Navid Nowakhtar
Business Development and Resource Planner

Florida Public Service Commission
Donald Phillips
Division of Engineering
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
E-Filing addresses: DPhillip@psc.state.fl.us;

Re: FMPA's 2022 Ten-Year Site Plan

March 31, 2022

Dear Donald:

Pursuant to Rule 25-22.071(1) Florida Administrative Code and pursuant to the FPSC staff's email dated March 7, 2022, FMPA is hereby submitting an electronic copy of its 2022 Ten-Year Site Plan and the associated schedules and tables. All additional responses required by Data Request #1 will be e-mailed and filed electronically on or before May 6, 2022, as indicated in the March 7 email. Please do not hesitate to contact me at (321) 239-1028 if you have any questions.

Sincerely,

Navid Nowakhtar
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Navid Nowakhtar
Resource and Strategic Planning Manager

Enc.

cc. File

TEN-YEAR SITE PLAN

2022-2031

Submitted to
Florida Public Service Commission
April 1, 2022

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819
(407) 355-7767

FLORIDA MUNICIPAL POWER AGENCY

2022 Ten-Year Site Plan

April 1, 2022

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Appendices

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 to participate in that project. FMPA currently has six such power supply projects – Stanton, Tri-City, Stanton II, St. Lucie, Florida Municipal Solar Project Phase I, and Florida Municipal Solar Project Phase II. FMPA's TYSP is focused on the resources of, and planning for, the ARP.

The total summer capacity of ARP resources for the year 2022 is 1,745 MW. This capacity is comprised of ARP Participant-owned resources, ARP Participant and ARP entitlements and ownership shares in nuclear, coal and gas-fired power plants located in the State of Florida, ARP owned resources, and power purchase agreements, and is summarized below in Table ES-1.

Table ES-1
FMPA ARP Summer 2022 Capacity Resources

Resource Category	Summer Capacity (MW)
Nuclear (Excluded Resource and ARP)	48
ARP System Generation	1,437
Power Purchases excluding Solar	243
Power Purchases of Solar	16
Net Total 2022 ARP Resources [1]	1,745

[1] Totals may not add due to rounding

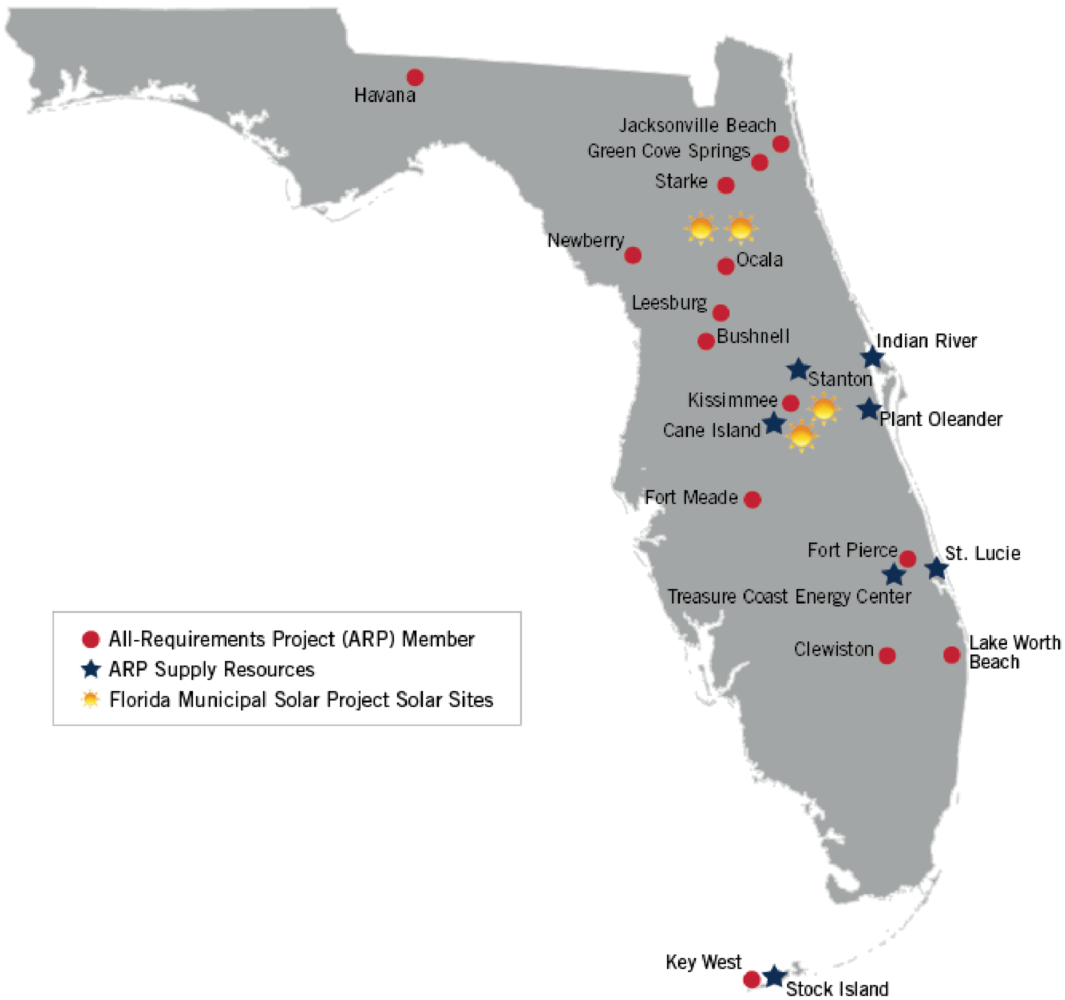
The ARP expects to meet its generation capacity requirements and maintain a 15% reserve margin with existing resources through the end of 2024. For the remainder of the TYSP study period (through December 31, 2031), FMPA anticipates additional seasonal (summer) peaking purchases, which could be comprised of additional solar (as assumed herein as part of the ARP's Phase III Solar), energy storage, offsets from load management, and reserve capacity will be required to maintain a 15% reserve margin. The projected peak native ARP summer load, inclusive of sales for resale, is 1,509 MW in 2022 and 1,439 MW in 2031, with reductions driven solely from assumed changes in sales for resale. FMPA is expecting to no longer burn coal after 2027. One jointly owned coal unit (Stanton 1) is scheduled to retire in 2025, and the second is expected to undergo a conversion to natural gas in 2027. FMPA will continue to evaluate and develop sufficient, cost-effective resource alternatives for the ARP through its integrated resource planning process and work to optimize reserve levels to reduce costs for the ARP Participants.

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 six years (the 6th year being subject to an extension that has been finalized with the City). For the first three years of the agreement, FMPA supplied peaking power to Bartow for its needs above 40 MW. In 2022 and 2023, FMPA will supply Bartow's full-requirements power supply needs. Additionally, the ARP began supplying the City of Winter Park wholesale capacity and energy on January 1, 2019 under an agreement that will run for nine years. Through 2027, the ARP will serve Winter Park on a partial requirements basis, net of other existing Winter Park wholesale power agreements. In 2020, FMPA entered into a long-term agreement to supply Williston's full-requirements power supply needs from January 2021 through the end of 2027. In 2021, FMPA entered into a long-term agreement to supply Alachua on a partial-requirements basis, net of other existing Alachua wholesale power agreements, from April 2022 through the end of 2027. Additionally, (i) the ARP has entered into a short-term wholesale power agreement with Tampa Electric to supply seasonal firm capacity and energy on an as-scheduled basis through February 2022, and (ii) the ARP has entered into an agreement to provide no greater than 15 MW of capacity to the City of Homestead through the end of 2026. The projections of future ARP obligations for Bartow, Winter Park, Williston, Alachua, Tampa Electric, and Homestead are included in the ARP's load and resource balance and all TYSP schedules herein.

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, some of which achieved commercial operation in 2020, with full deployment anticipated in 2023. In February 2020, the ARP further expanded solar in the portfolio by approving a second 20-year power purchase agreement for approximately 96 MW-AC of solar energy as an ARP resource, which is estimated to achieve commercial operation by 2024. The combined ARP solar entitlement will significantly increase the proportion of ARP energy derived from renewable generation, which FMPA has included in its energy mix projections herein. Furthermore, as part of the 2022 TYSP, it has been assumed herein that the ARP will procure an additional 100 MW of solar resources (Solar Phase III) with an estimated in-service year of 2026, in the form of a power purchase agreement. This is estimated to increase the percentage of solar in the portfolio to over 10% of delivered energy.

A map of the ARP Participants and FMPA's power resources as of December 31, 2021 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 14 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, 14 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 Lake Worth Beach has exercised the right to modify its ARP participation by implementation of a Contract Rate of Delivery (CROD). The CROD amount for Lake Worth Beach pursuant to contract terms is 0 MW. While Lake Worth Beach remains a participant in the ARP, effective January 1, 2014, they no longer are purchasing capacity and energy from the ARP and no longer have a representative 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. Mike Eastburn is the interim City Manager and 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 https://www.clewiston-fl.gov/.

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. Jan Bagnall 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. Javier Cisneros, 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. Steve Kennedy is the City Manager. 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. Tracy Smith 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. 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. Brian Horton 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. Brad Chase 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 Director, and Mike New is the City Manager. The City's service area is approximately 3 square miles. For more information about the City of Newberry, please visit www.newberryfl.gov.

City of Ocala

The City of Ocala, doing business as Ocala Electric Utility, is located in central Florida in Marion County. The City joined the ARP in May 1986. Sandra Wilson is the City Manager. Doug Peebles 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. Russell Mullins 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 five other power supply projects as discussed below.

St. Lucie Project

On May 12, 1983, FMPA purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit located in St. Lucie County. St. Lucie Unit No. 2 was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fourteen FMPA Members and the ARP 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

Participant	% Entitlement	Participant	% 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
ARP	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. Five FMPA Members and the ARP 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

Participant	% Entitlement	Participant	% Entitlement
Fort Pierce	24.390	Homestead	12.195
Kissimmee	12.195	Lake Worth	16.260
Starke	2.439	ARP	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

Participant	% 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. Six FMPA Members and the ARP 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

Participant	% Entitlement	Participant	% Entitlement
Fort Pierce	16.4880	Homestead	8.2443
Key West	9.8932	Kissimmee	32.9774
St. Cloud	14.6711	Starke	1.2366
ARP	16.4887		

Solar Projects

In March 2018, the FMPA Board of Directors approved the formation of the Florida Municipal Solar Project Phase I, as a sixth FMPA power supply project, which has entered a power purchase agreement for solar energy on behalf of its participants, with full deployment anticipated in 2023. The power purchase agreement represents a 57.0 MW-ac share of a 74.5 MW-ac solar facility, the remaining share of which certain ARP participants have entered into an agreement to purchase. Six FMPA Members are participants in the Florida Municipal Solar Project with the following entitlements as shown in Table 1-5. Additionally, five FMPA Members are participating in the Florida Municipal Solar Project Phase II, the formation of which was approved by the FMPA Board of Directors in February 2020. The total entitlement is approximately 54 MW-AC and is allocated as shown in Table 1-6.

Table 1-5
Florida Municipal Solar Project Participants

Participant	% Entitlement
Alachua	15.789
Bartow	22.807
Homestead	17.544
Lake Worth	17.544
Wauchula	8.772
Winter Park	17.544

Table 1-6
Florida Municipal Solar Project Phase II Participants

Participant	% Entitlement
Homestead	9.337
Lake Worth Beach	49.580
Mount Dora	3.735
New Smyrna Beach	18.674
Winter Park	18.674

1.4 Summary of Projects

Table 1-7 provides a summary of FMPA project participation as of December 31, 2021.

Table 1-7
Summary of FMPA Power Supply Project Participants

Participant	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Power Supply Project	Stanton II Project	Florida Municipal Solar Project	Florida Municipal Solar Project Phase II
City of Alachua	X					X	
City of Bartow						X	
City of Bushnell				X			
City of Clewiston	X			X			
City of Ft. Meade	X			X [1]			
Ft. Pierce Utilities Authority	X	X	X	X	X		
City of Green Cove Springs	X			X [2]			
Town of Havana				X			
City of Homestead	X	X	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 Beach	X	X		X [3]		X	X
City of Leesburg	X			X			
City of Moore Haven	X						
City of Mount Dora							X
City of Newberry	X			X			
City of New Smyrna Beach	X						X
City of Ocala				X			
City of St. Cloud					X		
City of Starke	X	X		X	X		
City of Wauchula						X	
City of Winter Park						X	X
ARP	X [4]	X [4]			X [4]		

[1] Effective January 1, 2015, the City of Ft. Meade exercised the right to modify its ARP full requirements membership (CROD).
[2] Effective January 1, 2020, the City of Green Cove Springs will have exercised the right to modify its ARP full requirements membership (CROD).
[3] Effective January 1, 2014, the City of Lake Worth exercised the right to modify its ARP full requirements membership (CROD).
[4] Pursuant to the sale of the City of Vero Beach's electric system to Florida Power and Light in 2018, the ARP took entitlement to Vero Beach shares of the St. Lucie, Stanton, and Stanton II Projects.

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 and ARP entitlements and ownership shares in nuclear, coal and gas-fired power plants, ARP owned resources, and power purchase agreements. The supply-side resources for the ARP for the 2022 summer season are shown in Table 2-1.

Table 2-1
ARP Supply-Side Resources Summer 2022

Resource Category	Summer Capacity (MW)
1) Nuclear (Excluded Resource and ARP)	48
2) ARP System Generation	
Existing	1,437
New	-
Sub Total ARP System Generation	1,437
3) Power Purchases excluding Solar	243
Power Purchases of Solar	16
Total 2022 ARP Resources	1,745

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

1) **Excluded Resources (Nuclear):** A number of the ARP Participants, as well as the ARP (separate and distinct from such 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 the ARP Participants' individual 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's entitlement to the St. Lucie Project, as of the closing of the sale of the City of Vero

Beach's electric system to Florida Power and Light, is included in the ARP as a resource and a cost of the ARP. The ARP provides the balance of capacity and energy requirements for these ARP Participants (unless otherwise limited by CROD). Full Requirements ARP Participants' excluded resources are included 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 and the ARP's entitlements in the St. Lucie, Stanton, Tri-City, and Stanton II Projects (as applicable). FMPA has operational control of the ARP's and ARP Participants' capacity and energy from these resources, and such capacity and energy are dedicated solely to serving the ARP. OUC, the majority owner and operator of the assets included in the Stanton and Stanton II projects, has announced its intention to convert Stanton II to natural gas in 2027 and has further announced Stanton I's retirement in 2025. The ARP has conservatively planned for sufficient reserve capacity to replace Stanton I during the summer of 2025. If retirements and refiring occur as scheduled, coal fired generation will be removed from the ARP's fleet by the end of 2027.

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, 2021 includes capacity and energy purchased from NextEra from their Stanton Unit A and Oleander Unit 5 facilities. In addition, the ARP purchases solar energy from Florida Renewable Partners, LLC beginning in Summer of 2020 and from Origis Energy beginning no later than 2024 and has included this solar energy (including estimated dependable capacity to serve peak demand) in all schedules herein.

Information regarding existing ARP generation resources as of December 31, 2021, 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). 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 the 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 and the City of Winter Park are made across DEF's transmission system. Sales to the City of Homestead are made across FPL's transmission system. Sales to Tampa Electric are contingent upon the availability of firm transmission on Tampa Electric's system for delivery of capacity and energy from the ARP's Cane Island Power Park resources. Sales to Williston and Alachua are transmitted across the DEF 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 FPL, both at 138 kV. FPUA's Hartman Substation interconnects with FPL's Emerson Substation via one transmission line, and FPL's Midway Substation via two transmission lines. The Emerson and Midway #2 lines have FPL tapped substations along their route. The second interconnection point for FPUA is at the FPL owned Julia Substation (formerly jointly owned between COVB and FPUA and known as County Line). Julia Substation connects to FPUA's Garden City (No. 2) Substation and to FPL's Emerson 138 kV Substation and Canal 138 kV Substation. The tie line from Julia Substation to FPUA's Garden City substation is owned by FPUA.

KEYS

[2] The City of Lake Worth Beach's transmission system description is not being provided because Lake Worth Beach directly reports to the FRCC on their own system.

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 138 kV transmission system that interconnects to FPL's Farmlife 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 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 11 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 Domingo Torro 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 facilities have interconnections with both 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. The OEU Ergle, Dearmin and Shaw Substations each have two auto-transformers to provide transformation from 230 kV to 69 kV. 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 Valley 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 two radial 3.5-mile 138 kV transmission lines from FPL's McCarthy Substation (formerly owned by the City of Clewiston) 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 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 modify certain ARP Participant 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 modify certain ARP Participant points of delivery.

Schedule 1
Existing Generating Facilities as of December 31, 2021

(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)
Nuclear												
St Lucie	2	St Lucie	NP	UR	-	TK	-	08/83	NA	891	48 [2]	50 [2]
Total Nuclear Resources											48	50
ARP System Generation												
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	116 [3]	116 [3]
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	05/25	465	106 [4]	106 [4]
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	44 [5]	47 [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											1,437	1,485
Total Generation Resources											1,486	1,536

[1] Capabilities shown are as of December 31, 2021. 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 and the ARP's entitlement share in the St. Lucie Project.
[3] Amounts shown reflect the total capacity available to the ARP to serve ARP load from Stanton 1.
[4] Amounts shown reflect the total capacity available to the ARP to serve ARP load from Stanton 2.
[5] Amounts shown reflect the ARP's (3.5%) and KUA's (3.5%) ownership interests in Stanton A.
[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

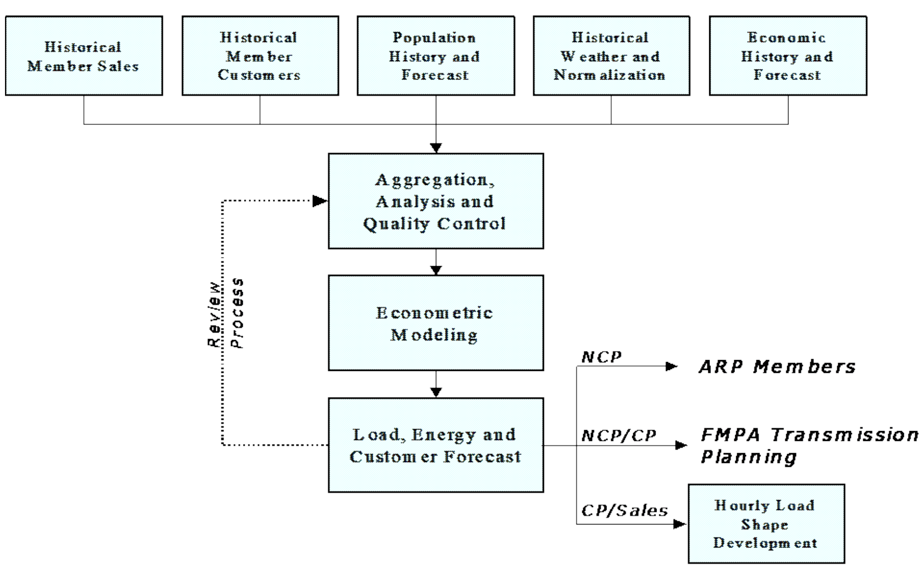
3.1 Introduction

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. Additional wholesale obligations of the ARP (e.g. Bartow, Winter Park, Williston, Alachua) are projected using a similar methodology. The following discussion summarizes the load forecasting process and the results of the ARP 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 2022 through 2041. 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 the Bureau of Economic and Business Research (BEBR) at the University of Florida 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 a rolling thirty-year average.

The Forecast reflects the City of Fort Meade's and the City of Green Cove Springs' establishment of Contract Rate of Delivery (CROD). However, both Ft. Meade and Green Cove Springs have executed a supplemental agreement with the ARP such that the ARP will serve all of Ft. Meade's and Green Cove Springs' load for the majority of the TYSP study period as if such Participants had not effectuated CROD, and this incremental load is included in the ARP's resource balance herein over the forecast horizon. 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 long-term economic uncertainty. The methodology and results of the High and Low 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 High and Low 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 2021. 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 a rolling thirty-year average of weather conditions, as reported by NOAA.

3.5.3 Economic Data

BEBR and Woods & Poole Economics, both nationally recognized providers of economic data, provided both historical and projected economic and demographic data for each of the 14 counties in which the ARP Participants' service territories reside (the service territory of Beaches includes portions of both Duval and St. Johns Counties). This data includes county population, households, employment, personal income, retail sales, and gross domestic product. Although all of the data was not necessarily used in each of the forecast equations, each was examined for its potential to explain changes in the ARP Participants' historical electric sales.

3.5.4 Real Electricity Price Data

The real price of electricity was derived from a twelve month or multi-year moving average of real average revenue. Projected real electricity prices were assumed to increase at a rate of 0.1% per year, generally based on projections provided by the Energy Information Administration in the 2021 Annual Energy Outlook for Florida.

3.6 Overview of Results

3.6.1 Base Case Forecast

The results of the Forecast show that the Base Case ARP forecast summer coincident peak (CP) demand and NEL for Calendar Year 2022, inclusive of sales for resale and transmission losses, are 1,509 MW and 7,172 GWh, respectively.

3.6.2 Economic and Other Sources of Uncertainty of the Forecast

In addition to the Base Case forecast, which relies on base case projections of future economic conditions, FMPA has developed high and low economic forecasts, referred to herein as the High and Low cases, intended to capture the volatility resulting from deviations from base case economic conditions equivalent to 90 percent of potential occurrences.

While BEBR does not publish information regarding the potential error of their projections, FMPA relied on such statistics from Woods & Poole, which relies on a similar underlying data set and methodology. Woods & Poole publishes several statistics that define the average amount by which various projections they have prepared through time are different from actual results. FMPA utilizes these statistics to develop ranges of the trends of economic activity and population representing approximately 90% of potential outcomes (i.e., 1.7 standard deviations) and re-simulates our econometric models using these alternative futures. The High and Low cases reflect the results of these revised simulations, which reflect increasing load forecast uncertainty over time commensurate with increased forecast error over time inherent in the economic projections.

Additional sources of load uncertainty are closely monitored by FMPA and are fused into the planning process for the ARP. Recent events across the national power grid that have stressed the ability of certain regions to provide service under extreme weather conditions, as well as the pace with which transportation is electrified and could result in significant load growth are key areas of focus over the current and future study horizons.

FMPA recurrently evaluates severe weather scenarios. These scenarios simulate cold-stressed temperatures at weather stations near the ARP loads to determine the differential that could be experienced with persistent cold as compared to various prior winter peak conditions (e.g., 1989 and 2010 winters, 90% confidence interval for HDD) when controlling for organic load growth that has occurred (absent weather deviations) since that time. Such scenarios, among other scenarios, are considered in operational planning to support reliable dispatch of wholly owned natural gas generation. FMPA has allocated a budget for weatherization of wholly owned natural gas units as deemed necessary. FMPA intends to continue to maintain dual-fuel capabilities on wholly owned units and maintain natural gas reserves into the future to support reliable operations in extreme weather.

A significant transition in the transportation sector from internal combustion engine gasoline-fueled to electric vehicles (EV) over the next few decades is expected. FMPA continues to monitor these actual and projected trends. However, to date, the adoption of EVs has not been discernable in the historical consumption data. FMPA expects that an explicit projection of the impact of increased EV adoption will be infused into the forecast in future iterations.

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 Case, and Schedules 3.1b and 3.2b present the High Case. Schedule 4 presents the actual (2021) and forecasted (Base Case for 2022 and 2023) 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], [2]	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
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	211,026	13,137	2,680	38,337	69,893
2016	NA	NA	2,844	214,422	13,264	2,711	39,004	69,511
2017	NA	NA	2,791	218,399	12,781	2,675	39,300	68,074
2018	NA	NA	2,899	221,799	13,072	2,707	39,347	68,807
2019	NA	NA	2,965	226,405	13,095	2,721	39,694	68,561
2020	NA	NA	3,100	230,856	13,426	2,626	40,262	65,216
2021	NA	NA	3,109	235,647	13,195	2,685	40,771	65,849
2022	NA	NA	3,090	239,456	12,905	2,752	41,329	66,588
2023	NA	NA	3,104	242,642	12,793	2,808	41,809	67,174
2024	NA	NA	3,143	245,830	12,787	2,841	42,178	67,348
2025	NA	NA	3,192	249,011	12,819	2,868	42,506	67,473
2026	NA	NA	3,240	252,158	12,849	2,894	42,829	67,566
2027	NA	NA	3,287	255,278	12,877	2,919	43,150	67,646
2028	NA	NA	3,333	258,475	12,896	2,943	43,470	67,703
2029	NA	NA	3,377	261,671	12,904	2,966	43,787	67,740
2030	NA	NA	3,423	264,832	12,924	2,989	44,102	67,777
2031	NA	NA	3,470	267,823	12,955	3,012	44,410	67,820

[1] Amounts shown for 2012 through 2021 represent historical values. Amounts shown for 2022 through 2031 represent forecast values.
[2] Loads and customer counts only reflects the ARP. Sales to other municipal utilities 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
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	1,768,700	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	5,630
2018	1	1	992,000	0	56	107	5,771
2019	2	1	1,657,000	0	56	98	5,842
2020	1	1	842,100	0	56	94	5,876
2021	1	1	1,336,000	0	56	92	5,944
2022	1	1	1,289,033	0	57	93	5,993
2023	1	1	1,289,033	0	57	93	6,064
2024	1	1	1,289,033	0	57	94	6,136
2025	1	1	1,289,033	0	57	94	6,213
2026	1	1	1,289,033	0	57	95	6,287
2027	1	1	1,289,033	0	57	95	6,360
2028	1	1	1,289,033	0	57	96	6,430
2029	1	1	1,289,033	0	57	96	6,497
2030	1	1	1,289,033	0	57	97	6,567
2031	1	1	1,289,033	0	57	97	6,637

[1] Amounts shown for 2012 through 2021 represent historical values. Amounts shown for 2022 through 2031 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], [2]	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
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	354	5,984	0	257,700
2018	12	356	6,139	0	261,147
2019	100	348	6,290	0	266,100
2020	389	371	6,637	0	271,119
2021	709	285	6,937	0	276,418
2022	849	330	7,172	0	280,786
2023	822	322	7,209	0	284,452
2024	395	333	6,864	0	288,010
2025	482	315	7,010	0	291,518
2026	482	311	7,080	0	294,988
2027	395	301	7,056	0	298,429
2028	0	301	6,732	0	301,945
2029	0	262	6,760	0	305,459
2030	0	203	6,770	0	308,935
2031	0	186	6,823	0	312,234

[1] Amounts shown for 2012 through 2021 represent historical values. Amounts shown for 2022 through 2031 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
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	1,281	1,281	0	0	0	0	0	0	1,281
2019	1,349	1,349	0	0	0	0	0	0	1,349
2020	1,463	1,463	0	0	0	0	0	0	1,463
2021	1,467	1,467	0	0	0	0	0	0	1,467
2022	1,509	1,509	0	0	0	0	0	0	1,509
2023	1,508	1,508	0	0	0	0	0	0	1,508
2024	1,450	1,450	0	0	0	0	0	0	1,450
2025	1,474	1,474	0	0	0	0	0	0	1,474
2026	1,489	1,489	0	0	0	0	0	0	1,489
2027	1,490	1,490	0	0	0	0	0	0	1,490
2028	1,415	1,415	0	0	0	0	0	0	1,415
2029	1,427	1,427	0	0	0	0	0	0	1,427
2030	1,428	1,428	0	0	0	0	0	0	1,428
2031	1,439	1,439	0	0	0	0	0	0	1,439

[1] Amounts shown for 2012 through 2021 represent historical values. Amounts shown for 2022 through 2031 represent forecast values.

Schedule 3.2
History and Forecast of Winter 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
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	1,228	1,228	0	0	0	0	0	0	1,228
2018/19	950	950	0	0	0	0	0	0	950
2019/20	1,165	1,165	0	0	0	0	0	0	1,165
2020/21	1,351	1,351	0	0	0	0	0	0	1,351
2021/22	1,296	1,296	0	0	0	0	0	0	1,296
2022/23	1,285	1,285	0	0	0	0	0	0	1,285
2023/24	1,227	1,227	0	0	0	0	0	0	1,227
2024/25	1,250	1,250	0	0	0	0	0	0	1,250
2025/26	1,265	1,265	0	0	0	0	0	0	1,265
2026/27	1,265	1,265	0	0	0	0	0	0	1,265
2027/28	1,198	1,198	0	0	0	0	0	0	1,198
2028/29	1,210	1,210	0	0	0	0	0	0	1,210
2029/30	1,210	1,210	0	0	0	0	0	0	1,210
2030/31	1,222	1,222	0	0	0	0	0	0	1,222

[1] Amounts shown for 2011/12 through 2020/21 represent historical values. Amounts shown for 2021/22 through 2030/31 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], [2]	Total Sales to Ultimate Customers (including Sales for Resale)	Residential Conservation	Commercial/ Industrial Conservation	Utility Use & Losses	Net Energy for Load	Load Factor % [2]
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	5,630	0	0	354	5,984	54%
2018	5,783	0	0	356	6,139	55%
2019	5,942	0	0	348	6,290	53%
2020	6,266	0	0	371	6,637	52%
2021	6,653	0	0	285	6,937	54%
2022	6,842	0	0	330	7,172	54%
2023	6,887	0	0	322	7,209	55%
2024	6,531	0	0	333	6,864	54%
2025	6,695	0	0	315	7,010	54%
2026	6,769	0	0	311	7,080	54%
2027	6,755	0	0	301	7,056	54%
2028	6,430	0	0	301	6,732	54%
2029	6,497	0	0	262	6,760	54%
2030	6,567	0	0	203	6,770	54%
2031	6,637	0	0	186	6,823	54%

[1] Amounts shown for 2012 through 2021 represent historical values. Amounts shown for 2022 through 2031 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)	(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
2022	1,496	1,496	0	0	0	0	0	0	1,496
2023	1,476	1,476	0	0	0	0	0	0	1,476
2024	1,404	1,404	0	0	0	0	0	0	1,404
2025	1,413	1,413	0	0	0	0	0	0	1,413
2026	1,415	1,415	0	0	0	0	0	0	1,415
2027	1,405	1,405	0	0	0	0	0	0	1,405
2028	1,326	1,326	0	0	0	0	0	0	1,326
2029	1,328	1,328	0	0	0	0	0	0	1,328
2030	1,323	1,323	0	0	0	0	0	0	1,323
2031	1,325	1,325	0	0	0	0	0	0	1,325

[1] Values represent predicted summer peak demand under pessimistic economic conditions.

Schedule 3.1b
Forecast of Summer Peak Demand (MW)
All-Requirements Project – High 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
2022	1,522	1,522	0	0	0	0	0	0	1,522
2023	1,540	1,540	0	0	0	0	0	0	1,540
2024	1,495	1,495	0	0	0	0	0	0	1,495
2025	1,533	1,533	0	0	0	0	0	0	1,533
2026	1,561	1,561	0	0	0	0	0	0	1,561
2027	1,573	1,573	0	0	0	0	0	0	1,573
2028	1,503	1,503	0	0	0	0	0	0	1,503
2029	1,524	1,524	0	0	0	0	0	0	1,524
2030	1,530	1,530	0	0	0	0	0	0	1,530
2031	1,550	1,550	0	0	0	0	0	0	1,550

[1] Values represent predicted summer peak demand under optimistic economic 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
2021/22	1,295	1,295	0	0	0	0	0	0	1,295
2022/23	1,265	1,265	0	0	0	0	0	0	1,265
2023/24	1,195	1,195	0	0	0	0	0	0	1,195
2024/25	1,205	1,205	0	0	0	0	0	0	1,205
2025/26	1,208	1,208	0	0	0	0	0	0	1,208
2026/27	1,199	1,199	0	0	0	0	0	0	1,199
2027/28	1,127	1,127	0	0	0	0	0	0	1,127
2028/29	1,131	1,131	0	0	0	0	0	0	1,131
2029/30	1,126	1,126	0	0	0	0	0	0	1,126
2030/31	1,131	1,131	0	0	0	0	0	0	1,131

[1] Values represent predicted winter peak demand under pessimistic economic conditions.

Schedule 3.2b
Forecast of Winter Peak Demand (MW)
All-Requirements Project – High 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
2021/22	1,297	1,297	0	0	0	0	0	0	1,297
2022/23	1,305	1,305	0	0	0	0	0	0	1,305
2023/24	1,259	1,259	0	0	0	0	0	0	1,259
2024/25	1,295	1,295	0	0	0	0	0	0	1,295
2025/26	1,320	1,320	0	0	0	0	0	0	1,320
2026/27	1,331	1,331	0	0	0	0	0	0	1,331
2027/28	1,267	1,267	0	0	0	0	0	0	1,267
2028/29	1,287	1,287	0	0	0	0	0	0	1,287
2029/30	1,291	1,291	0	0	0	0	0	0	1,291
2030/31	1,310	1,310	0	0	0	0	0	0	1,310

[1] Values represent predicted winter peak demand under optimistic economic 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 %
2022	5,947	0	0	5,947	849	328	7,124	62%
2023	5,942	0	0	5,942	822	316	7,080	61%
2024	5,950	0	0	5,950	395	324	6,668	58%
2025	5,966	0	0	5,966	482	303	6,751	58%
2026	5,988	0	0	5,988	482	296	6,766	58%
2027	6,013	0	0	6,013	395	284	6,692	58%
2028	6,039	0	0	6,039	0	282	6,321	54%
2029	6,065	0	0	6,065	0	245	6,310	54%
2030	6,094	0	0	6,094	0	195	6,289	54%
2031	6,125	0	0	6,125	0	177	6,302	54%

[1] Values represent predicted net energy for load under pessimistic economic conditions.

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
2022	6,038	0	0	6,038	849	332	7,219	61%
2023	6,185	0	0	6,185	822	328	7,335	61%
2024	6,320	0	0	6,320	395	343	7,057	57%
2025	6,455	0	0	6,455	482	327	7,264	58%
2026	6,580	0	0	6,580	482	326	7,388	58%
2027	6,699	0	0	6,699	395	318	7,413	57%
2028	6,812	0	0	6,812	0	320	7,132	54%
2029	6,919	0	0	6,919	0	279	7,198	54%
2030	7,027	0	0	7,027	0	211	7,238	54%
2031	7,135	0	0	7,135	0	194	7,329	54%

[1] Values represent predicted net energy for load under optimistic economic 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 - 2021		Forecast - 2022		Forecast - 2023	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,020	493	1,296	547	1,285	555
February	1,351	483	1,212	481	1,198	488
March	1,144	511	1,103	510	1,137	529
April	1,199	517	1,214	533	1,225	538
May	1,375	626	1,357	628	1,368	634
June	1,386	659	1,444	682	1,447	684
July	1,428	706	1,435	735	1,433	732
August	1,467	734	1,509	745	1,508	743
September	1,312	652	1,413	676	1,410	674
October	1,314	604	1,303	609	1,300	607
November	941	461	1,089	498	1,096	497
December	937	492	1,041	528	1,048	528

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 333,000 kWh of energy from the system. In 2021, FMPA's share of energy production amounted to 16,500 kWh.

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, some of which achieved commercial operation in 2020, with full deployment anticipated in 2023. In February 2020, the ARP further expanded solar in the portfolio by approving a second 20-year power purchase agreement for approximately 96 MW-AC of solar energy as an ARP resource, which is estimated to achieve commercial operation by 2024. This TYSP has assumed additional solar capacity of 100 MW (Solar Phase III) with an estimated in-service year of 2026.

The ARP solar entitlements, both expected to be online and planned, will significantly increase the proportion of ARP energy derived from renewable generation. Such estimates are 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 2021, FMPA purchased 40,905 MWh of energy from this renewable resource.

- In 2021, the Stanton Units 1 and 2 consumed 546,720 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 26.02% of the energy output of Stanton Unit 1 and 23.08% of the energy output of Unit 2 as of December 31, 2021. Thus, the ARP utilized 134,861 MMBtu of landfill gas as a supplemental fuel source[3].

These renewable resources help the ARP meet current and future energy needs.

FMPA's forecast of renewable energy is provided in Schedule 6.1 of Section 5.

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

[3] For 2019 and beyond, Stanton landfill gas usage includes the ARP's distinct entitlement to Stanton 1 and Stanton 2 capacity and energy.

Since the inception of the program in 2008, the ARP Participants have allocated approximately $10.4 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. 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 September 2021, ARP Participants had approximately 24,100 kW of solar photovoltaic renewable generation (AC) connected to the grid through their net metering programs.

The ARP load forecast reflected in this TYSP projects that the impact of ARP Participants' net metering programs will exceed the 0.5% FMPA set threshold of significance over the study period. Consequently, FMPA has included the estimated effects of net metering in the forecast schedules included herein. FMPA intends to continue to monitor the trend in installations of distributed generation across the Participants' systems and adapt future forecasts accordingly.

4.5 Load Management Program

Currently, there are no ARP-sponsored load management programs in place. FMPA is in discussions with ARP Members to identify the potential loads or behind-the-meter generation that could be viable load management resources. If cost-effective, FMPA could utilize these types of resources as alternatives to new build or purchases to maintain a 15% reserve margin. FMPA expects that a sustainable load management program will be established prior to the seasonal (summer) peaking need.

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.

Annually, FMPA and the ARP Executive Committee will assess the need for an update to the integrated resource plan. 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 2024. For the remainder of the TYSP study period (through December 31, 2031), FMPA anticipates additional seasonal (summer) peaking purchases, which could be comprised of additional solar, energy storage, offsets from load management, and reserve capacity will be required to maintain a 15% reserve margin. 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.

5.3 Capacity and Power Purchase Requirements

The current system firm power supply purchase resources of the ARP include two purchases from NextEra as well as forthcoming solar power purchase agreements, which provide an estimated amount of dependable capacity. 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 NextEra. The term of the purchase ends in September 2023. For 2022, 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, NextEra'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 term of the purchase ends in December 2027.
- **Solar:** FMPA on behalf of the ARP, has entered into twenty-year power purchase agreements with two different counterparties for solar resources, with AC output equal to approximately 58 MW and 96 MW, respectively. The estimated dependable capacity associated with solar generation, which varies by year as a function of projected online dates for solar facilities, is included as appropriate in all schedules herein.

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 2024. For the remainder of the TYSP study period (through December 31, 2031), FMPA anticipates additional seasonal (summer) peaking purchases, which could be comprised of additional solar, energy storage, offsets from load management, and reserve capacity will be required to maintain a 15% reserve margin. FMPA continually monitors and evaluates resource requirements.

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

Line No.	Resource Description	Summer Rating (MW) 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Nuclear [1,6]	48	48	48	48	48	48	48	48	47	47
2	Stanton Coal Plant [2,7]	222	222	222	106	106	106	106	106	106	106
3	Stanton CC Unit A [2]	44	44	44	44	44	44	44	44	44	44
4	Cane Island 1-4 [3]	684	694	694	694	713	713	713	713	713	713
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	319	319	319	319	319	319
7	Stock Island Units	113	113	113	113	113	113	113	113	113	113
	Planned Resource Additions										
9	None	-	-	-	-	-	-	-	-	-	-
10	Sub Total Planned Resource Additions	-	-	-	-	-	-	-	-	-	-
11	Total Installed Capacity	1,486	1,496	1,496	1,380	1,418	1,418	1,417	1,417	1,416	1,416
	Firm Capacity Import										
12	Stanton A Purchase [2]	81	81	-	-	-	-	-	-	-	-
13	Oleander Purchase	162	162	162	162	162	162	-	-	-	-
14	ARP Solar Phase I	16	16	23	23	23	23	23	23	23	23
15	ARP Solar Phase II	-	-	19	38	38	38	38	38	38	38
16	ARP Solar Phase III	-	-	-	-	40	40	40	40	40	39
	Capacity Purchases	-	-	-	91	31	33	109	124	126	139
17	Peaking Purchase(s) [5]	-	-	-	91	31	33	109	124	126	139
	Sub Total Without Reserves	260	260	204	315	294	296	210	224	226	239
18	Total Firm Capacity Import	260	260	204	315	294	296	210	224	226	239
19	Total Available Capacity	1,745	1,755	1,700	1,695	1,712	1,713	1,627	1,641	1,642	1,655

[1] Includes capacity from the St. Lucie Project.
[2] Capacities shown have been reduced to account for losses through the OUC transmission system (assumed to be 2.0% for planning period).
[3] Reflects Cane Island 3 upgrade to increase plant capacity in 2023 and Cane Island 4 upgrade to increase plant capacity in 2026.
[4] Reflects Treasure Coast Energy Center upgrade to increase plant capacity in 2026.
[5] Additional peaking capacity required to maintain a 15% reserve margin during the summer season.
[6] Reflects decrease in capacity as a result of the expiration of Green Cove Springs' supplemental power purchase agreement with the ARP.
[7] Reflects assumed retirement of Stanton 1 in 2025.

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

Line No.	Resource Description	Winter Rating (MW) 2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Nuclear [1]	50	50	50	50	50	50	50	50	48	48
2	Stanton Coal Plant [2,6]	222	222	222	106	106	106	106	106	106	106
3	Stanton CC Unit A [2]	47	47	47	47	47	47	47	47	47	47
4	Cane Island 1-4 [3]	711	721	721	721	740	740	740	740	740	740
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	329	329	329	329	329	329
7	Stock Island Units	113	113	113	113	113	113	113	113	113	113
8	Sub Total Existing Resources	1,536	1,546	1,546	1,430	1,468	1,468	1,467	1,467	1,466	1,466
	Planned Resource Additions										
9	None	-	-	-	-	-	-	-	-	-	-
10	Sub Total Planned Resource Additions	-	-	-	-	-	-	-	-	-	-
11	Total Installed Capacity	1,536	1,546	1,546	1,430	1,468	1,468	1,467	1,467	1,466	1,466
	Firm Capacity Import										
12	Stanton A Purchase [2]	87	87	-	-	-	-	-	-	-	-
13	Oleander Purchase	180	180	180	180	180	180	-	-	-	-
14	ARP Solar Phase I	-	-	-	-	-	-	-	-	-	-
15	ARP Solar Phase II	-	-	-	-	-	-	-	-	-	-
16	ARP Solar Phase III	-	-	-	-	-	-	-	-	-	-
17	Peaking Purchase(s) [5]	-	-	-	-	-	-	-	-	-	-
18	Total Firm Capacity Import	267	267	180	180	180	180	-	-	-	-
19	Total Available Capacity	1,803	1,813	1,726	1,610	1,648	1,648	1,467	1,467	1,466	1,466

[1] Includes capacity from the St. Lucie Project.
[2] Capacities shown have been reduced to account for losses through the OUC transmission system (assumed to be 2.0% for planning period).
[3] Reflects Cane Island 3 upgrade to increase plant capacity in 2023 and Cane Island 4 upgrade to increase plant capacity in 2026.
[4] Reflects Treasure Coast Energy Center upgrade to increase plant capacity in 2026.
[5] No additional capacity will be required to maintain a 15% reserve margin during the winter season.
[6] Reflects assumed retirement of Stanton 1 in 2025.

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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Nuclear [1]		Trillion BTU	4	4	4	4	4	4	4	4	4	4	4
2	Coal		000 Ton	511	516	485	340	203	154	-	-	-	-	-
	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	7	2	4	1	1	2	1	2	2	2	2
10		Total	000 BBL	7	2	4	1	1	2	1	2	2	2	2
	Natural Gas													
11		Steam [2]	000 MCF	847	705	663	465	277	210	2,883	2,621	2,837	2,916	2,857
12		CC	000 MCF	40,606	39,999	40,952	36,884	38,341	37,322	37,919	36,604	36,703	36,836	37,124
13		CT	000 MCF	610	702	618	295	1,033	1,292	1,640	1,146	1,224	1,335	1,460
14		Total	000 MCF	42,063	41,407	42,233	37,644	39,651	38,825	42,441	40,372	40,764	41,086	41,441
	Renewables [3]													
15		Biofuels	Billion BTU	409	276	276	276	276	276	276	276	276	276	276
16		Biomass	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
17		Geothermal	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
18		Hyrdro	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
19		Landfill Gas	Billion BTU	135	188	177	124	74	56	43	39	42	43	42
20		MSW	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
21		Solar	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
22		Wind	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
23		Other	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
24		Total	Billion BTU	544	464	453	400	350	332	319	315	318	319	318
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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Annual Firm Inter-Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	383	402	405	392	404	405	390	404	399	376	390
3	Coal		GWh	1,126	1,199	1,113	753	446	336	-	-	-	-	-
	Residual													
4		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	3	1	2	0	0	1	0	0	1	1	1
11		Total	GWh	3	1	2	0	0	1	0	0	1	1	1
	Natural Gas													
12		Steam	GWh	82	70	65	44	26	20	263	238	256	266	258
13		CC [2]	GWh	5,134	5,277	5,410	5,301	5,566	5,445	5,506	5,234	5,244	5,264	5,302
14		CT	GWh	55	60	52	25	85	104	131	91	96	104	115
15		Total	GWh	5,271	5,407	5,527	5,370	5,677	5,569	5,900	5,563	5,596	5,635	5,675
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
	Renewables [3]													
17		Biofuels	GWh	41	28	28	28	28	28	28	28	28	28	28
18		Biomass	GWh	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	GWh	-	-	-	-	-	-	-	-	-	-	-
20		Hyrdro	GWh	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	GWh	13	18	17	12	7	5	4	3	4	4	4
22		MSW	GWh	-	-	-	-	-	-	-	-	-	-	-
23		Solar	GWh	100	118	117	310	447	737	735	734	733	727	726
24		Wind	GWh	-	-	-	-	-	-	-	-	-	-	-
25		Other	GWh	-	-	-	-	-	-	-	-	-	-	-
26		Total	GWh	154	164	162	349	482	769	766	765	764	759	757
27	Interchange [4]		GWh	-	-	-	-	-	-	-	-	-	-	-
28	Net Energy for Load		GWh	6,937	7,172	7,209	6,864	7,010	7,080	7,056	6,732	6,760	6,770	6,823

[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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	5.5%	5.6%	5.6%	5.7%	5.8%	5.7%	5.5%	6.0%	5.9%	5.5%	5.7%
3	Coal		%	16.2%	16.7%	15.4%	11.0%	6.4%	4.7%	0.0%	0.0%	0.0%	0.0%	0.0%
	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	%	1.2%	1.0%	0.9%	0.6%	0.4%	0.3%	3.7%	3.5%	3.8%	3.9%	3.8%
13		CC	%	74.0%	73.6%	75.0%	77.2%	79.4%	76.9%	78.0%	77.8%	77.6%	77.8%	77.7%
14		CT	%	0.8%	0.8%	0.7%	0.4%	1.2%	1.5%	1.9%	1.4%	1.4%	1.5%	1.7%
15		Total	%	76.0%	75.4%	76.7%	78.2%	81.0%	78.7%	83.6%	82.6%	82.8%	83.2%	83.2%
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	%	0.6%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
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		Hyrdro	%	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%	0.3%	0.2%	0.2%	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	%	1.4%	1.6%	1.6%	4.5%	6.4%	10.4%	10.4%	10.9%	10.8%	10.7%	10.6%
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	%	2.2%	2.3%	2.2%	5.1%	6.9%	10.9%	10.9%	11.4%	11.3%	11.2%	11.1%
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)
							Reserve Margin before Maintenance			Reserve Margin after Maintenance	
Year	Total Installed Capacity (MW) [1]	Firm Capacity Import (MW)	Firm Capacity Export (MW)	QF (MW)	Total Available Capacity (MW)	System Firm Summer Peak Demand [2] (MW)	(MW)	(% of Peak)	Scheduled Maintenance (MW)	(MW)	(% of Peak)
2022	1,486	260	0	0	1,745	1,509	236	16%	0	236	16%
2023	1,496	260	0	0	1,755	1,508	247	16%	0	247	16%
2024	1,496	204	0	0	1,700	1,450	250	17%	0	250	17%
2025	1,380	315	0	0	1,695	1,474	221	15%	0	221	15%
2026	1,418	294	0	0	1,712	1,489	223	15%	0	223	15%
2027	1,418	296	0	0	1,713	1,490	223	15%	0	223	15%
2028	1,417	210	0	0	1,627	1,415	212	15%	0	212	15%
2029	1,417	224	0	0	1,641	1,427	214	15%	0	214	15%
2030	1,416	226	0	0	1,642	1,428	214	15%	0	214	15%
2031	1,416	239	0	0	1,655	1,439	216	15%	0	216	15%

[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 and additional ARP wholesale obligations 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)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Available Capacity	System Firm Winter Peak Demand [2]	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance	
Year	(MW) [1]	(MW) [1]	(MW) [2]	QF (MW)	(MW)	(MW)	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2021/22	1,536	267	0	0	1,803	1,296	507	39%	0	507	39%
2022/23	1,546	267	0	0	1,813	1,285	528	41%	0	528	41%
2023/24	1,546	180	0	0	1,726	1,227	499	41%	0	499	41%
2024/25	1,430	180	0	0	1,610	1,250	359	29%	0	359	29%
2025/26	1,468	180	0	0	1,648	1,265	383	30%	0	383	30%
2026/27	1,468	180	0	0	1,648	1,265	382	30%	0	382	30%
2027/28	1,467	0	0	0	1,467	1,198	270	23%	0	270	23%
2028/29	1,467	0	0	0	1,467	1,210	257	21%	0	257	21%
2029/30	1,466	0	0	0	1,466	1,210	256	21%	0	256	21%
2030/31	1,466	0	0	0	1,466	1,222	244	20%	0	244	20%

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

[2] System Firm Winter Peak Demand includes transmission losses for the ARP Participants and additional ARP wholesale obligations 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		Fuel Transport		Alt. Fuel Days Use	Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max. Nameplate kW	Net Capability		Status
				Primary	Alt.	Primary	Alt.					Summer MW	Winter MW	
Resource Additions														
Changes to Existing Resources														
TREASURE COAST	1	ST. LUCIE	CT	NG	DFO	PL	TK		1/1/2026			10	10	OT [1]
TREASURE COAST	1	ST. LUCIE	CA	WH	DFO	NA	TK		1/1/2026			10	10	OT [1]
CANE ISLAND	3CT	OSCEOLA	CT	NG	DFO	PL	TK		1/12023			6	6	OT [1]
CANE ISLAND	3CW	OSCEOLA	CA	WH	DFO	NA	TK		1/1/2023			4	4	OT [1]
CANE ISLAND	4CT	OSCEOLA	CT	NG		PL			1/1/2026			10	10	OT [1]
CANE ISLAND	4CW	OSCEOLA	CA	WH		NA			1/1/2026			10	10	OT [1]
St. Lucie	2	ST. LUCIE	NP	UR		TK			10/1/2027			(0)	(0)	OT [2]
St. Lucie	2	ST. LUCIE	NP	UR		TK			10/1/2029			(2)	(2)	OT [3]
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-		5/1/2025			(118)	(118)	RT [4]

[1] Upgrade to increase plant capacity. Reflects upgrade to ARP capacity and entitlements only.
[2] Reflects decrease in St. Lucie capacity available to the ARP as a result of the expiration of Ft. Meade's supplemental power purchase agreement with the ARP.
[3] Reflects decrease in St. Lucie capacity available to the ARP as a result of the expiration of Green Cove Springs' supplemental power purchase agreement with the ARP.
[4] Expected retirement of SEC 1 to occur during 2025.

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 and 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 uses on-site groundwater. The site receives delivery of fuel oil to its unloading system through deliveries primarily via truck and also has the capability of receiving fuel oil via waterborne delivery.

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
2022 through 2031 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Ocala Electric Utility	Shaw (OEU)	Dearmin (OEU)	900	230	1	6/2027
Kissimmee Utility Authority	Marydia sub 2nd auto transformer		125	230/69 kV	2	12/2023
	Osceola Parkway Substation		80	69 kV		6/2025
	Lake Bryan	Osceola Parkway	111	69 kV	1	6/2025
	Lake Cecile	Osceola Parkway	111	69 kV	1	6/2025
Fort Pierce Utility Authority	King Substation - Replace KT2 20 MVA with 25 MVA Transformer		25	69/13.2 kV		3/2022
	Lawnwood Substation - Replace LT2 20 MVA with 25 MVA Transformer		25	69/13.2 kV		1/2023
	Lawnwood Substation - Replace LT1 20 MVA with 25 MVA Transformer		25	69/13.2 kV		1/2024
	King Substation - Replace KT1 20 MVA with 25 MVA Transformer		25	69/13.2 kV		1/2025
	Savannah Substation - Replace ST1 20 MVA with 25 MVA Transformer		25	69/13.2 kV		1/2026