TEN-YEAR SITE PLAN

2018-2027

Submitted to
Florida Public Service Commission
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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 achieve economies of scale in power generation and related services. FMPA's direct responsibility for power supply planning can be separated into two roles. First, for the 13 All Requirements Power Supply Project (ARP) Participants who receive capacity and energy from the ARP, FMPA supplies all of the electric power and energy, transmission and associated services, unless limited by a contract rate of delivery, except for certain excluded resources. Second, for member systems that do not purchase their full requirements from the ARP, the Agency's role has been to evaluate joint action opportunities and make the findings available to such members, whereby each member can elect whether or not to participate in that project. FMPA currently has four such power supply projects – the Stanton, Tri-City, Stanton II, and St. Lucie Projects; and, as of the date of this TYSP, is in the process of developing a new Solar Project. FMPA's TYSP is focused on the resources of, and planning for, the ARP.

The total summer capacity of ARP resources for the year 2018 is 1,670 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 2018 Capacity Resources

Resource Category	Summer Capacity (MW)
Excluded Resources (Nuclear)	35
ARP System Generation	1,392
Power Purchases	243
Net Total 2018 ARP Resources [1]	1,670

[1] Totals may not add due to rounding

The ARP expects to meet its generation capacity requirements and maintain a 15% reserve margin with existing resources through the end of the TYSP study period, or December 31, 2027. As a result of (i) FMPA's revised long-term load forecast as detailed herein, (ii) anticipated upgrades to plant capacity for resources used to serve ARP load throughout the study period, and (iii) the transfer of the City of Vero Beach's entitlement shares in certain coal and nuclear power plants to the ARP, which has been assumed to occur as of January 1, 2019 for capacity planning purposes, no additional resources will be required to meet generation capacity requirements. The projected peak native ARP summer load, inclusive of sales for resale, for 2018 is 1,307 MW and is forecasted to increase to 1,409 MW in 2027. FMPA will continue to evaluate and develop sufficient, cost-effective resource alternatives for the ARP through its integrated resource planning process.

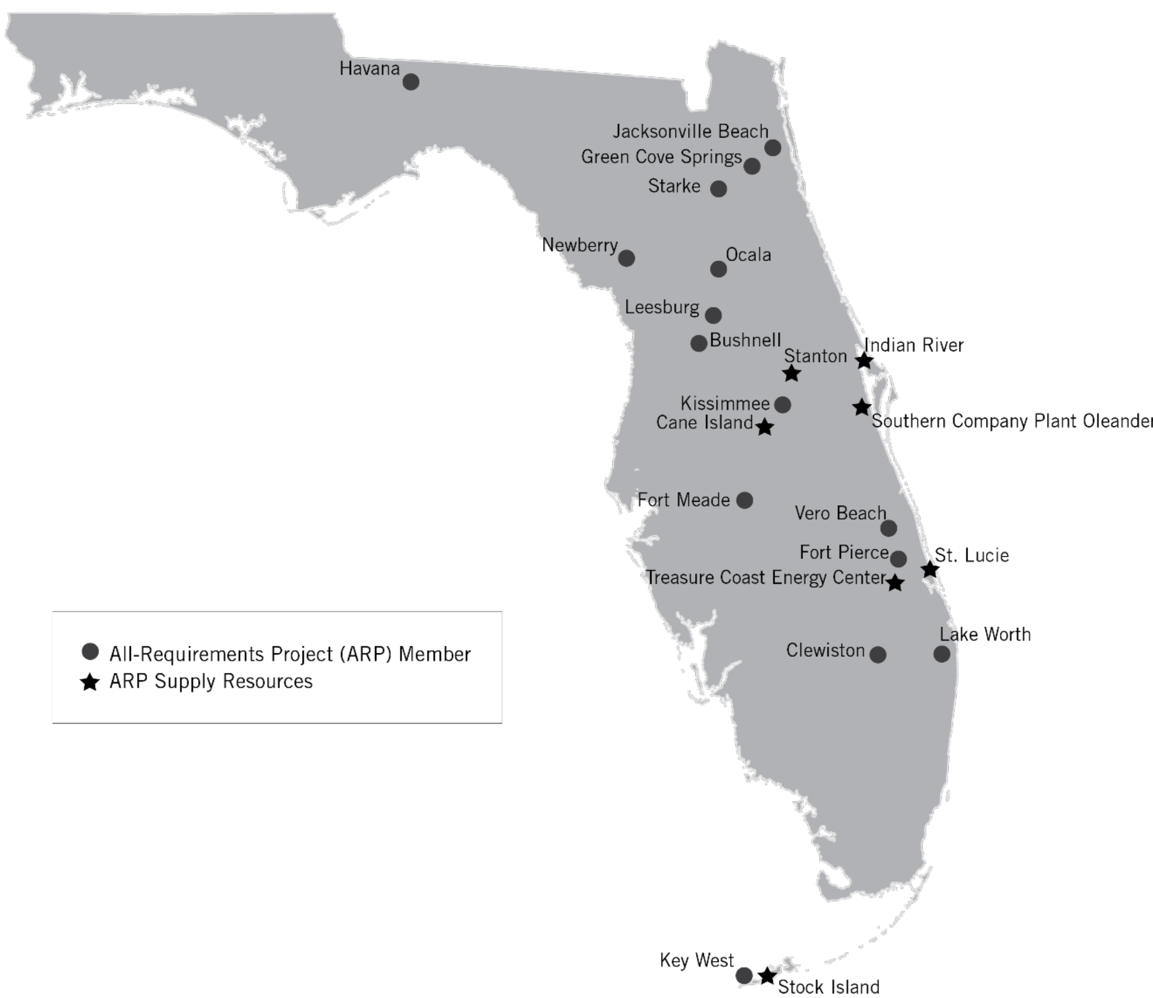
FMPA, on behalf of the ARP, began supplying the City of Bartow wholesale capacity and energy on January 1, 2018 under an agreement that will run for five years. For the first three years of the agreement, FMPA will supply peaking power to Bartow for its needs above 40 MW. In 2021 and 2022, FMPA will supply Bartow's full-requirements power supply needs.

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. In March

2018, FMPA's ARP Executive Committee approved a 20-year power purchase agreement for a total of 58 MW-AC of solar energy as an ARP resource, which is estimated to achieve commercial operation by mid-2020. The ARP solar entitlement is anticipated to increase the proportion of ARP energy derived from renewable generation, which FMPA will include as additional information in future site plans as appropriate.

A location map of the ARP Participants and FMPA's power resources as of December 31, 2017 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], 13 of which are supplied capacity and energy by the ARP. 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.

Unless they have elected to receive power through a contract rate of delivery (which converts the full-requirements to partial requirements), ARP Participants are required to purchase all of their capacity and energy requirements above their excluded resources, if any, 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 non-contract rate of delivery ARP Participants that own generating resources or have entitlements in FMPA power supply projects (other than entitlements in the St. Lucie Project), contract with the ARP to sell the electric capacity and energy of their resource entitlements to the ARP.

[1]The City of Vero Beach, City of Lake Worth, the City of Ft. Meade and the City of Green Cove Springs, 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 CROD amount for the City of Green Cove Springs will be established in 2019. The City of Ft. Meade and the City of Green Cove Springs continue to have representation on the Executive Committee.

Figure 1-1
ARP Participant Cities

Following is a brief description of each of the ARP Participants who is provided capacity and energy from the ARP.

City of Bushnell

The City of Bushnell is located in central Florida in Sumter County. The City joined the ARP in May 1986. Jody Young is the Interim City Manager and the Finance Director. 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. 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. John Tompeck, P.E., 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, d/b/a Beaches Energy Services

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 Leesburg

The City of Leesburg is located in central Florida in Lake County. The City joined the ARP in May 1986. Glenn Spurlock 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. Jamie Jones is the Utilities/Public Works Director**,** and Bill Conrad is the City's FMPA representative. 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. Michael Poucher, P.E., is the Director of Electric Utility. 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. Robert Milner 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.

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. In March 2018, the FMPA Board of Directors approved the formation of the Solar Project, as a sixth FMPA power supply project, which will enter a power purchase agreement for solar energy on behalf of its participants beginning in Summer of 2020. FMPA will include additional information on the Solar Project in future site plans as appropriate.

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.

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 to FMPA's undivided interest 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 to FMPA's undivided interest as shown in Table 1-4.

Table 1-4
Stanton II Project Participants

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

1.4 Summary of Projects

Table 1-5 provides a summary of FMPA Member project participation as of December 31, 2017.

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 exercised the right to modify its ARP full requirements membership (CROD).

[3] Effective January 1, 2015, the City of Ft. Meade 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, ARP owned resources and ownership shares in coal and gas-fired power plants, and power purchase agreements. The supply-side resources for the ARP for the 2018 summer season are shown in Table 2-1.

Table 2-1
ARP Supply-Side Resources Summer 2018*

Resource Category	Summer Capacity (MW)
1) Excluded Resources (Nuclear)	35
2) ARP System Generation	
Existing	1,392
New	-
Sub Total ARP System Generation	1,392
3) Power Purchases	243
Total 2018 ARP Resources	1,670

* Note that the ARP does not ascribe capacity value to its solar for planning purposes.

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

1) **Excluded Resources (Nuclear):** 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 their entitlement shares in the St. Lucie Project 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 entitlement in the St. Lucie Project and individually

receive the benefits of the capacity and energy from the St. Lucie Project. The ARP provides the balance of capacity and energy requirements for these ARP Participants (unless otherwise limited by CROD). Full Requirements ARP Participants' entitlements in the nuclear units are considered in the capacity planning for the ARP.

2) **ARP System Generation:** This category includes 1) generation that is wholly or jointly owned by FMPA as agent for the ARP; 2) generation that is wholly or jointly owned by ARP Participants; and 3) generation from ARP Participants' entitlements in the Stanton, Tri-City, and Stanton II Projects that is purchased by the ARP. FMPA has operational control of the ARP's and ARP Participants' capacity and energy from these resources, and such capacity and energy is dedicated solely to serving the ARP.

3) **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, 2017 includes capacity and energy purchased from Southern Power Company from their Stanton Unit A and Oleander Unit 5 facilities. In addition, the ARP expects to purchase solar energy from NextEra Florida Renewables beginning in Summer of 2020.

Information regarding existing ARP generation resources as of December 31, 2017, 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 boundary and along the Apalachicola River in the Florida Panhandle, referred to as the Florida – Southern Interface. FPL, Duke Energy Florida (DEF), 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). FPUA is also interconnected and co-owns transmission facilities with the City of Vero Beach. Note that the City of Vero Beach is moving forward with the sale of its electric utility and is anticipated to complete the sale in the near future, which affects FPUA's jointly owned transmission facilities. 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, Starke and KEYS are transmitted across FPL's transmission system. Capacity and energy for the Cities of Ocala, Leesburg, Bushnell, Newberry, Ft. Meade and Town of Havana are transmitted across the DEF transmission system. Capacity and energy for KUA from resources external to KUA's service territory is transmitted across the transmission systems of FPL, DEF and OUC. Sales to the City of Bartow 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, supplied by three 138 kV to 69 kV autotransformers, two at Hartman Substation and one at Garden City substation. FPUA supplies power to its distribution system at 13.2 kV via six 69 kV substations. There are two interconnection points 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. As of January 2019, it is expected that the second interconnection point for FPUA will be at the FPL owned County Line Substation (formerly jointly owned between COVB and FPUA). County Line Substation connects FPUA's Garden City (No. 2) Substation to the FPL Emerson and South 138 kV substations, via three single circuit 138-kV transmission lines. The tie line from County Line Substation to FPUA's Garden City substation is owned by FPUA.

KEYS

KEYS maintains and operates an electric generation, transmission, and distribution system, which supplies electric capacity 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 transmission system that interconnects to FPL's Florida City Substation at the Dade/Monroe County Line and proceeds southwest via several FKEC substations to the FKEC's Marathon Substation. This system includes two interconnections with FPL at the Dade/ Monroe County line. At these interconnections, FKEC and KEYS own 21 miles of a 36.8 mile 138 kV tie line between the

[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.

FKEC's Tavernier and FPL's Florida City Substations and 14 miles of a 27.8 mile 138 kV tie line between FKEC's Jewfish Creek and FPL's Florida City Substations. KEYS owns and operates a 38.2-mile long 138 kV radial transmission system from Marathon Substation to Big Coppitt 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. KEYS owns two 138 kV lines of approximately 5.5 and 7.84 miles in length connecting Big Coppitt Substation to Stock Island 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 owns two STATCOM/shunt capacitors installations, one at Big Pine and one at Stock Island Power Plant Substation. Additionally, KEYS and FKEC jointly own a 138 kV series capacitor, installed at FKEC's Islamorada Substation; and an automated transmission protection system to automatically shed load for select contingency conditions. These projects ensure the import limit of the Florida Keys (KEYS/FMPA and FKEC) 138 kV transmission system is equal to the thermal limit of the installed transmission conductor.

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 DEF, OUC, TECO and the City of St. Cloud (STC) in the following locations: (1) At Cane Island Substation, one 230 kV transmission line to DEF's Intercession City Substation, one 230 kV transmission line to OUC's Taft Substation, and one 230 kV transmission line to OUC/TECO's Osceola Substation; (2) at KUA's Marydia Substation, one 230 kV transmission line to OUC's Taft Substation; (3) At KUA's Lake Cecile Substation, one 69 kV transmission line to DEF's Lake Bryan Substation; (4) At KUA's Employee Substation, one 69 kV transmission line to DEF's Meadow Woods East Substation; (5) At KUA's Buenaventura Lakes Substation, one 69 kV transmission line to OUC's Taft substation (230 to 69 kV autotransformer owned by KUA) and (6) At KUA's Cark A, Wall Substation, one 69 kV line to STC's Central Substation .

City of Ocala

The City of Ocala, operating under the name Ocala Electric Utility (OEU), owns its bulk power supply system which consists of three 230 kV to 69 kV substations, 13 miles of 230 kV transmission, 67.1 miles of a 69 kV transmission loop, and 18 – 69 kV distribution substations delivering power at 12.47 kV. Ocala's 230 kV transmission facilities are dedicated to serving the

OEU load pocket and are not part of the FRCC networked 230 kV transmission system. The OEU distribution system consists of 759 miles of overhead lines and 384 miles of underground lines.

OEU's 230 kV transmission system interconnects with DEF's Silver Springs Switching Station and SECI's Silver Springs North Switching Station. OEU's Dearmin Substation interconnects to both DEF's Silver Springs Switching Station and SECI's Silver Springs North Switching Stations. OEU's Ergle and Shaw substations are interconnected at SECI's Silver Springs North Switching Station. OEU has added a 2nd auto-transformer at Ergle Substation. OEU also has a 69 kV radial tie from its Airport 69 kV Substation to Sumter Electric Cooperative's Martel Substation. OEU owns a 13 mile 230 kV transmission line from Shaw Substation to Silver Springs North Switching Station.

City of Jacksonville Beach, d/b/a Beaches Energy Services

Beaches owns and maintains a 138 kV transmission system that supplies electric capacity and energy to its distribution substations, with connections to both FPL and JEA. 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 radial 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. One 138 kV to 13.8 kV transformer at the City of Clewiston Substation provides a connection to the US Sugar co-generation facility.

2.2.2 ARP Transmission Agreements

OUC provides transmission service for delivery of power associated with ARP Participants' entitlements in Stanton, Tri-City, Stanton II Projects, and St. Lucie 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 any additional ARP power purchases from Stanton A. OUC transmission service is for the delivery of this energy to either the FPL, DEF or KUA 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 and remove certain ARP Participants as points of delivery. The Network Service and Network Operating Agreements with DEF were executed and filed with FERC in January 2011, and were subsequently amended to remove certain ARP Participants as points of delivery.

Schedule 1
Existing Generating Facilities as of December 31, 2017

(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 [1]	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	MM/YY	MW	Summer (MW)	Winter (MW)
Excluded Resources												
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	NA	891	35 [2]	36 [2]
Total Excluded Resources											35	36
ARP System Generation												
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	92 [3]	92 [3]
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	NA	465	85 [4]	85 [4]
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	43 [5]	45 [5]
Indian River	CT A	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	16 [6]	19 [6]
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	07/89	NA	41	16 [6]	19 [6]
Indian River	CT C	Brevard	GT	NG	DFO	PL	TK	08/92	NA	130	22 [7]	23 [7]
Indian River	CT D	Brevard	GT	NG	DFO	PL	TK	10/92	NA	130	22 [7]	23 [7]
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	35 [8]	38 [8]
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	109 [8]	113 [8]
Cane Island	3	Osceola	CC	NG	-	PL	-	01/02	NA	280	240 [8]	250 [8]
Cane Island	4	Osceola	CC	NG	-	PL	-	08/11	NA	350	300	310
Stock Island	CT1	Monroe	GT	DFO	-	WA	-	11/78	NA	20	19 [9]	19 [9]
Stock Island	CT2	Monroe	GT	DFO	-	WA	-	06/99	NA	21	16	16
Stock Island	CT3	Monroe	GT	DFO	-	WA	-	06/99	NA	21	14	14
Stock Island	GT4	Monroe	GT	DFO	-	WA	-	06/06	NA	61	46	46
Stock Island	MSD1	Monroe	IC	DFO	-	WA	-	06/91	NA	9	8 [9]	8 [9]
Stock Island	MSD2	Monroe	IC	DFO	-	WA	-	06/91	NA	9	8 [9]	8 [9]
Stock Island	EP2	Monroe	IC	DFO	-	WA	-	07/12	NA	2	2 [9]	2 [9]
Treasure Coast	1	St. Lucie	CC	NG	DFO	PL	TK	05/08	NA	350	300	310
Total ARP System Generation											1,391	1,439
Total Generation Resources											1,426	1,475

[1] Capabilities shown are as of December 31, 2017. Net capabilities shown for the Stanton and Indian River resources reflect the ARP's ownership capacity less losses across OUC's transmission system, which were assumed to be 2 percent over the study period.
[2] Amounts shown reflect non-CROD ARP Participants'' Power Entitlement Shares in the St. Lucie Project.
[3] Amounts shown reflect the ARP's (6.5060%) and KUA's (4.8193%) ownership interests in Stanton 1, as well as non-CROD ARP Participants' Power Entitlement Shares in the Stanton and Tri-City Projects.
[4] Amounts shown reflect the ARP's (5.1724%) ownership interest in Stanton 2, as well as non-CROD ARP Participants' Power Entitlement Shares in the Stanton II Project.
[5] Amounts shown reflect the ARP's (3.5%) and KUA's (3.5%) ownership interests in Stanton A. Excludes Stanton A unit upgrade effective 1/1/2018.
[6] Amounts shown reflect the ARP's (39.0%) and KUA's (12.2%) ownership interests in Indian River CTs A&B.
[7] Amounts shown reflect the ARP's (21.0%) ownership interest in Indian River CTs C&D.
[8] The ARP and KUA each own 50% of Cane Island Units 1-3. Amounts shown reflect the entire capability for each unit. FMPA has operational control of the units, which are dedicated entirely to serving the capacity and energy requirements of the ARP.
[9] Key West owns 100% of these units. FMPA has operational control of the units, which are dedicated entirely to serving the capacity and energy requirements of the ARP.

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

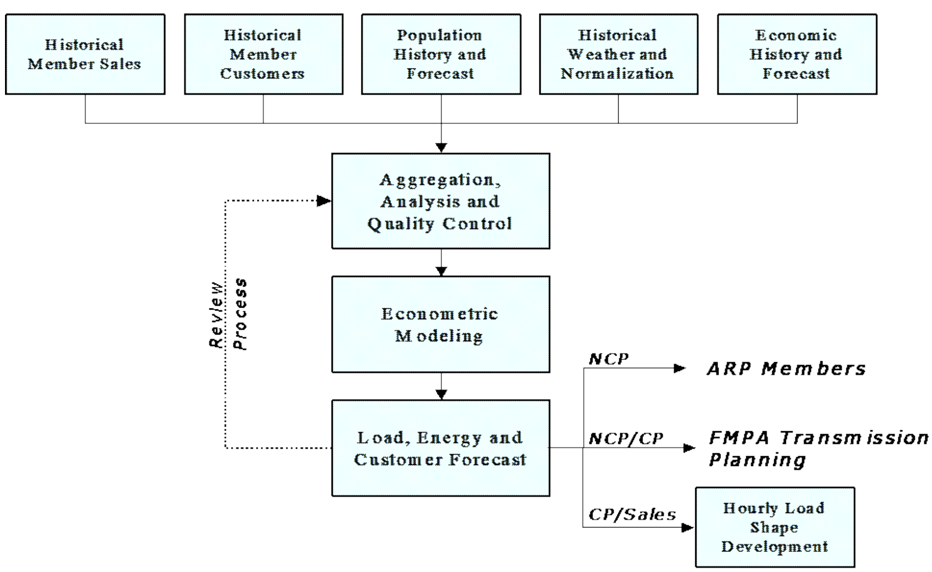
3.1 Introduction

To secure sufficient capacity and energy, FMPA forecasts each ARP Participant's electrical power demand and energy requirements from the ARP on an individual basis and aggregates the results into a forecast for the ARP. The following discussion summarizes the load forecasting process and the results of the load forecast contained in this Ten-Year Site Plan.

3.2 Load Forecast Process

FMPA prepares its load and energy forecast by month and summarizes the forecast annually. The load and energy forecast includes projections of customers, demand, and energy sales by rate classification for each of the ARP Participants who receive capacity and energy from the ARP. Forecasts are prepared on an individual Participant basis and are then aggregated into projections of the total ARP demand and energy requirements. Projections of the total ARP demand and energy requirements include real power losses on the transmission systems used by FMPA to deliver requirements to the ARP Participants. Figure 3-1 below identifies FMPA's load forecast process.

Figure 3-1
Load Forecast Process



Note on Figure 3-1:

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 Load Forecast Overview

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2017 through 2036. 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. In addition, the Forecast reflects the City of Green Cove Spring's establishment of CROD effective on January 1, 2020, and an estimate of FMPA's obligation to serve up to a maximum of 27.6 MW of load requirements of Green Cove Springs. As discussed above, the actual amount of the CROD for the City of Green Cove Springs will be determined, pursuant to contract terms by December 1, 2019. The results of the Base Case forecast are discussed in Section 3.6.1.

In addition to a 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 distribution system loss, load, and coincidence factors, generally based on the recent historical values for such factors. 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 Participant. 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 (described further below) 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 forecasts of sales for each rate classification described above were summed to equal the total retail sales of each ARP Participant. An assumed distribution system loss factor, based either on a regression analysis or a recent average of historical distribution system loss factors, was then applied to the total sales to derive monthly delivered net energy for load (NEL).

Projections of summer and winter non-coincident peak (NCP) demand were developed by applying projected annual load factors to the forecasted delivered NEL 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.

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.

Once the monthly NEL and Peak Demand requirements were projected for each ARP Participant on an as delivered basis, expected losses on the transmission systems used to deliver the requirements, using assumed Real Power Loss percentages throughout the forecasted period, were added in to arrive at NEL and Peak Demand requirements on an as generated basis. These are summed across all ARP Participants for the ARP's total demand and energy requirements.

3.5 Data Sources

3.5.1 Historical ARP Participant Retail Sales Data

Data was generally available and analyzed over January 1993 through September 2016. 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 1.0% per year, generally based on projections provided by the Energy Information Administration in the 2017 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 plus estimated sales for resale, including transmission losses, is expected to grow at an annual average growth rate of 0.96% from 2018-2027. The Base Case ARP forecast summer coincident peak (CP) demand and NEL for Calendar Year 2018, inclusive of sales for resale and transmission losses, are 1,307 MW and 6,154 GWh, respectively.

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 and 3.2a present the low, or Mild weather case, and Schedules 3.1b and 3.2b present the high or Severe weather case. Schedule 4 presents the actual (2017) and forecasted (Base Case for 2018 and 2019) peak demand and NEL by month.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Residential					Commercial		
Year [1]	Population Served by ARP Participants	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
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	222,086	12,831	2,803	40,139	69,826
2012	NA	NA	2,725	224,546	12,135	2,778	40,185	69,123
2013	NA	NA	2,756	226,612	12,160	2,771	40,409	68,585
2014	NA	NA	2,615	207,910	12,577	2,574	37,783	68,124
2015	NA	NA	2,772	211,022	13,137	2,680	38,341	69,888
2016	NA	NA	2,844	214,417	13,264	2,711	39,010	69,504
2017	NA	NA	2,790	218,391	12,778	2,675	39,306	68,061
2018	NA	NA	2,852	220,841	12,916	2,721	39,941	68,119
2019	NA	NA	2,886	223,252	12,926	2,752	40,380	68,150
2020	NA	NA	2,918	225,566	12,936	2,781	40,807	68,145
2021	NA	NA	2,952	227,875	12,956	2,810	41,234	68,141
2022	NA	NA	2,989	230,126	12,987	2,840	41,662	68,164
2023	NA	NA	3,025	232,368	13,019	2,868	42,089	68,141
2024	NA	NA	3,061	234,587	13,049	2,896	42,507	68,134
2025	NA	NA	3,097	236,752	13,082	2,925	42,916	68,158
2026	NA	NA	3,133	238,913	13,113	2,952	43,320	68,135
2027	NA	NA	3,169	241,092	13,146	2,978	43,719	68,110

[1] Amounts shown for 2008 through 2017 represent historical values. Amounts shown for 2018 through 2027 represent forecast values.
[2] Loads and customer counts only reflects the ARP. Wholesale sales other than sales to the ARP Participants 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 Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial			Railroads and Railways	Street & Highway Lighting		Total Sales to Ultimate Customers
Year [1]	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	GWh	Other Sales GWh	GWh
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	5,669
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	1,767,700	0	55	109	5,618
2016	2	1	2,359,000	0	55	109	5,722
2017	2	1	1,734,000	0	56	106	5,629
2018	2	1	1,975,190	0	55	108	5,738
2019	2	1	1,975,190	0	56	108	5,803
2020	2	1	1,975,190	0	56	108	5,864
2021	2	1	1,975,190	0	56	108	5,928
2022	2	1	1,975,190	0	56	108	5,995
2023	2	1	1,975,190	0	56	109	6,060
2024	2	1	1,975,190	0	56	109	6,125
2025	2	1	1,975,190	0	56	109	6,190
2026	2	1	1,975,190	0	57	110	6,253
2027	2	1	1,975,190	0	57	110	6,316

[1] Amounts shown for 2008 through 2017 represent historical values. Amounts shown for 2018 through 2027 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)
Year [1]	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
2008	0	380	7,053	0	294,827
2009	0	396	6,980	0	294,675
2010	0	413	6,371	0	260,476
2011	105	305	6,230	0	262,226
2012	96	386	6,151	0	264,732
2013	92	356	6,138	0	267,022
2014	91	334	5,778	0	245,695
2015	88	336	6,042	0	249,364
2016	0	317	6,039	0	253,427
2017	0	355	5,984	0	257,698
2018	21	395	6,154	0	260,783
2019	25	399	6,226	0	263,633
2020	28	393	6,285	0	266,374
2021	308	390	6,625	0	269,110
2022	312	389	6,696	0	271,790
2023	0	391	6,451	0	274,459
2024	0	396	6,520	0	277,095
2025	0	391	6,581	0	279,669
2026	0	391	6,644	0	282,233
2027	0	392	6,708	0	284,813

[1] Amounts shown for 2008 through 2017 represent historical values. Amounts shown for 2018 through 2027 represent forecast values.

[2] Loads and customer counts only reflects the ARP. Wholesale sales other than sales to the ARP Participants are shown as Sale for Resale on Schedule 2.3.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year [1]	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
2008	1,468	1,468	0	0	0	0	0	0	1,468
2009	1,500	1,500	0	0	0	0	0	0	1,500
2010	1,287	1,287	0	0	0	0	0	0	1,287
2011	1,302	1,302	0	0	0	0	0	0	1,302
2012	1,238	1,238	0	0	0	0	0	0	1,238
2013	1,257	1,257	0	0	0	0	0	0	1,257
2014	1,218	1,218	0	0	0	0	0	0	1,218
2015	1,227	1,227	0	0	0	0	0	0	1,227
2016	1,296	1,296	0	0	0	0	0	0	1,296
2017	1,263	1,263	0	0	0	0	0	0	1,263
2018	1,307	1,307	0	0	0	0	0	0	1,307
2019	1,322	1,322	0	0	0	0	0	0	1,322
2020	1,336	1,336	0	0	0	0	0	0	1,336
2021	1,390	1,390	0	0	0	0	0	0	1,390
2022	1,405	1,405	0	0	0	0	0	0	1,405
2023	1,353	1,353	0	0	0	0	0	0	1,353
2024	1,368	1,368	0	0	0	0	0	0	1,368
2025	1,381	1,381	0	0	0	0	0	0	1,381
2026	1,395	1,395	0	0	0	0	0	0	1,395
2027	1,409	1,409	0	0	0	0	0	0	1,409

[1] Amounts shown for 2008 through 2017 represent historical values. Amounts shown for 2018 through 2027 represent forecast values.

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

(1) Year [1]	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2007/08	1,347	1,347	0	0	0	0	0	0	1,347
2008/09	1,436	1,436	0	0	0	0	0	0	1,436
2009/10	1,427	1,427	0	0	0	0	0	0	1,427
2010/11	1,272	1,272	0	0	0	0	0	0	1,272
2011/12	1,133	1,133	0	0	0	0	0	0	1,133
2012/13	1,034	1,034	0	0	0	0	0	0	1,034
2013/14	1,028	1,028	0	0	0	0	0	0	1,028
2014/15	1,161	1,161	0	0	0	0	0	0	1,161
2015/16	1,019	1,019	0	0	0	0	0	0	1,019
2016/17	879	879	0	0	0	0	0	0	879
2017/18	1,133	1,133	0	0	0	0	0	0	1,133
2018/19	1,147	1,147	0	0	0	0	0	0	1,147
2019/20	1,160	1,160	0	0	0	0	0	0	1,160
2020/21	1,211	1,211	0	0	0	0	0	0	1,211
2021/22	1,224	1,224	0	0	0	0	0	0	1,224
2022/23	1,177	1,177	0	0	0	0	0	0	1,177
2023/24	1,190	1,190	0	0	0	0	0	0	1,190
2024/25	1,202	1,202	0	0	0	0	0	0	1,202
2025/26	1,214	1,214	0	0	0	0	0	0	1,214
2026/27	1,226	1,226	0	0	0	0	0	0	1,226

[1] Amounts shown for 2007/08 through 2016/17 represent historical values. Amounts shown for 2017/18 through 2026/27 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year [1]	Total Sales to Ultimate Customers (including Sales for Resale)	Residential Conservation	Commercial/ Industrial Conservation	Utility Use & Losses	Net Energy for Load	Load Factor % [2]
2008	6,674	0	0	380	7,053	55%
2009	6,584	0	0	396	6,980	53%
2010	5,958	0	0	413	6,371	51%
2011	5,926	0	0	305	6,230	55%
2012	5,765	0	0	386	6,151	57%
2013	5,782	0	0	356	6,138	56%
2014	5,444	0	0	334	5,778	54%
2015	5,706	0	0	336	6,042	56%
2016	5,722	0	0	317	6,039	53%
2017	5,629	0	0	355	5,984	54%
2018	5,759	0	0	395	6,154	54%
2019	5,828	0	0	399	6,226	54%
2020	5,893	0	0	393	6,285	54%
2021	6,236	0	0	390	6,625	54%
2022	6,307	0	0	389	6,696	54%
2023	6,060	0	0	391	6,451	54%
2024	6,125	0	0	396	6,520	54%
2025	6,190	0	0	391	6,581	54%
2026	6,253	0	0	391	6,644	54%
2027	6,316	0	0	392	6,708	54%

[1] Amounts shown for 2008 through 2017 represent historical values. Amounts shown for 2018 through 2027 represent forecast values.
[2] The load factor reflects the annual calendar peak in the denominator (rather than, for example, the summer peak).

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2018	1,281	1,281	0	0	0	0	0	0	1,281
2019	1,284	1,284	0	0	0	0	0	0	1,284
2020	1,286	1,286	0	0	0	0	0	0	1,286
2021	1,328	1,328	0	0	0	0	0	0	1,328
2022	1,334	1,334	0	0	0	0	0	0	1,334
2023	1,277	1,277	0	0	0	0	0	0	1,277
2024	1,285	1,285	0	0	0	0	0	0	1,285
2025	1,290	1,290	0	0	0	0	0	0	1,290
2026	1,297	1,297	0	0	0	0	0	0	1,297
2027	1,304	1,304	0	0	0	0	0	0	1,304

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

Schedule 3.1b
Forecast of Summer Peak Demand (MW)
All-Requirements Project – High Case [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
2018	1,330	1,330	0	0	0	0	0	0	1,330
2019	1,358	1,358	0	0	0	0	0	0	1,358
2020	1,383	1,383	0	0	0	0	0	0	1,383
2021	1,448	1,448	0	0	0	0	0	0	1,448
2022	1,472	1,472	0	0	0	0	0	0	1,472
2023	1,426	1,426	0	0	0	0	0	0	1,426
2024	1,448	1,448	0	0	0	0	0	0	1,448
2025	1,468	1,468	0	0	0	0	0	0	1,468
2026	1,489	1,489	0	0	0	0	0	0	1,489
2027	1,509	1,509	0	0	0	0	0	0	1,509

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

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2017/18	1,111	1,111	0	0	0	0	0	0	1,111
2018/19	1,114	1,114	0	0	0	0	0	0	1,114
2019/20	1,116	1,116	0	0	0	0	0	0	1,116
2020/21	1,156	1,156	0	0	0	0	0	0	1,156
2021/22	1,162	1,162	0	0	0	0	0	0	1,162
2022/23	1,111	1,111	0	0	0	0	0	0	1,111
2023/24	1,118	1,118	0	0	0	0	0	0	1,118
2024/25	1,123	1,123	0	0	0	0	0	0	1,123
2025/26	1,128	1,128	0	0	0	0	0	0	1,128
2026/27	1,134	1,134	0	0	0	0	0	0	1,134

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

Schedule 3.2b
Forecast of Winter Peak Demand (MW)
All-Requirements Project – High Case [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
2017/18	1,154	1,154	0	0	0	0	0	0	1,154
2018/19	1,179	1,179	0	0	0	0	0	0	1,179
2019/20	1,201	1,201	0	0	0	0	0	0	1,201
2020/21	1,262	1,262	0	0	0	0	0	0	1,262
2021/22	1,284	1,284	0	0	0	0	0	0	1,284
2022/23	1,242	1,242	0	0	0	0	0	0	1,242
2023/24	1,261	1,261	0	0	0	0	0	0	1,261
2024/25	1,279	1,279	0	0	0	0	0	0	1,279
2025/26	1,296	1,296	0	0	0	0	0	0	1,296
2026/27	1,314	1,314	0	0	0	0	0	0	1,314

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/ Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2018	5,631	0	0	5,631	21	390	6,041	55%
2019	5,639	0	0	5,639	24	389	6,052	55%
2020	5,650	0	0	5,650	27	394	6,071	55%
2021	5,669	0	0	5,669	295	384	6,349	57%
2022	5,696	0	0	5,696	297	385	6,379	57%
2023	5,723	0	0	5,723	0	394	6,117	55%
2024	5,752	0	0	5,752	0	399	6,151	55%
2025	5,784	0	0	5,784	0	397	6,180	55%
2026	5,813	0	0	5,813	0	398	6,211	55%
2027	5,844	0	0	5,844	0	400	6,243	55%

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/ Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2018	5,843	0	0	5,843	21	401	6,266	55%
2019	5,962	0	0	5,962	25	408	6,395	55%
2020	6,070	0	0	6,070	29	407	6,506	55%
2021	6,176	0	0	6,176	321	401	6,898	57%
2022	6,281	0	0	6,281	327	402	7,010	57%
2023	6,381	0	0	6,381	0	412	6,793	54%
2024	6,478	0	0	6,478	0	418	6,897	54%
2025	6,575	0	0	6,575	0	414	6,989	54%
2026	6,669	0	0	6,669	0	415	7,084	54%
2027	6,761	0	0	6,761	0	417	7,178	54%

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 2017		Forecast - 2018		Forecast - 2019	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	879	428	1,133	475	1,147	481
February	847	377	1,104	417	1,118	423
March	938	431	873	439	883	444
April	1,128	472	999	455	1,011	460
May	1,198	555	1,148	530	1,162	537
June	1,203	558	1,258	586	1,273	592
July	1,243	624	1,262	631	1,277	638
August	1,263	640	1,307	640	1,322	647
September	1,178	531	1,195	569	1,210	575
October	1,146	521	1,100	512	1,113	517
November	871	412	847	437	856	442
December	917	436	882	463	892	468

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 has adopted a Net Metering Policy that promotes and facilitates ARP Participants' implementation of their Net Metering programs.

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 231,000 kWh of energy from the system. In 2017, FMPA's share of energy production amounted to 28,000 kWh.

In March 2018, the FMPA Executive Committee approved a 20-year power purchase agreement (among other enabling agreements) for a total of 58 MW-AC of solar energy as an ARP resource, which is estimated to achieve commercial operation by mid-2020. FMPA will include additional information on the solar project in future site plans as appropriate. The ARP solar entitlement is anticipated to increase the proportion of ARP energy derived from renewable generation. Such estimates are pending and are not included in the schedules that support this TYSP.

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 2017, FMPA purchased 23,000 MWh of energy from this renewable resource.

- In 2017, the Stanton Units 1 and 2 consumed 574,250 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 20.77% of the energy output of Stanton Unit 1 and 18.86% of the energy output of Unit 2 as of December 31, 2017. Thus, the ARP utilized 111,728 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.

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 videos
- Equipment and training for utility energy auditors

Since the inception of the program in 2008, the ARP Participants have allocated more than $7.3 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 of 0.5 percent of load over the 20-year planning horizon. 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, the key assumptions for which were subjected to a detailed refresh during calendar year 2017. 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. As of December 2017, ARP Participants had approximately 4,486 kW of solar photovoltaic renewable generation (DC) connected to the grid through their net metering programs.

As with the conservation programs, FMPA is currently not including the effects of its Participants' net metering 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. 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. FMPA continues to evaluate load management technologies in order to identify cost-effective load management programs for the ARP.

Section 5 Forecast of Facilities Requirements

5.1 ARP Planning Process

FMPA's integrated resource planning (IRP) policy 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 15 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 Case load forecast, the ARP currently does not require any additional resources from undesignated sources to maintain FMPA's 15% reserve margin through the end of the TYSP study period. Schedule 8 at the end of this section shows planned and prospective ARP generating resources changes during the next 10-year period, which include several planned upgrades to existing resource entitlement capacities as well as the assumed transfer of the City of Vero Beach's entitlements in certain coal and nuclear power plants to the ARP as of January 1, 2019 for capacity planning purposes.

5.3 Capacity and Power Purchase Requirements

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

- **Stanton A:** FMPA on behalf of the ARP has a contract for the purchase of 13 percent of the net operating capability of the Stanton A combined cycle facility from Southern Power Company. The initial term of the purchase ends in September 2023 and the contract includes two subsequent extension options. For 2018, the ARP's purchase from Stanton A amounts to 81 MW based on the current summer rating of the facility.
- **Oleander:** FMPA on behalf of the ARP 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 the contract 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. 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 included in Schedule 8.

As evidenced by Tables 5-1 and 5-2, the ARP expects to meet its generation capacity requirements and maintain a 15% reserve margin with existing resources through the end of the TYSP study period, or December 31, 2027. As a result of (i) FMPA's revised long-term load forecast as detailed herein, (ii) anticipated upgrades to plant capacity for resources used to serve ARP load throughout the study period, and (iii) the transfer of the City of Vero Beach's entitlement shares in certain coal and nuclear power plants to the ARP, which has been assumed to occur as of January 1, 2019 for capacity planning purposes, no additional resources will be required to meet generation capacity requirements with a 15% reserve margin. FMPA continually monitors and evaluates resource requirements, and will include additional information on the joint-venture solar project in future site plans, as appropriate.

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

Line No.	Resource Description	Summer Rating (MW)									
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear) [1]	35	48	46	46	46	46	46	46	46	46
2	Stanton Coal Plant [2]	177	214	222	222	222	222	222	222	222	222
3	Stanton CC Unit A [2]	44	44	44	44	44	44	44	44	44	44
4	Cane Island 1-4 [3]	684	684	684	684	684	684	684	684	684	699
5	Indian River CTs [2]	75	75	75	75	75	75	75	75	75	75
6	Treasure Coast Energy Center [4]	300	300	300	300	300	300	315	315	315	315
7	Stock Island Units	113	113	113	113	113	113	113	113	113	113
8	Sub Total Existing Resources	1,427	1,478	1,484	1,484	1,484	1,484	1,499	1,499	1,499	1,514
	Planned Resource Additions										
9	None [5]	-	-	-	-	-	-	-	-	-	-
10	Sub Total Planned Resource Additions	-	-	-	-	-	-	-	-	-	-
11	Total Installed Capacity	1,427	1,478	1,484	1,484	1,484	1,484	1,499	1,499	1,499	1,514
	Firm Capacity Import										
12	Stanton A Purchase [2]	81	81	81	81	81	81	-	-	-	-
13	Oleander Purchase	162	162	162	162	162	162	162	162	162	162
14	Peaking Purchase(s) [5]	-	-	-	-	-	-	-	-	-	-
15	Total Firm Capacity Import	243	243	243	243	243	243	162	162	162	162
16	Total Available Capacity	1,670	1,721	1,727	1,727	1,727	1,727	1,661	1,661	1,661	1,676

[1] Includes capacity from the St. Lucie Project. Assumes the transfer of Vero Beach's entitlement share in the Project to the ARP for summer 2019 and beyond. Amounts shown beginning 2020 have been reduced to reflect Green Cove Springs' conversion to CROD effective January 1, 2020.

[2] Capacities shown have been reduced to account for losses through the OUC transmission system (assumed to be 2.0% for planning period). For Stanton and Stanton II, assumes the transfer of Vero Beach's entitlement shares in the Stanton and Stanton II Projects to the ARP for summer 2019 and beyond.

[3] Reflects Cane Island 4 upgrade to increase plant capacity in 2027.

[4] Reflects Treasure Coast Energy Center upgrade to increase plant capacity in 2024.

[5] No additional capacity will be required to maintain a 15% reserve margin during the summer season.

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

Line No.	Resource Description	Winter Rating (MW)									
		2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear) [1]	36	50	48	48	48	48	48	48	48	48
2	Stanton Coal Plant [2]	177	214	222	222	222	222	222	222	222	222
3	Stanton CC Unit A [2]	47	47	47	47	47	47	47	47	47	47
4	Cane Island 1-4 [3]	711	711	711	711	711	711	711	711	711	726
5	Indian River CTs [2]	83	83	83	83	83	83	83	83	83	83
6	Treasure Coast Energy Center [4]	310	310	310	310	310	310	325	325	325	325
7	Stock Island Units	113	113	113	113	113	113	113	113	113	113
8	Sub Total Existing Resources	1,476	1,528	1,534	1,534	1,534	1,534	1,549	1,549	1,549	1,564
	Planned Resource Additions										
9	None [5]	-	-	-	-	-	-	-	-	-	-
10	Sub Total Planned Resource Additions	-	-	-	-	-	-	-	-	-	-
11	Total Installed Capacity	1,476	1,528	1,534	1,534	1,534	1,534	1,549	1,549	1,549	1,564
	Firm Capacity Import										
12	Stanton A Purchase [2]	87	87	87	87	87	87	-	-	-	-
13	Oleander Purchase	180	180	180	180	180	180	180	180	180	180
14	Peaking Purchase(s) [5]	-	-	-	-	-	-	-	-	-	-
15	Total Firm Capacity Import	267	267	267	267	267	267	180	180	180	180
16	Total Available Capacity	1,744	1,795	1,801	1,801	1,801	1,801	1,729	1,729	1,729	1,744

[1] Includes capacity from the St. Lucie Project. Assumes the transfer of Vero Beach's entitlement share in the Project to the ARP for summer 2019 and beyond. Amounts shown beginning 2020 have been reduced to reflect Green Cove Springs' conversion to CROD effective January 1, 2020.

[2] Capacities shown have been reduced to account for losses through the OUC transmission system (assumed to be 2.0% for planning period). For Stanton and Stanton II, assumes the transfer of Vero Beach's entitlement shares in the Stanton and Stanton II Projects to the ARP for summer 2019 and beyond.

[3] Reflects Cane Island 4 upgrade to increase plant capacity in 2027.

[4] Reflects Treasure Coast Energy Center upgrade to increase plant capacity in 2024.

[5] No additional capacity will be required to maintain a 15% reserve margin during the summer season.

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	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Nuclear [1]		Trillion BTU	3	3	4	4	4	4	4	4	4	4	4
2	Coal		000 Ton	406	204	209	204	213	210	212	230	238	241	215
	Residual													
3		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-
6		Total	000 BBL	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
7		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
9		CT	000 BBL	3	2	1	0	3	1	1	1	2	2	3
10		Total	000 BBL	3	2	1	0	3	1	1	1	2	2	3
	Natural Gas													
11		Steam [2]	000 MCF	201	360	370	361	376	372	376	407	421	427	380
12		CC	000 MCF	33,082	37,270	37,252	37,888	40,161	40,674	38,946	39,249	39,299	39,698	40,392
13		CT	000 MCF	473	316	237	161	358	243	290	303	413	503	906
14		Total	000 MCF	33,756	37,946	37,859	38,409	40,895	41,289	39,611	39,959	40,133	40,629	41,678
	Renewables [3]													
15		Biofuels	Billion BTU	225	232	232	232	232	232	232	232	232	232	232
16		Biomass	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
17		Geothermal	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
18		Hydro	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
19		Landfill Gas	Billion BTU	112	88	91	89	92	91	92	100	103	105	93
20		MSW	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
21		Solar	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
22		Wind	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
23		Other	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
24		Total	Billion BTU	337	320	323	321	324	323	324	332	335	337	325
25	Other		Trillion BTU	-	-	-	-	-	-	-	-	-	-	-

[1] Nuclear generation shown is the ARP Participants' Entitlement Shares in the St. Lucie Project.
[2] Includes natural gas used as an Igniter Fuel at the Stanton Energy Center.
[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 by FMPA.

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	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Annual Firm Inter-Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	294	312	402	391	376	390	390	377	390	390	376
3	Coal		GWh	915	441	447	440	459	455	459	501	523	529	472
	Residual													
4		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	1	1	0	0	1	0	0	0	1	1	1
11		Total	GWh	1	1	0	0	1	0	0	0	1	1	1
	Natural Gas													
12		Steam	GWh	20	34	34	33	35	35	35	38	40	40	36
13		CC [2]	GWh	4,679	5,309	5,290	5,376	5,692	5,764	5,509	5,546	5,560	5,609	5,714
14		CT	GWh	42	27	21	14	31	21	25	26	35	43	78
15		Total	GWh	4,741	5,369	5,345	5,423	5,758	5,819	5,569	5,610	5,634	5,692	5,828
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
	Renewables [3]													
17		Biofuels	GWh	23	23	23	23	23	23	23	23	23	23	23
18		Biomass	GWh	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	GWh	-	-	-	-	-	-	-	-	-	-	-
20		Hydro	GWh	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	GWh	11	8	8	8	8	8	8	9	10	10	9
22		MSW	GWh	-	-	-	-	-	-	-	-	-	-	-
23		Solar	GWh	-	-	-	-	-	-	-	-	-	-	-
24		Wind	GWh	-	-	-	-	-	-	-	-	-	-	-
25		Other	GWh	-	-	-	-	-	-	-	-	-	-	-
26		Total	GWh	33	31	31	31	32	32	32	32	33	33	32
27	Interchange [4]		GWh	-	-	-	-	-	-	-	-	-	-	-
28	Net Energy for Load		GWh	5,984	6,154	6,226	6,285	6,625	6,696	6,451	6,520	6,581	6,644	6,708

[1] Nuclear generation shown is the ARP Participants' 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.

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		Prime		Actual	Forecasted									
No.	Energy Source	Mover	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	4.9%	5.1%	6.5%	6.2%	5.7%	5.8%	6.0%	5.8%	5.9%	5.9%	5.6%
3	Coal		%	15.3%	7.2%	7.2%	7.0%	6.9%	6.8%	7.1%	7.7%	7.9%	8.0%	7.0%
	Residual													
4		Steam	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7		Total	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distillate													
8		Steam	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
9		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11		Total	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Natural Gas													
12		Steam	%	0.3%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.6%	0.6%	0.6%	0.5%
13		CC	%	78.2%	86.3%	85.0%	85.5%	85.9%	86.1%	85.4%	85.1%	84.5%	84.4%	85.2%
14		CT	%	0.7%	0.4%	0.3%	0.2%	0.5%	0.3%	0.4%	0.4%	0.5%	0.6%	1.2%
15		Total	%	79.2%	87.2%	85.8%	86.3%	86.9%	86.9%	86.3%	86.0%	85.6%	85.7%	86.9%
16	NUG		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Renewables													
17		Biofuels	%	0.4%	0.4%	0.4%	0.4%	0.4%	0.3%	0.4%	0.4%	0.4%	0.3%	0.3%
18		Biomass	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19		Geothermal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20		Hydro	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21		Landfill Gas	%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
22		MSW	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23		Solar	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24		Wind	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
25		Other	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
26		Total	%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
27	Interchange		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
28	Net Energy for Load		%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

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

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak
All-Requirements Power Supply Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Available Capacity	System Firm Summer Peak Demand [2]	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance	
Year	(MW) [1]	(MW)	(MW)	QF (MW)	(MW)	(MW)	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2018	1,427	243	0	0	1,670	1,307	364	28%	0	364	28%
2019	1,478	243	0	0	1,721	1,322	399	30%	0	399	30%
2020	1,484	243	0	0	1,727	1,336	391	29%	0	391	29%
2021	1,484	243	0	0	1,727	1,390	337	24%	0	337	24%
2022	1,484	243	0	0	1,727	1,405	322	23%	0	322	23%
2023	1,484	243	0	0	1,727	1,353	375	28%	0	375	28%
2024	1,499	162	0	0	1,661	1,368	293	21%	0	293	21%
2025	1,499	162	0	0	1,661	1,381	280	20%	0	280	20%
2026	1,499	162	0	0	1,661	1,395	266	19%	0	266	19%
2027	1,514	162	0	0	1,676	1,409	267	19%	0	267	19%

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

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (MW) [1]	Firm Capacity Import (MW) [1]	Firm Capacity Export (MW)	QF (MW)	Total Available Capacity (MW)	System Firm Winter Peak Demand [2] (MW)	Reserve Margin before Maintenance (MW)	Reserve Margin before Maintenance (% of Peak)	Scheduled Maintenance (MW)	Reserve Margin after Maintenance (MW)	Reserve Margin after Maintenance (% of Peak)
2017/18	1,476	267	0	0	1,744	1,133	610	54%	0	610	54%
2018/19	1,528	267	0	0	1,795	1,147	648	56%	0	648	56%
2019/20	1,534	267	0	0	1,801	1,160	642	55%	0	642	55%
2020/21	1,534	267	0	0	1,801	1,211	590	49%	0	590	49%
2021/22	1,534	267	0	0	1,801	1,225	577	47%	0	577	47%
2022/23	1,534	267	0	0	1,801	1,177	624	53%	0	624	53%
2023/24	1,549	180	0	0	1,729	1,190	539	45%	0	539	45%
2024/25	1,549	180	0	0	1,729	1,202	527	44%	0	527	44%
2025/26	1,549	180	0	0	1,729	1,214	515	42%	0	515	42%
2026/27	1,564	180	0	0	1,744	1,226	518	42%	0	518	42%

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

[2] System Firm Winter Peak Demand includes transmission losses for the ARP Participants served through FPL, DEF, and KUA.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No.	Location (County)	Unit Type	Fuel Primary	Fuel Alt.	Fuel Transport Primary	Fuel Transport Alt.	Alt. Fuel Days Use	Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Status
Resource Additions														
Changes to Existing Resources														
STANTON	1	ORANGE	ST	BIT		RR			1/1/2019			21	21	OT [1]
STANTON	2	ORANGE	ST	BIT		RR			1/1/2019			17	17	OT [1]
ST. LUCIE	2	ST LUCIE	NP	UR		TK			1/1/2019			13	14	OT [1]
STANTON	1	ORANGE	ST	BIT		RR			1/1/2020			6	6	OT [2]
STANTON	1	ORANGE	ST	BIT		RR			1/1/2020			1	1	OT [3]
ST. LUCIE	2	ST. LUCIE	NP	UR		TK			1/1/2020			(2)	(2)	OT [4]
TREASURE COAST	1	ST. LUCIE	CT	NG	DFO	PL	TK		1/1/2024			8	8	OT [2]
TREASURE COAST	1	ST. LUCIE	CA	WH	DFO	NA	TK		1/1/2024			8	8	OT [2]
CANE ISLAND	4CT	OSCEOLA	CT	NG		PL			1/1/2027			8	8	OT [2]
CANE ISLAND	4CW	OSCEOLA	CA	WH		NA			1/1/2027			8	8	OT [2]

[1] Reflects the transfer of Vero Beach's entitlement shares in the Stanton, Stanton II, and St. Lucie Projects to the ARP as of January 1, 2019 for capacity planning purposes.
[2] Upgrade to increase plant capacity. Reflects upgrade to ARP capacity and entitlements only.
[3] Upgrade to increase plant capacity. Reflects upgrade to KUA's entitlement, which the ARP uses to serve ARP load.
[4] Reflects capacity from Green Cove Springs' Power Entitlement Share in the St. Lucie Project, which will no longer be included in the capacity shown for the ARP upon the City's conversion to CROD effective January 1, 2020.

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.
- 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 684 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 on behalf of the ARP 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 FMPA 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
Planned and Proposed Transmission Additions for ARP Participants
2018 through 2029 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Beaches Energy Services	Guana tap to ring bus conversion			138 kV		2019
	Guana second 56 MVA transformer		56	138/27 kV		2019
Kissimmee						
	Lake Cecile-Third Transformer Addition-Complete Ring Bus		30	69 kV		6/2018
	Osceola Parkway Substation		80	69 kV		6/2021
	Lake Bryan	Osceola Parkway	111	69 kV	1	6/2021
	Lake Cecile	Osceola Parkway	111	69 kV	1	6/2021
	Domingo Toro Substation		120	69 kV		6/2019
	Carl Wall	Domingo Toro	111	69 kV	1	6/2019
	Carl Wall	Domingo Toro	111	69 kV	2	6/2019
	Hansel	Domingo Toro	111	69 kV	1	6/2019
	OUC STC Central	Domingo Toro	111	69 kV	1	6/2019