



Florida Municipal Power Agency

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Manager of Power Supply

March 30, 2007

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Dear Ms. Bayo:

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Enclosed are 25 copies of Florida Municipal Power Agency's April 2007 Ten-Year Site Plan as jointly prepared by R.W. Beck and FMPA and submitted by R.W. Beck 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, 2006.

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

Sincerely,

William S May

William May
Manager of Power Supply

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Florida Municipal Power Agency

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Florida Municipal Power Agency

Executive Summary

Community Power + Statewide Strength

Executive Summary

The following information is provided in accordance with Florida Public Service Commission (PSC) 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 (TYSP). The TYSP 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 and transmission additions.

The Florida Municipal Power Agency (FMPA, or the Agency) 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 whereby each member can elect whether or not to participate. This report presents planning information for the ARP and on the existing Agency projects.

The ARP and existing Agency summer capacity resources for the year 2007 total 1,786 MW. This capacity is comprised of “excluded” nuclear resources, member-owned resources, ARP-owned resources, and purchase power, and is summarized below in Table ES-1.

**Table ES-1
FMPA Summer 2007 Capacity Resources**

Resource Category	Summer Capacity (MW)
Nuclear	85
ARP Ownership	565
Member Ownership	666
Purchase Power	470
Total 2007 ARP Resources	1,786

FMPA has a total of 1,240 MW of power supply projects currently under construction or planned for construction. Future ARP TYSP expansion resources are presented below in Table ES-2.

**Table ES-2
FMPA TYSP Planned Expansion Resources**

Unit Description	Commercial Operation (MM/YY)	Summer Capacity (MW)
Southern Company Peaking Purchase	12/07	175
Treasure Coast Energy Center Unit 1	06/08	296
Peaking Units (or Power Purchase) ^[1]	06/10	90
Combined Cycle Unit (or Power Purchase) ^[1]	06/11	296
Taylor Energy Center Unit 1	06/12	293
Peaking Units	06/16	90
Total		1,240

[1] FMPA is currently undergoing an RFP evaluation regarding potential power supply purchases that may delay these resources.

FMPA issued a Request for Power Supply Proposals (Power Supply RFP) in November 2006. The purpose of the Power Supply RFP is to determine whether a sufficient and cost-effective source of capacity and energy can be obtained as a replacement for the peaking units and combined cycle facility that are planned for commercial operation in 2010 and 2011, respectively. Based on the outcome of this decision, FMPA will determine whether to delay the in-service dates for these units.

FMPA utilizes a variety of fuel sources to provide power to its members, including generation from nuclear, coal-fired, natural gas-fired, oil-fired resources and renewable resources. Worthy of note is FMPA’s awareness of the potential benefits of increased fuel diversity among its generating portfolio, which has prompted FMPA to participate with JEA, the City of Tallahassee, and Reedy Creek Improvement District in the development of the Taylor Energy Center, a 754 MW supercritical coal unit to be located approximately 5 miles southeast of Perry, in Taylor County, Florida. The primary advantage of this publicly-owned, coal-fired project would be to diversify resources, while supplying competitively priced power into the future.

The TEC “Need for Power” application (Need Determination) was submitted to the PSC in September 2006. Hearings on the Need Determination have been held, with a decision

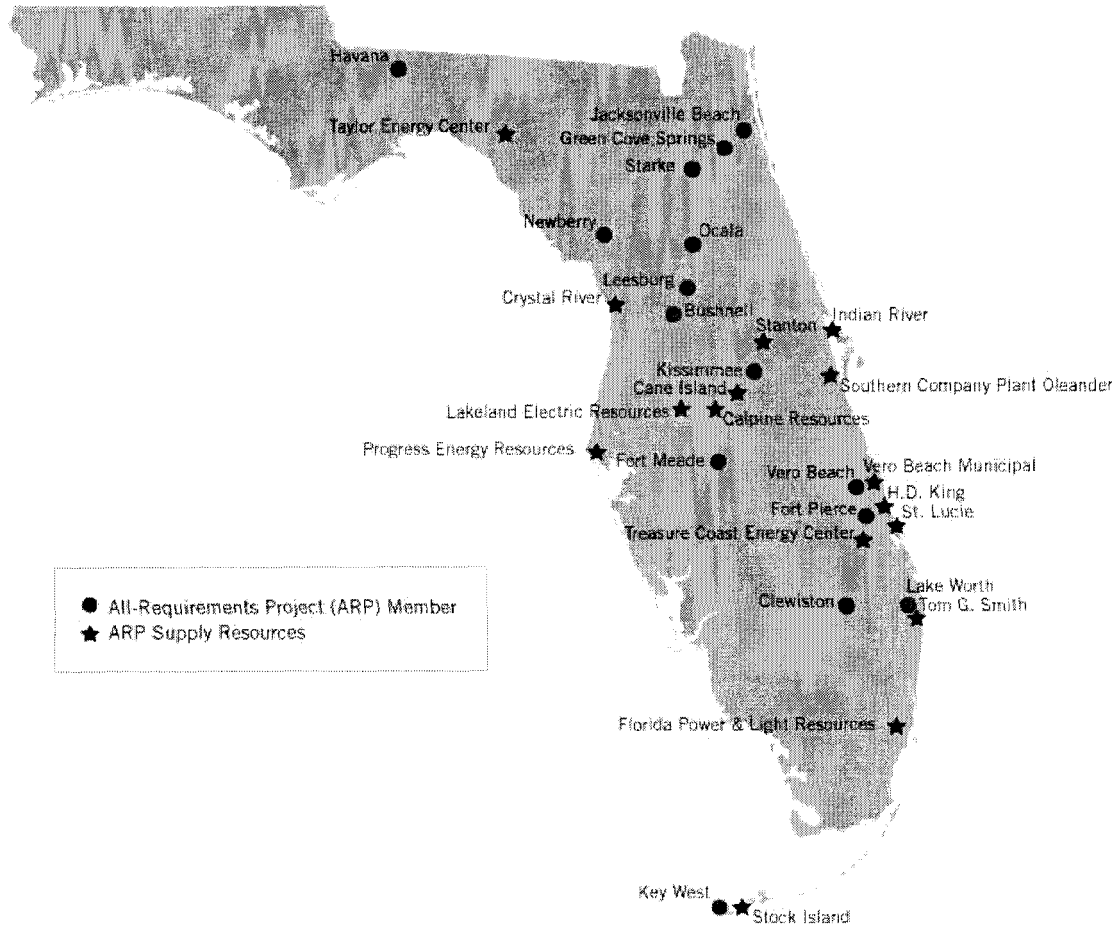
expected from the PSC in the spring of 2007. TEC Unit 1 is scheduled to begin commercial operation in May 2012.

FMPA will soon add capacity from two additional resources that utilize natural gas. The first is the Treasure Coast Energy Center (TCEC), a 296 MW combined cycle unit that FMPA is developing at a site near Fort Pierce. FMPA received site certification in June 2006, and physical construction began on TCEC Unit 1 in August 2006. Construction is on schedule, with an in-service date for TCEC Unit 1 of June 2008. The second capacity resource under construction is through a contract to purchase 175 MW of new peaking power from Southern Company's Oleander plant beginning in December 2007. The purchase will have a term of 20 years.

FMPA participates in "Green Energy" through renewable power purchases and member conservation programs. FMPA receives renewable energy from two renewable power purchases. FMPA receives power from a cogeneration plant owned and operated by U.S. Sugar Corporation that is fueled by sugar bagass, a byproduct of sugar production. The second renewable resource utilizes landfill gas provided by the Orange County Landfill to supplement the coal requirements of the Stanton Energy Center, which is partially owned by FMPA. FMPA and its members continue to investigate additional sources of "Green Energy" through renewable power purchases or conservation programs.

A location map of the ARP members and FMPA's power resources is shown in Figure ES-1 below.

Figure ES-1
ARP Member and FMPA Power Supply Resource Locations





Florida Municipal Power Agency

Section 1.0

Description of FMPPA

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Section 1 Description of FMPA

1.1 FMPA

Florida Municipal Power Agency (FMPA) is a wholesale power company created to provide a means by which its members could cooperatively gain mutual advantage and meet present and projected electric energy requirements and is owned by 30 municipal electric utilities. FMPA also 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, constructing, 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, 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.

1.2 All-Requirements Project

FMPA developed the All-Requirements Project (ARP) to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the needs of the ARP members. Fifteen FMPA member municipals form the ARP. The locations of the ARP members are shown in Figure 1-1.

Bushnell, Green Cove Springs, Jacksonville Beach, Leesburg, and Ocala were the original ARP members, all joining at the formulation of FMPA in 1978. The remaining ten members joined as follows:

- 1991 – The City of Clewiston;
- 1997- The Cities of Vero Beach and Starke;
- 1998 – Fort Pierce Utilities Authority (FPUA) and the City of Key West;
- 2000 - The City of Fort Meade, the Town of Havana, and the City of Newberry; and
- 2002 – Kissimmee Utility Authority (KUA) and the City of Lake Worth.

The City of Vero Beach has provided notice to FMPA to exercise their right to modify their ARP full requirements membership beginning January 1, 2010.

**Figure 1-1
ARP Member Cities**



ARP members are required to purchase all of their capacity and energy from the ARP. ARP members that own generating capacity 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 owners receive capacity and energy (C&E) payments. All ARP members are supplied 100 percent of their ARP capacity and energy requirements from FMPA at the average capacity and energy rate of the ARP.

Following is a brief description of each of the ARP member cities. The information provided is based on the Florida Municipal Electric Association's 2006 membership directory (www.publicpower.com) and additional information obtained during 2006.

Bushnell

The City of Bushnell is located in central Florida in Sumter County. The City joined the ARP in May 1986. Vince Ruano is the City Manager and Bruce Hickie is the Director of Utilities. The City's service area is approximately 1.4 square miles. For more information about the City of Bushnell, please visit www.cityofbushnellfl.com.

Clewiston

The City of Clewiston is located in southern Florida in Hendry County. The City joined the ARP in May 1991. Kevin McCarthy is the Utilities Director. The City's service area is approximately 5 square miles. For more information about the City of Clewiston, please visit www.clewiston-fl.gov.

Fort Meade

The City of Fort Meade is located in central Florida in Polk County. The City joined the ARP in February 2000. Katrina Powell is the City Manager. The City's service area is approximately 5 square miles. FMPA serves capacity and energy requirements for the City 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 the City from the ARP's portfolio of power supply resources. For more information about the City of Fort Meade, please visit www.state.fl.us/ftmeade/.

Fort Pierce Utilities Authority

The City of Fort Pierce is located on Florida's east coast in St. Lucie County. FPUA joined the ARP in January 1998. William Theiss is the Director of Utilities and Thomas W. Richards is Director of Electric & Gas Systems. FPUA's service area is approximately 35 square miles. For more information about Fort Pierce Utilities Authority, please visit www.fpua.com.

Green Cove Springs

The City of Green Cove Springs is located in northeast Florida in Clay County. The City joined the ARP in May 1986. Gregg Griffin is the Director of Electric Utility. The City's service area is approximately 25 square miles. For more information about the City of Green Cove Springs, please visit www.greencovesprings.com.

Town of Havana

The Town of Havana is located in the panhandle of Florida in Gadsden County. The Town joined the ARP in July 2000. Howard McKinnon is the Town Manager. The Town's service area is approximately 4.5 square miles. For more information about the Town of Havana, please visit www.havanaflorida.com.

Jacksonville Beach

The City of Jacksonville Beach's electric department, more commonly known as Beaches Energy Services (Beaches), is located in northeast Florida in Duval and St. Johns Counties. Beaches joined the ARP in May 1986. George D. Forbes is the City Manager and Don Ouchley is the Utilities Director. Beaches' service area is approximately 45 square miles. For more information about Beaches, please visit www.beachesenergy.com.

Utility Board, City of Key West

The Utility Board of the City of Key West, also known as Keys Energy Services (KEYS), provides electric service to the lower Keys in Monroe County. KEYS joined the ARP in April 1998. Robert R. Padron is Chairman of the Utility Board and Lynne Tejada is the General Manager and CEO. KEYS' service area is approximately 45 square miles. For more information about Keys Energy Services, please visit www.keysenergy.com.

Kissimmee Utility Authority

Kissimmee is located in central Florida in Osceola County. Kissimmee Utility Authority (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 and plans to retire in the Spring of 2007. After Mr. Sharma's retirement, Larry Mattern will replace him as Vice President of Power Supply. KUA's service area is approximately 85 square miles. For more information about Kissimmee Utility Authority, please visit www.kua.com.

Lake Worth

Lake Worth is located on Florida's east coast in Palm Beach County. Lake Worth joined the ARP in October 2002. Laura Hannah is the Assistant City Manager/Interim City Manager. Lake

Worth's service area is approximately 12.5 square miles. For more information about the City of Lake Worth, please visit www.lakeworth.org.

Leesburg

The City of Leesburg is located in central Florida in Lake County. The City joined the ARP in May 1986. Ron Stock is the City Manager and Paul Kalv is the Director of Electric Department. The City's service area is approximately 50 square miles. For more information about the City of Leesburg, please visit www.leesburgflorida.gov.

Newberry

The City of Newberry is located in the northern part of Florida in Alachua County. The City joined the ARP in December 2000. Blaine Suggs is the Utilities and Public Works Director. The City's service area is approximately 6 square miles. For more information about the City of Newberry, please visit www.cityofnewberryfl.com.

Ocala

The City of Ocala is located in central Florida in Marion County. The City joined the ARP in May 1986. Paul K. Nugent is the City Manager, and Rebecca Matthey is the Director of Electric Utility. The City's service area is approximately 161 square miles. For more information about the City of Ocala, please visit www.ocalafl.org.

Starke

Starke is located in north Florida in Bradford County. The City joined the ARP in October 1997. Ricky Thompson is the Project Director and Safety Director. The City's service area is approximately 6.5 square miles. For more information about the City of Starke, please visit www.cityofstarke.org.

Vero Beach

The City of Vero Beach is located on Florida's east coast in Indian River County. Vero Beach joined the ARP in June 1997. James M. Gabbard is the City Manager. The City's service area is approximately 40 square miles.

On December 9, 2004, the City of Vero Beach sent FMPA their "Notice of Establishment of Contract Rate of Delivery." The effective date of the notice is January 1, 2010. The effect of the notice is that the ARP will no longer utilize the City's generating resources, and the ARP will commence serving Vero Beach on a partial requirements basis. The amount of the partial

requirements will be determined in 2009. For more information about the City of Vero Beach, please visit www.covb.org.

1.3 FMPA Other Generation Projects

In addition to the ARP, FMPA has four other power supply projects as discussed below.

St. Lucie Project

On May 12, 1983, FMPA purchased from Florida Power & Light (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit. The St. Lucie Unit No. 2 was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of FMPA’s members are participants in the St. Lucie Project, with the following entitlements as shown in Table 1-1.

**Table 1-1
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		

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 (the Stanton Project). Stanton Unit No. 1 went into commercial operation July 1, 1987. Six of FMPA’s members are participants in the Stanton Project with entitlements as shown in Table 1-2.

**Table 1-2
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	32.521

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 1-3.

**Table 1-3
Tri-City Project Participants**

City	% Entitlement
Fort Pierce	22.727
Homestead	22.727
Key West	54.546

Stanton II Project

On June 6, 1991, under the Stanton II Project structure, FMPA purchased from OUC a 23.2367 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 1-4.

**Table 1-4
Stanton II Project Participants**

City	% Entitlement	City	% Entitlement
Fort Pierce	16.4880	Homestead	8.2443
Key West	9.8932	Kissimmee	32.9774
St. Cloud	14.6711	Starke	1.2366
Vero Beach	16.4887		

1.4 Summary of Projects

Table 1-5 provides a summary of FMPA member project participation as of January 1, 2007.

**Table 1-5
Summary of FMPA Power Supply Project Participants**

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project	Stanton II Project
City of Alachua	X				
City of Bushnell				X	
City of Clewiston	X			X	
City of Ft. Meade	X			X	
Ft. Pierce Utilities Authority	X	X	X	X	X
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 Lake Worth	X	X		X	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Newberry	X			X	
City of New Smyrna Beach	X				
City of Ocala				X	
City of St. Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X	X

[1] Other FMPA non-project participants include the City of Bartow, the City of Blountstown, the City of Chattahoochee, Gainesville Regional Utilities, City of Lakeland Electric & Water, the City of Mt. Dora, Orlando Utilities Commission, the City of Quincy, the City of Wauchula, and the City of Williston.



Florida Municipal Power Agency

Section 2.0

Description of Existing Facilities

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Section 2 Description of Existing Facilities

2.1 ARP Supply-Side Resources

The ARP supply-side resources consist of a diversified mix of generation ownership, purchase power, and fuel supply. The supply side resources for the ARP for the 2007 summer season are shown by ownership capacity in Table 2-1

**Table 2-1
ARP Supply-Side Resources Summer 2007**

Resource Category	Summer Capacity (MW)
1) Nuclear	85
2) ARP Ownership	
Existing	565
New	-
Sub Total ARP Ownership	565
3) Member Ownership	
Fort Pierce	110
KES	41
KUA	291
Lake Worth	87
Vero Beach	137
Sub Total Member Ownership	666
4) Purchase Power	470
Total 2007 ARP Resources	1,786

The resource categories shown in Table 2-1 are described in more detail below.

- 1) **Nuclear Generation:** 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, which provides 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 considered in the capacity planning for the ARP.

- 2) **ARP Owned Generation:** This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation. Such ARP ownership capacity includes the Stanton Energy Center (including the Stanton, Tri-City, and Stanton II projects, as well as Stanton A), Indian River, Cane Island, and Stock Island units.
- 3) **Member Owned 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.
- 4) **Purchase Power Generation:** This category 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. Purchase power generation includes capacity and energy received from other suppliers such as Progress Energy Florida (PEF), FPL, Lakeland Electric, Calpine, and Southern Company.

Information regarding existing ARP generating facilities as of December 31, 2006, can be found in Schedule 1 at the end of this section.

2.2 ARP Transmission System

The Florida electric transmission grid is interconnected by high voltage transmission lines ranging from 69 KV to 500 KV. Florida's electric grid is tied to the rest of the continental United States at the Florida/Georgia/Alabama interface. Florida Power and Light Co, (FPL), Progress Energy Florida (PEF), JEA and the City of Tallahassee own the transmission tie lines at the Florida/Georgia/Alabama interface. ARP members' transmission lines are interconnected with transmission facilities owned by FPL, PEF, Orlando Utilities Commission (OUC), JEA, Seminole Electric Cooperative, Florida Keys Electric Cooperative Association (FKEC), and Tampa Electric Co. (TECO).

Capacity and energy (C&E) resources for the ARP are transmitted to the ARP members utilizing the transmission systems of FPL, PEF, TECO, and OUC. C&E resources for the Cities of Jacksonville Beach, Green Cove Springs, Clewiston, Fort Pierce, Key West, Lake Worth, Starke and Vero Beach are delivered by FPL's transmission system. C&E resources for the Cities of Ocala, Leesburg, Bushnell, Newberry, and Havana are delivered by the PEF transmission system. C&E resources for KUA are delivered by the transmission systems of FPL, PEF and

OUC. C&E resources for the City of Fort Meade are delivered by the PEF and TECO transmission systems.

2.2.1 Member Transmission Systems

Fort Pierce Utility Authority

Fort Pierce Utility Authority (FPUA) is a municipally owned utility operating electric, water, wastewater, and natural gas utilities. The electric utility owns an internal, looped, 69kV transmission system for system load and a 118 MW local power generating plant. There are two interconnections with other utilities, both at 138 kV. The FPUA's Hartman Substation interconnects to FPL's Midway and Emerson Substations. The second interconnection is from the FPUA's Garden City (#2) Substation to County Line Substation No. 20 by a 7.5 mile, single circuit 138 kV line. FPUA and the City of Vero Beach jointly own County Line Substation, the 138 kV line connecting to Emerson Substation, and some parts of the tie between the two cities.

Keys Energy Services

The Utility Board of the City of Key West (KEYS) owns and maintains an electric generation, transmission, and distribution system, which supplies electric power and energy south of Florida Keys electric Cooperative's (FKEC) Marathon Substation to the City of Key West. KEYS and FKEC jointly own a 64 mile long, 138 kV transmission tie line from FKEC's Marathon Substation that interconnects to FPL's Florida City Substation at the Dade/Monroe County Line. In addition, a second interconnection with FPL was completed in 1995, which consists of a jointly owned 21 mile 138 kV tie line between the FKEC's Tavernier and Florida City Substations at the Dade/Monroe County line and is independently operated by FKEC. KEYS owns a 49.2 mile long 138 kV radial transmission line from Marathon Substation to KEYS' Stock Island Substation. Two autotransformers at the Stock Island Substation provide transformation between 138 kV and 69 kV. KEYS has five 69 kV and four 138 kV substations which supply power at 13.8 kV and 4.16 kV to its distribution system. KEYS owns approximately 227 miles of 13.8 kV distribution line.

City of Lake Worth Utilities

The City of Lake Worth Utilities (LWU) owns and maintains an electric generation, transmission, and distribution system, which supplies electric power and energy in and around the City of Lake Worth. The total generating capability, located at the Tom G. Smith power-generating plant is rated at approximately 87 MW. LWU has one 138 kV interconnection with FPL at the LWU owned Hypoluxo Switching Station. A 3-mile radial 138 kV transmission line connects the Hypoluxo Switching Station to LWU's Main Plant Substation. In addition, a 2.4-mile radial 138 kV transmission line connects the Main Plant Substation to LWU's Canal

Substation. Two 138/26 kV autotransformers are located at the Main Plant, and one 138/26 kV autotransformer is located at Canal Substation. The utility owns an internal 26 kV sub-transmission system to serve system load.

Kissimmee Utility Authority

KUA owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines. KUA serves a total area of approximately 85 square miles. KUA's 230 kV and 69 kV transmission system includes interconnections with PEF, OUC, TECO and the City of St. Cloud. KUA owns 24.6 circuit miles of 230 kV and 46.9 circuit miles of 69 kV transmission lines. KUA and FMPA jointly own 21.6 circuit miles of 230 kV lines out of Cane Island Power Park. Electric capacity and energy supplied from KUA owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to nine distribution substations. KUA has direct transmission interconnections with: (1) PEF at PEF's 230 kV Intercession City Substation, 69 kV Lake Bryan Substation, and 69 kV Meadow Wood South Substation; (2) OUC at OUC's 230 kV Taft Substation and TECO / OUC's 230 kV Osceola Substation from Cane Island Substation; and (3) the City of St. Cloud at KUA's 69 kV Carl A. Wall Substation.

City of Ocala Electric Utility

Ocala Electric Utility (OEU) owns its bulk power supply system which consists of three 230 kV to 69 kV substations, 13 miles radial 230 kV and 48 miles 69 kV transmission loop and 18 distribution substations delivering power at 12.47 kV. The distribution system consists of 773 miles of overhead lines and 302 miles of underground lines.

OEU's 230kV transmission system interconnects with PEF's Silver Springs Switching Station and Seminole Electric Cooperative, Inc.'s (SECI) Silver Springs North Switching Station. OEU's Dearmin Substation ties at PEF's Silver Springs Switching Station and OEU's Ergle Substation ties at SECI's Silver Springs North Switching Station. OEU also has a 69 kV tie from the Airport Substation with Sumter Electric Cooperative's Martel Substation. In addition, OEU owns a 13 mile radial 230 kV transmission line from Ergle Substation to Shaw Substation. OEU is planning to add a second 230 kV tie by rerouting the existing Shaw to Ergle 230 kV line from Shaw Substation to a direct radial connecting to SECI's Silver Springs North Switching Station.

City of Vero Beach

The City of Vero Beach (CVB) has a municipally owned electric utility. The utility owns an internal, looped, 69 kV transmission system for system load and a 155 MW local power generating plant. CVB has two 138 kV interconnections with FPL and one with FPUA. CVB's

interconnection with FPL is at CVB's West Substation No. 7. CVB also has a second FPL interconnection from County Line Substation No. 20. County Line Substation No. 20 is connected by two separate, single circuit, 138 kV transmission lines to FPL's Emerson 230/138 kV substation and FPUA's Garden City (No. 2) Substation. CVB & FPUA jointly own County Line Substation No. 20, the connecting lines to FPL's Emerson Station, and some part of the tie between the two municipal utilities.

2.2.2 ARP Transmission Agreements

OUC provides transmission service for delivery of power and energy from FMPA's ownership in Stanton Unit No. 1, Stanton Unit No. 2, Stanton A combined cycle (CC), and the Indian River combustion turbine (CT) units to the FPL and PEF interconnections for subsequent delivery to the ARP. Rates for such transmission wheeling service are based upon OUC's costs of providing such transmission wheeling service and under terms and conditions of the OUC-FMPA Firm Transmission Service contracts for the ARP.

FMPA also has contracts with PEF and FPL to transmit the various ARP resources over the transmission systems of each of these two utilities. The Network Service Agreement with FPL was executed in March 1996 and was subsequently amended to both conform to FERC's Pro forma Tariff and to add additional members to the ARP. The FPL agreement provides for network transmission service for the ARP member cities located in FPL's service territory. To provide transmission-wheeling service for ARP member cities located in PEF's service territory, FMPA operates under an existing agreement with PEF, which was executed in April 1985 and provides for network type transmission services.

Schedule 1
ARP Existing Generating Resources as of December 31, 2006

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Type		(6) Fuel Transportation		(7) Commercial	(8) Expected	(9) Gen. Max	(10) Net Capability		
				Primary	Alternate	Primary	Alternate	In-Service	Retirement	Nameplate	Summer (MW)		Winter (MW)
											MM/YY	MM/YY	MW
Nuclear Capacity													
Crystal River	3	Citrus	NP	UR	-	TK	-	03/77	NA	891	25	25	
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	NA	891	60	61	
Total Nuclear Capacity											85	86	
ARP-Owned Generation													
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	102	103	
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	NA	465	101	101	
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	21	23	
Indian River	CT A	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	14	18	
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	07/89	NA	41	14	18	
Indian River	CT C	Brevard	GT	NG	DFO	PL	TK	08/92	NA	112	22	26	
Indian River	CT D	Brevard	GT	NG	DFO	PL	TK	10/92	NA	112	22	26	
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	15	
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	54	60	
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	123	125	
Stock Island	CT2	Monroe	GT	DFO	-	WA	-	06/99	NA	21	15	18	
Stock Island	CT3	Monroe	GT	DFO	-	WA	-	06/99	NA	21	15	18	
Stock Island	GT4	Monroe	GT	DFO	-	WA	-	06/06	NA	61	45	45	
Total ARP-Owned Generation											565	596	
Member-Owned Generation													
Vero Beach													
Municipal Plant	1	Indian River	ST	NG	RFO	PL	TK	11/61	NA	13	12	12	
Municipal Plant	2	Indian River	CA	NG	RFO	PL	TK	08/64	NA	13	12	13	
Municipal Plant	3	Indian River	ST	NG	RFO	PL	TK	09/71	NA	33	30	34	
Municipal Plant	4	Indian River	ST	NG	RFO	PL	TK	08/76	NA	56	51	56	
Municipal Plant	5	Indian River	CT	NG	RFO	PL	TK	12/92	NA	40	32	40	
Sub Total Vero Beach											137	155	
Fort Pierce Utilities Authority													
H.D. King	5	St. Lucie	CA	WH	-	-	-	01/53	05/08	8	8	8	
H.D. King	7	St. Lucie	ST	NG	RFO	PL	TK	01/64	05/08	32	24	32	
H.D. King	8	St. Lucie	ST	NG	RFO	PL	TK	05/76	05/08	50	50	50	
H.D. King	9	St. Lucie	CT	NG	DFO	PL	TK	05/90	05/08	23	23	23	
H.D. King	D1	St. Lucie	IC	DFO	-	TK	-	04/70	05/08	3	3	3	
H.D. King	D2	St. Lucie	IC	DFO	-	TK	-	04/70	05/08	3	3	3	
Sub Total Fort Pierce											110	118	

Schedule 1 (Continued)
ARP Existing Resources as of December 31, 2006

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Type		(7) Fuel Transportation		(9) Commercial In-Service	(10) Expected Retirement	(11) Gen. Max Nameplate	(12) Net Capability	
				Primary	Alternate	Primary	Alternate	MM/YY	MM/YY	MW	Summer (MW)	Winter (MW)
Kissimmee Utility Authority												
Hansel Plant	21	Osceola	CT	NG	DFO	PL	TK	02/83	12/11	38	31	34
Hansel Plant	22	Osceola	CA	WH	-	-	-	11/83	12/11	8	8	5
Hansel Plant	23	Osceola	CA	WH	-	-	-	11/83	12/11	8	8	5
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	15
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	54	60
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	123	125
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	21	21
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	21	23
Indian River	CT A	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	4	6
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	4	6
Sub Total KUA											291	300
Lake Worth												
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	12/76	06/12	31	26	31
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	03/78	06/12	20	20	22
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	11/67	06/12	27	22	24
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	03/78	06/12	10	8	10
Sub Total Lake Worth											87	97
Keys Energy Services												
Stock Island	CT1	Monroe	GT	DFO	-	WA	-	11/78	NA	20	18	20
Stock Island HSD	IC1	Monroe	IC	DFO	-	WA	-	01/65	NA	2	2	2
Stock Island HSD	IC2	Monroe	IC	DFO	-	WA	-	01/65	NA	2	2	2
Stock Island HSD	IC3	Monroe	IC	DFO	-	WA	-	01/65	NA	2	2	2
Stock Island MSD	MSD1	Monroe	IC	DFO	-	WA	-	06/91	NA	9	9	9
Stock Island MSD	MSD2	Monroe	IC	DFO	-	WA	-	06/91	NA	9	9	9
Sub Total Keys											41	43
Total Member-Owned Generation											666	714
Total Generation Resources											1,316	1,395



Florida Municipal Power Agency

Section 3.0

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

Community Power + Statewide Strength

Section 3 Forecast of Demand and Energy for the All-Requirements Power Supply Project

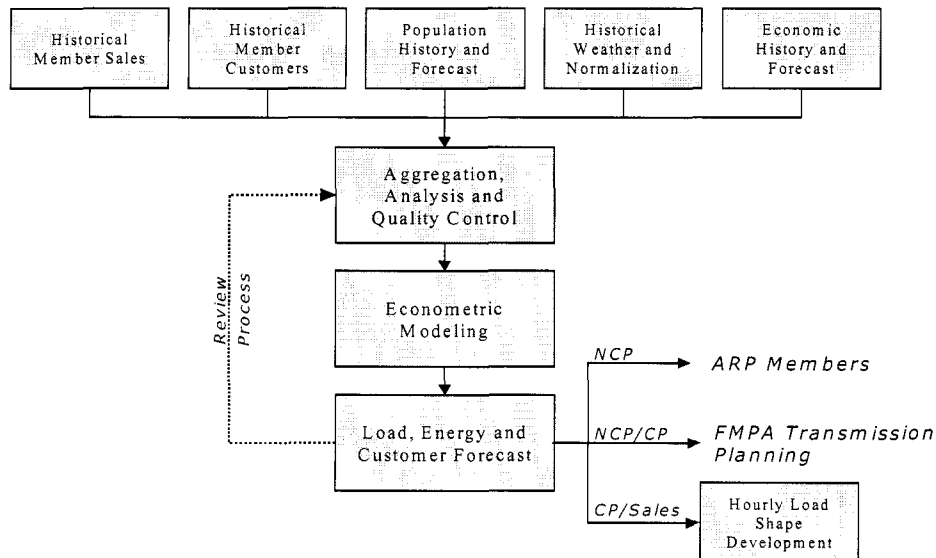
3.1 Introduction

Under the ARP structure, FMPA agrees to meet all of the ARP members' power requirements. To secure sufficient capacity and energy, FMPA forecasts each ARP member's electrical power demand and energy requirements on an individual basis and integrates the results into a forecast for the entire ARP. The following discussion summarizes the load forecasting process and the results of the load forecast contained in this Ten-Year Site Plan.

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 currently supplies and ARP members that FMPA is scheduled to begin supplying in the future. Forecasts are prepared on an individual member basis and are then aggregated into projections of the total ARP demand and energy requirements. Figure 3-1 below identifies FMPA's load forecast process.

**Figure 3-1
Load Forecast Process**



In addition to the Base Case load and energy forecast, FMPA has prepared high and low case forecasts, which are intended to capture the majority of the uncertainty in certain driving variables, for each of the ARP members. The high and low load forecast scenarios are considered in FMPA's resource planning process. In this way, power supply plans are tested for their robustness under varying future load conditions.

3.3 2006 Load Forecast Overview

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2006 through 2025. The Forecast was 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 were provided by Economy.com, a nationally recognized provider of such data. The Forecast also relied on information regarding local economic and demographic issues specific to each ARP member. The Forecast reflects the City of Vero Beach Notice of Establishment of Contract Rate of Delivery (CROD). The Forecast was performed assuming that Vero Beach's CROD becomes effective on January 1, 2010; however, the results of the Forecast do not currently include the partial requirements load referred to in Section 1.2 of this document that may be served by FMPA beginning January 1, 2010. The results of the Base Case forecast are discussed in Section 3.6.1.

In addition to the Base Case forecast, FMPA has prepared high and low forecasts to capture the uncertainty of weather. The methodology and results of the high (Severe) and low (Mild) weather cases are discussed in Section 3.6.2.

3.4 Methodology

The forecast of peak demand and net energy for load to be supplied from the ARP relies on an econometric forecast of each ARP member's retail sales, combined with various assumptions regarding loss, load, and coincidence factors, generally based on the recent historical values for such factors, which are then summed across the ARP members. Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience.

In this approach, the significance of historical relationships is evaluated using commonly accepted statistical measures. Models that, in the view of the analyst, best explain the historical variation of energy consumption are selected. The ability of a model to explain historical variation is often referred to as "goodness-of-fit." These historical relationships are generally assumed to continue into the future, barring any specific information or

assumptions to the contrary. The selected models are then populated with projections of explanatory variables, resulting in projections of energy requirements.

Econometric forecasting can be a more reliable technique for long-term forecasting than trend-based approaches and other techniques, because the approach results in an explanation of variations in load rather than simply an extrapolation of history. As a result of this approach, utilities are more likely to anticipate departures from historical trends in energy consumption, given accurate projections of the driving variables. In addition, understanding the underlying relationships which affect energy consumption allows utilities to perform scenario and risk analyses, thereby improving decisions. The Severe and Mild Cases are examples of this capability.

Forecasts of monthly sales were prepared by rate classification for each ARP member. In some cases, rate classifications were combined to eliminate the effects of class migration or redefinition. In this way, greater stability is provided in the historical period upon which statistical relationships are based.

3.4.1 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. The 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) weather variables. 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.

The non-residential electricity sales models reflect that energy sales 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) weather variables. For the majority of models, total personal income was selected as the measure of economic activity, because it performed better by certain statistical measures than other variables and is measured historically with more accuracy at the local level. For the industrial class, GDP was more

often the long-term driving variable, except in cases where the forecast was based on an assumption to address a single, large customer (e.g., Clewiston and Key West).

Weather variables include 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.

3.4.2 Projection of NEL and Peak Demand

The forecast of sales for each rate classification described above were summed to equal the total retail sales of each ARP member. An assumed loss factor, typically based on a 5-year average of historical loss factors, was then applied to the total sales to derive monthly NEL. To the extent historical loss factors were deemed anomalous, they were excluded from these averages.

Projections of summer and winter non-coincident peak (NCP) demand were developed by applying projected annual load factors to the forecasted net energy for load on a total member system basis. The projected load factors were based on the average relationship between annual NEL and the seasonal peak demand generally over the period 1996-2005 (i.e., a 10-year average).

Monthly peak demand was based on the average relationship between each monthly peak and the appropriate seasonal peak. This average relationship was computed after ranking the historical demand data within the summer and winter seasons and reassigning peak demands to each month based on the typical ranking of that month compared to the seasonal peak. This process avoids distortion of the averages due to randomness as to the months in which peak weather conditions occur within each season. For example, a summer peak period can occur during July or August of any year. It is important that the shape of the peak demands reflects that only one of those two months is the peak month and that the other is typically some percentage less.

Projected coincident peak demands related to the total ARP, the ARP member groups, and the transmission providers were derived from monthly coincidence factors averaged generally over a 5-year period (2001-2005). The historical coincidence factors are based on historical coincident peak demand data that is maintained by FMPA. Similarly, the timing of the total ARP and ARP member group peaks was determined from an appropriate summation of the hourly load data.

3.5 Data Sources

3.5.1 Historical Member Retail Sales Data

Data was generally available and analyzed over January 1992, or the year a new member joined the ARP, through the end of fiscal year 2005 (i.e., September 2005) (the Study Period). Data included historical customers, sales, and revenues by rate classification for each of the members. However, for a small part of the Study Period, only total revenues were available.

3.5.2 Weather Data

Historical weather data was provided by the National Climatic Data Center (a division of the National Oceanic and Atmospheric Administration) (NCDC), which was generally used to supplement an existing weather database maintained by FMPA. Weather stations, from which historical weather was obtained, were selected by their quality and proximity to the ARP members. 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. In three cases (Beaches Energy Services, serving Jacksonville Beach, Fort Pierce, and Vero Beach), however, weather data from a “cooperative” weather station, which was closer than the closest first-order station, appeared to more accurately reflect the weather conditions that affect the ARP members’ loads, based on statistical measures, than the closest first-order weather station.

The influence on electricity sales of weather 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 a base temperature, 65 degrees Fahrenheit. To the extent the average daily temperature exceeds 65 degrees Fahrenheit, the difference between that average temperature and the base is the number of CDD for the day in question. Conversely, HDD result from average daily temperatures which are below 65 degrees Fahrenheit. Heating and cooling degree days are then summed over the period of interest, in this case, months. The majority of this monthly data was obtained directly from the NCDC rather than calculated from daily data.

Normal weather conditions have been assumed in the projected period. Thirty-year normal monthly HDD and CDD are based on average weather conditions from 1971 through 2000, as reported by the NCDC.

3.5.3 Economic Data

Economy.com, a nationally recognized provider of economic data, provided both historical and projected economic and demographic data for each of the 16 counties in which the Members' service territories reside (the service territory of Beaches Energy Services includes portions of both Duval and St. Johns Counties). These data included county population, households, employment, personal income, retail sales, and gross domestic product. Although all of the data was not necessarily used in each of the forecast equations, each was examined for its potential to explain changes in the ARP members' historical electric sales.

3.5.4 Real Electricity Price Data

The real price of electricity was derived from a twelve month moving average of real average revenue. To the extent average revenue data specific to a certain rate classification was unavailable, it was assumed to follow the trend of total average revenue of the utility. Projected electricity prices were assumed to increase at the rate of inflation. Consequently, the real price was projected to be essentially constant.

3.6 Overview of Results

3.6.1 Base Case Forecast

The results of the Forecast show that the Base Case 2007 forecast ARP winter peak demand is 1,489 MW, forecast summer peak demand is 1,552 MW, and forecast annual NEL is 7,668 GWh. The winter peak demand is projected to grow at an average annual growth rate of 2.4 percent from 2007 through 2009, and then grow at an annual rate of 2.1 percent from 2010 through 2025. The summer peak demand is projected to grow at an average annual growth rate of 2.3 percent from 2007 through 2009, and then grow at an annual rate of 2.0 percent from 2010 through 2025. NEL is expected to grow at an annual average growth rate of 2.3 percent from 2007 through 2009, and then grow at an annual average rate of 2.0 percent from 2010 through 2025. Growth rates have been shown separately for these periods to avoid distortion due to Vero Beach's establishment of CROD, effective January 1, 2010.

3.6.2 Weather-Related Uncertainty of the Forecast

While a forecast that is derived from projections of driving variables that are obtained from reputable sources provides a sound basis for planning, there is significant uncertainty in the future level of such variables. To the extent that economic, demographic, weather, or other conditions occur that are different from those assumed or provided, the actual member load can be expected to vary from the forecast. For various

purposes, it is important to understand the amount by which the forecast can be in error and the sources of error.

In addition to the Base Case forecast, which relies on normal weather conditions, FMPA has developed high and low forecasts, referred to herein as the Severe and Mild weather cases, intended to capture the volatility resulting from weather variations in the summer and winter seasons equivalent to 90 percent of potential occurrences. Accordingly, load variations due to weather should be outside the resulting "band" between the Mild and Severe weather cases less than 1 out of 10 years. For this purpose, the summer and winter seasons were assumed to encompass June through September and December through February, respectively.

The potential weather variability was developed using weather data specific to each weather station generally over the period 1971-2005. These weather scenarios simultaneously reflect more and less severe weather conditions in both seasons, although this is less likely to happen than severe conditions in one season or the other. Accordingly, it should be recognized that annual NEL may be somewhat less volatile than the annual NEL variation shown herein. Conversely, NEL in any particular month may be *more* volatile than shown herein. Finally, because the forecast methodology derives peak demand from NEL via constant load factor assumptions, annual summer and winter peak demand are effectively assumed to have the same weather-related volatility as annual NEL.

The weather scenarios result in bands of uncertainty around the Base Case that are essentially constant through time, so that the projected growth rate is the same as the Base Case. The differential between the Severe Case and Base Case is somewhat larger than between the Mild Case and Base Case as a result of a somewhat non-linear response of load to weather.

3.7 Load Forecast Schedules

Schedules 2.1 through 2.3 and 3.1 through 3.3 present the Base Case load forecast. Schedules 3.1a through 3.3a present the high, or Severe weather case, and Schedules 3.1b through 3.3b present the low, or Mild weather case. Schedule 4 presents the Base Case monthly load forecast.

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)
Year [1]	Rural and Residential				Commercial			
	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1997	NA	NA	1,242	93,149	13,336	833	16,710	49,829
1998	NA	NA	1,977	143,049	13,822	1,593	26,001	61,276
1999	NA	NA	1,980	151,885	13,035	1,652	27,774	59,465
2000	NA	NA	2,065	154,942	13,326	1,721	28,456	60,480
2001	NA	NA	2,105	156,857	13,422	1,750	29,015	60,298
2002	NA	NA	2,426	174,357	13,913	1,996	32,415	61,589
2003	NA	NA	3,180	227,851	13,955	2,603	42,132	61,791
2004	NA	NA	3,170	234,698	13,508	2,630	42,914	61,274
2005	NA	NA	3,235	237,776	13,607	2,692	44,405	60,614
2006	NA	NA	3,344	243,992	13,707	2,819	44,968	62,696
2007	NA	NA	3,420	248,718	13,749	2,884	45,533	63,348
2008	NA	NA	3,483	252,944	13,770	2,940	46,074	63,810
2009	NA	NA	3,585	259,773	13,802	3,013	47,188	63,849
2010	NA	NA	3,262	234,776	13,894	2,676	42,112	63,538
2011	NA	NA	3,323	238,680	13,923	2,730	42,614	64,053
2012	NA	NA	3,391	243,067	13,951	2,785	43,123	64,578
2013	NA	NA	3,463	247,686	13,980	2,844	43,649	65,149
2014	NA	NA	3,538	252,567	14,007	2,906	44,193	65,753
2015	NA	NA	3,616	257,644	14,033	2,970	44,754	66,373
2016	NA	NA	3,693	262,758	14,053	3,036	45,332	66,962

[1] Amounts shown for 1997 through 2005 represent historical values. Amounts shown for 2006 through 2016 represent forecast values.

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)
Year [1]	Industrial			Railroads and Railways GWh	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Customers GWh
	GWh	Average No. of Customers	Average kWh Consumption per Customer				
1997	566	944	599,349	0	17	41	2,698
1998	643	972	661,427	0	31	44	4,288
1999	678	1,031	657,495	0	32	45	4,386
2000	695	1,078	644,762	0	33	48	4,561
2001	692	1,104	626,720	0	36	49	4,631
2002	718	1,132	634,523	0	45	46	5,232
2003	708	1,151	615,521	0	57	46	6,594
2004	700	1,137	615,842	0	56	56	6,613
2005	732	1,169	626,396	0	58	45	6,762
2006	768	1,195	643,122	0	61	51	7,044
2007	789	1,218	647,156	0	62	53	7,207
2008	804	1,241	648,103	0	63	54	7,344
2009	823	1,263	651,277	0	65	55	7,541
2010	842	1,285	655,522	0	62	56	6,898
2011	863	1,307	660,399	0	64	57	7,037
2012	884	1,328	665,839	0	66	58	7,183
2013	906	1,348	672,039	0	67	59	7,339
2014	929	1,369	679,069	0	69	60	7,502
2015	954	1,389	686,719	0	71	61	7,672
2016	977	1,408	693,909	0	73	63	7,841

[1] Amounts shown for 1997 through 2005 represent historical values. Amounts shown for 2006 through 2016 represent forecast values.

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 [1]	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
1997	0	152	2,850	0	110,803
1998	0	242	4,530	0	170,022
1999	0	271	4,657	0	180,690
2000	0	276	4,838	0	184,476
2001	0	246	4,877	0	186,977
2002	0	301	5,532	0	207,904
2003	0	414	7,008	0	271,134
2004	0	388	7,000	0	278,749
2005	0	438	7,201	0	283,349
2006	0	450	7,494	0	290,155
2007	0	460	7,668	0	295,469
2008	0	469	7,813	0	300,260
2009	0	482	8,023	0	308,224
2010	0	444	7,342	0	278,173
2011	0	453	7,489	0	282,601
2012	0	462	7,645	0	287,518
2013	0	471	7,810	0	292,683
2014	0	482	7,984	0	298,128
2015	0	492	8,164	0	303,787
2016	0	503	8,344	0	309,498

[1] Amounts shown for 1997 through 2005 represent historical values. Amounts shown for 2006 through 2016 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year [1]	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	Net Firm Demand
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	962	0	0	0	0	0	0	0	962
2002	992	0	0	0	0	0	0	0	992
2003	1,343	0	0	0	0	0	0	0	1,343
2004	1,416	0	0	0	0	0	0	0	1,416
2005	1,524	0	0	0	0	0	0	0	1,524
2006	1,516	0	0	0	0	0	0	0	1,516
2007	1,552	0	0	0	0	0	0	0	1,552
2008	1,582	0	0	0	0	0	0	0	1,582
2009	1,625	0	0	0	0	0	0	0	1,625
2010	1,489	0	0	0	0	0	0	0	1,489
2011	1,519	0	0	0	0	0	0	0	1,519
2012	1,551	0	0	0	0	0	0	0	1,551
2013	1,584	0	0	0	0	0	0	0	1,584
2014	1,619	0	0	0	0	0	0	0	1,619
2015	1,657	0	0	0	0	0	0	0	1,657
2016	1,694	0	0	0	0	0	0	0	1,694

[1] Amounts shown for 1997 through 2005 represent historical values. Amounts shown for 2006 through 2016 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year [1]	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	Net Firm Demand
1996/97	497	0	0	0	0	0	0	0	497
1997/98	675	0	0	0	0	0	0	0	675
1998/99	926	0	0	0	0	0	0	0	926
1999/00	947	0	0	0	0	0	0	0	947
2000/01	1,008	0	0	0	0	0	0	0	1,008
2001/02	1,008	0	0	0	0	0	0	0	1,008
2002/03	1,473	0	0	0	0	0	0	0	1,473
2003/04	1,194	0	0	0	0	0	0	0	1,194
2004/05	1,340	0	0	0	0	0	0	0	1,340
2005/06	1,455	0	0	0	0	0	0	0	1,455
2006/07	1,489	0	0	0	0	0	0	0	1,489
2007/08	1,517	0	0	0	0	0	0	0	1,517
2008/09	1,561	0	0	0	0	0	0	0	1,561
2009/10	1,401	0	0	0	0	0	0	0	1,401
2010/11	1,429	0	0	0	0	0	0	0	1,429
2011/12	1,459	0	0	0	0	0	0	0	1,459
2012/13	1,491	0	0	0	0	0	0	0	1,491
2013/14	1,524	0	0	0	0	0	0	0	1,524
2014/15	1,559	0	0	0	0	0	0	0	1,559
2015/16	1,594	0	0	0	0	0	0	0	1,594

[1] Amounts shown for 1997 through 2005 represent historical values. Amounts shown for 2006 through 2016 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year [1]	Total	Residential Conservation	Commercial/Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1997	2,698	0	0	2,698	0	152	2,850	51%
1998	4,288	0	0	4,288	0	242	4,530	55%
1999	4,386	0	0	4,386	0	271	4,657	54%
2000	4,561	0	0	4,561	0	276	4,838	57%
2001	4,631	0	0	4,631	0	246	4,877	55%
2002	5,232	0	0	5,232	0	301	5,532	63%
2003	6,594	0	0	6,594	0	414	7,008	54%
2004	6,613	0	0	6,613	0	388	7,000	56%
2005	6,762	0	0	6,762	0	438	7,201	54%
2006	7,044	0	0	7,044	0	450	7,494	56%
2007	7,207	0	0	7,207	0	460	7,668	56%
2008	7,344	0	0	7,344	0	469	7,813	56%
2009	7,541	0	0	7,541	0	482	8,023	56%
2010	6,898	0	0	6,898	0	444	7,342	56%
2011	7,037	0	0	7,037	0	453	7,489	56%
2012	7,183	0	0	7,183	0	462	7,645	56%
2013	7,339	0	0	7,339	0	471	7,810	56%
2014	7,502	0	0	7,502	0	482	7,984	56%
2015	7,672	0	0	7,672	0	492	8,164	56%
2016	7,841	0	0	7,841	0	503	8,344	56%

[1] Amounts shown for 1997 through 2005 represent historical values. Amounts shown for 2006 through 2016 represent forecast values.

**Schedule 3.1a
Forecast of Summer Peak Demand (MW) - High Case
All-Requirements Project ^[1]**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	Net Firm Demand
2007	1,618	0	0	0	0	0	0	0	1,618
2008	1,649	0	0	0	0	0	0	0	1,649
2009	1,694	0	0	0	0	0	0	0	1,694
2010	1,553	0	0	0	0	0	0	0	1,553
2011	1,584	0	0	0	0	0	0	0	1,584
2012	1,617	0	0	0	0	0	0	0	1,617
2013	1,652	0	0	0	0	0	0	0	1,652
2014	1,689	0	0	0	0	0	0	0	1,689
2015	1,727	0	0	0	0	0	0	0	1,727
2016	1,766	0	0	0	0	0	0	0	1,766

[1] Values represent predicted summer peak demand under severe weather conditions.

Schedule 3.2a
Forecast of Winter Peak Demand (MW) - High Case
All-Requirements Project [1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	Net Firm Demand
2006/07	1,553	0	0	0	0	0	0	0	1,553
2007/08	1,582	0	0	0	0	0	0	0	1,582
2008/09	1,628	0	0	0	0	0	0	0	1,628
2009/10	1,462	0	0	0	0	0	0	0	1,462
2010/11	1,491	0	0	0	0	0	0	0	1,491
2011/12	1,523	0	0	0	0	0	0	0	1,523
2012/13	1,556	0	0	0	0	0	0	0	1,556
2013/14	1,590	0	0	0	0	0	0	0	1,590
2014/15	1,627	0	0	0	0	0	0	0	1,627
2015/16	1,663	0	0	0	0	0	0	0	1,663

[1] Values represent predicted winter peak demand under severe weather conditions.

Schedule 3.3a
 Forecast of Annual Net Energy for Load (GWh) - High Case
 All-Requirements Project [1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2007	7,512	0	0	7,512	0	474	7,986	56%
2008	7,654	0	0	7,654	0	483	8,137	56%
2009	7,859	0	0	7,859	0	496	8,355	56%
2010	7,195	0	0	7,195	0	457	7,651	56%
2011	7,338	0	0	7,338	0	466	7,804	56%
2012	7,491	0	0	7,491	0	475	7,966	56%
2013	7,652	0	0	7,652	0	485	8,137	56%
2014	7,822	0	0	7,822	0	496	8,318	56%
2015	7,999	0	0	7,999	0	507	8,505	56%
2016	8,175	0	0	8,175	0	517	8,692	56%

[1] Values represent predicted net energy for load under severe weather conditions.

**Schedule 3.1b
Forecast of Summer Peak Demand (MW) – Low Case
All-Requirements Project [1]**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	Net Firm Demand
2007	1,502	0	0	0	0	0	0	0	1,502
2008	1,531	0	0	0	0	0	0	0	1,531
2009	1,572	0	0	0	0	0	0	0	1,572
2010	1,439	0	0	0	0	0	0	0	1,439
2011	1,468	0	0	0	0	0	0	0	1,468
2012	1,499	0	0	0	0	0	0	0	1,499
2013	1,532	0	0	0	0	0	0	0	1,532
2014	1,566	0	0	0	0	0	0	0	1,566
2015	1,602	0	0	0	0	0	0	0	1,602
2016	1,638	0	0	0	0	0	0	0	1,638

[1] Values represent predicted summer peak demand under mild weather conditions.

Schedule 3.2b
Forecast of Winter Peak Demand (MW) – Low Case
All-Requirements Project [1]

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2006/07	1,440	0	0	0	0	0	0	0	1,440
2007/08	1,467	0	0	0	0	0	0	0	1,467
2008/09	1,509	0	0	0	0	0	0	0	1,509
2009/10	1,353	0	0	0	0	0	0	0	1,353
2010/11	1,381	0	0	0	0	0	0	0	1,381
2011/12	1,410	0	0	0	0	0	0	0	1,410
2012/13	1,441	0	0	0	0	0	0	0	1,441
2013/14	1,473	0	0	0	0	0	0	0	1,473
2014/15	1,507	0	0	0	0	0	0	0	1,507
2015/16	1,541	0	0	0	0	0	0	0	1,541

[1] Values represent predicted winter peak demand under mild weather conditions.

**Schedule 3.3b
Forecast of Annual Net Energy for Load (GWh) - Low Case
All-Requirements Project [1]**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2007	6,971	0	0	6,971	0	451	7,422	56%
2008	7,103	0	0	7,103	0	460	7,563	56%
2009	7,292	0	0	7,292	0	472	7,765	56%
2010	6,668	0	0	6,668	0	435	7,103	56%
2011	6,802	0	0	6,802	0	443	7,245	56%
2012	6,944	0	0	6,944	0	452	7,396	56%
2013	7,094	0	0	7,094	0	462	7,556	56%
2014	7,253	0	0	7,253	0	472	7,724	56%
2015	7,417	0	0	7,417	0	482	7,899	56%
2016	7,581	0	0	7,581	0	493	8,073	56%

[1] Values represent predicted net energy for load under mild weather conditions.

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)
Month	Actual - 2006		Forecast - 2007		Forecast - 2008	
	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,064	523	1,489	599	1,517	611
February	1,388	490	1,190	517	1,213	527
March	1,017	515	1,134	590	1,156	601
April	1,225	560	1,255	560	1,279	571
May	1,280	636	1,374	672	1,400	684
June	1,392	684	1,462	695	1,490	708
July	1,444	737	1,552	779	1,582	794
August	1,472	759	1,538	797	1,568	812
September	1,336	674	1,450	700	1,479	713
October	1,270	603	1,308	637	1,334	649
November	1,001	501	1,099	541	1,121	551
December	963	522	1,253	580	1,278	592



Florida Municipal Power Agency

Section 4.0

Renewable Resources and Conservation Programs

Community Power + Statewide Strength

Section 4 Renewable Resources and Conservation Programs

4.1 Introduction

Renewable resources are considered resources that do not require the consumption of additional fossil fuels in order to provide energy. Conservation resources are typically those resources that reduce the amount of demand or energy being provided to the customer. Both renewable resources and conservation programs are considered “Green Resources”, or resources that include renewable resources and other significantly reduced pollutant resources such as conservation programs.

FMPA provides renewable energy resources through dispatching renewable generation to serve the ARP aggregate load requirements. FMPA offers services as needed to assist members in increasing the promotion and use of conservation programs to customers and will assist all of its members in the evaluation of any new programs to ensure their cost effectiveness. 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.

FMPA is a member of the American Public Power Association's Demonstration of Energy-Efficient Developments (DEED) program. Through FMPA's membership in this program, all of FMPA's members are also DEED members. DEED is a research and development program funded by and for public power utilities. Established in 1980, DEED encourages activities that promote energy innovation, improve efficiencies and lower costs of energy to public power customers.

FMPA is also a member of a new group of Florida municipal utilities, called Florida Municipal Efficiency Coalition (FMEC). This group was recently formed to explore new options for efficiency programs that can result in greater energy conservation and savings to customers. Other members of FMEC are GRU, JEA, Lakeland Electric, OUC, Tallahassee, and Florida Municipal Electric Association. The utilities have agreed to develop consistent data and share best practices as they evaluate demand-side management programs to save energy that are specific to the state of Florida.

4.2 Renewable Resources

FMPA and its members are reviewing Green Energy programs that may be a benefit to their customers. Renewable sources include solar thermal, solar photovoltaic, wind energy, and bioenergy.

FMPA receives power from two sources of renewable energy. FMPA receives power from a cogeneration plant owned and operated by U.S. Sugar Corporation. Landfill gas is received from the Orange County landfill which is used to supplement the fuel requirements of Stanton Energy Center, which is partially owned by FMPA.

U.S. Sugar Cogeneration plant is a power plant fueled by sugar bagass. Bagass is a biomass remaining after the sugar cane stalks have been crushed for their juice. U. S. Sugar uses the bagass to fuel their generation plants to provide power for their processes. FMPA purchases the excess unused power from these generators. During 2006, FMPA purchased 3,876 MWh of energy from this renewable resource.

Orange County, Florida has a landfill located near the Stanton Energy Center, which is jointly owned by OUC, FMPA, and KUA. Through its contract with OUC, the landfill provides landfill gas as a supplemental fuel source to coal consumed by the Stanton Energy Center. In 2006 the Stanton Energy Center consumed 769,843 MMbtu of landfill gas.

FMPA's forecast of renewable energy is provided in Schedule 6.1 of Section 5 (Forecast of Facility Requirements).

4.3 Conservation Programs

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

- Energy Audits Program.
- High-Pressure Sodium Outdoor Lighting Conversion.
- PURPA Time-of-Use Standard.
- Energy Star® Program Participation.
- Demand-Side Management (DSM).
- Distributed Generation.

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.

4.3.1 Energy Audits Program

Energy audits are offered to residential, commercial, and industrial customers. The program offers walk-through audits to identify energy savings opportunities. 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.

As a supplement to the Energy Audits program, some FMPA members offer online energy surveys to their customers. These tools allow customers to enter specific information on their homes and review specific measures that they can implement in their homes to reduce energy consumption. FMPA also assists member cities with their Key Accounts program, which is designed to build and maintain relationships between members and their key customers. FMPA coordinates the relationship between participating members and contractors to provide project-type services such as lighting retrofits, HVAC upgrades, and energy management system services.

4.3.2 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.

4.3.3 PURPA Time-of-Use Standard

In order to assist members with complying with the Public Utilities Regulatory Policy Act of 2005 (PURPA) Smart Metering standard, FMPA staff has initiated a work effort to evaluate ARP members' opportunities to provide time-based rates. Time-based meters would allow utilities to provide time-of-use pricing, critical pricing, real time pricing and provide credits for load interruptions.

The PURPA Smart Metering standard applies to any utility whose total sales of electric energy, for purposes other than resale, exceeds 500 million kWh (FPUA, Beaches Energy Services, Keys Energy Services, KUA, Ocala and Vero Beach). FMPA, however, will be

conducting this analysis for each ARP city. FMPA is continuing to promote energy conservation with each of its member cities.

4.3.4 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. The Energy Star® program includes seasonal campaigns, each promoting different conservation themes. Members are provided with promotional materials including newsletter, posters, bill stuffers, and web banners to participate in the campaigns and promote the conservation message to their customers.

4.3.5 Demand-Side Management

FMPA and its members are interested in demand-side initiatives that are of overall benefit to the ARP, but they are not currently pursuing the implementation of specific dispatchable DSM programs.

4.3.6 Distributed Generation

Distributed Generation (DG) involves the use of small generators with capacities generally ranging between 10 and several thousand kilowatts spread throughout an electric system. Because they are normally located at customer sites, and those customers are generally demand customers, DG serves well as a vehicle for reducing demands during peak periods.

At this point in time, there is no active DG program. However, if there are significant advantages in DG technology or price, FMPA will review these possible benefits with members as needed.

The risks associated with DG include fuel storage, maintainability, permitting, and security. Control issues associated with DG include relinquishing customer control and having remote startup and shutdown monitoring. Cost issues associated with DG include high unit heat rates, high fuel costs, and redundant control equipment per location.



Florida Municipal Power Agency

Section 5.0

Forecast of Facilities Requirements

Community Power + Statewide Strength

Section 5 Forecast of Facilities Requirements

5.1 ARP Planning Process

FMPA's planning process involves evaluating new generating capacity, along with new purchased power options 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 power 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. 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.

5.2 Planned ARP Generating Facility Requirements

FMPA is planning to add a 296 MW combined cycle unit at the Treasure Coast Energy Center site in June 2008, 90 MW of combustion turbine capacity in 2010, an additional 296 MW combined cycle unit in 2011, a 293 MW share of a jointly owned coal-fired unit in June 2012, and an additional 90 MW of combustion turbine capacity in 2016. These resources are described in additional detail below.

- **Treasure Coast Energy Center (TCEC):** FMPA is constructing a 296 MW combined cycle unit at the Treasure Coast Energy Center site near Fort Pierce. FMPA received site certification in June 2006, and physical construction began on TCEC Unit 1 in August 2006. Construction is on schedule, and the scheduled in-service date for TCEC Unit 1 is June 2008.
- **2010 Peaking Units:** FMPA is currently planning to construct 90 MW of combustion turbine (GT) peaking capacity with a planned in-service date of summer 2010. FMPA anticipates that these LM6000 simple cycle GT units could be installed at an ARP member owned generation site, most likely at the Tom G.

Smith Power Plant site at Lake Worth, the Cane Island Power Park site at the Kissimmee Utility Authority (KUA), or at FMPA's TCEC site.

- **Cane Island Combined Cycle:** FMPA is currently planning to construct a 296 MW combined cycle unit at the Cane Island Power Park site at KUA. The scheduled in-service date for Cane Island Unit 4 is summer 2011.
- **Taylor Energy Center (TEC):** FMPA is currently participating with JEA, the City of Tallahassee, and Reedy Creek Improvement District in the development of the Taylor Energy Center, a 754 MW supercritical coal unit to be located approximately 5 miles southeast of Perry, in Taylor County, Florida. The primary advantage of this publicly-owned, coal-fired project would be to diversify resources, while supplying competitively priced power into the future. The TEC "Need for Power" application (Need Determination) was submitted to the PSC in September 2006. Hearings on the Need Determination have been held, and a decision is expected from the PSC in spring 2007. TEC Unit 1 is scheduled to begin commercial operation in May 2012.
- **2016 Peaking Units:** FMPA is currently planning to construct an additional 90 MW of GT peaking capacity with a planned in-service date of summer 2016. These units are similar to the 2010 Peaking Units described above.

FMPA issued a Request for Power Supply Proposals (Power Supply RFP) in November 2006. The purpose of the Power Supply RFP is to determine whether a sufficient and cost-effective source of capacity and energy can be obtained as a replacement for the GT units and Cane Island Unit 4 combined cycle facility that are planned for commercial operation in 2010 and 2011, respectively. Based on the outcome of this decision, FMPA will determine whether to delay the in-service dates for these units.

Schedule 8 at the end of this section shows the planned and prospective ARP generating resources additions and changes.

5.3 Capacity and Purchase Power Requirements

The current system firm power supply purchase resources of ARP include purchases from PEF, FPL, Lakeland Electric, Calpine, and the Southern Company-Florida Stanton A capacity that is purchased power. Additionally, FMPA is planning a peaking power purchase from Southern Company's Oleander plant beginning in December 2007 and a capacity purchase from one or more suppliers for the summer of 2007. The existing and future 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 2007 and 2008, 40 MW in 2009, and 90 MW in 2010. The PR capacity also includes reserves.
- **FPL:** FMPA has two contracts with FPL, including a short-term 75 MW purchase through 2007 and a long-term 45 MW purchase until June 2013. The FPL short and long-term purchases include reserves.
- **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.
- **Calpine:** FMPA has a contract with Calpine that provides 100 MW from 2007 until the contract expires in 2009.
- **Southern Company-Florida:** FMPA has a contract for 80 MW of purchase power including KUA's share from Stanton A that extends to 2013 for the initial term and has various extension options.
- **Southern Company:** FMPA has a contract to purchase 175 MW of new peaking power from Southern Company's Oleander plant beginning in December 2007. The purchase will have a term of 20 years.
- **Seasonal Peaking Purchase:** FMPA is in the final stages of negotiations for the purchase of 40 MW of capacity from various suppliers for the summer of 2007.

5.4 Summary of Current and Future ARP Resource Capacity

Tables 5-1 and 5-2 provide a summary, ten-year projection of the ARP resource capacity for the summer and winter seasons, respectively. A projection of the ARP fuel requirements by fuel type is shown in Schedule 5. Schedules 6.1 (quantity) and 6.2 (percent of total) present the forecast of ARP energy sources by resource type. Schedules 7.1 and 7.2 summarize the capacity, demand, and resulting reserve margin forecasts for the summer and winter seasons, respectively. Information on planned and prospective ARP generating facility additions and changes is located in Schedule 8.

**Table 5-1
Summary of All-Requirements Project Resource Summer Capacity**

Line No.	Resource Description (a)	Summer Rating (MW)									
		2007 (b)	2008 (c)	2009 (d)	2010 (e)	2011 (f)	2012 (g)	2013 (h)	2014 (i)	2015 (j)	2016 (k)
Installed Capacity											
Existing Resources											
1	Excluded Resources (Nuclear)	85	85	85	74	78	78	78	78	78	78
2	Stanton Coal Plant	224	224	224	186	186	186	186	186	186	186
3	Stanton CC Unit A	42	42	42	42	42	42	42	42	42	42
4	Cane Island 1-3	386	386	386	386	386	386	386	386	386	386
5	Indian River CTs	82	82	82	82	82	82	82	82	82	82
6	Key West Units 2&3	31	31	31	31	31	31	31	31	31	31
7	Key West Unit 4	45	45	45	45	45	45	45	45	45	45
8	Ft. Pierce Native Generation	110	-	-	-	-	-	-	-	-	-
9	Key West Native Generation	41	41	41	41	41	41	41	41	41	41
10	Kissimmee Native Generation	48	48	48	48	48	-	-	-	-	-
11	Lake Worth Native Generation	87	87	87	87	87	-	-	-	-	-
12	Vero Beach Native Generation	137	137	137	-	-	-	-	-	-	-
13	Sub Total Existing Resources	1,316	1,207	1,207	1,021	1,025	891	891	891	891	891
Planned Additions											
14	Treasure Coast Energy Center	-	296	296	296	296	296	296	296	296	296
15	Taylor Energy Center	-	-	-	-	-	293	293	293	293	293
16	New Peaking Capacity	-	-	-	90	90	90	90	90	90	180
17	New Base/Intermediate Capacity	-	-	-	-	296	296	296	296	296	296
18	Sub Total Planned Additions	-	296	296	386	682	975	975	975	975	1,065
19	Total Installed Capacity	1,316	1,503	1,503	1,407	1,707	1,866	1,866	1,866	1,866	1,956
Firm Capacity Import											
Firm Capacity Import Without Reserves											
20	Lakeland Purchase	100	-	-	-	-	-	-	-	-	-
21	Calpine Purchase	100	100	100	-	-	-	-	-	-	-
22	Stanton A Purchase	80	80	80	80	80	80	80	-	-	-
23	Peaking Purchase(s)	40	-	-	-	-	-	-	-	-	-
24	Southern Company Purchase	-	175	175	175	175	175	175	175	175	175
25	Sub Total Without Reserves	320	355	355	255	255	255	255	175	175	175
Firm Capacity Import With Reserves											
26	PEF Partial Requirements	30	30	40	90	-	-	-	-	-	-
27	FPL Partial Requirements	75	-	-	-	-	-	-	-	-	-
28	FPL Long-Term Partial Requirements	45	45	45	45	45	45	-	-	-	-
29	Sub Total With Reserves	150	75	85	135	45	45	-	-	-	-
30	Total Firm Capacity Import	470	430	440	390	300	300	255	175	175	175
Firm Capacity Export											
31	Vero Beach CROD Sale	-	-	-	(35)	(35)	(35)	(35)	(35)	(35)	(35)
32	Total Firm Capacity Export	-	-	-	(35)	(35)	(35)	(35)	(35)	(35)	(35)
33	Total Available Capacity	1,786	1,933	1,943	1,762	1,972	2,131	2,086	2,006	2,006	2,096

**Table 5-2
Summary of All-Requirements Project Resource Winter Capacity**

Line No.	Resource Description (a)	Winter Rating (MW)									
		2007 (b)	2008 (c)	2009 (d)	2010 (e)	2011 (f)	2012 (g)	2013 (h)	2014 (i)	2015 (j)	2016 (k)
Installed Capacity											
Existing Resources											
1	Excluded Resources (Nuclear)	86	87	87	75	75	79	79	79	79	79
2	Stanton Coal Plant	224	224	224	186	186	186	186	186	186	186
3	Stanton CC Unit A	46	46	46	46	46	46	46	46	46	46
4	Cane Island 1-3	400	400	400	400	400	400	400	400	400	400
5	Indian River CTs	99	100	100	100	100	100	100	100	100	100
6	Key West Units 2&3	36	36	36	36	36	36	36	36	36	36
7	Key West Unit 4	45	45	45	45	45	45	45	45	45	45
8	Ft. Pierce Native Generation	118	118	-	-	-	-	-	-	-	-
9	Key West Native Generation	43	43	43	43	43	43	43	43	43	43
10	Kissimmee Native Generation	45	45	45	45	45	-	-	-	-	-
11	Lake Worth Native Generation	97	97	97	97	97	97	-	-	-	-
12	Vero Beach Native Generation	155	155	155	-	-	-	-	-	-	-
13	Sub Total Existing Resources	1,395	1,396	1,278	1,073	1,073	1,032	935	935	935	935
Planned Additions											
14	Treasure Coast Energy Center	-	-	318	318	318	318	318	318	318	318
15	Taylor Energy Center	-	-	-	-	-	-	305	305	305	305
16	New Peaking Capacity	-	-	-	-	90	90	90	90	90	90
17	New Base/Intermediate Capacity	-	-	-	-	-	318	318	318	318	318
18	Sub Total Planned Additions	-	-	318	318	408	726	1,031	1,031	1,031	1,031
19	Total Installed Capacity	1,395	1,396	1,596	1,391	1,481	1,758	1,967	1,967	1,967	1,967
Firm Capacity Import											
Firm Capacity Import Without Reserves											
20	Lakeland Purchase	100	-	-	-	-	-	-	-	-	-
21	Calpine Purchase	100	100	100	-	-	-	-	-	-	-
22	Stanton A Purchase	80	80	80	80	80	80	80	-	-	-
23	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	-
24	Southern Company Purchase	-	195	195	195	195	195	195	195	195	195
25	Sub Total Without Reserves	280	375	375	275	275	275	275	195	195	195
Firm Capacity Import With Reserves											
26	PEF Partial Requirements	30	30	40	90	-	-	-	-	-	-
27	FPL Partial Requirements	75	-	-	-	-	-	-	-	-	-
28	FPL Long-Term Partial Requirements	45	45	45	45	45	45	45	-	-	-
29	Sub Total With Reserves	150	75	85	135	45	45	45	-	-	-
30	Total Firm Capacity Import	430	450	460	410	320	320	320	195	195	195
Firm Capacity Export											
31	Vero Beach CROD Sale	-	-	-	(35)	(35)	(35)	(35)	(35)	(35)	(35)
32	Total Firm Capacity Export	-	-	-	(35)	(35)	(35)	(35)	(35)	(35)	(35)
33	Total Available Capacity	1,825	1,846	2,056	1,766	1,766	2,043	2,252	2,127	2,127	2,127

**Schedule 5
Fuel Requirements - All-Requirements Project**

Line No.	(1) Fuel Type	(2) Unit Type	(3) Fuel Units	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
				Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	
1	Nuclear [1]		Trillion BTU	7	7	8	8	6	7	7	7	7	7	7	
2	Coal		000 Ton	548	590	566	624	517	513	921	1,229	1,238	1,248	1,263	
3	Residual	Steam	000 BBL	-	-	-	0	0	0	0	-	-	-	-	
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-	
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-	
6		Total	000 BBL	-	-	-	0	0	0	0	-	-	-	-	
7		Distillate	Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8			CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
9	CT		000 BBL	41	63	75	80	87	92	95	103	112	118	125	
10	Total		000 BBL	41	63	75	80	87	92	95	103	112	118	125	
11	Natural Gas	Steam	000 MCF	412	86	60	9	0	0	0	-	-	-	-	
12		CC	000 MCF	14,313	18,534	27,485	30,463	27,810	32,215	31,472	27,858	26,772	27,508	25,841	
13		CT	000 MCF	105	367	584	217	320	379	263	202	291	212	262	
14		Total	000 MCF	14,829	18,987	28,130	30,688	28,131	32,594	31,736	28,060	27,063	27,720	26,104	
15	Renewables [2]		Billion BTU	237	283	309	335	264	248	232	221	210	199	189	
16	Other		Trillion BTU	-	0	0	0	0	0	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.

[2] Includes landfill gas consumed by FMPA's ownership share of the Stanton Energy Center as a supplemental fuel source, as well as bagass consumed by U.S. Sugar cogeneration facility in the production of power purchased by FMPA.

**Schedule 6.1
Energy Sources (GWh) - All-Requirements Project**

Line No.	(1) Energy Source	(2) Prime Mover	(3) Units	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Actual	Forecasted									
				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Annual Firm Inter-Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	684	678	706	720	594	648	657	648	625	678	627
3	Coal		GWh	1,450	1,561	1,482	1,619	1,343	1,333	2,450	3,302	3,323	3,348	3,372
4	Residual	Steam	GWh	-	-	-	0	0	0	0	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	0	0	0	0	-	-	-	-
8	Distillate	Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	19	26	32	35	39	41	43	48	55	60	64
11		Total	GWh	19	26	32	35	39	41	43	48	55	60	64
12	Natural Gas	Steam	GWh	25	6	4	0	-	-	-	-	-	-	-
13		CC	GWh	1,892	2,429	3,670	4,078	3,736	4,288	4,147	3,645	3,509	3,614	3,385
14		CT	GWh	10	33	53	20	31	37	26	20	28	21	26
15		Total	GWh	1,927	2,468	3,728	4,098	3,767	4,325	4,172	3,665	3,537	3,634	3,410
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
17	Hydro		GWh	-	-	-	-	-	-	-	-	-	-	-
18	Renewables [2]		GWh	24	29	31	34	27	25	23	22	21	20	19
19	Interchange		GWh	3,100	3,003	1,933	1,617	1,742	1,289	478	304	605	611	1,043
20	Net Energy for Load		GWh	7,204	7,764	7,912	8,123	7,511	7,662	7,824	7,990	8,166	8,352	8,535

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

[2] Includes power purchased from U.S. Sugar cogeneration facility and power generated from FMPA's ownership share of the Stanton Energy Center using landfill gas.

**Schedule 6.2
Energy Sources (%) - All-Requirements Project**

Line No.	(1) Energy Source	(2) Prime Mover	(3) Units	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	9.5	8.7	8.9	8.9	7.9	8.5	8.4	8.1	7.7	8.1	7.3
3	Coal		%	20.1	20.1	18.7	19.9	17.9	17.4	31.3	41.3	40.7	40.1	39.5
4	Residual	Steam	%	-	-	-	0.0	0.0	0.0	0.0	-	-	-	-
5		CC	%	-	-	-	-	-	-	-	-	-	-	-
6		CT	%	-	-	-	-	-	-	-	-	-	-	-
7		Total	%	-	-	-	0.0	0.0	0.0	0.0	-	-	-	-
8	Distillate	Steam	%	-	-	-	-	-	-	-	-	-	-	-
9		CC	%	-	-	-	-	-	-	-	-	-	-	-
10		CT	%	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.6	0.7	0.7	0.7
11		Total	%	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.6	0.7	0.7	0.7
12	Natural Gas	Steam	%	0.3	0.1	0.1	0.0	-	-	-	-	-	-	-
13		CC	%	26.3	31.3	46.4	50.2	49.7	56.0	53.0	45.6	43.0	43.3	39.7
14		CT	%	0.1	0.4	0.7	0.2	0.4	0.5	0.3	0.2	0.3	0.2	0.3
15		Total	%	26.7	31.8	47.1	50.5	50.2	56.4	53.3	45.9	43.3	43.5	40.0
16	NUG		%	-	-	-	-	-	-	-	-	-	-	-
17	Hydro		%	-	-	-	-	-	-	-	-	-	-	-
18	Renewables [2]		%	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2
19	Interchange		%	43.0	38.7	24.4	19.9	23.2	16.8	6.1	3.8	7.4	7.3	12.2
20	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.

[2] Includes power purchased from U.S. Sugar cogeneration facility and power generated from FMPA's ownership share of the Stanton Energy Center using landfill gas.

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)
Year	Total Installed Capacity (MW) [1]	Firm Capacity Import (MW)	Firm Capacity Export (MW)	QF (MW)	Total Available Capacity (MW)	System Firm Summer Peak Demand (MW) [2]	Reserve Margin before Maintenance [3]		Scheduled Maintenance (MW)	Reserve Margin after Maintenance [3]			
							(MW)	(% of Peak)		(MW)	(% of Peak)		
2007	1,316	470	0	0	1,786	1,573	213	15%	0	213	15%		
2008	1,503	430	0	0	1,933	1,603	329	22%	0	329	22%		
2009	1,503	440	0	0	1,943	1,646	296	19%	0	296	19%		
2010	1,407	390	(35)	0	1,762	1,506	256	19%	0	256	19%		
2011	1,707	300	(35)	0	1,972	1,548	424	28%	0	424	28%		
2012	1,866	300	(35)	0	2,131	1,581	551	36%	0	551	36%		
2013	1,866	255	(35)	0	2,086	1,615	471	29%	0	471	29%		
2014	1,866	175	(35)	0	2,006	1,651	355	22%	0	355	22%		
2015	1,866	175	(35)	0	2,006	1,689	318	19%	0	318	19%		
2016	1,956	175	(35)	0	2,096	1,726	370	21%	0	370	21%		

[1] See Table 5-1 for a listing of the resources identified as Installed Capacity and Firm Capacity Import.

[2] System Firm Summer Peak Demand includes transmission losses for the members served through FPL, PEF (beginning in 2011), and KUA.

[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). See Appendix III to this Ten-Year Site Plan for the calculation of reserve margins.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)		(12)
Year	Total Installed Capacity (MW) [1]	Firm Capacity Import (MW) [1]	Firm Capacity Export (MW)	QF (MW)	Total Available Capacity (MW)	System Firm Winter Peak Demand (MW) [2]	Reserve Margin before Maintenance [3]		Scheduled Maintenance (MW)	Reserve Margin after Maintenance [3]			
							(MW)	(% of Peak)		(MW)	(% of Peak)		
2006/07	1,395	430	0	0	1,825	1,509	316	23%	0	316	23%		
2007/08	1,396	450	0	0	1,846	1,538	309	21%	0	309	21%		
2008/09	1,596	460	0	0	2,056	1,581	475	32%	0	475	32%		
2009/10	1,391	410	(35)	0	1,766	1,419	347	27%	0	347	27%		
2010/11	1,481	320	(35)	0	1,766	1,456	310	22%	0	310	22%		
2011/12	1,758	320	(35)	0	2,043	1,487	556	39%	0	556	39%		
2012/13	1,967	320	(35)	0	2,252	1,519	732	50%	0	732	50%		
2013/14	1,967	195	(35)	0	2,127	1,553	574	37%	0	574	37%		
2014/15	1,967	195	(35)	0	2,127	1,589	538	34%	0	538	34%		
2015/16	1,967	195	(35)	0	2,127	1,625	502	31%	0	502	31%		

[1] See Table 5-2 for a listing of the resources identified as Installed Capacity and Firm Capacity Import.

[2] System Firm Winter Peak Demand includes transmission losses for the members served through FPL, PEF (beginning in 2011), and KUA.

[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). See Appendix III to this Ten-Year Site Plan for the calculation of reserve margins.

**Schedule 8
Planned and Prospective Generating Facility Additions and Changes**

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Alt. Fuel Days Use	Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max. Nameplate kW	Net Capability	
				Primary	Alt.	Primary	Alt.					Summer MW	Winter MW
				Resource Additions									
Treasure Coast Energy Center	Unit 1	St. Lucie	CC	NG	DFO	PL	TK	NA	06/08	NA	NA	296	318
Unsite Combustion Turbine	CT1	Unknown	GT	NG	DFO	PL	TK	NA	06/10	NA	NA	45	45
Unsite Combustion Turbine	CT2	Unknown	GT	NG	DFO	PL	TK	NA	06/10	NA	NA	45	45
Cane Island	CC4	Osceola	CC	NG	DFO	PL	-	NA	06/11	NA	NA	296	318
Taylor Energy Center	Unit 1	Taylor	ST	BIT	-	RR	-	NA	05/12	NA	NA	293	305
Unsite Combustion Turbine	CT3	Unknown	GT	NG	DFO	PL	TK	NA	06/16	NA	NA	45	45
Unsite Combustion Turbine	CT4	Unknown	GT	NG	DFO	PL	TK	NA	06/16	NA	NA	45	45
Changes to Existing Resources													
H.D. King	5	St. Lucie	CA	WH	-	-	-	NA	01/53	05/08	8	(8)	(8)
H.D. King	7	St. Lucie	ST	NG	RFO	PL	TK	NA	01/64	05/08	32	(24)	(32)
H.D. King	8	St. Lucie	ST	NG	RFO	PL	TK	NA	05/76	05/08	50	(50)	(50)
H.D. King	9	St. Lucie	CT	NG	DFO	PL	TK	NA	05/90	05/08	23	(23)	(23)
H.D. King	D1	St. Lucie	IC	DFO	-	TK	-	NA	04/70	05/08	3	(3)	(3)
H.D. King	D2	St. Lucie	IC	DFO	-	TK	-	NA	04/70	05/08	3	(3)	(3)
Hansel Plant	21	Osceola	CT	NG	DFO	PL	TK	NA	02/83	12/11	38	(31)	(34)
Hansel Plant	22	Osceola	CA	WH	-	-	-	NA	11/83	12/11	8	(8)	(5)
Hansel Plant	23	Osceola	CA	WH	-	-	-	NA	11/83	12/11	8	(8)	(5)
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	NA	12/76	06/12	31	(26)	(31)
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	NA	03/78	06/12	20	(20)	(22)
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	NA	11/67	06/12	27	(22)	(24)
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	NA	03/78	06/12	10	(8)	(10)



Florida Municipal Power Agency

Section 6.0

Site and Facility Descriptions

Community Power + Statewide Strength

Section 6 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 is 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.

- Treasure Coast Energy Center – Identified Preferred Site for Treasure Coast Energy Center Unit 1 and Potential Site for additional future generation
- Taylor Energy Center – Identified Preferred Site for Taylor Energy Center Unit 1 and Potential Site for additional future generation
- Cane Island – Identified Preferred Site for Cane Island Unit 4 and Potential Site for additional future generation
- Tom G. Smith – Potential Site
- Stock Island – Potential Site

FMPA anticipates that the LM6000 simple cycle combustion turbines could be installed at an ARP member owned generation site, most likely at the Tom G. Smith Power Plant site at Lake Worth, the Cane Island Power Park site at KUA, or at FMPA's Treasure Coast Energy Center site. FMPA anticipates that combined cycle generation could be installed at an existing ARP site, either at Cane Island or at the Treasure Coast Energy Center. Additional coal generation could be located at the Taylor Energy Center site or in joint ownership at another utility's site. FMPA continuously explores the feasibility of other sites located within Florida with the expectation that member cities would provide the best option for future development.

Treasure Coast Energy Center

FMPA is currently constructing a new 296 MW, 1x1 7FA combined cycle facility at the Treasure Coast Energy Center site. The Treasure Coast Energy Center will be located in St. Lucie County near the City of Fort Pierce. The site was certified in June 2006 and can accommodate construction of future units beyond TCEC Unit 1, up to a total of 1,200 MW. Physical construction of TCEC Unit 1 commenced in August 2006, and commercial operation is scheduled for June 2008.

Cane Island Power Park

FMPA is currently planning to construct a new 296 MW, 1x1 7FA combined cycle facility at the Cane Island Power Park. FMPA has received alternative power supply proposals which are currently being evaluated. Decisions are forthcoming on accepting the alternative proposals and submitting the Need Determination request.

Cane Island Power Park is located south and west of KUA's service area and contains 380 MW (summer) of gas turbine and combined cycle capacity. The Cane Island Power Park currently 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.

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.

Stock Island

The Stock Island site currently consists of five diesel generating units, as well as four combustion turbines. The site receives water from the Florida Keys Aqueduct Authority via a pipeline from the mainland, and also uses on-site groundwater. 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, or any designated natural resources.

Taylor Energy Center

The TEC is being proposed as a joint development project by four municipal utilities, including the FMPA, JEA, RCID, and the City of Tallahassee (The Participants). FMPA is a wholesale supplier to 15 city-owned electric utilities throughout Florida. JEA is a retail supplier in Jacksonville, Florida, and in parts of three adjacent counties. RCID is a retail supplier in parts of Orange and Osceola counties. Tallahassee is the principal retail supplier in Tallahassee, Florida.

The Participants are developing the proposed TEC to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant. Table

6-1 presents each Participant’s ownership percentage in TEC, with each Participant responsible for the costs associated with TEC in proportion to its individual ownership percentage.

**Table 6-1
Proposed TEC Ownership Percentages**

Participant	Percent Ownership
FMPA	38.9
JEA	31.5
RCID	9.3
City of Tallahassee	20.3

The TEC will be developed on a site consisting of approximately 3,000 acres to be located approximately 5 miles southeast of Perry, in Taylor County, Florida. The land is bordered by Highway 27 on the north and the Fenholloway River on the west. Though the TEC project consists of one unit, the site will be designed and constructed with consideration given to allowing the addition of a second unit. However, a second unit is not planned at this time.

Schedules 9.1 through 9.7 present the status report and specifications for each of the proposed ARP generating facilities. Schedule 10 contains the status report and specifications for proposed ARP transmission line projects.

**Schedule 9.1
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	296
	b. Winter	318
(3)	Technology Type	CC (1x1 GE 7FA)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	Aug-06
	b. Commercial In-Service Date	Jun-08
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Low NO2 Combustors, Water Injection
(7)	Cooling Method	Mechanical Draft
(8)	Total Site Area	69 Acres
(9)	Construction Status	Under construction, less than or equal to 50% complete
(10)	Certification Status	Approved
(11)	Status with Federal Agencies	Approved
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5.7%
	Forced Outage Factor (FOF)	6.3%
	Equivalent Availability Factor	88.3%
	Resulting Capacity Factor	34.9%
	Average Net Operating Heat Rate (ANOHR)	7,582 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year \$/kW)	\$1,072
	Direct Construction Cost (2006 \$/kW)	\$891
	AFUDC Amount (\$/kW) [1]	\$104
	Escalation (\$/kW)	\$77
	Fixed O&M (\$/kW)	6.91 \$/kW-yr
	Variable O&M (\$/MWh)	\$2.74

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Unsiteed Combustion Turbine Unit 1
(2)	Capacity	
	a. Summer	45
	b. Winter	45
(3)	Technology Type	GT (General Electric LM6000 PC-SPRINT)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2008
	b. Commercial In-Service Date	Jun-10
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Existing Site
(11)	Status with Federal Agencies	Existing Site
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	1.9%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor	95.2%
	Resulting Capacity Factor	1.8%
	Average Net Operating Heat Rate (ANOHR)	10,136 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year \$/kW)	\$1,299
	Direct Construction Cost (2006 \$/kW)	\$1,027
	AFUDC Amount (\$/kW) [1]	\$121
	Escalation (\$/kW)	\$151
	Fixed O&M (\$/kW)	31.17 \$/kW-yr
	Variable O&M (\$/MWh)	\$3.00

[1] Includes AFUDC and bond issuance expenses

**Schedule 9.3
Status Report and Specifications of Proposed Generating Facilities
All-Requirements Project
(Preliminary Information)**

(1)	Plant Name and Unit Number	Unsitied Combustion Turbine Unit 2
(2)	Capacity	
	a. Summer	45
	b. Winter	45
(3)	Technology Type	GT (General Electric LM6000 PC-SPRINT)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2008
	b. Commercial In-Service Date	Jun-10
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Existing Site
(11)	Status with Federal Agencies	Existing Site
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	1.9%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor	95.2%
	Resulting Capacity Factor	1.6%
	Average Net Operating Heat Rate (ANOHR)	10,136 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year \$/kW)	\$1,299
	Direct Construction Cost (2006 \$/kW)	\$1,027
	AFUDC Amount (\$/kW) [1]	\$121
	Escalation (\$/kW)	\$151
	Fixed O&M (\$/kW)	31.17 \$/kW-yr
	Variable O&M (\$/MWh)	\$3.00

[1] Includes AFUDC and bond issuance expenses

**Schedule 9.4
Status Report and Specifications of Proposed Generating Facilities
All-Requirements Project
(Preliminary Information)**

(1)	Plant Name and Unit Number	Cane Island Unit 4
(2)	Capacity	
	a. Summer	296
	b. Winter	318
(3)	Technology Type	CC
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2009
	b. Commercial In-Service Date	Jun-11
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Low NO2 Combustors, Water Injection
(7)	Cooling Method	Mechanical Draft
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Existing Site
(11)	Status with Federal Agencies	Existing Site
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5.7%
	Forced Outage Factor (FOF)	6.3%
	Equivalent Availability Factor	88.3%
	Resulting Capacity Factor	36.8%
	Average Net Operating Heat Rate (ANOHR)	7,516 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year \$/kW)	\$1,154
	Direct Construction Cost (2006 \$/kW)	\$891
	AFUDC Amount (\$/kW) [1]	\$104
	Escalation (\$/kW)	\$159
	Fixed O&M (\$/kW)	6.91 \$/kW-yr
	Variable O&M (\$/MWh)	\$2.74

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Taylor Energy Center
(2)	Capacity	
	a. Summer	754.1 [3]
	b. Winter	785.3 [3]
(3)	Technology Type	ST (Supercritical Pulverized Coal)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	Apr-08
	b. Commercial In-Service Date	May-12
(5)	Fuel	
	a. Primary Fuel	Bituminous Coal / Petroleum Coke
	b. Alternate Fuel	NA
(6)	Air Pollution Control Strategy	BACT Compliant
(7)	Cooling Method	Mechanical Draft
(8)	Total Site Area	Approximately 3,000 Acres
(9)	Construction Status	Not Started
(10)	Certification Status	Underway
(11)	Status with Federal Agencies	Underway
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	4.38%
	Forced Outage Factor (FOF)	5.23%
	Equivalent Availability Factor (EAF)	90%
	Resulting Capacity Factor (%)	90%
	Average Net Operating Heat Rate (ANOHR) [1]	9,238 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year \$/kW) [1]	\$2,664
	Direct Construction Cost (\$/kW) [1]	\$2,152
	AFUDC Amount (\$/kW) [1]	\$208
	Escalation (\$/kW) [1]	\$304
	Fixed O&M (\$/kW) [1] [2]	\$24.31
	Variable O&M (\$/MWh) [1] [2]	\$1.43

[1] Based on operation at average ambient conditions.

[2] In 2007 dollars.

[3] FMPA ownership share is 38.9%.

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

(1)	Plant Name and Unit Number	Unsiteed Combustion Turbine Unit 3
(2)	Capacity	
	a. Summer	45
	b. Winter	45
(3)	Technology Type	GT (General Electric LM6000 PC-SPRINT)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2014
	b. Commercial In-Service Date	Jun-16
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Existing Site
(11)	Status with Federal Agencies	Existing Site
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	10.4%
	Forced Outage Factor (FOF)	1.7%
	Equivalent Availability Factor	88.1%
	Resulting Capacity Factor	1.2%
	Average Net Operating Heat Rate (ANOHR)	10,136 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year \$/kW)	\$1,506
	Direct Construction Cost (2006 \$/kW)	\$1,027
	AFUDC Amount (\$/kW) [1]	\$121
	Escalation (\$/kW)	\$358
	Fixed O&M (\$/kW)	31.17 \$/kW-yr
	Variable O&M (\$/MWh)	\$3.00

[1] Includes AFUDC and bond issuance expenses

**Schedule 9.7
Status Report and Specifications of Proposed Generating Facilities
All-Requirements Project
(Preliminary Information)**

(1)	Plant Name and Unit Number	Unsiteed Combustion Turbine Unit 4
(2)	Capacity	
	a. Summer	45
	b. Winter	45
(3)	Technology Type	GT (General Electric LM6000 PC-SPRINT)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2014
	b. Commercial In-Service Date	Jun-16
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Existing Site
(11)	Status with Federal Agencies	Existing Site
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	10.4%
	Forced Outage Factor (FOF)	1.7%
	Equivalent Availability Factor	88.1%
	Resulting Capacity Factor	1.1%
	Average Net Operating Heat Rate (ANOHR)	10,136 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year \$/kW)	\$1,506
	Direct Construction Cost (2006 \$/kW)	\$1,027
	AFUDC Amount (\$/kW) [1]	\$121
	Escalation (\$/kW)	\$358
	Fixed O&M (\$/kW)	31.17 \$/kW-yr
	Variable O&M (\$/MWh)	\$3.00

[1] Includes AFUDC and bond issuance expenses

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines
All-Requirements Project

(1)	Point of Origin and Termination	TCEC (FMPA) to Ralls (FPL) [1]
(2)	Number of Lines	One
(3)	Right-of-Way	New Transmission Right-of-Way
(4)	Line Length	500 feet
(5)	Voltage	230 kV
(6)	Anticipated Construction Timing	February 2007
(7)	Anticipated Capital Investment	\$12,484,000 [2]
(8)	Substations	TCEC
(9)	Participation with Other Utilities	FPL

Notes:

[1] New FPL substation

[2] Planned network upgrades



Florida Municipal Power Agency

Appendix I

List of Abbreviations

Community Power + Statewide Strength

Appendix I List of Abbreviations

Generator Type

CA	Steam Portion of Combined Cycle
CC	Combined Cycle (Total Unit)
CT	Combustion Turbine Portion of Combined Cycle
GT	Combustion Turbine
IC	Internal Combustion Engine
NP	Nuclear Power
ST	Steam Turbine

Fuel Type

BIT	Bituminous Coal
DFO	Distillate Fuel Oil
NG	Natural Gas
RFO	Residual Fuel Oil
UR	Uranium
WH	Waste Heat

Fuel Transportation Method

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water Transportation

Status of Generating Facilities

P	Planned Unit (Not Under Construction)
L	Regulatory Approval Pending. Not Under Construction
RT	Existing Generator Scheduled for Retirement
U	Under Construction, Less Than or Equal to 50% Complete.

Other

NA	Not Available or Not Applicable
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Florida Municipal Power Agency

Appendix II

Other Member Transmission Information

Community Power + Statewide Strength

Appendix II Other Member Transmission Information

Table II-1 presented on the following pages 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 that are not required to file a Ten-Year Site Plan.

**Table II-1
Planned and Proposed Transmission Additions for FMPA Members
2007 through 2015 (69 kV and Above)**

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date		
FMPA	TCEC (FMPA)	Ralls (FPL)	759	230 kV	1	9/2007		
	TCEC Substation			230 kV		9/2007		
Ft. Pierce	Hartman Auto-Xfmr1 Upgrade		100	138/69 kV	1	5/2008		
	Hartman Auto-Xfmr2 Upgrade		100	138/69 kV	2	5/2008		
	Southwest Sub Auto-Xfmr Addition		20	138/13.2 kV	1	9/2010		
	Southwest Sub Auto-Xfmr Addition		20	138/13.2 kV	2	9/2010		
	Southwest Substation			138/13.2 kV		9/2010		
Homestead	Redland Substation			138/13.2 kV		5/2007		
	Renaissance Substation			138/13.2 kV		6/2007		
	Redland			Lucy		138 kV	1	2/2009
	Renaissance			Lucy		138 kV	1	2/2009
Jacksonville Beach	Jacksonville Beach Substation (Reconductor)	JEA Neptune Substation		138 kV	1	6/2011		
Key West & FKEC	SIS 3rd Ave Transformer			69/13.8kV		3/2009		
	Tavernier			Islamorada		138 kV	2	6/2015
	Islamorada			Marathon		138 kV	2	6/2015
	Florida City			Tavernier		138 kV	2	6/2015
	Tavernier					ring bus		6/2015
Kissimmee	Hansel (Reconductor)	C.A.Wall		69 kV	1	6/2008		
	Pleasant Hill Substation	Hansel		69 kV	1	6/2008		
	Pleasant Hill Substation	Clay Street		69 kV	1	6/2008		
	Pleasant Hill Substation			69 kV		6/2008		
	Cane Island (Reconductor)	Tie Point (Taft)		230 kV	1	12/2009		
	Cane Island (Reconductor)	Tie Point (Osceola)		230 kV	1	12/2009		
	C.A.Wall	Turnpike		69 kV	1	6/2010		
	Neptune Road Substation			69 kV	1	6/2010		
	Neptune Road Substation	Tie Point with St.Cloud		69 kV	1	6/2010		
	Osceola Parkway Substation					6/2011		
	Lake Bryan	Osceola Parkway		69 kV	1	6/2011		

**Table II-1 (Continued)
Planned and Proposed Transmission Additions for FMPA Members
2007 through 2016 (69 kV and Above)**

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date	
Kissimmee (continued)	Lake Cecile	Osceola Parkway Airport	200	69 kV	1	6/2011	
	Clay Street (Reconductor)			69 kV	1	6/2011	
	Clay Auto-Txfmr			230/69 kV	2	6/2011	
	Upgrade 69 kV Breakers at Cane Island Substation			69 kV		6/2011	
	Marydia Auto-Txfmr (Upgrade)			230/69 kV	1	6/2012	
Lake Worth	Canal Transformer	Canal	60	138/26 kV	2	12/2009	
	Hypoluxo			138 kV	1	12/2009	
New Smyrna Beach	30 MVA Txfmr (Smyrna Substation)		30	115/23 kV	1	12/2008	
	115 kV Loop Field St - Airport			115 kV	1	12/2008	
	30 MVA Txfmr (Field Street Substation)		30	115/23 kV	1	12/2011	
Ocala	Richmond 2 Station		5	69 kV		5/2007	
	Nuby's Corner Substation		25	69 kV		8/2007	
	Nuby's Corner		Silver Springs	69 kV	1	8/2007	
	Nuby's Corner		Baseline Rd	69 kV	1	10/2007	
	Shaw		Silver Springs North	230 kV	1	10/2007	
	Ergle		Silver Springs North	230 kV	2	10/2007	
	Shaw Auto-Txfmr			150	230/69 kV	2	10/2007
	Ergle Substation Third Breaker				69 kV		10/2008
	Ergle		Silver Springs		69 kV	1	10/2008
	Dearmin		Baseline Rd		69 kV	1	6/2009
	Dearmin / Baseline Substation (Improvements)				69 kV		6/2009
	Fore Corners Substation			30	69 kV		6/2009
	Fore Corners		Ergle		69 kV	1	6/2009
	Fore Corners		Ocala North		69 kV	1	6/2009
	Shaw Second 30 MVA Transformer			30	69 kV		6/2009
	Shaw		Silver Springs		230 kV	1	6/2012
Vero Beach	Sub #7 (2nd Auto-Transformer)		100	138/69 kV	2	6/2007	



Florida Municipal Power Agency

Appendix III

Additional Reserve Margin Information

Community Power + Statewide Strength

Appendix III Additional Reserve Margin Information

FMPA excludes Partial Requirements (PR) purchases that are being supplied by the PR utility in the calculation of reserves being supplied in Schedules 7.1 and 7.2. The PR utility is required to serve the ARP load equivalent to that of the PR utility’s own native load. Thus, the PR purchase by FMPA is equal to the purchase capacity plus equivalent reserves of the selling utility and therefore does not require additional reserves to be carried by FMPA. Tables III-1 and III-2 below are provided as supplements to Ten-Year Site Plan Schedules 7.1 and 7.2 to demonstrate how the reserve margin percentages were calculated for the summer and winter peaks, respectively.

**Table III-1
Calculation of Reserve Margin at Time of Summer Peak
All-Requirements Project**

Year	Total Available Capacity (MW)	System Firm Peak Demand (MW)	Partial Requirements Purchases (MW)	Reserve Margin (MW) [1]	Reserve Margin (%) [2]
(a)	(b)	(c)	(d)	(e)	(f)
2007	1,786	1,573	150	213	15%
2008	1,933	1,603	75	329	22%
2009	1,943	1,646	85	296	19%
2010	1,762	1,506	135	256	19%
2011	1,972	1,548	45	424	28%
2012	2,131	1,581	45	551	36%
2013	2,086	1,615	0	471	29%
2014	2,006	1,651	0	355	22%
2015	2,006	1,689	0	318	19%
2016	2,096	1,726	0	370	21%

[1] Reserve Margin MW calculated as follows: (Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)

[2] Reserve Margin % calculated as follows: [(Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)] / (System Firm Peak Demand - Partial Requirements Purchases)

**Table III-2
Calculation of Reserve Margin at Time of Winter Peak
All-Requirements Project**

Year	Total Available Capacity (MW)	System Firm Peak Demand (MW)	Partial Requirements Purchases (MW)	Reserve Margin (MW) [1]	Reserve Margin (%) [2]
(a)	(b)	(c)	(d)	(e)	(f)
2006/07	1,825	1,509	150	316	23%
2007/08	1,846	1,538	75	309	21%
2008/09	2,056	1,581	85	475	32%
2009/10	1,766	1,419	135	347	27%
2010/11	1,766	1,456	45	310	22%
2011/12	2,043	1,487	45	556	39%
2012/13	2,252	1,519	45	732	50%
2013/14	2,127	1,553	0	574	37%
2014/15	2,127	1,589	0	538	34%
2015/16	2,127	1,625	0	502	31%

[1] Reserve Margin MW calculated as follows: (Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)

[2] Reserve Margin % calculated as follows: [(Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)] / (System Firm Peak Demand - Partial Requirements Purchases)



Florida Municipal Power Agency

Appendix IV

Supplemental Information

Community Power + Statewide Strength

Appendix IV Supplemental Information

This appendix presents information typically requested by and provided to the PSC in a supplemental filing.

- Q1. Provide all data requested on the attached forms. If any of the requested data is already included in FMPA's Ten-Year Site Plan, state so on the appropriate form.**

See Tables IV-1 through IV-7.

- Q2. Illustrate what FMPA's generation expansion plan would be as a result of sensitivities to the base case demand and fuel price forecast. Include the cumulative present worth revenue requirements of each sensitivity case.**

FMPA's Base Case generation expansion plan was held constant for the sensitivities to the demand forecast. FMPA performed sensitivities to the Base Case demand forecast using the Severe and Mild weather forecasts as discussed in Section 3 of the Ten-Year Site Plan. Some adjustments to the timing of certain planned resources could be made in the event that a material change in demand was to occur in the future.

FMPA's Base Case generation expansion plan was also held constant for the various sensitivities to the fuel price forecast. In addition to the Base Case, FMPA has performed High and Low Fuel Price sensitivities, as well as an additional sensitivity that held non-nuclear fuel prices constant over the study period (the "Constant Fuel" case).

The cumulative present worth revenue requirements (CPWRR) over the period 2007-2036 for the Base Case were approximately \$12.4 billion. The CPWRR for the Severe and Mild weather sensitivities were approximately \$12.6 billion and \$11.9 billion, respectively. The CPWRR for the High and Low Fuel Price sensitivities were approximately \$17.9 billion and \$9.2 billion, respectively. The CPWRR for the Constant Fuel case was approximately \$12.6 billion.

Q3. Describe the nature of FMPA’s options to continue purchasing capacity under its existing contracts.

FMPA has options in several power agreements to purchase additional power if required.

Q4. For each of the generating units contained in FMPA’s Ten-Year Site Plan, discuss the “drop-dead” date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.

Typical project schedules for coal, combined cycle and peaking units are shown below. There may moderate to significant costs associated with cancelling a decision to build a unit at any time in the project schedule. Typical “drop-dead” dates for a schedule may be just prior to when construction begins, or just after the final permitting stages. This would allow for resale of any equipment without having been installed. The construction period typically begins four years prior to the in-service date of coal plants, two years prior to the in service date of combined cycle units and one year prior to the in-service date of peaking units.

Typical Coal Unit Schedule																
Coal Unit Activities	Months	6	12	18	24	30	36	42	48	54	60	66	72	78	84	
Planning & Project Development	18	[Gantt bar from 0 to 18]														
Regulatory and Permitting	24	[Gantt bar from 6 to 30]														
Engineering and Procurement	48	[Gantt bar from 12 to 60]														
Construction	48	[Gantt bar from 30 to 78]														
Total	84	[Gantt bar from 0 to 84]														

Typical Combined Cycle Unit Schedule																
Combined Cycle Unit Activities	Months	6	12	18	24	30	36	42	48	54	60	66	72	78	84	
Planning & Project Development	12	[Gantt bar from 0 to 12]														
Regulatory and Permitting	18	[Gantt bar from 6 to 24]														
Engineering and Procurement	24	[Gantt bar from 12 to 36]														
Construction	24	[Gantt bar from 30 to 54]														
Total	48	[Gantt bar from 0 to 48]														

Typical Combustion Turbine Unit Schedule																
Combustion Turbine Unit Activities	Months	6	12	18	24	30	36	42	48	54	60	66	72	78	84	
Planning & Project Development	12	[Gantt bar from 0 to 12]														
Regulatory and Permitting	18	[Gantt bar from 6 to 24]														
Engineering and Procurement	18	[Gantt bar from 12 to 30]														
Construction	12	[Gantt bar from 30 to 42]														
Total	36	[Gantt bar from 0 to 36]														

- Q5. Discuss whether FMPA anticipates any problems with purchasing capacity and energy from Calpine given Calpine Corporation's bankruptcy proceedings.**

FMPA expects Calpine to provide capacity and energy as contracted.

- Q6. Provide, on a system-wide basis, historical annual heating degree day (HDD) data for the period 1997-2006 and forecasted HDD data for the period 2007-2016. Describe how FMPA derives system-wide temperature if more than one weather station is used.**

FMPA forecasts demand and energy data for each All-Requirements participant using temperature data. Demands are then combined using historical coincident information to produce a coincident peak demand for the All-Requirements Project as a whole. Data reported in Table IV-8 is from the Orlando International Airport weather station, which may be used as an indicator of weather conditions over FMPA's geographically diverse service area.

- Q7. Provide, on a system-wide basis, historical annual cooling degree day (CDD) data for the period 1997-2006 and forecasted CDD data for the period 2007-2016. Describe how FMPA derives system-wide temperature if more than one weather station is used.**

Available cooling degree-day information is contained in Table IV-8. See question 6 regarding the use of temperature data.

- Q8. Provide, on a system-wide basis, historical annual average real retail price of electricity in FMPA's service territory for the period 1997-2006. Also, provide the forecasted annual average real retail price of electricity in FMPA's service territory for the period 2007-2016. Indicate the type of price deflator used to calculate the historical and forecasted prices.**

FMPA provides wholesale power to its members. Individual member cities are responsible for setting their own retail price of electricity.

- Q9. **Provide the following data to support Schedule 4 of FMPA's Ten-Year Site Plan: the 12 monthly peak demands for the years 2004, 2005, and 2006; the date when each of these monthly peaks occurred; and the temperature at the time of these monthly peaks. Describe how FMPA derives system-wide temperature if more than one weather station is used.**

See Table IV-9 for monthly peak demand information. Temperature data reported in Table IV-9 is from the Orlando International Airport weather station, which may be used as an indicator of weather conditions over FMPA's geographically diverse service area.

- Q10. **Discuss how FMPA compares its fuel price forecasts to recognized, authoritative independent forecast.**

FMPA utilizes independent fuel forecasting consultants as well as information from general consultants, other utilities, market exchanges, trade literature, FMPA members and staff to evaluate the reasonableness of a given fuel forecast.

- Q11. **Discuss the actions taken by FMPA or its members to promote and encourage competition within and among coal transportation members.**

FMPA is a joint owner in existing coal capacity with OUC. OUC is FMPA's primary coal transportation manager for Stanton Units 1 and 2. Such information may be obtained from OUC.

- Q12. **Provide documents that support FMPA's fuel price forecasts for natural gas, residual fuel oil, and distillate fuel oil for the 2007-2016 period. Separate the delivered price into commodity and transportation components.**

The base case fuel price forecasts were provided by NewEnergy Associates, a wholly owned subsidiary of Siemens Power Generation. The base case fuel price forecast data for coal was provided by Platt's, a division of the McGraw-Hill Companies, Inc. It cannot be reproduced, distributed, or sold without the express written permission of Platt's. Fuel price sensitivities and fuel transportation costs were developed by FMPA through internal resources. The commodity and transportation components of the base, high and low fuel price forecast can be found in Tables IV-10, IV-11, and IV-12, respectively.

Table IV-1

Existing Generating Unit Operating Performance ⁽¹⁾

(1) Plant Name	(2) Unit No.	(3) Planned Outage Factor (POF)			(4) Forced Outage Factor (FOF)			(5) Equivalent Availability Factor (EAF)			(6) Average Net Operating Heat Rate (ANOH) ^R	
		Historical [2]	Projected [3]	Historical [2]	Projected [3]	Historical [2]	Projected [3]	Historical [2]	Projected [3]	Historical [2]	Projected [3]	
FPL/St Lucie	2	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	
KUA/Cane Island CT	1	3.8%	3.0%	[5]	6.3%	3.0%	[5]	93.3%	[5]	10,380	[4]	
KUA/Cane Island CC	2	5.8%	6.3%	[5]	6.3%	[5]	88.3%	[5]	[5]	8,130	[5]	
KUA/Cane Island CC	3	6.0%	6.3%	[5]	6.3%	[5]	88.1%	[5]	[5]	7,536	[5]	
OUC/Stanton	1	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	
OUC/Stanton	2	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	
OUC/Stanton	A	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	
OUC/Indian River CT	A	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	
OUC/Indian River CT	B	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	
OUC/Indian River CT	C	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	
OUC/Indian River CT	D	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	
Key West (Stock Island) CT	2	1.9%	3.0%	[5]	3.0%	[5]	95.1%	[5]	15,760	[5]		
Key West (Stock Island) CT	3	1.9%	3.0%	[5]	3.0%	[5]	95.1%	[5]	14,709	[5]		
Key West (Stock Island) CT	4	1.9%	3.0%	[5]	3.0%	[5]	95.1%	[5]	10,655	[5]		

[1] For those generating units wholly or partially owned by the All-Requirements Project

[2] Historical data represents the average of the most recent three years.

[3] Projected data represents the average of the next ten years.

[4] Historical and projected operating data for this unit is available from Florida Power & Light.

[5] Historical and projected operating data for this unit is available from Orlando Utilities Commission.

**Table IV-2
Nominal, Delivered Fuel Prices Base Case**

(1) Year	(2) (3) Residual Oil		(4) (5) Distillate Oil		(6) (7) Natural Gas		(8) (9) Coal [1]		(10) (11) Nuclear	
	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)
History:										
2004										
2005										
2006										
Forecast:										
2007	1,235		1,426		828		306		46	
2008	1,106	-10.48%	1,377	-3.49%	812	-1.84%	310	1.31%	47	2.50%
2009	931	-15.81%	1,267	-7.95%	756	-6.95%	270	-12.98%	49	2.50%
2010	786	-15.59%	1,172	-7.48%	739	-2.18%	271	0.27%	50	2.50%
2011	799	1.67%	1,187	1.26%	692	-6.37%	264	-2.25%	51	2.50%
2012	802	0.36%	1,197	0.83%	671	-3.09%	252	-4.59%	52	2.50%
2013	810	0.99%	1,193	-0.35%	679	1.14%	236	-6.62%	54	2.50%
2014	818	1.03%	1,209	1.33%	675	-0.57%	242	2.78%	55	2.50%
2015	841	2.77%	1,239	2.46%	668	-1.04%	242	0.14%	56	2.50%
2016	870	3.52%	1,292	4.28%	669	0.19%	248	2.18%	58	2.50%

[1] The base case fuel price forecast for coal was provided by Platt's, a division of the McGraw-Hill Companies, Inc. It cannot be reproduced, distributed, or sold without the express written permission of Platt's.

**Table IV-3
Nominal, Delivered Fuel Prices High Case**

(1) Year	(2) Residual Oil		(4) Distillate Oil		(6) Natural Gas		(8) Coal [1]		(10) Nuclear	
	(3) ¢/Mbtu	Escalation (%)	(5) ¢/Mbtu	Escalation (%)	(7) ¢/Mbtu	Escalation (%)	(9) ¢/Mbtu	Escalation (%)	(11) ¢/Mbtu	Escalation (%)
History:										
2004										
2005										
2006										
Forecast:										
2007	1,830		3,369		1,650		459		46	
2008	1,799	-1.69%	3,307	-1.83%	1,618	-1.92%	465	1.31%	47	2.50%
2009	1,681	-6.59%	3,078	-6.92%	1,502	-7.13%	405	-12.98%	49	2.50%
2010	1,647	-1.98%	3,012	-2.16%	1,468	-2.28%	406	0.27%	50	2.50%
2011	1,549	-5.99%	2,821	-6.34%	1,372	-6.57%	397	-2.25%	51	2.50%
2012	1,505	-2.82%	2,734	-3.07%	1,328	-3.22%	378	-4.59%	52	2.50%
2013	1,523	1.21%	2,766	1.15%	1,342	1.11%	353	-6.62%	54	2.50%
2014	1,517	-0.42%	2,750	-0.56%	1,334	-0.65%	363	2.78%	55	2.50%
2015	1,504	-0.85%	2,722	-1.02%	1,318	-1.13%	364	0.14%	56	2.50%
2016	1,509	0.32%	2,728	0.20%	1,320	0.13%	372	2.18%	58	2.50%

[1] The base case fuel price forecast for coal was provided by Platt's, a division of the McGraw-Hill Companies, Inc. It cannot be reproduced, distributed, or sold without the express written permission of Platt's. Sensitivities to the base case forecast were developed by FMPA through internal resources.

Table IV-4
Nominal, Delivered Fuel Prices Low Case

(1) Year	(2) (3) Residual Oil		(4) (5) Distillate Oil		(6) (7) Natural Gas		(8) (9) Coal [1]		(10) (11) Nuclear	
	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)
History:										
2004										
2005										
2006										
Forecast:										
2007	447		736		333		205		46	
2008	444	-0.70%	727	-1.21%	327	-1.60%	208	1.31%	47	2.50%
2009	425	-4.39%	686	-5.53%	306	-6.41%	181	-12.98%	49	2.50%
2010	421	-0.82%	677	-1.41%	301	-1.88%	181	0.27%	50	2.50%
2011	406	-3.71%	644	-4.87%	283	-5.79%	177	-2.25%	51	2.50%
2012	400	-1.31%	630	-2.07%	276	-2.69%	169	-4.59%	52	2.50%
2013	407	1.59%	639	1.40%	279	1.24%	158	-6.62%	54	2.50%
2014	409	0.46%	639	0.02%	278	-0.34%	162	2.78%	55	2.50%
2015	409	0.17%	637	-0.33%	276	-0.76%	162	0.14%	56	2.50%
2016	413	1.00%	642	0.66%	277	0.38%	166	2.18%	58	2.50%

[1] The base case fuel price forecast for coal was provided by Platt's, a division of the McGraw-Hill Companies, Inc. It cannot be reproduced, distributed, or sold without the express written permission of Platt's. Sensitivities to the base case forecast were developed by FMPA through internal resources.

**Table IV-5
Financial Assumptions Base Case**

AFUDC Rate		5.00%
Capitalization Ratios (%):		
	Debt	100%
	Preferred	N/A
	Equity	N/A
Rate of Return (%):		
	Debt	N/A
	Preferred	N/A
	Equity	N/A
Income Tax Rate (%):		
	State	N/A
	Federal	N/A
	Effective	N/A
Other Tax Rate:		N/A
Discount Rate:		5.0%
Tax Depreciation Rate (%):		N/A

**Table IV-6
Financial Escalation Assumptions**

(1) Year	(2) General Inflation %	(3) Plant Construction Cost %	(4) Fixed O&M Cost %	(5) Variable O&M Cost %
2007	2.50%	2.50%	2.50%	2.50%
2008	2.50%	2.50%	2.50%	2.50%
2009	2.50%	2.50%	2.50%	2.50%
2010	2.50%	2.50%	2.50%	2.50%
2011	2.50%	2.50%	2.50%	2.50%
2012	2.50%	2.50%	2.50%	2.50%
2013	2.50%	2.50%	2.50%	2.50%
2014	2.50%	2.50%	2.50%	2.50%
2015	2.50%	2.50%	2.50%	2.50%
2016	2.50%	2.50%	2.50%	2.50%

**Table IV-7
Loss of Load Probability, Reserve Margin, and Expected Unserved Energy Base Case Load Forecast**

(1) Year	(2) Annual Isolated			(5) Annual Assisted		
	(2) Loss of Load Probability (Days/Yr)	(3) Reserve Margin (%) (Including Firm Purchases)	(4) Expected Unserved Energy (MWh)	(5) Loss of Load Probability (Days/Yr)	(6) Reserve Margin (%) (Including Firm Purchases)	(7) Expected Unserved Energy (MWh)
2007	(See note below)			(See note below)		
2008						
2009						
2010						
2011						
2012						
2013						
2014						
2015						
2016						

Note: FMPA does not develop projections of either Isolated or Assisted Loss of Load Probability nor Expected Unserved Energy.

Table IV-8
Historical and Projected Heating and Cooling Degree Days ^[1]

(1) Year	(2) Annual Heating Degree Days	(3) Annual Cooling Degree Days
(a)	(b)	(c)
1997	395	3,323
1998	621	3,490
1999	350	3,637
2000	452	3,413
2001	706	3,202
2002	457	3,591
2003	714	3,529
2004	531	3,447
2005	524	3,424
2006	433	3,545
Projected Values for 2007 to 2016	580	3,428

[1] Projections are based on normal heating and cooling degree day data reported by the National Oceanic Atmospheric Administration (NOAA) and are based on the historical period from 1971-2000 inclusive. Data reported is for the Orlando International Airport (OIA) annual weather station, which may be used as an indicator of weather conditions over FMPA's geographically diverse service area.

Table IV-9
All-Requirements Project Monthly Peak Demand Information [1] [2]

(1) Month	(2) (3) (4) (5) Actual - 2004				(6) (7) (8) (9) Actual - 2005				(10) (11) (12) (13) Actual - 2006			
	Peak Demand MW	Day of Month	Max Temp (°F)	Min Temp (°F)	Peak Demand MW	Day of Month	Max Temp (°F)	Min Temp (°F)	Peak Demand MW	Day of Month	Max Temp (°F)	Min Temp (°F)
January	1,194	29	68	37	1,340	24	58	33	1,064	08	66	34
February	1,104	19	69	37	1,031	11	60	41	1,388	14	63	33
March	905	06	87	61	1,033	31	87	64	1,017	21	89	66
April	1,078	26	88	64	1,036	01	86	68	1,225	20	93	68
May	1,301	27	95	67	1,290	24	92	70	1,280	30	90	72
June	1,385	24	95	73	1,361	14	92	72	1,392	21	92	74
July	1,416	14	95	75	1,486	28	96	78	1,444	26	94	76
August	1,378	31	94	76	1,524	17	96	78	1,472	02	94	76
September	1,346	17	92	77	1,348	02	93	77	1,336	25	92	74
October	1,243	04	89	73	1,283	10	89	75	1,270	20	91	70
November	1,133	03	86	65	1,011	16	83	64	1,001	01	77	68
December	1,147	15	57	38	1,011	22	64	44	963	01	84	67

[1] The historical hourly demand data maintained by FMPA has improved in numerical accuracy. This may result in differences in the value and timing of monthly peak demand shown above to similar data shown in prior Ten-Year Site Plans for the same year.

[2] Temperature data is taken from recordings of the Orlando International Airport weather station, which may be used as an indicator of weather conditions over FMPA's geographically diverse service area.

**Table IV-10
Nominal, Delivered Fuel Price Components Base Case**

Year	Residual Oil			Distillate Oil			Natural Gas [1]			Coal [2]		
	Commodity	Transportation	Total	Commodity	Transportation	Total	Commodity	Transportation	Total	Commodity	Transportation	Total
	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu
2007	1,106	129	1,235	1,297	129	1,426	798	29	828	230	76	306
2008	973	132	1,106	1,244	132	1,377	782	30	812	233	77	310
2009	795	136	931	1,132	136	1,267	725	31	756	191	79	270
2010	647	139	786	1,033	139	1,172	708	32	739	190	81	271
2011	656	142	799	1,045	142	1,187	660	33	692	182	82	264
2012	656	146	802	1,051	146	1,197	638	33	671	168	84	252
2013	660	150	810	1,043	150	1,193	644	34	679	151	85	236
2014	665	153	818	1,055	153	1,209	640	35	675	155	87	242
2015	683	157	841	1,081	157	1,239	632	36	668	153	89	242
2016	709	161	870	1,130	161	1,292	632	37	669	157	91	248

[1] Transportation costs shown for natural gas reflect variable delivery charges and do not include fixed capacity charges.

[2] The base case fuel price forecast for coal was provided by Platt's, a division of the McGraw-Hill Companies, Inc. It cannot be reproduced, distributed, or sold without the express written permission of Platt's.

**Table IV-11
Nominal, Delivered Fuel Price Components High Case**

Year	Residual Oil			Distillate Oil			Natural Gas [1]			Coal [2]		
	Commodity	Transportation	Total	Commodity	Transportation	Total	Commodity	Transportation	Total	Commodity	Transportation	Total
	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu
2007	1,701	129	1,830	3,240	129	3,369	1,620	29	1,650	383	76	459
2008	1,667	132	1,799	3,175	132	3,307	1,588	30	1,618	388	77	465
2009	1,545	136	1,681	2,943	136	3,078	1,471	31	1,502	326	79	405
2010	1,508	139	1,647	2,873	139	3,012	1,436	32	1,468	325	81	406
2011	1,406	142	1,549	2,678	142	2,821	1,339	33	1,372	315	82	397
2012	1,359	146	1,505	2,588	146	2,734	1,294	33	1,328	294	84	378
2013	1,373	150	1,523	2,616	150	2,766	1,308	34	1,342	268	85	353
2014	1,363	153	1,517	2,597	153	2,750	1,298	35	1,334	276	87	363
2015	1,347	157	1,504	2,565	157	2,722	1,283	36	1,318	275	89	364
2016	1,348	161	1,509	2,567	161	2,728	1,283	37	1,320	280	91	372

[1] Transportation costs shown for natural gas reflect variable delivery charges and do not include fixed capacity charges.

[2] The base case fuel price forecast for coal was provided by Platt's, a division of the McGraw-Hill Companies, Inc. It cannot be reproduced, distributed, or sold without the express written permission of Platt's. Sensitivities to the base case forecast were developed by FMPA through internal resources.

**Table IV-12
Nominal, Delivered Fuel Price Components Low Case**

Year	Residual Oil			Distillate Oil			Natural Gas [1]			Coal [2]		
	Commodity	Transportation	Total	Commodity	Transportation	Total	Commodity	Transportation	Total	Commodity	Transportation	Total
	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu	¢/Mbtu
2007	318	129	447	607	129	736	303	29	333	129	76	205
2008	312	132	444	594	132	727	297	30	327	131	77	208
2009	289	136	425	551	136	686	275	31	306	102	79	181
2010	282	139	421	538	139	677	269	32	301	100	81	181
2011	263	142	406	501	142	644	251	33	283	95	82	177
2012	254	146	400	485	146	630	242	33	276	85	84	169
2013	257	150	407	490	150	639	245	34	279	73	85	158
2014	255	153	409	486	153	639	243	35	278	75	87	162
2015	252	157	409	480	157	637	240	36	276	73	89	162
2016	252	161	413	480	161	642	240	37	277	75	91	166

[1] Transportation costs shown for natural gas reflect variable delivery charges and do not include fixed capacity charges.

[2] The base case fuel price forecast for coal was provided by Platt's, a division of the McGraw-Hill Companies, Inc. It cannot be reproduced, distributed, or sold without the express written permission of Platt's. Sensitivities to the base case forecast were developed by FMPA through internal resources.