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FMPA
Florida Municipal Power Agency

William "Bill" May
Planning and Contracts Manager

April 14, 2005

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Ms. Blanca Bayo
Florida Public Service Commission
Bureau of Electric Reliability
Capital Circle Office Center
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Dear Ms. Bayo:

Enclosed are 25 copies of Florida Municipal Power Agency's April 2005 Ten-Year Site Plan as prepared and submitted by Black & Veatch (B&V) on behalf of FMPA.

The Ten-Year Site Plan information is provided in accordance with Florida Public Service Commission rule 25-22.070, 25-22.071, and 25-22.072, which require certain electric utilities in the State of Florida to submit a Ten-Year Site Plan. The plan is required to describe the estimated electric power generating needs and to identify the general location of any proposed near-term power plant sites as of December 31, 2004.

If you should have any questions, please feel free to contact me at 321-239-1033.

Sincerely,

William S. May

William May
Planning and Contracts Manager

Enclosure

WM/tg

XC: Michael Haff (FPSC)
Myron Rollins (B&V)
Fred Bryant
Rick Casey

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Florida Municipal Power Agency

Ten-Year Site Plan

April 2005

Community Power + Statewide Strength

Florida Municipal Power Agency

Ten-Year Site Plan 2005-2014

Submitted to

Florida Public Service Commission

April 14, 2005

Community Power + Statewide Strength

Florida Municipal Power Agency

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Executive Summary

The following information is provided in accordance with Florida Public Service Commission Rules 25-22.070, 25-22.071, and 25-22.072, which require certain electric utilities in the State of Florida to submit a Ten-Year Site Plan. The Ten-Year Site Plan is required to describe the estimated electric power generating needs and to identify the general location and type of any proposed near-term generation capacity additions.

The Florida Municipal Power Agency (FMPA) is a project-oriented, joint-action agency. FMPA's direct responsibility for power supply planning can be separated into two parts. First, for the All-Requirements Project (ARP), where the Agency has committed to supplying all of the power requirements of 15 cities, the Agency is solely responsible for power supply planning. Second, for member systems that are not in the ARP, the Agency's role has been to evaluate joint action opportunities and make the findings available to the membership where each member can elect whether or not to participate. This report presents information on the existing Agency projects and planning information for the ARP.

The ARP winter and summer capacity including owned generation and purchase power for the year 2005 is 1,744 MW and 1,723 MW, respectively. In October, 2003, Stanton Energy Center A began commercial operation, providing FMPA with 127 MW of capacity. This includes the capacity allocated to Kissimmee Utility Authority pursuant to the applicable Stanton Energy Center A joint-ownership and purchase power agreements.

Table ES-1 presents uture ARP generation construction plans. Worthy of note is FMPA's awareness of the potential benefits of increased fuel diversity among its generating portfolio, which has prompted FMPA to consider a solid-fuel capacity addition. Due to permitting and scheduling constraints, commercial operation of such a unit, if ultimately decided upon, would not be feasible until the summer of 2011 at the earliest. Nonetheless, consideration and further study of the potential benefits related to construction of a new solid-fueled unit are appropriate from FMPA's perspective.

The capacity expansion plan outlined in this Ten-Year Site Plan is consistent with the determination of the least-cost capacity expansion plan presented in FMPA's Treasure Coast Energy Center Unit 1 (TCEC Unit 1) Need for Power Application. The TCEC Unit 1 Need for Power Application provides the results of a detailed, 20-year (2005-2024) capacity planning study which identified construction of a new 1x1 7FA combined cycle at a new site, TCEC Unit 1, with a summer 2008 commercial operation date. The TCEC Unit 1 Need for Power Application considered a number of sensitivity analyses to quantify the effects of changes to key input assumptions, including high and low fuel price forecasts, high and low load and energy growth forecasts, high and low capital cost, and an increased present worth discount rate.

Table ES-1
FMPA Generation Construction Plans

Unit Description	Commercial Operation (MM/YY)	Summer Capacity (MW)
Stock Island CT4	01/06	42
Two LM6000 CTs	12/07	84
Treasure Coast Energy Center Unit 1	05/08	287
Joint Development Coal Project	06/11	250
LM6000 CT	06/14	47

Florida Municipal Power Agency

Section 1.0

Description of FMPA

Community Power + Statewide Strength

1.0 Description of FMPA

1.1 FMPA

FMPA is a joint action agency comprised of 29 municipal electric utilities. FMPA provides economies of scale in power generation and related services to support community-owned electric utilities. FMPA was created on February 24, 1978, by the signing of the Interlocal Agreement among its original members to provide a means by which its members could cooperatively gain mutual advantage and meet present and projected electric energy requirements. This agreement specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution, the Joint Power Act, Chapter 361, Part II, Florida Statutes, and the Florida Interlocal Cooperation Act of 1969, Section 163.01, Florida Statutes.

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 the 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, utility commission, or authority, which is a signatory to the Interlocal Agreement, has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility of developing and approving FMPA's budget, approving and financing projects, hiring a General Manager and General Counsel, and establishing bylaws that govern how FMPA operates and creating policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, Treasurer, and an Executive Committee. The Executive Committee consists of 13 representatives, which include nine elected by the Board, the current Board Chairman, Vice Chairman, Secretary, and Treasurer. The Executive Committee meets regularly to control FMPA's day-to-day operations and to approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and assuring that authorized work is completed in a timely manner.

1.1.1 All-Requirements Project

FMPA developed the ARP to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the needs of the ARP members. ARP members, both with and without their own generating capacity, are required to purchase all their capacity and energy from the ARP. Members with their own generating capacity and purchases (generating members) are required to sell the electric capacity and energy of their generating resources to FMPA. In exchange for the sale of their electric capacity and energy, the generating members receive credits.

The ARP serves approximately 280,000 customer accounts in the following 15 municipal utilities. The following information is from the Florida Municipal Electric Association's 2004 membership directory (www.publicpower.com).

Bushnell

Bushnell is located in central Florida in Sumter County. The city electric department serves 1,088 customers with a total load of 6.3 MW. Bushnell joined the ARP in May 1986. Vince Ruano is the City Manager and Bruce Hickle is the Director of Utilities. Bushnell's service area is approximately 1.4 square miles.

Clewiston

Clewiston is located in southern Florida in Hendry County. The city electric department serves 4,121 customers with a total load of 27.3 MW. Clewiston joined the ARP in May 1991. Kevin McCarthy is the Utilities Director. Clewiston's service area is approximately 5 square miles.

Fort Meade

Fort Meade is located in central Florida in Polk County. The city electric department serves 2,500 customers with a total load of 12 MW. Fort Meade joined the ARP in February 2000. Al Minner is the City Manager. Fort Meade's service area is approximately 5 square miles.

Fort Pierce Utilities Authority

Fort Pierce is located on Florida's east coast in St. Lucie County. The Fort Pierce Utilities Authority (FPUA) serves 25,300 customers with a total load of 136 MW. FPUA joined the ARP in January 1998. Elie J. Boudreaux III, P.E., is the Director of Utilities and Thomas W. Richards, P.E. is Director of Electric & Gas Systems. FPUA's service area is approximately 35 square miles.

Green Cove Springs

Green Cove Springs is located in northeast Florida in Clay County. The city electric department serves 3,279 customers with a total load of 25 MW. Green Cove

Springs joined the ARP in May 1986. Jimmy Knight is the Director of Electric Utility. Green Cove Springs' service area is approximately 25 square miles.

Town of Havana

The Town of Havana is located in the panhandle of Florida in Gadsden County. The town electric department serves 1,311 customers with a total load of 5.4 MW. The Town joined the ARP in July 2000. Susan J. Freiden is the Town Manager. The Town's service area is approximately 4.5 square miles.

Jacksonville Beach

Jacksonville Beach is located in northeast Florida in Duval and St. Johns Counties. The city electric department, doing business as Beaches Energy Services, serves 31,351 customers with a total load of 227.8 MW. Jacksonville Beach joined the ARP in May 1986. George D. Forbes is the City Manager, and Gary Quick is the Utilities Director. Jacksonville Beach's service area is approximately 45 square miles.

Keys Energy Services

Keys Energy Services (KEYS), provides electric service to the lower Keys in Monroe County. KEYS serves 29,021 customers with a total load of 138.9 MW. KEYS joined the ARP in April 1998. Robert R. Padron is Chairman of the Utility Board and Carl R. Jansen, Jr., is the General Manager. KEYS' service area is approximately 45 square miles.

Kissimmee Utility Authority

Kissimmee is located in central Florida in Osceola County. The Kissimmee Utility Authority (KUA) serves 50,600 customers with a total load of 272 MW. KUA joined the ARP in October 2002. James C. Welsh is the President & General Manager, and A. K. (Ben) Sharma is Vice President of Power Supply. KUA's service area is approximately 85 square miles.

Lake Worth

Lake Worth is located on Florida's east coast in Palm Beach County. Lake Worth Utilities serves 26,383 customers with a total load of 91 MW. Lake Worth joined the ARP in October 2002. George Adair is the Utilities Director. Lake Worth's service area is approximately 12.5 square miles.

Leesburg

Leesburg is located in central Florida in Lake County. The city electric department serves 19,673 customers with a total load of 101.6 MW. Leesburg joined the ARP in May 1986. Lloyd Shank is the Director of Electric Department. Leesburg's service area is approximately 50 square miles.

Newberry

Newberry is located in the northern part of Florida in Alachua County. The city electric department serves 1,129 customers with a total load of 7.4 MW. Newberry joined the ARP in December 2000. Blaine Suggs is the Utilities and Public Works Director. Newberry's service area is approximately 6 square miles.

Ocala

Ocala is located in central Florida in Marion County. Ocala Electric Utility serves 47,460 customers with a total load of 295 MW. Ocala joined the ARP in May 1986. Paul K. Nugent is the City Manager, and Rebecca Mattey is the Director of Electric Utility. Ocala's service area is approximately 161 square miles.

Starke

Starke is located in north Florida in Bradford County. The city electric department serves 2,661 customers with a total load of 19 MW. Starke joined the ARP in October 1997. Ken Sauer is the City Administrator. Starke's service area is approximately 6.5 square miles.

Vero Beach

Vero Beach is located on Florida's east coast in Indian River County. The city electric department serves 31,849 customers with a total load of 210 MW. Vero Beach joined the ARP in June 1997. David Mekarski is the City Manager, and Paul Thompson is the Utilities Director. Vero Beach's service area is approximately 40 square miles.

The supply resources of the ARP include capacity and energy purchases from several ARP cities for city-owned generation and/or the assumption of cities' firm purchase power resources. FMPA serves capacity and energy requirements for the City of Fort Meade, via the full requirements agreement currently in place with Tampa Electric Company (TECO). When the Fort Meade/TECO agreement terminates in January 2009, FMPA will serve Fort Meade from the ARP's portfolio of power supply resources.

Similarly, the City of Newberry is currently served by a full-requirements agreement with Progress Energy Florida (PEF). FMPA will assume power supply responsibilities for Newberry when the current agreement expires in January 2006.

1.2 FMPA Generation Projects

FMPA currently has five power supply projects in operation as discussed below. Table 1-1 gives a summary of ARP member participation as of January, 2005.

1.2.1 Overview of Existing Generation Projects

FMPA has five power supply projects in operation: (i) St. Lucie Unit No. 2 (the St. Lucie Project), (ii) the Stanton Project, (iii) the Tri-City Project, (iv) the Stanton II Project, and (v) the ARP.

1.2.1.1 St. Lucie Project. On May 12, 1983, FMPA purchased from FPL an 8.806 percent undivided ownership interest in the St. Lucie Project, a nuclear generating unit. The St. Lucie Project was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of FMPA's members are participants in the St. Lucie Project, with the following entitlements as shown in Table 1-2.

Table 1-1
Summary of Project Participants

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project	Stanton II Project
City of Alachua	X				
City of Bartow					
City of Bushnell				X	
City of Chattahoochee					
City of Clewiston	X			X	
City of Ft Meade	X			X	
Ft Pierce Utilities Authority	X	X	X	X	X
Gainesville Regional Utilities					
City of Green Cove Springs	X			X	
Town of Havana				X	
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Key West City Electric System			X	X	X
Kissimmee Utility Authority	X	X		X	X
City of Lakeland Electric & Water					
City of Lake Worth	X	X		X	
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					

Table 1-2 St. Lucie Project Participants			
City	% Entitlement	City	% Entitlement
Alachua	0.431	Clewiston	2.202
Fort Meade	0.336	Fort Pierce	15.206
Green Cove Springs	1.757	Homestead	8.269
Jacksonville Beach	7.329	Kissimmee	9.405
Lake Worth	24.870	Leesburg	2.326
Moore Haven	0.384	Newberry	0.184
New Smyrna Beach	9.884	Starke	2.215
Vero Beach	15.202		

1.2.1.2 Stanton Project. On August 13, 1984, FMPA purchased from the Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit No. 1. Stanton Unit No. 1 went into commercial operation July 1, 1987. Six of FMPA's members are participants in the Stanton Project with the following entitlements as shown in Table 1-3.

Table 1-3 Stanton Project Participants			
City	% Entitlement	City	% Entitlement
Fort Pierce	24.390	Homestead	12.195
Kissimmee	12.195	Lake Worth	16.260
Starke	2.439	Vero Beach	35.521

1.2.1.3 Tri-City Project. On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton Unit No. 1. Three of FMPA's members are participants in the Tri-City Project with the following entitlements as shown in Table 1-4.

Table 1-4 Tri-City Project Participants	
City	% Entitlement
Fort Pierce	22.727
Homestead	22.727
Key West	54.546

1.2.1.4 Stanton II Project. On June 6, 1991, under the Stanton II Project structure, FMPA purchased from OUC a 23.2 percent undivided ownership interest in OUC's Stanton Unit No. 2, a coal fired unit virtually identical to Stanton Unit No. 1. The unit commenced commercial operation in June 1996. Seven of FMPA's members are participants in the Stanton II Project with the following entitlements as shown in Table 1-5.

Table 1-5 Stanton II Project Participants			
City	% Entitlement	City	% Entitlement
Fort Pierce	16.488	Homestead	8.2443
Key West	9.8932	Kissimmee	32.9774
St. Cloud	14.6711	Starke	1.2366
Vero Beach	16.4887		

1.2.1.5 ARP. As discussed above, under the ARP, FMPA currently serves all the power requirements (above certain excluded resources) for 15 of its members. Bushnell, Green Cove Springs, Jacksonville Beach, Leesburg, and Ocala were the original ARP members. Clewiston joined in 1991. In 1997, the cities of Vero Beach and Starke joined the ARP. In 1998, FPUA and Key West joined the ARP. The City of Fort Meade, the Town of Havana, and the City of Newberry joined in 2000. In 2002, KUA and Lake Worth joined the ARP.

1.2.2 ARP Power Supply Resources

A summary of existing ARP resources, as well as changes to existing purchase power contracts, is shown in Table 1-6. In addition to these resources, the ARP is currently implementing one generation project planned for operation January 1, 2006, referred to herein as Stock Island Combustion Turbine Unit 4. This project is currently ongoing in the areas of preliminary engineering, permitting, and combustion turbine procurement.

The Stock Island Combustion Turbine Unit 4 will be a General Electric LM6000 PC-SPRINT combustion turbine with variable inlet guide vanes (VIGVs) rated for approximately 42 MW net at summer conditions. The combustion turbine will be installed at the KEYS' Stock Island site in Key West adjacent to Combustion Turbine Unit 3, and will burn low-sulfur fuel oil.

FMPA is in the process of filing its Treasure Coast Energy Cent Unit 1 (TCEC Unit 1) Need for Power Application, which explains its determination that the addition of a 1x1 7FA combined cycle is the most cost-effective unit addition to satisfy forecast capacity requirements in the summer of 2008. It has also been assumed, consistent with the TCEC Unit 1 Need for Power Application, that FMPA would participate with other municipal utilities in the development of an 800 MW coal-fired project in the state of Florida. The primary advantage of a publicly-owned coal-fired project would be to diversify resources, while supplying competitively priced power into the future. The group is actively assessing sites and performing preliminary environmental and transmission line studies related to the project. FMPA's current participation is assumed to be 250 MW, with an anticipated commercial operation date of June 1, 2011. It should be noted that neither the capacity associated with TCEC Unit 1 nor FMPA's participation in the 800 MW coal project are included in Table 1-6.

Table 1-6
ARP's Existing Resource Capacity

Generating Resources	Existing Summer Rating							
	2005	2006	2007	2008	2009	2010	2011-2012	2013-2024
Excluded Resources (Nuclear)	83	83	83	83	83	83	83	83
Stanton Coal Plant	220	220	220	220	220	220	220	220
Stanton CC Unit A[1]	127	127	127	127	127	127	127	127
Cane Island 1-3	379	379	379	379	379	379	379	379
Indian River CTs	80	80	80	80	80	80	80	80
Key West Units 2&3	36	36	36	36	36	36	36	36
Ft. Pierce Native Generation	118	118	118	118	118	118	118	118
Key West Native Generation	50	50	50	50	50	50	50	50
Kissimmee Native Generation	61	61	61	61	61	61	61	61
Lake Worth Native Generation	88	88	88	88	88	88	88	88
Vero Beach Native Generation	150	150	150	150	150	150	150	150
Total Generating Capacity	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392
Purchased Power								
PEF Partial Requirements	30	40	0	20	0	25	0	0
FPL Partial Requirements	75	75	75	0	0	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	45	45	0
OUC Indian River Purchase	43	22	0	0	0	0	0	0
Starke (GRU)	3	3	0	0	0	0	0	0
Lakeland Purchase	100	100	100	0	0	0	0	0
Calpine Purchase	35	75	100	100	100	0	0	0
Total Purchased Power Resources	331	360	320	165	145	70	45	0
Total Resources	1,723	1,752	1,712	1,551	1,537	1,462	1,437	1,392

Current supply side resources for the ARP are classified into five main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in Progress Energy Florida's Crystal River Unit 3. Likewise, a number of ARP members participate in the St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. Capacity from these two nuclear units is classified as "excluded resources" in the ARP. As such, the ARP members pay their own costs associated with the nuclear units and receive the benefits of the capacity and energy from these units. The

ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are, however, considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the Stanton, Tri-City, and Stanton II projects.

The third category of resources is member generation. Capacity included in this category is generation owned by the ARP members either solely or jointly. The ARP purchases this capacity from the ARP members and then commits and dispatches the generation to meet the total requirements of the ARP.

The fourth category is capacity solely owned by FMPA for the ARP. This capacity consists of Stock Island Combustion Turbine Units 2 and 3.

The fifth category of resources is purchase power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP members, which were entered into prior to the member joining the ARP.

1.3 Capacity and Power Purchase Contracts

The current system firm power supply purchase resources of ARP include purchases from Progress Energy Florida (PEF), Florida Power & Light (FPL), Orlando Utilities Commission (OUC), Lakeland Electric, Gainesville Regional Utilities (GRU), Calpine, and the Southern Company-Florida Stanton A capacity that is purchased power. The power purchase contracts are briefly summarized below:

- PEF:
  - FMPA has a power contract with PEF for Partial Requirements (PR) Services. FMPA expects to take 30 MW in 2005, 40 MW in 2006, 20 MW in 2008, and 25 MW in 2010. The PR capacity also includes reserves.
- FPL:
  - FMPA has two contracts with FPL, including a short-term 75 MW purchase until 2007 and a long-term 45 MW purchase until 2010. The FPL short and long-term purchases include reserves.
- OUC:
  - FMPA has a 43 MW purchase in 2005 from the OUC Indian River plant, which decreases to 22 MW in 2006 and expires thereafter.

- Lakeland Electric:
  - FMPA has a 100 MW contract with Lakeland Electric. This contract originally extended through 2010, but it has been renegotiated so that the capacity will be replaced with FMPA resources in December, 2007.
- GRU:
  - FMPA has a 3 MW contract with GRU through 2006.
- Calpine:
  - FMPA has a contract with Calpine that begins in 2005 for 35 MW and increases to 100 MW in 2007, expiring in 2009.
- Southern Company-Florida:
  - FMPA has a contract for 82 MW of purchase power including KUA's share from Stanton A that extends to 2013 for the initial term and has various extension options.

Florida Municipal Power Agency

Section 2.0

Description of Existing Facilities

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2.0 Description of Existing Facilities

The following section presents a map (Figure 2-1) illustrating the location of FMPA's members as well as tables presenting detailed descriptions of existing ARP generating resources (Table 2-1) and purchase power resources (Table 2-2).

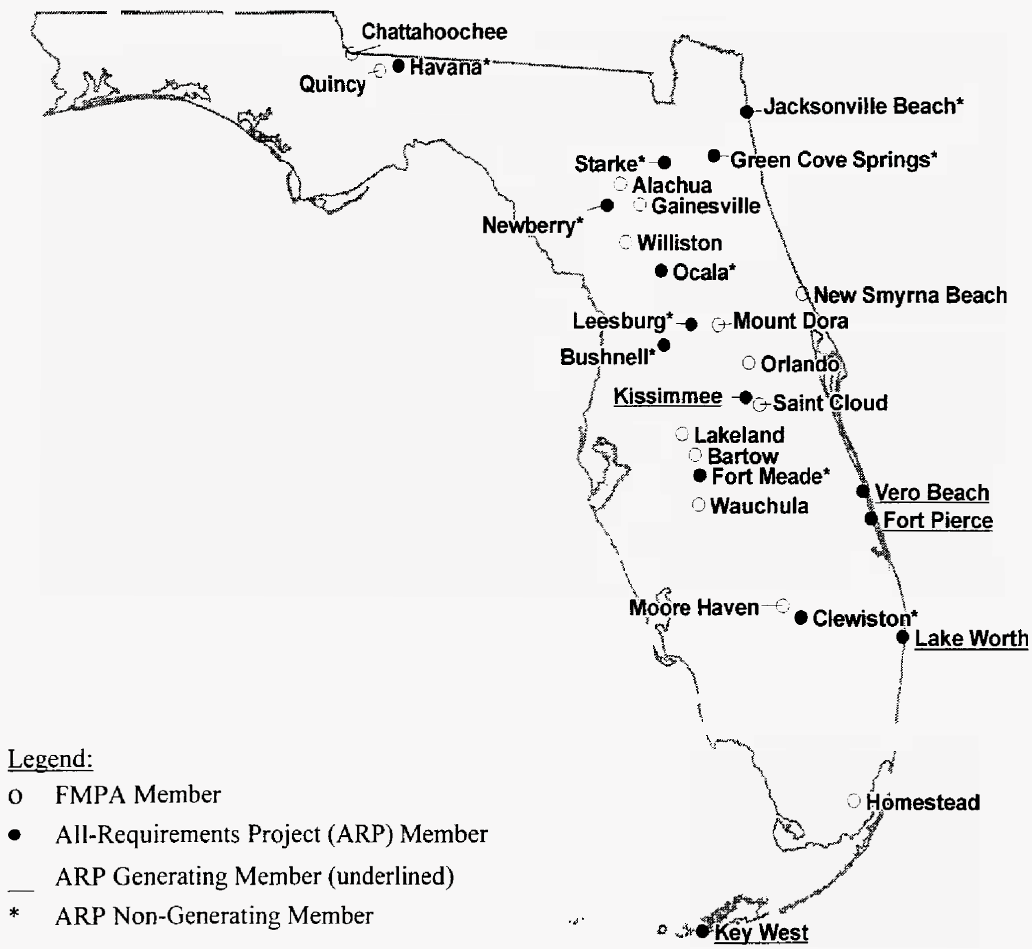

Figure 2-1
FMPA Member Cities

Table 2-1
ARP Existing Generating Resources (as of December 31, 2004)

Plant Name	Unit No.	Location	Unit Type	Fuel Type Primary	Fuel Type Alternate	Fuel Transportation Primary	Fuel Transportation Alternate	Commercial In-Service MM/YY	Expected Retirement Mo/Yr	Gen. Max Nameplate MW	Net Capability[1] Summer (MW)	Net Capability[1] Winter (MW)
Crystal River	3	Citrus	NP	UR	-	TK	-	03/77	UNK	891	23	23
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	UNK	839	60	60
									Total Nuclear Capacity		83	83
Stanton Energy Center	1	Orange	ST	BIT	(2)	RR		07/87	UNK	465	122	122
Stanton Energy Center	2	Orange	ST	BIT	(2)	RR		06/96	UNK	465	98	98
Stanton Energy Center	A	Orange	CC	NG	FO2	PL	TK	10/03	UNK	671	22	22
Indian River	CT A	Brevard	CT	NG	FO2	PL	TK	06/89	UNK	41	14	19
Indian River	CT B	Brevard	CT	NG	FO2	PL	TK	07/89	UNK	41	14	19
Indian River	CT C	Brevard	CT	NG	FO2	PL	TK	08/92	UNK	112	23	27
Indian River	CT D	Brevard	CT	NG	FO2	PL	TK	10/92	UNK	112	23	27
Cane Island	1	Osceola	GT	NG	FO2	PL	TK	01/95	UNK	40	15	20
Cane Island	2	Osceola	CC	NG	FO2	PL	TK	06/95	UNK	122	54	60
Cane Island	3	Osceola	CC	NG	FO2	PL	TK	01/02	UNK	280	120	125
Stock Island	CT 2	Monroe	CT	FO2	-	WA		06/99	UNK	21	18	18
Stock Island	CT 3	Monroe	CT	FO2		WA		06/99	UNK	21	18	18
									Total Owned Generation		541	575

(1) Totals may not add due to rounding.

(2) Stanton Units 1 and 2 have the ability to supplement primary fuel with landfill methane gas on an as-available basis.

Table 2-1 (Continued)
ARP Existing Generating Resources (as of December 31, 2004)

				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	Mo/Yr	MW	Summer (MW)	Winter (MW)
Member Generation												
Municipal Plant	1	Indian River	ST	NG	RFO	PL	TK	11/61	UNK	13	13	13
Municipal Plant	2	Indian River	CA	NG	RFO	PL	TK	8/64	UNK	13	13	13
Municipal Plant	3	Indian River	ST	NG	RFO	PL	TK	9/71	UNK	33	33	33
Municipal Plant	4	Indian River	ST	NG	RFO	PL	TK	8/76	UNK	56	56	56
Municipal Plant	5	Indian River	CT	NG	RFO	PL	TK	12/92	UNK	40	35	40
										Total Vero Beach	150	155
H.D. King	5	St. Lucie	CA	WH				1/53	UNK	8	8	8
H.D. King	7	St. Lucie	ST	NG	RFO	PL	TK	1/64	UNK	32	32	32
H.D. King	8	St. Lucie	ST	NG	RFO	PL	TK	5/76	UNK	50	50	50
H.D. King	9	St. Lucie	CT	NG	FO2	PL	TK	5/90	UNK	23	23	23
H.D. King	D1	St. Lucie	IC	FO2		TK		4/70	UNK	3	3	3
H.D. King	D2	St. Lucie	IC	FO2		TK		4/70	UNK	3	3	3
										Total Fort Pierce Utilities Authority	118	118
Hansel Plant	8	Osceola	IC	NG	FO2	PL	TK	02/59	UNK	2	2	2
Hansel Plant	14	Osceola	IC	NG	FO2	PL	TK	02/72	UNK	2	2	2
Hansel Plant	15	Osceola	IC	NG	FO2	PL	TK	02/72	UNK	2	2	2
Hansel Plant	16	Osceola	IC	NG	FO2	PL	TK	02.72	UNK	2	2	2
Hansel Plant	17	Osceola	IC	NG	FO2	PL	TK	02/72	UNK	2	2	2
Hansel Plant	18	Osceola	IC	NG	FO2	PL	TK	02/72	UNK	2	2	2
Hansel Plant	19	Osceola	IC	FO2		TK		02/83	UNK	2	2	2
Hansel Plant	20	Osceola	IC	FO2		TK		02/83	UNK	3	2	3
Hansel Plant	21	Osceola	CT	NG	FO2	PL	TK	02/83	UNK	38	30	38
Hansel Plant	22	Osceola	CA	WH				11/83	UNK	8	8	6
Hansel Plant	23	Osceola	CA	WH	-	-		11/83	UNK	8	8	6

(1) Totals may not add due to rounding.

Table 2-1 (Continued)
ARP Existing Generating Resources (as of December 31, 2004)

				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	Mo/Yr	MW	Summer (MW)	Winter (MW)
Member Generation (continued)												
Kissimmee Utility Authority (continued)												
Cane Island	1	Osceola	GT	NG	FO2	PL	TK	1/95	UNK	40	15	20
Cane Island	2	Osceola	CC	NG	FO2	PL	TK	6/95	UNK	122	54	60
Cane Island	3	Osceola	CC	NG	FO2	PL	TK	1/02	UNK	280	120	125
Stanton	A	Orange	CC	NG	FO2	PL	TK	10/03	UNK	671	22	22
Indian River	A	Brevard	CT	NG	FO2	PL	TK	6/89	UNK	41	5	6
Indian River	B	Brevard	CT	NG	FO2	PL	TK	6/89	UNK	41	5	6
										Total Kissimmee Utility Authority	283	306
Lake Worth												
Tom G. Smith	GT-1	Palm Beach	GT	FO2		TK		12/76	UNK	31	26	31
Tom G. Smith	GT-2	Palm Beach	CT	NG	FO2	PL	TK	3/78	UNK	20	21	23
Tom G. Smith	MU1	Palm Beach	IC	FO2		TK		12/65	UNK	2	2	2
Tom G. Smith	MU2	Palm Beach	IC	FO2		TK		12/65	UNK	2	2	2
Tom G. Smith	MU3	Palm Beach	IC	FO2		TK		12/65	UNK	2	2	2
Tom G. Smith	MU4	Palm Beach	IC	FO2		TK		12/65	UNK	2	2	2
Tom G. Smith	MU5	Palm Beach	IC	FO2		TK		12/65	UNK	2	2	2
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	11/67	UNK	27	22	24
Tom G. Smith	S-5	Palm Beach	CA	WA				3/78	UNK	10	9	9
										Total Lake Worth	88	97

(1) Totals may not add due to rounding.

Table 2-1 (Continued)
ARP Existing Generating Resources (as of December 31, 2004)

Plant Name	Unit No.	Location	Unit Type	Fuel Type Primary	Fuel Type Alternate	Fuel Transportation Primary	Fuel Transportation Alternate	Commercial In-Service MM/YY	Expected Retirement Mo/Yr	Gen. Max Nameplate MW	Net Capability[1] Summer (MW)	Net Capability[1] Winter (MW)
	1	Monroe	IC	FO2	-	TK		2/69	UNK	3	3	3
Cudjoe Key Peaker	2	Monroe	IC	FO2	-	TK		8/68	UNK	3	3	3
Cudjoe Key Peaker	3	Monroe	IC	FO2	-	TK		8/68	UNK	2	2	2
Stock Island	GT1	Monroe	GT	FO2		WA		11/78	UNK	20	20	20
Stock Island HSD	IC1	Monroe	IC	FO2	-	WA	-	1/65	UNK	2	2	2
Stock Island HSD	IC2	Monroe	IC	FO2	-	WA	-	1/65	UNK	2	2	2
Stock Island HSD	IC3	Monroe	IC	FO2	-	WA	-	1/65	UNK	2	2	2
Stock Island MSD	MSD1	Monroe	IC	FO2	-	WA	-	6/91	UNK	9	9	9
Stock Island MSD	MSD2	Monroe	IC	FO2	-	WA		6/91	UNK	9	9	9
										Total Keys Energy Services	50	50
										Total Member Generation	689	726
										Total Generation Resources	1,309	1,364

(1) Totals may not add due to rounding.

Table 2-2
Annual Purchased Power Summary (as of January 1, 2005)

	Annual Capacity Purchased[1]								
	2005	2006	2007	2008	2009	2010	2011	2012	2013-2024
Stanton A[2]	105	105	105	105	105	105	105	105	105
PEF Partial Requirements[3]	30	40	0	20	0	25	0	0	0
FPL Short-Term Purchase[3]	75	75	75	0	0	0	0	0	0
FPL Long-Term Purchase[3]	45	45	45	45	45	45	45	45	0
OUC Indian River Purchase	43	22	0	0	0	0	0	0	0
Starke (GRU)	3	3	0	0	0	0	0	0	0
Lakeland Purchase	100	100	100	0	0	0	0	0	0
Calpine Purchase	35	75	100	100	100	0	0	0	0
Total Purchased Power Resources	436	465	425	270	250	175	150	150	105

[1]Based on summer season.
[2]Includes FMPA and KUA's purchase power from Stanton A as well as KUA's equity ownership in Stanton A.
[3]PEF and FPL (short- and long-term) purchases include reserves.

Florida Municipal Power Agency

Section 3.0

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

Community Power + Statewide Strength

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

3.1 Introduction

Under the ARP structure, FMPA agrees to meet all of its members' power requirements. To secure sufficient capacity and energy, FMPA forecasts each ARP member's loads on an individual basis and integrates the results into an FMPA forecast of electrical power demand and energy consumption for the entire ARP. The following discussion summarizes the load forecasting process and the results of the most recent forecast.

3.2 Load Forecast Process

FMPA prepares its load and energy forecast by month and summarizes the forecast annually. The load and energy forecast includes projections of customers, demand, and energy sales by rate classification for each of the ARP members. The forecast process includes existing ARP member cities that FMPA is currently supplying and ARP members that FMPA will supply in the future. Forecasts are prepared on an individual city basis and then aggregated into projections of FMPA's demand and energy requirements.

In addition to the base case load and energy forecast, FMPA has prepared high and low case forecasts for each of the ARP participants. Though the high and low case forecasts do not represent defined scenarios, they capture a confidence band around the base case forecast. This band provides sufficient variation about which to develop robust power supply plans. In addition to the base case, the high and low case load forecasts were considered in the TCEC Unit 1 Need for Power Application.

3.3 2004 Load Forecast Overview

FMPA retained R. W. Beck, Inc. (Beck) to prepare a forecast of peak load and net energy for the ARP. The load and energy requirement forecast is a critical input to many utility processes including, but not limited to, generation expansion planning, fuel and purchased power budgeting, transmission planning, financial planning and budgeting, and staffing. Consequently, a rigorous and detailed process that relies on recognized standards of practice, as well as a thorough review of results by various parties, is essential to FMPA operations and long-term planning.

The load and energy forecast (Forecast) was prepared for a 20 year period, (2004 through 2023) and was extrapolated to 2024 to allow a 20 year planning period from 2005 to 2024. The Forecast has been prepared on a monthly basis using municipal utility data provided to FMPA by the ARP members and load data maintained by FMPA. Historical and projected economic and demographic data was provided by Economy.com, a nationally recognized provider of such data. Beck also relied on ARP members and their staffs for information and expert judgment regarding local economic and demographic issues specific to each member.

The results of the Forecast show that the calendar year net energy for load supplied from the ARP is expected to grow at an annual average growth rate of 2.5 percent from 2005-2013, and then 2.2 percent through 2024.

The actual 2004 peak of 1,414 MW was slightly higher than the projected peak. However, the actual 2004 peak fell in the range of the high and low cases. The high and low cases do not reflect different projections of future conditions with respect to the explanatory variables. Rather, the high and low cases represent a band of uncertainty within which, in the near term, the annual peak and net energy are likely to fall under a single set of assumptions about the future.

3.4 Load Forecast Methodology

Because perfect knowledge about the future energy consumption of each member is not possible, FMPA relies on a forecasting process that balances complex mathematical models with sound judgment and, to the extent available, local, expert knowledge.

In order to predict energy requirements, utilities need a forecasting methodology that explains variations in energy requirements. In addition, understanding relationships, that affect energy consumption, allows utilities to perform "what-if" analyses, thereby improving decisions. For this reason, electric utilities typically rely on econometric forecasting techniques. Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience. These historical relationships (models) are evaluated, and then selected on their statistical ability to explain variations in the dependent variable of concern. The ability of a model to explain variations is often referred to as "goodness-of-fit."

The models are assumed to continue explaining variation in the future as they have in the past. Using projections of explanatory variables, the selected models produce a forecast of dependent variables.

3.5 Model Specification

The following discussion summarizes the development of econometric models used to forecast load, energy sales, and customer accounts on a monthly basis. This overview will present a common basis upon which each classification of models was prepared.

For the residential class, the analysis of electric sales was separated into residential usage per customer and the number of customers, the product of which is total residential sales. This process is common for homogenous customer groups. For other rate classifications, the total sales series is the primary forecasted variable, and the customer forecast is generated for reporting purposes and to check the sensibility of the sales forecast.

Residential class models typically reflect that energy sales are dependent on, or driven by: (i) the number of residential customers, (ii) real personal income per household, (iii) real electricity prices, and (iv) the weather. The number of residential customers was projected on the basis of the estimated historical relationship between the number of residential customers of the ARP members and the number of households in each ARP member's county.

For the general service class models, the econometric models reflect that energy requirements are best explained by: (i) real retail sales, total personal income, or gross domestic product (GDP) as a measure of economic activity and population in and around the member's service territory, (ii) the real price of electricity, and (iii) the weather. In the case of the general service nondemand class, retail sales were typically selected as the long-term driving variable either because it performed better by certain measures, or because the resulting forecast was more sensible. Similarly, for the general service demand class, total personal income was typically selected. For the industrial class, GDP was the typical long-term driving variable, except in cases where the forecast was based on an assumption (e.g., Clewiston and Key West).

The weather model includes heating and cooling degree-days for the current month and for the prior month. Lagged degree-day variables are included to account for the typical billing cycle offset from calendar data. In other words, sales that are billed in any particular month are typically made up of electricity that was used during some portion of the current month and of the prior month.

The Beck 2004 Load Forecast Report also provides an explanation of member-specific modifications of the general theoretical model designed to account for dynamic behavior that occurred during the study period or is expected to occur in the future and for changes in the dependent variable that could not be adequately explained by the available data. The latter includes adjustments to account for observations of the dependent variable that are believed to be anomalous. While these adjustments artificially increase the "fit" of regression equations and are typically discouraged, large deviations from expected behavior tend to have a significant impact on the resulting forecast parameters.

3.6 Principal Considerations and Assumptions

3.6.1 Historical Member Data

FMPA staff provided historical data for each member. In addition, FMPA staff provided work papers and documentation for the 2003 Load and Energy Forecast, which were prepared by FMPA staff. Data provided by FMPA staff included historical customers and sales by rate classification for each of the members. Revenue data was also provided; however, for part of the Study Period, only total revenues were available. Data was provided from January 1992 or the year a new member joined ARP through at least June 2003 and, in many cases, the end of fiscal year 2003 (i.e., September 2003).

3.6.2 Weather Data

Historical weather data was obtained from the National Climatic Data Center (a division of the National Oceanic and Atmospheric Administration), which was generally used to supplement an existing weather database maintained by FMPA. Weather stations, from which historical weather was provided, were selected by their quality first, and second by their proximity to the member. In most cases, the closest first-order weather station was the best source of weather data. First-order weather stations (usually airports) generally provide the highest quality and most reliable weather data. However, based on statistical measures, there were two cases (Jacksonville Beach and Vero Beach) that weather from cooperative weather stations, which were closer than the first-order station to the members, appeared to be more reflective of select member conditions than the closest first-order weather station.

The weather's influence on electricity sales has been represented through the use of two data series: heating and cooling degree-days (HDD and CDD, respectively). Degree-days are derived by comparing the average daily temperature and (in the case of this forecast) 65° F. To the extent that the average daily temperature exceeds 65° F, the difference is the number of CDD required to cool the average daily temperature to 65° F. Conversely, HDD is the result of average daily temperatures, which are below 65° F.

Because predicting future long-term weather patterns is impossible, normal weather conditions have been assumed in the projected period. Thirty-year normal monthly HDD and CDD are based on average weather conditions over the 1971-2000 period.

3.6.3 *Economic Data*

Economy.com, a nationally recognized organization, provided both historical and projected economic and demographic data. The data included economic and demographic data for each of the 15 counties in which members' service territory resides. This data includes county population, households, employment, personal income, retail sales, and gross domestic product. Although all the data was not necessarily used in each of the forecast equations, each was examined for its potential to explain changes in the members' historical electric sales.

3.7 Overview of Results

3.7.1 *Base Load Forecast*

The results of the Forecast show that, for each calendar year, ARP's net energy for load is expected to grow at an annual average growth rate of 2.5 percent from 2005 through 2014, and then grow at an annual average rate of 2.2 percent through 2024. Forecasts for the year 2024 were developed by applying the growth rate from 2022 to 2023 to the 2023 forecasts.

3.7.2 *High and Low Load Forecast*

The base case projection consists of an estimate of the future values for each of the dependent variables, the electricity sales by rate classification for each of the members, and all of the derived load determinants, including net energy for load and peak demand. The base case projection represents the most likely estimate of the dependent variables, given a particular projection of the independent variables. However, there is some uncertainty in those projections related solely to the uncertainty of the estimated parameters in the regression equations. This uncertainty is referred to as the standard error of the regression. Given this uncertainty, high and low projections were developed by adding and subtracting one standard error of the regression to the base case monthly projections. The high and low projections combine to form a band of uncertainty that is intended to capture approximately 67 percent of occurrences.

3.8 Conclusions and Recommendations

The results of this forecast have been influenced by several factors including data integrity, economic projections, and local knowledge. Each of these factors brings elements of bias and error, only some of which is controllable. To the extent that bias and error are removed from the forecast, the ability of the forecast to predict future load and energy requirements improves.

The econometric methods used in this body of work thrive on large amounts of data. The larger the amount of data, the more likely it is that useful, stable relationships can be drawn from the data. In addition to the amount of data, the more closely the data represent what actually happened historically (and what will happen in the future), the better the models will be at predicting future load and energy requirements.

In this forecast, Beck relied on economic projections provided by Economy.com. Though Economy.com is a recognized provider used by many Florida utilities, they seem unlikely to inject significant local knowledge into their economic projections. To the extent that county-level economics are not representative of ARP member economics, the forecasting models may be biased. In addition, due to the lag of economic data reporting, the last two years or more of historical economic data are actually projections. To the extent that the projections of historical economics differ from actual economics, the forecasting models will be affected.

As a general rule, local knowledge can play a significant role in developing reliable forecasting models. Local knowledge adds both a deeper understanding of historical data behavior and relationships and a useful expectation regarding how both are likely to change in the future. However, adjustments to forecasting models or underlying data should be made with considerable care.

Overall, it is important to remember that the load forecast is an annual process. As projections become historical values, uncertainties in the current near term will diminish and be replaced with other uncertainties. However, barring significant and lasting changes to the underlying relationships, the econometric load forecast is a prudent and reliable means of forecasting load and energy.

Tables 3-1 through 3-6 present the base case load forecast. Tables 3-7 through 3-9 present the high load forecast, and Tables 3-10 through 3-12 present the low load forecast. Table 3-13 presents the base case monthly load forecast.

Table 3-1 (Schedule 2.1)
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential				Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1995			1,041	76,070	13,690	1,146	13,766	83,250
1996			1,072	77,423	13,840	1,163	14,141	82,210
1997			1,234	103,507	11,920	1,380	19,723	69,960
1998			1,878	141,969	13,230	1,919	27,302	70,280
1999			1,980	151,969	13,030	2,318	28,789	80,520
2000			2,065	154,938	13,330	2,448	29,518	82,930
2001			2,105	156,751	13,430	2,466	30,097	81,940
2002			2,359	173,977	13,560	2,803	33,211	84,400
2003			3,138	227,099	13,820	3,271	43,374	75,413
2004			3,150	227,939	13,819	3,310	44,282	74,748
2005			3,184	234,264	13,591	3,371	44,301	76,097
2006			3,277	239,341	13,692	3,457	45,228	76,435
2007			3,358	243,420	13,797	3,521	45,852	76,799
2008			3,443	247,468	13,914	3,592	46,540	77,191
2009			3,568	254,104	14,040	3,676	47,529	77,343
2010			3,665	258,577	14,175	3,752	48,192	77,851
2011			3,766	263,295	14,304	3,834	48,892	78,422
2012			3,870	268,081	14,436	3,919	49,590	79,024
2013			3,978	273,207	14,561	4,006	50,311	79,630
2014			4,081	277,142	14,725	4,091	50,688	80,709

Table 3-2 (Schedule 2.2)
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways GWh	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Customers GWh
1995					65	11	2,263
1996					76	10	2,321
1997					62	14	2,690
1998					65	15	3,877
1999					69	18	4,385
2000					32	22	4,567
2001					33	22	4,626
2002					36	24	5,222
2003					47	58	6,514
2004					47	60	6,567
2005					47	63	6,665
2006					47	65	6,846
2007					48	67	6,995
2008					48	68	7,152
2009					49	70	7,362
2010					49	72	7,538
2011					50	73	7,723
2012					50	75	7,914
2013					50	77	8,112
2014					51	79	8,302

Table 3-3 (Schedule 2.3)
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
1995	0	80	2,343	0	89,836
1996	0	84	2,405	0	91,564
1997	0	160	2,850	0	123,230
1998	0	680	4,557	0	169,271
1999	0	272	4,657	0	180,758
2000	0	271	4,838	0	184,456
2001	0	240	4,866	0	186,848
2002	0	300	5,522	0	207,188
2003	0	474	6,988	0	270,473
2004	0	410	6,977	0	272,221
2005	0	404	7,069	0	278,565
2006	0	415	7,262	0	284,569
2007	0	424	7,419	0	289,273
2008	0	434	7,586	0	294,008
2009	0	448	7,810	0	301,633
2010	0	459	7,996	0	306,768
2011	0	470	8,193	0	312,187
2012	0	482	8,396	0	317,671
2013	0	494	8,606	0	323,517
2014	0	507	8,809	0	327,830

Table 3-4 (Schedule 3.1)
History and Forecast of Summer Peak Demand (MW)
All-Requirements Project – Base Case

(1)	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm/Ind Load Management	(9) Comm/Ind Load Conservation	(10) Net Firm Demand
1995	504	0	0	0	0	0	0	0	504
1996	509	0	0	0	0	0	0	0	509
1997	643	0	0	0	0	0	0	0	643
1998	947	0	0	0	0	0	0	0	947
1999	982	0	0	0	0	0	0	0	982
2000	972	0	0	0	0	0	0	0	972
2001	965	0	0	0	0	0	0	0	965
2002	992	0	0	0	0	0	0	0	992
2003	1,340	0	0	0	0	0	0	0	1,340
2004	1,414	0	0	0	0	0	0	0	1,414
2005	1,407	0	0	0	0	0	0	0	1,407
2006	1,445	0	0	0	0	0	0	0	1,445
2007	1,476	0	0	0	0	0	0	0	1,476
2008	1,509	0	0	0	0	0	0	0	1,509
2009	1,554	0	0	0	0	0	0	0	1,554
2010	1,591	0	0	0	0	0	0	0	1,591
2011	1,629	0	0	0	0	0	0	0	1,629
2012	1,670	0	0	0	0	0	0	0	1,670
2013	1,711	0	0	0	0	0	0	0	1,711
2014	1,752	0	0	0	0	0	0	0	1,752

Table 3-5 (Schedule 3.2)
History and Forecast of Winter Peak Demand (MW)
All-Requirements Project – Base Case

(1)	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm/Ind Load Management	(9) Comm/Ind Load Conservation	(10) Net Firm Demand
1994/95	502	0	0	0	0	0	0	0	502
1995/96	553	0	0	0	0	0	0	0	553
1996/97	499	0	0	0	0	0	0	0	499
1997/98	686	0	0	0	0	0	0	0	686
1998/99	926	0	0	0	0	0	0	0	926
1999/00	948	0	0	0	0	0	0	0	948
2000/01	1,008	0	0	0	0	0	0	0	1,008
2001/02	1,007	0	0	0	0	0	0	0	1,007
2002/03	1,473	0	0	0	0	0	0	0	1,473
2003/04	1,195	0	0	0	0	0	0	0	1,195
2004/05	1,340	0	0	0	0	0	0	0	1,340
2005/06	1,452	0	0	0	0	0	0	0	1,452
2006/07	1,483	0	0	0	0	0	0	0	1,483
2007/08	1,515	0	0	0	0	0	0	0	1,515
2008/09	1,562	0	0	0	0	0	0	0	1,562
2009/10	1,598	0	0	0	0	0	0	0	1,598
2010/11	1,636	0	0	0	0	0	0	0	1,636
2011/12	1,676	0	0	0	0	0	0	0	1,676
2012/13	1,717	0	0	0	0	0	0	0	1,717
2013/14	1,757	0	0	0	0	0	0	0	1,757

Table 3-6 (Schedule 3.3)
History and Forecast of Annual Net Energy for Load (GWh)
All-Requirements Project – Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)
	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1995	2,363	0	0	0	0	0	2,363	54%
1996	2,405	0	0	0	0	0	2,405	54%
1997	2,850	0	0	0	0	0	2,850	51%
1998	4,530	0	0	0	0	0	4,530	55%
1999	4,657	0	0	0	0	0	4,657	54%
2000	4,838	0	0	0	0	0	4,838	57%
2001	4,866	0	0	0	0	0	4,866	58%
2002	5,541	0	0	0	0	0	5,541	64%
2003	7,019	0	0	0	0	0	7,019	60%
2004	6,977	0	0	0	0	0	6,977	58%
2005	7,069	0	0	0	0	0	7,069	58%
2006	7,262	0	0	0	0	0	7,262	58%
2007	7,419	0	0	0	0	0	7,419	58%
2008	7,586	0	0	0	0	0	7,586	58%
2009	7,810	0	0	0	0	0	7,810	58%
2010	7,996	0	0	0	0	0	7,996	58%
2011	8,193	0	0	0	0	0	8,193	58%
2012	8,396	0	0	0	0	0	8,396	58%
2013	8,606	0	0	0	0	0	8,606	58%
2014	8,809	0	0	0	0	0	8,809	57%

Table 3-7 (Schedule 3.1a)
Forecast of Summer Peak Demand (MW)
All-Requirements Project – High Case

(1)	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm/Ind Load Management	(9) Comm/Ind Load Conservation	(10) Net Firm Demand
2005	1,490	0	0	0	0	0	0	0	1,490
2006	1,531	0	0	0	0	0	0	0	1,531
2007	1,565	0	0	0	0	0	0	0	1,565
2008	1,600	0	0	0	0	0	0	0	1,600
2009	1,648	0	0	0	0	0	0	0	1,648
2010	1,687	0	0	0	0	0	0	0	1,687
2011	1,729	0	0	0	0	0	0	0	1,729
2012	1,772	0	0	0	0	0	0	0	1,772
2013	1,817	0	0	0	0	0	0	0	1,817
2014	1,861	0	0	0	0	0	0	0	1,861

Table 3-8 (Schedule 3.2a)
Forecast of Winter Peak Demand (MW)
All-Requirements Project – High Case

(1)	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm/Ind Load Management	(9) Comm/Ind Load Conservation	(10) Net Firm Demand
2004/05	1,498	0	0	0	0	0	0	0	1,498
2005/06	1,539	0	0	0	0	0	0	0	1,539
2006/07	1,573	0	0	0	0	0	0	0	1,573
2007/08	1,607	0	0	0	0	0	0	0	1,607
2008/09	1,658	0	0	0	0	0	0	0	1,658
2009/10	1,696	0	0	0	0	0	0	0	1,696
2010/11	1,737	0	0	0	0	0	0	0	1,737
2011/12	1,780	0	0	0	0	0	0	0	1,780
2012/13	1,824	0	0	0	0	0	0	0	1,824
2013/14	1,867	0	0	0	0	0	0	0	1.867

Table 3-9 (Schedule 3.3a)
Forecast of Annual Net Energy for Load (GWh)
All-Requirements Project – High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)
	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2005	7,489	0	0	0	0	0	7,489	57%
2006	7,697	0	0	0	0	0	7,697	57%
2007	7,865	0	0	0	0	0	7,865	57%
2008	8,045	0	0	0	0	0	8,045	57%
2009	8,285	0	0	0	0	0	8,285	57%
2010	8,486	0	0	0	0	0	8,486	57%
2011	8,698	0	0	0	0	0	8,698	57%
2012	8,916	0	0	0	0	0	8,916	57%
2013	9,142	0	0	0	0	0	9,142	57%
2014	9,363	0	0	0	0	0	9,363	57%

Table 3-10 (Schedule 3.1b)
Forecast of Summer Peak Demand (MW)
All-Requirements Project – Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2005	1,325	0	0	0	0	0	0	0	1,325
2006	1,359	0	0	0	0	0	0	0	1,359
2007	1,389	0	0	0	0	0	0	0	1,389
2008	1,419	0	0	0	0	0	0	0	1,419
2009	1,461	0	0	0	0	0	0	0	1,461
2010	1,495	0	0	0	0	0	0	0	1,495
2011	1,531	0	0	0	0	0	0	0	1,531
2012	1,568	0	0	0	0	0	0	0	1,568
2013	1,607	0	0	0	0	0	0	0	1,607
2014	1,644	0	0	0	0	0	0	0	1,644

Table 3-11 (Schedule 3.2b)
Forecast of Winter Peak Demand (MW)
All-Requirements Project – Low Case

(1)	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm/Ind Load Management	(9) Comm/Ind Load Conservation	(10) Net Firm Demand
2004/05	1,330	0	0	0	0	0	0	0	1,330
2005/06	1,365	0	0	0	0	0	0	0	1,365
2006/07	1,394	0	0	0	0	0	0	0	1,394
2007/08	1,424	0	0	0	0	0	0	0	1,424
2008/09	1,467	0	0	0	0	0	0	0	1,467
2009/10	1,501	0	0	0	0	0	0	0	1,501
2010/11	1,536	0	0	0	0	0	0	0	1,536
2011/12	1,572	0	0	0	0	0	0	0	1,572
2012/13	1,610	0	0	0	0	0	0	0	1,610
2013/14	1,647	0	0	0	0	0	0	0	1,647

Table 3-12 (Schedule 3.3b)
Forecast of Annual Net Energy for Load (GWh)
All-Requirements Project – Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)
	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2005	6,652	0	0	0	0	0	6,652	57%
2006	6,830	0	0	0	0	0	6,830	57%
2007	6,976	0	0	0	0	0	6,976	57%
2008	7,131	0	0	0	0	0	7,131	57%
2009	7,339	0	0	0	0	0	7,339	57%
2010	7,511	0	0	0	0	0	7,511	57%
2011	7,693	0	0	0	0	0	7,693	57%
2012	7,880	0	0	0	0	0	7,880	57%
2013	8,073	0	0	0	0	0	8,073	57%
2014	8,260	0	0	0	0	0	8,260	57%

Table 3-13 (Schedule 4)
Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 2004		Forecast - 2005		Forecast - 2006	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,195	527	1,340	561	1,452	575
February	1,104	486	1,100	465	1,130	477
March	905	500	1,042	534	1,070	548
April	1,078	504	1,151	524	1,182	538
May	1,291	626	1,268	615	1,302	632
June	1,386	697	1,325	626	1,361	643
July	1,414	725	1,407	724	1,445	745
August	1,372	683	1,382	729	1,419	750
September	1,347	597	1,321	648	1,356	666
October	1,243	603	1,151	598	1,182	616
November	1,135	494	963	500	989	513
December	1,147	535	1,126	544	1,156	559

Florida Municipal Power Agency

Section 4.0

Conservation Programs

Community Power + Statewide Strength

4.0 Conservation Programs

As a wholesale supplier, FMPA does not directly provide demand side programs to retail customers. The demand side programs are provided to the retail customers by the ARP members. The demand side programs are designed to improve efficiency, implement direct control of residential appliances, encourage time-of-use rates, and achieve additional conservation through commercial and industrial audits.

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

FMPA is also supporting 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.

4.1 Existing Demand-Side Management Programs

FMPA is a supporter of electricity conservation where cost-effective, and promotes such programs to its members. FMPA will continue to assist members in increasing the promotion and use of such conservation programs to retail customers and will assist its members in the evaluation of any new programs to ensure their cost-effectiveness. FMPA staff and member cities promote conservation programs through a number of methods, including providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, and so forth. Additionally, bill inserts are utilized to keep customers aware of available conservation programs.

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

- Energy Audits Program.
- High-Pressure Sodium Outdoor Lighting Conversion.
- Load Profiling for Commercial Customers.
- Fix-Up Program for the Elderly and Handicapped.
- Energy Star® Program Participation.

A brief description of each conservation program is provided in the following subsections. The exact implementation varies somewhat from member to member and not all programs are offered by all members.

4.2 Energy Audits Program

Energy audits are offered to residential, commercial, and industrial 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 information on water heater temperature reduction and the installation of the water heater insulating blanket upon customer request.

4.3 High-Pressure Sodium Outdoor Lighting Conversion

This program involves eliminating mercury vapor street and yard lighting. The mercury vapor fixtures are converted to high-pressure sodium fixtures whenever maintenance is required.

4.4 Load Profiling for Commercial Customers

Load profiling involves the expert study of a company's energy use. The utility provides the customer with a clear picture of its power use, including patterns and trends during specific hours. Potential adjustments to the company's operations are presented in order to conserve energy, save costs, and improve efficiency.

4.5 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, and participants are chosen according to grant mandates. Energy auditors recommend homes for the weatherization program.

4.6 Energy Star®

FMPA has a partnership agreement with Energy Star®, a government-backed program helping businesses and individuals protect the environment and save energy through end-use products with superior energy efficiency characteristics. Partnering with Energy Star® and working together through FMPA makes it convenient and cost-effective for FMPA's members to bring the benefits of energy efficiency to their hometown utility.

Florida Municipal Power Agency

Section 5.0

Forecast of Facilities Requirements

Community Power + Statewide Strength

5.0 Forecast of Facilities Requirements

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

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

Currently, the Agency, on behalf of the All-Requirements Project, is planning to add combustion turbine capacity at Stock Island in 2006, additional combustion turbine capacity anticipated to be located at the Lake Worth site in 2007, a 301 MW combined cycle unit (pursuant to the FMPA's Treasure Coast Energy Center Unit 1 Need for Power Application) in 2008, 250 MW of coal-fired capacity in 2011 (refer to Section 1.0 for discussion of this capacity addition), and will require a capacity addition in 2014, likely to be a combustion turbine. FMPA's most recent capacity addition is represented by its share of Stanton Energy Center Unit A (Stanton A), a 633 MW gas-fired combined cycle unit which began commercial operation on October 1, 2003. Stanton A is jointly owned by FMPA, KUA, OUC, and Southern-Florida. Combined, FMPA and KUA own seven percent of Stanton A, and purchase an additional 13 percent of the unit's capacity under a ten-year power purchase agreement with various provisions for capacity reductions as well as contract extensions.

The addition of Treasure Coast Energy Center Unit 1 (TCEC Unit 1) was identified as the least-cost capacity addition to meet FMPA's forecast capacity requirements in the summer of 2008 in FMPA's TCEC Unit 1 Need for Power Application. It has also been assumed that, consistent with the TCEC Unit 1 Need for Power Application, FMPA would participate with other public utilities in the development of an 800 MW coal-fired project in the state of Florida. The primary advantage of a publicly-owned coal-fired project would be to diversify resources, while supplying competitively priced power into the future. The group is actively assessing sites and performing preliminary environmental and transmission line studies related to the project. FMPA's current participation is assumed to be 250 MW, with an anticipated commercial operation date of June 1, 2011.

Additionally, generation can be added at the Cane Island Power Park, at Lake Worth Utilities, at Vero Beach's Power Plant, and at Keys Energy Services' Stock Island Plant. Further, reciprocating engines or small combustion turbine generation can be installed on all fifteen ARP member systems.

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

Table 5-1 (Schedule 5)
Fuel Requirements – All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		**Units**	**Actual 2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
(1)	Nuclear[1]		Trillion BTU	7	7	7	6	7	6	7	7	7	7	7
(2)	Ccal		000 Ton	542	749	773	715	761	763	760	1,204	1,489	1,487	1,492
	Residual													
(3)		Steam	000 BBL	0	0	0	0	0	0	0	0	0	0	0
(4)		CC	000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	000 BBL	0	0	0		0	0	0	0	0	0	0
(6)		TOTAL	000 BBL	0	0	0	0	0	0	0	0	0	0	0
	Distillate													
(7)		Steam	000 BBL											
(8)		CC	000 BBL											
(9)		CT	000 BBL	43	38	39	25	9	9	68	50	58	89	96
(10)		TOTAL	000 BBL	43	38	39	25	9	9	68	50	58	89	96
	Natural Gas													
(11)		Steam	000 MCF	90	2,129	2,107	2,212	2,249	1,583	2,240	1,487	1,093	1,525	1,754
(12)		CC	000 MCF	14,580	25,652	25,094	25,041	34,458	37,761	40,519	34,987	30,817	33,505	34,883
(13)		CT	000 MCF	1,187	1,717	975	2,557	2,485	1,732	2,890	1,785	1,214	1,674	3,086
(14)		TOTAL	000 MCF	15,857	29,498	28,176	29,810	39,192	41,076	45,849	38,259	33,124	36,704	39,723
(15)	Other (Specify)		Trillion BTU	0	3	4	5	4	3	0	0	0	0	0

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

Table 5-2 (Schedule 6.1)
Energy Sources (GWh) – All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		**Units**	**Actual 2004**	**2005**	**2006**	**2007**	**2009**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
(1)	Annual Firm Inter-Region	Interchange	GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear[1]		GWh	677	630	674	599	675	577	651	659	667	635	675
(3)	Coal		GWh	1,366	1,696	1,753	1,623	1,723	1,729	1,720	2,844	3,567	3,564	3,574
	Residual													
(4)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL	GWh	0	0	0	0	0	0	0	0	0	0	0
	Distillate													
(8)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWh	17	2	3	3	4	5	31	33	33	51	49
(11)		TOTAL	GWh	17	2	3	3	4	5	31	33	33	51	49
	Natural Gas													
(12)		Steam	GWh	9	162	159	163	177	125	188	114	88	123	139
(13)		CC	GWh	1,944	2,890	2,757	2,856	4,076	4,594	4,863	4,196	3,737	4,028	4,145
(14)		CT	GWh	113	102	111	160	158	113	189	114	83	114	227
(15)		TOTAL	GWh	2,066	3,154	3,027	3,179	4,411	4,832	5,240	4,424	3,908	4,2654	4,511
(16)	NUG		GWh	0	0	0	0	0	0	0	0	0	0	0
(17)	HYDRO		GWh	0	0	0	0	0	0	0	0	0	0	0
(18)	Interchange		GWh	2,851	1,586	1,805	2,014	773	667	354	233	220	90	0
(19)	Net Energy for Load		GWh	6,977	7,068	7,262	7.418	7,586	7,810	7,996	8,193	8,395	8,605	8,809

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

Table 5-3 (Schedule 6.2)
Energy Sources (%) – All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Annual Firm Inter-Region Interchange		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	Nuclear[1]		%	9.70%	8.91%	9.28%	8.07%	8.90%	7.39%	8.14%	8.04%	7.95%	7.38%	7.66%
(3)	Coal		%	19.58%	24.0%	24.14%	21.88%	22.71%	22.14%	21.51%	34.71%	42.49%	41.42%	40.57%
	Residual													
(4)		Steam	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distillate													
(8)		Steam	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CT	%	0.24%	0.3%	0.4%	0.4%	0.5%	0.06%	0.39%	0.40%	0.39%	0.59%	0.56%
(11)		TOTAL	%	0.24%	03%	0.4%	0.4%	0.5%	0.6%	0.39%	0.40%	0.39%	0.59%	0.56%
	Natural Gas													
(12)		Steam	%	0.13%	2.29%	2.19%	2.20%	2.33%	1.60%	2.35%	1.39%	1.05%	1.43%	1.58%
(13)		CC	%	27.86%	40.89%	37.96%	38.50%	53.73%	58.82%	60.82%	51.21%	44.51%	46.81%	47.05%
(14)		CT	%	1.62%	1.44%	1.53%	2.16%	2.08%	1.45%	2.36%	1.39%	0.99%	1.32%	2.58%
(15)		TOTAL	%	29.61%	44.62%	41.68%	42.86%	58.15%	61.87%	65.53%	54%	46.55%	49.56%	51.21%
(16)	NUG		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(17)	HYDRO		%	%	%	%	%	%	%	%	%	%	%	%
(18)	Interchange		%	40.86%	22.44%	24.86%	27.15%	10.19%	8.54%	4.43%	2.84%	2.62%	1.05%	0.00%
(19)	Net Energy for Load		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

Table 5-4 (Schedule 7.1)
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity[1]	Firm Capacity Import[2]	Firm Capacity Export		Total Available Capacity	System Firm Summer Peak Demand	Reserve Margin before Maintenance[3]		Scheduled Maintenance	Reserve Margin after Maint nance[3]	
Year	MW	MW	MW	QF MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2005	1,287	436	0	0	1,723	1,407	316	25.1%	0	316	25.1%
2006	1,329	465	0	0	1,794	1,445	349	27.2%	0	349	27.2%
2007	1,329	425	0	0	1,754	1,476	278	20.5%	0	278	20.5%
2008	1,700	270	0	0	1,970	1,509	461	31.9%	0	461	31.9%
2009	1,700	250	0	0	1,950	1,554	396	26.2%	0	396	26.2%
2010	1,700	175	0	0	1,875	1,591	284	18.7%	0	284	18.7%
2011	1,950	150	0	0	2,100	1,629	471	29.7%	0	471	29.7%
2012	1,950	150	0	0	2,100	1,670	430	26.5%	0	430	26.5%
2013	1,950	105	0	0	2,055	1,711	344	20.1%	0	344	20.1%
2014	1,997	105	0	0	2,102	1,752	350	20.0%	0	350	20.0%

1. Total Installed Capacity includes existing capacity as well as the addition of Stock Island Combustion Turbine 4 (42 MW in 2006), two combustion turbines (84 MW in 2008), Treasure Coast Energy Center Unit 1 (287 MW in 2008), and FMPA's share of a joint development coal project (250 MW in 2011), and a combustion turbine (47 MW in 2014).
2. Firm Capacity Import includes FMPA's Partial Requirement (PR) purchases, currently expected to be 150 MW in 2005, 160 MW in 2006, 120 MW in 2007, 65 MW in 2008, 45 MW in 2009, 70 MW in 2010, and 45 MW in 2011 and 2012.
3. Reserve Margin calculated as [(Total Available Capacity – Partial Requirements Purchases) – (System Firm Peak Demand – Partial Requirements Purchases)] / (System Firm Peak Demand – Partial Requirements Purchases).

Table 5-5 (Schedule 7.2)
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity[1]	Firm Capacity Import[2]	Firm Capacity Export		Total Available Capacity	System Firm Winter Peak Demand	Reserve Margin before Maintenance[3]		Scheduled Maintenance	Reserve Margin after Maintenance[3]	
Year	MW	MW	MW	QF MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2004/05	1,343	401	0	0	1,744	1,414	330	26.1%	0	330	26.1%
2005/06	1,343	465	0	0	1,808	1,452	356	27.6%	0	356	27.6%
2006/07	1,385	425	0	0	1,810	1,483	327	24.0%	0	327	24.0%
2007/08	1,482	270	0	0	1,752	1,515	237	16.3%	0	237	16.3%
2008/09	1,800	250	0	0	2,050	1,562	488	32.2%	0	488	32.2%
2009/10	1,800	175	0	0	1,975	1,598	377	24.7%	0	377	24.7%
2010/11	1,800	150	0	0	1,950	1,636	314	19.7%	0	314	19.7%
2011/12	2,050	150	0	0	2,200	1,676	524	32.1%	0	524	32.1%
2012/13	2,050	150	0	0	2,200	1,717	483	28.9%	0	483	28.9%
2013/14	2,050	105	0	0	2,155	1,757	398	22.7%	0	398	22.7%

1. Total Installed Capacity includes existing capacity as well as the addition of Stock Island Combustion Turbine 4 (42 MW in 2006), two combustion turbines (97 MW in 2008), Treasure Coast Energy Center Unit 1 (318 MW in 2008), and FMPA's share of a joint development coal project (250 MW in 2011).
2. Firm Capacity Import includes FMPA's Partial Requirement (PR) purchases, currently expected to be 150 MW in 2005, 160 MW in 2006, 120 MW in 2007, 65 MW in 2008, 45 MW in 2009, 70 MW in 2010, and 45 MW in 2011, 2012 and 2013.
3. Reserve Margin calculated as [(Total Available Capacity – Partial Requirements Purchases) – (System Firm Peak Demand – Partial Requirements Purchases)] / (System Firm Peak Demand – Partial Requirements Purchases).

Florida Municipal Power Agency

Section 6.0

Site and Facility Descriptions

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6.0 Site and Facility Descriptions

Florida Public Service Commission Rule 25-22.072 F.A.C. requires that the State of Florida Public Service Commission Electric Utility Ten-Year Site Plan Information and Data Requirements Form PSC/EAG 43 dated 11/97 govern the submittal of information regarding Potential and Identified Preferred sites. Ownership or control are required for sites to be Potential or Identified Preferred. The following are Potential and Identified Preferred sites for FMPA as specified by PSC/EAG 43.

- Stock Island – Identified Preferred Site for Stock Island Combustion Turbine Unit 4
- Treasure Coast Energy Center – Identified Preferred Site for Treasure Coast Energy Center Unit 1
- Cane Island – Potential Site

Sites for the un-sited LM6000 simple cycle combustion turbines and the unnamed coal unit shown in FMPA's expansion plan do qualify as Potential or Identified Preferred Sites because the sites were not owned or under FMPA control as of December 31, 2004, the governing date for this Ten-Year Site Plan.

FMPA anticipates that the LM6000 simple cycle combustion turbines will be installed at an existing ARP member owned generation site, most likely the Tom G. Smith Power Plant Site at Lake Worth. Likewise, the site for the unnamed coal unit was also not under ownership or control of FMPA by December 31, 2004.

Stock Island

A 42 MW combustion turbine will be installed at the Keys Energy Services Stock Island Plant in Monroe County with a commercial in-service date of summer 2006. The site currently consists of five diesel generating units, as well as three combustion turbines. The Stock Island site receives water from the Florida Keys Aqueduct Authority via a pipeline from the mainland, and also uses on-site groundwater. The new 42 MW combustion turbine will utilize water injection for NO_x control (42 ppm) and SO_2 control will consist of limited hours of operation. The 42 MW combustion turbine will be limited to 2,500 hours of operation per year. Standard noise attenuation is used for existing units, and will be used for the 42 MW combustion turbine. The site receives delivery of fuel oil to its unloading system through waterborne delivery, and also has the capability of receiving fuel oil deliveries via truck. The site has no adverse impact on surrounding wetlands, threatened or endangered animal species, nor any designated natural resources.

Treasure Coast Energy Center

As discussed throughout this Ten-Year Site Plan, FMPA is planning to construct a new 1x1 7FA combined cycle facility at the Treasure Coast Energy Center in 2008. The information related to this unit contained herein is consistent with the contents of FMPA's Treasure Coast Energy Center Unit 1 (TCEC Unit 1) Need for Power Application. The Treasure Coast Energy Center will be located in St. Lucie County near the City of Ft. Pierce. The site will be designed to accommodate construction of future units beyond TCEC Unit 1. Detailed information about this site can be found in the TCEC Unit 1 Site Certification Application filed April, 2005.

Cane Island Power Park

Cane Island Power Park is located south and west of the Kissimmee Utility Authority's (KUA) service area and contains 380 MW (summer) of gas turbine and combined cycle capacity. The Cane Island Power Park consists of a simple cycle gas turbine and two combined cycle generating units, each of which is 50 percent owned by FMPA and 50 percent owned by KUA. Cane Island Unit 3, the newest unit at the site, began commercial operation in January, 2002. Details of the Cane Island Power Park can be found in the Cane Island Power Park Site Certification Application filed August, 1998.

In addition to the Potential and Identified Preferred sites described above, FMPA may also be able to use the following sites for future construction.

Tom G. Smith Power Plant (Lake Worth)

The Tom G. Smith Power Plant is located in the City of Lake Worth's service area in Palm Beach County and currently consists of 88 MW of steam, combined cycle, and reciprocating engine generation. The site is suitable for possible future repowering or addition of new combustion turbines or combined cycle capacity.

Vero Beach Power Plant Site

The Vero Beach Power Plant Site is located in the City of Vero Beach's service area in Indian River County and currently consists of 150 MW of steam, combined cycle, and reciprocating engine generation and is suitable for possible future repowering or addition of new combustion turbines or combined cycle units.

Table 6-1 (Schedule 8)
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Alt. Fuel Days Use	Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net Capability		
Plant Name	Unit No.	Location (County)	Unit Type	Primary	Alt.	Primary	Alt.		MM/YY	MM/YY	kW	Summer MW	Winter MW	Status
Stock Island	CT4	Monroe	CT	DFO	DFO	TK	TK		3/2006	UNK	UNK	42	42	P
Tom G. Smith*	CT2	Palm Beach	CT	DFO	DFO	TK	TK		12/2007	UNK	UNK	42	49	P
Tom G. Smith*	CT3	Palm Beach	CT	DFO	DFO	TK	TK		12/2007	UNK	UNK	42	49	P
Treasure Coast Energy Center	Unit 1	St. Lucie	CC	NG	DFO	PL	TK		6/2008	UNK	UNK	296	318	P
Unknown	Unit 1	unknown	ST	BIT	BIT	RR	RR		6/2011	UNK	UNK	250	250	P
Combustion Turbine	CT	unknown	CT	NG	NG	PL	PL		6/2014	UNK	UNK	47	49	P

* Anticipated site

Table 6-2 (Schedule 9.1)
Status Report and Specifications of
Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	Plant Name and Unit Number	Stock Island CT4
(2)	Capacity	
	a. Summer	42
	b. Winter	42
(3)	Technology Type	CT
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	Jul-05
	b. Commercial In-Service Date	Mar-06
(5)	Fuel	
	a. Primary Fuel	No. 2 oil
	b. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	N/A
(8)	Total Site Area	N/A
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	Applications being prepared
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	2.7%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.4%
	Resulting Capacity Factor	4.0%
	Average Net Operating Heat Rate (ANOHR)	11,936 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	20
	Total Installed Cost (In-Service Year $/kW)	646
	Direct Construction Cost (2004 $/kW)	630
	AFUDC Amount ($/kW)	16
	Escalation ($/kW)	0
	Fixed O&M ($/kW)	0
	Variable O&M ($/MWh)	6.40

Table 6-3 (Schedule 9.2)
Status Report and Specifications of
Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Tom G. Smith CT2*
(2)	**Capacity**	
	a. Summer	42
	b. Winter	48.5
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Dec-06
	b. Commercial In-Service Date	Dec-07
(5)	**Fuel**	
	a. Primary Fuel	No. 2 oil
	b. Alternate Fuel	
(6)	**Air Pollution Control Strategy**	Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	2.7%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.4%
	Resulting Capacity Factor	3.0%
	Average Net Operating Heat Rate (ANOHR)	11,370 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	20
	Total Installed Cost (In-Service Year $/kW)	786
	Direct Construction Cost (2004 $/kW)	671
	AFUDC Amount ($/kW)	53
	Escalation ($/kW)	62
	Fixed O&M ($/kW)	13.33
	Variable O&M ($/MWh)	6.40

* Anticipated site

Table 6-4 (Schedule 9.3)
Status Report and Specifications of
Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Tom G. Smith CT3*
(2)	**Capacity**	
	a. Summer	42
	b. Winter	48.5
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Dec-06
	b. Commercial In-Service Date	Dec-07
(5)	**Fuel**	
	a. Primary Fuel	No. 2 oil
	b. Alternate Fuel	
(6)	**Air Pollution Control Strategy**	Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	2.7%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.4%
	Resulting Capacity Factor	3.0%
	Average Net Operating Heat Rate (ANOHR)	11,370 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	20
	Total Installed Cost (In-Service Year $/kW)	786
	Direct Construction Cost (2004 $/kW)	671
	AFUDC Amount ($/kW)	53
	Escalation ($/kW)	62
	Fixed O&M ($/kW)	13.33
	Variable O&M ($/MWh)	6.40

* Anticipated site

Table 6-5 (Schedule 9.4)
Status Report and Specifications of
Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Treasure Coast Energy Center Unit 1
(2)	**Capacity**	
	a. Summer	287
	b. Winter	318
(3)	**Technology Type**	CC
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jul-06
	b. Commercial In-Service Date	May-08
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	Mechanical Draft
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	Application submitted or being prepared
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	2.0%
	Forced Outage Factor (FOF)	4.0%
	Equivalent Availability Factor (EAF)	94.1%
	Resulting Capacity Factor	68.0%
	Average Net Operating Heat Rate (ANOHR)	9,445 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	763
	Direct Construction Cost (2004 $/kW)	672
	AFUDC Amount ($/kW)	40
	Escalation ($/kW)	52
	Fixed O&M ($/kW)	5.90
	Variable O&M ($/MWh)	3.01

Table 6-6 (Schedule 9.5)
Status Report and Specifications of
Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Unknown Unit 1
(2)	**Capacity**	
	a. Summer	250
	b. Winter	250
(3)	**Technology Type**	ST
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jan-07
	b. Commercial In-Service Date	Jun-11
(5)	**Fuel**	
	a. Primary Fuel	BIT
	b. Alternate Fuel	
(6)	**Air Pollution Control Strategy**	Unknown
(7)	**Cooling Method**	Unknown
(8)	**Total Site Area**	Unknown
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	Unknown
	Forced Outage Factor (FOF)	Unknown
	Equivalent Availability Factor (EAF)	Unknown
	Resulting Capacity Factor	Unknown
	Average Net Operating Heat Rate (ANOHR)	Unknown
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	Unknown
	Total Installed Cost (In-Service Year $/kW)	Unknown
	Direct Construction Cost (2004 $/kW)	Unknown
	AFUDC Amount ($/kW)	Unknown
	Escalation ($/kW)	Unknown
	Fixed O&M ($/kW)	Unknown
	Variable O&M ($/MWh)	Unknown

Table 6-7 (Schedule 9.6)
Status Report and Specifications of
Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Unknown CT
(2)	**Capacity**	
	a. Summer	47
	b. Winter	49
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Oct-2013
	b. Commercial In-Service Date	Jun-14
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	2.7%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.4%
	Resulting Capacity Factor	4.0%
	Average Net Operating Heat Rate (ANOHR)	10,620 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	20
	Total Installed Cost (In-Service Year $/kW)	862
	Direct Construction Cost (2004 $/kW)	677
	AFUDC Amount ($/kW)	14
	Escalation ($/kW)	170
	Fixed O&M ($/kW)	17.60
	Variable O&M ($/MWh)	2.70

Table 6-8 (Schedule 10) Status Report and Specifications of Proposed Directly Associated Transmission Lines All-Requirements Project		
(1)	**Point of Origin and Termination**	FMPA has no Proposed Transmission Lines for inclusion in Schedule 10.
(2)	**Number of Lines**	N/A
(3)	**Right-of-Way**	N/A
(4)	**Line Length**	N/A
(5)	**Voltage**	N/A
(6)	**Anticipated Construction Timing**	N/A
(7)	**Anticipated Capital Investment**	N/A
(8)	**Substations**	N/A
(9)	**Participation with Other Utilities**	N/A

Florida Municipal Power Agency

Appendix I

Planned and Proposed Transmission Additions

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Appendix I
Planned and Proposed Transmission Additions

Appendix I
Planned and Proposed Transmission Additions

Table I-1 presented on the following page contains a list of planned and proposed transmission line additions for member cities of the Florida Municipal Power Agency who participate in the All-Requirements Project, as well as other (non-ARP) member cities who are not required to file a Ten-Year Site Plan. In view of current efforts to form the new Florida Regional Transmission Organization (RTO), it was considered necessary to document these plans in the public record.

Table I-1
Planned and Proposed Transmission Additions for FMPA Members
2005 through 2014 (69 kV and above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Ft. Pierce	Hartman Auto-Xfmr1Upgrade		100	138/69		9/2007
	Hartman Auto-Xfmr2 Upgrade		100	138/69		9/2007
	King (Reconductor)	Garden City		69	1	9/2009
	King (Reconductor)	Savannah		69	1	9/2009
Homestead	Redland	Lucy		138 kV	1	12/2006
	Redland	McMinn		138 kV	1	12/2006
	FPL (Florida City #2)	Redland		138 kV	1	12/2006
Jacksonville Beach	Jacksonville Beach (Reconductor)	Neptune		138 kV	1	6/2008
	Penman Road Substation			138 kV		3/2005
Key West & FKEC	Tavernier	Islamorada		138 kV	2	6/2015
	Islamorada	Marathon		138 kV	1	6/2015
	Florida City	Tavernier		138 kV	2	6/2015
	Tavernier			Ring Bus		6/2015
	Marathon		Var Improvements			7/2005
	Big Pine		Var Improvements			7/2005
	Big Coppitt		Var Improvements			7/2005
	KWD Transformer			69/13.8kV		2005
	SIS 4th Ave Transformer			69/13.8kV		2008
Kissimmee	Clay Auto-Transformer		200	230/69 kV		6/2010
	Clay (Reconductor)	Hansel		69 kV	1	6/2010
	Clay (Reconductor)	Airport		69 kV	1	6/2010
	Hansel (Reconductor)	C.A.Wall		69 kV	1	6/2010
	Auto-Transformer @South-West (OUC)		200	230/69 kV		6/2010
	Hord	South-West (OUC)		69 kV	1	6/2010
	Lake Cecile	South-West (OUC)		69 kV	1	6/2010
	Pleasant Hill Substation	Hansel		69 kV	1	6/2010
	Pleasant Hill Substation	Clay Street		69 kV	1	6/2010
	Neptune Road Substation	Tie Point with St. Cloud		69 kV	1	6/2010
Lake Worth	Main Plant Transformer		80	138/26 kV		6/2005
	Canal Transformer		60	138/26 kV		12/2006
	Hypoluxo	Canal		138 kV	1	12/2006

Table I-1 (Continued)
Planned and Proposed Transmission Additions for FMPA Members
2005 through 2014 (69 kV and above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
New Smyrna Beach	30 MVA Transformer		30	115/23 kV		11/2005
	Smyrna	Cassadega		115 kV	2	1/2008
Ocala	Shaw	Silver Springs North		230 kV	1	6/2005
	Ergle	Silver Springs North		230 kV	2	6/2006
	Ergle Auto-Transformer		150	230/69 kV	2	6/2006
	Ocala Palms	Airport		69 kV	1	6/2005
	Ocala Palms	Richmond		69 kV	1	12/2004
	Nuby's Corner Substation			69 kV		6/2005
	Nuby's Corner	Silver Springs		69 kV	1	6/2005
	Nuby's Corner	Baseline Rd		69 kV	1	6/2006
	Ocala Springs Substation			69 kV		6/2008
	Ocala Springs	Ergle		69 kV	1	6/2008
	Ocala Springs	Silver Springs		69 kV	1	6/2008
	Dearmin	Baseline Rd		69 kV	1	6/2009
	Dearmin / Baseline Substation (Improvements)			69 kV		6/2009
	Fore Corners Substation			69 kV		6/2011
	Fore Corners	Ergle		69 kV	1	6/2011
	Fore Corners	Ocala North		69 kV	1	6/2017
	Shaw	Silver Springs		230 kV	1	6/2012
	Shaw Auto-Transformer		150	230/69 kV	2	6/2012
Vero Beach	Sub #6	Sub #1		69 kV	1	6/2007