ARP EXECUTIVE COMMITTEE AGENDA PACKAGE

OCTOBER 17,2024

9:15 a.m. [NOTE TIME] (or immediately following the Board of Directors meeting)

Dial-in info: 1-321-299-0575

Meeting ID Number: 295 285 900 335 #

Committee Members

Howard McKinnon, Havana - Chair

Lynne Tejeda, Key West – Vice Chair

Christina Simmons, Bushnell
Lynne Mila, Clewiston
Steve Doyle, Fort Meade
Javier Cisneros, Fort Pierce
Robert Page, Green Cove Springs
Allen Putnam, Jacksonville Beach

Brian Horton, Kissimmee
Brad Chase, Leesburg
Mike New, Newberry
Doug Peebles, Ocala
Drew Mullins, Starke

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

MEMORANDUM

TO: FMPA Executive Committee

FROM: Jacob A. Williams, General Manager and CEO

DATE: October 14, 2024

RE: FMPA Executive Committee Meeting
Thursday, October 17, 24 at 9:15 a.m. [NOTE TIME]
(or immediately following the Board of Directors meeting)

PLACE: Florida Municipal Power Agency
8553 Commodity Circle, Orlando, FL 32819
Fredrick M. Bryant Board Room

DIAL-IN: **321-299-0575, Meeting Number 295 285 900 335#**

LINK: **Click here to join the meeting**

(If you have trouble connecting via phone or internet, call 407-355-7767)

Chairman Howard McKinnon, Presiding

AGENDA

***Item also on the Board of Directors Agenda.**

**** Item(s) Subject to Super Majority Vote**

NOTE: One or more participants in the above referenced public meeting may participate by telephone. At the above location there will be a speaker telephone so that any interested person can attend this public meeting and be fully informed of the discussions taking place either in person or by telephone communication. If anyone chooses to appeal any decision that may be made at this public meeting, such person will need a record of the proceedings and should accordingly ensure that a verbatim record of the proceedings is made, which includes the oral statements and evidence upon which such appeal is based. This public meeting may be continued to a date and time certain, which will be announced at the meeting. Any person requiring a special accommodation to participate in this public meeting because of a disability, should contact FMPA at (407) 355-7767 or (888) 774-7606, at least two (2) business days in advance to make appropriate arrangements.

AGENDA ITEM 1 - CALL TO ORDER, ROLL CALL, DECLARATION OF QUORUM

Executive Committee
October 17, 2024

AGENDA ITEM 2 – Set Agenda (by Vote)

Executive Committee
October 17, 2024

AGENDA ITEM 3 – RECOGNITION OF GUESTS

Executive Committee
October 17, 2024

AGENDA ITEM 4 – PUBLIC COMMENTS (INDIVIDUAL COMMENTS TO BE LIMITED TO 3 MINUTES)

Executive Committee
October 17, 2024

AGENDA ITEM 5 – COMMENTS FROM THE CHAIRMAN

Executive Committee
October 17, 2024

VERBAL REPORT

AGENDA ITEM 6 – REPORT FROM THE GENERAL MANAGER

Executive Committee
October 17, 2024

AGENDA ITEM 7 – CONSENT AGENDA

a. **Approval of Meeting Minutes – Meetings Held September 19, 2024 and ARP Telephonic Rate Workshop Held September 12, 2024**

Executive Committee
October 17, 2024

CLERKS DULY NOTIFIED .... SEPTEMBER 12, 2024
AGENDA PACKAGES POSTED .... SEPTEMBER 12, 2024

MINUTES
EXECUTIVE COMMITTEE MEETING
THURSDAY, SEPTEMBER 19, 2024
FLORIDA MUNICIPAL POWER AGENCY
8553 COMMODITY CIRCLE
ORLANDO, FL 32819

PARTICIPANTS PRESENT:	Lynne Mila, Clewiston Fred Hilliard, Fort Meade Javier Cisneros, Fort Pierce Bob Page, Green Cove Springs Howard McKinnon, Havana Allen Putnam, Jacksonville Beach (Virtual) Lynne Tejeda, Key West (Virtual) Jason Terry, Kissimmee Brad Chase, Leesburg (Virtual) Doug Peebles, Ocala Drew Mullins, Starke
OTHERS PRESENT	Barbara Mika, Fort Pierce Danny Retherford, Fort Pierce Barbara Quiñones, Homestead Karen Nelson, Jacksonville Beach (virtual) Mike Staffopoulos, Jacksonville Beach (virtual) Efren Chavez, New Smyrna Beach (virtual) Craig Dunlap, Dunlap & Associates, Inc. Jonathan Nunes, nFront Consulting Matt Eckhart, nFront Consulting Kevin Williams, nFront Consulting
STAFF PRESENT	Jacob Williams, General Manager and CEO Jody Finklea, General Counsel and Chief Legal Officer Ken Rutter, Chief Operating Officer Rich Popp, Chief Financial Officer Chris Gowder, Vice President, IT/OT and System Ops Dan O'Hagan, Deputy General Counsel and Manager of Regulatory Compliance Mike McCleary, Member Services Manager Sharon Adams, Chief People and Member Services Officer Susan Schumann, Manager of External Affairs and Solar Projects John Bradley, Business Development Analyst Emily Maag, Public Relations Specialist Jason Wolfe, Financial Planning Rates and Budget Director LaKenya VanNorman, Senior Regulatory Compliance Specialist

Mary Kathryn Patterson, Senior Public Relations Specialist
Wayne Koback, IT Manager
Lindsay Jack, Senior Administrative & Member Services Assistant
MacKayla Cross, Administrative Assistant

ITEM 1 - CALL TO ORDER, ROLL CALL, AND DECLARATION OF QUORUM

Chairperson Howard McKinnon, Havana, called the FMPA Executive Committee meeting to order at 12:30 p.m., Thursday, September 19, 2024, in the Frederick M. Bryant Board Room at Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida. The roll was taken, and a quorum was declared with 11 members present out of a possible 13.

ITEM 2 – SET AGENDA (BY VOTE)

MOTION: Javier Cisneros, Fort Pierce, moved approval of the agenda as presented. Jason Terry, Kissimmee, seconded the motion. Motion carried 11-0.

ITEM 3 – RECOGNITION OF GUESTS

None.

ITEM 4 – PUBLIC COMMENTS

None.

ITEM 5 – COMMENTS FROM THE CHAIRMAN

None.

ITEM 6 – REPORT FROM GENERAL MANAGER

None.

ITEM 7 –CONSENT AGENDA

a. Approval of Meeting Minutes – Meetings Held August 22, 2024 and ARP Telephonic Rate Workshop Held August 13, 2024

b. Approval of Treasury Reports – As of July 31, 2024

c. Approval of the Agency and All-Requirements Project Financials as of July 31, 2024

d. ARP 12-month Capacity Reserve Margin Report

MOTION: Javier Cisneros, Fort Pierce, moved approval of the Consent Agenda as presented. Doug Peebles, Ocala, seconded the motion. Motion carried 11-0.

ITEM 8 – ACTION ITEMS:

a. FMSP Amendments to Phase II and Phase III PPA's

Susan Schumann presented the FMSP Amendments to Phase II and Phase III PPA's.

Such approvals to be conditioned upon receipt of all required local governing board approvals. Authorize execution of all documents necessary to effect the same.

MOTION: Javier Cisneros, Fort Pierce, moved approval of FMSP Amendments to Phase II and Phase III PPA's.

- Amendment Number 2 to Whistling Duck Solar PPA
- Amendment Number 1 to Hampton Solar PPA
- Amendment Number 1 to New River Solar PPA
- New Leyland Solar PPA
- Mutual Termination & Release of Penholoway Solar PPA
- Amendment Number 2 to Solar II Project Sales Contract
- Amendment Number 1 to Solar III Project Power Sales Contract

Doug Peebles, Ocala, seconded the motion. Motion carried 11-0.

b. Approval of Spending Authority Modification FY 2025

Danyel Sullivan-Marrero presented the Approval of Spending Authority Modification FY 2025.

MOTION: Jason Terry, Kissimmee, moved approval of the Revised Spending Authority Limits as presented to the Executive Committee. Doug Peebles, Ocala, seconded the motion. Motion carried 11-0.

Howard McKinnon, Havana, requested to vote on the Approval of Procurement Limit Modifications for FY 2025 as presented to the Board of Directors.

MOTION: Jason Terry, Kissimmee, moved approval of the revised Procurement Limit Modifications as presented to the Board of Directors. Doug Peebles, Ocala, seconded the motion. Motion carried 11-0.

c. Approval of Resolution 2024-EC4 for Budget Amendment for All-Requirements Project

Denise Fuentes presented the Approval of Resolution 2024-EC4 for Budget Amendment for All-Requirements Project.

Resolution 2024-EC4 was addressed as read by title:

> RESOLUTION OF THE EXECUTIVE COMMITTEE OF THE FLORIDA MUNICIPAL POWER AGENCY: (I) AMENDING THE ALL-REQUIREMENTS POWER SUPPLY PROJECT BUDGET FOR THE FISCAL YEAR BEGINNING OCTOBER 1, 2023, AND ENDING SEPTEMBER 30, 2024; (II) ADOPTING THE AMENDED BUDGET FOR THE ALL-REQUIREMENTS POWER SUPPLY PROJECT FOR THE FISCAL YEAR BEGINNING OCTOBER 1, 2023, AND ENDING SEPTEMBER 30, 2024; AND (III) PROVIDING AN EFFECTIVE DATE.

MOTION: Javier Cisneros, Fort Pierce, moved approval of Resolution 2024-EC4. Jason Terry, Kissimmee, seconded the motion. Motion carried 11-0.

d. Approval for Previously Budgeted ARP Capital Project Dollars to be Spent During FY 2025.

Jason Wolfe presented the Approval for Previously Budgeted ARP Capital Project Dollars to be Spent During FY 2025.

Bob Page, Green Cove Springs, asked what the process would be if projects go over the already approved budget amount of $4.3 million.

Jacob Williams explained we would defer projects or come to the Executive Committee for approval.

Howard McKinnon, Havana, confirmed the Executive Committee would just need to stay informed.

MOTION: Doug Peebles, Ocala, moved approval of allowing $4.3 million of specified FY 2024 capital projects to be completed during FY 2025 without counting towards the FY 2025 capital budget, pursuant to the Asset Management & Operations Policy. Javier Cisneros, Fort Pierce, seconded the motion. Motion carried 11-0.

ITEM 9 – INFORMATION ITEMS

a. Quarterly Natural Gas Price Stability Program Update

John Bradley presented the Quarterly Natural Gas Price Stability Program Update.

Howard McKinnon, Havana, asked if we are selling excess because we are not burning enough gas.

John Bradley explained we are buying at a lower cost for the prepaid to then sell at a higher cost on other markets when the price goes up. Confirmed it is a one-to-one trade happening in real time.

Jason Terry, Kissimmee, asked how to know what the real cost of gas going through the units are based on the hedges.

Jacob Williams explained gas through the units are always priced at current market because a decision is being made at that moment to run the gas or sell it back at that market price. He He further explained that every morning on the fuel rate call, everyone agrees to the common price for that day for gas.

Jacob Williams explained that until there is a target approved, no gas will be purchased for the Summer of 2027.

Doug Peebles, Ocala, questioned if nothing is done, is there a risk or should action be taken since the prepaid rates are low.

Jacob Williams confirmed no action can be taken without approval from the Executive Committee.

Javier Cisneros, Fort Pierce, stated he thinks it would be beneficial to at least secure 5% for the summer of 2027 given the uncertainty with future gas prices after the election.

Jacob Williams confirmed a minimum of 5% and a maximum of 25% could be secured with an approved target for the Summer of 2027.

Discussion amongst members: Javier Cisneros, Fort Pierce, Bob Page, Green Cove Springs, Doug Peebles, Ocala, Jason Terry, Kissimmee, and Howard McKinnon determined a motion to approve the purchase of prepaid gas for Summer of 2027 at the same target price as Summer of 2025 of $3.33.

MOTION: Jason Terry, Kissimmee, moved approval for a target price of $3.33 for Summer of 2027. Javier Cisneros, Fort Pierce, seconded the motion. Motion carried 11-0.

b. Annual Disclosure Training for the Board of Directors and Executive Committee will be held after the last Information Item on the Board of Directors Agenda.

Randy Clement of Bryant Miller Olive, FMPA disclosure counsel, presented the Annual Disclosure Training for the Board of Directors and Executive Committee.

c. Regulatory Compliance Update

Dan O'Hagan and LaKenya VanNorman provided the Regulatory Compliance Update.

ITEM 10 – Member Comments

None.

ITEM 11 – Adjournment

There being no further business, the meeting was adjourned at 1:19 p.m.

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Howard McKinnon
Chairman, Executive Committee

____
Sue Utley
Assistant Secretary

Approved: ________________________

Seal

PUBLIC NOTICE SENT TO CLERKS.. SEPTEMBER 6, 2024
AGENDA PACKAGES SENT TO MEMBERS .... SEPTEMBER 12, 2024

MINUTES
EXECUTIVE COMMITTEE
ALL-REQUIREMENTS POWER SUPPLY PROJECT
TELEPHONIC RATES MEETING
THURSDAY, SEPTEMBER 12, 2024
FLORIDA MUNICIPAL POWER AGENCY
8553 COMMODITY CIRCLE
ORLANDO, FLORIDA 32819

COMMITTEE MEMBERS PRESENT VIA TELEPHONE

Lynne Mila, Clewiston
Daniel Retherford, Fort Pierce
Sue Wang, Green Cove Springs
Howard McKinnon, Havana
Mike Staffopoulos, Jacksonville Beach
Jesse Perloff, Key West
Lynne Tejeda, Key West
Jason Terry, Kissimmee
Marie Brooks, Ocala

STAFF PRESENT

Jacob Williams, General Manager and Chief Executive Officer
Jody Finklea, General Counsel and Chief Legal Officer
Rich Popp, Chief Financial Officer
Lindsay Jack, Senior Administrative Assistant and
Member Services Assistant
Denise Fuentes, Financial Planning, Budget and Financial Analyst II
MacKayla Cross, Administrative Assistant
John Bradley, Business Development Analyst

<u>Item 1 – Call to Order and Roll Call</u>

Howard McKinnon, Havana, Chair, called the Executive Committee All-Requirements Telephonic Rate Workshop to order at 2:02 p.m. on Thursday, September 12, 2024, via telephone. A speaker telephone for public attendance and participation was located in the Executive Conference Room at Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida.

<u>Item 2 – Review of August ARP Rate Calculation</u>

Denise Fuentes gave an update on the August natural gas markets, provided an overview of the August loads, and reviewed the August ARP rate calculation.

Lynne Tejeda, Key West, asked what the September 1st cost was. John Bradley, FMPA, stated the cost was $1.91.

Jacob Williams, FMPA, wanted to point out that John and the team have continued to work below the targets each month and pick up more to slowly fill in.

John Bradley, FMPA, confirmed Summer 2025 targets are $3.33.

Item 3 – Member Comments

None.

Item 4 - Adjournment

There being no further business, the meeting was adjourned at 2:10 p.m.

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Approved

LT/lj

AGENDA ITEM 7 – CONSENT AGENDA

b. Approval of Treasury Reports as of August 31, 2024

Executive Committee
October 17, 2024

AGENDA PACKAGE MEMORANDUM

TO: FMPA Executive Committee

FROM: Melissa Cain

DATE: October 10, 2024

ITEM: EC 7(b) – Approval of the All-Requirements Project Treasury Reports as of August 31, 2024

Introduction

- This report is a quick summary update on the Treasury Department's functions.
- The Treasury Department reports for August are posted in the member portal section of FMPA's website.

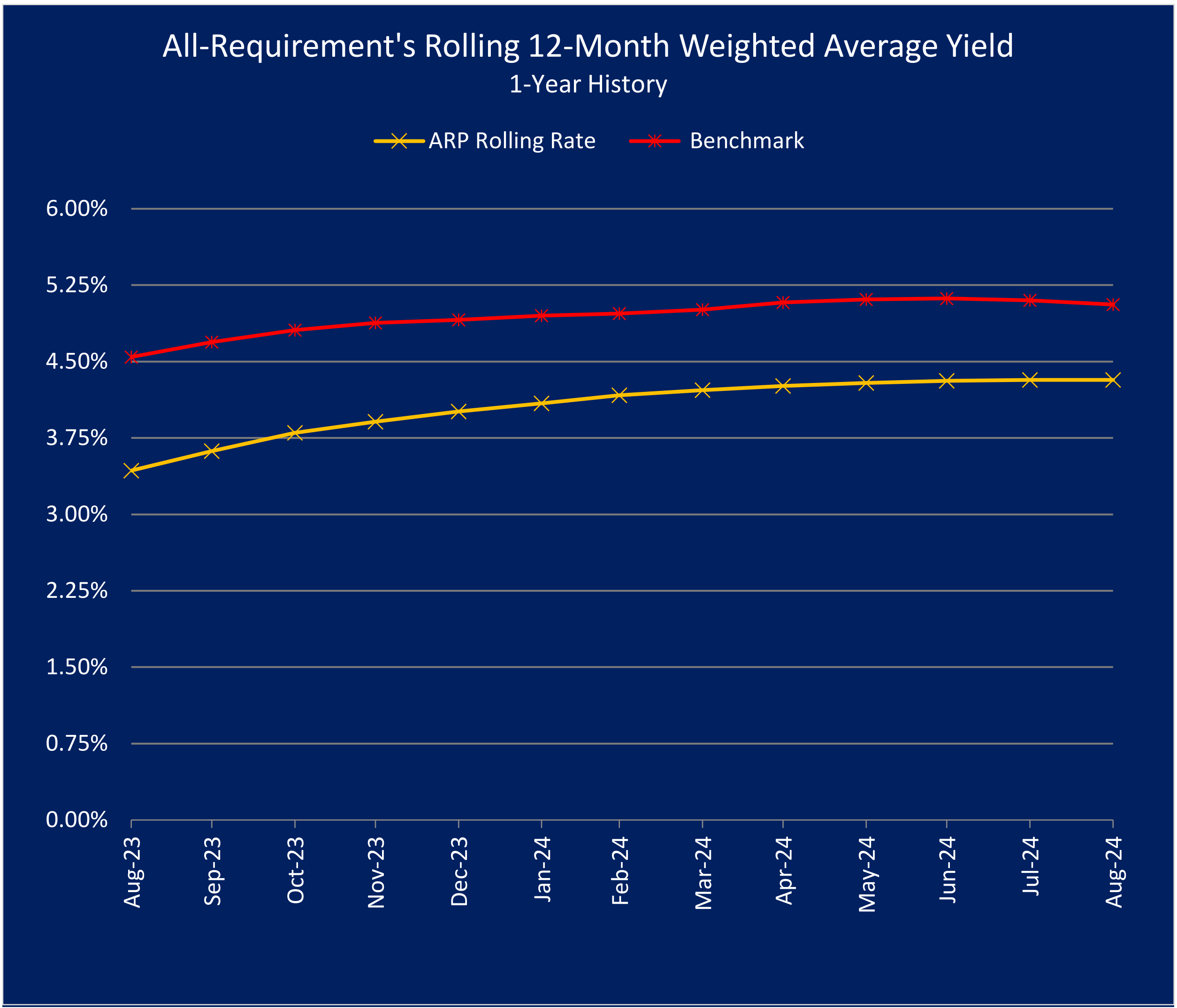
Debt Discussion

The All-Requirements Project has variable rate and fixed rate debt. The variable rate and fixed rate percentages of total debt are 2.01% and 97.99% respectively. The estimated debt interest funding for fiscal year 2024 as of August 31, 2024, is $32,204,631.59. The total amount of debt outstanding is $747,410,000.

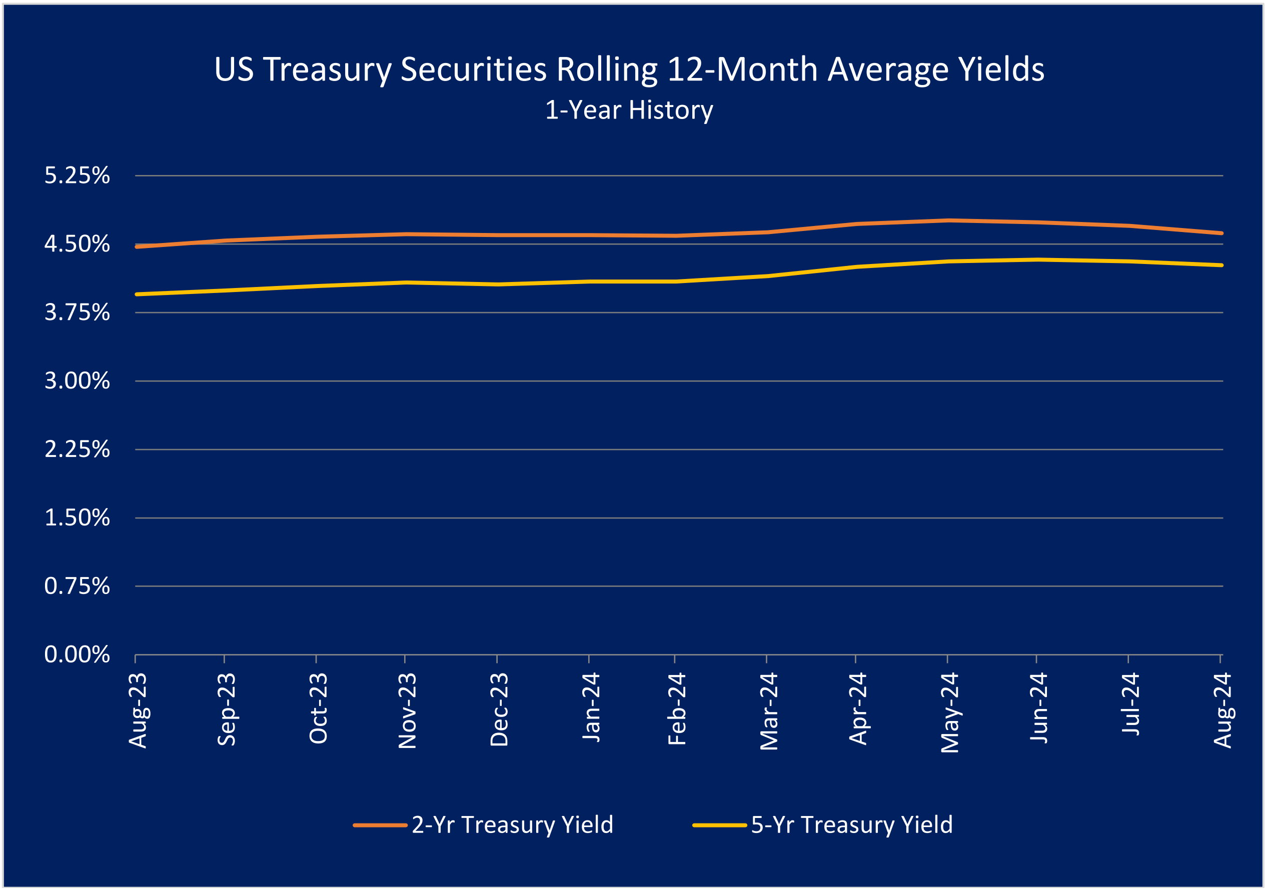
Investment Discussion

The investments in the Project are comprised of debt from the government-sponsored enterprises such as the Federal Farm Credit Bank, Federal Home Loan Bank, Federal Home Loan Mortgage Corporation (Freddie Mac), and Federal National Mortgage Association (Fannie Mae), as well as investments in U.S. Treasuries, Municipal Bonds, Certificates of Deposits, Corporate Notes, Commercial Paper, Local Government Investment Pools, and Money Market Mutual Funds.

As of August 31, 2024, the All-Requirements Project investment portfolio had a rolling 12-month weighted average yield of 4.32%, reflecting the All-Requirements Project need for liquidity. The benchmarks (SBA's Florida Prime Fund and the 2-year US Treasury Note) and the Project's rolling 12-month weighted average yields are graphed below:



Below is a graph of the rolling 12-month average US Treasury yields for the past year. The orange line is the 2-year Treasury which had a rolling 12-month average yield on August 31, 2024 of 4.62%. The yellow line is the 5-year Treasury rolling 12-month average yield which was 4.27%.



The Investment Report for August is posted in the "Member Portal" section of FMPA's website.

Recommended Motion

Move for approval of the Treasury Reports for August 31, 2024

AGENDA ITEM 7 – CONSENT AGENDA

c. Approval of the Agency and All-Requirements Project Financials as of August 31, 2024

Executive Committee
October 17, 2024

FMPA MUNICIPAL POWER

Rich Popp
Chief Financial Officer

AGENDA PACKAGE MEMORANDUM

TO: **FMPA Executive Committee**

FROM: **Rich Popp**

DATE: **October 10, 2024**

SUBJECT: **EC 7c– Approval of the Agency and All Requirements Project Financials as of the period ended August 31, 2024**

Discussion: The summary and detailed financial statements, which include GASB #62 transactions, of the Agency and All Requirements Project for the period ended August 31, 2024, are posted on the Document Portal section of FMPA's website.

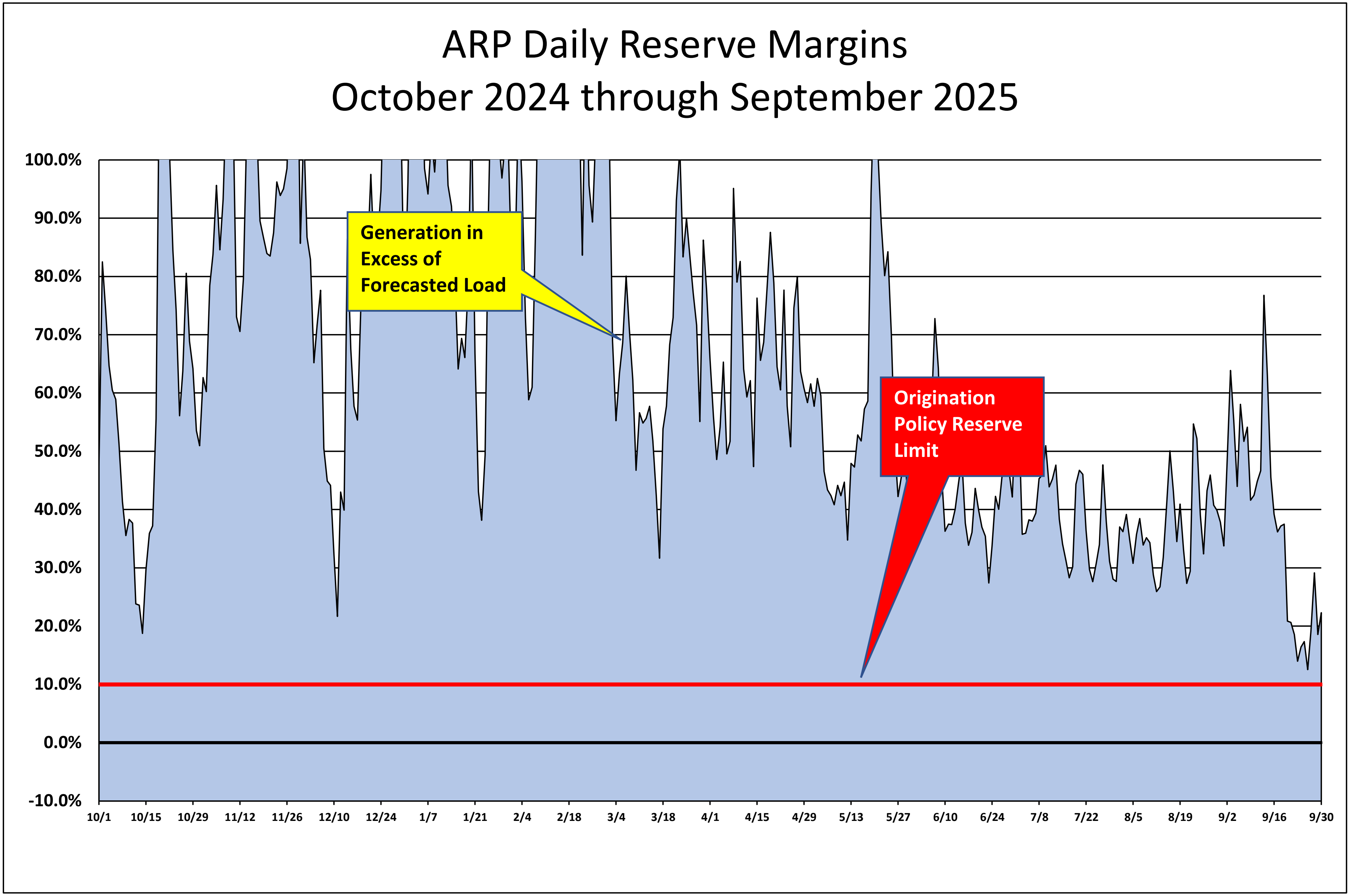
Recommended: Move approval of the Agency and All-Requirements Project Financial Reports for the month ended August 31, 2024.

RP/GF

AGENDA ITEM 7 – CONSENT AGENDA

d. ARP 12-month Capacity Reserve Margin Report

Executive Committee
October 17, 2024


ARP Daily Reserve Margins
October 2024 through September 2025
100.0%
90.0%
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
-10.0%
10/1
10/15
10/29
11/12
11/26
12/10
12/24
1/7
1/21
2/4
2/18
3/4
3/18
4/1
4/15
4/29
5/13
5/27
6/10
6/24
7/8
7/22
8/5
8/19
9/2
9/16
9/30
Generation in Excess of Forecasted Load
Origination Policy Reserve Limit

AGENDA ITEM 8 – ACTION ITEMS

a. Approval of CY 2025 Meeting Schedule

Executive Committee
October 17, 2024

EC 8a – Approval of Calendar Year 2025 Meeting Schedule

Executive Committee

October 17, 2024

Proposed Meeting Dates for 2025

Board of Directors and Executive Committee

Meeting Date	Meeting Date
January 16	July 23 (during FMEA Annual Conference)
February 13 (APPA Leg. Rally Feb. 24-26, 2025)	August 21
March 20	September 18
April 17	October 16
May 15	November 13 (2nd Thursday due to holiday)
June 26 (APPA National Conf. June 6-11, 25 & Juneteenth June 19, 25)	December 11 (2nd Thursday due to holidays)

*Approved by Board of Directors at the September 19th meeting.

FMPA MUNICIPAL POWER

Recommended Motion

- Move approval of the recommended meeting schedule for calendar year 2025.

AGENDA ITEM 8 – ACTION ITEMS

b. Approval of Revising Rate Schedule B-1 to be effective October 1, 2024

Executive Committee
October 17, 2024

8b – Approval of Revised Rate Schedule B-1 to Be Effective Oct. 1, 2024

Executive Committee

October 17, 2024

Summary

- Each October, staff brings a revised Rate Schedule B-1 to the EC for approval to update base rates to reflect new fiscal year budget
- Demand rate based on avg. of Summer CP Demands (Net of Excluded Resources) for Fiscal Years 2022 through 2024
- Redline and clean versions of Rate Schedule B-1 attached
- The following riders are included for completeness of the rate schedule, but no changes included:
  - Load Attraction Incentive Rate (LAIR)
  - Economic Development Rate (EDR)

FY 2025 ARP Rates – Based on Approved Budget

Demand Rate Reflects Final Billing Demands for FY 2025

Rate Category	FY24 Base Rate	FY 25 Base Rate
Demand	$15.50 /kW-mo.	$16.04 /kW-mo.
Transmission (all except KUA)	$4.32 kW-mo.	$5.06 /kW-mo.
Transmission (KUA)	$0.64 / kW-mo.	$0.65 /kW-mo.
Energy	$33.04 /MWh	$32.66 /MWh

FMPA MUNICIPAL POWER

Recommended Motion

- Move approval of revised ARP Rate Schedule B-1, effective Oct. 1, 2024*

* Subject to Super Majority vote

FLORIDA MUNICIPAL POWER AGENCY
POWER SUPPLY RATE SCHEDULE
FOR
ALL-REQUIREMENTS PROJECT PARTICIPANTS

1. **Applicability.** Electric service for All-Requirements Services and Back-up and Support Services as defined in the All-Requirements Power Supply Project Contract for their own use and for resale.

2. **Availability.** This Schedule B-1 is available to the Project Participants purchasing electric capacity and energy from FMPA under the terms of the All-Requirements Power Supply Project Contracts as All-Requirements Services and, if applicable, as Back-Up and Support Services.

3. **Character of Service.** Electricity furnished under this Schedule B-1 at one or more Points of Delivery as set forth in Schedule A shall be sixty-hertz, three phase, alternating current.

4. **Billing Rate for All-Requirements Services.**
   (a) For electricity furnished hereunder as All-Requirements Services, the charges for each month shall be determined as follows:

Customer Charge	For each Project Participant, the charge is \$1,000.00 per Point of Delivery. Notwithstanding the above, the charge for a Project Participant that has both (1) established its Contract Rate of Delivery and (2) does not receive Network Integration Transmission Service under an ARP agreement is \$0.00.
Demand Capacity Charge	\$ 16.04~~15.50~~ per kilowatt ("kW") of capacity billing demand
Demand Transmission	\$ 5.06~~4.32~~ per kilowatt ("kW") of transmission billing demand
Demand Transmission Kissimmee Utility Authority	\$ 0.65~~0.64~~ per kilowatt ("kW") of transmission billing demand
Energy Charge	\$ 32.66~~33.04~~ per megawatt-hour ("MWh") for all energy supplied as All-Requirements Services

Solar Energy Surcharge	A $ per megawatt-hour ("MWh") rate, as calculated monthly in accordance with 10 below, for all energy pursuant to the applicable solar Power Purchase Agreement(s) ("PPA"), as specifically agreed to by individual Project Participants pursuant to Solar Participant Agreements between the ARP and individual Project Participants (hereinafter "Solar Participants").
Reactive Demand Charge	$0.00 per kilo-var ("kVAR") of excess billing reactive demand

(b) Delivery Voltage Adjustment for All-Requirements Services. The Billing Rates under paragraph (a) are based on delivery of electric capacity and energy to the Project Participant at 115,000 volts or higher. Where capacity and energy are delivered at voltages less than 115,000 volts, the Billing Rates under paragraph (a) shall be increased as follows:

Delivery Voltage	Demand Charge Adjustment	Energy Charge Adjustment
69,000 volts	$0.000/kW	$0.0000/kWh
12,000/25,000 volts	$0.722/kW	$0.0000/kWh
Under 12,000 volts	$0.722/kW	$0.0000/kWh

5. **Billing Metering ~~For~~for All-Requirements Services.** The metered demand in kW in each month shall be the individual Project Participant's total 60 minute integrated demand at the time of the highest 60 minute integrated demand for the total of all ARP system Project Participants (or corrected to a 60 minute basis if demand registers other than 60 minute demand registers are installed) measured during the month.

The metered reactive demand in kVAR in each month shall be the reactive demand, which occurred during the same 60-minute demand interval in which the metered kilowatt demand occurred.

Demand and energy meter readings shall be adjusted, if appropriate, as provided in Schedule A of the All-Requirements Power Supply Project Contract.

6. **Billing Demand-Capacity for All-Requirements Services.** The billing demand capacity in any period shall be the arithmetic average of the metered demands, as determined under paragraph 5, giving effect to all adjustments, less the Project Participant's Excluded Power Supply Resources capacity, if any, for the

months of June, July, August, and September for the preceding three fiscal years. For avoidance of doubt, unless otherwise adjusted as follows in this paragraph 6, the monthly billing demand capacity for each Project Participant shall be based on the arithmetic average of 12 data points and shall remain fixed over the current fiscal year.

If a Project Participant has permanently lost a large load during the preceding three fiscal years that would cause the metered demands utilized for that Project Participant in the billing demand capacity calculation not to be representative of its current load, the metered demands utilized in the calculation for that Project Participant may be adjusted accordingly by a majority vote of the Executive Committee in its sole discretion. Such load must represent a minimum of five percent of the Project Participant's total load based on demonstrable load data. It is the responsibility of the Project Participant to notify FMPA of any such loss of load, and no adjustments shall be made to billings for months prior to the effective date of any adjustment approved by the Executive Committee.

If a Project Participant has added a large load during the preceding three years for which a demand-related financial incentive will be provided through a rider to this Rate Schedule B-1, the metered demands utilized in the calculation for that Project Participant will be adjusted as set forth in the respective rider.

Anomalous loads for an individual Project Participant may be excluded from the billing demand capacity calculation by majority vote of the Executive Committee.

7. **Billing Demand-Transmission for All-Requirements Services.** The billing demand capacity in any period shall be the metered demand for the period as determined under paragraph 5, giving effect to all adjustments, but including the Project Participant's, Excluded Power Supply Resources capacity, if any.

8. **Billing Reactive Demand for All-Requirements Services.**
The billing reactive demand for any month shall be the amount of reactive demand in kVAR by which the metered reactive demand exceeds one-half of the metered kilowatt demands, or such other amount as shall be determined from time to time by FMPA.

9. **Energy Cost Adjustment for All-Requirements Services.**
The monthly bill computed hereunder shall adjust the base energy rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

ER = $0.03266~~$0.03304~~/kWh ±ETCA

Where:

ER = Energy Rate to be applied <u>to</u> each kWh of billed energy.
ETCA = Energy Total Cost Adjustment to be determined according to the following procedure:

1. The number <u>of</u> days of available cash will be determined each month and rounded to the nearest five days.

2. A confidence percentage based on <u>the</u> following table will be selected to determine the amount of the total cost adjustment. The Confidence Percentage will then be applied to the output of the probabilistic model discussed below.

Days of Available Cash	Associated Confidence Percentage
30 day or less	95%
35 days	88%
40 days	80%
45 days	73%
50 days	65%
55 days	58%
60 days	50%
65 days	43%
70 days	35%
75 days	28%
80 days	20%
85 days	13%
90 days and over	5%

3. A probabilistic model will be used to estimate <u>the</u> next four months of projected energy total cost and projected total kWh sales for providing the All-Requirements Project power supply. For purposes of this adjustment, FMPA's owned and controlled generating units including purchased power or interchange power purchased by FMPA from other suppliers less the energy cost of sales to other utilities, will be used in the calculations.

4. A probabilistic model will also be used to allocate the most current ARP Participant over-recovery and under-recovery balance as listed in the ARP's Comparative Statement of Net Asset report. This balance will be applied over the next four months and tied to the appropriate percentage level listed in the table above.

10. Solar Energy Surcharge.

The Solar Energy Surcharge shall equal the difference between the adjusted energy rate calculated in 9 above (ER) and the actual monthly cost per MWh of the solar energy (note the surcharge could be negative). The following provisions shall apply to the calculation of the surcharge:

1. Solar energy costs shall equal the sum of the applicable solar PPA charges, FMPA A&G charges allocated to the solar PPA(s), the return to the Agency Development Fund of the costs advanced to enter into and implement the solar PPA(s), and other costs or charges that the ARP may incur related to utilizing solar energy as part of its resource portfolio, e.g. increased regulation charges assessed by the ARP's Balancing Authority.

2. The following All-Requirements Project Participants have responsibility for solar energy (MWh) in each hour that solar energy is produced under the applicable solar PPA(s):

Phase I solar PPAs between the ARP and NextEra Florida Renewables, or its successor or assigns:

The City of Jacksonville Beach	17.241%
Fort Pierce Utilities Authority	5.173%
Utility Board, City of Key West	8.621%
Kissimmee Utility Authority	51.724%
The City of Ocala	17.241%

Phase II solar Rice Creek PPA between the ARP and Origis Energy, or its successors or assigns:

The City of Jacksonville Beach	15.584%
Fort Pierce Utilities Authority	15.584%
The Town of Havana	0.260%
Utility Board, City of Key West	25.975%
Kissimmee Utility Authority	20.779%

The City of Newberry	1.039%
The City of Ocala	20.779%

Phase II solar Whistling Duck PPA between the ARP and Origis Energy, or its successors or assigns:

Utility Board, City of Key West	100.000%

Phase III solar PPA between the ARP and Origis Energy, or its successors or assigns:

Utility Board, City of Key West	21.751%
The City of Ocala	6.869%

3. In the event that one or more of the Solar Participants defaults by not paying the Solar Energy Surcharge, the defaulting Project Participant(s) shall remain liable for all payments to be made on its part pursuant to this Rate Schedule B-1. In such event, each non-defaulting Solar Participant's All-Requirements bill shall be increased, on a pro rata basis based on its respective Solar Energy Surcharge percentage of the applicable solar PPA(s), the amount in default unless and until FMPA shall recover from the defaulting Solar Participant(s) all amounts owed, upon which FMPA shall reimburse the non-defaulting Solar Participants. If all Solar Participants default by not paying the Solar Energy Surcharge, the All-Requirements Project will be obligated for the applicable Power Purchase Agreement(s) and the solar costs will become part of the Energy Rate (ER) above applicable to all All-Requirements Project Participants, including the defaulting Solar Participants, unless and until FMPA shall recover from at least one of the defaulting Solar Participants all amounts owed by all Solar Participants, upon which FMPA shall reimburse the All-Requirements Project Participants either through rates or through such other method as directed by the Executive Committee

4. A Solar Participant may only exit from the financial obligation to pay the Solar Energy Surcharge if one of the following four conditions are met, subject to approval of the Executive Committee:

   a. One or more Solar Participants assumes the exiting Solar Participant's entire Solar Energy Surcharge financial obligation to the ARP;

   b. One or more All-Requirements Project Participants assumes the exiting Solar Participant's entire Solar Energy Surcharge financial obligation to the ARP;

c. One or more FMPA Members that is not an All-Requirements Project Participant assumes the financial entitlement to the Solar Participant's percentage share of the applicable solar PPA(s) and commits that it will take on the (i) associated financial obligation and (ii) obligation to take solar energy, in a form suitable to the ARP; or

d. Pay stranded cost obligations, as determined by FMPA in its sole discretion, to hold the other Solar Participants harmless from the costs associated with the Solar Participant's exit.

   Stranded cost obligations are defined as an estimate of the solar energy costs (defined in 10.1) that the ARP will pay for the exiting Solar Participant's solar energy entitlement during each remaining month of the remaining term of the applicable solar PPA(s) based on (i) a forecast of expected solar production and (ii) a reasonable assessment of unforeseen costs, and are to be paid at the time of exit. The forecast of expected solar production is defined as a P50 (probability of exceedance is 50 percent) production estimate under typical meteorological year conditions using an industry standard modeling tool (PV Syst or its successor/peer products) reflective of a degradation rate of 0.3% per year relative to the original nominal alternating current capacity of the solar resource in the current year (prorated over a partial year as applicable) and each subsequent remaining year of the applicable solar PPA(s) term.

11. **Demand Cost True-up for All-Requirements Services.**
Each Project Participant shall be charged or credited, as applicable, during the twelve months commencing with the billing for October service of a subsequent fiscal year by a dollar amount equal to one twelfth of the dollar amount share of the difference between the Project Participant's actual demand costs (excluding transmission) and the demand charges collected during the previous fiscal year. The amount to be charged or credited to each Project Participant shall be calculated on the basis of each Project Participant's demand costs (excluding transmission) collected during the previous fiscal year as a percentage of the total demand costs collected from all Project Participants.

12. **Transmission Cost Adjustment for All-Requirements Services.**
The monthly bill computed hereunder shall adjust the base demand transmission capacity rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

TR = Transmission per kW/month ±TTCA

Where:
TR = Demand Transmission Rate to be applied to each kW of billed transmission demand.

TTCA = Transmission Total Cost Adjustment to be determined according to the same procedure as the ETCA except where kWh will be replaced by kW in item 3 within section 9.

13. **Funding for Participants' Load Retention Programs.**
Each Participant shall be credited with an amount equal to the Participants monthly billing energy times $0.30 per MWh. This credit may be used by the Participant to fund Load Retention Programs approved by the Participants' governing body, or for other lawful usage.

14. **Tax Adjustment Clause for All-Requirements Services.**
In the event of the imposition of any tax, or payment in lieu thereof, by any lawful authority on FMPA for production, transmission, or sale of electricity, the charges hereunder may be increased to pass on to the Project Participant its share of such tax or payment in lieu thereof.

15. **Late Payment Charge.** FMPA may impose a late payment charge on the unpaid balance of any amount not paid when due. Such charge shall be equal to the interest on the unpaid balance from the due date to the date of payment, with the interest rate being the arithmetic mean, to the nearest one-hundredth of one percent (.01%) of the prime rate values published in the Federal Reserve Bulletin for the fourth, third, and second months prior to the due date. The interest required to be paid under this clause will be compounded monthly.

16. **Month.** The month shall be in accordance with a schedule established by FMPA.

17. **Special Jacksonville Beach Charge.** In the event that FMPA pays or is billed for any amounts by the JEA for back-up transmission capability and/or transmission services and /or back-up electric service supplied by JEA for the City of Jacksonville Beach, such amounts shall be added to any amounts otherwise billed to the City of Jacksonville Beach by FMPA pursuant to this Schedule B-1, less one-third of such amounts, at such times as FMPA shall determine.

REVISIONS APPROVED BY THE FMPA EXECUTIVE COMMITTEE ON OCTOBER 17~~SEPTEMBER 19~~, 2024

FLORIDA MUNICIPAL POWER AGENCY
POWER SUPPLY RATE SCHEDULE
FOR
ALL-REQUIREMENTS PROJECT PARTICIPANTS

LOAD ATTRACTION INCENTIVE RATE RIDER

1. **Purpose.** The purpose of this Load Attraction Incentive Rate (LAIR) Rider is to encourage economic growth in Project Participant service territories by providing a financial incentive that a Project Participant can use as part of its package to attract a new, large load to its service territory that it would not otherwise have been able to attract, with the ultimate goal of reducing ARP excess capacity.

2. **Availability.** This Rider is available to all Project Participants except for those Project Participants that have established a Contract Rate of Delivery (CROD), have not executed a Supplemental Power and Ancillary Services Agreement, and meet at least one of the following conditions:
   - Zero (0) MW CROD
   - CROD/MAXD ratio below 1.0

3. **Applicability; Definition of New Load.** This Rider is available to each New Load of a Project Participant that meets the qualifying criteria set forth herein.

   For purposes of this Rider, "New Load" is defined as load being established after the date of the original approval date of this Rider:

   (a) by a new business (including occupation of an existing, dormant facility by a new business), by the expansion of an existing establishment, or

   (b) by the expansion of service territory by the Project Participant.

   (c) For existing establishments, New Load is the net incremental load, due to an expansion of business, above that which existed prior to approval for credits under this Rider.

   This Rider is not available for (1) New Load that would have occurred in the Project Participant's service territory without the financial incentive provided by this Rider, or (2) retention of existing load or for relocation of existing load within the Project Participant's service territory, except that relocating businesses that provide expansion of existing business may qualify for the expanded load only.

4. **Qualifying Criteria.** To qualify to receive the LAIR, each New Load must meet or exceed the following minimum size requirements, as measured in Section 5.:

(a) *For New Load in the service territories of Project Participants with a maximum weather-normalized annual All-Requirements Services demand less than 35 MW:* Each New Load must be (i) a minimum of 250 kW for each month at a single delivery point, or (ii) a minimum of 1 MW for new service territory at multiple delivery points.

(b) *For New Load in the service territories of Project Participants with a maximum weather-normalized annual All-Requirements Services demand greater than 35 MW:* Each New Load must be either (i) a minimum of 500 kW for each month at a single delivery point, or (ii) a minimum of 1 MW for new service territory at multiple delivery points.

Further, for purposes of computing its ARP billing demand capacity pursuant to paragraph 6 of Rate Schedule B-1, the Project Participant has hereby agreed to the following adjustments to its billing demand capacity calculation:

(a) Prior to the first fiscal year for which at least one month of metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 is available, the billing demand capacity for the New Load will be based on the Project Participant's best estimate of the New Load size. To the extent that actual metered demand data, once available, reveals a material difference between the estimated load size and the actual load size, FMPA will adjust the estimate for future months' billings. Further, the Executive Committee, in its sole discretion, may approve a true-up billing adjustment to the extent that the original estimate caused excess or deficient credits to be paid to the Project Participant, as applicable.

(b) For fiscal years for which at least one month, but less than twelve months, of metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 is available, the billing demand capacity for the New Load will be based on the arithmetic average of the available months' data.

(c) For fiscal years for which all of the metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 are available, the billing demand capacity for the New Load will be computed in accordance with paragraph 6 of Rate Schedule B-1.

(d) Notwithstanding the preceding, the billing demand capacity for the Project Participant's remaining load will be computed in accordance with paragraph 6 of Rate Schedule B-1.

5. **LAIR Description.** A credit based on the percentages below will be applied to the then-current base Demand Capacity Charge (in $/kW-mo.) set forth in Rate Schedule B-1 for each qualifying New Load of the Project Participant.

Service Month	Discount
1-12	50%
13-24	40%
25-36	30%
37-48	20%
49-60	10%
61 and beyond	0%

The credit shall be applied to the individual New Load's total 60 minute integrated demand at the time of the highest 60 minute integrated demand for the total of all ARP system Project Participants (or corrected to a 60 minute basis if demand registers other than 60 minute demand registers are installed) measured during the month (New Load CP Demand).

Credits for the previous month will be issued by FMPA to the Project Participant no later than the twentieth (20th) day of each month. Unless otherwise agreed between FMPA and the Project Participant, credits will be paid in the form of a check.

In no event can FMPA provide a credit for New Load that is proportionally above the Project Participant's load that is served by the ARP.

For a CROD Participant that has a CROD/MAXD ratio that falls below 1.0 following the addition of one or more qualifying New Loads, the monthly metered demand for the New Load(s) to which the credit is applied shall thereafter be adjusted by the following New Load Adjustment Factor over the remainder of the term under this Rider:

$$NLAdj = 1 - \frac{(MAXD - CROD)}{NLD}$$

Where:

NLAdj = New Load Adjustment Factor, expressed as a percentage, which shall be established in the month during which the CROD Participant's MAXD value first exceeds its CROD amount, and recomputed each time the CROD Participant's MAXD value changes.

CROD = The CROD Participant's Contract Rate of Delivery, which is a one-time calculation developed pursuant to Section 3(a) of the ARP Contract, as amended, and the Contract Rate of Delivery Implementation Protocols adopted by the Executive Committee.

MAXD = The CROD Participant's highest demand during the 12 months ending with the end of the current billing month, which is computed in accordance with Schedule C to the ARP Contract and the Contract Rate of Delivery Implementation Protocols adopted by the Executive Committee.

NLD = The sum of the metered demands of all of the CROD Participant's New Loads, as determined in this Section 5., computed during the first month in which the CROD Participant's MAXD value first exceeds its CROD amount, and recomputed in each subsequent month that either (i) the CROD Participant's MAXD value changes, or (ii) a New Load ceases to receive credits under this Rider.

And where NLAdj can never be greater than 100% or less than 0%.

Once the CROD/MAXD ratio falls below 1.0, per Section 2., the CROD Participant will be ineligible to apply for credits for additional New Load under this Rider.

All other charges to the Project Participant, including but not limited to the Demand Transmission Charge and the Energy Charge, shall be as set forth in the otherwise applicable ARP Rate Schedule(s). In addition, all other provisions of the Rate Schedule(s) otherwise applicable to the Project Participant shall continue to apply.

6. **Meter Requirements.** Metering equipment that can be used to measure each qualifying New Load separately from existing Project Participant load will be required to be installed in order to receive credits under this Rider. All meters shall be of a quality acceptable to FMPA. All metering costs pertaining to this program will be borne by the Project Participant or Project Participant's customer. The Project Participant may request FMPA to provide and install the required metering equipment; if so, FMPA will bill the Project Participant for the equipment costs. The

Project Participant must either provide FMPA with access to the meter information, or the Project Participant must provide the meter information for the previous calendar month to FMPA no later than the tenth (10^{th}) day of each month. In the event that it is either not possible or not practical to install metering that can measure the New Load CP Demand separate from existing Project Participant load, an alternative method for measuring the New Load CP Demand may be utilized at FMPA's sole discretion. Prior to being utilized, the alternative method must be approved by FMPA's General Manager and CEO as to its reasonableness in accurately measuring the New Load CP Demand, and the utilization of such alternative method must be reported to the FMPA Executive Committee at its next regularly scheduled meeting.

7. **Term of Service.** Except as limited below in this Section 7., credits provided under this Rider shall be for a term of five (5) years from the commencement of service of each New Load. Such credits under this Rider will terminate at the end of the five (5) year period.

Each New Load must meet or exceed the minimum size requirements, as measured by the New Load CP Demand, at least once during the initial six (6) month service period in order to continue to be eligible to receive the credit beyond that initial period.

Beginning in the seventh (7^{th}) service month, and continuing for the remainder of the service period under this Rider, the credit will be discontinued for any New Load that fails to maintain the minimum size requirements, as measured by the New Load CP Demand, during any three (3) consecutive months. Thereafter, if the New Load is able to resume meeting the minimum size requirements for three (3) consecutive months, payment of the credit will be reinstated beginning with the following month. The credit will be based on the percentage for the then-applicable service month in the table shown in Section 5. No retroactive credits shall be provided.

If the New Load either (1) ceases to take service from the Project Participant, or (2) reduces operations to such a level that it will no longer meet the qualifying criteria, the credit will be terminated immediately. The Project Participant must notify FMPA of such situations in a timely manner.

In the event of early termination of the credit, the Project Participant will not be required to reimburse FMPA for any credits received to that point, unless the Project Participant knowingly fails to notify FMPA in a timely fashion of any change to the New Load that would cause it to no longer qualify to receive the credit. In such a situation, the Project Participant will be required to reimburse FMPA for any credits received after the date on which the credits should have ceased.

8. **Sunset Provision.** This Rider will be available to qualifying New Loads that begin service on or before December 31,2024, or until a total of 30 MW of New Load has qualified under this Rider and/or any other incentive rate rider to Rate Schedule B-1, whichever occurs first.

9. **Exceptions.** Any exceptions to the requirements set forth under this Rider must be approved by the Executive Committee on a case-by-case basis.

THIS RIDER APPROVED BY THE FMPA EXECUTIVE COMMITTEE ON MAY 16, 2019, AMENDED ON OCTOBER 15, 2020

FLORIDA MUNICIPAL POWER AGENCY
POWER SUPPLY RATE SCHEDULE
FOR
ALL-REQUIREMENTS PROJECT PARTICIPANTS

ECONOMIC DEVELOPMENT RATE RIDER

1. **Purpose.** The purpose of this Economic Development Rate (EDR) Rider is to encourage economic growth in Project Participant service territories by providing a financial incentive that a Project Participant can use as part of its package to attract large, energy-intensive new business to its service territory that it would not otherwise have been able to attract, with the ultimate goal of reducing ARP excess capacity.

2. **Availability.** This Rider is available to all Project Participants except for those Project Participants that have established a Contract Rate of Delivery (CROD), have not executed a Supplemental Power and Ancillary Services Agreement, and meet at least one of the following conditions:
   - Zero (0) MW CROD
   - CROD/MAXD ratio below 1.0

3. **Applicability; Definition of New Load.** This Rider is available to each New Load of a Project Participant that meets the qualifying criteria set forth herein.

   For purposes of this Rider, “New Load” is defined as load being established after the effective date of this Rider by a new business (including occupation of an existing, dormant facility by a new business) or by the expansion of an existing establishment.

   This Rider is not available for (1) new load that would have occurred in the Project Participant’s service territory without the financial incentive provided by this Rider, or (2) retention of existing load or for relocation of existing load within the Project Participant’s service territory, except that relocating businesses that provide expansion of existing business may qualify for the expanded load only.

4. **Qualifying Criteria.** To qualify to receive the EDR, the ARP must have sufficient capacity available to serve each New Load for the first 10 years of service, and each New Load and Project Participant must meet the following criteria and conditions:

   (a) Each New Load must be a minimum of 5,000 kW for each month, as measured in Section 5, at a single location (multiple meters are allowed at a single campus)

(b) Each New Load must be energy-intensive, meaning the business uses a significant amount of electricity per square foot (at least 100 kWh/ft^2/year)

(c) Each New Load must be separately metered with information from such meters being available to FMPA, as described in Section 6

(d) Electricity price must be a significant determining factor in the site selection competition of the new or expanded business

(e) Project Participant must pass through the EDR demand and energy rates directly to the new or expanded business

- o Project Participant must recover its distribution, metering, and customer charges through an adder to the EDR demand rate at a discount, including reductions to general fund transfers. Such adder is not to be increased from the initially determined level during the first 10 years of service
- o Project Participant must pass through the EDR energy rate with zero adders

(f) Project Participant cannot receive generation capacity credits, through a Capacity and Energy Sales Contract, higher than the EDR for the amount of capacity used to serve the new or expanded business

For purposes of computing its ARP billing demand capacity pursuant to paragraph 6 of Rate Schedule B-1, the Project Participant has hereby agreed to the following adjustments to its billing demand capacity calculation:

(a) Prior to the first fiscal year for which at least one month of metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 is available, the billing demand capacity for the New Load will be based on the Project Participant’s best estimate of the New Load size. To the extent that actual metered demand data, once available, reveals a material difference between the estimated load size and the actual load size, FMPA will adjust the estimate for future months’ billings. Further, the Executive Committee, in its sole discretion, may approve a true-up billing adjustment to the extent that the original estimate caused excess or deficient credits to be paid to the Project Participant, as applicable.

(b) For fiscal years for which at least one month, but less than twelve months, of metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 is available, the billing demand capacity for the New Load will be based on the arithmetic average of the available months’ data.

(c) For fiscal years for which all of the metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 are available, the billing demand capacity for the New Load will be computed in accordance with paragraph 6 of Rate Schedule B-1.

(d) Notwithstanding the preceding, the billing demand capacity for the Project Participant's remaining load will be computed in accordance with paragraph 6 of Rate Schedule B-1.

5. **EDR Description.** The following Demand Charges will be applied in lieu of the then-current base Demand Capacity Charge (in $/kW-mo.) set forth in Rate Schedule B-1 for each qualifying New Load of the Project Participant for the period described in Section 7.

Service Month	Demand Charge ($/kW-mo)
EDR Demand Charge to be negotiated on a case-by-case basis and must be approved by the FMPA Executive Committee	

The EDR Demand Charge shall be applied to the individual New Load's total 60 minute integrated demand at the time of the highest 60 minute integrated demand for the New Load measured during the month (New Load Demand).

The EDR Energy Charge will negotiated on a case-by-case basis and must be (a) designed such that it attempts to recover no less than the ARP's cost to serve the new load, including fuel and non-fuel variable costs, and (b) approved by the FMPA Executive Committee

If the New Load fails to meet the 5,000 kW threshold in any three (3) consecutive months, the rates will automatically revert to the applicable Load Attraction Incentive Rate (LAIR) rider.

6. **Meter Requirements.** Metering equipment that can be used to measure each qualifying New Load separately from existing Project Participant load will be

required to be installed in order to receive EDR pricing for the New Load under this Rider. All meters must meet the same qualifications as those required at the Point of Measurement in the ARP Contract.

7. **Term of Service.** Except as limited below in this Section 7, pricing provided under this Rider shall be for a term to be negotiated on a case-by-case basis and approved by the FMPA Executive Committee. Such pricing under this Rider will terminate at the end of the negotiated service period.

   If the New Load either (1) ceases to take service from the Project Participant, or (2) modifies operations in such a way that it will no longer meet the qualifying criteria, the EDR pricing will be terminated immediately. The Project Participant must notify FMPA of such situations in a timely manner.

   In the event of early termination of the EDR pricing, the Project Participant will not be required to reimburse FMPA for any credits received to that point, unless the Project Participant knowingly fails to notify FMPA in a timely fashion of any change to the New Load that would cause it to no longer qualify. In such a situation, the Project Participant will be required to reimburse FMPA for any credits received after the date on which the EDR pricing should have ceased.

8. **Sunset Provision.** This Rider will be available to qualifying New Loads that begin service on or before December 31, 2024.

9. **Good Faith Business Development Efforts.** The Project Participant must demonstrate to the Executive Committee that a reasonable amount of good faith business development effort was undertaken to attract the New Load in order to qualify for EDR pricing as set forth in Section 5. Qualification for EDR pricing is at the discretion of the Executive Committee on a case-by-case basis.

10. **Exceptions.** Any exceptions to the requirements set forth under this Rider must be approved by the Executive Committee on a case-by-case basis.

THIS RIDER APPROVED BY THE FMPA EXECUTIVE COMMITTEE ON OCTOBER 15, 2020, AMENDED ON DECEMBER 10, 2020

FLORIDA MUNICIPAL POWER AGENCY
POWER SUPPLY RATE SCHEDULE
FOR
ALL-REQUIREMENTS PROJECT PARTICIPANTS

1. **Applicability.** Electric service for All-Requirements Services and Back-up and Support Services as defined in the All-Requirements Power Supply Project Contract for their own use and for resale.

2. **Availability.** This Schedule B-1 is available to the Project Participants purchasing electric capacity and energy from FMPA under the terms of the All-Requirements Power Supply Project Contracts as All-Requirements Services and, if applicable, as Back-Up and Support Services.

3. **Character of Service.** Electricity furnished under this Schedule B-1 at one or more Points of Delivery as set forth in Schedule A shall be sixty-hertz, three phase, alternating current.

4. **Billing Rate for All-Requirements Services.**
   (a) For electricity furnished hereunder as All-Requirements Services, the charges for each month shall be determined as follows:

Customer Charge	For each Project Participant, the charge is $1,000.00 per Point of Delivery. Notwithstanding the above, the charge for a Project Participant that has both (1) established its Contract Rate of Delivery and (2) does not receive Network Integration Transmission Service under an ARP agreement is $0.00.
Demand Capacity Charge	$ 16.04 per kilowatt ("kW") of capacity billing demand
Demand Transmission	$ 5.06 per kilowatt ("kW") of transmission billing demand
Demand Transmission Kissimmee Utility Authority	$ 0.65 per kilowatt ("kW") of transmission billing demand
Energy Charge	$ 32.66 per megawatt-hour ("MWh") for all energy supplied as All-Requirements Services

Solar Energy Surcharge	A $ per megawatt-hour ("MWh") rate, as calculated monthly in accordance with 10 below, for all energy pursuant to the applicable solar Power Purchase Agreement(s) ("PPA"), as specifically agreed to by individual Project Participants pursuant to Solar Participant Agreements between the ARP and individual Project Participants (hereinafter "Solar Participants").
Reactive Demand Charge	$0.00 per kilo-var ("kVAR") of excess billing reactive demand

(b) Delivery Voltage Adjustment for All-Requirements Services. The Billing Rates under paragraph (a) are based on delivery of electric capacity and energy to the Project Participant at 115,000 volts or higher. Where capacity and energy are delivered at voltages less than 115,000 volts, the Billing Rates under paragraph (a) shall be increased as follows:

Delivery Voltage	Demand Charge Adjustment	Energy Charge Adjustment
69,000 volts	$0.000/kW	$0.0000/kWh
12,000/25,000 volts	$0.722/kW	$0.0000/kWh
Under 12,000 volts	$0.722/kW	$0.0000/kWh

5. **Billing Metering for All-Requirements Services.** The metered demand in kW in each month shall be the individual Project Participant's total 60 minute integrated demand at the time of the highest 60 minute integrated demand for the total of all ARP system Project Participants (or corrected to a 60 minute basis if demand registers other than 60 minute demand registers are installed) measured during the month.

The metered reactive demand in kVAR in each month shall be the reactive demand, which occurred during the same 60-minute demand interval in which the metered kilowatt demand occurred.

Demand and energy meter readings shall be adjusted, if appropriate, as provided in Schedule A of the All-Requirements Power Supply Project Contract.

6. **Billing Demand-Capacity for All-Requirements Services.** The billing demand capacity in any period shall be the arithmetic average of the metered demands, as determined under paragraph 5, giving effect to all adjustments, less the Project Participant's Excluded Power Supply Resources capacity, if any, for the months of June, July, August, and September for the preceding three fiscal years. For avoidance of doubt, unless otherwise adjusted as follows in this

paragraph 6, the monthly billing demand capacity for each Project Participant shall be based on the arithmetic average of 12 data points and shall remain fixed over the current fiscal year.

If a Project Participant has permanently lost a large load during the preceding three fiscal years that would cause the metered demands utilized for that Project Participant in the billing demand capacity calculation not to be representative of its current load, the metered demands utilized in the calculation for that Project Participant may be adjusted accordingly by a majority vote of the Executive Committee in its sole discretion. Such load must represent a minimum of five percent of the Project Participant's total load based on demonstrable load data. It is the responsibility of the Project Participant to notify FMPA of any such loss of load, and no adjustments shall be made to billings for months prior to the effective date of any adjustment approved by the Executive Committee.

If a Project Participant has added a large load during the preceding three years for which a demand-related financial incentive will be provided through a rider to this Rate Schedule B-1, the metered demands utilized in the calculation for that Project Participant will be adjusted as set forth in the respective rider.

Anomalous loads for an individual Project Participant may be excluded from the billing demand capacity calculation by majority vote of the Executive Committee.

7. **Billing Demand-Transmission for All-Requirements Services.** The billing demand capacity in any period shall be the metered demand for the period as determined under paragraph 5, giving effect to all adjustments, but including the Project Participant's, Excluded Power Supply Resources capacity, if any.

8. **Billing Reactive Demand for All-Requirements Services.**
The billing reactive demand for any month shall be the amount of reactive demand in kVAR by which the metered reactive demand exceeds one-half of the metered kilowatt demands, or such other amount as shall be determined from time to time by FMPA.

9. **Energy Cost Adjustment for All-Requirements Services.**
The monthly bill computed hereunder shall adjust the base energy rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

$$ER = \$0.03266/kWh \pm ETCA$$

Where:
ER = Energy Rate to be applied to each kWh of billed energy.
ETCA = Energy Total Cost Adjustment to be determined according to the following procedure:

1. The number of days of available cash will be determined each month and rounded to the nearest five days.

2. A confidence percentage based on the following table will be selected to determine the amount of the total cost adjustment. The Confidence Percentage will then be applied to the output of the probabilistic model discussed below.

Days of Available Cash	Associated Confidence Percentage
30 day or less	95%
35 days	88%
40 days	80%
45 days	73%
50 days	65%
55 days	58%
60 days	50%
65 days	43%
70 days	35%
75 days	28%
80 days	20%
85 days	13%
90 days and over	5%

3. A probabilistic model will be used to estimate the next four months of projected energy total cost and projected total kWh sales for providing the All-Requirements Project power supply. For purposes of this adjustment, FMPA's owned and controlled generating units including purchased power or interchange power purchased by FMPA from other suppliers less the energy cost of sales to other utilities, will be used in the calculations.

4. A probabilistic model will also be used to allocate the most current ARP Participant over-recovery and under-recovery balance as listed in the ARP's Comparative Statement of Net Asset report. This balance will be applied over the next four months and tied to the appropriate percentage level listed

in the table above.

10. **Solar Energy Surcharge.**

The Solar Energy Surcharge shall equal the difference between the adjusted energy rate calculated in 9 above (ER) and the actual monthly cost per MWh of the solar energy (note the surcharge could be negative). The following provisions shall apply to the calculation of the surcharge:

1. Solar energy costs shall equal the sum of the applicable solar PPA charges, FMPA A&G charges allocated to the solar PPA(s), the return to the Agency Development Fund of the costs advanced to enter into and implement the solar PPA(s), and other costs or charges that the ARP may incur related to utilizing solar energy as part of its resource portfolio, e.g. increased regulation charges assessed by the ARP's Balancing Authority.

2. The following All-Requirements Project Participants have responsibility for solar energy (MWh) in each hour that solar energy is produced under the applicable solar PPA(s):

Phase I solar PPAs between the ARP and NextEra Florida Renewables, or its successor or assigns:

The City of Jacksonville Beach	17.241%
Fort Pierce Utilities Authority	5.173%
Utility Board, City of Key West	8.621%
Kissimmee Utility Authority	51.724%
The City of Ocala	17.241%

Phase II solar Rice Creek PPA between the ARP and Origis Energy, or its successors or assigns:

The City of Jacksonville Beach	15.584%
Fort Pierce Utilities Authority	15.584%
The Town of Havana	0.260%
Utility Board, City of Key West	25.975%
Kissimmee Utility Authority	20.779%
The City of Newberry	1.039%
The City of Ocala	20.779%

Phase II solar Whistling Duck PPA between the ARP and Origis Energy, or its successors or assigns:

Utility Board, City of Key West	100.000%

Phase III solar PPA between the ARP and Origis Energy, or its successors or assigns:

Utility Board, City of Key West	21.751%
The City of Ocala	6.869%

3. In the event that one or more of the Solar Participants defaults by not paying the Solar Energy Surcharge, the defaulting Project Participant(s) shall remain liable for all payments to be made on its part pursuant to this Rate Schedule B-1. In such event, each non-defaulting Solar Participant's All-Requirements bill shall be increased, on a pro rata basis based on its respective Solar Energy Surcharge percentage of the applicable solar PPA(s), the amount in default unless and until FMPA shall recover from the defaulting Solar Participant(s) all amounts owed, upon which FMPA shall reimburse the non-defaulting Solar Participants. If all Solar Participants default by not paying the Solar Energy Surcharge, the All-Requirements Project will be obligated for the applicable Power Purchase Agreement(s) and the solar costs will become part of the Energy Rate (ER) above applicable to all All-Requirements Project Participants, including the defaulting Solar Participants, unless and until FMPA shall recover from at least one of the defaulting Solar Participants all amounts owed by all Solar Participants, upon which FMPA shall reimburse the All-Requirements Project Participants either through rates or through such other method as directed by the Executive Committee

4. A Solar Participant may only exit from the financial obligation to pay the Solar Energy Surcharge if one of the following four conditions are met, subject to approval of the Executive Committee:

   a. One or more Solar Participants assumes the exiting Solar Participant's entire Solar Energy Surcharge financial obligation to the ARP;

   b. One or more All-Requirements Project Participants assumes the exiting Solar Participant's entire Solar Energy Surcharge financial obligation to the ARP;

   c. One or more FMPA Members that is not an All-Requirements Project Participant assumes the financial entitlement to the Solar Participant's percentage share of the applicable solar PPA(s) and commits that it will take on the (i) associated financial obligation and (ii) obligation to take solar energy, in a form suitable to the ARP; or

d. Pay stranded cost obligations, as determined by FMPA in its sole discretion, to hold the other Solar Participants harmless from the costs associated with the Solar Participant's exit.

   Stranded cost obligations are defined as an estimate of the solar energy costs (defined in 10.1) that the ARP will pay for the exiting Solar Participant's solar energy entitlement during each remaining month of the remaining term of the applicable solar PPA(s) based on (i) a forecast of expected solar production and (ii) a reasonable assessment of unforeseen costs, and are to be paid at the time of exit. The forecast of expected solar production is defined as a P50 (probability of exceedance is 50 percent) production estimate under typical meteorological year conditions using an industry standard modeling tool (PV Syst or its successor/peer products) reflective of a degradation rate of 0.3% per year relative to the original nominal alternating current capacity of the solar resource in the current year (prorated over a partial year as applicable) and each subsequent remaining year of the applicable solar PPA(s) term.

11. **Demand Cost True-up for All-Requirements Services.**
Each Project Participant shall be charged or credited, as applicable, during the twelve months commencing with the billing for October service of a subsequent fiscal year by a dollar amount equal to one twelfth of the dollar amount share of the difference between the Project Participant's actual demand costs (excluding transmission) and the demand charges collected during the previous fiscal year. The amount to be charged or credited to each Project Participant shall be calculated on the basis of each Project Participant's demand costs (excluding transmission) collected during the previous fiscal year as a percentage of the total demand costs collected from all Project Participants.

12. **Transmission Cost Adjustment for All-Requirements Services.**
The monthly bill computed hereunder shall adjust the base demand transmission capacity rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

$$TR = \text{Transmission per kW/month} \pm TTCA$$

Where:
TR = Demand Transmission Rate to be applied to each kW of billed transmission demand.

TTCA = Transmission Total Cost Adjustment to be determined according to the same procedure as the ETCA except where kWh will be replaced by kW in item 3 within section 9.

13. **Funding for Participants' Load Retention Programs.**
Each Participant shall be credited with an amount equal to the Participants monthly billing energy times $0.30 per MWh. This credit may be used by the Participant to fund Load Retention Programs approved by the Participants' governing body, or for other lawful usage.

14. **Tax Adjustment Clause for All-Requirements Services.**
In the event of the imposition of any tax, or payment in lieu thereof, by any lawful authority on FMPA for production, transmission, or sale of electricity, the charges hereunder may be increased to pass on to the Project Participant its share of such tax or payment in lieu thereof.

15. **Late Payment Charge.** FMPA may impose a late payment charge on the unpaid balance of any amount not paid when due. Such charge shall be equal to the interest on the unpaid balance from the due date to the date of payment, with the interest rate being the arithmetic mean, to the nearest one-hundredth of one percent (.01%) of the prime rate values published in the Federal Reserve Bulletin for the fourth, third, and second months prior to the due date. The interest required to be paid under this clause will be compounded monthly.

16. **Month.** The month shall be in accordance with a schedule established by FMPA.

17. **Special Jacksonville Beach Charge.** In the event that FMPA pays or is billed for any amounts by the JEA for back-up transmission capability and/or transmission services and /or back-up electric service supplied by JEA for the City of Jacksonville Beach, such amounts shall be added to any amounts otherwise billed to the City of Jacksonville Beach by FMPA pursuant to this Schedule B-1, less one-third of such amounts, at such times as FMPA shall determine.

REVISIONS APPROVED BY THE FMPA EXECUTIVE COMMITTEE ON OCTOBER 17, 2024

FLORIDA MUNICIPAL POWER AGENCY
POWER SUPPLY RATE SCHEDULE
FOR
ALL-REQUIREMENTS PROJECT PARTICIPANTS

LOAD ATTRACTION INCENTIVE RATE RIDER

1. **Purpose.** The purpose of this Load Attraction Incentive Rate (LAIR) Rider is to encourage economic growth in Project Participant service territories by providing a financial incentive that a Project Participant can use as part of its package to attract a new, large load to its service territory that it would not otherwise have been able to attract, with the ultimate goal of reducing ARP excess capacity.

2. **Availability.** This Rider is available to all Project Participants except for those Project Participants that have established a Contract Rate of Delivery (CROD), have not executed a Supplemental Power and Ancillary Services Agreement, and meet at least one of the following conditions:
   - Zero (0) MW CROD
   - CROD/MAXD ratio below 1.0

3. **Applicability; Definition of New Load.** This Rider is available to each New Load of a Project Participant that meets the qualifying criteria set forth herein.

   For purposes of this Rider, "New Load" is defined as load being established after the date of the original approval date of this Rider:

   (a) by a new business (including occupation of an existing, dormant facility by a new business), by the expansion of an existing establishment, or

   (b) by the expansion of service territory by the Project Participant.

   (c) For existing establishments, New Load is the net incremental load, due to an expansion of business, above that which existed prior to approval for credits under this Rider.

   This Rider is not available for (1) New Load that would have occurred in the Project Participant's service territory without the financial incentive provided by this Rider, or (2) retention of existing load or for relocation of existing load within the Project Participant's service territory, except that relocating businesses that provide expansion of existing business may qualify for the expanded load only.

4. **Qualifying Criteria.** To qualify to receive the LAIR, each New Load must meet or exceed the following minimum size requirements, as measured in Section 5.:

(a) *For New Load in the service territories of Project Participants with a maximum weather-normalized annual All-Requirements Services demand less than 35 MW:* Each New Load must be (i) a minimum of 250 kW for each month at a single delivery point, or (ii) a minimum of 1 MW for new service territory at multiple delivery points.

(b) *For New Load in the service territories of Project Participants with a maximum weather-normalized annual All-Requirements Services demand greater than 35 MW:* Each New Load must be either (i) a minimum of 500 kW for each month at a single delivery point, or (ii) a minimum of 1 MW for new service territory at multiple delivery points.

Further, for purposes of computing its ARP billing demand capacity pursuant to paragraph 6 of Rate Schedule B-1, the Project Participant has hereby agreed to the following adjustments to its billing demand capacity calculation:

(a) Prior to the first fiscal year for which at least one month of metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 is available, the billing demand capacity for the New Load will be based on the Project Participant's best estimate of the New Load size. To the extent that actual metered demand data, once available, reveals a material difference between the estimated load size and the actual load size, FMPA will adjust the estimate for future months' billings. Further, the Executive Committee, in its sole discretion, may approve a true-up billing adjustment to the extent that the original estimate caused excess or deficient credits to be paid to the Project Participant, as applicable.

(b) For fiscal years for which at least one month, but less than twelve months, of metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 is available, the billing demand capacity for the New Load will be based on the arithmetic average of the available months' data.

(c) For fiscal years for which all of the metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 are available, the billing demand capacity for the New Load will be computed in accordance with paragraph 6 of Rate Schedule B-1.

(d) Notwithstanding the preceding, the billing demand capacity for the Project Participant's remaining load will be computed in accordance with paragraph 6 of Rate Schedule B-1.

5. **LAIR Description.** A credit based on the percentages below will be applied to the then-current base Demand Capacity Charge (in $/kW-mo.) set forth in Rate Schedule B-1 for each qualifying New Load of the Project Participant.

Service Month	Discount
1-12	50%
13-24	40%
25-36	30%
37-48	20%
49-60	10%
61 and beyond	0%

The credit shall be applied to the individual New Load's total 60 minute integrated demand at the time of the highest 60 minute integrated demand for the total of all ARP system Project Participants (or corrected to a 60 minute basis if demand registers other than 60 minute demand registers are installed) measured during the month (New Load CP Demand).

Credits for the previous month will be issued by FMPA to the Project Participant no later than the twentieth (20th) day of each month. Unless otherwise agreed between FMPA and the Project Participant, credits will be paid in the form of a check.

In no event can FMPA provide a credit for New Load that is proportionally above the Project Participant's load that is served by the ARP.

For a CROD Participant that has a CROD/MAXD ratio that falls below 1.0 following the addition of one or more qualifying New Loads, the monthly metered demand for the New Load(s) to which the credit is applied shall thereafter be adjusted by the following New Load Adjustment Factor over the remainder of the term under this Rider:

$$NLAdj = 1 - \frac{(MAXD - CROD)}{NLD}$$

Where:

NLAdj = New Load Adjustment Factor, expressed as a percentage, which shall be established in the month during which the CROD Participant's MAXD value first exceeds its CROD amount, and recomputed each time the CROD Participant's MAXD value changes.

CROD = The CROD Participant's Contract Rate of Delivery, which is a one-time calculation developed pursuant to Section 3(a) of the ARP Contract, as amended, and the Contract Rate of Delivery Implementation Protocols adopted by the Executive Committee.

MAXD = The CROD Participant's highest demand during the 12 months ending with the end of the current billing month, which is computed in accordance with Schedule C to the ARP Contract and the Contract Rate of Delivery Implementation Protocols adopted by the Executive Committee.

NLD = The sum of the metered demands of all of the CROD Participant's New Loads, as determined in this Section 5., computed during the first month in which the CROD Participant's MAXD value first exceeds its CROD amount, and recomputed in each subsequent month that either (i) the CROD Participant's MAXD value changes, or (ii) a New Load ceases to receive credits under this Rider.

And where NLAdj can never be greater than 100% or less than 0%.

Once the CROD/MAXD ratio falls below 1.0, per Section 2., the CROD Participant will be ineligible to apply for credits for additional New Load under this Rider.

All other charges to the Project Participant, including but not limited to the Demand Transmission Charge and the Energy Charge, shall be as set forth in the otherwise applicable ARP Rate Schedule(s). In addition, all other provisions of the Rate Schedule(s) otherwise applicable to the Project Participant shall continue to apply.

6. **Meter Requirements.** Metering equipment that can be used to measure each qualifying New Load separately from existing Project Participant load will be required to be installed in order to receive credits under this Rider. All meters shall be of a quality acceptable to FMPA. All metering costs pertaining to this program will be borne by the Project Participant or Project Participant's customer. The Project Participant may request FMPA to provide and install the required metering equipment; if so, FMPA will bill the Project Participant for the equipment costs. The

Project Participant must either provide FMPA with access to the meter information, or the Project Participant must provide the meter information for the previous calendar month to FMPA no later than the tenth (10^{th}) day of each month. In the event that it is either not possible or not practical to install metering that can measure the New Load CP Demand separate from existing Project Participant load, an alternative method for measuring the New Load CP Demand may be utilized at FMPA's sole discretion. Prior to being utilized, the alternative method must be approved by FMPA's General Manager and CEO as to its reasonableness in accurately measuring the New Load CP Demand, and the utilization of such alternative method must be reported to the FMPA Executive Committee at its next regularly scheduled meeting.

7. **Term of Service.** Except as limited below in this Section 7., credits provided under this Rider shall be for a term of five (5) years from the commencement of service of each New Load. Such credits under this Rider will terminate at the end of the five (5) year period.

Each New Load must meet or exceed the minimum size requirements, as measured by the New Load CP Demand, at least once during the initial six (6) month service period in order to continue to be eligible to receive the credit beyond that initial period.

Beginning in the seventh (7^{th}) service month, and continuing for the remainder of the service period under this Rider, the credit will be discontinued for any New Load that fails to maintain the minimum size requirements, as measured by the New Load CP Demand, during any three (3) consecutive months. Thereafter, if the New Load is able to resume meeting the minimum size requirements for three (3) consecutive months, payment of the credit will be reinstated beginning with the following month. The credit will be based on the percentage for the then-applicable service month in the table shown in Section 5. No retroactive credits shall be provided.

If the New Load either (1) ceases to take service from the Project Participant, or (2) reduces operations to such a level that it will no longer meet the qualifying criteria, the credit will be terminated immediately. The Project Participant must notify FMPA of such situations in a timely manner.

In the event of early termination of the credit, the Project Participant will not be required to reimburse FMPA for any credits received to that point, unless the Project Participant knowingly fails to notify FMPA in a timely fashion of any change to the New Load that would cause it to no longer qualify to receive the credit. In such a situation, the Project Participant will be required to reimburse FMPA for any credits received after the date on which the credits should have ceased.

8. **Sunset Provision.** This Rider will be available to qualifying New Loads that begin service on or before December 31,2024, or until a total of 30 MW of New Load has qualified under this Rider and/or any other incentive rate rider to Rate Schedule B-1, whichever occurs first.

9. **Exceptions.** Any exceptions to the requirements set forth under this Rider must be approved by the Executive Committee on a case-by-case basis.

THIS RIDER APPROVED BY THE FMPA EXECUTIVE COMMITTEE ON MAY 16, 2019, AMENDED ON OCTOBER 15, 2020

FLORIDA MUNICIPAL POWER AGENCY
POWER SUPPLY RATE SCHEDULE
FOR
ALL-REQUIREMENTS PROJECT PARTICIPANTS

ECONOMIC DEVELOPMENT RATE RIDER

1. **Purpose.** The purpose of this Economic Development Rate (EDR) Rider is to encourage economic growth in Project Participant service territories by providing a financial incentive that a Project Participant can use as part of its package to attract large, energy-intensive new business to its service territory that it would not otherwise have been able to attract, with the ultimate goal of reducing ARP excess capacity.

2. **Availability.** This Rider is available to all Project Participants except for those Project Participants that have established a Contract Rate of Delivery (CROD), have not executed a Supplemental Power and Ancillary Services Agreement, and meet at least one of the following conditions:
   - Zero (0) MW CROD
   - CROD/MAXD ratio below 1.0

3. **Applicability; Definition of New Load.** This Rider is available to each New Load of a Project Participant that meets the qualifying criteria set forth herein.

   For purposes of this Rider, "New Load" is defined as load being established after the effective date of this Rider by a new business (including occupation of an existing, dormant facility by a new business) or by the expansion of an existing establishment.

   This Rider is not available for (1) new load that would have occurred in the Project Participant's service territory without the financial incentive provided by this Rider, or (2) retention of existing load or for relocation of existing load within the Project Participant's service territory, except that relocating businesses that provide expansion of existing business may qualify for the expanded load only.

4. **Qualifying Criteria.** To qualify to receive the EDR, the ARP must have sufficient capacity available to serve each New Load for the first 10 years of service, and each New Load and Project Participant must meet the following criteria and conditions:

   (a) Each New Load must be a minimum of 5,000 kW for each month, as measured in Section 5, at a single location (multiple meters are allowed at a single campus)

(b) Each New Load must be energy-intensive, meaning the business uses a significant amount of electricity per square foot (at least 100 kWh/ft^2/year)

(c) Each New Load must be separately metered with information from such meters being available to FMPA, as described in Section 6

(d) Electricity price must be a significant determining factor in the site selection competition of the new or expanded business

(e) Project Participant must pass through the EDR demand and energy rates directly to the new or expanded business

- o Project Participant must recover its distribution, metering, and customer charges through an adder to the EDR demand rate at a discount, including reductions to general fund transfers. Such adder is not to be increased from the initially determined level during the first 10 years of service
- o Project Participant must pass through the EDR energy rate with zero adders

(f) Project Participant cannot receive generation capacity credits, through a Capacity and Energy Sales Contract, higher than the EDR for the amount of capacity used to serve the new or expanded business

For purposes of computing its ARP billing demand capacity pursuant to paragraph 6 of Rate Schedule B-1, the Project Participant has hereby agreed to the following adjustments to its billing demand capacity calculation:

(a) Prior to the first fiscal year for which at least one month of metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 is available, the billing demand capacity for the New Load will be based on the Project Participant’s best estimate of the New Load size. To the extent that actual metered demand data, once available, reveals a material difference between the estimated load size and the actual load size, FMPA will adjust the estimate for future months’ billings. Further, the Executive Committee, in its sole discretion, may approve a true-up billing adjustment to the extent that the original estimate caused excess or deficient credits to be paid to the Project Participant, as applicable.

(b) For fiscal years for which at least one month, but less than twelve months, of metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 is available, the billing demand capacity for the New Load will be based on the arithmetic average of the available months’ data.

(c) For fiscal years for which all of the metered demands to be utilized in the calculation set forth in paragraph 6 of Rate Schedule B-1 are available, the billing demand capacity for the New Load will be computed in accordance with paragraph 6 of Rate Schedule B-1.

(d) Notwithstanding the preceding, the billing demand capacity for the Project Participant's remaining load will be computed in accordance with paragraph 6 of Rate Schedule B-1.

5. **EDR Description.** The following Demand Charges will be applied in lieu of the then-current base Demand Capacity Charge (in $/kW-mo.) set forth in Rate Schedule B-1 for each qualifying New Load of the Project Participant for the period described in Section 7.

Service Month	Demand Charge ($/kW-mo)
EDR Demand Charge to be negotiated on a case-by-case basis and must be approved by the FMPA Executive Committee	

The EDR Demand Charge shall be applied to the individual New Load's total 60 minute integrated demand at the time of the highest 60 minute integrated demand for the New Load measured during the month (New Load Demand).

The EDR Energy Charge will negotiated on a case-by-case basis and must be (a) designed such that it attempts to recover no less than the ARP's cost to serve the new load, including fuel and non-fuel variable costs, and (b) approved by the FMPA Executive Committee

If the New Load fails to meet the 5,000 kW threshold in any three (3) consecutive months, the rates will automatically revert to the applicable Load Attraction Incentive Rate (LAIR) rider.

6. **Meter Requirements.** Metering equipment that can be used to measure each qualifying New Load separately from existing Project Participant load will be

required to be installed in order to receive EDR pricing for the New Load under this Rider. All meters must meet the same qualifications as those required at the Point of Measurement in the ARP Contract.

7. **Term of Service.** Except as limited below in this Section 7, pricing provided under this Rider shall be for a term to be negotiated on a case-by-case basis and approved by the FMPA Executive Committee. Such pricing under this Rider will terminate at the end of the negotiated service period.

   If the New Load either (1) ceases to take service from the Project Participant, or (2) modifies operations in such a way that it will no longer meet the qualifying criteria, the EDR pricing will be terminated immediately. The Project Participant must notify FMPA of such situations in a timely manner.

   In the event of early termination of the EDR pricing, the Project Participant will not be required to reimburse FMPA for any credits received to that point, unless the Project Participant knowingly fails to notify FMPA in a timely fashion of any change to the New Load that would cause it to no longer qualify. In such a situation, the Project Participant will be required to reimburse FMPA for any credits received after the date on which the EDR pricing should have ceased.

8. **Sunset Provision.** This Rider will be available to qualifying New Loads that begin service on or before December 31, 2024.

9. **Good Faith Business Development Efforts.** The Project Participant must demonstrate to the Executive Committee that a reasonable amount of good faith business development effort was undertaken to attract the New Load in order to qualify for EDR pricing as set forth in Section 5. Qualification for EDR pricing is at the discretion of the Executive Committee on a case-by-case basis.

10. **Exceptions.** Any exceptions to the requirements set forth under this Rider must be approved by the Executive Committee on a case-by-case basis.

THIS RIDER APPROVED BY THE FMPA EXECUTIVE COMMITTEE ON OCTOBER 15, 2020, AMENDED ON DECEMBER 10, 2020

AGENDA ITEM 8 – ACTION ITEMS

c. Approval of Resolution 2024-EC5 – Approval of FMPA's PGP Board of Directors Appointment

Executive Committee
October 17, 2024

RESOLUTION OF THE EXECUTIVE COMMITTEE OF THE FLORIDA MUNICIPAL POWER AGENCY: (I) PROVIDING FOR DEFINED TERMS; (II) PROVIDING FOR THE APPOINTMENT OF FLORIDA MUNICIPAL POWER AGENCY'S DIRECTOR FOR PUBLIC GAS PARTNERS, INC.; AND (III) PROVIDING AN EFFECTIVE DATE.

Whereas, FMPA is a Member of Public Gas Partners, Inc. ("**PGP**"), which is governed by a Board comprised of Directors appointed by each Member of PGP;

Whereas, Jacob A. Williams has served as FMPA's Director on the PGP Board of Directors since 2016, but FMPA now desires to appoint Richard M. Popp, as FMPA's Chief Financial Officer, to serve as its Director on the Board of PGP.

BE IT RESOLVED BY THE EXECUTIVE COMMITTEE OF THE FLORIDA MUNICIPAL POWER AGENCY THAT:

SECTION I. **Defined Terms**. Capitalized terms used in this resolution, but not defined herein, shall have the meanings ascribed to them in the Bylaws of PGP.

SECTION II. **Appointment of Richard M. Popp as PGP Director**. FMPA hereby appoints Richard M. Popp, Chief Financial Officer, to serve as FMPA's Director on the Board of PGP.

SECTION III. **Effective Date**. This Resolution shall take effect immediately upon its adoption.

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This Resolution 2024-EC5 is hereby approved and adopted by the Executive Committee of the Florida Municipal Power Agency on October 17, 2024.

____
Chairperson, Executive Committee

I HEREBY CERTIFY that on October 27, 2024, the above Resolution 2024-EC5 was approved and adopted by the Executive Committee of the Florida Municipal Power Agency, and that this is a true and conformed copy of Resolution 2024-EC5.

ATTEST:

______________________________ SEAL
Secretary or Assistant Secretary

AGENDA ITEM 9 – INFORMATION ITEMS

a. Section 29 Withdrawal Payment Estimates for 2024

Executive Committee
October 17, 2024

9a - Section 29 Withdrawal Payment Estimates for 2024

Executive Committee

October 17, 2024

Section 29 – Early Termination of ARP Contract

Withdrawal May Occur w/ 3-Years Notice, Payments Required

- ARP contract allows participant to withdraw from ARP with three-years notice, but must pay to keep remaining participants whole
- In 2016, FMPA committed to providing each participant with biennial estimate of its Section 29 withdrawal cost
- In August 2016, EC approved a set of “Protocols” to guide the calculation of the withdrawal payment
- Withdrawal cost estimates were provided to all participants in 2018, 2020, and 2022 based on the approved Protocols
- Vero Beach Section 29 withdrawal completed in December 2018, Section 29 withdrawal payment ~$30M
- We are now providing the next biennial withdrawal payment estimates

2 Components to Withdrawal Payment

Methodology Set Forth in Section 29(c)

- 29(c)1: Load ratio share of outstanding ARP Bonds
- 29(c)2: "Stranded costs" over remaining term of withdrawing Participant's ARP Contract

Section 29(c)1 Costs Are Debt Costs

Ensures Bondholders Recover Exiting Participant's Share of Outstanding Debt

- Costs include:
  - Principal amounts of ARP revenue bonds projected to be outstanding after withdrawal date, excluded principal amounts already accrued through rates
  - Interest on the bonds until the earliest projected call date
  - Outstanding balances on lines of credit
- Costs assigned to withdrawing participant based on load ratio share

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Section 29(c)2 Costs Referred to as "Stranded Costs"

Contract Not Prescriptive on Methodology for Stranded Costs

- Per ARP Contract, stranded costs are computed:
  - Over "term specified in such Project Participant's All-Requirements Power Supply Project Contract (as determined on the anticipated withdrawal date)"
  - Assuming that "FMPA was unable to make use of or sell any generating, transmission or other resources (or portions thereof) which FMPA had anticipated would be used to supply, or had acquired with the intention of supplying, all or any portion of the withdrawing Project Participant's electric load."
- Stranded costs allocated based on a load ratio share basis, with specific allocation based on timing and purpose of the resource acquisition
- Projected stranded costs are present valued to the withdrawal date at a contractually-specified 6% discount rate

Cost Categories Included in Stranded Costs

Included Feedback from Baker Tilly

- Generating resource operation and maintenance costs
- Generating resource capital additions costs
- Generating resource decommissioning costs
- Fixed natural gas transportation costs
- Firm Point-to-Point transmission costs
- Fixed purchased power costs
- Member Project capacity costs (Stanton, Tri-City, Stanton II Projects)
- Debt related costs (other than Bonds)
- Direct charges & other

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Payment Calculation Is Not a Market Valuation

FMPA Manages Risk for Members in Calculating Withdrawal Payment

- Section 29 withdrawal payment must protect bondholders, credit support providers, non-withdrawing Participants from financial harm
- One-time payment with no clawback provision if FMPA undercollects withdrawal costs, so must estimate in FMPA's favor
- Payment calculation is not an analysis of whether ARP assets are above or below market value
- Note if FMPA achieves "Additional Benefits" as result of Participant's withdrawal, FMPA must refund such amounts to Participant, up to 90% of 29(c)2 withdrawal payment (Section 29(f))

Additional Notes on Estimates

- Estimates assume participant gives Section 29 withdrawal notice no later than 9/30/2024, for 9/30/2027 withdrawal date
- Withdrawal cost estimates are not additive across participants
  - Each estimate calculated as if only that participant withdraws
- Solar costs reflected for those cities participating in ARP solar commitments Estimates do not include additional costs that may be specific to certain participants if they withdraw
  - e.g., certain costs to KUA and Keys pursuant to TARP agreements
- These estimates are subject to change; actual withdrawal costs would be computed at the time of the participant’s withdrawal

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2024 Section 29 Withdrawal Cost Estimates ($Millions)

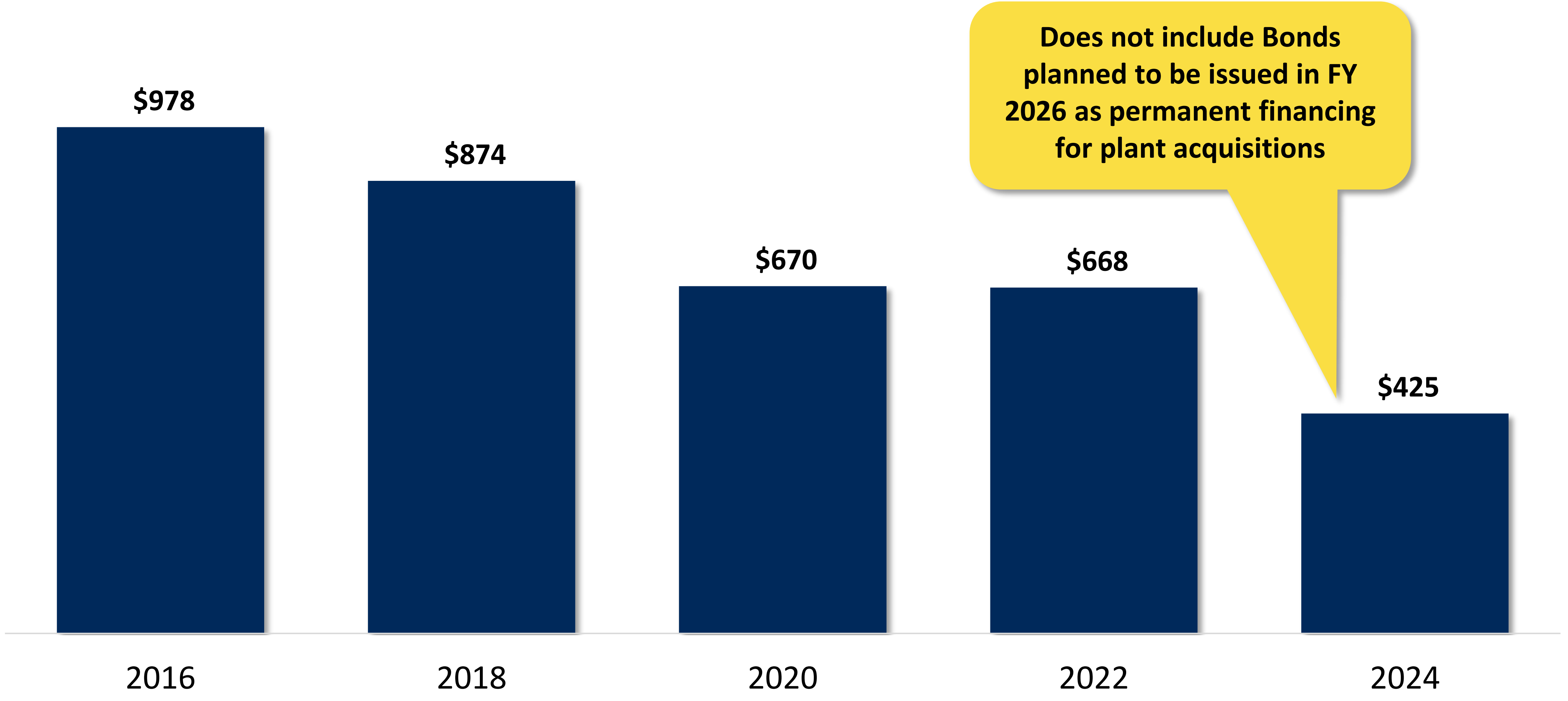
Member	Section 29(c)1	Section 29(c)2	Total	2022 Total
Bushnell	$4.3	$27.3	$31.6	$29.3
Clewiston	$6.3	$54.2	$60.5	$56.7
Fort Meade	$3.0	$17.3	$20.4	$21.1
Fort Pierce	$34.7	$279.4	$314.1	$299.1
Green Cove Springs	$7.2	$38.3	$45.5	$48.0
Havana	$1.7	$13.7	$15.3	$14.5
Jacksonville Beach	$49.0	$474.8	$523.8	$493.7
Key West	$45.4	$377.2	$422.6	$404.0
KUA	$123.8	$1,061.6	$1,185.4	$1,155.6
Lake Worth Beach	$0.0	$47.4	$47.4	$49.8
Leesburg	$38.4	$298.8	$337.2	$319.2
Newberry	$3.6	$29.4	$32.9	$30.2
Ocala	$103.3	$886.7	$990.0	$943.4
Starke	$4.2	$34.0	$38.8	$21.1

Estimated Withdrawal Costs Higher than 2022 Estimates

- 11 of 14 participants had higher estimated total Section 29 withdrawal payments from 2022 estimates
  - Average was 5% increase
  - Fort Meade, Green Cove Springs, and Lake Worth Beach were only 3 Participants w/ decrease
- Less ARP debt outstanding reduced average Section 29(c)1 costs 36% from 2022 estimates
  - All participants had reduced 29(c)1 estimate from 2022 (Lake Worth is $0)
  - Estimate does not include anticipated debt to finance capital additions (2025) or refinance plant acquisition costs (2026); costs assumed to be paid through rates for this analysis
- Only Lake Worth Beach had lower estimated Section 29(c)2 costs than 2022 estimates
- Starke had highest Section 29(c)2 percent cost increase due to revocation of Section 2 withdrawal notice
- Large driver of higher Section 29(c)2 costs was addition of Sand Lake, Mulberry, and Orange plants

Debt Portion of Section 29 Estimates Declining Over Time

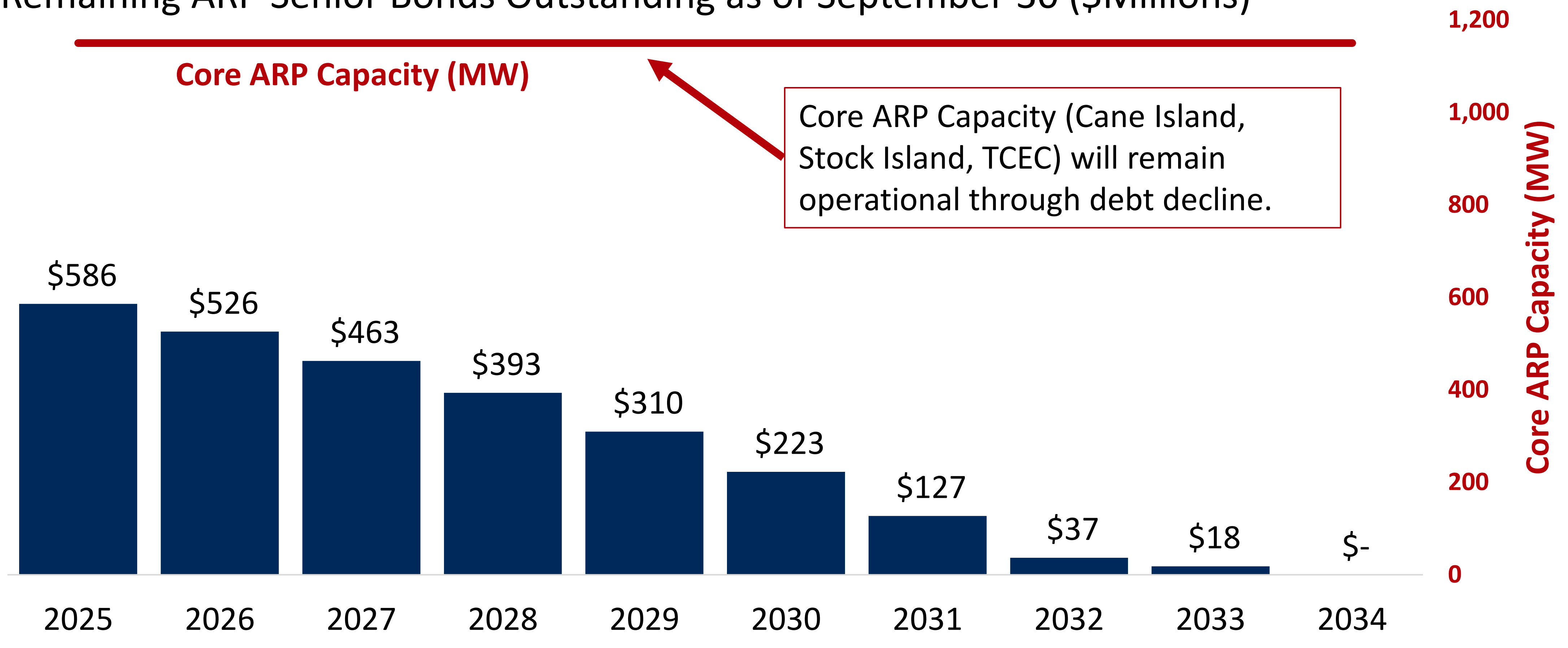
Total Biennial Section 29(c)1 Estimates ($Millions)



94% of Current Senior Debt Paid Off After FY 2031

Core ARP Generating Resources Useful Lives Well Beyond Debt Payoff

Remaining ARP Senior Bonds Outstanding as of September 30 ($Millions)



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Supplemental Information

Contract Requirements for Section 29(c)1. Payment (Bonds)

The amount necessary to call (including payment of any required call premiums and interest to the call date or dates), on the first permissible call date or dates, a percentage of FMPA's then outstanding Bonds (other than Bonds issued to finance additions to the System which FMPA committed to after the receipt of the Project Participant's withdrawal notice) equal to the greater of the Project Participant's share of the All-Requirements Power Supply Project's total electric load on the date of receipt of the withdrawal notice or such share on the withdrawal date. Such amount shall be calculated on the assumption that the Bonds to be called will be the applicable percentage of each series of such Bonds and of each maturity within each such series.

Contract Requirements for Section 29(c)2. Payment ("Stranded Costs")

An amount equal to the present value on the Withdrawal Date, calculated at the rate of 6% per annum, of all of the additional costs reasonably paid or incurred, reasonably anticipated to be paid or incurred, or reasonably projected to be incurred by FMPA (as determined by FMPA in its sole discretion) as a result of the withdrawal of the Project Participant, over the term specified in such Project Participant's All-Requirements Power Supply Project Contract (as determined on the anticipated withdrawal date). Such costs shall be determined on the assumption that, during the remaining term of such Project Participant's All-Requirements Power Supply Project Contract, FMPA was unable to make use of or sell any generating, transmission or other resources (or portions thereof) which FMPA had anticipated would be used to supply, or had acquired with the intention of supplying, all or any portion of the withdrawing Project Participant's electric load.

“Stranded Cost” Cost Categories

- Generating Resource O&M Costs
- Generating Resource Capital Additions Costs
- Generating Resource Decommissioning Costs
- Fixed Natural Gas Transportation Costs
- Fixed Point-to-Point Transmission Costs
- Fixed Purchased Power Costs
- Member Project Capacity Costs
- Debt Related Costs (Other than Bonds)
- Direct Charges & Other

“Stranded Cost” Calculation Periods

Participant	Withdrawal Date	Stranded Cost End Date	# of Years
Bushnell	09/30/2027	09/30/2058	31
Clewiston	09/30/2027	09/30/2058	31
Fort Meade	09/30/2027	09/30/2041*	14
Fort Pierce	09/30/2027	09/30/2058	31
Green Cove Springs	09/30/2027	09/30/2037*	10
Havana	09/30/2027	09/30/2058	31
Jacksonville Beach	09/30/2027	09/30/2058	31
Key West	09/30/2027	09/30/2058	31
KUA	09/30/2027	09/30/2058	31
Lake Worth	09/30/2027	09/30/2058	31
Leesburg	09/30/2027	09/30/2058	31
Newberry	09/30/2027	09/30/2058	31
Ocala	09/30/2027	09/30/2058	31
Starke	09/30/2027	09/30/2058	31

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* Section 2 notice dates: Green Cove Springs - Sep. 2005; Fort Meade - Sep. 2009

AGENDA ITEM 9 – INFORMATION ITEMS

b. ARP Rate/Cash Change Concepts

Executive Committee
October 17, 2024

EC 9b - ARP Rate/Cash Change Concepts

Executive Committee

October 17, 2024

3 Concepts to Discuss

- Removing probabilistic analysis/confidence level adjustment from rate setting process
- Increasing ARP cash target from forward looking 60 days to peak 60 day need
- Managing margin dollars to reduce O&M cash/rate impacts

Removing Probabilistic Analysis/Confidence Level Adjustment from Rate Setting

Current ARP Energy Rate Setting Approach ~20 Yrs Old

- Current energy rate adjustment mechanism established in 2006 to help ARP manage 60-day cash target (working capital)
- Designed to address energy rate volatility ARP was experiencing, ensure ARP had sufficient cash on hand to pay monthly expenses
- Probabilistic model designed to adjust monthly energy rates to help collect or return cash towards 60-day target
- Projected natural gas prices adjusted by confidence level selected based on current days cash on hand, using a probabilistic model
- Over/under recoveries designed to be returned to/collected from Participants over 4-month period

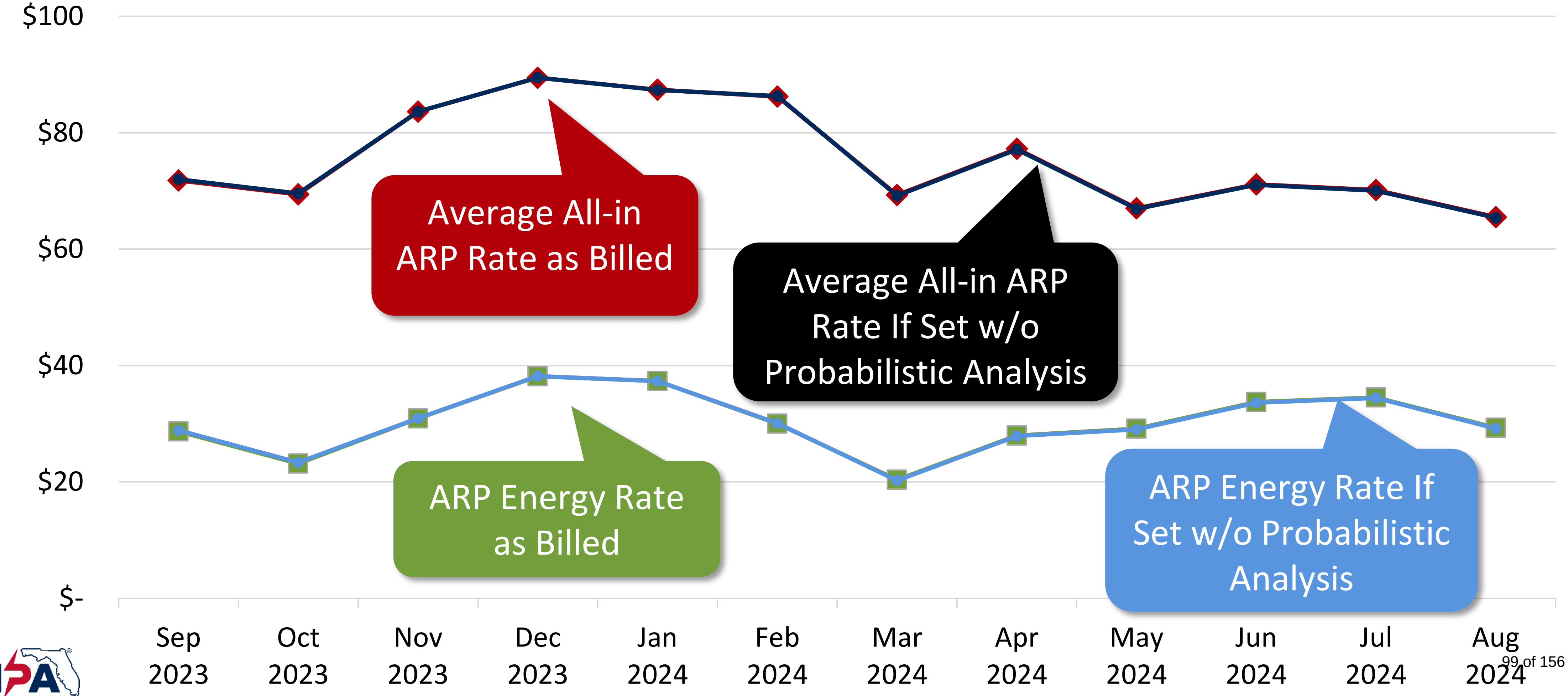
ARP Price Stability Limits Usefulness of Probabilistic Analysis

- Natural gas price stability program significantly reduces ARP exposure to natural gas price volatility, provides greater cost certainty
- At time of rate setting, gas costs for billing month are known, much of following month's gas needs locked down
- That means probabilistic model has limited room to adjust projected 60-day cash need
  - Confidence level adjustments have little to no impact on billing month rate setting
- Currently, adjusting confidence levels only serves to increase volatility in monthly rate projections beyond billing month
- Re-ran monthly rate setting process for Sep. 2023 – Aug. 2024 to test impact of removing probabilistic analysis, compared to actual rates

Probabilistic Analysis Has Almost No Rate Impact

Financial Risk to ARP Not Increased by Eliminating

Historical ARP Rates With and Without Probabilistic Analysis ($/MWh)



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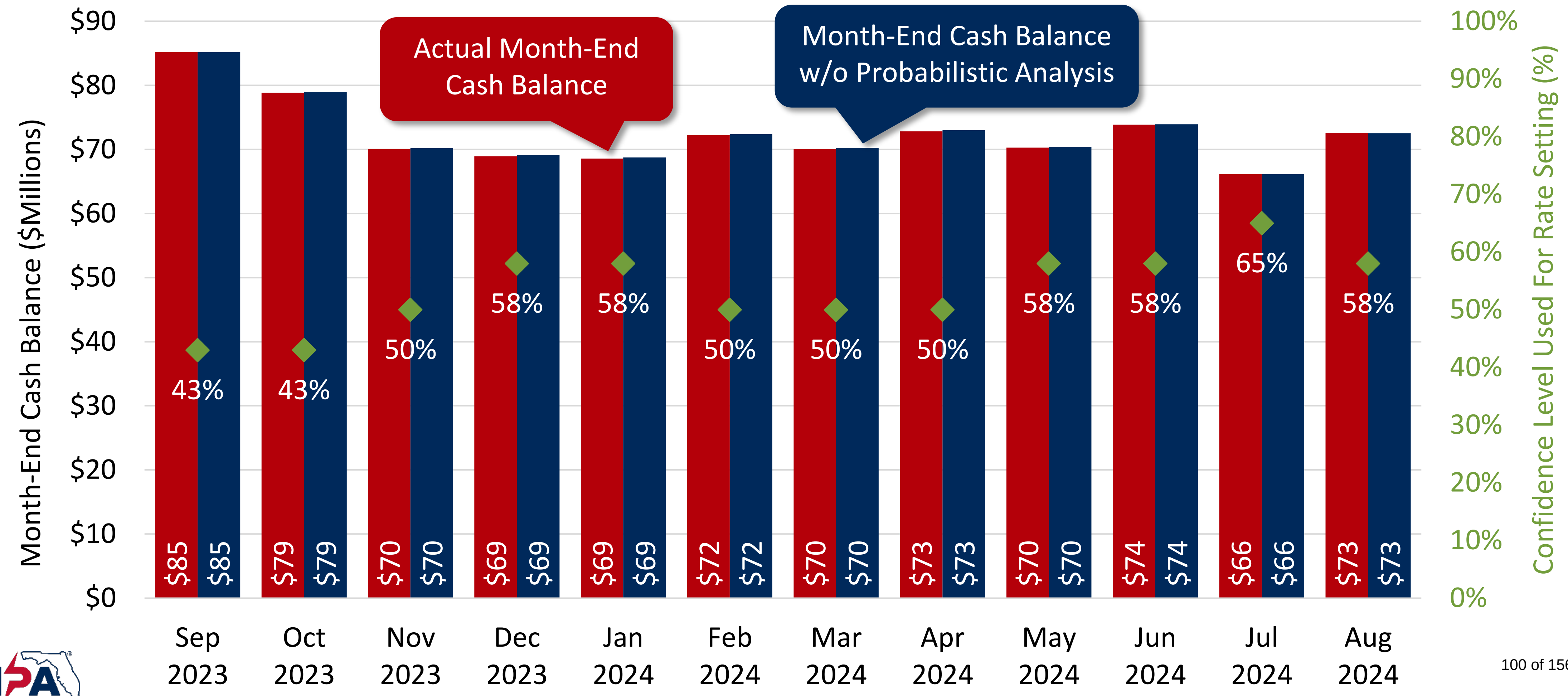
Confidence Level Has Negligible Impact on Cash

Confidence Level Adjustment to Change Cash Collection - Adjusting Gas Price Forecast

Month-End ARP Cash Balances With and Without Probabilistic Analysis ($Millions)



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Benefits of Eliminating Probabilistic Adjustments

- Greatly simplifies rate calculation with negligible impact to rates and cash
- Increases understandability of the rate setting process
- Makes calculation easier to review, and increases ability to explain changes from prior months' projections
- Reduces short-term volatility in rate projections

Changing ARP Cash Target

Should ARP Increase 60-Day Cash Target?

- ARP working capital policy is to have enough cash on hand to cover next 60 days of expenses
- Monthly ARP energy rate adjusted to bring cash position to 60-day target, but adjustment is spread over a 4-month period, which can cause challenges
  - 4-month recovery was intended to prevent rate shock vs. shorter recovery period, but can cause cash challenges during periods of rapid cost increases
  - For summer 2022 – spring 2023, bond proceeds used to supplement available cash for rate setting
  - During highest cash need months (summer), cash lags 60-day need
- From time to time, members have suggested the ARP target a higher cash position (e.g., 90 days)
- Moving to a 90-days cash target would not lead to ratings upgrade; rating agencies want much higher cash reserves

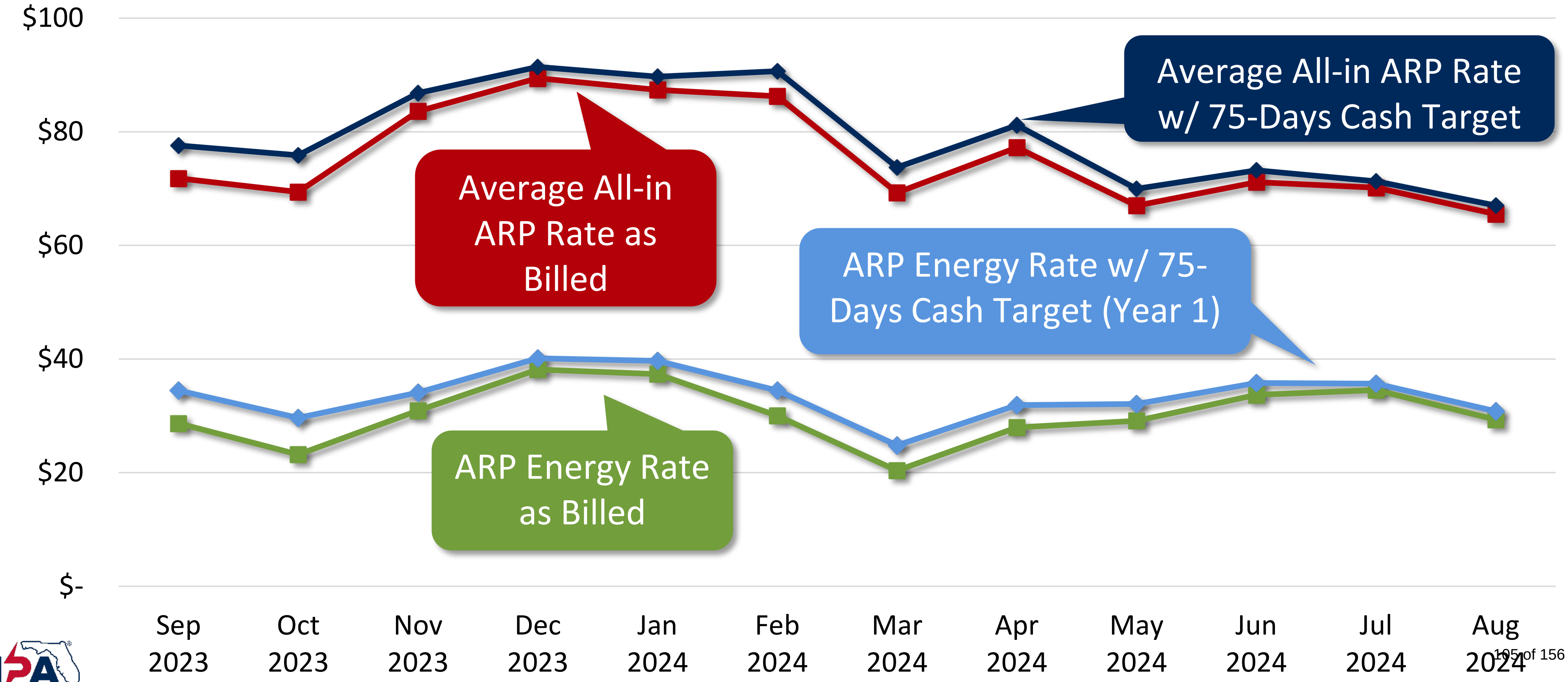
Two Scenarios Considered for Increasing ARP Working Capital

- Modeled moving ARP towards 90-days cash target using same test period (Sep. 2023 – Aug. 2024)
  - Building an additional 30 days cash would require more than 1 year to limit rate shock
  - Assumed 2-stage process w/ phased in targets: moving from 60 days to 75 days in year 1, then move to 90 days in year 2
- Also modeled an alternative approach - targeting highest 60-day cash need over rolling 12-month period
  - Would provide additional liquidity support to meet ARP cash needs while still tied to a 60-day cash need

Rates ~$3.20/MWh Higher for 90-Days Cash Case (Y1)

Analysis Assumed Step Move to 75 Days for 1st Year (Reflected Below), with Step Move to 90 Days in 2nd Year

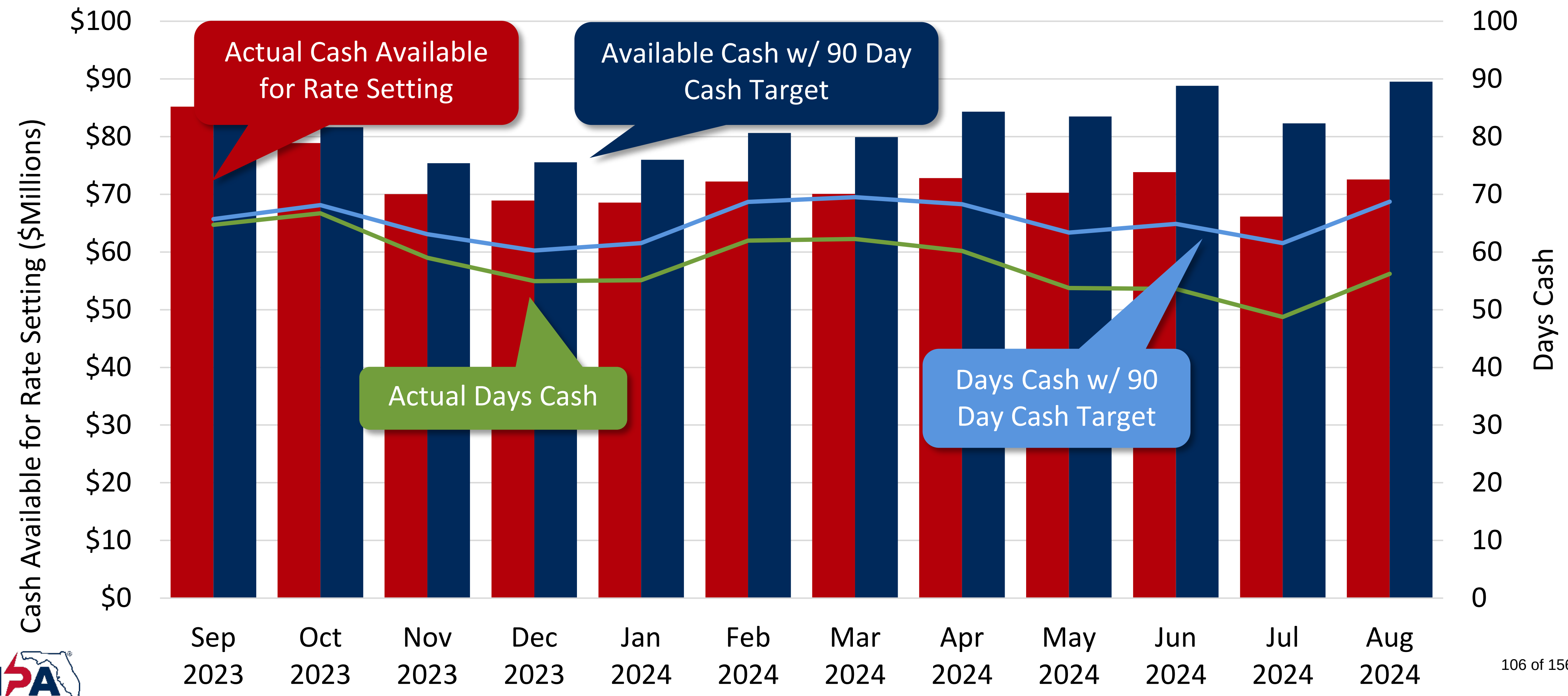
Rate Impact of Moving to 90-Days Cash Target (Initial Year w/ 75-Day Target Shown) ($/MWh)



Reaching 90-Day Cash Target Requires > 1 Year

2-Yr Phase-In Reduces Rate Impact; Additional Year Would Need to Be Included to Evaluate Total Cost of Reaching 90-Day Target

Cash Impact of Moving to 90 Day Cash Target (Initial Year w/ 75-Day Target Shown) ($Millions)



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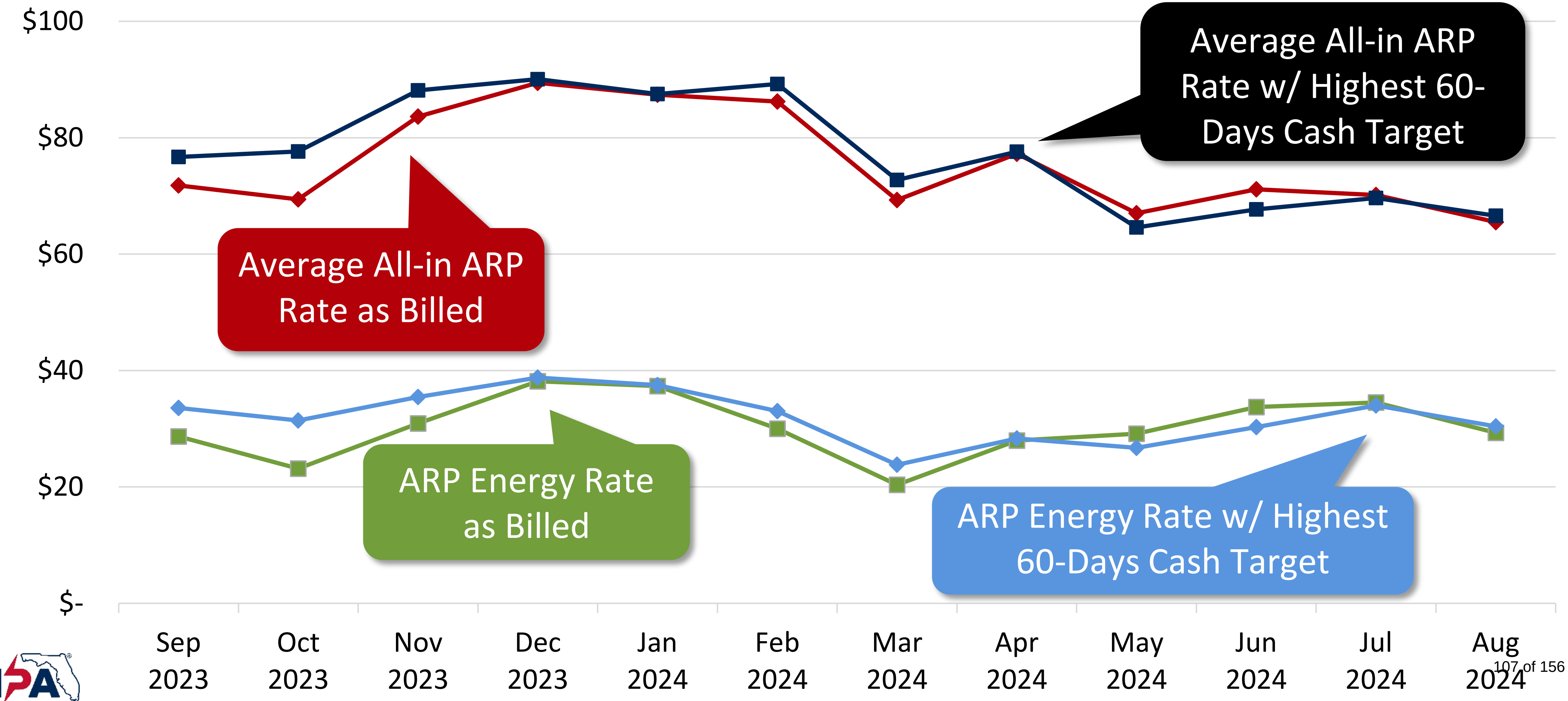
Rates Up ~$1.60/MWh for Highest 60-Days Cash Case

After Initial 3 Month, Rates within ± $3.50/MWh vs. Actual Rates

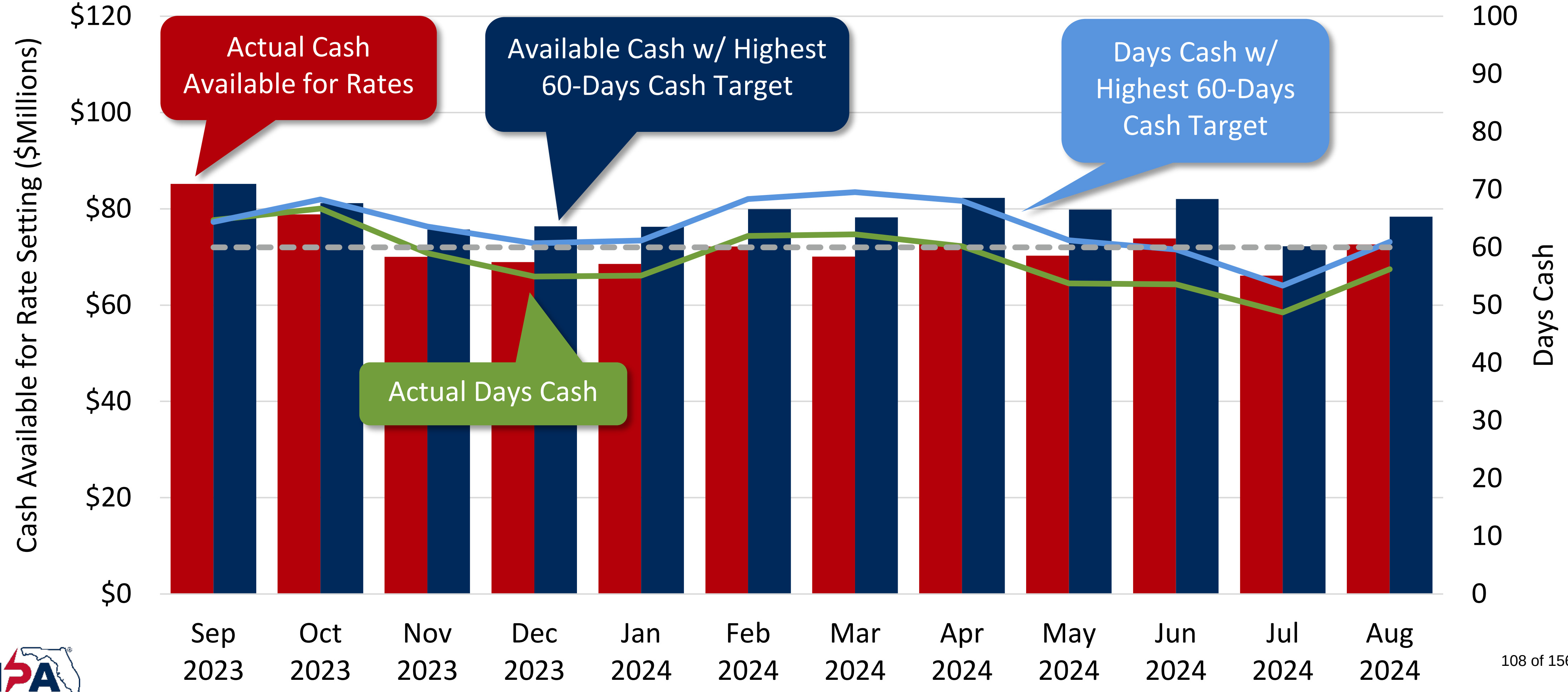
Rate Impact of Moving to Highest 60-Days Cash Target ($/MWh)



Highest 60-Days Target Provides Additional Cash

11 Months Had ≥ 60 Days Cash vs. 5 Months Under Actuals; Only Month Under 60 Days Was Due to Large Margin Posting in July 2024

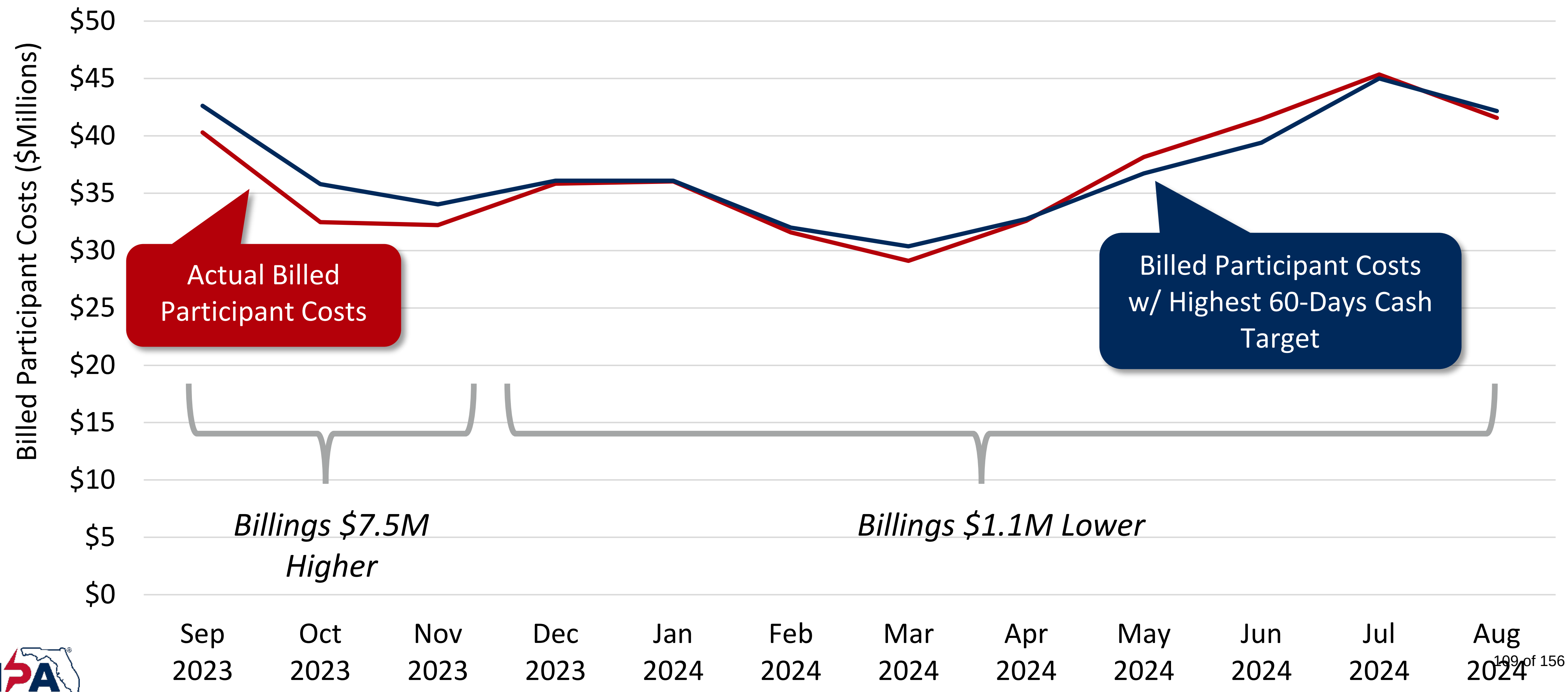
Cash Impact of Moving to Highest 60-Days Cash Target ($Millions)



Billings Up $6.4M (1.5%) for Highest 60-Days Cash Case

Billings $7.5M Higher - First 3 Months, but $1.1M Lower - Next 9 Months

Impact on Total Billed Participant Costs from Moving to Highest 60-Days Cash Target ($Millions)



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Managing Margin Dollars

Funding Margins Using O&M Dollars Causes Rate Volatility

- Currently, all margin calls for natural gas price stability program are funded through O&M account, with returned margins also going to O&M account
- Margins are essentially unrealized gains or losses on future positions based on gas curve at a given point in time
- Changes in natural gas curve mean future gas prices impact current rate setting
  - Margins posted from O&M account reduce cash balance available for rate setting, so rates increased to recover those costs
  - Runs counter to concept of price stability
- Extreme example: In July, falling gas prices led to $8M posted during month, had $3.50/MWh upward impact on July rate

Creating a Margin Account May be Desirable

- Would be an account held by FMPA, utilized to manage margin calls and returns without impacting current rates
- Any margins (other than initial margins) returned to ARP would be deposited into this account
- Future margin calls would pull first from this account and only be funded from O&M if the account balance reaches $0
- Account balance would not be included in cash used for rate setting
- Account balance would be reported to EC as part of monthly rate call to maintain transparency

Timeline

- Removing Probabilistic Analysis – Seeking EC action in November
- Creating Separate Margin Account – Could be done later this CY
- Changing ARP Cash Target – Start discussion early CY 2025; would likely look to hold implementation of changes until next fall

Supplemental Slides: Rate Schedule Revisions to Remove Probabilistic Modeling

2 Sections of Rate Schedule B-1 Would Require Revisions

- Section 9: Energy Cost Adjustment for All-Requirements Services
- Section 12: Transmission Cost Adjustment for All-Requirements Services (References adjustment process in Section 9)

Revised Energy Cost Adjustment (Section 9)

9. **Energy Cost Adjustment for All-Requirements Services.**

The monthly bill computed hereunder shall adjust the base energy rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

ER = [redacted]/kWh ±ETCA

Where:

ER = Energy Rate to be applied to each kWh of billed energy.

ETCA = Energy Total Cost Adjustment to be determined according to the following procedure:

1. *Energy rate adjustment:* The total projected energy costs for the current billing month, including the cost of energy and physical natural gas sold to other utilities, net of any energy revenues projected to be collected from sources other than the Energy Rate, will be computed and then divided by the total kWh energy sales for providing the All-Requirements Project power supply the current billing month. This $/kWh rate, less the base energy rate, will become an adder (if positive) or reduction (if negative) to the base energy rate.

2. *Cash adjustment to energy rate:* The total projected expenses for the All-Requirements Project for the current billing month and subsequent month, including the cost of sales to other utilities, net of any revenues projected to be collected from sources other than Project Participant rates, will be computed to determine the estimated 60-day cash need for the All-Requirements Project. This net 60-day cash need will be compared to the current cash balance for the All-Requirements Project to determine the current amount of cash above or below the cash need. Cash amounts greater or less than the projected 60-day cash need will be modeled to be returned to or collected from Project Participants, respectively, over the current and subsequent three billing months based on projected total kWh sales for providing the All-Requirements Project power supply over that same period. The resulting $/kWh rate will be added to the sum of the base energy rate and the energy rate adjustment.

Revised Transmission Cost Adjustment (Section 12)

12. **Transmission Cost Adjustment for All-Requirements Services.**
The monthly bill computed hereunder shall adjust the base demand transmission capacity rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

TR = Transmission per kW/month $\pm$TTCA

Where:
TR = Demand Transmission Rate to be applied to each kW of billed transmission demand.

TTCA = Transmission Total Cost Adjustment to be determined based on the current All-Requirements Project over-recovery or under-recovery balance for transmission expenses as listed in the All-Requirements Project Comparative Statement of Net Asset report. This balance will be applied over the current and subsequent three billing months based on projected total kW transmission sales (excluding Kissimmee Utility Authority) for providing the All-Requirements Project power supply.

Note: this adjustment is applied to the transmission rate paid by all Project Participants except for KUA, which pays a separate transmission charge.

AGENDA ITEM 9 – INFORMATION ITEMS

c. Energy Intensive Loads and ARP Incentive Rates

Executive Committee
October 17, 2024

9c – Energy Intensive Loads and ARP Incentive Rates

Executive Committee

October 17, 2024

Cloud Computing and Generative AI Load Growing

Load Looking For Cheapest Power, Largest Incentives Possible

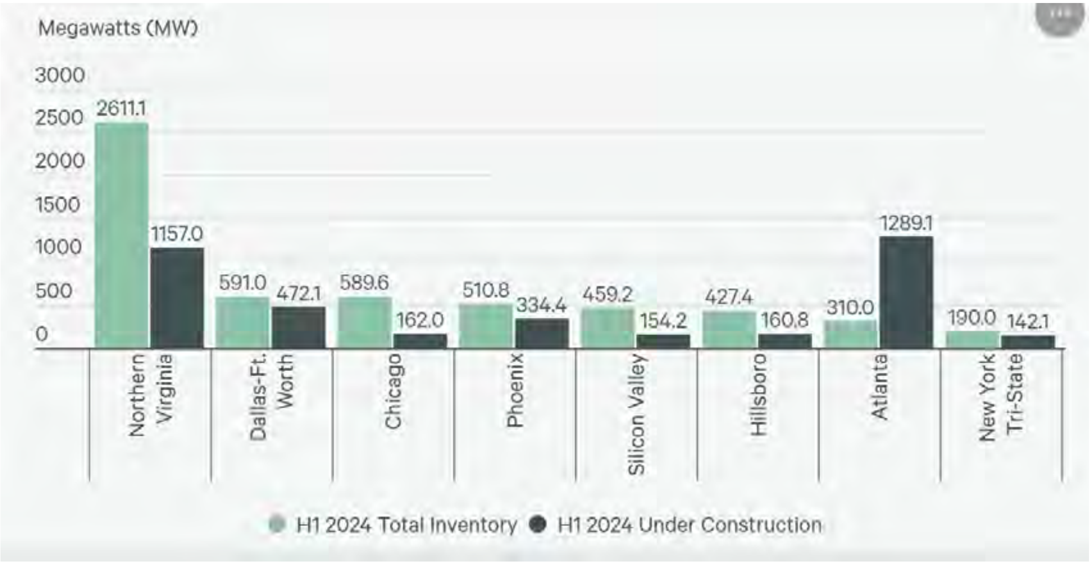
- ~3.8 GW of primary construction in first half of 2024 in US estimated to support new generative AI and cloud computing load
  - Someone else’s computer
  - Ingest/synthesize data to enhance searching insights, language models, picture/film/script generation, medical record review/diagnostics, automated data science, development of draft legal briefs/contracts for Dan O’Hagan, etc.
- Key current challenges – shortage of available power and lead times for electrical/power delivery infrastructure
- Scientific American estimates ~1.5% of global energy use for AI in 2023, recognizing the art in designating electrons as “AI” vs. all else

*SOURCES: https://www.scientificamerican.com/article/what-do-googles-ai-answers-cost-the-environment/; https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2024

Thus Far, Key Primary and Secondary Markets Emerge

FRCC Entities Not Placing Large Centers in Load Forecasts Yet

Primary Markets Inventory and Under Construction
First Half of 2024 (MW)



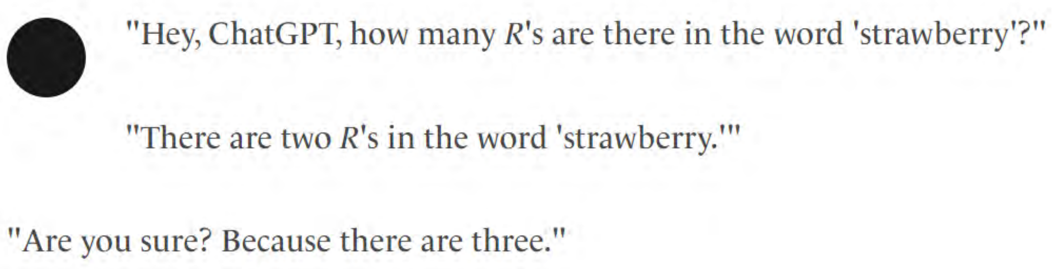
Secondary Markets Inventory and Under Construction
First Half of 2024 (MW)

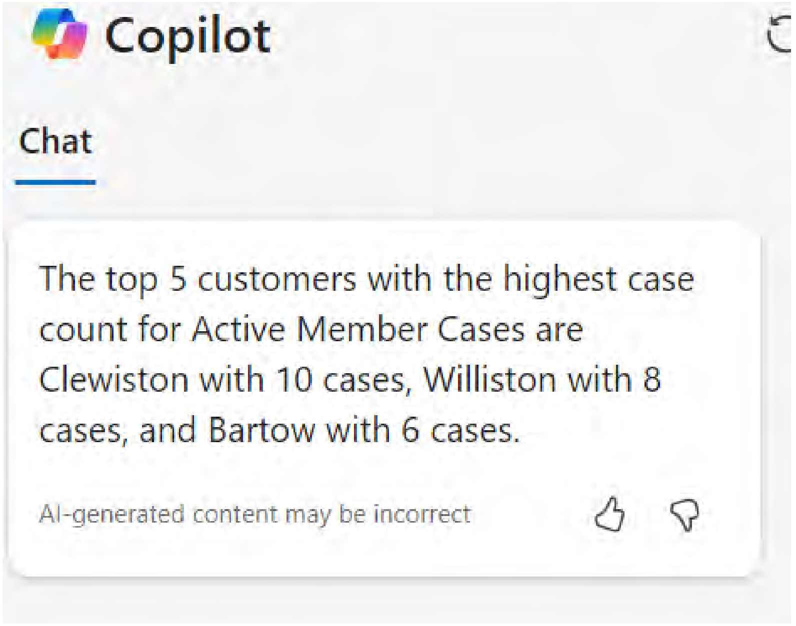
*SOURCE: https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2024

Energy Usage High But Likely To Evolve Over Time

Technology Enhancements + Desire for Carbon Free MWh Key

- AI research firm Hugging Face suggests higher-insight text generation ~30x more energy intensive than traditional Googling
  - Cooling AI servers takes energy
- Two AI generated images about the same as charging an iPhone
- High variability and uncertainty based on tasks – hardware, engineering breakthroughs could lower intensity
- Costs of AI search reported to be down 80% since incubator stages per Google
- Large companies prefer carbon free MWh





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*SOURCE: https://www.scientificamerican.com/article/what-do-googles-ai-answers-cost-the-environment/

Municipal Offering To Load Full of Complex Issues
Stranded Cost Risk and Equitable Rate Design Important

- Capacity and energy – how much and when?
  - If long, can leverage for value; if short, significant capital & energy risk
  - Credit risk already raised as issue by Moody's and Fitch*
  - Timing of need mismatch between renewables & 90% load factor demand
- Power delivery infrastructure – transmission and distribution expansion and associated cost allocation should be equitable to avoid stranded cost risk
  - Regulatory implications of transmission expansion or other concessions may need to be addressed
- Timing and lag in supply chain and resources – load follows provider timing, not vise versa
- Equitable retail rate design to avoid higher costs/risks for others
  - Some entities suggesting concepts such as 90% energy pre-pay for 10 yrs*
- Proper alignment on value proposition – utility rates and operating margin versus tax revenue or other community benefits, such as economic development and system efficiency gains

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*SOURCE: S&P Global Market Intelligence. 90% energy pre-pay based on AEP-Ohio filed proposal.

ARP Incentive Rates

ARP Incentive Rates Sunsetting

- Load Attraction Incentive Rate (LAIR) and Economic Development Rate (EDR) riders approved in 2017 set to end December 2024
- Incentive riders designed to help Participants attract large, new loads to their service areas by providing discount to ARP demand rate
- Put in place when ARP had significant excess capacity
- Growing native load with discounted demand rate provided greater return than selling capacity to others
- Used for Bushnell’s system expansion (LAIR); discount ends 9/30/24
- ARP length declining, reducing need to incentivize load growth

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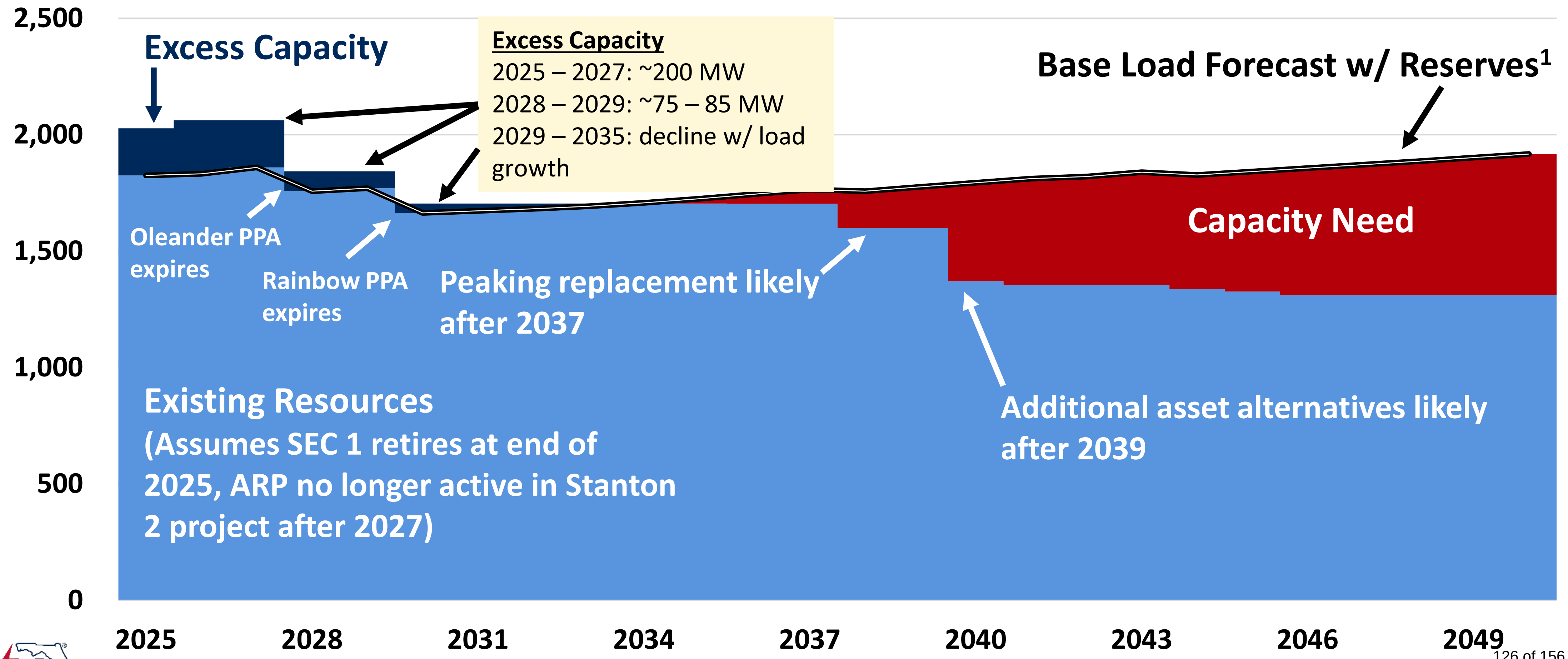
ARP Excess Capacity Through ~2035 At Base Reserves

More Gradual PV Adds Can Moderate Reserve Hold to Support

FMPA 2024 Load and Resource Balance (18%-20% Reserves) (MW)



1 – Reserves: 18% for 2025 – 2026, 20% for 2027 and beyond.

Load Attraction Incentive Rate Key Facts

- Provides 50% discount on ARP base demand for new loads for 1st year
  - Discount decreases by 10% each year, thereafter, through 5th year
  - After 5th year, the new load is charged the full ARP demand rate
- Minimum size requirements apply for new loads to qualify
  - Participants > 35 MW: 500 kW at single delivery point or 1 MW for new service territory
  - Participants < 35 MW: 250 kW at single delivery point or 1 MW for new service territory
- No discounts to the ARP energy or transmission rates
- Load receiving the discount must be separately metered
- Availability limited to first 30 MW of load to begin service under any ARP incentive rate rider

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Economic Development Rate Key Facts

- Reduced demand charge for new load, negotiated on a case-by-case basis
- Energy charge tied to heat rate X natural gas prices + VOM adder
- The new load must be a minimum of 5 MW/month and energy-intensive
- Electricity price must be a significant determining factor in the site selection decision of the new or expanded business
- Participant must pass the EDR demand rate and energy rates directly to the new customer with no adders
  - Participant must discount its own distribution, metering, and customer charges through a fixed adder to the EDR demand rate
- Each use of the EDR must be approved by the EC

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Backup Slides

Resources & Load w/ 18 – 20% Reserve Margin (MW)

Year	Resources	Load w/ 18-20% Reserve	Excess Generation	Generation Need	Year	Resources	Load w/ 18-20% Reserve	Excess Generation	Generation Need
2025	2,027	1,825	202	0	2038	1,599	1,757	0	158
2026	2,062	1,832	230	0	2039	1,599	1,776	0	177
2027	2,062	1,860	202	0	2040	1,371	1,793	0	422
2028	1,843	1,757	85	0	2041	1,356	1,812	0	456
2029	1,843	1,770	73	0	2042	1,355	1,820	0	464
2030	1,705	1,664	41	0	2043	1,355	1,838	0	483
2031	1,705	1,673	32	0	2044	1,337	1,827	0	490
2032	1,704	1,682	23	0	2045	1,327	1,841	0	515
2033	1,704	1,692	12	0	2046	1,310	1,856	0	546
2034	1,704	1,707	0	3	2047	1,310	1,871	0	561
2035	1,704	1,725	0	21	2048	1,310	1,886	0	576
2036	1,704	1,745	0	41	2049	1,310	1,902	0	591
2037	1,703	1,764	0	60	2050	1,310	1,917	0	607

Resources & Load w/ 15% Reserve Margin (MW)

Year	Resources	Load w/ 15% Reserve	Excess Generation	Generation Need	Year	Resources	Load w/ 15% Reserve	Excess Generation	Generation Need
2025	2,027	1,779	248	0	2038	1,599	1,684	0	84
2026	2,062	1,785	277	0	2039	1,599	1,702	0	103
2027	2,062	1,782	280	0	2040	1,371	1,719	0	348
2028	1,843	1,684	158	0	2041	1,356	1,736	0	381
2029	1,843	1,696	147	0	2042	1,355	1,744	0	389
2030	1,705	1,595	110	0	2043	1,355	1,762	0	407
2031	1,705	1,603	102	0	2044	1,337	1,751	0	414
2032	1,704	1,612	93	0	2045	1,327	1,765	0	438
2033	1,704	1,622	83	0	2046	1,310	1,779	0	469
2034	1,704	1,636	68	0	2047	1,310	1,793	0	483
2035	1,704	1,653	51	0	2048	1,310	1,808	0	498
2036	1,704	1,672	32	0	2049	1,310	1,822	0	512
2037	1,703	1,690	13	0	2050	1,310	1,837	0	527

AGENDA ITEM 9 – INFORMATION ITEMS

d. Stock Island Operational Overview

Executive Committee
October 17, 2024

9d – Stock Island Operational Overview

Executive Committee

October 17, 2024

Load Growth & Asset Age Drive Review of SI Generation

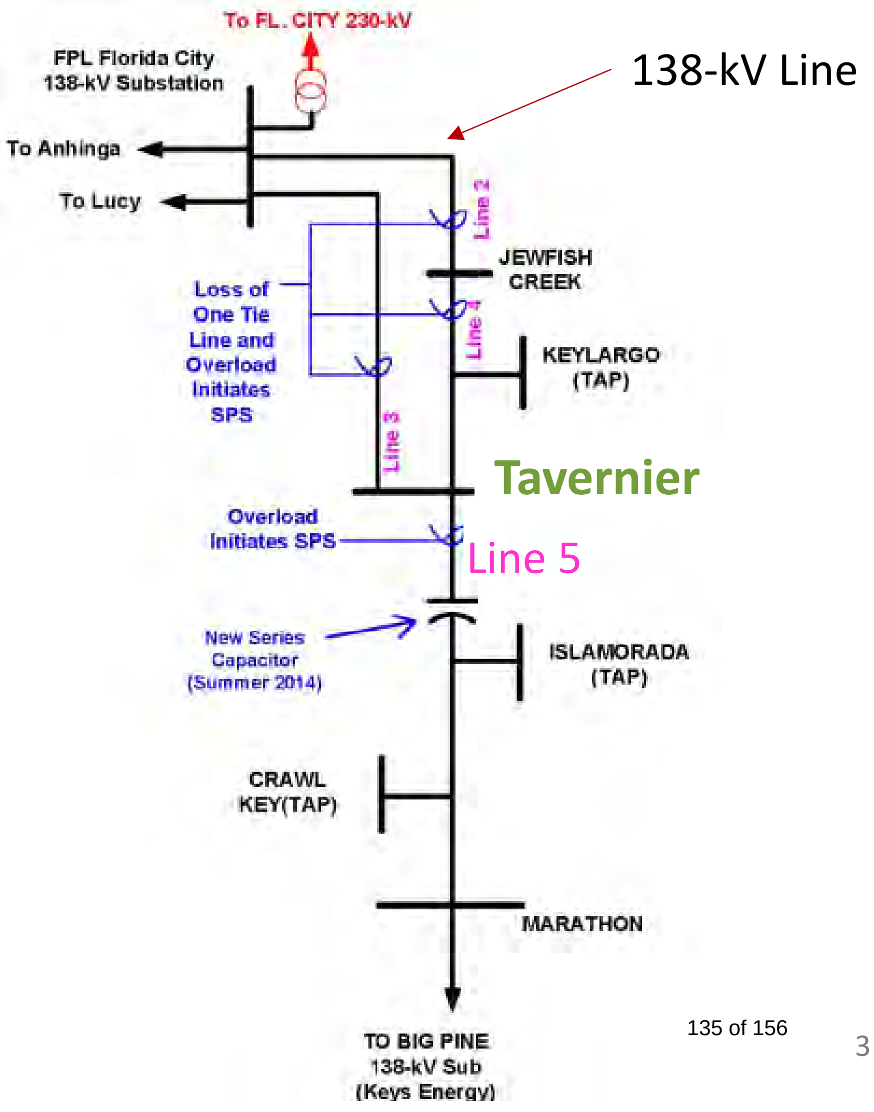
Potential Need for Realignment of Resource Strategy by Early 2030s

- Greater risk of load growth in Keys impacts need to operate generation
- Tie line and FMPP support runs continue to increase and outpace forecasts
- Prudent tie line investments "maxed out"
- New transmission line or reconductoring cost prohibitive
- CTs 1-3 will require major outages (turbine and generator) in next 20 years
- Primary goal in assessing assets is long-term, cost-effective reliability
- Comprehensive analysis focused on existing & other generation alternatives
- FMPA & Keys Energy grant application for battery storage still pending

Keys Energy Primarily Served with Imported Energy

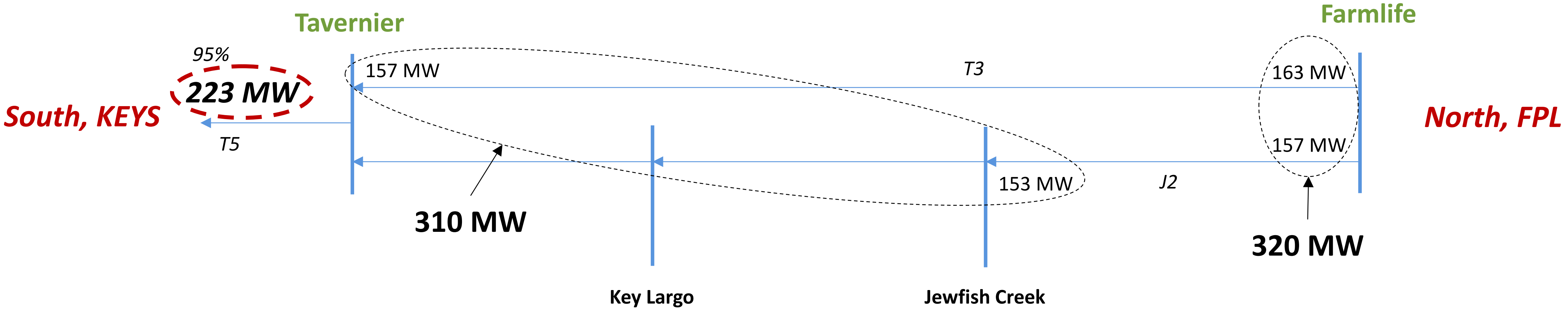
KEYS and Keys Cooperative Share 138-kV Line Capacity

- Keys Energy (KEYS) is principally served with ARP Generation utilizing FPL network transmission
- KEYS and Florida Keys Electric Cooperative (FKEC) utilize their jointly owned 138-kV tie line connection to the FPL Florida City Substation to supply their systems
- The tie line capacity entitlement is split:
  - KEYS = 40%
  - FKEC = 60%
- Since construction, multiple enhancements including STATCOM and capacitors have been made to increase voltage support and overall tie-line capabilities



2022 Study Results Limit N-0 Import to 320 MW

Thermal Loading of Line 5 Drives ~223 MW Limit at Tavernier



- Today, KEYS borrows FKEC tie line capacity when load exceeds ownership allocation
- When load exceeds available capacity, Stock Island generation must operate to mitigate loading on the tie line
- Eventually, load growth for KEYS and FKEC are expected to reach a point where units will operate daily for roughly 25-30% of year

Line 5 Limit: 223 MW @ 95% Thermal Loading
~235 MW @ 100% Thermal Loading

- FKEC → 99 MW
- KEYS → 124 MW

2022 Load Forecast (2033 Peak):

- FKEC (ISL, CWL, MAR) → 79 MW (20)
- KEYS → 158 MW (-34)

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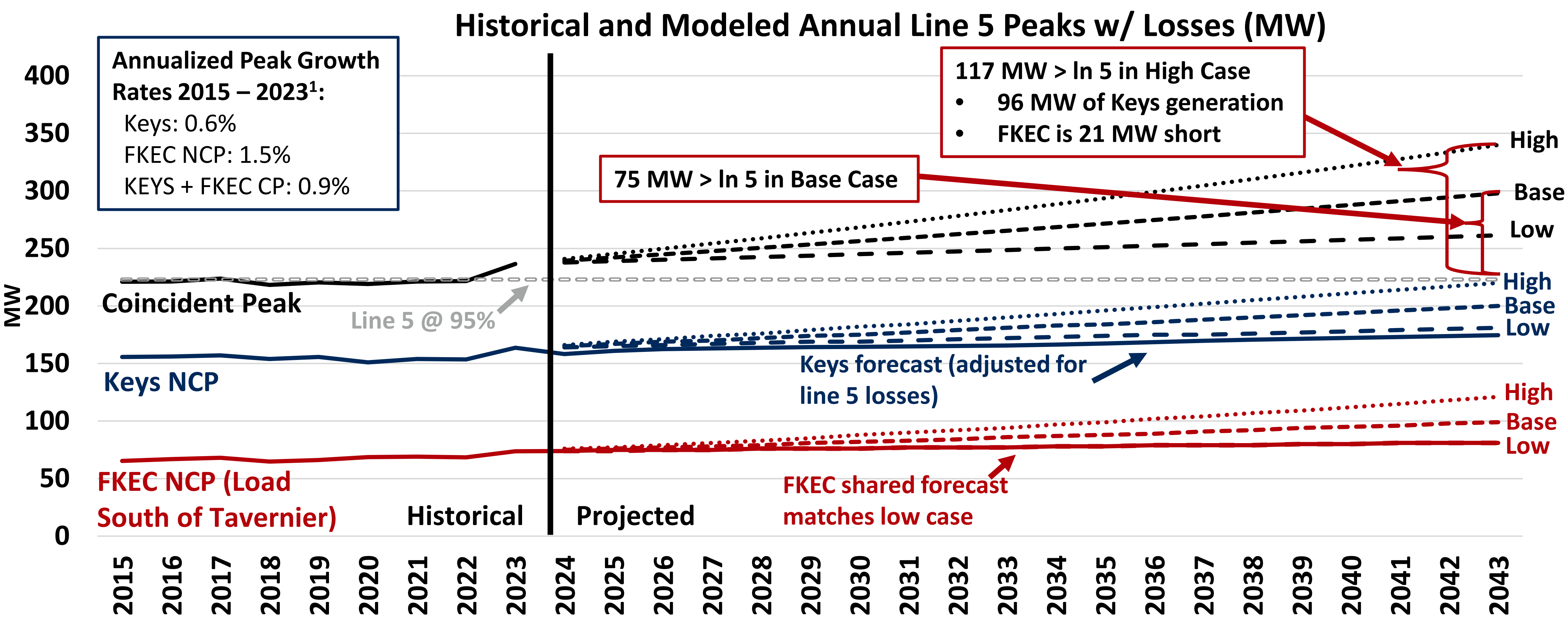
Post Covid Coincident Peak Faster Growth Than Individually

Utilization of SI Generation Dependent on Coincident Peak



1 – Non weather adjusted. 2023 abnormally hot summer significant factor in growth rate since 2015.

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Florida Commerce Opening Up New Building Allocations

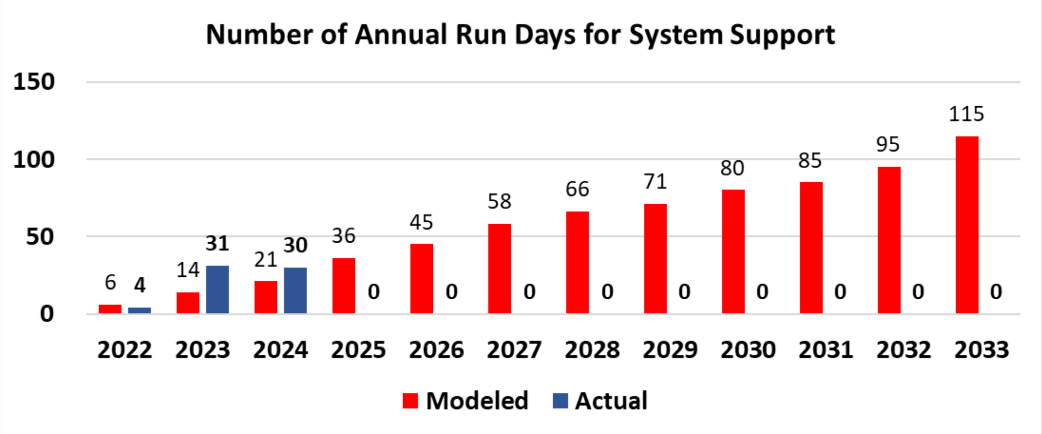
Monroe County Evaluating Potential to Handle New Development

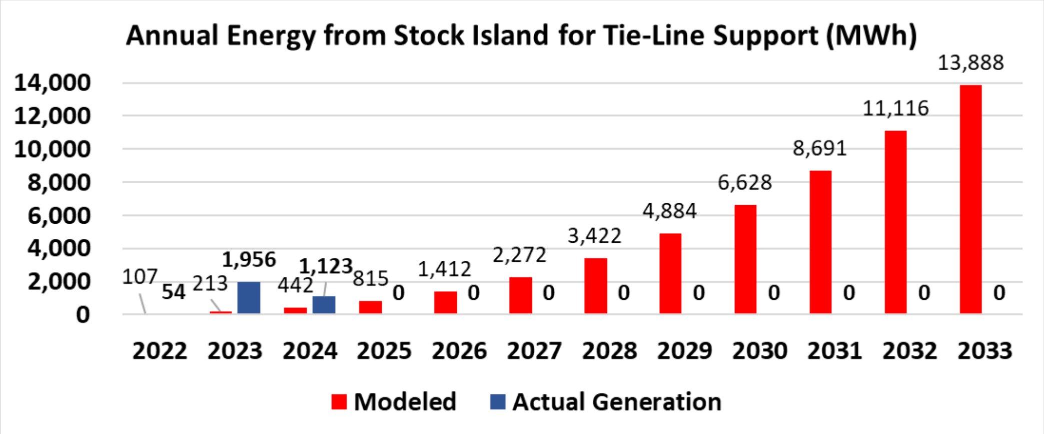
- Florida Commerce, which oversees development in the Keys, proposed giving the Keys as many as 8,000 new building allocations
- The 8,000 roughly represents the number of vacant lots in the Keys
- Local gov't officials estimate that ~3,000 of those units are buildable
- Need has focused on affordable housing
- Hurricane evacuation time and impacts on infrastructure must also be evaluated

Overall Unit Operations Outpacing Expectations

Weather, FMPP and Other Factors Increase Unanticipated Ops

- The Stock Island assets generated 1,123 MWh for tie-line support so far this year under 30 event days
- Units called for operation a total of 44 days, in support of all operation req.
  - Transmission maintenance: 5
  - Forced outages/emergency: 4
  - Reserve calls/FMPP: 2
- Continued warmer, earlier summer patterns will outpace base projections
- Weather-adjustment increasingly difficult due to spread to 10-year averages

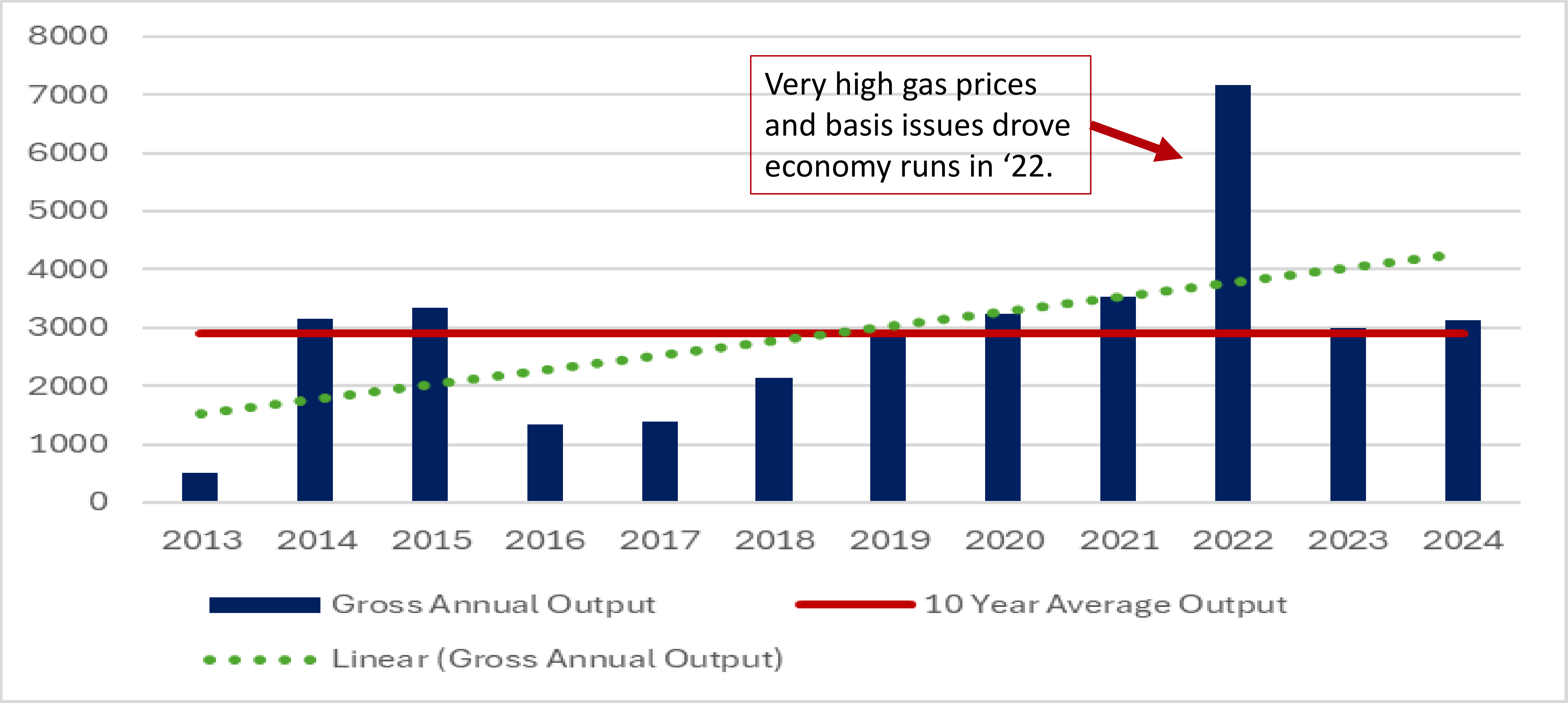




FMPA MUNICIPAL POWER

Historical Operational Need Allowed Some Flexibility

Future Needs Will Require Stronger Reliability and Availability



FMPA MUNICIPAL POWER

Transmission Limits Provide Unique BESS Opportunity

Battery Storage Operation Could Displace High-Cost Diesel

- FMPA conducted battery feasibility study for Stock Island in 2022
- Utilization of batteries would displace running high-cost diesel generation
- Site viable for 15 MW, 60 MWh-type system
- Value of displacement grows with higher load growth
- Initial study concluded that with current battery storage pricing, the project was not stand-alone economically viable
- GRIP grant program provided an opportunity to receive 50% matching Federal grant for this type of project

FMPA & KEYS Jointly Submitted Application for Battery Grant

Concept Paper Accepted for 2nd Round Of Funding in May

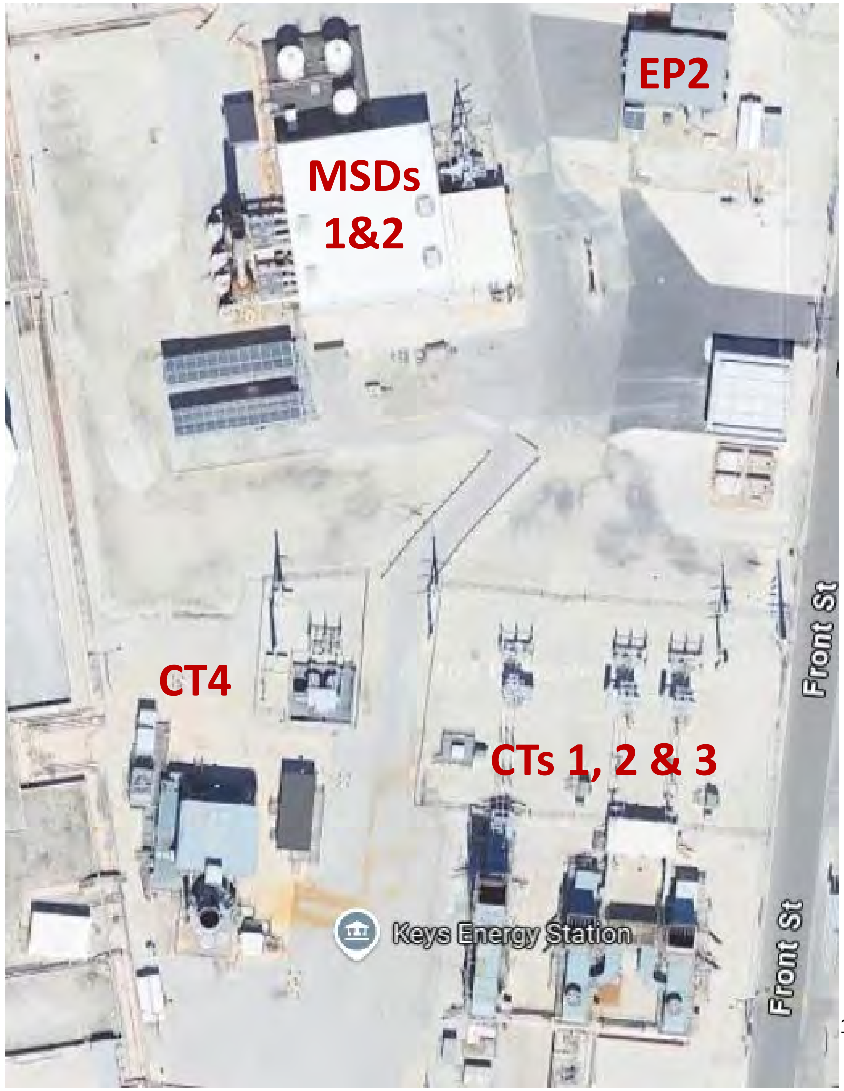
- Pursuing 2nd round GRIP grant funding from $3.9B IRA pool
- Goals - enhance grid flexibility and improve resilience of power system
- Concept paper submitted January 2024 and encouraged to prepare full package by May 2024
- Proposal key elements includes AMI, Battery Energy Storage System (BESS), enlarging two autotransformers, distribution reclosers, and other related technology components
- FMPA supported KEYS with package, focusing on BESS (direct and indirect through emissions reductions) and overall value proposition
- FMPA/Keys opportunity to get 50% cost share for Battery project
- Still awaiting any notification of selection or award of grant

FMPA MUNICIPAL POWER

KEYS Targets Least Cost Minimum 60% On-Island MW

Reliable Power Delivery For Tie line Loss, Reserves, Trans Caps

- The ARP targets 60% of KEYS’ system peak maintained as on-island capacity
- All assets owned by FMPA ARP
- No debt associated with existing assets
- Currently, SI has ~110 MW on-island capacity
- All generation currently on Stock Island fueled with #2 Diesel
- Lowest unit dispatch cost ~$240/MWh



Units Reliable Despite Several Exceeding 50 Year Age

Salt-Water Environment Continuing Challenge to Reliability

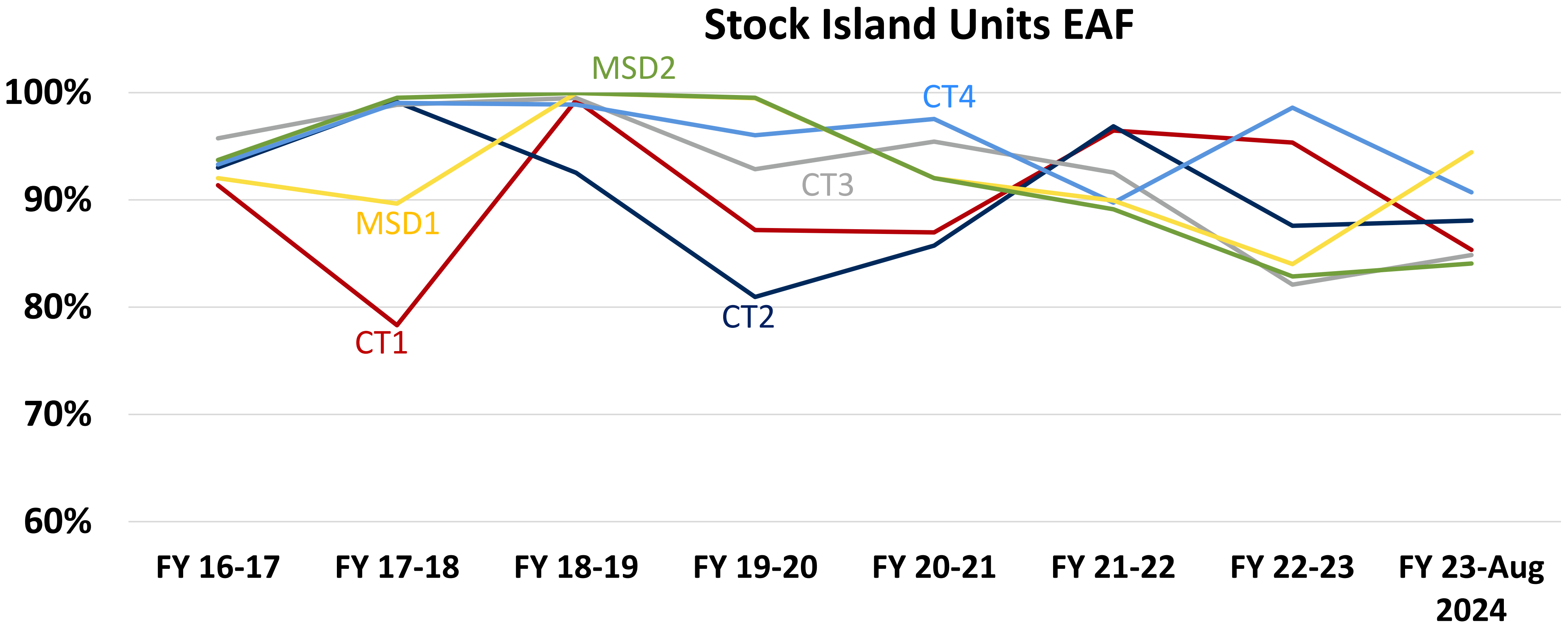
- Target 100% success rate for operation of assets when called to support load or tie-line issues
- Target 92% EAF for Stock Island Assets
  - Winter season: 80%
  - Summer season: 95%
- Site is black start capable
- Average capex spend ~$3M over last 5 years

Unit Name	Max Capacity (MW)	Heat Rate	Unit Desc	Install Year	Vintage Date	Dispatch Cost
EP2	2	10.9	Recip	2010	1968est	$251
MSD 1	8	10.7	Recip	1991	1991	$246
MSD 2	8	10.7	Recip	1991	1991	$246
CT1	17	14.0	Frame 5	1997	1978	$318
CT2	14	15.2	Frame 5	1998	1960s	$345
CT3	14	15.1	Frame 5	1998	1960s	$343
CT4	42	10.4	LM6000	2006	2006	$240
	105					

FMPA MUNICIPAL POWER

Annual EAFs Average >92% Over Last 8 Years

Sustaining Reliability on Aging Units Comes at a Cost



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CTs 1-3 Reliable But Aging & Will Require Investment

Corrosion & Major Maintenance Potential Hurdles vs. Alternatives

- Many structural issues addressed over last 5 years to extend life
- Capital investment will continue to extend life for CTs 1-3
- Next 20 years horizon increased operations will require some form of generator or turbine major outages
- Balance of plant, pumps, motors, transformers also require ongoing maintenance

Is There a More Cost-Effective Alternative?

Staff in Process of Evaluating Other Means to Achieve Goals

- Multiple Alternatives Being Evaluated to Balance Cost & Availability
  - Status quo base case: continued investment in existing units
  - Reconductoring Line 5
  - Other transmission enhancements
  - Battery storage system
  - Solar, distributed PV or demand management downstream of constraints
  - Pre-owned generation asset transfer
  - New build generation
  - Merit order dispatch adjustments

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Solving for Lowest $ Answer to Long-Term Availability Need

Resolution Requires Reliable Energy Supply in Demanding Environment

- ***Capacity modeling*** targets least cost 60% on-island portfolio
  - Life extensions, new builds, and used resource moves all capacity-qualified
- ***Energy modeling for investments*** seeks reductions in NPV cost driven from other types of investments that layer onto or displace a portion of the base portfolio
  - Battery storage, line reconductoring, solar PV downstream of constraint
- ***Cases*** reflect (i) status quo/base for comparison against (ii) range of alternatives
- Additional updates will be provided to the Executive Committee in FY25

FMPA MUNICIPAL POWER

AGENDA ITEM 9 – INFORMATION ITEMS

e. ISDA Agreements for Price Risk Management Program

Executive Committee
October 17, 2024

EC 9d – ISDA Agreements for Price Risk Management Program

Executive Committee

October 17, 2024

What Value Can An International Swaps & Derivatives Association Agreement (ISDA) Bring To ARP?

- **ARP's Price Risk Management Program purchase positions only on NYMEX**
  - NYMEX contract has no credit risk
    - Daily True-up of valuation
  - Settlement based on widely openly traded Henry Hub delivery point
    - Not where FMPA purchases physical gas
- **An ISDA can be structured to mitigate the issues of the NYMEX contract**
  - ISDA: No need for daily True-up of the valuation if within credit limits
    - "Swaps" have counter-party credit risk
  - Settlement can be based on FGT Zone 3 pricing
    - Matches physical gas location

How Does An ISDA Work?

- **Standardized by a 2002 Master Agreement**
  - FMPA developing some modifications to the 2002 Master Agreement, for the benefit of FMPA
    - Using an ISDA helps protect participating in OTC transactions
    - Outlines T&Cs which will govern transactions between the two parties
      - Limited to only natural gas transactions
- **Credit Support Agreement determines collateral and credit**
  - Using ARP's public credit rating to avoid margin posting
  - Posting will earn interest vs no interest on NYMEX postings

Using Expert Team To Craft Best Agreement For ARP

FMPA Already Has Relationships with Experts

- Staff working with Nixon Peabody and PFM to lead development of Master Agreement and Credit Support
  - Nixon and PFM have multiple clients who use ISDAs and are knowledgeable of what works and with whom.
- Goal to have 2 to 4 ISDA Agreements with highly credit worthy counterparties

Next Steps

- Bring back the Master Agreement and Credit Support for approval in substantial form.
    - Work with PFM negotiating with counterparties the terms of two agreements
- New Price Risk Management Program purchases under ISDA Agreements

AGENDA ITEM 10 – MEMBER COMMENTS

Executive Committee
October 17, 2024

AGENDA ITEM 11 – ADJOURNMENT

Executive Committee
October 17, 2024