Florida Municipal Power Agency

Michele A. Jackson, P.E.
System Planning Manager

Florida Public Service Commission
Office of Commission Clerk
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
E-Filing address: Filings@psc.state.fl.us

Re: FMPA's 2015 Ten Year Site Plan

March 31, 2015

Dear Sir/Madam:

Pursuant to Rule 25-22.071(1) Florida Administrative Code, and Staff's partial waiver of certain requirements of the Rule pursuant to an e-mail dated March 3, 2015, FMPA is hereby filing 1 electronic copy of its 2014 Ten Year Site Plan, and providing notice that 5 hardcopies are being shipped to your address above. If you have any questions, please do not hesitate to contact me at (321) 239-1013.

Sincerely,

Michele A. Jackson

Michele A. Jackson, P.E.
System Planning Manager

Enc.

cc. File

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Florida Municipal Power Agency

Ten-Year Site Plan 2015-2024

Submitted to

Florida Public Service Commission

April 1, 2015

Community Power + Statewide Strength ®

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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 provides, among other things, a description of existing electric utility resources, a 10-year forecast of electric power generating needs and an identification of the general location and type of any proposed generation capacity and transmission additions for the next 10-year period.

The Florida Municipal Power Agency (FMPA or the Agency) is a project-oriented, joint-action agency. There are currently 31 Members of FMPA – each a municipal electric utility – located throughout the State of Florida. As a joint-action agency, FMPA facilitates opportunities for FMPA Members to participate in power supply projects developed by third-party Florida utilities and other power producers. For example, FMPA facilitated the participation of 15 FMPA Members in an 8.8 percent undivided ownership interest in the St. Lucie Nuclear Power Plant Unit No. 2, developed by Florida Power & Light Company (FPL). FMPA's direct responsibility for power supply is with the All-Requirements Power Supply Project (the ARP) where the Agency has committed to planning for and supplying all of the power requirements of 12 ARP Participants and a Contract Rate of Delivery for one (1) ARP Participant. FMPA's TYSP is focused on the resources of, and planning for, the ARP.

The total summer capacity of ARP resources for the year 2015 is 1,665 MW. This capacity is comprised of ARP Participant-owned resources, ARP Participant entitlements and ownership shares in nuclear, coal and gas-fired power plants located in the State of Florida, ARP owned resources and ownership shares in coal and gas-fired power plants located in the State of Florida, and power purchase agreements, and are summarized below in Table ES-1.

Table ES-1
FMPA ARP Summer 2015 Capacity Resources

Resource Category	Summer Capacity (MW)
Nuclear	36
ARP Ownership	1,116
ARP Participant Ownership	272
Power Purchases	241
Net Total 2015 ARP Resources	*1,665

* Totals may not add due to rounding

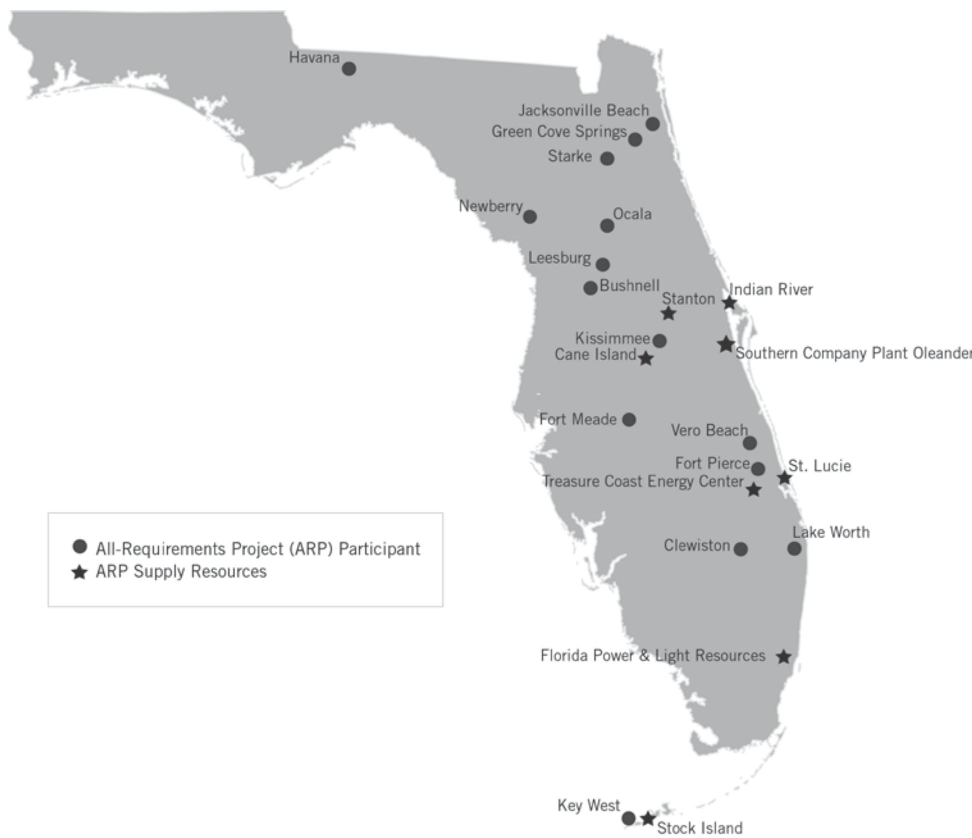
Based on the ARP's 2015 Load Forecast, the ARP expects to meet its generation capacity requirements, with an 18% reserve margin with existing resources, through 2023. FMPA will need to acquire 33 MW from an undetermined source in 2024 to be able to meet generation capacity requirements with an 18% reserve margin. The projected peak native ARP summer load for 2015 is 1,176 MW and is forecast to increase to 1,349 MW in 2024. FMPA will continue to evaluate and develop sufficient and cost-effective resource alternatives for the ARP through its integrated resource planning process.

In 2010, FMPA, on behalf of the ARP, responded to a Request for Proposals from the City of Quincy for providing full-requirements capacity and energy beyond Quincy's entitlement in a Southeastern Power Administration (SEPA) Project. The ARP was awarded the Quincy contract for the term of January 1, 2011 through December 31, 2015. The ARP is expecting to provide a peak requirement of 26 MW to Quincy above its SEPA entitlement during the summer of 2015. The sale to Quincy increases the projected ARP load to 1,202 MW for the summer of 2015.

FMPA is actively involved in planning and developing new renewable energy resources and demand side resource opportunities consistent with, and in consideration of the planning requirements of the State of Florida and the Public Utility Regulatory Policies Act (PURPA). Currently, the ARP purchases renewable energy from a cogeneration plant fueled by sugar bagasse, and utilizes landfill gas as a secondary fuel to supplement its coal fuel requirements. In December 2009, the ARP commissioned its first solar photovoltaic system, a jointly-owned 30 kW DC system located in Key West, FL. In addition, ARP-Participants are engaged in an ARP-sponsored energy conservation program.

A location map of the ARP Participants and FMPA's power resources as of December 31, 2014 is shown in Figure ES-1.

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



Section 1 Description of FMPA

1.1 FMPA

Florida Municipal Power Agency (FMPA or the Agency) is a governmental wholesale power company owned by municipal electric utilities. FMPA provides economies of scale in power generation and related services to support community-owned electric utilities.

FMPA was created on February 24, 1978, by the signing of the Interlocal Agreement among its original members to provide a means by which its members could cooperatively gain mutual advantage and meet present and projected electric energy requirements. This agreement specifies the purposes and authority of FMPA. FMPA was formed under the provisions of the Florida Interlocal Cooperation Act of 1969, Section 163.01, Florida Statutes and the supplemental authority granted by the Joint Power Act, Part II, Chapter 361, Florida Statutes, implementing Article VII, Section 10 of the Florida Constitution.

The Interlocal Cooperation Act of 1969 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. The Florida Constitution and the Joint Power Act provide the supplemental authority for municipal electric utilities to join together with public utilities, electric cooperatives, foreign public utilities and other persons, as defined, for the joint financing, constructing, acquiring, managing, operating, utilizing, and owning of electric power plants.

Each city commission and council, utility commission, board, or authority that 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 approving FMPA's project budgets (except for the All-Requirements Power Supply Project budget which is approved by the FMPA Executive Committee), approving new projects and project financing (except for All-Requirements Power Supply Project financing which is approved by the FMPA Executive Committee), hiring a General Manager and General Counsel, establishing by-laws that govern how FMPA operates, and creating policies that implement such by-laws. At its annual meeting, the Board elects a Chairperson, Vice Chairperson, Secretary, and Treasurer.

The Executive Committee consists of 13 members, representing the 15 participants in the All-Requirements Power Supply Project (ARP)[1]. The Executive Committee has the responsibility of approving the ARP budget and agency general budget, approving and financing ARP projects, approving ARP expenditures and contracts, and governs and manages the business and affairs of the ARP. At its annual meeting, the Executive Committee elects a Chairperson and Vice Chairperson.

1.2 All-Requirements Power Supply Project

FMPA developed the ARP to secure an adequate, economical, and reliable supply of electric capacity and energy as directed by FMPA Members. Currently, 15 FMPA Members (the ARP Participants) participate in the ARP. The geographical locations of the ARP Participants are shown in Figure 1-1.

Bushnell, Green Cove Springs, Jacksonville Beach, Leesburg, and Ocala were the original ARP Participants. The ARP began delivering capacity and energy to these original five participants in 1986. The remaining 10 ARP Participants joined as follows:

- 1991 – The City of Clewiston;
- 1997 – The Cities of Vero Beach and Starke;
- 1998 – Fort Pierce Utilities Authority (FPUA) and the Utility Board of City of Key West, Florida (KEYS)
- 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.

ARP Participants are required to purchase all of their capacity and energy requirements from the ARP pursuant to the All-Requirements Power Supply Project Contract at rates that are established by the Executive Committee to recover all ARP costs. Those ARP Participants that own generating resources, or entitlements shares in FMPA power supply projects sell the electric capacity and energy of their resource entitlements to the ARP pursuant to a Capacity & Energy Sales Agreement between FMPA and the ARP Participant.

[1] As further discussed in this section, the City of Vero Beach, City of Lake Worth and the City of Ft. Meade, have exercised the right to modify their ARP participation by implementation of a Contract Rate of Delivery (CROD). The CROD amount for both the cities of Vero Beach and Lake Worth pursuant to contract terms is 0 MW. While they remain participants in the ARP, effective January 1, 2010 (for Vero Beach) and effective January 1, 2014 (for Lake Worth), they no longer are purchasing capacity and energy from the ARP and no longer have representatives on the Executive Committee. The CROD amount for the City of Ft. Meade is 10.36 MW of capacity and energy effective January 1, 2015. The City of Ft. Meade continues to have representation on the Executive Committee.

Figure 1-1
ARP Participant Cities

On December 9, 2004, the City of Vero Beach provided notice to FMPA, pursuant to the All-Requirements Power Supply Project Contract, that it was going to exercise the right to modify its ARP full requirements membership and request and establish a Contract Rate of Delivery (CROD) which began January 1, 2010. On December 17, 2008, the City of Lake Worth provided notice to FMPA that it was going to exercise the right to modify its ARP full requirements membership and establish a CROD beginning January 1, 2014. On July 14, 2009, the City of Fort Meade provided notice to FMPA that it will also exercise its right to modify its full requirements membership and establish a CROD beginning January 1, 2015. Finally, on December 10, 2014, the City of Green Cove Springs (GCS) provided notice to FMPA that it was going to exercise the right to modify its ARP full requirements membership and establish a CROD beginning January 1, 2020. The effect of these notices is that the ARP will no longer utilize these ARP Participants' generating resources (if any), and the ARP will commence serving up to a calculated maximum amount of capacity and energy for these ARP Participants (with these ARP participants being responsible for meeting all of their electric demand in excess of FMPA's obligation). The amount of the CROD for Vero Beach and Lake Worth served by the ARP has been established as zero (0) MW, and the amount of the CROD for Fort Meade has been established as a maximum of 10.36 MW. The amount of the CROD for the City of Green Cove Springs will be determined, pursuant to contract terms by December 1, 2019.

A brief description of each of the ARP Participants begins on the following page.

City of Bushnell

The City of Bushnell is located in central Florida in Sumter County. The City joined the ARP in May 1986. Bruce Hickle is the City Manager and 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.

City of Clewiston

The City of Clewiston is located in southern Florida in Hendry County. The City joined the ARP in May 1991. The City's FMPA representative, Danny Williams, is the Director of Utilities. The City's service area is approximately 5 square miles. For more information about the City of Clewiston, please visit www.cityofclewiston.org.

City of Fort Meade

The City of Fort Meade is located in central Florida in Polk County. The City joined the ARP in February 2000. Fred Hilliard is the City Manager. The City's service area is approximately 5 square miles. For more information about the City of Fort Meade, please visit www.cityoffortmeade.com.

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. Clay Lindstrom is the Director of Utilities**.** FPUA's service area is approximately 35 square miles. For more information about Fort Pierce Utilities Authority, please visit www.fpua.com.

City of 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. The City's FMPA representative is Robert C. Page. 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 5 square miles. For more information about the Town of Havana, please visit www.townofhavana.com.

City of Jacksonville Beach

The City of Jacksonville Beach is located in northeast Florida in Duval County. Jacksonville Beach's electric department, operating under the name Beaches Energy Services (Beaches), serves customers in Duval and St. Johns Counties. Beaches joined the ARP in May 1986. George D. Forbes is the City Manager and Allen Putnam is the Director of Electric Utilities. Beaches' service area is approximately 45 square miles. For more information about Beaches, please visit www.beachesenergy.com.

Utility Board of the City of Key West

The Utility Board of the City of Key West, Florida, doing business as Keys Energy Services (KEYS), provides electric service to the lower Keys in Monroe County. KEYS joined the ARP in April 1998. Lynne Tejeda 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

The City of Kissimmee is located in central Florida in Osceola County. KUA joined the ARP in October 2002. James C. Welsh is the President & General Manager, CEO, and Larry Mattern is the Vice President of Power Supply**.** KUA's service area is approximately 85 square miles. For more information about KUA, please visit www.kua.com.

City of Lake Worth

The City of Lake Worth is located on Florida's east coast in Palm Beach County. Lake Worth joined the ARP in October 2002. 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.

City of Leesburg

The City of Leesburg is located in central Florida in Lake County. The City joined the ARP in May 1986. Patrick Foster 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.

City of Newberry

The City of Newberry is located in north central Florida in Alachua County. The City joined the ARP in December 2000. Bill Conrad is the Mayor, and Blaine Suggs is the Utilities Director. The City's service area is approximately 3 square miles. For more information about the City of Newberry, please visit www.ci.newberry.fl.us.

City of Ocala

The City of Ocala, doing business as Ocala Utility Services, is located in central Florida in Marion County. The City joined the ARP in May 1986. John Zobler is the City Manager, and Sandra Wilson is the Deputy City Manager. The City's service area is approximately 161 square miles. For more information about Ocala Utility Services, please visit www.ocalaelectric.com.

City of Starke

The City of Starke is located in north Florida in Bradford County. The City joined the ARP in October 1997. Tom Ernharth is the City Manager. The City's service area is approximately 6.5 square miles. For more information about the City of Starke, please visit www.cityofstarke.org.

City of 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. Dick Winger is the Mayor. The City's service area is approximately 41 square miles. For more information about the City of Vero Beach, please visit www.covb.org.

1.3 Other FMPA Power Supply Projects

In addition to the ARP, FMPA facilitates the participation of FMPA Members in four other power supply projects as discussed below.

St. Lucie Project

On May 12, 1983, FMPA purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit located in St. Lucie County. 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 FMPA Members are participants in the St. Lucie Project, with the following entitlements to FMPA's undivided ownership interest 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. Stanton Unit No. 1 went into commercial operation July 1, 1987. Six FMPA Members are participants in the Stanton Project with entitlements to FMPA's undivided interest as shown in Table 1-2 on the following page.

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, and FMPA purchased from OUC an additional 5.3012 percent undivided ownership interest in Stanton Unit No. 1. Three FMPA 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. The unit commenced commercial operation in June 1996. Seven FMPA 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	16.4480	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 December 31, 2014.

Table 1-5
Summary of FMPA Power Supply Project Participants

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Power Supply Project	Stanton II Project
City of Alachua	X				
City of Bushnell				X	
City of Clewiston	X			X	
City of Ft. Meade	X			X [3]	
Ft. Pierce Utilities Authority	X	X	X	X	X
City of Green Cove Springs	X			X [4]	
Town of Havana				X	
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Utility Board of the City of Key West			X	X	X
Kissimmee Utility Authority	X	X		X	X
City of Lake Worth	X	X		X [2]	
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 [1]	X

[1] Effective January 1, 2010, the City of Vero Beach exercised the right to modify its ARP full requirements membership (CROD)

[2] Effective January 1, 2014, the City of Lake Worth will have exercised the right to modify its ARP full requirements membership (CROD)

[3] Effective January 1, 2015, the City of Ft. Meade will have exercised the right to modify its ARP full requirements membership (CROD)

[4] Effective January 1, 2020, the City of Green Cove Springs will have exercised the right to modify its ARP full requirements membership (CROD)

Section 2 Description of Existing Facilities

2.1 ARP Supply-Side Resources

The ARP supply-side resources consist of ARP Participant-owned resources, ARP Participant entitlements and ownership shares in nuclear, coal and gas-fired power plants located in the State of Florida, ARP owned resources and ownership shares in coal and gas-fired power plants located in the State of Florida, and power purchase agreements. The supply side resources for the ARP for the 2015 summer season are shown by ownership capacity in Table 2-1.

Table 2-1
ARP Supply-Side Resources Summer 2015

	Resource Category	Summer Capacity (MW)
1)	Nuclear	36
2)	ARP Ownership	
	Existing	1,116
	New	-
	Sub Total ARP Ownership	1,116
3)	Participant Ownership	
	KEYS	33
	KUA	239
	Sub Total Participant Ownership	272
4)	Power Purchases	241
Total 2014 ARP Resources		*1,665

*Totals may not add due to rounding

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

1) **Nuclear Generation:** A number of the ARP Participants participate in FMPA's St. Lucie Project, and are entitled to capacity and energy shares from St. Lucie Unit No. 2. Capacity from this nuclear unit is classified as an "Excluded Power Supply Resource" in the All-Requirements Power Supply Project Contract between FMPA and the ARP

Participants. As such, the ARP Participants pay their own costs associated with their ownership and/or entitlement in the nuclear units and individually receive the benefits of the capacity and energy from these units. The ARP provides the balance of capacity and energy requirements for these ARP Participants. As Excluded Power Supply Resources, ARP Participants' entitlements in the nuclear units are considered in the capacity planning for the ARP.

2) **ARP Owned Generation:** This category includes 1) generation that is wholly owned and operated by FMPA as agent for the ARP, specifically, Treasure Coast Energy Center, Stock Island Generating Facility, and Cane Island Unit 4; 2) ownership shares that the ARP acquired in OUC's Stanton Units 1 and 2 (separate from the Stanton and Stanton II Projects), OUC's Indian River Power Plant Units A through D, KUA's Cane Island Units 1-3 and Southern Company's Stanton Unit A; and 3) generation entitlements assigned to the ARP by ARP Participants via their participation in other FMPA Power Supply Projects.

3) **Participant Owned Generation:** Capacity included in this category is generation wholly owned by the ARP Participants. The ARP purchases this capacity through Capacity and Energy Sales Agreements between FMPA and the ARP Participants, and then commits and economically dispatches this generation to meet the total requirements of the ARP.

4) **Power Purchases:** This category includes power purchases between FMPA, as agent for the ARP, and third-parties. Purchased power generation used to serve the ARP as of December 31, 2014 includes capacity and energy purchased from Southern Company from their Stanton Unit A and Oleander Unit 5 facilities.

Information regarding existing ARP generation resources as of December 31, 2014, 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. Peninsular Florida's electric grid is tied to the rest of the continental United States at the Florida/Georgia interface and along the Apalachicola River in the Florida Panhandle, referred to as the Florida – Southern Interface. Florida Power and Light (FPL), DEF, Jacksonville Energy Association (JEA) and the City of Tallahassee own the transmission tie lines at the Florida – Southern Interface. ARP Participants are interconnected to the transmission systems of FPL, DEF, OUC, JEA, Seminole Electric Cooperative Incorporated

(SECI), Florida Keys Electric Cooperative Incorporated (FKEC), and Tampa Electric Company (TECO). Also, the City of Vero Beach and FPUA are interconnected. Some ARP Participants own transmission facilities within their service territories, and the ARP has an ownership share of the transmission facilities associated with the Cane Island Power Park.

The ARP transmits capacity and energy to the ARP Participants utilizing the transmission systems of FPL, DEF, and OUC. Capacity and energy for the Cities of Jacksonville Beach, Green Cove Springs, Clewiston, Fort Pierce, Key West, and Starke are transmitted across FPL's transmission system. Capacity and energy for the Cities of Ocala, Leesburg, Bushnell, Newberry, Havana, and Ft. Meade are transmitted across the DEF transmission system. Capacity and energy for KUA is transmitted across the transmission systems of FPL, DEF and OUC. Sales to the City of Quincy are made across DEF's transmission system.

2.2.1 ARP Participant Transmission Systems[2]

FPUA

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. There are two interconnections with other utilities, both at 138 kV. FPUA's Hartman Substation interconnects with FPL's Emerson Substation via one transmission line, and FPL's Midway Substation via two transmission lines. The Emerson and Midway #2 lines have FPL tapped substations along their route. The second interconnection point for FPUA is from the jointly-owned transmission facilities of FPUA and the City of Vero Beach at County Line Substation to FPL's Emerson Substation. County Line Substation No. 20 connects FPL's Emerson Substation to Vero Beach's South Substation and FPUA's Garden City (No. 2), via three single circuit 138-kV transmission lines. . FPUA and Vero Beach jointly own the County Line Substation, the connecting lines to FPL's Emerson Substation, and some part of the 138kV tie lines between the two municipal utilities.

KEYS

KEYS owns and maintains an electric generation, transmission, and distribution system, which supplies electric power and energy south of FKEC's Marathon Substation to the Lower Florida Keys and the City of Key West. KEYS and FKEC jointly own a 64 mile long 138 kV

[2] The City of Vero Beach and the City of Lake Worth's transmission systems descriptions are not being provided because these cities directly report to the FRCC on their own systems.

transmission system 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. All the jointly owned 138-kV facilities are independently operated by FKEC. KEYS owns a 49.2 mile long 138 kV radial transmission system from Marathon Substation to KEYS’ Stock Island Substation. The KEYS radial 138-kV system loops in and out of KEYS’ Big Pine and Big Coppitt Substations and taps off at Cudjoe Key Substation. Two autotransformers at the Stock Island Substation provide transformation between 138 kV and 69 kV. KEYS has six 69 kV and four 138 kV substations which supply power at 13.8 kV to its distribution system. KEYS owns approximately 227 miles of 13.8 kV distribution line. KEYS/FMPA installed STATCOMS and shunt capacitors at Big Pine and Stock Island Substations in the summer of 2012. A series capacitor at Islamorada Substation was installed and commissioned in November, 2014 in conjunction with FKEC, and a Special Protection System to automatically she load post-contingency in accordance with reliability standard TPL-001-4, Table 1, footnote 12, is scheduled for commissioning in May, 2015. These projects will enable the Florida Keys (KEYS/FMPA and FKEC) to increase the import limit of the 138 kV transmission line to be equal to its thermal limit.

KUA

KUA serves a total area of approximately 85 square miles, and owns 24.6 circuit miles of 230 kV and 48.8 circuit miles of 69 kV transmission lines that deliver capacity and energy to 10 distribution substations. KUA and FMPA jointly own 21.6 circuit miles of 230 kV lines out of Cane Island Power Park. KUA has direct transmission interconnections with: (1) DEF at DEF’s 230 kV Intercession City Substation, 69 kV Lake Bryan Substation, and 69 kV Meadow Wood East 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.

Ocala Utility Services

Ocala Utility Services (OUS) owns its bulk power supply system which consists of three 230 kV to 69 kV substations, 13 miles of radial 230 kV transmission, 71.19 miles of a 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.

OUS’ 230 kV transmission system interconnects with DEF’s Silver Springs Switching Station and Seminole Electric Cooperative, Inc.’s (SECI) Silver Springs North Switching Station. OUS’

Dearmin Substation ties at DEF's Silver Springs Switching Station and OUS' Ergle and Shaw substations are tied at SECI's Silver Springs North Switching Station. OUS also has a 69 kV tie from the Airport Substation with Sumter Electric Cooperative's Martel Substation. In addition, OUS owns a 13 mile, radial 230 kV transmission line from Shaw Substation to Silver Springs North Switching Station. OUS completed this 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.

Beaches

Beaches owns the 230 kV Sampson transmission switching station that interconnects to FPL at FPL's Orangedale Substation and to JEA at JEA's Switzerland Substation. Beaches has a second interconnection that ties to JEA's Neptune Beach Substation from its Penman Substation at 138 kV.

Three auto-transformers at Sampson substation provide transformation from 230 kV to 138 kV. Beaches has five 138 kV distribution substations, which deliver energy at 26.4 kV to its distribution system. Beaches owns 47.9 miles of 138 kV transmission lines.

City of Clewiston

The City of Clewiston owns the 138 kV McCarthy transmission switching station that interconnects to FPL at FPL's Okeelanta and Ft. Myers substations via several tapped FPL 138-kV distribution stations. Clewiston owns two 3.5 mile 138 kV transmission lines from its McCarthy substation to the City of Clewiston substation. Two transformers at the City of Clewiston substation provide transformation from 138 kV to 12.47 kV to its distribution system.

2.2.2 ARP Transmission Agreements

OUC provides transmission service for delivery of power associated with ARP Participants' entitlements in Stanton, Tri-City and Stanton II Projects, and the ARP's ownership interests in Stanton Units 1 and 2. OUC also provides transmission service for delivery of power associated with ARP ownership interests in the Stanton A, combined cycle (CC), and the Indian River combustion turbine (CT) units, as well as the ARP's power purchase from Stanton A. OUC transmission service is for the delivery of this energy to either the FPL or DEF interfaces with OUC for subsequent delivery to ARP Participants. Rates for such transmission wheeling service from the Stanton and Indian River units are pursuant to the terms and conditions of Firm Transmission Service Agreements, and rates for transmission service for wheeling service from Stanton A are pursuant to OUC's OATT.

FMPA also has contracts with DEF and FPL for Network Integration Transmission Service that allow FMPA to integrate its resources to serve its load (those loads interconnected with either FPL or DEF) in a manner comparable to how FPL and DEF integrate resources to serve FPL and DEF native loads. The Network Service and Network Operating Agreements with FPL were executed in March 1996 and were subsequently amended to both conform to FERC's Pro forma Tariff and to add additional ARP Participants as points of delivery. The Network Service and Network Operating Agreements with DEF were executed and filed with FERC in January 2011.

Schedule 1
Existing Generating Facilities as of December 31, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	MM/YY	MW	Summer (MW)	Winter (MW)
Nuclear Capacity												
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	NA	891	36	37
Total Nuclear Capacity											36	37
ARP Owned Generation												
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	71	71
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	NA	465	86	86
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	12	16
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	07/89	NA	41	12	16
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	19
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	54	57
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	120	125
Cane Island	4	Osceola	CC	NG	DFO	PL	TK	08/11	NA	315	300	310
Stock Island	CT2	Monroe	GT	DFO	-	WA	-	06/99	NA	21	15	15
Stock Island	CT3	Monroe	GT	DFO	-	WA	-	06/99	NA	21	15	15
Stock Island	GT4	Monroe	GT	DFO	-	WA	-	06/06	NA	61	45	45
Treasure Coast	1	St. Lucie	CC	NG	DFO	PL	TK	05/08	NA	315	300	310
Total ARP Owned Generation											1,114	1,159
Participant Owned Generation												
Kissimmee Utility Authority (TARP)												
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	19
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	54	57
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	120	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	5
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	4	5
Sub Total KUA											241	254
Keys Energy Services (TARP)												
Stock Island	CT1	Monroe	GT	DFO	-	WA	-	11/78	NA	20	18	18
Stock Island MSD	MSD1	Monroe	IC	DFO	-	WA	-	06/91	NA	9	6	6
Stock Island MSD	MSD2	Monroe	IC	DFO	-	WA	-	06/91	NA	9	7	7
Stock Island	EP2	Monroe	IC	DFO	-	WA	-	07/12	NA	2	2	2
Sub Total Keys											33	33
Total Participant Owned Generation											274	287
Total Generation Resources											1,424	1,483

[1] Capabilities shown are as of December 31, 2014. The Cities of Vero Beach and Lake Worth have exercised the right to modify their ARP full requirements membership. Effective January 1, 2010 (for Vero Beach) and January 1, 2014 for Lake Worth, the ARP will no longer Utilize Vero Beach's or Lake Worth's generating resources, including their entitlement shares in the Stanton, Stanton II, and St. Lucie Projects. See Schedule 8 for information on the change in net capabilities for the ARP for these resources effective January 1, 2015. The capacities for ARP generation resources that are located in OUC's service territory are the ARP's ownership capacity minus losses across OUC's transmission system. The losses are assumed to be an average of 2.00% for the study period.

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

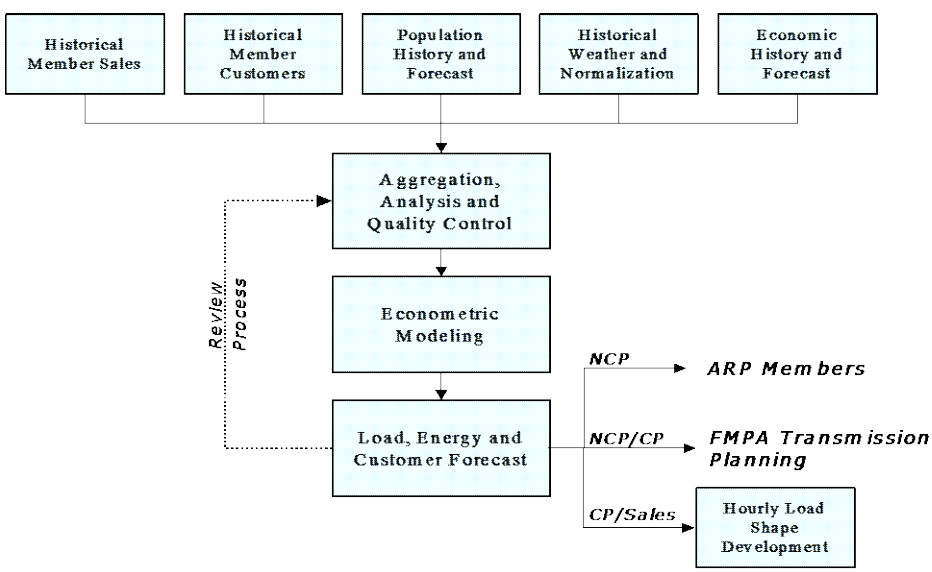
3.1 Introduction

To secure sufficient capacity and energy, FMPA forecasts each ARP Participant's electrical power demand and energy requirements on an individual basis and aggregates 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, with updates during the year if warranted. The load and energy forecast includes projections of customers, demand, and energy sales by rate classification for each of the ARP Participants. Forecasts are prepared on an individual Participant 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



Note:

NCP is the Non-Coincident Peak demand, which represents the maximum hourly demand for an ARP Participant in a given month.

CP is the Coincident Peak demand which represents the maximum hourly demand of the ARP system in aggregate, or the hourly demand of the ARP Participant at the time of the ARP CP.

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 Participants. 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 2015 Load Forecast Overview

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2015 through 2034. The Forecast was prepared on a monthly basis using municipal utility data provided to FMPA by the ARP Participants and load data maintained by FMPA. Historical and projected economic and demographic data were provided by IHS Global Insight and Woods & Poole Economics, nationally recognized providers of such data, from which averages were developed for the forecast horizon. The Forecast also relied on information regarding local economic and demographic issues specific to each ARP Participant. Weather data was provided by the National Oceanic and Atmospheric Administration (NOAA) for a variety of weather stations in close proximity to the ARP Participants. The forecast assumes normal weather conditions, as reported by NOAA and reflecting the 1981-2010 period.

The Forecast reflects the City of Fort Meade's establishment of Contract Rate of Delivery (CROD) effective on January 1, 2015, and FMPA's obligation to serve up to a maximum of 10.36 MW of the load requirements of Fort Meade. 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 Participant'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 Participants. 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. 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 Participants. 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 Specifications

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 Participants and the number of households in each ARP Participant'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 ARP Participant's service territory, (ii) the real price of electricity, and (iii) weather variables. For certain large non-residential customers, the forecast was based on assumptions developed in consultation with the Participants (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 Participant. An assumed loss factor, based either on a regression analysis or a recent average of historical loss factors, was then applied to the total sales to derive monthly NEL.

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 ARP Participant system basis. The projected load factors were based on the average relationship between annual NEL and the seasonal peak demand generally over the period 2000-2014.

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 typically occurs during July or August of each 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 Participant groups, and the transmission providers were derived from monthly coincidence factors averaged generally over a 5-year period (2010-2014). 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 Participant group peaks was determined from an appropriate summation of the hourly load data.

3.5 Data Sources

3.5.1 Historical ARP Participant Retail Sales Data

Data was generally available and analyzed over January 1993 through December 2014. Data included historical customer counts, sales, and revenues by rate classification for each of the ARP Participants.

3.5.2 Weather Data

Historical weather data was provided by the National Climatic Data Center (a subsidiary of the National Oceanic and Atmospheric Administration) (NCDC). Weather stations, from which historical weather was obtained, were selected by their quality and proximity to the ARP Participants. 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 two cases (Beaches and FPUA), 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 Participants' loads, based on statistical measures, than the closest first-order weather station.

The influence of weather on electricity sales has been represented through the use of two data series: heating and cooling degree days (HDD and CDD, respectively). Degree days are derived by comparing the average daily temperature and 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.

Normal weather conditions have been assumed in the projected period. Thirty-year normal monthly HDD and CDD are based on average weather conditions from 1981 through 2010, as reported by NOAA.

3.5.3 Economic Data

IHS Global Insight and Woods & Poole Economics, both nationally recognized providers of economic data, provided both historical and projected economic and demographic data for each of the 14 counties in which the ARP Participants' service territories reside (the service territory of Beaches includes portions of both Duval and St. Johns Counties). This data includes 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 Participants' historical electric sales.

3.5.4 Real Electricity Price Data

The real price of electricity was derived from a twelve month or multi-year moving average of real average revenue. Projected real electricity prices were assumed to increase at a rate of 0.5% per year, generally based on projections provided by the Energy Information Administration in the 2014 Annual Energy Outlook for Florida.

3.6 Overview of Results

3.6.1 Base Case Forecast

The results of the Forecast show that the net energy for load (NEL) to be supplied to ARP Participants is expected to grow at an annual average growth rate of 1.5% from 2015-2024, and at 1.2% from 2025-2034. The Base Case 2015 ARP forecast summer coincident peak (CP) demand is 1,176 MW and forecast annual NEL for Calendar Year 2015 is 5,666 GWh. (These values do not include the Quincy Sale and are measured at each ARP Participant's delivery point, or "city gate".)

FMPA's ARP has entered into a five year contract with the City of Quincy (Quincy) to provide all of its bulk power requirements which are above and beyond purchases from Southeastern Power Administration (SEPA). Quincy's load forecast was developed by FMPA staff and was based on Quincy monthly historical peaks and energy for 2008 through 2009. Monthly distribution ratios were developed and then projected forward taking into account Quincy's SEPA contract and escalated at 1.2% annually. Quincy's 2015 forecast summer peak demand requirement from the ARP at the time of the ARP CP is 26 MW, and forecast annual NEL for Calendar Year 2015 is 119 GWh.

The combination of Quincy's energy requirements from the ARP and the requirements of ARP Participants results in a 2015 forecast summer CP demand of 1,202 MW and a Calendar Year NEL forecast of 5,785 GWh.

3.6.2 Weather-Related Uncertainty of the Forecast

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 1970-2013. 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.

As a general note, the ARP provides wholesale power to the ARP Participants who, in turn, serve retail load. In addition, the ARP has entered into a wholesale power contract to provide full requirements capacity and energy to the City of Quincy, as a wholesale customer of the ARP. The reported demands and energy shown in Schedules 2.1 through 4 are at the "city gate" of each ARP Participant and the City of Quincy. For example, Schedules 2.1 – 2.3 reflect the energy consumption of the retail customers of the ARP Participants and a sale-for-resale to the City of Quincy (as discussed in section 3.6.1) which, when combined with utility use and losses within each ARP Participant, represents the NEL that the ARP delivers on an aggregated basis to each city gate.

Schedule 2.1
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Power Supply Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential [2]					Commercial [2]		
Year [1]	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
2005	NA	NA	3,269	237,882	13,743	3,313	44,096	75,133
2006	NA	NA	3,293	244,195	13,487	3,356	45,180	74,284
2007	NA	NA	3,273	248,455	13,173	3,407	45,717	74,531
2008	NA	NA	3,127	248,305	12,593	3,365	46,521	72,333
2009	NA	NA	3,169	248,675	12,743	3,232	45,999	70,253
2010	NA	NA	2,951	220,301	13,395	2,835	40,174	70,575
2011	NA	NA	2,850	222,080	12,831	2,803	40,139	69,822
2012	NA	NA	2,724	224,555	12,132	2,778	40,185	69,119
2013	NA	NA	2,755	226,586	12,159	2,771	40,407	68,586
2014	NA	NA	2,614	207,883	12,576	2,574	37,780	68,128
2015	NA	NA	2,652	210,812	12,582	2,624	38,137	68,795
2016	NA	NA	2,698	213,642	12,629	2,664	38,569	69,059
2017	NA	NA	2,740	216,557	12,651	2,704	39,034	69,266
2018	NA	NA	2,787	219,498	12,699	2,745	39,504	69,497
2019	NA	NA	2,835	222,029	12,767	2,787	39,966	69,738
2020	NA	NA	2,879	224,419	12,829	2,829	40,433	69,978
2021	NA	NA	2,922	226,814	12,882	2,872	40,906	70,214
2022	NA	NA	2,964	229,112	12,936	2,915	41,377	70,446
2023	NA	NA	3,007	231,364	12,995	2,958	41,848	70,678
2024	NA	NA	3,050	233,603	13,057	3,001	42,314	70,913

[1] Amounts shown for 2005 through 2014 represent historical values. Amounts shown for 2015 through 2024 represent forecast values.
[2] Loads and customer counts only reflects the ARP. Quincy's loads are shown as Sale for Resale on Schedule 2.3.

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Power Supply Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial [2]						
Year [1]	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Customers GWh
2005	15	1	15,440,470	0	58	117	6,773
2006	11	1	11,480,000	0	61	110	6,832
2007	20	1	19,516,750	0	62	114	6,876
2008	4	1	3,694,000	0	63	116	6,674
2009	6	1	5,889,000	0	64	114	6,584
2010	3	1	2,862,000	0	60	109	5,958
2011	3	1	2,653,000	0	60	106	5,821
2012	3	1	2,738,000	0	60	104	5,668
2013	2	1	1,983,000	0	60	101	5,690
2014	3	1	2,512,000	0	55	107	5,353
2015	2	1	2,301,600	0	54	105	5,438
2016	2	1	2,301,600	0	55	105	5,524
2017	2	1	2,301,600	0	55	105	5,606
2018	2	1	2,301,600	0	56	106	5,696
2019	2	1	2,301,600	0	56	106	5,786
2020	2	1	2,301,600	0	56	106	5,874
2021	2	1	2,301,600	0	57	107	5,960
2022	2	1	2,301,600	0	57	107	6,046
2023	2	1	2,301,600	0	58	108	6,132
2024	2	1	2,301,600	0	58	109	6,220

[1] Amounts shown for 2005 through 2014 represent historical values. Amounts shown for 2015 through 2024 represent forecast values.
[2] Loads and customer counts only reflects the ARP. Quincy's loads are shown as Sale for Resale on Schedule 2.3.

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Power Supply Project

(1) Year [1]	(2) Sales for Resale GWh [2]	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers
2005	0	372	7,145	0	282,203
2006	0	379	7,211	0	289,600
2007	0	370	7,246	0	294,397
2008	0	292	6,966	0	295,051
2009	0	309	6,894	0	294,899
2010	0	341	6,299	0	260,700
2011	105	201	6,127	0	262,443
2012	96	295	6,059	0	264,965
2013	130	272	6,090	0	267,266
2014	91	259	5,703	0	245,664
2015	121	228	5,787	0	248,950
2016	0	236	5,760	0	252,212
2017	0	235	5,841	0	255,592
2018	0	238	5,935	0	259,003
2019	0	242	6,028	0	261,996
2020	0	249	6,123	0	264,853
2021	0	249	6,209	0	267,721
2022	0	252	6,298	0	270,491
2023	0	255	6,388	0	273,213
2024	0	263	6,483	0	275,917

[1] Amounts shown for 2005 through 2014 represent historical values. Amounts shown for 2015 through 2024 represent forecast values.

[2] Sales to cover the City of Quincy's loads are shown as Sale for Resale. Year 2015 include expected sales to the City of Quincy.

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Wholesale				Residential Load		Commercial/ Industrial Load	Commercial/ Industrial Load	ARP Net Firm
Year [1]	Total	ARP	Quincy	Retail	Interruptible	Management	Residential Conservation	Management	Conservation	Demand
2005	1,524	1,524	0	0	0	0	0	0	0	1,524
2006	1,478	1,478	0	0	0	0	0	0	0	1,478
2007	1,521	1,521	0	0	0	0	0	0	0	1,521
2008	1,450	1,450	0	0	0	0	0	0	0	1,450
2009	1,482	1,482	0	0	0	0	0	0	0	1,482
2010	1,272	1,272	0	0	0	0	0	0	0	1,272
2011	1,280	1,258	22	0	0	0	0	0	0	1,280
2012	1,224	1,203	21	0	0	0	0	0	0	1,224
2013	1,240	1,222	18	0	0	0	0	0	0	1,240
2014	1,202	1,185	17	0	0	0	0	0	0	1,202
2015	1,203	1,176	27	0	0	0	0	0	0	1,203
2016	1,196	1,196	0	0	0	0	0	0	0	1,196
2017	1,213	1,213	0	0	0	0	0	0	0	1,213
2018	1,233	1,233	0	0	0	0	0	0	0	1,233
2019	1,253	1,253	0	0	0	0	0	0	0	1,253
2020	1,273	1,273	0	0	0	0	0	0	0	1,273
2021	1,291	1,291	0	0	0	0	0	0	0	1,291
2022	1,310	1,310	0	0	0	0	0	0	0	1,310
2023	1,329	1,329	0	0	0	0	0	0	0	1,329
2024	1,349	1,349	0	0	0	0	0	0	0	1,349

[1] Amounts shown for 2005 through 2014 represent historical values. Amounts shown for 2015 through 2024 represent forecast values.

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Wholesale						Commercial/	Commercial/	
Year [1]	Total	ARP	Quincy	Retail	Interruptible	Residential Load Management	Residential Conservation	Industrial Load Management	Industrial Load Conservation	ARP Net Firm Demand
2005/06	1,401	1,401	0	0	0	0	0	0	0	1,401
2006/07	1,202	1,202	0	0	0	0	0	0	0	1,202
2007/08	1,330	1,330	0	0	0	0	0	0	0	1,330
2008/09	1,419	1,419	0	0	0	0	0	0	0	1,419
2009/10	1,412	1,412	0	0	0	0	0	0	0	1,412
2010/11	1,258	1,258	0	0	0	0	0	0	0	1,258
2011/12	1,118	1,097	21	0	0	0	0	0	0	1,118
2012/13	1,032	1,010	22	0	0	0	0	0	0	1,032
2013/14	1,014	997	17	0	0	0	0	0	0	1,014
2014/15	1,115	1,088	27	0	0	0	0	0	0	1,115
2015/16	1,106	1,106	0	0	0	0	0	0	0	1,106
2016/17	1,122	1,122	0	0	0	0	0	0	0	1,122
2017/18	1,140	1,140	0	0	0	0	0	0	0	1,140
2018/19	1,159	1,159	0	0	0	0	0	0	0	1,159
2019/20	1,178	1,178	0	0	0	0	0	0	0	1,178
2020/21	1,194	1,194	0	0	0	0	0	0	0	1,194
2021/22	1,212	1,212	0	0	0	0	0	0	0	1,212
2022/23	1,230	1,230	0	0	0	0	0	0	0	1,230
2023/24	1,249	1,249	0	0	0	0	0	0	0	1,249
2024/25	1,266	1,266	0	0	0	0	0	0	0	1,266

[1] Amounts shown for 2005/06 through 2013/14 represent historical values. Amounts shown for 2014/15 through 2024/25 represent forecast values.

[2] The 2010/11 Winter Peak with the ARP occurred in Dec 2010 (prior to the Quincy Contract) and was larger than the Jan-Feb 2011 Peaks including the Quincy Contract.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year [1]	Total	Residential Conservation	Commercial/ Industrial Conservation	Retail [2]	Wholesale [3]	Utility Use & Losses	ARP Net Energy for Load [4]	Load Factor %
2005	6,773	0	0	6,773	0	372	7,145	54%
2006	6,832	0	0	6,832	0	379	7,211	56%
2007	6,876	0	0	6,876	0	370	7,246	54%
2008	6,674	0	0	6,674	0	292	6,966	55%
2009	6,584	0	0	6,584	0	309	6,894	53%
2010	5,958	0	0	5,958	0	341	6,299	51%
2011	5,821	0	0	5,821	105	201	6,127	55%
2012	5,668	0	0	5,668	96	295	6,059	57%
2013	5,690	0	0	5,690	130	270	6,090	56%
2014	5,353	0	0	5,353	91	259	5,703	54%
2015	5,438	0	0	5,438	121	228	5,787	55%
2016	5,524	0	0	5,524	0	236	5,760	55%
2017	5,606	0	0	5,606	0	235	5,841	55%
2018	5,696	0	0	5,696	0	238	5,935	55%
2019	5,786	0	0	5,786	0	242	6,028	55%
2020	5,874	0	0	5,874	0	249	6,123	55%
2021	5,960	0	0	5,960	0	249	6,209	55%
2022	6,046	0	0	6,046	0	252	6,298	55%
2023	6,132	0	0	6,132	0	255	6,388	55%
2024	6,220	0	0	6,220	0	263	6,483	55%

[1] Amounts shown for 2005 through 2014 represent historical values. Amounts shown for 2015 through 2024 represent forecast values.
[2] Represents the Retail Load of the ARP Participants.
[3] Represents the sales in 2011 through 2015 to the City of Quincy from the ARP.
[4] Includes both ARP and Quincy loads and distribution losses only.

Schedule 3.1a
Forecast of Summer Peak Demand (MW) – High (Severe Weather) Case
All-Requirements Power Supply Project [1]

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Wholesale				Residential Load		Commercial/ Industrial Load	Commercial/ Industrial Load	Net Firm
Year	Total	ARP	Quincy	Retail	Interruptible	Management	Residential Conservation	Management	Conservation	Demand
2015	1,250	1,223	27	0	0	0	0	0	0	1,250
2016	1,244	1,244	0	0	0	0	0	0	0	1,244
2017	1,262	1,262	0	0	0	0	0	0	0	1,262
2018	1,282	1,282	0	0	0	0	0	0	0	1,282
2019	1,303	1,303	0	0	0	0	0	0	0	1,303
2020	1,324	1,324	0	0	0	0	0	0	0	1,324
2021	1,343	1,343	0	0	0	0	0	0	0	1,343
2022	1,362	1,362	0	0	0	0	0	0	0	1,362
2023	1,382	1,382	0	0	0	0	0	0	0	1,382
2024	1,404	1,404	0	0	0	0	0	0	0	1,404

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

Schedule 3.2a
Forecast of Winter Peak Demand (MW) – High (Severe Weather) Case
All-Requirements Power Supply 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
		ARP	Quincy							
2014/15	1,159	1,132	27	0	0	0	0	0	0	1,159
2015/16	1,151	1,151	0	0	0	0	0	0	0	1,151
2016/17	1,168	1,168	0	0	0	0	0	0	0	1,168
2017/18	1,187	1,187	0	0	0	0	0	0	0	1,187
2018/19	1,206	1,206	0	0	0	0	0	0	0	1,206
2019/20	1,226	1,226	0	0	0	0	0	0	0	1,226
2020/21	1,243	1,243	0	0	0	0	0	0	0	1,243
2021/22	1,261	1,261	0	0	0	0	0	0	0	1,261
2022/23	1,280	1,280	0	0	0	0	0	0	0	1,280
2023/24	1,300	1,300	0	0	0	0	0	0	0	1,300

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

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) ARP Retail [2]	(6) Wholesale [3]	(7) Utility Use & Losses	(8) Net Energy for Load [4]	(9) Load Factor %
2015	5,661	0	0	5,661	121	230	6,012	55%
2016	5,750	0	0	5,750	0	238	5,988	55%
2017	5,836	0	0	5,836	0	236	6,072	55%
2018	5,930	0	0	5,930	0	240	6,170	55%
2019	6,024	0	0	6,024	0	243	6,267	55%
2020	6,115	0	0	6,115	0	251	6,367	55%
2021	6,205	0	0	6,205	0	250	6,455	55%
2022	6,294	0	0	6,294	0	253	6,548	55%
2023	6,384	0	0	6,384	0	257	6,641	55%
2024	6,475	0	0	6,475	0	265	6,741	55%

[1] Values represent predicted net energy for load under severe weather conditions.
[2] Represents the Retail Load of the ARP Participants.
[3] Year 2015 includes the expected NEL of the City of Quincy, after other Quincy resources have been utilized.
[4] Includes both ARP and Quincy loads and distribution losses only.

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Wholesale				Residential Load		Commercial/ Industrial Load	Commercial/ Industrial Load	Net Firm
Year	Total	ARP	Quincy	Retail	Interruptible	Management	Residential Conservation	Management	Conservation	Demand
2015	1,161	1,134	27	0	0	0	0	0	0	1,161
2016	1,153	1,153	0	0	0	0	0	0	0	1,153
2017	1,170	1,170	0	0	0	0	0	0	0	1,170
2018	1,189	1,189	0	0	0	0	0	0	0	1,189
2019	1,208	1,208	0	0	0	0	0	0	0	1,208
2020	1,227	1,227	0	0	0	0	0	0	0	1,227
2021	1,245	1,245	0	0	0	0	0	0	0	1,245
2022	1,263	1,263	0	0	0	0	0	0	0	1,263
2023	1,281	1,281	0	0	0	0	0	0	0	1,281
2024	1,301	1,301	0	0	0	0	0	0	0	1,301

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

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Wholesale				Residential Load	Residential	Commercial/ Industrial Load	Commercial/ Industrial Load	Net Firm
Year	Total	ARP	Quincy	Retail	Interruptible	Management	Conservation	Management	Conservation	Demand
2014/15	1,074	1,047	27	0	0	0	0	0	0	1,074
2015/16	1,065	1,065	0	0	0	0	0	0	0	1,065
2016/17	1,081	1,081	0	0	0	0	0	0	0	1,081
2017/18	1,098	1,098	0	0	0	0	0	0	0	1,098
2018/19	1,116	1,116	0	0	0	0	0	0	0	1,116
2019/20	1,134	1,134	0	0	0	0	0	0	0	1,134
2020/21	1,151	1,151	0	0	0	0	0	0	0	1,151
2021/22	1,168	1,168	0	0	0	0	0	0	0	1,168
2022/23	1,185	1,185	0	0	0	0	0	0	0	1,185
2023/24	1,203	1,203	0	0	0	0	0	0	0	1,203

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

Schedule 3.3b
Forecast of Annual Net Energy for Load (GWh) – Low (Mild Weather) Case
All-Requirements Power Supply Project [1]

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) ARP Retail [2]	(6) Wholesale [3]	(7) Utility Use & Losses	(8) Net Energy for Load [4]	(9) Load Factor %
2015	5,239	0	0	5,239	121	225	5,585	55%
2016	5,321	0	0	5,321	0	232	5,554	55%
2017	5,401	0	0	5,401	0	232	5,633	55%
2018	5,487	0	0	5,487	0	236	5,723	55%
2019	5,573	0	0	5,573	0	239	5,813	55%
2020	5,658	0	0	5,658	0	247	5,905	55%
2021	5,741	0	0	5,741	0	247	5,987	55%
2022	5,823	0	0	5,823	0	250	6,073	55%
2023	5,907	0	0	5,907	0	253	6,160	55%
2024	5,991	0	0	5,991	0	261	6,252	55%

[1] Values represent predicted net energy for load under mild weather conditions.
[2] Represents the Retail Load of the ARP Participants.
[3] Year 2015 shows the expected NEL of the City of Quincy to be served by the ARP.
[4] Includes both ARP and Quincy loads and distribution losses only

Schedule 4
Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
All-Requirements Power Supply Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 2014 [1]		Forecast - 2015 [2]		Forecast - 2016	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,014	468	1,113	451	1,106	448
February	863	383	1,024	389	1,018	391
March	716	403	853	410	847	408
April	1,012	430	914	431	910	429
May	1,069	505	1,056	500	1,050	497
June	1,123	531	1,154	550	1,146	547
July	1,142	580	1,153	594	1,147	591
August	1,202	601	1,202	601	1,196	599
September	1,108	520	1,097	531	1,090	529
October	1,071	469	1,015	477	1,012	475
November	1,026	393	821	408	811	405
December	817	420	845	445	835	442

[1] Year 2014 included both the coincidental peaks and NEL of the ARP and Quincy
[2] Year 2015 shows the expected ARP requirements including the sale to the City of Quincy.

Section 4 Renewable Resources and Conservation Programs

4.1 Introduction

FMPA continually evaluates renewable and conservation resource opportunities as part of its integrated resource planning process for the ARP. The ARP currently utilizes renewable energy resources as part of the generation portfolio, including solar photovoltaic (PV) and biomass. In addition, the ARP operates a Conservation & Energy Efficiency Program and a Net Metering Program.

4.2 Renewable Resources

The following provides an overview of the ARP's current renewable resources, as well as new resources that are being considered as part of FMPA's integrated resource planning process:

4.2.1 Solar Photovoltaic

In December 2009, the ARP completed construction on a 30 kW (DC) solar photovoltaic (PV) project located in Key West, FL. This project was developed and constructed as a joint partnership between the National Oceanic and Atmospheric Administration (NOAA) and FMPA. FMPA receives 62% of the energy generated from the solar PV system: Since the completion of the project, FMPA has received approximately 145,871 kWh of energy from the system. In 2014, FMPA's share of energy production amounted to 29,203 kWh.

FMPA continues to evaluate new opportunities for Solar PV projects for the ARP.

4.2.2 Biomass

FMPA currently receives biomass renewable energy from two sources.

- FMPA purchases as-available power from a cogeneration plant owned and operated by U.S. Sugar Corporation. The U.S. Sugar cogeneration plant is fueled by sugar bagasse, a byproduct of sugar production. U.S. Sugar Corporation uses the bagasse to fuel their generation plants to provide power for their processes. FMPA purchases the excess power produced from these generators. During 2014, FMPA purchased 16,379 MWh of energy from this renewable resource.

- In 2014, the Stanton Units 1 and 2 consumed 822,651 MMBtu of landfill gas as a supplemental fuel source. The ARP receives energy from both the ARP's and ARP Participants' shares in the Stanton Energy Center Units 1 and 2, which amount to 23.6% of the energy output of Stanton Unit 1 and 19.3% of the energy output of Unit 2 as of December 31, 2014. Thus, the ARP utilized 166,128 MMBtu of landfill gas as a supplemental fuel source.

These renewable resources help the ARP meet current and future energy needs. However, the existing renewable resources are not considered firm capacity, so they do not assist the ARP in meeting current or future capacity needs.

In addition, FMPA continues to hold discussions with other biomass developers and evaluate proposals in an effort to find additional cost-effective biomass resources for the ARP.

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

4.3 Conservation & Energy Efficiency Program

The ARP Participants have developed the ARP Conservation Program to provide conservation and energy efficiency incentives and assistance to their retail customers. The project is funded through the ARP rates and members are allocated funds based on their energy load ratio share. Each ARP Participant can elect to implement programs that are most suitable for their community.

Conservation programs offered by ARP Participants include, but are not limited to, the following:

- Rebates on ENERGY STAR® qualified appliances
- Rebates on insulation upgrades and duct leak repair
- Residential and Commercial energy audits
- Customer education materials, including brochures and DVDs
- Equipment and training for utility energy auditors

Since the inception of the program in 2008, the ARP Participants have allocated more than $5.2 million to the ARP Conservation Program. The ARP Participants recurrently evaluate evolving conservation measures, and add those measures to their respective portfolio of offerings. FMPA supports these efforts by developing engineering assumptions to track the savings associated with new measures that are adopted, and has developed a historical tracking model to integrate participation statistics and estimated energy and demand savings per year since the inception of the program.

FMPA is currently not including the effects of its energy efficiency programs in its forecast of demand and net energy for load as the program results are still under FMPA's designated threshold for level of significance developed pursuant to NERC Reliability Standards for load and demand modeling. FMPA has developed reporting tools and techniques in order to be able to estimate program effects on demand and NEL and understand the level of significance of the program. Once the threshold is crossed, FMPA will separately account for the effects of the energy efficiency program in its demand and load forecast. To the extent that recent energy efficiency efforts have been captured in actual consumption data for the last few years, the effects of the program are included in the current load forecast.

4.4 Net Metering Program

In June 2008, the ARP Participants adopted a Net Metering Policy to permit interconnection of customer-owned renewable generation to its Members' distribution system. This policy facilitates the purchase of excess customer-owned renewable generation and outlines the metering, billing and crediting procedures to be followed by ARP Participants. Thus, through the Net Metering Program the ARP has been able to switch the fuel used to provide the energy from certain residential and commercial customer loads from traditional ARP fuel sources to PV. As of December 2014, the ARP had approximately 1,831 kW of solar photovoltaic renewable generation (DC) connected to the grid through the Net Metering Program.

As with the conservation programs, FMPA is currently not including the effects of its net metering program in its forecast of demand and net energy for load as the program results are still under FMPA's designated threshold for level of significance. However, to the extent that the net metering program has resulted in reduced customer consumption of utility generated electricity in the recent past, such impacts have been captured in actual consumption data, and the effects of the program are included in the current load forecast through the embedded reductions in actual data resulting from the program.

4.5 Load Management Program

Currently, there are no ARP-sponsored load management programs in place. However, beginning in 2009, some ARP Participants established load management programs for certain customers, such as those with standby generation, for the discreet use by the ARP Participant, not FMPA or the ARP's Balancing Authority. FMPA has been tracking the effects of these load management programs and has been accounting for them appropriately in the planning process, and in the load forecast by adding back the load pursuant to NERC Reliability Standards for load and demand modeling. Effective October 1, 2014 however, the ARP Executive Committee approved a policy that members would not engage in intermittent voltage reduction measures or deploy ARP Participant owned emergency generation as a way to intentionally reduce their load during the ARP coincident peak hour in an effort to pass ARP costs to other ARP Participants. In addition, after September 30, 2015 ARP Participants will not be allowed to deploy customer emergency generation for this purpose.

Section 5 Forecast of Facilities Requirements

5.1 ARP Planning Process

FMPA's integrated resource planning (IRP) mandate is to assure, on a long-term basis, a low-cost and reliable electricity supply to ARP Participants that reflects the goals and objectives established by the ARP Participants. FMPA's planning process is consistent with Florida Public Service Commission (PSC) statutory and regulatory requirements which do not specifically subject utilities in Florida to integrated resource planning, but when taken together equate to an integrated resource planning requirement. In addition, FMPA's process is considerate of the Public Utility Regulatory Act (PURPA) which requires certain standards of practice to comply with retail rate regulations.

The IRP planning process requires that FMPA and the ARP Executive Committee evaluate alternative resource portfolios and make certain decisions regarding implementing a particular preferred plan. Certain requirements, such as maintaining 18 percent Summer Peak Reserves and 15 percent Winter Peak Reserves on a planned basis, and "best efforts" goals, such as achieving the lowest net present value cost over the next 20 years, and integrating demand-side and renewable resources into the ARP power supply portfolio, have been developed as guidelines to assist FMPA and the Executive Committee in communicating and evaluating the key issues associated with making resource portfolio planning decisions.

5.2 Planned ARP Generating Facility Requirements

Based upon FMPA's current Base Load forecast, the ARP currently does not require any additional resources until the summer of 2024, when it will need to acquire 33 MW from an undesignated source to maintain FMPA's 18% reserve margin. Schedule 8 at the end of this section shows planned and prospective ARP generating resources changes during the next 10-year period.

5.3 Capacity and Power Purchase Requirements

The current system firm power supply purchase resources of the ARP include three purchases from Southern Company. Power purchase contracts included in the ARP plans are briefly summarized below:

- **Southern Company:** The ARP and KUA each have a contract for the purchase of 6.5 percent of the net operating capability of the Stanton A combined cycle facility from Southern Company – Florida LLC. The initial term of the purchase ends in September 2023 and includes subsequent extension options. For 2015, the ARP's and KUA's combined purchases from Stanton A amount to 80.6 MW based on the 620 MW summer rating of the facility. FMPA also has a contract to purchase the entire capacity of, and energy generated by, Southern Power Company's Oleander Unit 5, an approximately 162 MW (summer rating) or 180 MW (winter rating), simple cycle gas turbine unit primarily fueled with natural gas and located in Brevard County. The initial term of the purchase ends in December 2027 and includes a subsequent extension option.

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. The need of 33 MW in 2024 to maintain FMPA's 18% reserve margin, will be filled either by the extension of the existing Stanton A PPA, or from some other undesignated source. 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 Power Supply Project Resource Summer Capacity

Line No.	Resource Description	Summer Rating (MW)									
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear) [1]	36	36	36	36	36	34	34	34	34	34
2	Stanton Coal Plant [2]	177	177	177	177	177	177	177	177	177	177
3	Stanton CC Unit A [2]	43	43	43	43	43	43	43	43	43	43
4	Cane Island 1-4	683	683	683	683	683	683	683	683	683	683
5	Indian River CTs [2]	76	76	76	76	76	76	76	76	76	76
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	Treasure Coast Energy Center	300	300	300	300	300	300	300	300	300	300
9	Key West Native Generation	33	33	33	33	33	33	33	33	33	33
10	Kissimmee Native Generation	-	-	-	-	-	-	-	-	-	-
11	Sub Total Existing Resources	1,424	1,424	1,424	1,424	1,424	1,423	1,423	1,423	1,423	1,423
	Planned Additions										
12	Unindentified Resource [3]	-	-	-	-	-	-	-	-	-	33
13	Sub Total Planned Additions	-	-	-	-	-	-	-	-	-	33
14	Total Installed Capacity	1,424	1,424	1,424	1,424	1,424	1,423	1,423	1,423	1,423	1,456
	Firm Capacity Import										
	Firm Capacity Import Without Reserves										
15	Stanton A Purchase [2]	79	79	79	79	79	79	79	79	79	-
16	Oleander Purchase	162	162	162	162	162	162	162	162	162	162
17	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	-
18	Sub Total Without Reserves	241	241	241	241	241	241	241	241	241	162
19	Total Available Capacity	1,665	1,665	1,665	1,665	1,665	1,664	1,664	1,664	1,664	1,618

[1] Includes capacity from the St. Lucie Project. When Green Cover Springs exercises CROD effective 1/1/2020, its St. Lucie Project Entitlement Share is longer used by the ARP.
[2] Capacities are adjusted downward to account for losses through OUC's system (assumed to be 2.0% for planning period)
[3] Additional capacity will be required in 2024 to maintain an 18% reserve margin.

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

Line No.	Resource Description	Winter Rating (MW)									
		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear) [1]	37	37	37	37	37	35	35	35	35	35
2	Stanton Coal Plant [2]	178	178	178	178	178	178	178	178	178	178
3	Stanton CC Unit A [2]	45	45	45	45	45	45	45	45	45	45
4	Cane Island 1-4	711	711	711	711	711	711	711	711	711	711
5	Indian River CTs [2]	93	93	93	93	93	93	93	93	93	93
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	Treasure Coast Energy Center	310	310	310	310	310	310	310	310	310	310
9	Key West Native Generation	33	33	33	33	33	33	33	33	33	33
10	Kissimmee Native Generation	-	-	-	-	-	-	-	-	-	-
11	Sub Total Existing Resources	1,483	1,483	1,483	1,483	1,483	1,482	1,482	1,482	1,482	1,482
	Planned Additions										
12	Unindentified Resource [3]	-	-	-	-	-	-	-	-	-	-
13	Sub Total Planned Additions	-	-	-	-	-	-	-	-	-	-
14	Total Installed Capacity	1,483	1,483	1,483	1,483	1,483	1,482	1,482	1,482	1,482	1,482
	Firm Capacity Import										
	Firm Capacity Import Without Reserves										
15	Stanton A Purchase [2]	84	84	84	84	84	84	84	84	84	-
16	Oleander Purchase	180	180	180	180	180	180	180	180	180	180
17	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	-
18	Sub Total Without Reserves	264	264	264	264	264	264	264	264	264	180
19	Total Available Capacity	1,747	1,747	1,747	1,747	1,747	1,746	1,746	1,746	1,746	1,662

[1] Includes capacity from the St. Lucie Project. When Green Cover Springs exercises CROD effective 1/1/2020, its St. Lucie Project Entitlement Share is longer used by the ARP.

[2] Capacities are adjusted downward to account for losses through OUC's system (assumed to be 2.0% for planning period)

Schedule 5
Fuel Requirements – All-Requirements Power Supply Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Unit	Fuel	Actual	Forecasted									
No.	Fuel Type	Type	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Nuclear [1]		Trillion BTU	3	3	3	3	3	3	3	3	3	3	3
2	Coal		000 Ton	361	364	358	371	452	487	467	477	465	456	434
	Residual													
3		Steam	000 BBL	-	5	5	7	7	3	4	4	5	5	7
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-
6		Total	000 BBL	-	5	5	7	7	3	4	4	5	5	7
	Distillate													
7		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
9		CT	000 BBL	6	2	-	-	1	-	-	-	-	0	-
10		Total	000 BBL	6	2	-	-	1	-	-	-	-	0	-
	Natural Gas													
11		Steam	000 MCF	450	-	-	-	-	-	-	-	-	-	-
12		CC [2]	000 MCF	31,454	34,882.54	37,949	35,217	24,465	22,885	25,403	25,521	27,839	29,950	33,843
13		CT	000 MCF	443	240	221	207	48	59	70	201	148	211	440
14		Total	000 MCF	32,347	35,122	38,170	35,424	24,512	22,944	25,473	25,722	27,986	30,161	34,283
	Renewables [3]													
15		Biofuels	Billion BTU	164	130	130	130	130	130	130	130	130	130	130
16		Biomass	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
17		Geothermal	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
18		Hyrdro	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
19		Landfill Gas	Billion BTU	166	178	164	155	146	137	128	119	110	110	110
20		MSW	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
21		Solar	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
22		Wind	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
23		Other	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
24		Total	Billion BTU	330	308	294	285	276	267	258	249	240	240	240
25	Other		Trillion BTU	-	-	-	-	-	-	-	-	-	-	-

2015 TYSP

[1] Nuclear generation shown is the ARP Participant's Entitlement Shares in the St. Lucie Project.

[2] Actual and projected non-firm net interchange is included in the Natural Gas CC values assuming an average 7 MMBtu/MWh Heatrate.

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

Schedule 6.1
Energy Sources (GWh) – All-Requirements Power Supply Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Prime		Actual	Forecasted									
No.	Energy Source	Mover	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Annual Firm Inter-Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	286	286	269	285	285	269	286	285	269	285	286
3	Coal		GWh	837	827	811	848	1,053	1,144	1,093	1,119	1,089	1,066	1,011
	Residual													
4		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	3	1	-	-	0	-	-	-	-	0	-
11		Total	GWh	3	1	-	-	0	-	-	-	-	0	-
	Natural Gas													
12		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
13		CC [2]	GWh	4,569	4,724	4,732	4,763	4,668	4,687	4,817	4,868	5,010	5,102	5,233
14		CT	GWh	27	22	20	18	4	5	6	18	13	19	39
15		Total	GWh	4,596	4,746	4,752	4,781	4,671	4,692	4,823	4,886	5,023	5,121	5,273
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
	Renewables [3]													
17		Biofuels	GWh	16	13	13	13	13	13	13	13	13	13	13
18		Biomass	GWh	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	GWh	-	-	-	-	-	-	-	-	-	-	-
20		Hyrdro	GWh	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	GWh	15	17	15	15	14	13	12	11	11	11	10
22		MSW	GWh	-	-	-	-	-	-	-	-	-	-	-
23		Solar	GWh	-	-	-	-	-	-	-	-	-	-	-
24		Wind	GWh	-	-	-	-	-	-	-	-	-	-	-
25		Other	GWh	-	-	-	-	-	-	-	-	-	-	-
26		Total	GWh	32	30	28	28	27	26	25	24	24	24	23
27	Interchange [4]		GWh	42	-	-	-	-	-	-	-	-	-	-
28	Net Energy for Load [5]		GWh	5,795	5,889	5,860	5,943	6,036	6,131	6,227	6,314	6,404	6,496	6,593

[1] Nuclear generation shown is the ARP Participant's Entitlement Shares in the St. Lucie Project.
[2] Includes non-firm net interchange
[3] 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.
[4] Includes firm interchange
[5] Includes Bulk Electric System transmission losses.

Schedule 6.2
Energy Sources (%) – All-Requirements Power Supply Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Energy Source	Prime Mover	Units	Actual 2014	Forecasted 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	4.9	4.9	4.6	4.8	4.7	4.4	4.6	4.5	4.2	4.4	4.3
3	Coal		%	14.4	14.0	13.8	14.3	17.4	18.7	17.6	17.7	17.0	16.4	15.3
	Residual													
4		Steam	%	-	-	-	-	-	-	-	-	-	-	-
5		CC	%	-	-	-	-	-	-	-	-	-	-	-
6		CT	%	-	-	-	-	-	-	-	-	-	-	-
7		Total	%	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	%	-	-	-	-	-	-	-	-	-	-	-
9		CC	%	-	-	-	-	-	-	-	-	-	-	-
10		CT	%	0.0	0.0	-	-	0.0	-	-	-	-	0.0	-
11		Total	%	0.0	0.0	-	-	0.0	-	-	-	-	0.0	-
	Natural Gas													
12		Steam	%	-	-	-	-	-	-	-	-	-	-	-
13		CC	%	78.8	80.2	80.8	80.2	77.3	76.4	77.3	77.1	78.2	78.5	79.4
14		CT	%	0.5	0.4	0.3	0.3	0.1	0.1	0.1	0.3	0.2	0.3	0.6
15		Total	%	79.3	80.6	81.1	80.5	77.4	76.5	77.4	77.4	78.4	78.8	80.0
16	NUG		%	-	-	-	-	-	-	-	-	-	-	-
	Renewables [2]													
17		Biofuels	%	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
18		Biomass	%	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	%	-	-	-	-	-	-	-	-	-	-	-
20		Hyrdro	%	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	%	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
22		MSW	%	-	-	-	-	-	-	-	-	-	-	-
23		Solar	%	-	-	-	-	-	-	-	-	-	-	-
24		Wind	%	-	-	-	-	-	-	-	-	-	-	-
25		Other	%	-	-	-	-	-	-	-	-	-	-	-
26		Total	%	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
27	Interchange		%	0.7	-	-	-	-	-	-	-	-	-	-
28	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 shown is the ARP Participant's Entitlement Shares in the St. Lucie Project.

[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 Power Supply Project plus Quincy Sale

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Available Capacity	Total System Firm Summer Peak Demand (MW) [2][3]			Reserve Margin before Maintenance [4]		Scheduled Maintenance	Reserve Margin after Maintenance [4]	
Year	(MW) [1]	(MW)	(MW) [2]	QF (MW)	(MW)	Peak	Losses	Total	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2015	1,424	241	0	0	1,665	1,202	21	1,223	442	36%	0	442	36%
2016	1,424	241	0	0	1,665	1,196	20	1,216	449	37%	0	449	37%
2017	1,424	241	0	0	1,665	1,213	21	1,234	431	35%	0	431	35%
2018	1,424	241	0	0	1,665	1,233	21	1,254	411	33%	0	411	33%
2019	1,424	241	0	0	1,665	1,253	21	1,274	391	31%	0	391	31%
2020	1,423	241	0	0	1,664	1,273	22	1,295	369	28%	0	369	28%
2021	1,423	266	0	0	1,689	1,291	22	1,313	376	29%	0	376	29%
2022	1,423	291	0	0	1,714	1,310	22	1,332	382	29%	0	382	29%
2023	1,423	316	0	0	1,739	1,329	23	1,352	387	29%	0	387	29%
2024	1,456	162	0	0	1,618	1,349	23	1,372	246	18%	0	246	18%

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

[2] The Quincy Sale is represented as part of the System Firm Peak Demand.

[3] System Firm Summer Peak Demand includes transmission losses for the ARP Participants served through FPL, PEF, and KUA.

[4] 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 Power Supply Project plus Quincy Sale

(1)	(2)	(3)	(4)	(5)	(6)	(6)		(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Available Capacity	System Firm Winter Peak Demand (MW) [2][3]			Reserve Margin before Maintenance [4]		Scheduled Maintenance	Reserve Margin after Maintenance [4]	
Year	(MW) [1]	(MW) [1]	(MW) [2]	(MW)	(MW)	Peak	Losses	Total	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2014/15	1,483	264	0	0	1,747	1,113	19	1,132	615	54%	0	615	54%
2015/16	1,483	264	0	0	1,747	1,131	20	1,150	597	52%	0	597	52%
2016/17	1,483	264	0	0	1,747	1,122	20	1,142	606	53%	0	606	53%
2017/18	1,483	264	0	0	1,747	1,140	20	1,161	587	51%	0	587	51%
2018/19	1,483	264	0	0	1,747	1,159	21	1,179	568	48%	0	568	48%
2019/20	1,482	264	0	0	1,746	1,178	21	1,198	547	46%	0	547	46%
2020/21	1,482	289	0	0	1,771	1,194	21	1,216	555	46%	0	555	46%
2021/22	1,482	314	0	0	1,796	1,212	21	1,233	562	46%	0	562	46%
2022/23	1,482	339	0	0	1,821	1,230	22	1,252	569	45%	0	569	45%
2023/24	1,482	180	0	0	1,662	1,249	22	1,271	391	31%	0	391	31%

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

[2] The Quincy Sale is represented as part of the System Firm Peak Demand.

[3] System Firm Summer Peak Demand includes transmission losses for the ARP Participants served through FPL, PEF, and KUA.

[4] 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		Status
				Primary	Alt.	Primary	Alt.					Summer MW	Winter MW	
Resource Additions														
	?	?	?									33 [1]		
Changes to Existing Resources														
Stanton	A	Orange	CC	Gas		Pipe			10/03	NA	671	620 [2]	660 [2]	

[1] FMPA will need to acquire 33 MW from an undetermined resource to maintain an 18% summer reserve margin in 2024.

[2] Stanton A is a combined cycle unit jointly owned by FMPA on behalf of the ARP, along with KUA, OUC and Southern Company. KUA and the ARP each owns 3.5% of the unit, with the ARP purchasing the capacity and energy from KUA's ownership interest. Additionally, the ARP has a PPA with Southern Company for rights to an additional 13% of the capacity and energy from the unit (or 20% total, including the ARP and KUA ownership interests) ("Stanton A PPA"). The initial term of the Stanton A PPA expires in September 2023 and includes up to two, five-year extension terms. FMPA has not yet determined whether it will extend the Stanton A PPA beyond the initial term; however, FMPA does view extension of the Stanton A PPA to be a potential option for meeting the ARP's capacity need currently shown for the summer of 2024.

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 sites for FMPA as specified by PSC/EAG 43.

- Cane Island Power Park –Potential Site for additional future generation.
- Treasure Coast Energy Center – Potential Site.
- Stock Island – Potential Site.

FMPA anticipates that simple cycle combustion turbines could be installed at existing generation sites located within or adjacent to the service territories of ARP Participants, such as the Stock Island site at KEYS, the Cane Island Power Park site at KUA, or the Treasure Coast Energy Center in Fort Pierce. FMPA also anticipates that combined cycle generation could be installed at the Treasure Coast Energy Center site. FMPA continuously explores the feasibility of other sites located within Florida with the expectation that ARP Participants' service territories would provide the best option for future development.

Cane Island Power Park

Cane Island Power Park is located south and west of KUA's service area and contains 683 MW (summer ratings) of gas turbine and combined cycle capacity: Units 1-3 include a simple cycle gas turbine and two combined cycle generating units, each of which is 50 percent owned by FMPA and 50 percent owned by KUA. Cane Island Unit 4 (CI4), a nominal 300 MW (summer rating), natural gas-fired 1x1 GE 7FA combined cycle unit, is wholly owned by the ARP.

Treasure Coast Energy Center

FMPA commissioned Treasure Coast Energy Center (TCEC) Unit 1, a dual fuel low sulfur diesel and natural gas-fired 300 MW (summer rating) 1x1 GE 7FA combined cycle unit in May 2008. The Treasure Coast Energy Center is located in St. Lucie County in 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.

Stock Island

The Stock Island site currently consists of four combustion turbines, three diesel generating units, one of which is a high speed diesel that had been previously retired but refurbished and brought back into service in July of 2012. 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.

General

Schedule 9 presents the status report and specifications for any proposed ARP generating facility, if applicable. Schedule 10 contains the status report and specifications for proposed ARP transmission line projects.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities
All-Requirements Power Supply Project
(Preliminary Information)

(No Proposed Generating Facilities)

(1)	Plant Name and Unit Number	
(2)	Capacity	
	a. Summer	
	b. Winter	
(3)	Technology Type	
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	
	b. Commercial In-Service Date	
(5)	Fuel	
	a. Primary Fuel	
	b. Alternate Fuel	
(6)	Air Pollution Control Strategy	
(7)	Cooling Method	
(8)	Total Site Area	
(9)	Construction Status	
(10)	Certification Status	
(11)	Status with Federal Agencies	
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	
	Forced Outage Factor (FOF)	
	Equivalent Availability Factor	
	Resulting Capacity Factor	
	Average Net Operating Heat Rate (ANOHR)	
(13)	Projected Unit Financial Data	
	Book Life (Years)	
	Total Installed Cost (In-Service Year $/kW)	
	Direct Construction Cost (2010 $/kW)	
	AFUDC Amount ($/kW) [1]	
	Escalation ($/kW)	
	Fixed O&M ($/kW)	
	Variable O&M ($/MWh)	

[1] Includes AFUDC and bond issuance expenses

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

(1)	Point of Origin and Termination	
(2)	Number of Lines	
(3)	Right-of-Way	
(4)	Line Length	
(5)	Voltage	(See note below)
(6)	Anticipated Construction Timing	
(7)	Anticipated Capital Investment	
(8)	Substations	
(9)	Participation with Other Utilities	

Note: FMPA currently has no new proposed transmission lines.

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
V	Under Construction, More Than 50% Complete
A	Generation Unit Capability Increased
OT	Other
IR	Inactive Reserve (Emergency Only)

Other

NA	Not Available or Not Applicable

Appendix II
ARP Participant Transmission Information

Table II-1 presented on the following page contains a list of planned and proposed transmission facility additions for ARP Participant cities.

Table II-1
Planned and Proposed Transmission Additions for ARP Participants
2014 through 2023 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Kissimmee						
	Osceola Parkway Substation			69 kV		6/2018
	Lake Bryan	Osceola Parkway		69 kV	1	6/2018
	Lake Cecile	Osceola Parkway		69 kV	1	6/2018
	Domingo Toro Substation			69 kV		6/2020
Ocala						
	Shaw Second 30 MVA Transformer		30	69/12.47 kV	1	6/2017
	Ergle Second 165 MVA Transformer		165	230/69 kV	2	6/2016

Appendix III
Additional Reserve Margin Information

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. Should FMPA enter into any Partial Requirements (or similar type) agreements for purchase of a portion of its energy and capacity needs, FMPA would not include the Partial Requirements in its calculation of reserves, as reserves for this would be responsibility of the selling entity.

Table III-1
Calculation of Reserve Margin at Time of Summer Peak
All-Requirements Power Supply 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)
2015	1,665	1,223	0	442	36%
2016	1,665	1,216	0	449	37%
2017	1,665	1,234	0	431	35%
2018	1,665	1,254	0	411	33%
2019	1,665	1,274	0	391	31%
2020	1,664	1,295	0	369	28%
2021	1,689	1,313	0	376	29%
2022	1,714	1,332	0	382	29%
2023	1,739	1,352	0	387	29%
2024	1,618	1,372	0	246	18%

[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 Power Supply 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)
2014/15	1,747	1,132	0	615	54%
2015/16	1,747	1,150	0	597	52%
2016/17	1,747	1,142	0	606	53%
2017/18	1,747	1,161	0	587	51%
2018/19	1,747	1,179	0	568	48%
2019/20	1,746	1,198	0	547	46%
2020/21	1,771	1,216	0	555	46%
2021/22	1,796	1,233	0	562	46%
2022/23	1,821	1,252	0	569	45%
2023/24	1,662	1,271	0	391	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)