital Cost	Construction Period	Year Installed (vear)	Installed Cost (\$1,000)	Levelized Cost (\$1,000)	Fixed Charge [Rate	8 60%
Self Build WH 501F 2x1	61 257	129,241	24	2003 833 2006 417	31,458 156,602 06,404	2,706 13,471 8,203	Interest During Finance Term Plant Life	l Const (yrs)	30 0 % 30 0 %
WH 501F 1x1 WH 501F 1x1 WH 501F 2x1	125 125 257	73,984 73,984 73,984	23 23 24	2013 417 2013 417 2013 417	90,404 101,285 186,150	8,713 16,013	3		
	Fuel and	C	2	Fees and	Total Production	Total Capital	Total System	Cumulative Present Worth	
Year	Cost ¹ (\$1 000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cast (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
	1-1-1-1	5 75A		0	119,813	0	119,813	119,813	
2000	114,00% 136,867	10,066	0	0	146,933	00	146,933 154 364	395,813	
2002	142,073	3 12,291	325	0.6	154,354 156,985	677	157,662	528,189	
2003	143,913	13,979	333	51	153,649	2,706	156,355 160,114	652,037 771.683	
2005	140,66(0 16,354	1.375		153,874	10,564	164,438	887,605	
2007	133,86	19,47	2,15	57	155,544 164,417	16,177	171,721 180,594	1,001,809	
2008	140,77	9 21,37 4 21,78	5 2,68	+ -	170,87	21,014	191,889	1,228,695	
2010	151,02	5 22,49	3,06,	<u>ن</u> بر م	9 176,638	3 24,4/U 3 29,552	211,245	1,452,273	
2011	154,19	C3,85 23,85	1 0.00	0 0 0 0	192,418	33,182	225,600	1,564,390	
2012	149,91	5 27.43	4 6,77	00	184,18	4 42,523	5 226,707 5 233 198	1,573,822	
2014	146,05	4 29,01	3 8,87	u đ	5 184,UU	49,195	5 237,246	1,872,817	
2015	148,91	29,97	2 0.31	, 00 , 00	9 194,22	3 49, 195	243,417	1,968,637	
2010	156,54	32,17	4 9,55	2	1 198,34	0 49,199 70,104	5 24/.030	2,000,002 2,149.637	
2018	162,15 166 00	56 33,03 00 34,17	6 9,79 8 10,03	1 6	4 210,28	8 49 19	259,483	2,235,400	
Notes									
Includes sta	art-up costs	inth for new tint	ţ						
³ Includes fee	are incruded as for site lea	se as well as cre	edit for services	and cooling wate	10				

Control Control <t< th=""><th>Florida Mu</th><th>nicipal]</th><th>Power Ag(</th><th>ency</th><th></th><th></th><th></th><th>Economic</th><th></th><th></th></t<>	Florida Mu	nicipal]	Power Ag(ency				Economic		
Generation Additions Construction Testilied Cost Finance Financ	Scenario Souther	n-Florida FMF	PA AEO				<u> </u>	CPW Discour Capital Escala Base Year for	rt Rate ation Rate \$	6 0% 2 5% 2000
Unit Sze 2000 Construction Treatilied Central Installed Const Installed	Generation Additio	SL								
Dublement 21 256.561 42 2003 353 318.830 71.450 Parates Term (vis) 20 Publement Coal 257 129.241 24 2006 417 158.63 14.507 Parates Term (vis) 20 WH 50/F 2x1 257 129.241 24 2006 417 158.63 14.507 Parates Term (vis) 20 WH 50/F 2x1 257 129.241 24 2006 417 158.650 16.100 16.100 30.00	Luit C	Size (MW)	2000 Capital Cost (\$1,000)	Construction Period (months)	Year Installed (year)	Installed Cost (\$1,000)	Levelized Cost (\$1,000)	Finance Fixed Charge	Rate.	*8 60%
Fuel and Centry Fuel and Centry Cost (1100) Total (51,000) Total (51,000) Total (51,000) Total (51,000) Total (51,000) Cost (51,000) Cost (51,000) <thcost (51,000) Cost (51,000) Co</thcost 	Southern Pulverized Coal WH 501F 2x1 WH 501F 2x1	22 25 25	1 256,581 7 129,241 7 129,241	242 242	2003 833 2006 417 2009 417 2014 417	318,830 168,643 190,804	27,426 14,507 16,413	Interest Durin Finance Term Plant Life	g Const 1 (yrs)	90 0 % 90 %
Year Cost (\$1,000) Fixed 2 (\$1,000) Cost (\$1,000) Cost (\$1,000)<		Fuel and Energy	0		Fees and	Total Production	Total Capital	Total System	Cumulative Present Worth	
2000 101/705 6,268 0 0 107,973 107,901 107,173 107,901 107,173 107,901 107,173 107,901 107,173 107,901 107,173 107,901 107,153 107,901 107,1501 107,901 107,1501 107,901 107,1501 107,901 107,1501 108,916 <td>Year</td> <td>Cost¹ (\$1,000)</td> <td>Variable (\$1,000)</td> <td>Fixed ² (\$1,000)</td> <td>Credits ³ (\$1000)</td> <td>Cost (\$1,000)</td> <td>Cost (\$1,000)</td> <td>Cost (\$1,000)</td> <td>Cost (\$1,000)</td> <td></td>	Year	Cost ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
2001 111,935 10,218 0 122,212 223,257 2002 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 137,446 0 133,143 133,143 13,555 5,543 120,10 135,144 0 133,144 0 133,144 0 133,144 0 133,144 0 133,144 0 133,144 0 133,144 0 133,144 0 133,144 133,143 133,143 134,137 134,137 134,133 134,136 133,144 133,143 132,131 134,133 133,144 134,131 132,131 141,307 134,148 134,503 134,153 134,146 132,147 134,153 134,168<	2000	101,705	5 6,268	0	0	107,973	0	107,973	107,973	
2002 113,364 11,725 60 13,436 200 13,535 66,976 2003 133,364 12,555 60 70 13,436 206 147,902 469,776 2005 153,144 12,555 60 71,010 157,023 556,657 7453 712,175 714,457 724,557 713,477 724,557 713,477 724,557 713,7555 967,579 966,7579 967,769 966,7579 966,7579 966,752 967,761 962,522 967,729 966,767 966,766 <	2001	111,995	5 10,218	00	00	122,212	00	122,212	223,267	
2004 142, B41 13, 486 3, 203 (19) 159, 410 825 160, 235 566 507 2005 150, 963 16, 163 3, 225 (119) 170, 232 86, 507 724, 521 2006 139, 194 20, 155 7, 136 (120) 155, 252 28, 251 191, 503 967, 579 2009 139, 194 22, 638 7, 237 (120) 155, 252 28, 251 191, 503 967, 579 2009 144, 644 22, 646 9, 536 (122) 173, 781 28, 251 191, 503 964, 669 2011 155, 066 27, 652 9, 536 (122) 173, 781 215, 709 193, 1563 2011 155, 066 27, 652 9, 536 (122) 198, 166 196 139, 1563 2011 156, 169 9, 356 (122) 198, 166 1563 166, 116 1533, 200 2011 1661 173, 178, 178 169, 114 42, 758 221, 563 166, 196 1563, 602	2003	125,685 134,364	a 11,762 4 12,555	807	0) (06)	147,696	206	147,902	469,776	
2005 130,963 16,163 5,405 (113) 11,10,222 0.23 113,553 86,869 2006 133,144 18,255 5,453 (120) 156,729 16,833 56,759 56,757 36,767 36,946 36,757 36,946 37,751 36,7707 36,946	2004	142,841	13,486	3,203	(119)	159,410	825	160,235	596,697 704 504	
2007 126,112 20,125 7,136 (120) 153,252 28,251 181,503 967,579 2008 139,184 22,638 7,237 (121) 166,333 221,509 1097,190 1091,296 2009 141,310 23,844 8,456 (122) 173,477 35,173 317,319 216,190 1,216,709 2010 144,644 24,862 9,378 (122) 173,477 35,114 27,563 1,339,416 2011 153,086 26,516 9,535 (122) 198,114 42,758 241,651 261,503 1,461,563 2013 169,499 28,701 9,346 (124) 212,761 42,758 241,652 204,793 501,709 503,416 52,332 264,1563 2047,652 2047,793 501,709 1,916,196 1,215,709 1,217,709 244,552 2047,793 5047,709 5047,709 5047,709 2048 7017 2012 2047,793 5047,709 2047,709 2047 27,758	2005	150,960 133,144	3 16,163 4 18,252	5,453	(118)	156,729	16,823	173,553	846,869	
2006 139,144 22,638 7,237 (122) 173,73 20,190 1,091,590 2009 141,310 22,6384 8,445 (122) 178,782 26,731 210,190 1,291,509 2010 144,644 23,684 8,445 (122) 178,782 42,758 231,872 1,461,563 2011 153,086 26,616 9,535 (123) 199,114 42,758 231,872 1,461,563 2013 161,461 27,652 9,696 (124) 207,427 42,758 231,872 1,461,563 2014 174,766 28,701 9,346 (124) 207,427 42,758 247,633 1,932,902 2016 189,058 32,407 9,346 (124) 207,427 42,758 247,077 2016 189,058 32,407 9,345 (124) 207,437 1,932,902 2017 195,679 33,3556 9,170 29,170 297,937 256,448 2018 199,662 10,017 (126) 230,814 59,170 291,437 2018	2007	126,112	20,125	7,136	(120)	153,252	28,251	181,503	967,579	
2010 144,644 24,882 9,378 (122) 178,782 42,758 221,539 1,339,416 2011 153,086 26,616 9,555 (123) 189,114 42,758 231,852 1,561,552 2013 169,499 23,667 9,346 (123) 198,886 42,758 231,865 1,561,552 2014 174,766 29,326 (123) 199,886 42,758 250,93 1,616,196 2015 189,058 32,407 9,346 (124) 217,217 52,332 265,093 1,616,196 2017 189,058 32,407 9,302 (125) 220,51 59,170 290,465 2,047,077 2017 189,058 32,407 9,534 (126) 236,811 59,370 291,405 207 2017 196,679 33,356 9,773 (126) 236,811 59,370 291,70 292,664 297,652 2167,602 292,702 204,707 207,412 207,412 207,412 207,412 207,412 207,412 207,412 207,412 207,652 2167,602	2008 2009	139,184 141.31(4 22,638 0 23,844	8,445	(121) (122)	168,939 173,477	28,251 36,713	197,190 210,190	1,215,709	
2011 153,086 26,616 9,555 (123) 189,114 42,758 231,945 1,461,552 2012 161,661 27,652 9,696 (123) 198,886 42,758 241,643 1,581,652 2013 169,499 23,701 9,346 (124) 207,421 42,758 261,99 169,496 2014 174,766 29,325 9,346 (124) 207,421 42,758 261,99 280,007 2015 189,058 37,100 9,302 (126) 236,811 59,170 290,445 207,419 2017 189,058 32,407 9,534 (126) 236,811 59,170 290,456 204,007 2017 195,679 33,356 9,773 (126) 236,811 59,170 310,437 2,266,448 2018 266,600 34,552 10,017 (127) 251,267 59,170 310,437 2,266,448 2018 217,412 35,522 10,0268 (129) 263,203 59,170 310,437 2,266,448 2018 217,412 35,527 </td <td>2010</td> <td>144,64</td> <td>4 24,882</td> <td>9,378</td> <td>(122)</td> <td>178,782</td> <td>42,758</td> <td>221,539</td> <td>1,339,416</td> <td></td>	2010	144,64	4 24,882	9,378	(122)	178,782	42,758	221,539	1,339,416	
2012 169,499 21,01 9,346 (124) 207,421 42,758 250,179 1,698,946 2013 169,496 23,40 9,346 (124) 207,421 42,758 250,179 1,698,946 2014 174,766 29,27 8,194 (124) 212,761 52,332 265,093 1,616,196 2016 189,058 32,407 9,534 (125) 230,814 59,170 290,045 2,047,077 2017 195,679 33,356 9,773 (126) 238,815 59,170 290,045 2,047,077 2018 206,800 34,577 10,017 (127) 251,257 59,170 310,437 226,438 2019 2016 10,017 (127) 253,203 59,170 310,437 226,448 2018 206,800 34,577 10,017 (127) 256,523 157,648 2019 2016 202,652 15,723,997 30,477 2,365,448 10,470,432 2018 2017 2016 2017 2016 1233,232,374 2,377,3997	2011	153,08(161,661	5 26,616	6 9,535 0,606	(123)	189,114 198 886	42,758 42,758	231,872	1,461,563	
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 59,170 290,045 2,147,077 2017 199,058 32,407 9,534 (125) 230,814 59,170 290,045 2,147,077 2017 199,058 32,356 9,773 (126) 238,681 59,170 290,045 2,147,077 2018 206,800 34,577 10,017 (127) 265,1267 59,170 310,437 2,266,448 2019 2016,800 34,577 10,017 (129) 261,267 59,170 310,437 2,366,448 Notes 7 70,668 (129) 263,203 59,170 310,437 2,376,438 Notes 7 717,412 35,657 10,268 (129) 263,203 59,170 310,437 2,376,448 Notes 7 7 10,017 (129) 263,203 59,170 310,437 2,376,448 1ncludes start-up costs 7	2013	169,495	9 28,701	9,346	(124)	207,421	42,758	250,179	1,698,946	
2015 160.244 31,100 9,342 (125) 220,321 34,170 2047,077 2017 189,058 32,407 9,534 (125) 230,814 59,170 2047,077 2017 189,058 32,407 9,534 (125) 230,814 59,170 297,852 2157,688 2018 206,800 34,577 10,017 (126) 251,267 59,170 297,852 216,448 2019 217,412 35,652 10,017 (129) 263,203 59,170 322,374 2,372,997 Notes 7 10,017 (129) 263,203 59,170 322,374 2,372,997 Notes 7 10,016 (129) 263,203 59,170 322,374 2,372,997 Notes 7 16,017 (129) 263,203 56,170 322,374 2,372,997 Notes 7 16,016 7 263,203 56,170 322,374 2,372,997 * 7 2,656,448 56,57 10,276 (129) 263,203 56,170 310,437 2,372,997<	2014	174,76	6 29,927	8,194	(124)	212,761	52,332	265,093	1,816,196	
2010 195,673 3,356 9,773 (126) 238,681 59,170 297,652 2,165,688 2017 206,800 34,577 10,017 (127) 251,267 59,170 310,437 2,266,448 2019 217,412 35,652 10,017 (129) 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 1 1 1 1 263,203 59,170 322,374 2,372,997 2 2 1 2	2015	180,24	4 31,100) 9,302 . 0,534	(125)	730,874	071'89 201100	2/9/045	2.047.077	
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 2,372,997 2,372,997 2,372,997 * FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate 1 includes start-up costs 322,374 2,372,997 2,372,997 * FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate 322,574 2,372,997 322,574 2,372,997 * Includes start-up costs - included only for new units - assumed to finance the services and cooling water - assumed for site lease as well as credit for services and cooling water	2017	195,675	9 33,356	9,773	(126)	238,681	59,170	297,852	2,157,688	
Notes VII assumed to finance the Southern-Florida project at a 8 02 percent rate • FMPA assumed to finance the Southern-Florida project at a 8 02 percent rate ¹ includes start-up costs are included only for new units ² Fixed costs are included only for new units ³ includes fees for site lease as well as credit for services and cooling water	2018	206,80(0 34,577 2 36,677	7 10,017	(127)	1 251,267 263 203	59,170 59,170	310,437 322,374	2,266,448 2.372.997	
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	Notes * FMPA assum	and to finance	a the Southern-Fl	orida project at a	a 8 02 percent rat	te				
² Fixed costs are included only for new units ³ Includes fees for site lease as well as credit for services and cooling water	¹ Includes star	t-up costs		-						
	⁴ Fixed costs a ³ Includes fees	ire included o i for site lease	mly for new units as well as credit	for services and	1 cooling water					
		,								

Cise Economic Economic Economic Economic Scenario Self Build FMPA AEO Economic Economic Economic Economic Generation Additions (1) (1) (1) (1) (1) (1) Generation Additions (1) (1) (1) (1) (1) (1) (1) Set Build (1)	Florida Mur	nicipal P	ower Age	ancy						
Secretic Self Build FMPA AEO CPW Discount Rate Generation Self Build FMPA AEO Cerv Discount Rate Cerv Discount Rate Generation Additions Cerv Discount Rate Cerv Discount Rate Generation Additions Installed Cerv Discount Rate Memory Issue 2000 Cerv Discount Cerv Construction Memory Issue 2000 Cerv Discount Rate Contraction Memory Issue 2000 Cerv Discount Rate Contraction Memory Issue 2000 Installed Cerv Discount Rate Contraction Memory Issue 200 Installed Cerv Discount Rate Contraction Memory Installed Cerv Discount Rate Cerv Discount Rate Cerv Discount Rate Memory I	Case							Economic		
Centeration Additions Construction New Construction	Scenario Self Buik	I FMPA AEC	0					CPW Discour Capital Escal Base Year for	it Rate ation Rate ∶\$	6 0% 2 5% 2000
Unit Size Z000 Construction Year Installed Cost Construct on trading of transfer and	Generation Addition	S								
Unit Size 2000 (MWW) Construction (Retailed (Retailed) Freed (S1,000) Freed (S1,00								Finance		
Beil Build 61 2003 833 31,458 2706 Interest During Const 96,404 8733 Ammone Term (vs) WH 501F kri 125 73,984 23 2014 417 96,404 8,233 Part Life WH 501F kri 125 73,984 23 2014 417 96,404 8,733 Part Life WH 501F kri 125 73,984 23 2014 417 96,404 8,733 Part Life WH 501F kri 125 73,984 23 2014 417 96,404 8,733 Part Life Par	Unit	Size (MW)	2000 Capital Cost (\$1.000)	Construction Period (months)	Year Installed (vear)	Installed Cost (\$1,000)	Levelized Cost (\$1.000)	Fixed Charge	Rate	8 60%
WH 501F X1 125 7.3,944 2.3 2.011 417 10,246 7.3,944 2.3 2.011 417 110,256 8,713 Freser WH 501F X1 257 129,241 12 2013 417 101,256 8,713 Freser WH 501F X1 257 129,241 12 2013 417 101,256 8,713 Preser Fuel Energy Cost Cost Cost Preser Pre	Self Build Pulvenzed Coal	61 223 425	256,581	42	2003 833 2006 417	31,458 318,830 55,454	27,426	Interest Durin Finance Term	g Const (yrs)	50% 50%
Fuel and Energy Fuel and Energy Coast (\$1,000) Total (\$1,000) Present (\$1,000)	WH 501F 1x1 WH 501F 1x1 WH 501F 2x1	125 125 257	73,984	23 12	2013 417 2013 417 2013 417	90,404 101,285 183,051	8,713 15,746			06
Year Energy (\$1,000) O&M Fees and (\$1,000) Fooduction (\$1,000) Coart (\$1,000) Vaniable (\$1,000) Fees and (\$1,000) Production (\$1,000) Coart (\$1,000) Vaniable (\$1,000) Fixed ² Credits ³ Coart (\$1,000) Coart (\$1,000) Vaniable (\$1,000) Fixed ² Credits ³ Coart (\$1,000) Coart (\$1,000) <thcoart (\$1,000) Coart (\$1,000)</thcoart 		Fuet and				Total	Total	Total	Cumulative Present	
Year Cost ¹ Vanable Fred ² Creatis ³ Cost ³ <t< td=""><td>•</td><td>Energy</td><td>Ó</td><td>M8</td><td>Fees and</td><td>Production</td><td>Capital</td><td>System</td><td>Worth</td><td></td></t<>	•	Energy	Ó	M8	Fees and	Production	Capital	System	Worth	
2000 101,705 6,268 0 448 0 0 107,973 107,973 107,973 107,973 107,973 107,973 107,973 107,973 107,973 107,973 107,973 107,973 107,973 107,973 107,975 469 345,5 2003 134,409 12,554 325 481 13 677 147,976 469 345,5 2003 134,409 126,554 3235 547 5,706 153,556 596,256 596,751 1009,32 965,8 2001,32 108,70 170,400 172,900 875,166 1591,707 1093,32 965,32 1001,32 1001,32 1001,32 1001,32 1001,32 1001,32 1001,32 1001,32 1001,32 1001,32 <t< td=""><td>Year</td><td>Cost¹ (\$1,000)</td><td>Variable (\$1,000)</td><td>Fixed ² (\$1,000)</td><td>Credits³ (\$1000)</td><td>Cost (\$1,000)</td><td>Cost (\$1,000)</td><td>Cost (\$1,000)</td><td>Cost (\$1,000)</td><td></td></t<>	Year	Cost ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
Z001 111,995 10,218 0 381 0 0 122,212 223,23 Z002 125,685 11,762 0 351 0 0 137,446 345,5 Z003 134,409 12,554 325 481 13 365,5 345,5 Z004 142,998 13,470 333 547 51 2706 170,470 714,6 345,5 Z005 151,205 16,245 2,593 547 51 2706 170,470 734,6 596,5 596,2 206,3 27,06 170,470 723,6 596,5 596,2 206,130 20,132 198,76 596,2 596,2 206,3 21,145 214,714 208,393 596,20 214,714	2000	101.705	6.268	0	448	0	0	107.973	107,973	
Z002 123,060 11,02 331 401 137,440 403 2003 151,205 16,166 3341 718 53 2,706 177,440 469,856 2005 151,205 16,166 341 718 53 2,706 170,470 723,6 2006 153,332 20,124 4,283 60,6 57 30,132 186,556 596,8 2007 133,392 18,245 2,594 60,4 54 4,92 66,6 57 30,132 186,591 723,6 2007 135,542 23,296 4,927 60,6 57 30,132 186,937 236,656 57,30 130,321 196,511 133,55 96,8 595,14,3 201,47 723,459 1,338,5 167,14,3 333,139 167,10 723,459 1,338,5 167,14,3 333,139 167,10 723,459 1,338,5 166,7 214,3 220,14,3 220,14,3 221,43 214,71,3 220,14,3 221,43 22	2001	111,995	10,218	00	381	00	00	122,212	223,267	
2004 142.998 13,470 333 547 51 2,706 156,558 596,2 2005 151,205 16,166 341 718 53 2,706 170,470 723,6 2006 133,392 18,166 341 718 55 30,132 180,9393 966,5 153,470 723,6 2006 133,392 18,146 2,393 60,6 55 30,132 180,9393 966,5 153,450 153,450 153,450 153,450 153,450 153,450 153,450 153,450 153,450 153,450 154,650 153,450 154,650 153,450 154,650 153,450 154,650 153,450 154,650 153,450 154,71 133,550 164,70 172,450 154,71 133,505 164,70 172,450 154,70 133,505 154,70 133,505 154,70 133,505 154,70 133,505 154,70 133,505 154,70 133,505 154,70 133,505 154,70 133,505 154,70<	2003	120,080	11,752	0 325	481 481	າ ເ	0 677	13/,446 147,976	469,837	
Zudd 131,203 16,105 541 110 53 2,006 172,900 845.5 2006 133,332 18,245 2,554 604 55 30,132 186,751 1,089.3 2006 133,332 18,704 177,906 23,296 4,927 695 55 30,132 186,751 1,089.3 2008 139,542 22,631 4,390 705 57 30,132 180,392 965.51 1,089.3 2009 147,906 23,296 4,927 695 58 34,24 223,395 965.51 1,089.3 2010 165,604 24,012 5,359 8,10 54 30,132 186,70 124,332 2011 169,397 25,023 5,445 1,336.5 564,948 1,5867 2014 174,537 7,794 2,043 6,6538 244 233,327 266,618 1,723,7 2015 136,633 30,256 9,455 1,3867 21,4573,7	2004	142,998	13,470	333	242	51	2,706	159,558	596,223	
2007 126,338 20,124 4,283 605 55 30,132 180,932 965,8 2008 139,542 22,631 4,390 705 57 30,132 186,751 10893 2009 154,604 23,296 4,927 695 57 30,132 196,751 10893 2010 154,604 23,013 5,942 1,200 61 43,507 233,95 31,145 1,214,3 2011 169,397 25,028 5,942 1,200 61 43,507 234,537 1,330.5 2013 174,537 27,901 7,794 2,043 64 56,322 266,918 1,531.7 2014 178,463 29,333 8,870 1,567 66 62,883 272,615 1,487.03 2015 174,4537 27,901 7,794 2,043 64 56,322 266,618 1,533.7 2016 195,530 30,256 9,333 329,359 1,467.0 723.7 <	2006	133,392	19,100	341 2.594	604	54	2,705 18,704	172,990	1 45,558	
2008 139,42 22,531 4,390 23,296 4,390 53,132 196,131,13 1065,133 50,131 155 11,155 11,155 11,145 11,24,3 2010 147,606 23,296 5,329 6,415 1,200 61 43,507 243,956 13,456 1,24,3 2011 166,606 23,296 5,942 1,200 61 43,507 243,935 1,467,0 2013 174,537 25,028 5,942 1,200 61 43,507 243,935 1,467,0 2013 174,637 27,901 7,794 2,043 64 5,322 266,618 1,723,7 2014 185,630 31,086 3,310 092 1,542 67 62,883 296,916 1,847,3 2016 136,630 33,032 36,31 1,667 69 62,883 296,916 1,847,3 2017 203,595 32,406 9,552 1,667 67 62,883 308,507 2,315,5 2018 214,711 33,437 9,791 1,6167 69	2007	126,338	20,124	4,283	605	- 25 1	30, 132	180,932	965,889	
2010 154,604 24,012 5,359 810 59 38,424 222,459 1,330.5 2011 169,397 25,028 5,942 1,200 61 43,507 243,335 1,450.7 2012 165,181 26,153 6,415 1,330 62 47,137 264,948 1,569.7 2013 174,637 27,901 7,794 2,043 66 62,883 279,615 1,847.3 2015 145,630 30,255 8,70 1,667 66 62,883 279,615 1,947.3 2016 196,136 31,508 9,379 1,815 69 62,883 279,615 1,947.3 2017 203,595 32,406 9,552 1,697 71 62,883 299,916 2,005.5 2018 2,14,711 33,437 9,791 1,618 72 65 62,883 308,507 2,312.5 2019 2,44,711 33,437 9,791 1,618 72 65 62,883 308,507 2,323.15 2019 2,161 1,618 72	2009	139,542 147,906	23,296	4, 330	(U) (95	28 28	34,969 34,969	211,155	1,214,315	
2011 169.397 25.028 5.942 1.200 61 43.507 243.355 1.467.0 2012 185,181 26,153 6,415 1,330 62 47,137 264,948 1,596,7 2013 174,537 27,301 7,794 2,043 66 65,322 266,918 1,596,7 2014 174,637 27,303 8,70 1,667 66 65,322 266,918 1,233,7 2015 195,630 30,256 9,092 1,542 67 65 62,883 29916 2,085,5 2017 203595 32,405 9,552 1,692 71 62,883 299,916 2,065,5 2017 203595 32,406 9,552 1,692 71 62,883 398,916 2,065,5 2017 203595 32,406 9,552 1,692 71 62,883 398,507 2,201 2018 214,711 33,437 9,791 1,618 72 65 62,883 393,509 2,312,5 2019 214,711 33,437 9,751 1,692 74 62,883 308,507 2,201 2019 214,711 33,437 9,751 1,692 74	2010	154,604	24,012	5,359	810	23	38,424	222,459	1,338,535	
Z012 103,161 Z0,133 0,413 Z0,130 0,413 Z0,130 0,413 Z0,130 1,330 0,413 1,231 Z0,322 Z66,618 1,233 Z0,133 1,74,537 Z7,901 7,734 Z,043 66 65,322 Z66,618 1,233,201 7,233 Z0,133 Z79,615 1,437,332 Z79,615 1,431,537 Z79,615 1,431,537 Z016 1,847,5 66 62,883 Z99,916 Z,020,1 2016 196,136 31,508 9,319 1,815 69 62,883 299,916 2,067,5 200,1 2,067,5 200,1 2,067,5 2,005,5 2,005,5 2,005,5 2,005,5 2,005,5 2,005,5 2,005,5 2,005,5 2,005,5 2,005,5 2,005,7 2,005,7 2,001,7 2,001,3 2,005,5 2,005,5 2,005,5 2,005,65 2,12,0,7 1,0,05 2,001,7 2,001,3 2,001,5 2,001,3 2,001,3 2,001,3 2,001,3 2,001,3 2,001,3 2,001,3 2,001,3 2,001,3<	2011	169,397	25,028 26,453	5,942	1,200	9 1 0	43,507	243,935 764,040	1,467.037 4 508 709	
2014 178,463 29,333 8,870 1,667 66 62,883 279,615 1,847,3 2015 195,630 30,256 9,092 1,542 67 62,883 29316 1,967,5 2016 196,136 31,508 9,319 1,815 69 62,883 29916 2,005,5 2017 203,595 32,405 9,552 1,692 71 62,883 393,507 2,200,1 2018 2,14,711 33,437 9,791 1,618 72 62,883 309,507 2,200,1 2019 2,14,711 33,437 9,791 1,618 72 62,883 330,505 2,312,5 2019 2,25,836 34,501 10,036 1,667 74 62,883 333,329 2,422,17 Notes ' ' 16187 74 62,883 333,329 2,422,17 Notes ' ' 1667 1,867 74 62,883 333,329 2,422,17 * 1 1667 1,867 1,867 74 62,883 333,329 2,422,17 * 1 1 1618 74 62,883 333,329 2,422,17 * 1 <td>2012</td> <td>180,181</td> <td>201 107</td> <td>407 7</td> <td>2.043</td> <td>87</td> <td>41, 137 56.322</td> <td>266.618</td> <td>1,723,709</td> <td></td>	2012	180,181	201 107	407 7	2.043	87	41, 137 56.322	266.618	1,723,709	
2015 185,630 30,256 9,092 1,542 67 62,883 287,928 1,967,5 2016 166,136 31,508 9,319 1,815 69 62,883 299,916 2,085,5 2017 203,595 31,508 9,319 1,815 69 62,883 396,507 2,004,5 2018 2,14,711 33,437 9,791 1,692 71 62,883 306,507 2,200,1 2019 2,25,836 34,501 10,036 1,667 74 62,883 333,329 2,312,5 2019 2,25,836 34,501 10,036 1,867 74 62,883 333,329 2,422,7 Notes 'Includes start-up costs 10,036 1,867 74 62,883 333,329 2,422,7 * Includes start-up costs art rule base as well as creating thr services and combina water 1,867 74 62,883 333,329 2,422,7	2014	178,463	29,333	8,870	1,667	99	62,883	279,615	1,847,383	
2016 196 136 31 508 9.319 1,815 69 62.883 299.916 2.085.5 2017 203,595 32,405 9,552 1,692 71 62,883 306,507 2,200,1 2018 214,711 33,437 9,791 1,692 71 62,883 306,507 2,200,1 2019 225,836 34,501 10,036 1,667 74 62,883 333,329 2,422,7 Notes 1 10,036 1,967 74 62,883 333,329 2,422,7 Notes 1 10,036 1,967 74 62,883 333,329 2,422,7 Notes 1 1 1,967 74 62,883 333,329 2,422,7 * Includes start-up costs 3 10,036 1,967 74 62,883 333,329 2,422,7 * Includes start-up costs 5 6 6 6 6 6 6 6 6 6 6 6 6	2015	185,630	30,256	9,092	1,542	67	62, 883	287,928	1,967,525	
Z01 Z01,00 Z1,00 Z1,00 <thz< td=""><td>2016</td><td>196,136 203 505</td><td>31,508</td><td>9,319 0.557</td><td>1,815</td><td>69 71</td><td>62,883 67 883</td><td>299,916 308 507</td><td>2,085,586</td><td></td></thz<>	2016	196,136 203 505	31,508	9,319 0.557	1,815	69 71	62,883 67 883	299,916 308 507	2,085,586	
2019 225,836 34,501 10,036 1,867 74 62,883 333,329 2,422,7 Notes * includes start-up costs 333,329 2,422,7 2,422,7 * Includes start-up costs * <	2018	214.711	33.437	9.791	1.618	72	62,883	320,895	2.312.578	
Notes ¹ Includes start-up costs ² Fixed costs are included only for new units ³ Includes face for site based as well as credit for services and cooling water	2019	225,836	34,501	10,036	1,867	74	62,883	333,329	2,422,748	
Tricitudes staticult ucts. Tricitudes staticult ucts 1 incluides face for eits laced act will ac creatif for services and confine water	Notes ¹ Included start	atooo a								
Trade uses and minimum or in the minimum of the services and confirm water 3 includes face for eith laces as well as cracifif for services and confirm water	² Evad mete an	up coord a molindad or	the for new limits							
	³ Includes fees	for site lease	as well as cred	t for services an	nd cooling water					

Florida Mu	inicipal]	Power Ag	ency						
Case Scenario Southe	m-Florida FM	PA OUC + AEO					Economic CPW Discoul Capital Escali Base Year for	nt Rate ation Rate .\$	6 0% 2 5% 2000
Generation Additic Unit Southern Pulverized Coal WH 501F 2x1 WH 501F 2x1	222 255 255	2000 Capital Cost (51,000) 3 256,581 7 129,241 7 129,241	Construction Period (months) 24 24 24	Year Installed (vear) 2003 833 2006 417 2009 417 2014 417	Installed Cost (\$1,000) 318,830 168,643 190,804	Levelized Cost (\$1,000) 14,507 16,413	Finance Fixed Charge Interest Durin Finance Terr Plant Life	: Rate ig Const 1 (Vrs)	*8 60% 6% 30
Year	Fuel and Energy Cost ¹ (\$1,000)	Variable (\$1,000)	&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 2001 2002 2003 2004 2005 2005 2005 2005 2005 2005 2015 2014 2014 2015 2015 2015 2015 2015 2015 2015 2015	113, 987 129, 725 145, 527 157, 647 157, 647 167, 744 168, 004 188, 008 198, 223 198, 223 198, 225, 575 255, 575 255, 575 255, 575 255, 575 256, 575 268, 003 304, 755 304, 755 306, 75	5,744 5,744 10,284 10,284 11,812 13,860 11,812 13,860 11,812 13,860 11,812 13,860 11,812 13,860 11,812 14,812 11,812 15,294 12,5948 23,907 13,5648 23,907 14,912 28,338 13,33,454 33,454 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 34,645 14,914 <td>0 807 3,203 3,203 5,453 5,453 5,453 5,453 7,136 9,374 9,374 9,373 9,534 9,534 9,534 10,268 10,268 10,273 10,268 10,773 10,268 10,773 10,268 10,773 10,273 10</td> <td>0 (119) (119) (119) (120) (120) (122) (122) (123) (123) (123) (123) (123) (126) (127) (126) (126) (126) (126) (126) (126) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (127) (127) (127) (126) (126) (127) (126) (126) (127) (126) (126) (126) (127) (126) (127) (126) (126) (126) (127) (126) (127) (126) (126) (126) (127) (126) (127) (126) (126) (127) (127) (126) (127</td> <td>119,731 157,339 157,339 171,130 187,137 207,487 207,487 207,487 221,569 223,534 223,534 233,171 233,1712 333,172 333,121 349,715 267,681 333,121 349,715 293,733 367,681 377,681 377,691 377,691 377,691 377,691 377,691 377,691 377,691 377,691 377,6</td> <td>0 28,255 825 825 825 825 825 825 825 713 713 825 713 825 713 825 713 825 713 825 713 825 713 825 713 825 713 825 713 713 825 713 713 825 713 713 825 713 713 825 713 713 825 713 713 713 825 713 713 713 713 713 713 713 713 713 713</td> <td>119, 731 157, 339 157, 339 171, 336 171, 336 171, 336 208, 995 208, 995 208, 995 314, 914 314, 914 337, 584 363, 256 363, 256 363, 256 363, 256 363, 256 363, 256 366, 165 165 165 165 165 165 165 165 165 165</td> <td>119,731 251,814 331,845 535,702 685,172 846,172 846,172 846,172 1,132,141 1,1284,199 1,437,061 1,437,061 1,437,061 1,437,061 1,437,061 1,420 2,557,635 2,511,420 2,556,360 2,566,560 2,566,560,560 2,566,560 2,566,560,560 2,566,5</td> <td></td>	0 807 3,203 3,203 5,453 5,453 5,453 5,453 7,136 9,374 9,374 9,373 9,534 9,534 9,534 10,268 10,268 10,273 10,268 10,773 10,268 10,773 10,268 10,773 10,273 10	0 (119) (119) (119) (120) (120) (122) (122) (123) (123) (123) (123) (123) (126) (127) (126) (126) (126) (126) (126) (126) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (126) (127) (127) (127) (127) (126) (126) (127) (126) (126) (127) (126) (126) (126) (127) (126) (127) (126) (126) (126) (127) (126) (127) (126) (126) (126) (127) (126) (127) (126) (126) (127) (127) (126) (127	119,731 157,339 157,339 171,130 187,137 207,487 207,487 207,487 221,569 223,534 223,534 233,171 233,1712 333,172 333,121 349,715 267,681 333,121 349,715 293,733 367,681 377,681 377,691 377,691 377,691 377,691 377,691 377,691 377,691 377,691 377,6	0 28,255 825 825 825 825 825 825 825 713 713 825 713 825 713 825 713 825 713 825 713 825 713 825 713 825 713 825 713 713 825 713 713 825 713 713 825 713 713 825 713 713 825 713 713 713 825 713 713 713 713 713 713 713 713 713 713	119, 731 157, 339 157, 339 171, 336 171, 336 171, 336 208, 995 208, 995 208, 995 314, 914 314, 914 337, 584 363, 256 363, 256 363, 256 363, 256 363, 256 363, 256 366, 165 165 165 165 165 165 165 165 165 165	119,731 251,814 331,845 535,702 685,172 846,172 846,172 846,172 1,132,141 1,1284,199 1,437,061 1,437,061 1,437,061 1,437,061 1,437,061 1,420 2,557,635 2,511,420 2,556,360 2,566,560 2,566,560,560 2,566,560 2,566,560,560 2,566,5	

lorida Mu	nicipal F	ower Age	ancv						
	•								
Ð							Economic		
nario Self Bui	Id FMPA OUO	C + AEO					CPW Discoul Capital Escal Base Year foi	nt Rate ation Rate r \$	6 0% 2 5%
neration Additio	US								
							Finance		
	Size (MW)	2000 Capital Cost (\$1,000)	Construction Period (months)	Year Installed (year)	Installed Cost (\$1,000)	Levelized Cost (\$1,000)	Fixed Charge	Rate	8 60%
Build enzed Coal 501F 1x1	61 223 125	256,581 73,984	23	2003 833 2006 417 2009 417	31,458 318,830 96,404	2,706 27,426 8,293	Interest Durin Finance Term Plant Life	lg Const 1 (yrs)	9 30 0 % 30 %
501F 1x1 501F 2x1	125	73,984	23	2011 417 2013 417	101,285 186,150	8,713 16,013			
	Fuel and				Total	Total	Total	Cumulative Present	
	Energy	õ	\$M 7 2		Production	Capital	System		
Year	(\$1,000)	variable (\$1,000)	(\$1,000)	(\$1000)	COSI (\$1,000)	COST (\$1,000)	Cost (\$1,000)	COST (\$1,000)	
2000	113,987	5,744 10.284	00	00	119,731 140 008	00	119,731 140 008	119,731	
2002	145,527	11,812	010	00	157,339		157,339	391,845	
2004	cu/,/cl 171.296	12,708 13,846	675 333 335	13 51	1/U,/JU 185.527	۵/ / 2.706	1/1,42/ 188,233	684,876	
2005	188,401	16,271	341	23	205,066	2,706	207,772	840, 135	
2006	168,248 160,476	19,096	2,594 4 783	54 75	189,992 186 054	18,704 30,132	208,696 216,186	987,258	
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	
20102	206,837 245 826	25,397	5,947	50 19	231,633	38,424 43 507	2/6,U/7 320.749	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 20,507	8,870	60 8-7	299,836	63, 15U	302,985 474,074	1 806,107,2	
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 2019	316,932 334,520	33,743 34,757	9,791 10,036	72	360,539 379,387	63, 150 63, 150	423,688 442,536	2,867,705 3,013,969	
SS									
	-up costs	•							
Fixed costs a	re included or	Ily for new units							
Includes fees	for site lease	as well as credit	for services an	d cooling water					

Case Case Southern-Florida FMPA N Scenario Southern-Florida FMPA N Generation Additions Case Ca								
Scenario Southern-Florida FMPA N Generation Additions Unit Size Ca					<u> </u>	Economic		
Generation Additions Unit Size Ca	Vo Real					CPW Discour. Capital Escala Base Year for	t Rate ttion Rate \$	6 0% 2 5% 2000
Generation Additions Unit Size Ca (MWV) (3:					_			
Unit Size 20 (MWV) (5						Finance		
	000 CC apital Cost Pe 1 000) ((m	onstruction eriod	Year Installed (vear)	Installed Cost (\$1,000)	Levelized Cost (\$1,000)	Fixed Charge	Rate	*8 60%
Southern 21 Pulverized Coal 223 WH 501F 2x1 257 WH 501F 2x1 257	256,581 129,241 129,241	24 24 24	2003 833 2006 417 2009 417 2014 417	318,830 168,643 190,804	27,426 14,507 16,413	Interest Durin Finance Term Plant Life	g Const (yrs)	6% 30
							Cumulative	
Fuel and Energy	0&M		Fees and	Total Production	Total Capital	Total System	Present Worth	
Year Cost ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
2000 113.987	5.744	O	0	119,731	0	119,731	119,731	
2001 129,433	10,285	00	00	139,717	00	139,717	251,540 201 1 BB	
2003 156,195	11,850 12,898	807	0) (0E)	169,870	206	170,076	533,988	
2004 167,660	13,950	3,203	(119)	184,694 202 348	825 825	185,519 203-173	680,936 832,758	
2006 165,238	19,087	5,453	(120)	189,659	16,823	206,483	978,320	
2007 160,200	21,212	7,136	(120)	188,428 211 177	28,251 28,251	216,679 239,428	1,122,424 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 26,837	9,378 0,536	(122)	225,898 245,180	42,758 42,758	268,656 287 937	1,573,720	
2012 219,536	20,022 27,848	9,696 9,696	(123)	256,957	42,758	299,714	1,874,350	
2013 228,536	28,939	9,346	(124)	266,696	42,758 67 337	309,454 276,423	2,019,435 2,163,241	
234,649	30,083 31 195	8,194 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 2019 275,427	34,615 35,734	10,017 10,268	(127) (128)	309,860 321,300	59,170	380,471	2,829,879	
Notes * FMPA assumed to finance the	s Southern-Florid	ta project at a	18 02 percent rat	ē				
¹ Includes start-up costs								
² Fixed costs are included only fu	for new units							
³ Includes fees for site lease as v	well as credit for	services and	cooling water					

Florida Mu	nicipal P	ower Age	ancy						
Case							Economic		
Scenario Self Bui	Id FMPA No F	Real					CPW Discour Capital Escal Base Year for	it Rate ation Rate ∶\$	6 0% 2 5% 2000
Generation Additio	SU								
t Inst	510	2000	Construction	Year	Installed	Levelized	Finance		
	(MM)	(\$1,000)	(months)	(year)	(\$1,000)	(\$1,000)	Fixed Charge	Rate	8 60%
Self Build Pulvenzed Coal WH 501F 1x1	61 223 125	256,581 73.984	23	2003 833 2006 417 2009 417	31,458 318,830 96,404	2,706 27,426 8,293	Interest Durin Finance Term Plant Life	g Const I (yrs)	30 0% 30 %
WH 501F 1x1 WH 501F 2x1	125 257	73,984	23 24	2011 417 2013 417	101,285 186,150	8,713 16,013			
	Fuel and				Total	Total	Total	Cumulative	
	Energy	0	8M	Fees and	Production	Capital	System	Worth	
Year	Cost ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
2000	113.987	5744	0	0	119.731	0	119.731	119.731	
2001	129,433	10,285	00	00	139,717	00	139,717	251,540	
2002	156,304	11,950 12,895	325	0 EL	150, 909 169, 536	0 677	170,213	534,102	
2004	168,018	13,943	333	51	182,346	2,706	185,052	680,680	
2005	183,182 165 706	16,401	341	53	199,976	2,706	202,682 206.452	832, 136 077 /65	
2007	160, / UB 160, 610	19,093 21,208	4,283	55	187,447 186,156	30, 132	216,288	1,121,309	
2008	180,678	23,878	4,390	57	209,003	30,132	239,135 257,045	1,271,345	
2009	192,603 201 733	24,485 25.241	4,927 5.359	20 20 20	222,073 232,392	34,969 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 56,478	328,714	1,898,404	
2013	235,148 230 A06	28,302	1,194 870	64 66	805,172 777 976	30,478 63 150	341 125	2 207 963	
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 e3 150	369,657	2,627,881 7 764 607	
2019	2/4,68U 285.239	33,720 34,839	9, /91 10,036	47	330,188	63, 150	393,338	2,891,510	
Notes									
2 Fived mete a	rap costs re included of	oly for new tinits							
³ Includes fees	for site lease	as well as cred	t for services ar	id cooling water					

Florida Mu	nicipal P	ower Age	ancy						
						E-			
Case							Economic		
Scenario Self Buil	id FMPA High	ı Load					CPW Discour Capital Escala	it Rate ation Rate	6 0% 2 5%
							Base Year Ior	A	0007
Generation Additio	us								
							Finance		
Unit	Size	2000 Capital Cost	Construction Period	Year Installed	Installed Cost	Levelized Cost	i		
	(MW)	(\$1,000)	(months)	(year)	(\$1,000)	(\$1,000)	Fixed Charge	Kate	8 60%
Self Build	61 257	129.241	74	2003 833 2005 417	31,458 152 782	2,706 13,142	Interest Durin Finance Term	g Const I (vrs)	6% 20
WH 501F 2x1	257	129.241	24	2006 417	156,602	13,471	Plant Life		30
WH 501F 2x1	257	129,241	24	2008 417	164,529	14,153			
Pulvenzed Coal	223	3 256,581 5 73,984	42 23	2011 417 2017 417	360,726 117.459	31,030			-
	Fuei and				Total	Total	Total	Cumulative Present	
	Energy	0	8.M	Fees and	Production	Capital	System	Worth	•
Year	Cost ¹ (#1 000)	Variable	Fixed ² (\$1 000)	Credits ³	Cost (\$1 000)	Cost (\$1 000)	Cost (\$1.000)	Cost (\$1.000)	
	(200-1-0)	0000	100011		10001				
2000	124,613	6,230		20	150,844	5 0	130,044	130,044	
1002	CLC 231	L// 'D1			176,044		176,044	441566	
2002	169,022	13,022	325	ο ε	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	33 E	197,139	29,319 27 575	226,458	1,188,786	
2008	179,488	26,011	5,118 6 m6	/C	210,074 225,016	C/C'/S	240,249 768 488	1 503 458	
2009	191, 303 203, 108	960 66	6,176 6,176	0 0 0 0 0	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	95,107	11,202	64	267,512	74,502	342,014	2,147,125	
2014	235,427	36,538	11,482	99	283,513	74,502	358,015	2,305,475	-
2015	245,739	38,099	11,769	60	2/0'CA7	705 1/2	310,177	2,409,937	
2016	208,937	39,/90	12,004	50 17	324 617	80,396	405.013	2.762,043	
2018	2R6 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									
 Includes star 	t-up costs								
² Fixed costs a	ire included o	nly for new units							
³ Includes fees	for site lease	e as well as cred	it for services al	nd cooling water					

Florida Mu	nicipal P	ower Age	incy						
Case							Economic		
Scenario Souther	n-Flonda FMP,	A High Load					CPW Discour Capital Escal: Base Year for	it Rate ation Rate \$	6 0% 2 5% 2000
Generation Additio	SU								
							Finance		
Unit	Size (MW)	2000 Capital Cost (\$1,000)	Construction Period (months)	Year Installed (year)	Installed Cost (\$1,000)	Levelized Cost (\$1,000)	Fixed Charge	Rate	*8 60%
Southern	21			2003 833			Interest Durin	g Const	6%
WH 501F 2x1 WH 501F 2x1	257 257	129,241	24	2005 417	152,782 156,602	13,142	Finance Term Plant Life	(Vrs)	300
GE 7FA SC	156	76,681	12	2008 417	95,993	8,257			8
WH 501F 2x1	223 267	256,581 129,241	23 23	2011 417 2014 417	360,726 190,537	31,030 16,390			
	Fuel and				Total	Total	Totai	Cumulative Present	
	Energy	ŏ	W	Fees and	Production	Capital	System	Worth	
Year	Cost ¹ (\$1,000)	Variable (\$1.000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1.000)	Cost (\$1.000)	Cost (\$1.000)	Cost (\$1.000)	-
0000	010101			c					
0002	124,010 150 515	0,230			163 7R6		162 786	784 287	
2002	163.022	13.022	00	00	176.044		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	
5002	161,958	16,344	5,982	(120)	103, 29U 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	195,433 207 560	27,327 28,707	7,692 7,807	(122)	230,330	35,696 35,696	266,026 279 648	1,503,079	
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 70,020	336,885 212,245	2,138,039	
2014	234,332	36,394 38,037	11,125 12 306	(124)	281,726	/0,280 83 115	377,844	2,296,388	
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)	352,393 250,772	83,115 83,115	435,508	2,912,658	
2019	302,149	44,168	13,564	(126)	359,773	93,115	442,868	3,059,0361	
Notes * FMPA assum	ed to finance t	he Southern-Flo	rida project at a	8 02 percent rat	¢)				
¹ Includes start	-up costs								
² Fixed costs ar	e included only	y for new units							
³ Includes fees	for site lease a	is well as credit f	or services and	cooling water					

Florida Mui	nicıpal]	Power Ag	ency						
Case	T						Economic		
Scenario Southern	-Florida FMP,	A Low Load					CPW Discoun Capital Escala Base Year for	t Rate ttion Rate \$	6 0% 2 5% 2000
Generation Addition:	s								
Chit	Size	2000 Capital Cost	Construction	Year Installed	Installed Cost	Levelized Cost	Finance Even Charge	Data	*8 60%
Southern WH 501F 2x1 Pulverized Coal PC	21 257 223	129,241 256,581	24 42	2003 833 2008 417 2011 417	164,529 360,726	14,153 31,030	Interest During Finance Term Plant Life	g Const (yrs)	20 30 30
	Fuel and Energy			Fees and	Total Production	Total Capital	Total System	Cumulative Present Worth	
Year	Cast ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
2000	103,096	5,340	0	0 0	108,436	00	108,436	108,436	
2002	123,881	9,300 10,905	00	00	133,241	00	140,565	359,238	
2003 2004	129,669 128,251	11,138 12,391	807 3,203	(30) (119)	141,583 143,726	206 825	141,789 144,551	478,287 592,785	
2005	126.341 133 B77	13,255	3,205 3,208	(119)	142,682 151 847	825 875	143,507 152,672	700,021 807.649	
2007	141,111	16,176	3,212	(120)	160,378	825	161,203	914,858	
2008	140,274	18,757 19,546	4,292 5.101	(121) (122)	163,201 166.944	9,081 14,978	172,282 181,922	1,022,950	
2010	148,281	20,308	5,151	(122)	173,619 172,064	14,978 33.070	188,597 205 143	1,235,941 1 344 008	
2012	141,972	23,791	9,69,6	(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	153,488 158,332	25,137 25,832	5,945 7,118	(124) (125)	180,440 191,158	46,008 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	170,136 178 290	27,458 28.380	7,479 7,666	(126)	204,947	46,008 46.008	250,954 260.216	2.042.290	
2019	184,949	29,209	7,857	(128)	221,887	46,008	267,895	2,130,833	
Notes • FMPA assume	ed to finance t	the Southern-Floi	rida project at a 8	02 percent rate					
¹ Includes start-L	up costs								
² Fixed costs are	e included onl	y for new units							
³ Includes fees for	or site lease a	is well as credit f	or services and c	coling water					

Florida Mu	nicipal F	ower Age	ency						
Case							Economic		
Scenario Self Bui	IId FMPA Low	r Load					CPW Discoul Capital Escal Base Year fo	nt Rate atron Rate r \$	6 0% 2 5% 2000
Generation Additio	SU								
Unit	Size (MW)	2000 Capital Cost (\$1,000)	Construction Period (months)	Year Instailed (year)	Installed Cost (\$1,000)	Levelized Cost (\$1,000)	Finance Fixed Charge	Rate	8 60%
Seff Build WH 501F 2x1 Puvenzed Coal PC	61 257 226	1 256,581	24 42	2003 833 2008 417 2011 417	31,458 164,529 360,726	2,706 14,153 31,030	Interest Durin Finance Term Plant Life	ig Const (yrs)	80 30 30 80
	Fuel and Energy		¥	Fees and	Total Production	Total Canital	Total Svstem	Cumulative Present Worth	
Year	Cost ¹ (\$1,000)	Variable (\$1,000)	Fixed ² (\$1,000)	Credits ³ (\$1000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	Cost (\$1,000)	
2000 2001 2002 2002 2005 2006 2006 2011 2011 2011 2011 2011 2011	103, 896 123, 881 129, 746 129, 746 128, 388 128, 388 128, 388 128, 388 141, 303 141, 303 142, 623 142, 623 143, 623 144, 623 145, 625, 625, 625, 625, 625, 625, 625, 62	5,340 9,909 11,136 11,136 11,136 11,136 11,136 12,375 13,758 13,758 13,758 13,758 13,758 13,758 13,758 13,758 13,758 14,7588 14,7588 14,7588 14,7588 14,7588 14,7588 14,7588 14,7588 14,7588 14	0 0 335 341 333 350 341 350 351 351 355 351 355 351 355 351 355 357 355 357 355 357 355 357 355 357 355 357 355 357 355 357 355 357 355 357 355 357 355 357 355 355	000000000000000000000000000000000000000	108.436 143.524 140.525 141.215 141.215 144.146 157.890 157.890 157.890 157.890 159.716 173.073 173.073 173.073 173.073 178.042 178.042 178.042 199.198 199.198 199.198 204.493	0 677 677 677 677 677 677 677 687 16,859 16,859 16,859 16,859 16,859 16,859 14,7,889 47,889 47,889 47,889	108,436 133,241 141,855 141,855 141,855 141,855 142,854 152,068 165,505 181,352 181,352 181,352 204,675 204,675 222,935 233,238 223,328 224,7087 252,333 233,238 225,233	108,436 234,135 359,135 359,135 478,373 699,073 699,073 699,073 913,0094 1,228,156 1,289,156 1,280,994 1,259,498 1,356,730 1,556,730 1,556,730 1,950,498	
2019 2019 Notes ¹ includes start	1//.140 183,745 -up costs	29,322	8,170 8,170	74	221,312	47,005	269,201	2,131,090	
² Fixed costs al ³ Includes fees	re included or for site lease	as well as credu	t for services an	d cooling water					